Mid-term Adequacy Forecast Appendix 2

METHODOLOGY

2019 EDITION





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Glossary

Definitions

Base-Case Scenario – A scenario considering projected demand and supply forecasts, including best estimates on likelihood of retirement, mothballing, new-build of generation assets and measures to reach energy efficiency, and considering the state of the grid in line with the Ten-Year Network Development Plan and most recent national development plans.

Energy Not Served (ENS) [MWh] – Energy Not Served is defined as the unsupplied energy during a single Monte Carlo year due to the demand exceeding the available generating capacity and the electricity that can be imported into a market node.

Capacity Mechanism (CM) – An administrative measure used to ensure the achievement of the desired level of security of supply by remunerating resources for their availability and not including measures relating to ancillary services.

Demand-Side Response (DSR) – The change in electricity load on the part of final customers from their normal or current consumption patterns in response to market signals, including time-variable electricity prices or incentive payments, or in response to the acceptance of the final customer's bid, alone or in aggregate.

Expected Energy Not Served (EENS) [MWh] – The mathematical average of the annual demand that is not served from market-based resources over the total number of Monte Carlo sample years. The annual Energy Not Served is defined as the unsupplied energy during a single Monte Carlo year due to the demand exceeding the available generating capacity and the electricity that can be imported into a market node.

Explicitly modelled systems – Electrical systems which are an integral part of the European power system and for which System Operations Guideline (SO GL) article 81 or article 106 is applicable. These systems shall be modelled by considering each element of the probabilistic model set in this methodology.

Flow-Based (**FB**) **approach/model** – A capacity calculation method in which energy exchanges between bidding zones are limited by power transfer distribution factors and available margins on a critical network element.

Flow-Based Market Coupling (FBMC) – A mechanism to couple different electricity markets, increasing the overall economic efficiency, while taking into account the available transmission capacity between different bidding zones using the FB approach/model.

Forced Outage (also unplanned outage) – State of an asset when it is not available in the power system and the outage was not planned.

Frequency Containment Reserves (FCR) – The active power reserves available to contain the system frequency after the occurrence of an imbalance.

Frequency Restoration Reserves (FRR) – The active power reserves available to restore the system frequency to the nominal frequency and, for a synchronous area consisting of more than one load-frequency control area, to the restore power balance to the scheduled value.

Loss of Load Duration (LLD) [h] – The annual Loss of Load Duration is defined as the number of hours per Monte Carlo year during which the demand exceeds the available generating capacity and the electricity that can be imported into the market node.



Loss of Load Expectation (LOLE) [h] – The mathematical average of annual Loss of Load Durations, i.e., the duration for which demand cannot be covered by market-based resources over the total number of Monte Carlo simulations performed.

Market-based measures – Any supply or demand measures available in the system complying with market rules and commercial agreements.

Net Transfer Capacity (NTC) approach/model – A capacity calculation method based on the principle of assessing and defining ex-ante a maximum energy exchange between adjacent bidding zones.

Non-explicitly modelled systems – Electric systems which do not provide data for adequacy assessment but are tightly interconnected with any member of ENTSO-E or any other electric system for which SO GL article 81 or article 106 is applicable. The contribution of those systems to the Pan-European adequacy assessment is considered using assumptions provided by the responsible TSOs.

Planned outage – State of an asset when it is not available in the power system and the outage was planned. These outages include maintenance, mothballing and any other non-availabilities known in advance.

Reserve capacity – The frequency containment reserves, frequency restoration reserves or replacement reserves that need to be available to the transmission system operator.

Strategic reserve – A capacity mechanism in which resources are only dispatched in case day-ahead and intraday markets have failed to clear, transmission system operators have exhausted their balancing resources used to establish an equilibrium between demand and supply, and imbalances in the market during periods when the reserves were dispatched are settled at the value of lost load.

Target year – A specific year that is covered by the adequacy assessment.

Unit Commitment and Economic Dispatch (**UCED**) – A mathematical optimisation problem which determines the commitment schedule of generation units and their level of generation in order to meet demand for every time step of the modelling horizon. The objective of the problem is to minimize operational cost while satisfying the operational constraints of the power system.

Unplanned Outage - See Forced Outage.

Value of Lost Load (VoLL) [\notin /MWh] – An estimation of the maximum electricity price that customers are willing to pay to avoid an outage.



Abbreviations

CCGT	Combined Cycle Gas Turbine
CGMES	Common Grid Model Exchange Specification
CHP	Combined Heat and Power
CWE	Central Western Europe
DSR	Demand-Side Response
EENS	Expected Energy Not Served
ENS	Energy Not Served
EV	Electric Vehicle
FB	Flow-Based
FBMC	Flow-Based Market Coupling
FOR	Forced Outage Rate
HP	Heat Pump
HVAC	High-Voltage Alternating Current
HVDC	High-Voltage Direct Current
IEA	International Energy Agency
LOLE	Loss of Load Expectation
LOLP	Loss of Load Probability
MAF	Mid-Term Adequacy Forecast
MC	Monte Carlo
MILP	Mixed Integer Linear Programming
NGC	Net Generating Capacity
NRA	National Regulatory Authority
NTC	Net Transfer Capacity
OCGT	Open-Cycle Gas Turbine
OPF	Optimal Power Flow
PD	Probability Density
PECD	Pan-European Climate Database
PEMMDB	Pan-European Market Modelling Database
PLEF	Pentalateral Energy Forum (including AT, BE, CH, DE, FR, LU, NL)
PTDF	Power Transfer Distribution Factor
PV	Photovoltaics
RAM	Remaining Available Margin
minRAM	Minimum Remaining Available Margin
TYNDP	Ten-Year Network Development Plan



1 MAF methodology

Adequacy studies aim to evaluate a power system's available resources and projected electric demands in order to identify potential risks of supply and demand mismatches in developed scenarios. In an interconnected power system, such as the European system, this scope should be extended by considering the supply and demand balance under a defined network infrastructure, which can have a considerable impact on adequacy results. In this context, the focus of a Pan-European Mid-Term Adequacy Forecast (MAF), as presented in the current report by ENTSO-E, assesses the adequacy of supply to meet demand in the mid-term time horizon while considering the interconnections among different power systems across the European perimeter, as illustrated in Figure 1 below.



Figure 1: The interconnected European power system perimeter modelled in MAF 2019 (Burshtyn Island is also explicitly modelled in MAF)

1.1 Time horizon and time resolution

A mid-term assessment of adequacy focuses on a single year to multiple years ahead in order to assist stakeholders in making well-informed investment decisions and to highlight potential risks of supply shortages. It considers techno-economic trends as well as policy decisions, e.g., for a massive phase-out of certain generating technologies. In MAF 2019, the focus has been set on target years 2021 and 2025. Year 2021 offers an insight into what adequacy will look like in the near future with reliable data describing the system's expected state. Furthermore, increasing environmental awareness and safety concerns have led Member States to take measures to reduce CO_2 levels and motivated some countries reducing the use of nuclear power. These decisions led to ambitious plans to decommission power plants that are characterized by high emission rates, e.g., coal and lignite, as well as significant nuclear capacity in a number of countries, such as Belgium and Germany. These developments require an assessment of system adequacies, i.e., the "day after". Thus, the second target year assessed in MAF 2019 is the year 2025.

The resolution of the simulations for both target years is hourly, meaning that all data in the form of time series (e.g., RES generation, demand profiles and so forth) should be collected or calculated in an hourly fashion to serve as input for the Unit Commitment and Economic Dispatch (UCED) model.

1.2 Geographical scope

The geographical scope of the MAF study consists of the Pan-European perimeter as well as neighbouring zones that are interconnected with the European power system. Furthermore, all zones are modelled in the same way in MAF but can belong to two different categories, namely, the **explicitly** and **non-explicitly** modelled zones. Explicitly modelled zones are represented by market nodes that consider full information using the finest resolution of input data, i.e., information regarding generation and demand. Non-explicitly modelled zones are market nodes for which detailed information about the power system is not available to ENTSO-E, meaning that only expected hourly exchanges between these market nodes and corresponding nodes are considered.

The MAF model is built by considering only interconnections between market nodes, while the grid topology within the zones is not taken into account. However, for cases that are considered to be relevant to the outcomes of the analysis, countries have been divided into more than one zone, with each zone represented individually by a market node. Table 1 presents both the explicitly and non-explicitly modelled zones in MAF 2019, while the explicitly modelled zones are illustrated further in Figure 1.

