European Network of
Transmission System Operators
for Electricity

Mid-term Adequacy Forecast 2018

Appendix 1: Methodology and Detailed Results

2018 edition

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1 Methodology and assumptions

The methodology for adequacy assessments has been successfully implemented in five different market modelling tools[1]. All tools cover the same geographic perimeter (as presented in Figure 1 and the corresponding graphs of the MAF 2018 executive report) as well as the same time horizon (i.e. the target years 2020 and 2025). In the same vein, all tools deploy the same methodological approach, i.e. probabilistic market modelling. This approach has enabled a thorough analysis and benchmarking of the different models, and thus led to substantial improvements in terms of consistency and trust.

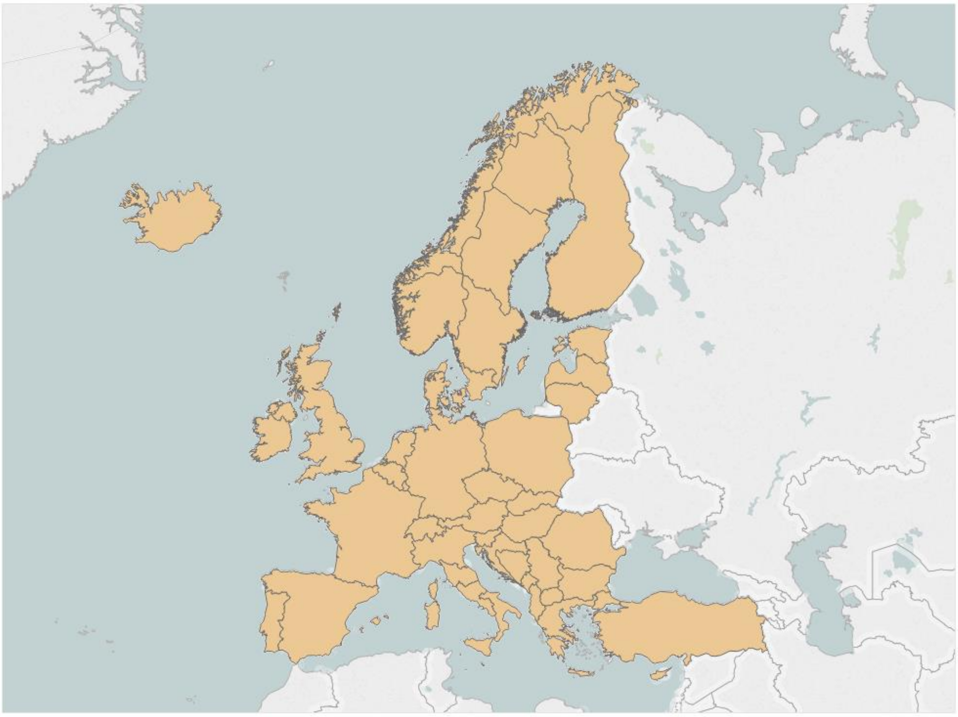

Figure 1: The interconnected European power system perimeter modelled in MAF 2018

Figure 2 provides an overview of the overall approach that has been chosen and followed in the MAF. Broadly speaking, adequacy refers to the relationship of available resources and demand which is balanced via network infrastructure. In this assessment, the supply and demand side are composed by a deterministic forecast, combined with stochastic uncertainty. The deterministic forecast is in line with ENTSOs' Scenarios which are published as a separate document. Stochastic uncertainty, driven by climatic variables and the risk of unplanned generator and line outages, is accommodated by means of Monte Carlo simulations, as explained hereafter.

[1] ANTARES, BID3, GRARE, PLEXOS and PowrSym. See Section 3 for a short presentation of the individual tools.

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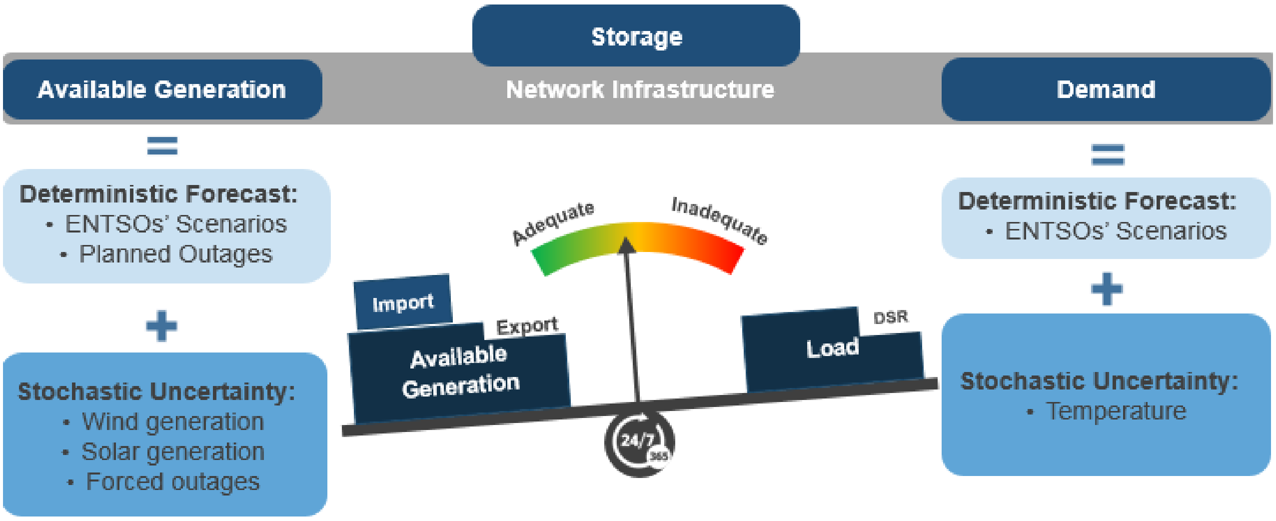

Figure 2: Overview of the methodological approach

1.1 Methodology – advanced tools for probabilistic market modelling

Our methodology compares supply and demand levels in an interconnected European power system by simulating the market operations on an hourly basis over a full year. In each of the scenarios for 2020 and 2025, we build upon ENTSOs' scenarios, forecasting net generating capacity (NGC), cross-border transmission capacity and annual level of demand. In addition, the simulations consider the main stochastic contingencies that may affect security of supply, including:

1. Outdoor **temperatures** (which result in load variations, principally driven by the heating and cooling patterns in winter and summer respectively),
2. **Wind and photovoltaic** power production**,**
3. **Unscheduled outages** of thermal generation units and relevant HVDC interconnectors,
4. **Maintenance schedules**,
5. Extended **hydro database**, including dry, wet or normal hydro conditions.

For each of these contingencies, all market modelling tools perform a large number of Monte Carlo simulations, built by the combinatorial stochastic process schematically depicted in Figure 3 below.

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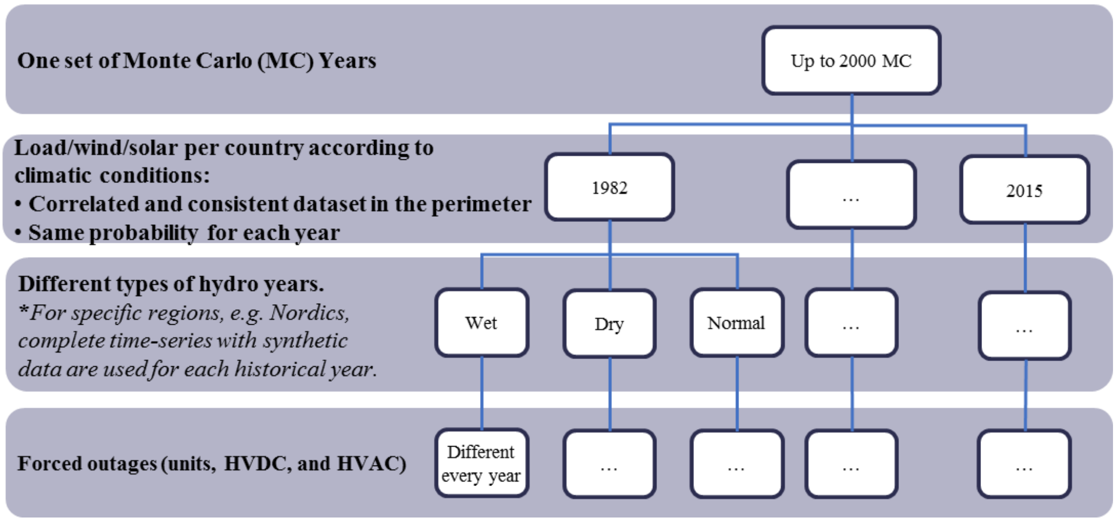

Figure 3: Graphical illustration of the number of Monte Carlo years required for convergence of the results

Monte Carlo simulations are built combining the aforementioned variables in the following way: climate years (1982-2015) are first selected one-by-one. Each climate year, consisting of a combination of demand (accounting temperature sensitivity), wind and solar time series, is assigned with one of the three possible hydro conditions (wet, dry, normal) or with historical year-specific time series of hydro generation. Each set of climate and hydro conditions is further associated with a relatively large number of Monte Carlo realisations, randomly assigning forced outage patterns for thermal units and interconnections.

In general, the tools employed are built upon a market simulation engine. Such an engine is not meant for modelling or simulating the behaviour of market players or optimal bidding, e.g. gaming, explicit capacity withdrawal from markets, etc., but is, rather, meant for simulating marginal costs (not prices) of the whole system and the different market nodes. Therefore, the main assumption is that the market is perfectly competitive, with no strategic behaviours present.

The tools calculate marginal costs as part of the outcome of a system cost-minimisation problem. Such a mathematical problem, also known as ‘Optimal Unit Commitment and Economic Dispatch’, is often formulated as a large-scale Mixed-Integer Linear-Programming (MILP) problem. 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.). In order to avoid infeasible solutions, very often the constraints are modelled as ‘soft’ constraints, i.e. constraints can potentially be violated at the expense of a high penalty in terms of cost. Most optimisation solvers nowadays are capable of solving large-scale MILP problems within acceptable computation times. However, with the presence of integer variables it is still common in commercial tools to solve the overall problem by applying a combination of heuristics and MILP. Moreover, the extensive number of Monte Carlo simulations makes the computation an intensive and challenging task.