Explicitly modelled zones	Zone Code	Non-explicitly modelled zones	Explicitly modelled zones	Zone Code	Non-explicitly modelled zones
Albania	AL00	-	Italy South	ITS1	-
Austria	AT00	-	Italy Sardinia	ITSA	-
Belgium	BE00		Italy Sicily	ITSI	-
Bosnia and	BA00	-	Lithuania	LT00	Belarus
Herzegovina					
Bulgaria	BG00	-	Luxembourg	LUG1	-
Cyprus	CY00	-	Latvia	LV00	-
Czech Republic	CZ00	-	Montenegro	ME00	-
Germany	DE00	-	North Macedonia	MK00	-
Germany KF	DEKF	-	Malta	MT00	-
Denmark East	DKE1	-	Northern Ireland	UKNI	-
Denmark KF	DKKF	-	Netherlands	NL00	-
Denmark West	DKW1	-	Norway Mid	NOM1	-
Estonia	EE00	-	Norway North	NON1	Russia
Spain	ES00	Morocco	Norway South	NOS1	-
Finland	FI00	Russia	Poland	PL00	-
France	FR00	-	Romania	RO00	-
United Kingdom	UK00	-	Serbia	RS00	-
Greece	GR00	-	Sweden	SE01	-
Greece Crete	GR03	-	Sweden	SE02	-
Croatia	HR00	-	Sweden	SE03	-
Hungary	HU00	-	Sweden	SE04	-
Ireland	IE00	-	Slovenia	SI00	-
Italy Central North	ITCN	-	Slovak Republic	SK00	-
Italy Central South	ITCS	-	Republic of Turkey	TR00	-
Italy North	ITN1	-	Burshtyn Island (Ukraine)	UA01	-

Table 1: Explicitly and non-explicitly modelled zones

1.3 Probabilistic market modelling methodology

Power systems are characterized by considerable uncertainties affecting their optimal operation. In unbundled power systems with ambitious climate targets, uncertainty is present through:

- Renewable energy sources: the level of solar, wind and hydro generation depends significantly on weather and climate conditions. This climate-dependent variation of generation should be considered in a probabilistic manner by an adequacy study.
- Demand variability: a part of the demand level in the power system is linked to weather variability. For example, demand levels are dependent on temperature variations due to electrical heating and cooling devices.
- Thermal generation and interconnection outages: the availability of full net generating capacities (NGCs) is not guaranteed continuously in power system operations. Forced outages can be expected throughout the operation of the power system and are not predictable by definition.

For the above-mentioned reasons, the MAF uses a probabilistic market modelling framework that incorporates the aforementioned uncertainties. The methodology for MAF 2019 uses the approach presented in MAF 2018 as a starting point while complementing it with significant improvements. In particular, MAF 2019 has been improved with regard to MAF 2018 with respect to data granularity and a larger number of historical climate years for hydro modelling.

A simplified overview of the MAF methodology is displayed in Figure 2. The three pillars of an adequacy assessment are **available generation**, **demand** and **network infrastructure**. Within each of these pillars, several assumptions must be introduced to reflect the main characteristics of the variables. These assumptions include, but are not limited to, the following important features:

- Availability of generation and demand levels. The first step in an adequacy assessment of this scale is to obtain reliable expectations of the available generation capacity and demand levels in the target years. In the current study, the dataset consists of best estimates provided by the TSOs within the modelled perimeter. The retrieved best estimates include deterministic forecasts of available generation capacity and include unavailabilities due to planned maintenance and expected demand levels.
- Uncertainty with respect to climatic conditions. To adequately assess adequacy under various climate conditions, ENTSO-E has built an extensive climate database consisting of N = 35 climate years. More specifically, one can identify the following main categories of uncertain variables:
 - \circ Uncertainty on the generation side is reflected through the consideration of different wind, solar and hydro generation outputs for *N* different scenarios, each being linked with a climate year.
 - \circ On the demand side, uncertainty introduced through climate variables is considered through a demand forecast, which considers temperature, irradiance and other climate variables that affect demand for each of the *N* climate years.
- Uncertainty with respect to random incidents. As commonly observed in power system operations, there is an unavoidable risk of unpredictable outage incidents, which can have an important impact on system adequacy. Thus, these events should be considered when evaluating system adequacy in such a way that their random nature is reflected in the outcomes. Randomness in the outage incidents (either related to generation units or transmission lines) is considered through a

probabilistic Monte-Carlo (MC) approach, where, for each simulation, a random outage pattern will be imposed on a network and/or generation element.

• **Demand side response, storage, electric vehicles, heat pumps.** In modern, unbundled power systems, evaluating the adequacy also involves the contribution of elasticity of demand with respect to prices. Furthermore, the effect of storage facilities (including their market-driven operation), electric vehicles and heat-pumps, along with their corresponding impacts on demand profiles, are considered.



Figure 2: Overview of the methodological approach

The MAF model is a representation of the Pan-European power system and, as are all models, it is built based on a set of assumptions. The main assumptions of the MAF 2019 model are listed below:

- Perfect market competition. In order to assess adequacy levels in the target years, an Economic Dispatch and Unit Commitment (EDUC) model is solved for each hour of the target years while considering available generation and demand. Generation offers that partially define the economic dispatch are considered to be equal to the generating costs of each unit without strategic bidding/offering. Thus, we assume perfect competition in the market.
- 2) **Elasticity of demand**. Only the part of the demand which is explicitly defined as a Demand-Side Response (DSR), followed by an activation price, is considered to be elastic. The remaining share of energy demand is regarded as being inelastic to price.
- 3) Focus on day-ahead and intraday markets. Adequacy is evaluated in MAF from a day-ahead/intraday market perspective. More specifically, resources that might be available to TSOs to help them cope with loss of load events close to real-time are not considered as available capacity in MAF. For example, operational reserves other than Replacement Reserves (RR) do not contribute to adequacy. It is worth noting that operational reserves are dimensioned to cover the unexpected imbalances resulting from second-by-second random variations in generation and load and to face a range of contingencies under the assumption that the system is balanced, on average. On the contrary, lack of adequacy, the primary focus of MAF, should reflect the expectation that the system is not balanced structurally, at least in some hours and/or even days. Furthermore, some of the capacity

considered in the scenarios might rely on considerations of existing or planned market-wide capacity mechanisms. Finally, out-of-the-market measures, such as strategic reserves, are not considered in MAF.

4) Perfect foresight of RES, hydro storage and demand. Even though dependency on RES generation and demand as a result of climate is considered through the climate years, forecast errors from dayahead to the real-time are not considered; thus, perfect foresight is assumed for the RES generation, hydro storage optimisation and demand.

1.4 Monte-Carlo assessment

The main feature of the MAF probabilistic methodology is the use of MC sampling to represent combinations of different climate conditions and random outages. Generation assets and lines are subject to failures that cannot be predicted beforehand and which may have significant impact on adequacy. In order to account for these random incidents, an MC approach is used.

MC simulations are built by combining climate-dependent variables and random outages, as visualised in Figure 3. First, climate years from 1982 to 2016 are selected one-by-one. Each climate year consists of temperature-dependent demand (accounting for temperature dependency) time series, time series for wind and solar load factors and hydro inflow time series, among others. Each set of climate conditions is further associated with a relatively large number of MC random outage realisations, i.e., randomly assigning forced outage patterns to thermal generating units and interconnections (high-voltage, direct current (HVDC) and some high-voltage alternating current (HVAC)).



Figure 3: Monte Carlo simulation principles

The tools used for MAF calculate marginal prices as part of the outcome of a system cost-minimisation problem, also known as a Unit Commitment and Economic Dispatch (UCED) problem. This problem is often formulated as a large-scale Mixed Integer Linear Programming (MILP) problem. The program attempts to find the least-cost solution while respecting all operational constraints such as minimum up/down time, transfer capacity limits and so on. In order to avoid infeasible solutions, the constraints are very often modelled as 'soft' constraints, i.e., constraints that can potentially be violated at the expense of a high penalty in terms of cost. Nowadays, most optimisation solvers are capable of solving large-scale MILP problems within acceptable computation times. However, the extensive number of MC simulations performed makes the computation a time-intensive and challenging task.

In the MAF study, the size of the problem is significant, including as it does thousands of variables and constraints and hourly resolutions for performing the economic dispatches. Furthermore, there are different



stages to the modelling process, starting with how hydro, UCED and maintenance schedules are optimised (Figure 4):

- (a) Maintenance schedules are optimised separately and fed into the model as explicit periods in which specified plants are unavailable for dispatch. Maintenance optimisation is built by a single tool and based on constraints collected by the TSOs.
- (b) Hydro storage targets are optimised separately ex-ante for the UCED model at a weekly or monthly resolution, but this is tool-specific. This pre-optimisation phase delivers a time series of available energy from hydro resources for each optimisation step while respecting the initial weekly/monthly target.
- (c) UCED optimisation is then performed on smaller time steps (e.g., one day), determining which units are *on* or *off* and their level of dispatch in each hour.