In the MAF study, the size of the problem is immense, i.e. including thousands of variables and constraints. Additionally, the size increases with the optimisation time horizon and resolution. The time horizon of the optimisation problem, e.g. hydro optimisation, maintenance or fault duration, etc., is one week, and the resolution of the simulation is hourly, i.e. given the constraints and boundary conditions, the total system cost is minimised for each week of the year on an hourly basis. The weekly optimisation horizon means that the

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optimal values for each hour of the whole year are calculated, with the optimisation problem broken up on a weekly basis, to reduce computation time. A weekly optimisation horizon is also common practice for market simulations at many TSOs for network planning. The latter means that the results such as generation output of the thermal and hydro plants, marginal costs, etc. are provided per hour. This setting of the parameters is also common practice for the market simulations which are conducted under the context of the ENTSO-E TYNDP and PLEF Generation Adequacy Assessment.

These tools also have the functionality to include network constraints to a varying degree of detail. Nowadays, the status-quo approach for pan-European or regional market studies is based on Net Transfer Capacity (NTC) Market Coupling. This means that the network constraints between the market nodes are modelled as limits only on the commercial exchanges at the border. This approach is followed in the current study as well.

The EU Internal Energy Market target model is based on Flow-Based Market Coupling (FBMC). In this model, the network constraints are modelled as real physical limits on selected 'critical branches'. Most TSO tools nowadays can perform FBMC, even though they have not been thoroughly tested for large-scale applications. There are also tools which can model the physical network explicitly including all the technical constraints such as contingencies, thermal and voltage constraints, therefore incorporating what is commonly known as Optimal Power Flow (OPF). Such a feature is not yet common in Europe since there is no agreement or plans for a regional scale application of nodal pricing. The possibility of including FBMC for future MAF reports is currently being evaluated within ENTSO-E. In this version of the MAF, in addition to the common NTC approach for the base case scenarios, additional innovative FB studies are conducted. More specifically, a FBMC approach is considered for the target year 2020 similarly to the PLEF study, while an explicit physical-network representation is considered on the simulations for the year 2025, paving the way for improvements to come in MAF future studies.

Five different tools were used in parallel in the current study, which are referred to as 'Voluntary Parties (VP)'. A comparison of results between the different tools ensures the quality and robustness of inputs and calculations, as well as outcomes. Meanwhile, it should be noted that a full alignment of results between different tools is not possible due to differences in the intrinsic optimisation logic of the 'Optimal Unit Commitment and Economic Dispatch' used by the different tools. Different features of the participating tools are also exploited in the simulations to understand the sensitivity of the results to the different optimisation objectives, *while the input dataset remains identical* among all tools. The aim of using different tools and the comparison of their output is to obtain consolidated and reliable results, while understanding their sensitivity to the assumptions and modelling choices made. The process is illustrated in Figure 4.

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

a) Preparation of aggregated output data of the models
b) Visualisation of the output data in the form of comparison charts
c) Discussions and analyses within the MAF market study group
d) Specification of actions regarding model or input data improvement

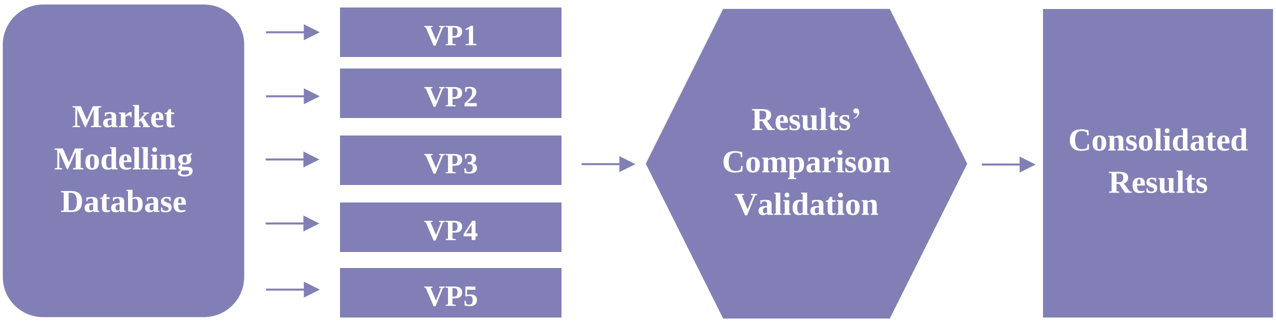

Figure 4: Use of multiple models and tools (principle)

The current MAF probabilistic methodology is considered as a reference at the pan-European perimeter. However, the methodology followed in each MAF report should be understood as an '*implementation release'* of ENTSO-E's Target Methodology, which is in itself subject to constant evolution and further improvements. It is worth mentioning that the expected major improvements for the base case in future MAF reports are, among others, the implementation of flow-based modelling as the base case and the extension of the climate database to cover hydrological conditions for all geographical areas of the study, as well as a unit-by-unit representation of the generation units in the longer term.

1.1.1 Adequacy Indices

System adequacy refers to the existence of sufficient resources to meet the consumers' demand and the operating requirements of the power system. As a metric, the so-called adequacy indices are used. 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 definition and scope of the indices of 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 effect 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.
- The overall hierarchical 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 this edition of the MAF 2018 report, the focus is on the hierarchical level I, generation adequacy level. The results of the simulations are expressed in terms of the following indices:

- **Expected Energy Not Served (EENS)** [MWh/year or GWh/year] is the average energy not supplied per year by the generating system due to the demand exceeding the available generating and import capacity. In reliability studies, it is common that Energy Not Served (ENS) is examined in expectation over a number of

Monte Carlo simulations. To this end, EENS is a metric that measures security of supply in expectation and is mathematically described by (1) below:

$$\text{EENS} = \frac{1}{N}\sum_{j\in S} ENS_j \qquad (1)$$

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

- **Loss Of Load Expectation**[2] (h/year) *LOLE* is the average number of hours per year in which the available generation plus import cannot cover the load in an area or region.

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

where, LLD_j is the loss of load duration of the system state j ($j \in S$) associated with the loss of load event of the j^{th} Monte Carlo simulation and where N is the number of Monte Carlo simulations considered. It should be noted that the LLD of the j^{th} Monte Carlo simulation can only be reported as an integer of hours because of 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.

The proposed metrics above are quantified by probabilistic modelling of the available flexible resources. Additional indices to measure, for example, the frequency and duration of the *EENS* or the power system flexibility can be considered in future evolutions.

1.1.2 Reliability indices and model convergence

With respect to the relationship of the probabilistic indices and convergence of the models, when multiple Monte Carlo simulations are conducted, these indices can also be expressed in average, minimum and maximum values accordingly. Annual values can also be used to construct a probability distribution curve.

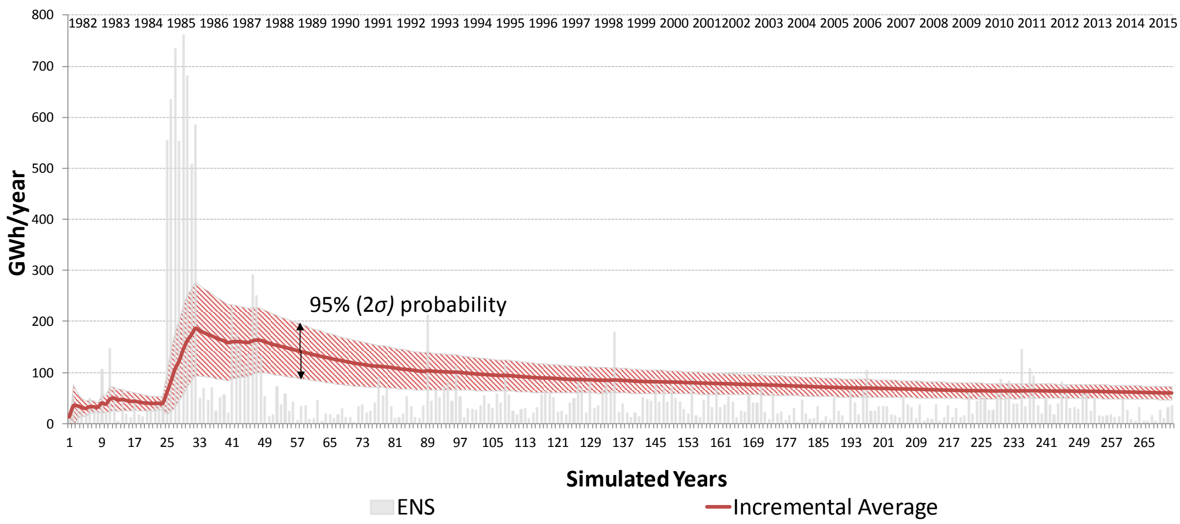

Figure 5: Example of EENS convergence over a number of Monte Carlo simulations

[2] When reported for a single Monte Carlo 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 it therefore provides the statistical measure of the expectation of the number of hours with ENS over that ensemble.

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The trend of the moving average of EENS against the total number of Monte Carlo simulations performed provides a good indication of the convergence of the simulations (example shown in Figure 5). When *N* is sufficiently large (i.e. when The Strong Law of Large Numbers and Central Limit Theorem hold), the error between the expected value and its average exhibits a Gaussian distribution and its upper bound with a probability of 95% can be calculated using the following formula:

$$|\varepsilon_n| \leq 1.96\frac{\sigma}{\sqrt{n}} \qquad (3)$$

where ε_n is the error at n iterations, and σ the standard deviation.

Correspondingly, the confidence interval can be calculated using the following formula:

$$\left[\overline{X}_N - 1.96\frac{\overline{\sigma_N}}{\sqrt{N}}, \overline{X}_N + 1.96\frac{\overline{\sigma_N}}{\sqrt{N}}\right] \qquad (4)$$

where $\overline{X}_N$ is the sample average.

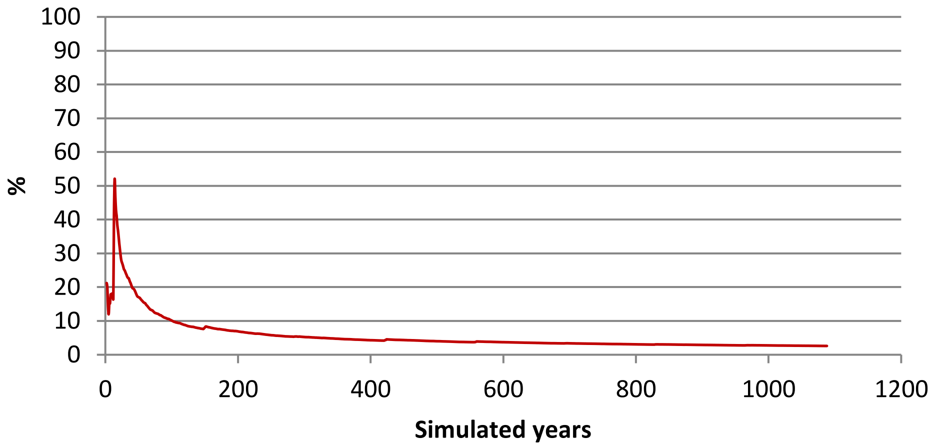

Figure 6: Example of confidence interval achieved by the simulations

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

- **Hydro power data usage and modelling**
- **NTCs**
- **Extreme historical climatic years (e.g. year 1985)**
- **Outages and their modelling**: this refers to both maintenance and forced outages. To understand the impact of forced outages, which are random by definition, it is important for all the tools to use one commonly agreed maintenance schedule. This maintenance schedule should respect the different constraints specific to the thermal plants in different countries, as provided by TSOs.

In order to obtain a satisfactory analysis of the influence of different inputs, parameters, outages and modelling with the use of different tools, various sensitivity analyses have been conducted in this report, as presented in the MAF Executive Report.

1.1.3 Reliability indices in practice

With respect to the various reliability indices introduced in the previous section, Table 1 presents a comprehensive overview of the different metrics that EU Member States apply to assess their national generation adequacy.

As is evident, the most relevant index is expressed in 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.

Other than 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, instead of the LOLE threshold used in Europe.[3] This, for instance, would correspond for Germany to around 2 million households not supplied for 5 hours.

Table 1: Situation of metrics used in EU Member States to assess generation adequacy at national level in 2015

Country	AT	BE*	BG	CH	CY	CZ	DE	DK	EE	ES	FI	FR	GB	GR*	HR	HU	IE	IT	LT	LU	LV	MT	NL	NO	PL	PT*	RO	SE	SI	SK
Reliability Standard	No	Yes	NS	No	NS	No	No	No	No	Yes	No	Yes	Yes	Yes	NS	Yes	NS	No	No	NS	NS	No	No	No	No	Yes	NS	No	NS	No
LOLE (h/y)		3	13									3	3	3		8	8						4			5				
LOLE P95 (h/y)		20																												
Capacity Margin										10%															9%					

Sources: ACER, CEER, Assessment of electricity generation adequacy in European countries, Staff Working Document accompanying the Interim Report of the Sector Inquiry on CMs and Pentalateral generation adequacy probabilistic assessment.

** Information about BE, GR and PT have been updated to reflect recent changes.*

Note: NS: Not specified reliability standard, LOLE: Loss of Load Expectation, LOLE P95: 95th percentile of LOLE (1 in 20 years probability).

1.2 Assumptions – comprehensive datasets for all parts of the system

All models use the same data input for their calculations. In order to have a consistent dataset, a common scenario framework is agreed upon. Therefore, a harmonised and centralised Pan-European Market Modelling Data Base (PEMMDB) for market studies has been prepared based on national generation data and outlooks provided to ENTSO-E by each individual TSO. The focus of the study is on the calibration of the models for two time horizons: years 2020 and 2025. This section describes the most important assumptions and how they are incorporated in the different tools to run the Pan-European market simulations.

1.2.1 Scenarios and Pan-European Market Modelling Data Base

The PEMMDB is the main source of data for the MAF. The PEMMDB contains collected data from TSOs for bottom-up scenarios as well as centrally analysed data for top-down scenarios.

The MAF framework uses collected data for 2020 and 2025 (i.e. bottom-up scenarios). Even though a detailed description of the PEMMDB is provided in the ENTSOs' scenario report[4], Figure 7 provides an overview of the most important data characteristics, i.e shares of the different electricity generation sources for 2020 and

[3] http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Energy-Adequacy-Assessment-Projection
[4] https://tyndp.entsoe.eu/tyndp2018/scenario-report/

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2025. Generation capacities are categorized based on the generation technology, e.g. total thermal capacity consists of coal, lignite, gas, nuclear, oil and biofuel.

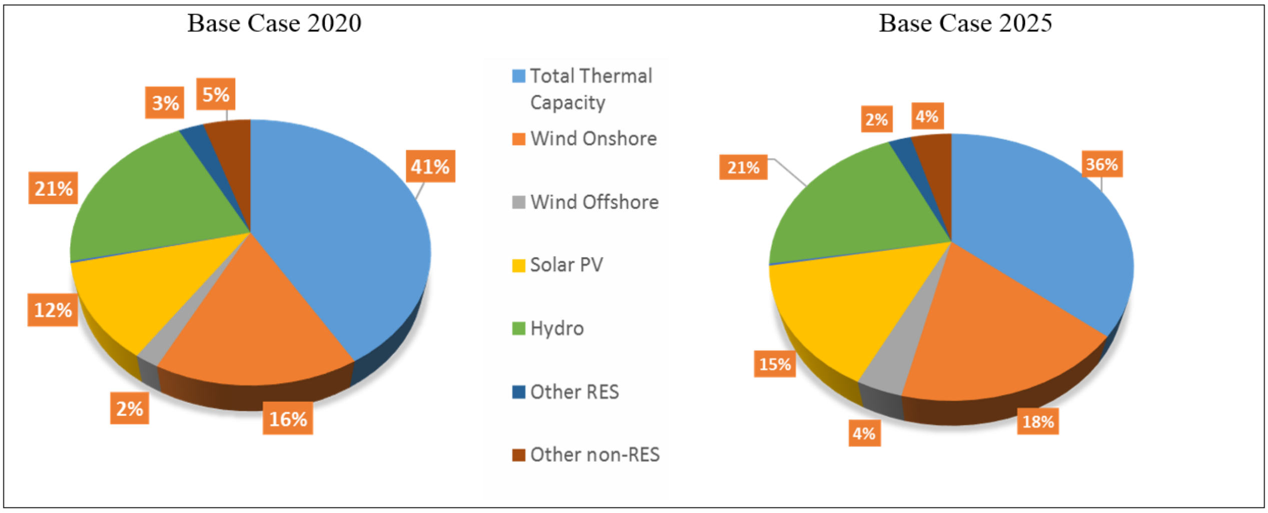


Figure 7: Distribution of generation capacity for all ENTSO-E zones (base case scenarios 2020 and 2025)

In addition to the above figures, the PEMMDB covers further elements important for the modelling of electricity markets, such as:

- Demand and Demand Side Response forecasts
- Information on thermal generation units, e.g. must-run properties, number of units etc.
- Information on hydro generation units
- Information on renewable generation capacities
- Reserves and exchanges with non ENTSO-E countries

Information about decommissioning of units due to an accelerated coal phase-out have been independently collected from the TSOs and are not part of the PEMMDB database. For further details and information on all scenarios, please refer to the ENTSO-E Scenario report and the accompanying MAF 2018 dataset.

1.2.2 Demand time series - Temperature dependency of demand

The electrical demand is dependent on weather conditions. The most important influencing factor is the temperature. Especially in the commercial and domestic sector, the widespread use of electrical heating and cooling has a significant impact on the electrical demand. The general change of temperature throughout the year leads to fluctuating demand. In addition, cold spells in winter and heat waves in summer represent extreme events that have a strong impact on demand. It is crucial to integrate these extreme conditions into the probabilistic models. Based on a refined sensitivity analysis of demand and temperature, time series of electrical demand are created and form fundamental inputs for the MAF.

Quantifying the impact of heating and cooling

Heating and cooling devices allow us to maintain a comfortable temperature in our indoor environment. Many of these devices work either directly or indirectly with electrical energy. This dependency of electrical demand and temperature can be illustrated as follows:

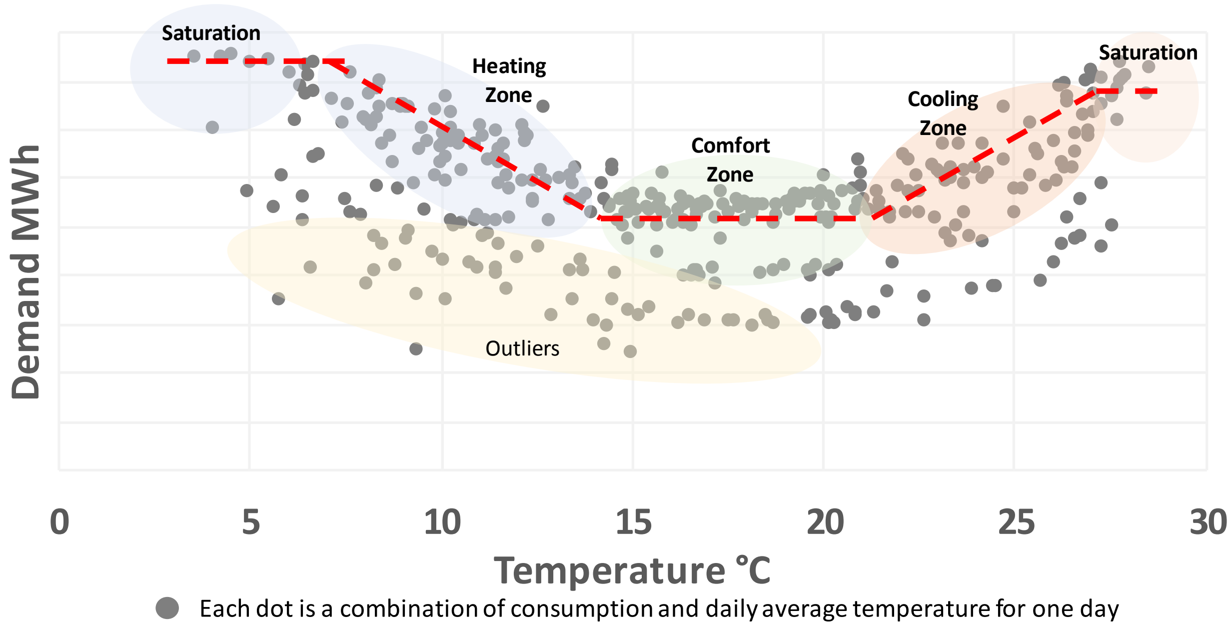


Figure 8: Temperature dependency of consumed energy

For very low temperatures, a lot of energy is consumed for heating (heating zone). When the outdoor temperature remains around 20 degrees, households generally neither use heating nor cooling and therefore the extra energy consumed by the devices is low. With rising temperatures, an increasing number of cooling devices are turned on, which in turn leads again to higher electrical demand (cooling zone).