Figure 4: Diagram illustrating the MAF process explained above.



Nowadays, the network modelling approach for pan-European or regional market studies is based on Net Transfer Capacity (NTC) market coupling, meaning that the network constraints between the market nodes are modelled not as physical limits but as commercial exchange limits at the border. This approach is followed in the current study as well while assuming a single value for the NTC for each interconnection throughout each modelled target year.

The EU Internal Energy Market target model is based on Flow-Based Market Coupling (FBMC). In this model, network constraints are modelled more accurately than in zonal models. The FBMC incorporates aspects which aim to model real physical limits on all network nodes while still performing market clearing in each zonal market area; hence, clearing at a single market price across each market region. FBMC calculates relevant parameters for the so-called selected Critical Network Elements and Contingencies (CNECs) via complete network models. The list of CNECs therefore considers the relevant network elements which limit commercial exchanges within the FB market coupling scheme. Most electricity market modelling tools nowadays can perform FBMC, even though such tools have not been thoroughly tested for large-scale applications. The use of FBMC in future MAF reports for the entire geographical region is currently being evaluated within ENTSO-E and is mandated as the target approach by the "Clean Energy for all Europeans" legislative package. In this version of the MAF, in addition to the common NTC approach for the Base-Case scenarios, an additional FB study was conducted, focusing on year 2021 and only on the Central Western Europe (CWE) area.

As in previous MAF versions, several market modelling tools used across European TSOs have been considered during the MAF 2019 assessment. A few tools are already used a high-resolution database that includes the unit-by-unit thermal generation fleet. The outcomes of this analysis could be compared to those produced by tools that use the previous database. A comparison of results between the different tools ensures the quality and robustness of inputs, calculations and outcomes. Meanwhile, it should be noted that a full alignment of results among different tools is not possible due to differences in the intrinsic optimisation logic of the UCEDs used by the different tools. Different features of tools are also exploited in the simulations to understand the sensitivity of the results to the different optimisation objectives. The aim of using different tools and comparing their outputs is to obtain consolidated and reliable results while understanding their sensitivity to the assumptions and modelling choices made. The process is illustrated in Figure 5.

Data collection based on the finest granularity was used for each thermal generation unit in the system within the Pan-European Market Modelling Database (PEMMDB) 3.0. Furthermore, the data for thermal generating units from PEMMDB 3.0 was aggregated into the granularity and categories used in previous MAF studies while making the required assumptions and simplifications according to the standards of PEMMDB 2.1.

The comparison of results was performed in the following four-step process:

- 1. Unit-by-unit PEMMDB 3.0 is used by two out of the five tools to construct the MAF models, while the remaining three tools use the PEMMDB 2.1 database.
- 2. Each tool's model outputs are aggregated.
- 3. Aggregated output data is visualised in comparative charts.
- 4. Discussions and analyses within the MAF market study group. Specification of actions regarding model or input data improvement.





Figure 5: Use of multiple models and tools (principle). The market modelling tools used in the MAF 2019 simulations were ANTARES¹, BID3², GRARE³, PLEXOS⁴ and POWRSYM⁵.

The current MAF probabilistic methodology is considered to be a reference within the Pan-European perimeter. However, the methodology followed in each MAF report up to the present should be understood as an *'implementation release'* of ENTSO-E's target methodology, which is, in itself, subject to constant evolution and further improvements. Note that the methodology used in future editions of the Pan-European resource adequacy assessment will evolve in line with the implementation of the "Clean Energy for all Europeans" legislative package. Consequently, subsequent MAF studies will follow the new Resource Adequacy methodology, once it has been approved by the European Agency for the Cooperation of Energy Regulators (ACER), and will be released under the revised heading "European Resource Adequacy Report" (ERAA).



Figure 6: Monte Carlo approach for assessing resource adequacy in a nutshell

¹ <u>https://antares-simulator.org/</u>

² <u>https://www.poyry.com/BID3</u>

³ <u>https://www.cesi.it/news_ideas/ideas/Pages/System-Adequacy-and-Market-Modelling.aspx</u>

⁴ <u>https://energyexemplar.com/solutions/plexos/</u>

⁵ <u>http://www.powrsym.com/index.htm</u>



For each hour of simulation, a reliability indicator, the Energy Not Served (ENS), is calculated, thus indicating if an adequacy problem is present (Figure 6). The following interpretations are then made:

ENS = 0, suggesting there is no adequacy problem, or, ENS \neq 0, indicating an adequacy problem.

For each area of interest, the intervals with non-zero ENS values are counted and stored. The total number of hours with non-zero ENS values is divided by the total number of simulations to estimate the probability that adequacy issues will occur. This allows the construction of a so-called Probability Distribution (PD) function and the Loss of Load Expectation (LOLE) to be derived, i.e., the expected number of hours with adequacy issues within a certain area during a year. It is important to recall that our analysis must not be understood as a forecast of actual scarcity situations. The actual realisation of scarcity events in a particular hour in the future will – of course – depend upon the actual realisation of all the variables impacting a power system and could be very different from the analysed situations. Meanwhile, the analysis provides a sound indication of the range of possible realisations.

2 Measuring adequacy levels

2.1 Adequacy indices

System adequacy refers to the existence of sufficient resources to meet consumers' demands and the operating requirements of the power system. The so-called adequacy indices are used as metrics. These indices can be quantified as deterministic indicators (capacity margins) or as probabilistic indicators, according to the methodologies used for the adequacy assessments.

With respect to the definitions and scope of the indices used in adequacy studies, three main functional zones of power systems are involved in the adequacy evaluation:

- **Generation adequacy level** (or hierarchical level I), which considers the total system generation, including the effects of transmission constraints in the form of NTCs.
- **Transmission adequacy level** (or hierarchical level II), which includes both the generation and transmission facilities in an adequacy evaluation.
- **Overall hierarchical adequacy level** (or hierarchical level III), which involves all three functional zones, from the generating points to the individual consumer load points, typically connected at the distribution level.

Traditionally, the adequacy indices can have different designations, depending on the hierarchical levels involved in the adequacy study. In MAF 2019, the focus is on hierarchical level I, i.e., the generation adequacy level.

In probabilistic adequacy studies, adequacy indices are expressed as expected values of random variables. Typical random variables include unserved energy or the number of hours with unserved energy. The expected values of the aforementioned random variables are not deterministic parameters but rather the Monte Carlo probabilistic averages of the variables.

In MAF 2019, adequacy levels are assessed in terms of the following indices:

• Expected Energy Not Served (EENS) [MWh/year or GWh/year] - the expected energy not supplied per year by the generating system due to the demand exceeding the available generating and import capacity. In reliability studies, it is common to see Energy Not Served (ENS) examined as an expectation over a number of MC simulations. To this end, EENS is a metric that measures the expected security of supply and is described mathematically in Eq. (1):



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$$EENS = \frac{1}{N} \sum_{j \in S} ENS_j, \tag{1}$$

where ENS_j is the energy not supplied in the system state j ($j \in S$) associated with a loss of load event in the j^{th} -Monte Carlo simulation, and N is the number of MC simulations.

Loss of Load Expectation⁶ (LOLE) [h/year] - the average number of hours per year in which the available generation plus imported electricity cannot meet demand in an area or region. LOLE is defined mathematically by Eq. (2):

$$LOLE = \frac{1}{N} \sum_{j \in S} LLD_j, \qquad (2)$$

where, LLD_j is the loss of load duration of the system state j ($j \in S$) associated with the loss of load event in the j^{th} MC simulation, and N is the number of MC simulations. It should be noted that the LLD of the j^{th} MC simulation can only be reported as an integer number of hours due to the hourly resolution of the simulation. Thus, it does not indicate the severity of the deficiency or the duration of the loss of load within that hour.

2.2 Convergence

In MAF 2019, the MC method comprises a repeated random sampling process in which a random outage pattern is drawn for every single simulation and adequacy indices are evaluated in the long-run for a large number of draws. This process creates a fluctuating convergence process for which the number of samples is negatively correlated with the convergence error.

The convergence of the MC assessment can be assessed via the coefficient of variation (α) of the *EENS* adequacy metric, which is defined by Eq. (3) below:

$$\alpha = \frac{\sqrt{\text{Var}[EENS])}}{EENS} \quad , \qquad (3)$$

where *EENS* is the expectation estimate of *ENS* over *N* samples, and Var[*EENS*] is the variance of the expectation estimate, i.e., Var[*EENS*] = $\frac{\text{Var}[ENS]}{N}$.

Notably, some inputs and parameters can have a significant impact on the numerical results of these indices and their convergences, such as:

- Hydro power modelling;
- NTCs;
- the use/ absence of extreme, yet realistic, historical climatic years (e.g., year 1985);
- outages and their modelling, including both maintenance and forced outages⁷.

In Figure 7, we present an example of the coefficient of variation from a single tool, showing how the model converges after a number of MC simulations. For this particular example, when observing the trend in the coefficient of variation, one can expect that a further increase in the number of scenarios will not bring significant improvements in convergence; therefore, no more MC simulations are attempted. In MAF, no explicit stopping criteria is set for the MC simulations. However, the evolution of the coefficient of variation, in combination with computational time, is observed in order to determine the number of MC samples needed for each tool.

⁶ When reported for a single MC simulation as the sum of all the hourly contributions with ENS, this quantity refers to the number of *hours (events)* within one year for which ENS occurs/is observed and this quantity should be referred to as a *Loss of Load Event*. The quantity calculated in Eq. (2) refers to the *average over the whole ensemble of Events* and therefore provides the statistical measure of the expectation of the number of hours with ENS over that ensemble.

⁷ To understand the impact of forced outages, which are random by definition, it is important for all the tools to use one commonly agreed upon maintenance schedule. This maintenance schedule should respect the different constraints specific to the thermal plants in different countries, as provided by TSOs. For more information about the maintenance schedule, see Section 3.5.1.





Simulated Monte Carlo years

Figure 7: The convergence of the coefficient of variation for an increasing number of MC samples

2.3 Reliability indices in practice

With respect to the various reliability indices introduced in the previous section, Table 2 presents a comprehensive overview of the different metrics that EU Member States apply to assess their national generation adequacy.

Table 2: Metrics used within EU Member States to assess generation adequacy at the national level in 2019

Member state	AT	BE	BG	СН	CY	CZ	DE	DK	EE	ES	FI	FR	GR	HR	HU
LOLE (h/y)	-	3	-	-	3	-	5	-	-	-	-	3	3	-	-
ENS (h/y)	-	-	-	-	Yes	-	-	-	-	-	-	-	-	-	-
Capaciy margin	-	-	-	-	Yes	-	-	-	Yes	-	-	-	-	-	-
Member state	IE	IT	LT	LU	LV	NL	NO	PL	PT	RO	RS	SE	SI	SK	UK
LOLE (h/y)	8	3	-	-	-	4	-	3	5	-	-	-	-	-	3
ENS (h/y)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Canaciv margin	_	_	_		_	_	_	_	_	_	_	_	_	_	_

Comments

CY	0.001 (% of annual demand); Capacity margin 20-40-%
BE	20h of LOLE95
BG	Optimized LOLE
DE	Latest Monitoring report from BMWi
EE	Capacity margin 10%
ES	LOLE of 0.2 only applicable on islands
FR	Consumer power cut expectation < 2h (draft NECP)
HU	LOLP < 1%
LT	Energy not delivered 6.3 MWh/year; Average interruption time <0.29 min
NL	Not officialy requested but target in national generation adequacy report
PT	Load Supply Index ≥1; Load Supply Index includes inadequacy risk looking at the day-ahead market only;
	LOLE value includes inadequacy risk looking to reserves close to real-time

As is evident, the most relevant index is LOLE (h/year), which is also the main indicator used in this report. Target reliability levels in terms of LOLE are typically in the range of 3-8 h/year. It should be noted that setting such reliability targets is a sensitive issue which needs to consider economic and technical aspects. For instance, these targets could be determined by means of counterbalancing the value of lost load (VoLL) against the costs related to maintaining a reliable generation capacity.

Beyond Europe, it is worth mentioning that AEMO's mid-term adequacy assessment for Australia sets an EENS threshold of 0.002% of the annual demand rather than using the LOLE threshold used in Europe.⁸

⁸ <u>http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Energy-Adequacy-Assessment-Projection</u>



2.4 Missing capacity: A useful adequacy index

As introduced early in the report, MAF 2019 focuses on LOLE and EENS in order to describe the European system's adequacy situation in the target years 2021 and 2025. According to Subsection 2.3, the most common indices for probabilistically assessing adequacy are, primarily, LOLE and, secondarily, EENS. However, LOLE and EENS do not always address the needs of all MAF stakeholders. In fact, when it comes to evaluating the need for new capacity mechanisms, a single question quickly arises: How much capacity is needed in order to reach one zone's reliability target? The question would be simple to answer if MAF was focusing on isolated zones. However, the reality is more complex, as summarised by the following questions:

- 1) Extending the question to an interconnected system like the European system, what are the optimal locations for this additional capacity?
- 2) How much of the missing generation capacity could be replaced by interconnection capacity?

The aforementioned extension of the scope of this pan-European adequacy assessment are in line with the objectives of the Clean Energy Package, thus motivating ENTSO-E to explore the validity of a new adequacy indicator, i.e., "Missing Capacity".

Missing Capacity is defined as an indicator that quantifies the extra capacity (generation or interconnection) that a region would need in a given future scenario to fulfil its adequacy targets. Defining the Missing Capacity of a system is challenged by the source of the capacity and area of assessment. The capacity required should be defined as a firm and technology-neutral capacity: the purpose of such an indicator should not be seen as a signal for investment in specific technologies. Regarding the assessment area, the Missing Capacity can be evaluated either in a single area (i.e., considering an isolated region) or multi-area.

When evaluating the Missing Capacity of a single area, only the reliability target of the country under study is considered. Therefore, the required capacity to reach the target in that country is calculated without assessing the adequacy levels of neighbouring regions. On the contrary, when the perimeter of study is expanded to a multi-area level, the Missing Capacity is defined as the required capacity to reach the reliability target in each of the investigated countries. In this case, an area formed by several neighbouring countries should be assessed and the reliability targets computed separately. Thus, the Missing Capacity is the capacity that fulfils each target simultaneously. Both in single and multi-area assessments, the Missing Capacity can be computed as a local or shared-generation capacity, a transmission capacity or any combination thereof.

Despite providing meaningful information for resource adequacy evaluation, the definition and evaluation of Missing Capacity are not straightforward, as they rely on boundaries and assumptions. The interconnected nature of power systems is one of the main challenges in the definition of Missing Capacity. Interconnections add complexity in interpreting the Missing Capacity, its impact on neighbouring regions and formulating a mathematical problem concerning it. Furthermore, the influence of flexible resources, such as hydro and its intertemporal constraints, e.g., reservoir levels, brings additional challenges in designing a robust methodology.

Within the framework of MAF, ENTSO-E is exploring and researching different approaches for evaluating the Missing Capacity, including:

- 1) A single-area approach with local generation: evaluation of the Missing Capacity while considering a single region and local generation capacity expansion. The reliability shortage of the assessed region is solved while considering only national resources.
- 2) Multi-area approach with generation expansion: calculation of the Missing Capacity in order to fulfil the reliability targets of two or more neighbouring regions. In this case, the extra capacity is shared among areas, and the adequacy standard is reached via imports/exports as well as local capacity.

3) Single-area approach, generation/interconnection capacity expansion: assessment of the Missing Capacity for a single region, considering expansion options, capacity and interconnections.

At the time of the publication of MAF 2019, investigations into this innovative concept were not sufficiently mature for publication. However, it is ENTSO-E's intent to communicate a more detailed description of the methodologies in the future, supported by results obtained with the main adequacy models.

3 Comprehensive datasets for building the MAF model

3.1 Pan-European Market Modelling Data Base (PEMMDB)

All models built for MAF use the same source of data input, i.e., the Pan-European Market Modelling Data Base (PEMMDB. The PEMMDB has improved significantly since its creation in 2017. However, this year, a milestone was reached in the evolution of the PEMMDB, namely, populating the database with unit-by-unit granularity for thermal generation.

The main improvements in the latest PEMMDB used for MAF 2019 are listed below:

- Increased granularity in the thermal generation data, i.e. the unit-by-unit resolution of all information concerning the generation fleet in the modelled perimeter;
- Improved representation of hydro power via climate-year dependency, which is consistent with PECD data for wind and solar generation;
- More information regarding the main variables affecting the demand profiles, including electric vehicle penetration, heat pump penetration, new technologies, battery storage (including price-responsive batteries) and more.