For a Pan-European assessment such as the MAF, it is crucial to observe what impact the heating and cooling have on the total consumption of electrical energy. Furthermore, it is important to quantify this effect for the different assessed areas. By finding mathematical correlations between the ambient temperature in an area and its consumption, the demand – temperature sensitivity can be calculated. This cubical polynomial approximation is the basis for creating synthetic hourly demand profiles for each area.

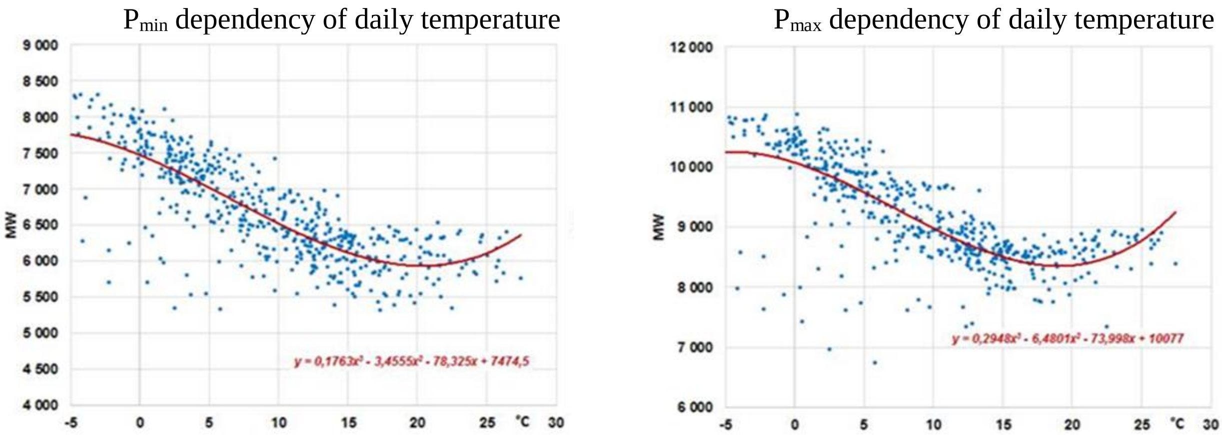


Figure 9: Cubical approximation of demand and daily average temperature

Figure 9 shows such cubical approximations (red lines). The blue dots represent the daily minimum (on the left graph) and maximum (on the right graph) demand respectively for a certain daily average temperature. It can be observed that most of the blue dots are clustered around the approximation. Only a couple of outliers with significant lower demand can be found. These points are bank and school holidays for which a majority of the commercial and industrial demand is lower. The outliers are not considered in the cubical approximations. The described analysis is carried out for all assessed market zones for the year 2015. The daily average temperature is calculated from a data set which includes 34 years of meteorological data.

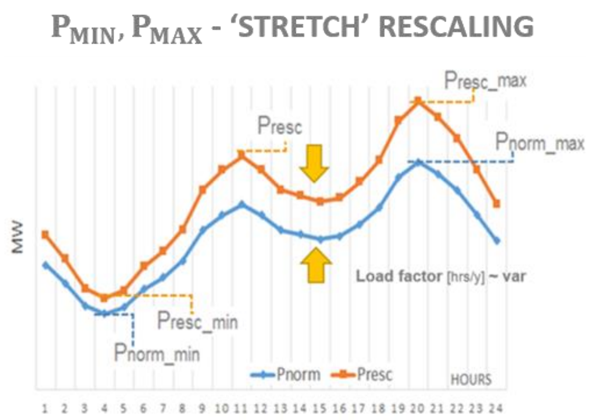
A demand profile for average temperatures

The next step is to calculate a demand profile under normal temperature conditions. The previously described polynomials are applied onto the measured demand profile of 2015. The outcome is an hourly profile that represents the demand of the market zones as if the daily temperature is equal to the 34-year average.

Summing up every hour of this normalised demand profile would result in the total electrical demand of 2015 of each zone. It is now necessary to up- or downscale this to a specified demand for the target years. The target annual consumption of 2020 or 2025 is part of the PEMMDB (see Section 1.2.1).

Creating a synthetic demand profile on historical temperatures

The last step is to calculate a synthetic demand profile for each available year of temperature measurement. See the following simplified example for clarification: Day 358 of year 1999 had an average temperature of 6.5°C. By observing all 34 years, we know that the temperature of this day on average was 8.5°C, i.e. colder than average by 2°C. Thus, the electrical load is expected to be comparatively higher than usual (since there is a need for more heating). To quantify this, the polynomial with the temperature difference is used and the *expected* daily maximum and minimum demand are calculated. With these two values, the load profile can now be rescaled for that specific day, as illustrated in Figure 10. The same approach is applied for every day of 34 years of the available temperature data for all market zones.



$$\frac{(P_{norm} - P_{norm\_min})}{(P_{norm\_max} - P_{norm\_min})} = \frac{(P_{resc} - P_{resc\_min})}{(P_{resc\_max} - P_{resc\_min})}$$

Figure 10: Stretch rescaling of a daily demand profile

Changing the shape of the demand profiles

The structure of the demand and the consumption patterns are subject to change in the future. In particular, electric vehicles (EV) and heat pumps (HP) are considered as changing the shape of the daily demand profile.

Therefore, they are treated separately. The following factors are considered to represent the electrical energy consumed by these devices (the example below refers to EVs):

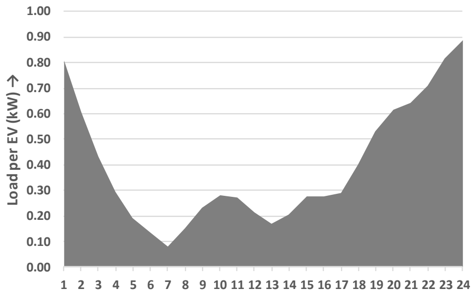
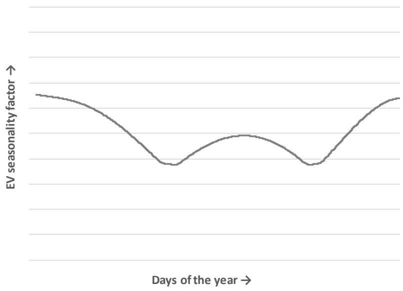
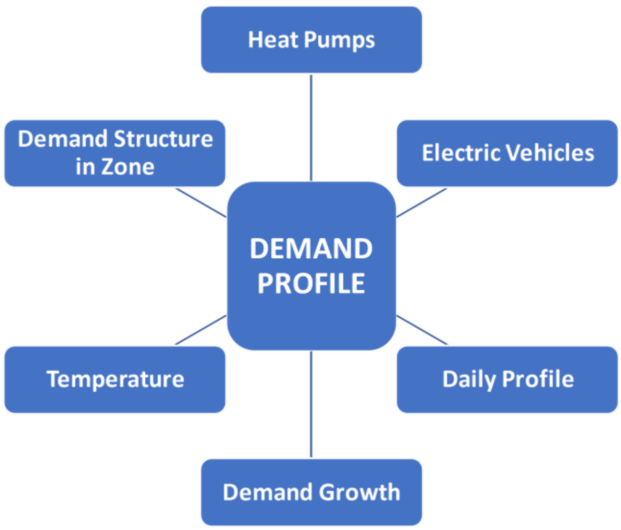
1. Number of devices	2. Daily load profile of device	3. Seasonality
PEMMDB data collection		

Figure 11: The figure illustrates the factors influencing electricity demand profiles from devices such as EVs and HPs. Using EVs as an example, the first factor is the number of EVs (collected through the PEMMDB), the second factor is an assumption on the daily demand profile of the EVs and, finally, the last factor refers to variations on the demand profile due to seasonality.

Demand in a nutshell

1. *Hourly demand profiles for 34 years representing a large range of realistic temperature conditions*
2. *Scaled to the target annual consumption of each zone in each scenario (2020, 2025)*
3. *EVs and HPs considered*
4. *Consistent approach for all MAF zones*



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

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

For this study, PECD was employed extensively to estimate a number of climate-dependent variables. Representative demand profiles were built, as explained in Section 1.2.2. Furthermore, estimates of variable generation were made based on information about load factors in PECD and variable generation capacities within PEMMDB. Different types of hydrological conditions were defined and applied for each climate year. These hourly time series were then combined with other random samples, as explained in Section 1.1, in sufficient number of Monte Carlo years, to give a statistically representative data set to be used in the adequacy study.

The PECD was launched in 2014 through a centralised approach to re-analyse climatic data ensuring a coherent data set. Key benefits include the precise representation of simultaneous extreme events (e.g. heat waves) as well as realistic wind and solar generation forecast for the whole study perimeter. Furthermore, since its creation PECD has been continuously developing to improve data quality, extend the geographical perimeter coverage and increase the number of historical years re-analysed. The use of the PECD is an important data quality improvement, recognised by all ENTSO-E’s members and used in pan-European and national studies.

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ENTSO-E PECD consists of the following data sets:

Wind speed, radiation and nebulosity time series

- Hourly average reference wind speed at 100 m for each market node [m/s], to be calculated according to the formula below:

$$Average\ reference\ wind\ speed\ (t, market\ node) = \sqrt[3]{\frac{1}{n}\sum_{i=1}^{n}\left(\sqrt{{U_{t,i}}^2 + {V_{t,i}}^2}\right)^3} \quad (5)$$

t: time [h]
U: Zonal component of the wind speed at 100m height (west-east direction) [m/s]
V: Meridional component of the wind speed at 100m height (north-south direction) [m/s]
n: total number of grid points in the market node
i: grid point

- Hourly average global horizontal irradiance for each market node [W/m^2]
- Hourly average cloud cover (nebulosity) for each market node [okta]

Onshore, offshore wind, solar PV and Concentrated Solar Power load factor time series

- Hourly normalised load factor time series for onshore and (if applicable) offshore wind production for each market node
- Hourly normalised load factor time series for solar PV production for each market node
- Hourly normalised load factor time series for concentrated solar power for each market node where relevant

Temperature time series

- Hourly city temperature time series [°C]

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1.2.4 Net Transfer Capacities

Assumptions on NTCs for each scenario 2020 and 2025 are based on TSO expertise (bottom up data collection). The transfer capacity between borders/ bidding zones, agreed between the respective TSOs, will be available within the data set 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 N-1 and operational security of these countries. For adequacy simulations, such constraints should be considered since they might be imposed for some borders (e.g. in the flow-based market coupling area) for reasons linked to internal grid stability and operational constraints.

Although an implementation of FBMC is already in place in some parts of the ENTSO-E zone (CWE), it is not considered in the MAF 2018 main results. The FBMC is only considered as an additional sensitivity analysis, testing different flow-based approaches. On the one hand, this is due to the fact that most ENTSO-E areas are still using an NTC approach. On the other hand, a common flow-based approach should be agreed, which would be applicable to the whole European perimeter and feasible to implement in all tools used in MAF.

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 and some High Voltage Alternating Current interconnections.

1.2.5 Thermal generation maintenance profile

The maintenance is understood as scheduled out-of-service network elements and in this case refers to thermal generating units. In the PEMMDB, it is possible to specify the number of days for maintenance and the percentage of maintenance that should be planned in winter/summer; additional constraints can be specified providing the maximum number of units for each generation technology type (nuclear, coal, etc.) being in maintenance for each week of the year.

An automated procedure has been adopted for the definition of the maintenance schedule of thermal generators for each area of the electrical system. The process is based on the principle of ‘constant reserve’: for each week of the year the difference between available thermal generation and residual load to be covered is calculated and the maintenance of each generator is never broken into discontinuous weeks.

A single maintenance schedule was calculated for each year horizon (2020, 2025) to be adopted from all the tools involved. Furthermore, maintenance schedules were not different among the various climatic years. This is conservative, however, and in line with the limited possibilities of adjusting planned maintenance work in reality (which is typically fixed between 6 and 12 months in advance).

It was verified that the use of a constant maintenance schedule for all climatic years does not significantly affect the adequacy evaluations. For a year with a high risk of unserved energy due to climatic conditions, a special maintenance profile has been tailored. Both evaluations with the common and the special maintenance schedule have shown similar results. Furthermore, it is worth mentioning that the maintenance schedule was calculated with two different tools and the adequacy results were comparable.

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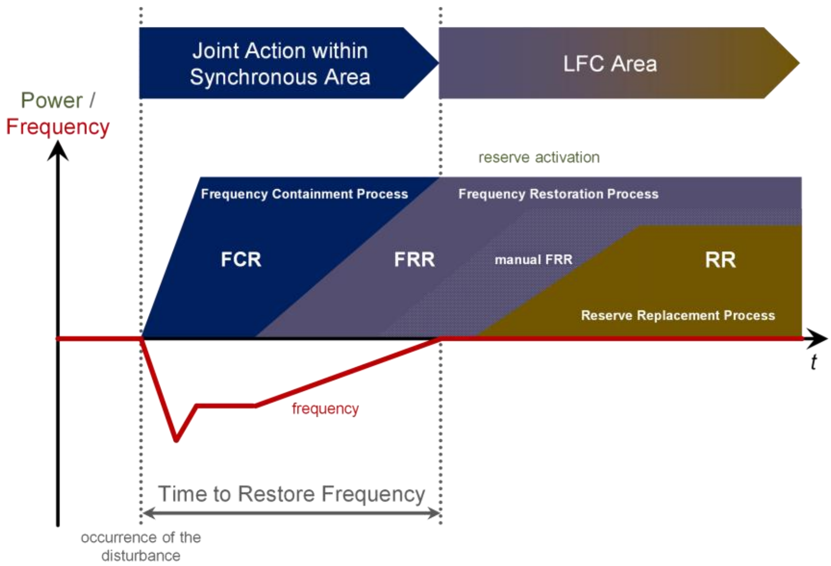
1.2.6 Reserves

Balancing reserves or ancillary services are 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 of certain sites. The aim is to compensate for the unbalance that could be caused by unforeseen loss of a production unit or demand/renewable forecasting errors. The balancing reserves are not responsible for maintaining the large-scale adequacy, and are deducted from available resources in the MAF.

Reserves

To permanently guarantee the balance between demand and generation of electrical energy, the TSO has to maintain certain levels of reserves. The reserve capacity is then requested when the electrical frequency deviates from its nominal value, possibly due to an unforeseen outage event which threatens the electrical stability of the system. Typically, fast acting conventional power plants are suitable for providing reserve capacity. In some cases, hydro power plants and interruptible loads are contracted.



In the event of major frequency deviations, the restoration process is guided by three reserve products:

1. *Frequency Containment Reserve (FCR)*
   refers to the active power reserves (automatically activated) available to contain system frequency after the occurrence of an unbalance.
2. *Automatic Frequency Restoration Reserve (aFRR)*
   stabilises the frequency and ensures the availability of the FCR is guaranteed. It is also utilised to maintain the balance of power imports and exports of a control area.
3. *Manual Frequency Restoration Reserve (mFRR)*
   guarantees the availability of the aFRR. It is manually activated (e.g. by ramping up/down generators) and is mostly used when there is a major disruption of the grid operation (e.g. failure of a generator).

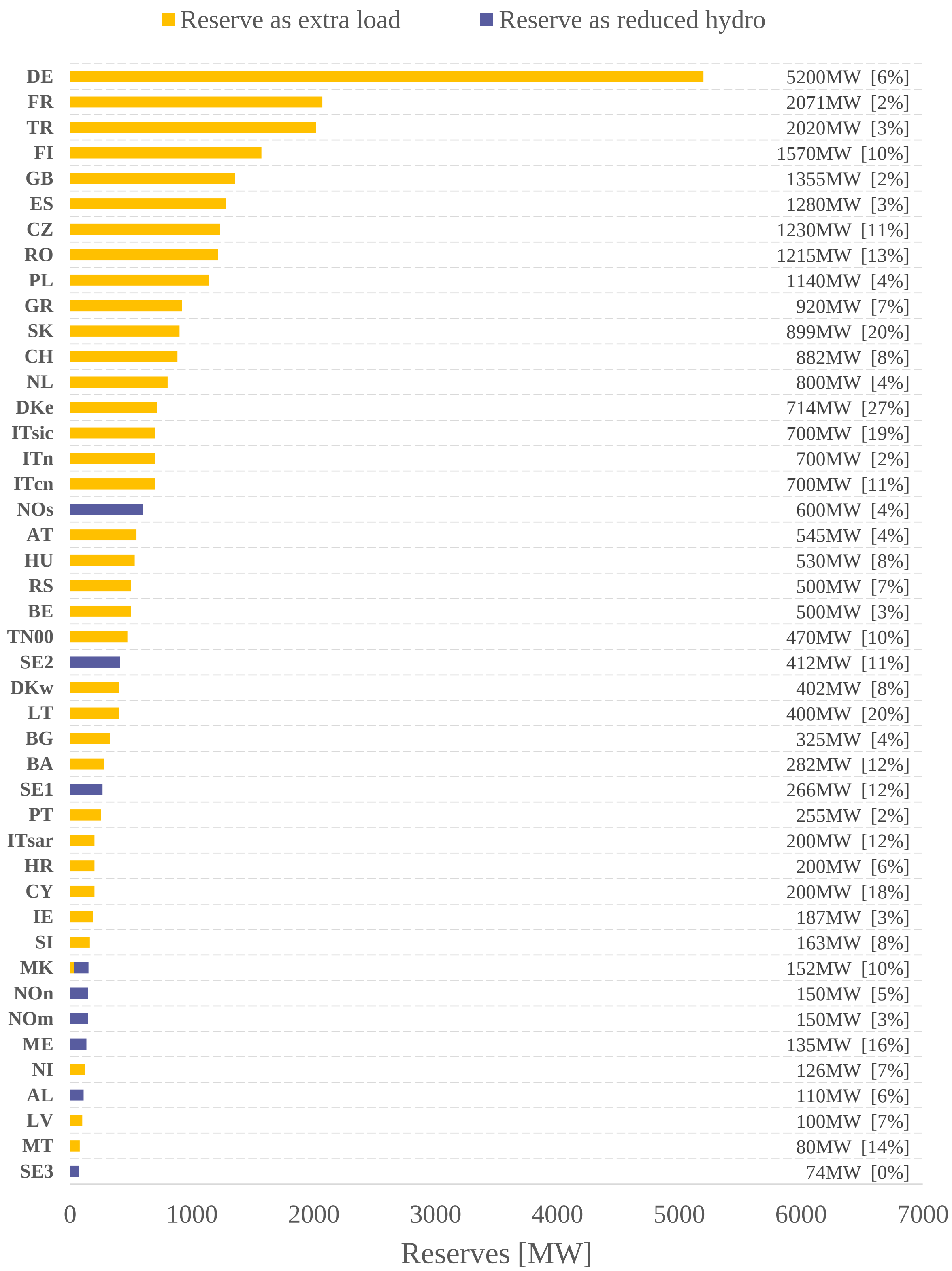


Figure 12: Reserved generation capacity as specified in the PEMMDB for 2020. Total reserved capacity is reported as a % of peak demand inside brackets.