Naturally, moving from a database with aggregated generation data to a unit-by-unit database is a major step forward, which has been followed by significant modelling challenges. Higher granularity comes with increased complexity in building representative models satisfying all input data, leads to huge models which are difficult to solve from a computational power/intensity perspective and leads to models which are more susceptible to errors and infeasibilities. Examples for major challenges faced during the modelling process follow:

- Data inconsistencies in hydro data, resulting from the various hydro-related constraints which could prove contradictory in some situations, such as situations concerning inflows, weekly reservoir targets and maximum and minimum generation.
- The parallelisation of optimisation problems was essential to cope with the increased computational time, which increased the hardware requirements compared to the previous MAF.
- The number of objects (generators, fuel types and storages) in one of the five modelling tools used increased by a factor of five, and the number of constraints by a factor of ten. In particular, the increased number of constraints, related mainly to hydro modelling, resulted in a larger and more complex optimisation problem.

MAF 2019 serves as a hybrid assessment with respect to data granularity. Two different cases were assessed for each scenario in MAF 2019: two tools were used to build models based on the unit-by-unit data, while at the same time and in order to cope with the aforementioned challenges, MAF was built by three tools based on past MAF granularity, also used in TYNDP, where generation data was aggregated by technology type.



3.2 Demand time series – temperature dependency of demand

A common tool for the construction of hourly load profiles for all zones (with some exceptions) was used in MAF 2019 and allowed electrical demand forecasting to be performed easily starting with data analyses of historical time series for electrical load, temperature, climate variables and more. Its overarching goal was to introduce an advanced demand modelling tool, thus leading eventually to a stronger harmonization of demand forecasting activities and the comparability of the demand forecasts provided by ENTSO-E members.

The methodology incorporates the decomposition of time series into basic functions using Singular Value Decomposition (SVD), which reduces the computational burden and the volume of data required to populate the forecast model.

In a second phase, the tool adjusts the forecasted load time series using bottom-up scenarios provided by the TSOs that reflect the future evolution of the market (e.g., penetration of heat pumps, electric vehicles and batteries). The forecast model considers a diverse set of data sources (e.g., historical load profiles, temperature time series, plus data on the projected penetration of heat pumps, electric vehicles and batteries) and can provide multi-year demand forecasts at an hourly resolution. The whole process is visualised in Figure 8.



Figure 8: The embedding of demand forecasting into European resource adequacy assessment

More information regarding the methodology for the calculation of demand time series is provided in the report "Demand forecasting methodology"⁹.

3.3 Climate data - Pan-European Climate Database (PECD)

The Pan-European Climate Database (PECD) is a database developed by ENTSO-E which consists of reanalysed hourly weather data and load factors for variable generation (namely, wind and solar). PECD datasets are prepared by external experts using industry best practices, thus ensuring a representative estimation of demand, variable generation and other climate-dependent variables.

In 2019, the PECD was extended to include hydro generation data. Based on re-analysis data concerning hydro inflows, a standardised central methodology has been designed to map historical inflows of generation

⁹ Demand methodology document: link



data and build a model to project hydro generation, including hydro run-of-river, hydro reservoirs and pump storage. More information about the methodology and relevant assumptions are included in the corresponding "Hydro Power Modelling" document¹⁰.

3.4 Network data

3.4.1 NTC model

Assumptions on NTCs for the 2021 and 2025 scenarios are based on TSO expertise for bottom-up data collection. The transfer capacity between borders/ bidding zones, agreed upon between the respective TSOs, will be available within the dataset published together with the present report.

TSOs were also asked to propose values for **simultaneous importable / exportable capacities** – meaning the maximum possible flow at the same time through all NTC corridors respecting the N-1 and operational security of these countries. In adequacy simulations, such constraints should be considered since they might be imposed at some borders (e.g., in the Flow-Based market coupling area) for reasons linked to internal grid stability and operational constraints. In the MAF, forced outages (e.g., unexpected failure of a line resulting in unavailability) are considered for all High-Voltage Direct Current (HVDC) interconnections.

3.4.2 Flow-Based model

Although an implementation of FBMC is already in place in some parts of the ENTSO-E zone, i.e., CWE, it is not considered in the MAF 2019 main results. The FBMC is only considered as an additional sensitivity analysis since: (1) most ENTSO-E areas are still using the NTC approach, and (2) a common Flow-Based approach is yet to be agreed upon by the ENTSO-E membership which would be applicable to the whole European perimeter and could feasibly be implemented in every tool used in the MAF.

A sensitivity analysis applying a Flow-Based approach to the MAF model for the target year 2021 was performed. The relevant input data was:

- Relevant Power Transfer Distribution Factors (PTDFs) derived from historical grid models covering the FB area under consideration. In the future evolution of the FB approach, grid models from the Ten-Year Network Development Plan (TYNDP) reference grid will be used by incorporating the relevant grid modifications applicable to the different target time horizons used in the assessment.
- Power Transfer Distribution Factors (PTDFs) were defined for each of the different Critical Network Elements and Contingencies (CNECs) within the grid model under consideration. The PTDFs take into account each of the relevant variables representing each market zone's net position, potentially relevant HVDC flows, Phase Shifting Transformer (PST) settings and other degrees of freedom that are given to the market under FBMC.
- Network constraints are defined further through the Remaining Available Margin (RAM) of each CNEC. The 20% minRAM rule was applied to the RAM calculation, as it is currently operational in the CWE FBMC.
- The capacity calculation should ensure the N-1 criterion is met at all times. The calculations of the PTDF and RAM thus account for the N-1 principle.

A detailed description of how the FB is implemented in MAF 2019 and the relevant methodology is presented in Section 0.

¹⁰ Hydro methodology document: <u>link</u>

3.5 Thermal generation

3.5.1 Maintenance profiles

Thermal generation units are subject to periods of planned maintenance, which is unavoidable for optimal operation. In principle, the maintenance of such units is scheduled to take place in periods when adequacy is secured. Thus, maintenance planning is optimised with respect to expected demand and takes into consideration the various requirements and specificities of each power plant. All relevant information needed to schedule the maintenance of the thermal generation fleet in MAF is included in the PEMMDB. This information includes the number of days per year of maintenance, the ratio of maintenance between the winter and summer periods and the maximum number of units in maintenance simultaneously to avoid risks.

In order to ensure sufficient alignment between market modelling tools using the same input data, a single maintenance planning profile was prepared and imposed for the tools using either PEMMDB 2.1 or PEMMDB 3.0. More specifically, a single optimisation run was performed based on the aforementioned constraints and the demand profiles for each of the two input datasets prior to the UCED calculation. The optimisation determines which units will be unavailable and for which period of the year. A moderate climate year was selected as a model basis for MAF 2019. The maintenance schedule was optimised given this demand profile by selecting low-demand times for planned maintenance.

Ideally, maintenance schedules should not be influenced by an extreme climate year but rather be developed in a manner consistent with average demand profiles. Instead of using a moderate year to comply with the above-mentioned requirements, another option would be to stochastically optimize maintenance based on a random selection of all climate years available. This option will be explored in future resource adequacy assessments.

In any case, it is also important to make sure that the optimised maintenance schedules are coherent, to the extent possible, with the forecasts published by the owners of relevant assets via the official transparency channels of the Regulation on Wholesale Energy Market Integrity and Transparency (REMIT) regarding their expected unavailability within the short-term period of three years ahead.

3.5.2 Reserves

Balancing reserves, or ancillary services, is fundamental to a power system. As foreseen in the **Electricity Balancing Guideline**, each TSO shall contract/procure ancillary services to ensure a secure, reliable and efficient electricity grid. These are agreements with certain producers and consumers to increase or decrease the production or demand at certain sites. The aim is to have sufficient resources to compensate for the imbalance that could be caused by the forced outage of a production unit or demand/renewable forecasting errors.

We distinguish between different categories of balancing reserves in MAF 2019:

- 1. Frequency Containment Reserves (FCRs) are active power reserves (automatically activated) available to maintain system frequency after the occurrence of an unbalance;
- 2. Automatic Frequency Restoration Reserves (aFRRs) stabilise the frequency (bring it to its normal range) and ensure the availability of the FCRs. They also maintain the balance of power imports and exports in a control area;
- 3. Manual Frequency Restoration Reserves (mFRRs) guarantee the availability of the aFRRs. They are activated manually (e.g., by ramping up/down generators) and are used mostly when there is a major disruption in the grid operation (e.g., failure of a generator).