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. They must therefore be removed from the available generation capacity. From a modelling perspective, this can be implemented in two ways: reducing the respective thermal generation capacity or increasing the demand by the hourly reserved capacity. For practical reasons, it was preferred to take reserves into account by adding them to consumption rather than applying a thermal capacity reduction. While this is easier to implement into the market models, it has the disadvantage of distorting the reported energy balance since 'virtual consumption' is added. Notably, in some countries, reserves are provided by hydroelectrical generation. In these cases, the maximum possible hydro generation is reduced by the reserved value. Furthermore, in special cases (e.g. where a TSO has agreements with large electricity users on demand reduction when needed or dedicated back-up power plants) the reserve specifications were directly coordinated with the data correspondent of the TSO.

Further assumptions regarding the modelling of operational reserves 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. Figure 12 presents an overview of the aforementioned data as used for the MAF assessment of year 2020.

1.2.7 Demand Side Response (DSR)

Based on the information specified in the PEMMDB, DSR is not modelled as a reduction of load, but as a set of flexible generators with discretely specified parameters. This modelling approach is feasible since Long-Term Adequacy Correspondents provided hourly availability of DSR assets in several price bands. The four distinctly modelled price bands enable more detailed simulations by considering, for example, industrial DSR and domestic DSR separately. Price bands are defined by a price (€/MWh) and a maximum number of hours of continuous availability of typical DSR installations. Since no economic analyses of the findings are carried out in the MAF framework[5], the price for the entirety of DSR assets is arbitrarily set to 500€/MWh, while the maximum number of available hours is respected in each band. The high price ensures its activation before loss of load, without interfering with the merit order dispatching. Thorough tests were conducted with all market modelling tools to ensure that this modelling approach is valid.

1.2.8 Other relevant parameters

To allow for a more accurate reflection of the diversity of generation technologies and better approach the operation in practice with respect to the simulated power plants and HVDC lines, basic parameters such as NGC, Number of Units and other additional technical parameters have been considered in the data collection. Some of these parameters present boundary conditions or thresholds that the VPs should comply with during the simulations.

Availability of the power system elements is considered in the simulation in two ways: i) Forced Outages and ii) Planned Outages. In the MAF, availability is considered on thermal power plants 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, with a focus on winter and summer, as well as the maximum number of simultaneously offline thermal units allowed within each month of the year, were specified by TSOs. Within these restrictions, an optimised maintenance schedule, common to all modelling tools, is prepared. Optimisation of the

[5] Note that investigations of economic indicators are foreseen for future editions of the MAF.

maintenance schedule refers to the minimisation of the number of units (simultaneously) in maintenance and the optimal distribution of the maintenance schedules to reduce the occurrence of potential adequacy problems, while respecting the constraints of their national power system provided by TSOs.

➔ **Forced outages** are represented by the parameter *Forced Outage Rate* (FOR) which defines the annual rate of forced outage occurrences of thermal power plants or grid elements. Forced outages are simulated by random occurrences of outages within the probabilistic Monte Carlo scheme, while respecting the annual rate defined. 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. Simulating the forced outages allows the resilience of a given area to be tested subject to such contingencies, potential adequacy problems that might occur and the ability of the area to share power (*via* spot market power and/or reserves).

Minimum stable generation (MW) is a parameter defining the technical minimum of the power output of a unit. The simulation does not allow the unit to run under this limit. It is defined by a percentage of the maximum power output of the unit.

Ramp up/down rates (MW/h) define the ability of the thermal power plant, which is already in operation, to increase/decrease its generation output within the range of its stable working area, which is constrained by the minimum stable generation parameter and the maximum power output.

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

Minimum Down Time parameter defines the minimum number of hours a unit must remain idle before it can be restarted. These parameters guarantee the optimal operation of units, e.g. prevents simulating units from being in and out in consecutive hours, if this is not compliant with the unit normal operation.

In addition to the main characteristics, other thermal characteristics have also been defined in the PEMMDB to allow for a more accurate reflection of the diversity of the different generation technologies.

1.3 Limitations of the MAF methodology

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

- **Perfect foresight and flexibility** is assumed. Wind, solar and demand forecast errors are considered to be modelled within the day-ahead fixed reserves, as MAF approach assumes a perfect day-ahead forecast. The anticipation of the future (next week, month) variables affecting optimal hydro dispatch is assumed in the model, while this is not the case in reality.
- **Energy-only market** is considered in MAF simulations. The MAF model considers neither the capacity nor the balancing market, both comprising an important topic that deserves further investigation in the future.
- **Perfect competition** is considered in the MAF simulations, assuming that no strategic behaviours are present in the market and all market agents behave competitively, revealing their true costs to the market.

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- **Uncertainty of decommissioning date** of thermal units. ENTSO-E is building a pan-European database with a higher level of granularity in terms of generation assets, to better cope with uncertainties related to decommissioning of thermal units.
- **Internal grid limitations within a bidding zone** are not considered in the base case approach. However, this was further investigated in innovative flow-based studies conducted as sensitivity analyses, which are presented in section 2.4. This topic needs further development and detailed comparison with the current MAF approach, also considering possible evolutions of the European market.

2 Detailed Model Results

This Section contains the detailed results of the market modelling studies for the MAF 2018. Primarily, it contains the detailed results of the base case scenario in years 2020 and 2025. In addition, several sensitivities and complementary results are presented.

Section 2 is divided into the following parts: Section 2.1 outlines the detailed results of the base case scenarios for the target years 2020 and 2025, while Section 2.2 presents the detailed results of the low-carbon sensitivity analysis. Section 2.3 offers a closer look at the hourly levels of imports and exports focusing on a test case for FR, BE and GB. The scope of this section is to investigate the hours of single or multiple simultaneous scarcity events. The innovative flow-based approaches are presented and explained in detail in Section 2.4, for both years 2020 and 2025. The impact of hydro constraints and their relaxation is then investigated in Section 462.5. Finally, a brief description of the methodology behind the Flexibility analysis, seen in the executive report, is presented in Section 2.6.

2.1 Base case results

In this section, the detailed simulation results of base case studies for the target years 2020 and 2025 are presented. In Section 2.1.1 below Table 2 and Table 3 present detailed results of the EENS and LOLE respectively, for all zones of the MAF. Apart from the LOLE and EENS values, which correspond to the average of all simulated results, the 50th and 95th percentiles of the distributions are also presented in the same tables. In Section 2.1.2, the LOLE results are illustrated for each of the modelling tools, i.e. results from VP1 to VP5, providing information about the statistical range of the simulation outcomes for each tool.

2.1.1 Adequacy in numbers – EENS and LOLE in 2020 and 2025

In this section, the base case scenario results are reported in tables. Results presented in the following tables correspond to the values extracted from the corresponding simulations and averaged among all tools, e.g. in base scenario 2020, the P50 value of Albania represents the average value of all P50 values of Albania considering all tools. Results of EENS and LOLE are provided, hereafter, for the base case scenarios 2020 and 2025.

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Table 2: EENS results for base case scenarios 2020 and 2025 by zone [6]

Zone Code	EENS - Base case scenario 2020				EENS - Base case scenario 2025			
	EENS [GWh]	EENS / Annual Demand [%]	P50 [GWh]	P95 [GWh]	EENS [GWh]	EENS / Annual Demand [%]	P50 [GWh]	P95 [GWh]
AL	0.1	0.001%	0.0	0.4	0.1	0.001%	0.0	0.3
AT	0.0	0.000%	0.0	0.0	0.0	0.000%	0.0	0.0
BA	0.0	0.000%	0.0	0.0	0.0	0.000%	0.0	0.0
BE	0.1	0.000%	0.0	0.0	3.4	0.004%	0.2	17.5
BG	6.7	0.017%	3.7	22.7	0.0	0.000%	0.0	0.1
CH	0.0	0.000%	0.0	0.0	0.0	0.000%	0.0	0.0
CY	6.0	0.102%	5.0	13.8	146.1	2.116%	143.6	197.9
CZ	0.0	0.000%	0.0	0.0	0.0	0.000%	0.0	0.0
DE	0.0	0.000%	0.0	0.0	0.0	0.000%	0.0	0.0
DEkf	0.0	0.000%	0.0	0.0	0.0	0.000%	0.0	0.0
DKe	0.0	0.000%	0.0	0.0	0.1	0.000%	0.0	0.3
DKkf	0.0	0.000%	0.0	0.0	0.0	0.000%	0.0	0.0
DKw	0.0	0.000%	0.0	0.0	0.0	0.000%	0.0	0.0
EE	0.0	0.000%	0.0	0.0	0.0	0.000%	0.0	0.0
ES	0.0	0.000%	0.0	0.0	0.0	0.000%	0.0	0.0
FI	1.2	0.001%	0.2	5.0	0.3	0.000%	0.0	1.5
FR	8.4	0.002%	0.0	18.1	10.0	0.002%	0.0	27.4
GB	1.4	0.000%	0.2	7.7	2.8	0.001%	0.4	15.2
GR	0.9	0.002%	0.1	4.7	0.2	0.000%	0.0	0.9
GR03[7]	2.6	0.083%	2.0	7.5	2.7	0.077%	1.8	8.1
HR	0.0	0.000%	0.0	0.0	0.0	0.000%	0.0	0.0
HU	0.0	0.000%	0.0	0.0	0.0	0.000%	0.0	0.0
IE	0.0	0.000%	0.0	0.0	0.7	0.002%	0.3	2.9
IS	0.0	0.000%	0.0	0.0	0.2	0.000%	0.0	0.6
ITcn	0.0	0.000%	0.0	0.0	0.6	0.002%	0.2	2.8
ITcs	0.0	0.000%	0.0	0.0	0.0	0.000%	0.0	0.0
ITn	0.1	0.000%	0.0	0.1	1.6	0.001%	0.0	4.7
ITs	0.0	0.000%	0.0	0.0	0.0	0.000%	0.0	0.0
ITsar	0.0	0.000%	0.0	0.0	0.1	0.001%	0.0	0.6
ITsic	0.7	0.004%	0.3	2.4	0.1	0.000%	0.0	0.5
LT	0.0	0.000%	0.0	0.1	0.0	0.000%	0.0	0.0
LUb	0.0	0.006%	0.0	0.1	0.1	0.028%	0.0	0.4
LUf	0.3	0.025%	0.0	1.0	0.4	0.034%	0.0	1.7
LUg	0.0	0.000%	0.0	0.0	0.3	0.006%	0.1	1.2
LUv	0.0	0.000%	0.0	0.0	0.0	0.000%	0.0	0.0

[6] For the definition of zone codes, see Section 4.1.

[7] Considering recent development plans of the Independent Power Transmission Operator (Greece), it is estimated that Crete will have better adequacy levels for year 2025 than the ones presented in the table, as a result of higher interconnection capacity.

LV	0.0	0.000%	0.0	0.1	0.0	0.000%	0.0	0.0
ME	0.0	0.000%	0.0	0.0	0.0	0.000%	0.0	0.0
MK	0.0	0.000%	0.0	0.0	0.0	0.000%	0.0	0.0
MT	0.4	0.017%	0.2	1.6	0.7	0.025%	0.2	2.8
NI	0.3	0.003%	0.1	1.4	0.4	0.004%	0.1	1.8
NL	0.0	0.000%	0.0	0.0	0.2	0.000%	0.0	0.9
NOm	0.0	0.000%	0.0	0.0	0.0	0.000%	0.0	0.0
NOn	0.0	0.000%	0.0	0.0	0.0	0.000%	0.0	0.0
NOs	1.0	0.001%	0.0	5.5	0.0	0.000%	0.0	0.1
PL	0.0	0.000%	0.0	0.0	0.7	0.000%	0.1	3.8
PT	0.0	0.000%	0.0	0.0	0.0	0.000%	0.0	0.0
RO	0.0	0.000%	0.0	0.0	0.0	0.000%	0.0	0.0
RS	0.0	0.000%	0.0	0.0	0.0	0.000%	0.0	0.0
SE1	0.0	0.000%	0.0	0.0	0.0	0.000%	0.0	0.0
SE2	0.0	0.000%	0.0	0.0	0.0	0.000%	0.0	0.0
SE3	0.0	0.000%	0.0	0.0	0.0	0.000%	0.0	0.0
SE4	0.0	0.000%	0.0	0.0	0.0	0.000%	0.0	0.0
SI	0.0	0.000%	0.0	0.0	0.0	0.000%	0.0	0.0
SK	0.0	0.000%	0.0	0.0	0.0	0.000%	0.0	0.0
TN00	7.8	0.031%	6.0	20.8	0.2	0.001%	0.0	1.1
TR	0.0	0.000%	0.0	0.0	0.0	0.000%	0.0	0.0

Table 3: LOLE [h/year] results for base case scenarios 2020 and 2025 by zone

Zone Code	LOLE - Base case scenario 2020			LOLE - Base case scenario 2025		
	LOLE [h/year]	P50 [h/year]	P95 [h/year]	LOLE [h/year]	P50 [h/year]	P95 [h/year]
AL	0.43	0.00	2.02	0.21	0.00	1.00
AT	0.00	0.00	0.00	0.00	0.00	0.00
BA	0.00	0.00	0.00	0.00	0.00	0.00
BE	0.07	0.00	0.06	2.02	0.22	10.83
BG	20.71	15.52	57.84	0.14	0.00	0.30
CH	0.01	0.00	0.00	0.04	0.00	0.01
CY	76.50	69.23	144.20	1199.47	1198.56	1469.07
CZ	0.00	0.00	0.00	0.01	0.00	0.00
DE	0.00	0.00	0.00	0.00	0.00	0.00
DEkf	0.00	0.00	0.00	0.00	0.00	0.00
DKe	0.02	0.00	0.00	0.15	0.00	0.62
DKkf	0.00	0.00	0.00	0.00	0.00	0.00
DKw	0.00	0.00	0.00	0.00	0.00	0.00
EE	0.06	0.03	0.24	0.00	0.00	0.02
ES	0.00	0.00	0.00	0.00	0.00	0.00
FI	3.56	0.80	18.65	0.72	0.00	4.61
FR	1.96	0.00	7.25	2.08	0.00	8.44

GB	1.29	0.29	6.14	1.30	0.41	6.33
GR	2.25	0.63	11.41	0.43	0.00	1.88
GR03	59.21	51.03	141.58	54.06	42.78	141.72
HR	0.00	0.00	0.00	0.00	0.00	0.00
HU	0.00	0.00	0.00	0.00	0.00	0.00
IE	0.01	0.00	0.00	3.23	1.84	11.65
IS	0.00	0.00	0.00	0.27	0.20	0.80
ITcn	0.04	0.00	0.06	1.31	0.44	5.85
ITcs	0.00	0.00	0.00	0.01	0.00	0.00
ITn	0.07	0.00	0.11	0.85	0.00	3.74
ITs	0.00	0.00	0.00	0.00	0.00	0.00
ITsar	0.04	0.00	0.20	0.97	0.33	4.17
ITsic	3.56	2.04	11.00	0.51	0.12	2.35
LT	0.21	0.18	0.52	0.01	0.00	0.03
LUb	0.62	0.00	2.48	2.62	0.46	14.49
LUf	2.36	0.00	7.91	3.10	0.00	12.94
LUg	0.00	0.00	0.00	1.09	0.20	5.88
LUv	0.00	0.00	0.00	0.00	0.00	0.00
LV	0.18	0.10	0.64	0.01	0.00	0.02
ME	0.00	0.00	0.00	0.00	0.00	0.00
MK	0.00	0.00	0.00	0.00	0.00	0.00
MT	8.55	4.15	32.34	13.56	5.12	54.51
NI	2.80	0.76	12.57	2.64	1.20	11.94
NL	0.00	0.00	0.00	0.21	0.00	1.13
NOm	0.01	0.00	0.03	0.00	0.00	0.00
NOn	0.00	0.00	0.00	0.00	0.00	0.00
NOs	0.80	0.00	4.28	0.04	0.00	0.40
PL	0.03	0.00	0.09	1.44	0.57	6.39
PT	0.00	0.00	0.00	0.04	0.00	0.02
RO	0.00	0.00	0.00	0.00	0.00	0.00
RS	0.00	0.00	0.00	0.00	0.00	0.00
SE1	0.00	0.00	0.00	0.00	0.00	0.00
SE2	0.00	0.00	0.00	0.00	0.00	0.00
SE3	0.00	0.00	0.00	0.00	0.00	0.00
SE4	0.11	0.00	0.25	0.11	0.00	0.25
SI	0.00	0.00	0.00	0.00	0.00	0.00
SK	0.00	0.00	0.00	0.01	0.00	0.05
TN00	38.51	34.61	82.93	1.05	0.13	5.73
TR	0.00	0.00	0.00	0.00	0.00	0.00

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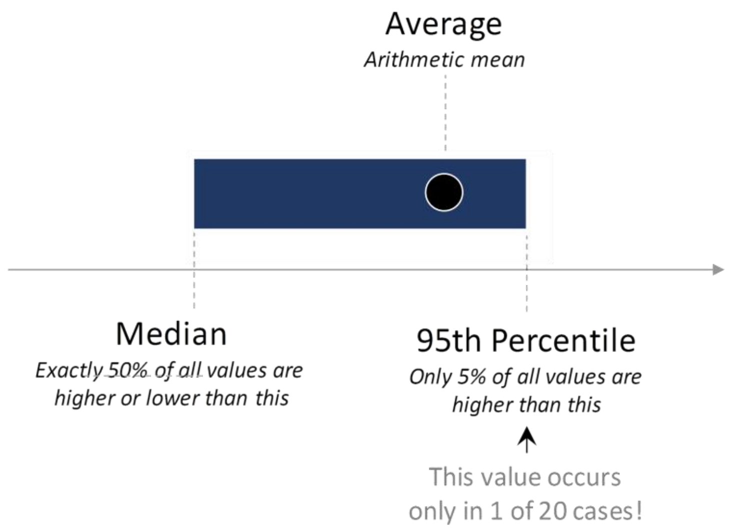
2.1.2 Detailed results of all modelling tools

Bar charts in Section **Error! Reference source not found.** indicate the probabilistic range of the adequacy index LOLE in 2020, namely the 50th and 95th percentiles of the distributions of simulation results (or in other words, the results for the risk of 1 in 2 years to 1 in 20 years). Moreover, average values of adequacy indices (LOLE) of all simulated climatic years are represented as dots for all simulation tools. Figure 13 below illustrates how the results are presented in this section.

How to read the results?