4. Replacement Reserves (RRs) are active power reserves that restore and guarantee the availability of the FRRs.

The market simulations are not real-time and have a resolution of one hour. Balancing reserves are assigned to deal with the hazards that can occur within this time step and are not considered in large-scale adequacy. Thus, FCR and FRR are removed from the available generation capacity. Operational reserves are aimed at maintaining the frequency at the nominal value. Hence, reserves are dimensioned to cover the unexpected imbalances resulting from second-by-second random variations of generation and load and to face a range of contingencies under the assumption that the system is balanced, on average. On the contrary, a lack of adequacy reflects the expectation that the system is not structurally balanced, at least in some hours and/or days, e.g., during peak loads or low renewable in-feed periods. In this case, reserves would be used to cover partially for inadequacies, but they would not be available for their actual purpose, resulting in severe violations of the frequency quality criteria set forth in legislation covering reserves.

From a modelling perspective, taking the reserves into account can be implemented in two ways: reducing the respective thermal generation capacity or increasing the demand by the hourly reserve capacity. For practical reasons, the reserves were taken into account by adding them to consumption rather than applying a thermal capacity reduction, making it easier to implement the market models. However, doing so has the disadvantage of distorting the reported energy balance since 'virtual consumption' has been added. Notably, in some countries, reserves are provided by hydroelectrical generation. In these cases, the maximum possible hydro generation is reduced by the reserved volume. Furthermore, in special cases (e.g., where a TSO has agreements with large electricity users regarding demand reduction when needed or dedicated back-up power plants) the reserve specifications were coordinated directly with the data correspondent of the responsible TSO. On the other hand, RRs are considered in the MAF adequacy calculations, i.e., RRs are available to meet demand.

3.6 Demand Side Response (DSR)

The DSR is modelled in a simplified way as a generator that participates in the market. Each DSR unit is characterized by an offer quantity and an offer price and can therefore be dispatched as part of the merit order curve. Additionally, the number of hours the units can operate per day can be limited.

Prices, quantities and operation constraints are delivered by the TSOs and can consist of multiple bands in cases in which a price differentiation is requested. For most countries, DSR units have relatively high prices, which ensures that they are the last dispatchable services before ENS occurs. However, in some countries, DSR units can be dispatched before the price-setting generator. Finally, the dispatch price of a DSR unit was set lower than each country's Value of Lost Load.

3.7 Other relevant parameters

To allow for a more accurate reflection of the diversity of generation technologies and to better capture operational practices, basic parameters, such as the NGC, number of units and other additional technical parameters, have been considered in the data collection process. Some of these parameters represent boundary conditions or thresholds that the modelling tools should comply with during the simulations.

Unavailability of the power system elements was considered in the simulations in two ways: i) via forced outages, and ii) via planned outages. In the MAF, availability was considered for thermal power plants that were active in the market and HVDC lines.

→ Planned outages refer to maintenance and are defined as the number of days on an annual basis that a given unit (blocks of-) is expected to be offline due to maintenance. Further restrictions regarding



the minimum percentage of the outages which can occur in each season of the year were specified by the TSOs with a focus on winter and summer. The maximum number of simultaneously offline thermal units allowed within each month of the year was specified by the TSOs as well. Within these restrictions, an optimised maintenance schedule was prepared, as described in Section 3.5.1.

→ Forced outages are represented by the parameter Forced Outage Rate (FOR), which defines the annual rate of forced outage occurrences for thermal power plants or grid elements. Forced outages are simulated by random occurrences of outages within the probabilistic MC scheme while respecting the defined annual rate. Simulated random forced outages are useful for assessing the impact of the availability of base-load thermal generation and its relationship with the available flexible thermal and hydro generation, renewable generation and imports.

Minimum stable generation in MW is a parameter defining the unit's technical minimum power output. The simulations do not allow the unit to run under this limit. It is defined as a percentage of the unit's nominal capacity.

Minimum Up Time defines the minimum number of hours a unit must stay in operation before it can be idled.

Minimum Down Time defines the minimum number of hours a unit must remain idle before it can be restarted.

These parameters guarantee the optimal operation of units, i.e., they prevent simulated units from experiencing unrealistic outage patterns.

4 Improvements over the previous MAF

4.1 Data and methodology

ENTSO-E is seeking constantly to enhance the quality of its methodologies. This year's edition of the MAF includes several advancements with respect to the previous edition, which are further explained below:

Improved data granularity and temporal coverage

Pan-European Market Modelling Data Base Version 3.0 (PEMMDB 3.0) – In its most recent version, the database contains information on the generation capacity fleet (Net Transfer Capacities, RES-based and fossil fuel-based generation capacities and their predicted evolution over time, maintenance and mothballing predictions, reserve requirements, and DSR potentials). As a main improvement, information on thermal generators is now available on a unit-by-unit basis. The commissioning and decommissioning of power plants is indicated by exact dates in the database, better representing the evolution of generation capacity throughout the year. Planned and unplanned outages are considered in the model on a unit-by-unit basis, providing information regarding available generation capacity and clearly differentiating the unavailable capacity.

Improved hydro modelling

• For this MAF, a new hydro database was implemented, increasing the number of climatic scenarios covered from three in the previous MAF to the same 35 Climatic Years used in PECD for wind and solar. The source of climatic data used to derive inflows and hydropower conditions is the same as for PECD, ensuring climatic coherence between these renewable energy sources. New methods for



the aggregation of hydro plants and technologies were also applied to better represent real hydropower operation behaviour in the market models.

Further improvements and actualised modelling assumptions are detailed below.

4.2 Specific data collection and model assumptions

In order to align the methodologies between the different tools that have been used in the MAF 2019 process, a modelling guideline was developed and applied. Its central points are listed in the following paragraph, including assumptions from previous MAF studies as well as the necessary adjustments to deal with the more granular input data from the Pan-European Market Modelling Database 3.0 (PEMMDB 3.0).

Thermal generation

The power plant fleet consists only of units that are flagged as "available to the market" by the respective TSO, meaning that out-of-the-market capacities, such as strategic or grid reserves, are not considered in the optimisation problem. Maintenance profiles are optimised based on a single mild weather year. The optimisation can include further constraints, such as winter ratios for maintenance, according to a TSO's best knowledge. If no data is provided by the TSO(s), default values from ENTSO-E's data collection are applied. This database also contains values for outage parameters, such as Forced Outage Rates or Mean Repair Times. The unit-by-unit data collection also contains accurate ramp rates and start-up/shut-down times for each unit. However, in the 2019 MAF edition, these parameters were neglected since the model complexity would have increased significantly, whereas the adequacy results would have remained largely unaffected.

Hydro modelling

The granularity of hydro data collection improved significantly compared to previous MAF studies. First, hydro data was collected for each climate year rather than for only "dry", "normal" and "wet" conditions, as in the previous MAF editions. For each climate year, weekly reservoir trajectories were collected and used in the model in order to form a realistic shape for the reservoir level. Also, the initial volume at the beginning of the year and the end volume at the end of the year were specified. By doing so, sudden changes in the reservoir volume from year to year could be avoided. PSP units are modelled with an efficiency of 75% per pump-turbine cycle.

Network representation

Limitations on electricity exchanges between countries are modelled using simplified bilateral NTC values. These NTCs limit the trade balance between market zones without taking into account actual physical power flows. Additionally, in some border simultaneous, import and export limitations are modelled to account for specific grid requirements. Power exchanges on interconnecting lines to non-EU countries are considered to be fixed, exogenously-given exchanges. Forced outages of network elements are taken into account within the current geographical granularity of the assessment. For HVAC and HVDC tie lines, the outage of specific network elements is already considered in the NTC values (N-1 contingencies). These N-1 values reflect the fact that the network operation will remain within safe operational standards even in the event of outages of network elements. Furthermore in the assessment, it is possible to model these random outages for selected HVDC and HVAC tie lines explicitly. For this purpose, a default value of 6% is assumed to account for these outages. For some borders, TSOs have delivered FOR values differing from the default values, which were then used instead.

4.3 Demand forecasting

Recently, ENTSO-E has procured a new model used for the creation of hourly load profiles for all European countries. This load projection model can handle a diverse set of data sources (historical load profiles, temperature time series, heat pumps, electric vehicles and so forth) and provide multi-year demand forecasts



with hourly resolution. Compared to the modelling approach used for the previous MAF editions, the utilization of the new demand forecasting model brings several advantages (what follows is a non-exhaustive list):

- Multiple historical climate and load time series are used to derive projected load profiles for each market node. In the previous methodology, only one reference year was used during the forecasting process;
- Automatic identification of different climate variables needed for the model calibration process (temperature, irradiance, wind speed, and so on);
- Better treatment of historical profiles used in the load projection process (correction of holiday periods, exceptional events and so forth);
- The load projection is decomposed into temperature-dependent and temperature-independent components. In this manner, final load profiles are adjusted by taking into account the additional consumption from heat pumps and electric vehicle charging. Hence, the load profiles also incorporate the interdependencies of historical temperatures during each climate year and historical load patterns.

4.4 Methodology and limitations

The current MAF methodology relies on an advanced probabilistic market modelling approach. Yet, like every modelling approach, it has its inherent limitations, which are presented briefly below:

- **Perfect foresight and flexibility** are assumed. Wind, solar and demand forecasting errors are not considered explicitly in day-ahead/intraday forecasts. Furthermore, it is considered that these errors, if any, are dealt with by the dimensioned operational reserves, which is why the reserves are subtracted from the available capacity in day-ahead/intraday forecasts used in the assessment. In other words, the MAF approach assumes: i) a perfect day-ahead/intraday forecast; ii) forecasting errors from day-ahead/intraday forecasts to real time are dealt with by operational reserves. Furthermore, perfect foresight regarding the future (next week, month) variables affecting optimal hydro dispatch is assumed in the model, while s not necessarily being the case in operational reality.
- An energy-only market is considered in MAF simulations. The MAF model considers neither capacity nor the balancing market explicitly; both are important topics perhaps deserving of further investigation in the future.
- **Perfect competition** is considered in the MAF simulations by assuming that no strategic behaviours are present in the market and all market agents behave competitively and in a fully rational manner, revealing their true short-term marginal costs to the market.
- Uncertainty of decommissioning dates for thermal units. Compared to the previous MAF edition, MAF 2019 is built on a more granular Pan-European database via a unit-by-unit representation of thermal generation assets, reflecting more accurately the commissioning and decommissioning dates (official country data or expected at the time of report preparation). However, the MAF model still does not incorporate an economic viability check of the generation fleet in the target years. Such an improvement is a future target for the Pan-European Resource Adequacy Assessment (ERAA).

• Internal grid limitations within a bidding zone are not considered in the Base-Case approach. However, they have been further investigated in a Flow-Based study conducted as a sensitivity analysis, as explained further in Section 0. This topic needs further development and needs to also consider possible evolutions of the European market. The future ERAA to be developed by ENTSO-E pursuant to article 23 of EU Regulation 2019/943 will need to be based on methodology which inter-alia provides for the use of a market model using the Flow-Based approach, where applicable.

4.5 Flow-Based innovations and methodology

One important simplification in the simulations is in the representation of the network. In the Base-Case simulations, the impedance of the network is not considered explicitly and is only taken into account in the values of the transmission constraints imposed as constant NTC between zones.

In MAF 2019, a more detailed representation of the network is attempted under the framework of a sensitivity analysis that incorporates an FB approach. The FB approach implemented for the year 2021 follows the implementation of FBMC for the Central Western Europe (CWE) area. In this approach, representative historical FB domains, including the effect of grid reinforcements up until 2019, are implemented for CWE countries (BE, FR, DE, NL, AT) as the basis for the modelling of cross-border capacity. The different types of FB domains used represent several situations with different levels of congestion across the grid. Their implementation in the model is further correlated to the expected climate and consumption conditions of each day of the simulations, which are the main drivers for congestion across the grid. A similar methodology was implemented at the regional level by the PLEF 2017 study¹¹. An important methodological improvement compared to the PLEF study is the implementation of the so-called minimum remaining available margin (minRAM), equal to 20% of the maximum allowed power flow on each Critical Network Element and Contingency (CNEC)¹².

The implementation of an FBMC approach in the adequacy simulations used in MAF 2019 is a significant step towards more realistic modelling of the operational planning in practice nowadays. Contrary to the constant NTC values defined for long-term planning and used in the Base-Case simulations here, representative historical FB domains are chosen as a basis and linked to expected climate and consumption conditions for each day in 2018 and 2019 for which historical records were available at the time of the assessment. This approach is a simple, yet realistic representation of what is observed in everyday practice in the region. As this approach requires more detailed modelling and realistic inputs, at the moment, it is only possible to do create a model for the near future since the FB approach relies on practical data from 2018/2019. Evolutions in both the methodology and the grid modelling and data are currently under consideration for subsequent MAF reports, hopefully making it possible to conduct such a FB approach for a longer time horizon of, e.g., five years ahead.

This step towards a more realistic modelling of operational planning in practice also means that the simulation results could better reflect the tight situations observed in practice, leading to more realistic adequacy assessment for the region. Due to the aforementioned reasons, the FB and NTC approaches used for the same time horizon 2021 lead to different outcomes. Implementation of the FB approach should be the goal, whenever possible, in order to reflect what is experienced in operational practice.

¹¹ Pentalateral Energy Forum (2018): Generation Adequacy Assessment;

http://www.benelux.int/files/1615/1749/6861/2018-01-31_-_2nd_PLEF_GAA_report.pdf

¹² JAO; <u>http://www.jao.eu/news/messageboard/view?parameters=%7B%22NewsId%22%3A%22bbb7dbda-a15d-454c-9225-a8c8012bb828%22%7D</u>



How does the Flow-Based method work in reality?

The Flow-Based method allows modellers to take properly into account interactions between market outcomes and the transmission grid. For instance, at moments when, e.g., both France and Belgium are in a structural shortage, the imports to Belgium can be reduced significantly if large flows are running through Belgium towards France. Using the Flow-Based method in an assessment makes it possible to calculate the likelihood and the impact of reduced imports on adequacy as a result of market conditions in neighbouring countries.

Figure 9 below shows the flows between four fictitious zones when 100 MW is sent from zone A to zone D. The resulting flows follow the path of least impedance, which can result in certain connections between zones not participating in this energy exchange (in this case, zones B and C).



Figure 9: Commercial exchanges between two countries can generate physical flows through other borders.

The Flow-Based method implemented in the day-ahead market coupling uses Power Transfer Distribution Factors (PTDF) that make it possible to model the real flows on the lines based on commercial exchanges between countries. PTDF division factors estimate the physical flow that can be expected on the different grid lines as a function of the commercial exchanges settled on the market between countries. The example in

Figure 9 above shows that energy flows are distributed unevenly over the different paths between the different zones when there is a commercial exchange of 100 MW between zones A and C. The PTDF factors of this example determine that:

- o 75 MW of the injection from A goes to B, and 25 MW of the injection from A goes to C.
- o 65 MW of the injection from B goes to C, and 10 MW of the injection from B goes to D.
- \circ Finally, the total injection coming into C is 25 MW + 65 MW = 90 MW, which then goes to D.

Since the commercial exchange of 100 MW is between A and D in the case above, i.e., exchange (A \rightarrow D), the PTDF for each interconnector is referred to as PTDF_(A \rightarrow D).

Commercial Exchange (A to D)	Grid Element 1	Grid Element 2	Grid Element 3	Grid Element 4	Grid Element 5
$PTDF_{(A \rightarrow D)}$	25%	75%	65%	90%	10%

A matrix of exchanges vs. lines can be therefore defined (only A \rightarrow D numbers shown for simplicity)

PTDF	Grid Element				
	1	2	3	4	5
$PTDF_{(A \rightarrow B)}$	-	-	-	-	-
$PTDF_{(A \rightarrow C)}$	-	-	-	-	-
$PTDF_{(A \rightarrow D)}$	25%	75%	65%	90%	10%
$PTDF_{(B} \rightarrow C)$	-	-	-	-	-
$PTDF_{(B \rightarrow D)}$	-	-	-	-	-
$PTDF_{(C \rightarrow D)}$	-	-	-	-	-

For each hour of the year, the impact of energy exchanges on each critical line or 'branch' is calculated while taking the N-1 criterion into account. A critical branch is a physical element of the grid which has reached its maximum transmission capacity and therefore constrains the total flow of the system around it. In typical situations, energy exchanges are subject to many constraints. These constraints form a domain of possible maximum energy exchanges between the countries within the FB area, i.e., the Flow-Based domain.

Looking at the system in

Figure 9 and, for example, the possible commercial exchanges $A \square B$ and $A \square C$, the basic equation defining the condition for each of the interconnections in the system above to be defined as a critical branch is given by Eq. (4) :

$$PTDF_{A-B,l} \cdot P_{A-B} + PTDF_{A-C,l} \cdot P_{A-C} \le RAM_l \forall l, \quad (4)$$

where RAM_l is the Remaining Available Margin (RAM) of each line l.

The constraint introduced by each critical branch, i.e., CNEC, can be drawn as a line on the plane defined by the relevant exchanges between any two areas of the system under consideration. Figure 10 shows an example of the plane for the power exchange $A \rightarrow B$ vs. the power exchange $A \rightarrow C$. The set of all CNECs relevant for exchange $A \rightarrow B$ vs. exchange $A \rightarrow C$ defines a polygon, the so-called FB domain, as depicted schematically in Figure 10 below. The coloured squares in the figure correspond to the Available Transfer Capacity (ATC) domains, which provide ATC with taking into consideration long-term nominated power flows and transfer capacities in conventional NTC schemes.





Figure 10: Example of a Flow-Based domain (see CWE Flow-Based¹³)

These Flow-Based domains are typically constructed based on CNECs while taking into account: i) the impact of an outage or contingency on a Critical Network Element (CNE), ii) a flow reliability margin (FRM) on each CNEC and possibly 'remedial actions' that can be taken after an outage to unload part of the CNECs.

These actions make it possible to maximise exchanges thanks to changes in the topology of the grid or the use of phase-shifting transformers. The various remedial actions that are used to form these domains are typically coordinated and approved by the other TSOs in the context of RSCs.

The domain used is viable if all network elements are available in the CWE zone. Faulty elements will have an impact on the domain and possible exchanges between countries.

Different assumptions are made for these Flow-Based domains, such as the expected renewable production, consumption, energy exchanges, location of generation, outage of units and lines and so forth.

For every hour, there might be a different Flow-Based domain because:

- the topology of the grid can change;
- outages or maintenance of grid elements can be scheduled or occur unexpectedly;
- the location of available production units can vary significantly from hour to hour.

The Flow-Based domain is calculated two days before real-time operation and is used to define the limits of energy exchange between countries for the day-ahead market.

 $^{^{13}} http://www.elia.be/nl/producten-en-diensten/cross-border-mechanismen/transmissiecapaciteit-op-de-grenzen/Flow-Based-marktkoppeling-centric w-europa and the second second$

How is the Flow-Based method implemented in this assessment?

Step 1 - Selection of 'typical' days

A statistical analysis of the geometrical shapes of available Flow-Based domains is performed on historical records of domains from the FB CWE operational tool. Historical days are clustered in families defined by the size of their 24-hourly domains. Typically 'large', 'medium' and 'small' families of domains are clustered. Each typical day consists of 24 domains (one for each hour):

- Small domains correspond to situations with a highly congested network and therefore small values for the maximum power exchanges possible between the different market areas considered by the given domain (related to the small volume inside the domain).
- Large domains correspond to situations with a less congested network and therefore relatively higher values of maximum possible power exchanges between the market nodes considered by the given domain (larger volume).
- A typical day is the historical day within a given family or cluster of domains which provides the best representation of all the other days in the cluster.
- Since FB domains are hourly, this typical day is selected by comparing its domain in every hour to the other days' equivalent domains (at the same hour).

Step 2 - Correlation between each 'typical' day and specific climatic combinations

Four typical days for winter and four typical days for the inter season are found as a result of the clustering (three weekdays and one weekend day). A probability matrix is then calculated as a function of daily energy ranges (high/medium/low) of wind production and load. This calculation provides the correlation of each typical day (24 hourly domains) to given climatic combinations.

Step 3 - Assignment of FB domains to hourly market simulations

The typical days for winter in Step 1 are used as proxies for the relevant domains expected during the simulations and are assigned to hourly simulations by the correlations found in Step 2 (Figure 11). Each hourly simulation of the interconnected power system presents different expected climatic, generation and demand situations during the assessment. This kind of systematic approach makes it possible to link specific combinations of expected climate conditions, e.g., high/low wind in-feed in one area, high low temperature and demand in the same or nearby areas, with representative domains for these conditions.



Figure 11: Step-wise implementation of FB domains



5 Future evolution of the Pan-European Adequacy Assessment

5.1 "Clean Energy for all Europeans" legislative package

The "Clean Energy for all Europeans" legislative package ("CEP") extends the scope of the ENTSO-E MAF and develops it further into the new ERAA. The CEP requirements for the ERAA include the development of five new methodologies within six to twelve months after the CEP's effective date. The future European adequacy assessment will see a major extension of its scope compared to the current MAF. It will need to cover new requirements such as yearly granularity for a ten-year horizon, Flow-Based calculations, generation viability assessments, sensitivities with and without capacity mechanisms, as well as sectorial integration, among others. ENTSO-E has developed a roadmap for the development and step-by-step implementation of the methodologies and requirements for the assessment and with respect to how the MAF will evolve into the ERAA.

The Electricity Regulation 2019/943 of the CEP¹⁴ requires ENTSO-E to develop several methodologies related to resource adequacy, which provide a further basis for assessing adequacy at a Pan-European level using the same methods and tools across countries to enable comparison (Electricity Regulation Chapter IV, Article 23 to 26):

- 1. A methodology for assessing European resource adequacy, including the definition of Expected Energy Not Served (EENS) and Loss of Load Expectation (LOLE) (required six months the CEP text enters into force);
- 2. A methodology for the definition of the Cost of New Entry (CONE) and Reliability Standards and Value of Lost Load (VoLL) (required six months the CEP text enters into force);
- 3. A methodology for calculating the maximum entry capacity for cross-border participation in capacity mechanisms (required twelve months after the CEP text enters into force).

Each methodology and resource adequacy report will be subject to public consultation, in accordance with both ENTSO-E's stakeholder engagement vision and the requirements of CEP.

5.2 Implementation and gap analysis with the current MAF methodology

The CEP brings a number of changes and updates to the methodology used for adequacy assessment, while the scope of the assessment is extended significantly. However, the implementation of the complete set of changes will take place gradually over the following years.

The features that are mainly impacted by the CEP implementation are summarized below:

Probabilistic market modelling approach (Monte Carlo): the core of the MAF methodology, i.e., probabilistic market modelling simulations, is already compliant with the requirements of the CEP. However, future adequacy assessments will be required to present results from a single tool only. It will only be possible to fulfil this requirement when the alignment between tools is achieved upon implementation of the CEP target methodology in order that it is not relevant which tool is chosen. This alignment will also guarantee the highest possible level of robustness for the results.

¹⁴ https://eur-lex.europa.eu/legal-content/PL/TXT/?uri=CELEX:52016DC0860



- 2) Target years and granularity: In the current MAF, the adequacy assessment is focused on two target years, i.e., 2021 and 2025. According to the new regulations, the Pan-European adequacy assessment should be performed for each one of the 10 years ahead, which increases the number of simulated target years by eight.
- 3) Economic viability: MAF 2019 is based on top-down scenarios for installed capacities and does not consider the economic viability of the fleet. Only expected or official commissioning and decommissioning dates of thermal generation plants are considered when building the MAF scenarios. The CEP requires the incorporation of an investment module, which will assess the economic viability of thermal units and their potential exits from the market.
- 4) **Capacity Mechanisms** (CM): Contribution of approved, existing and planned, CMs might be currently considered in the installed capacity for MAF on the part of some TSOs. In the target methodology, a systematic comparison of both cases should be considered, i.e., cases with and without the consideration of the contributions of approved, existing and planned CMs to future assumed installed capacities.
- 5) **Flow-Based (FB):** FBMC is tested and presented for the target year 2021 in this year's MAF edition. FB implementation is one of the target features of the future adequacy assessments to be expanded beyond the CWE to a larger geographical perimeter whenever feasible.
- 6) **Sectorial Integration:** Sectorial integration is not accounted for in the MAF but shall be considered in the future through, e.g., technologies for power-to-gas (P2G) and power-to-hydrogen (P2H) conversions or power conversions to other mediums (P2X).

An overview of the gap analysis regarding the target methodology and the current status of further developments in the MAF methodology are shown in Figure 12 below.

Торіс	MAF 2019	ERAA Methodology	Status	
Modelling approach	Probabilistic approach	Probabilistic approach		
Communication	Annual publication	Annual publication		
Network	NTC approach. Testing flow-based since 2018	Compliance with FBMC	$\mathbf{\Lambda}$	Legend
Time granularity	2 modeled Years (horizon 10 years ahead)	10 modeled Years (horizon10 years ahead)	$\overline{\mathbf{V}}$	
Available capacity	Bottom-up expectations: (de-)commissioning up to 7 years ahead	Economic viability of generation assets, integrated in the model (10-year ahead)		50 %
Capacity Mechanisms	No explicit CM considerations. Missing capacity investigation	Integrated consideration of CM		
Sectorial coverage	No sectorial integration	Sectorial integration (P2X consideration)	×	

Figure 12: The MAF methodology gap analysis when considering the legal requirements for the Clean Energy Package