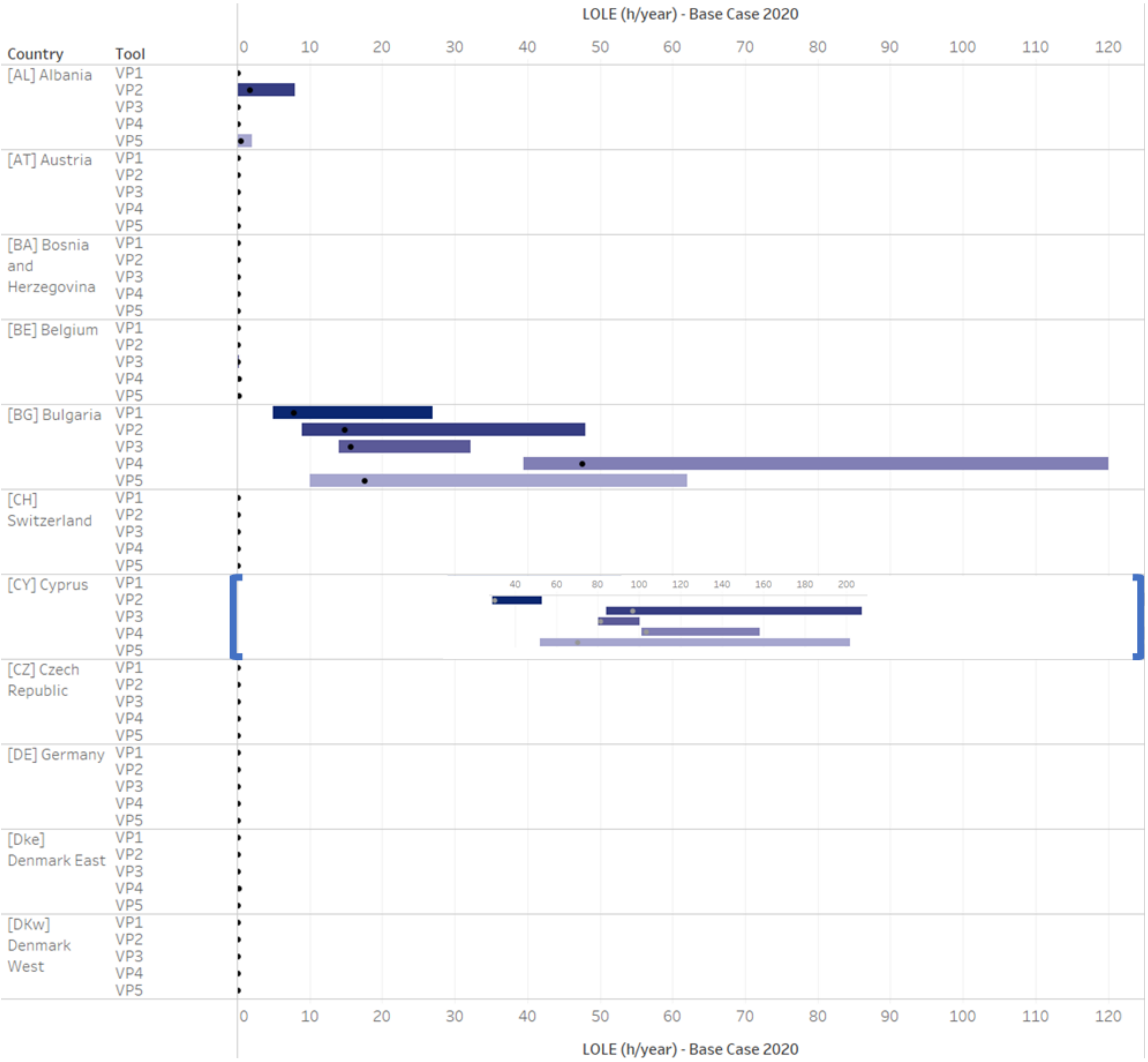


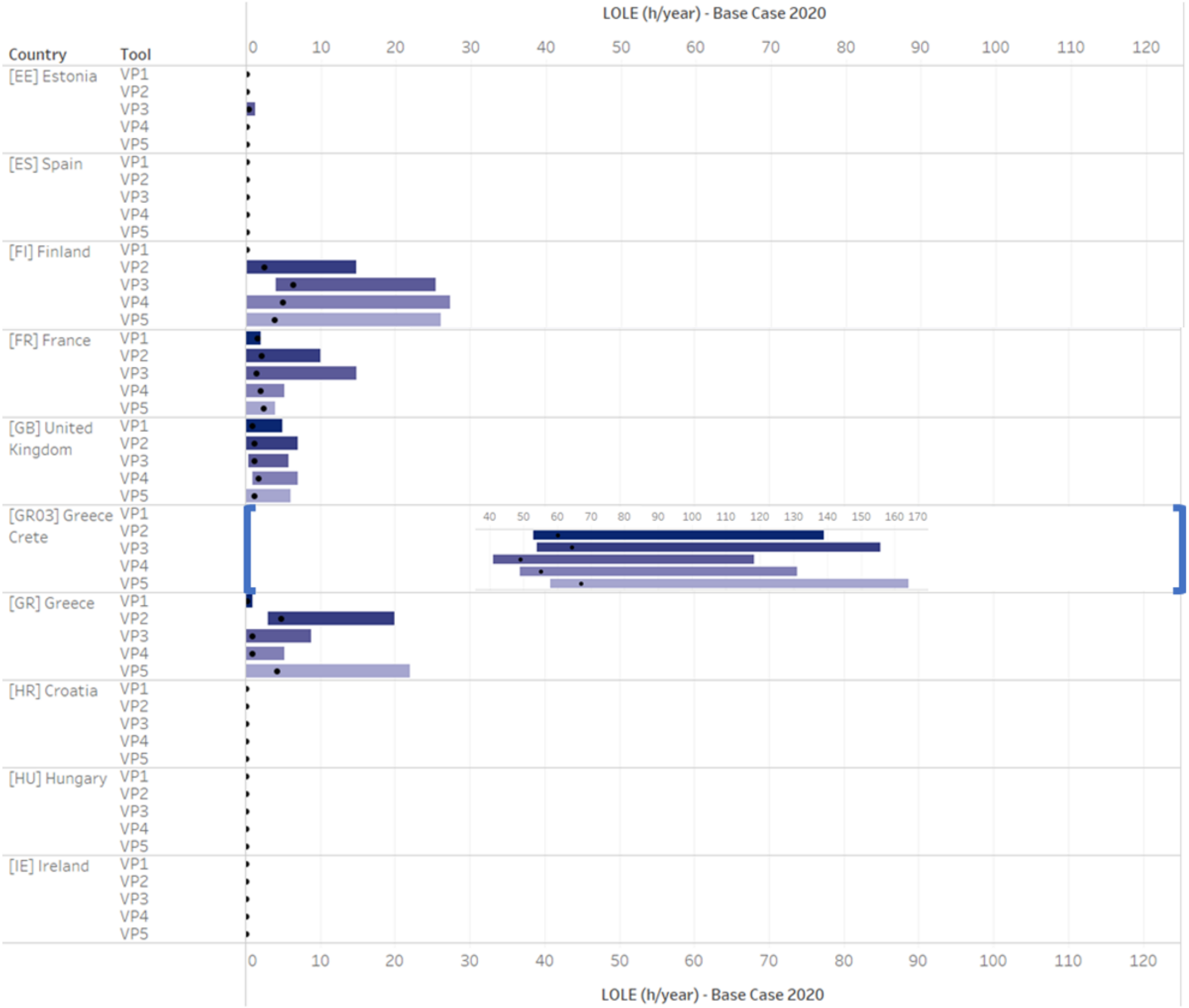
Example:
A market modelling tool calculates LOLE for 100 Monte Carlo years. The 95th percentile (often abbreviated as P95) of the results' distribution is the 5th highest value observed. This corresponds to a probability of '1 in 20'.

Figure 13: How to read the illustrated detailed MAF results

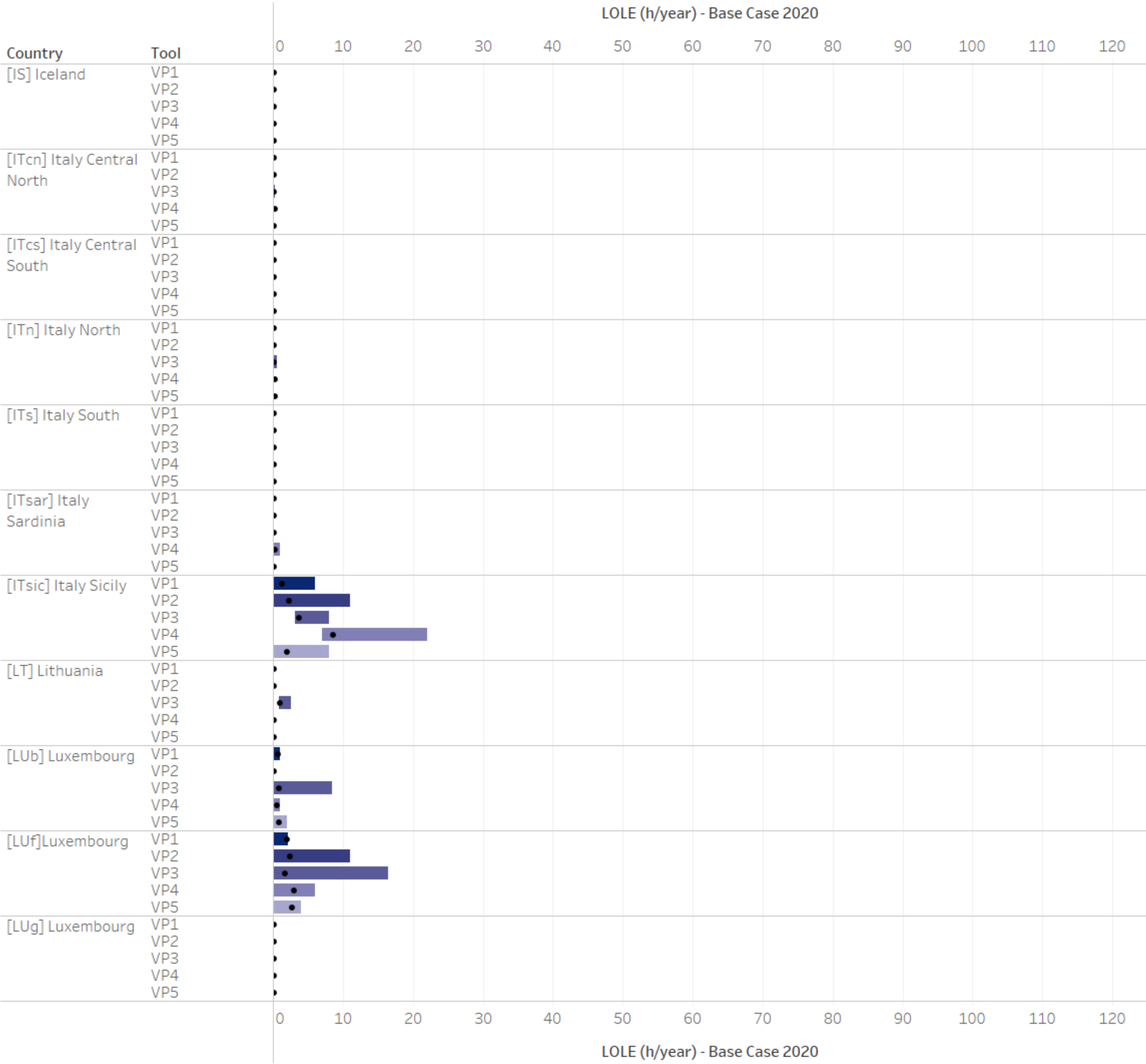
2.1.2.1 Adequacy results in 2020

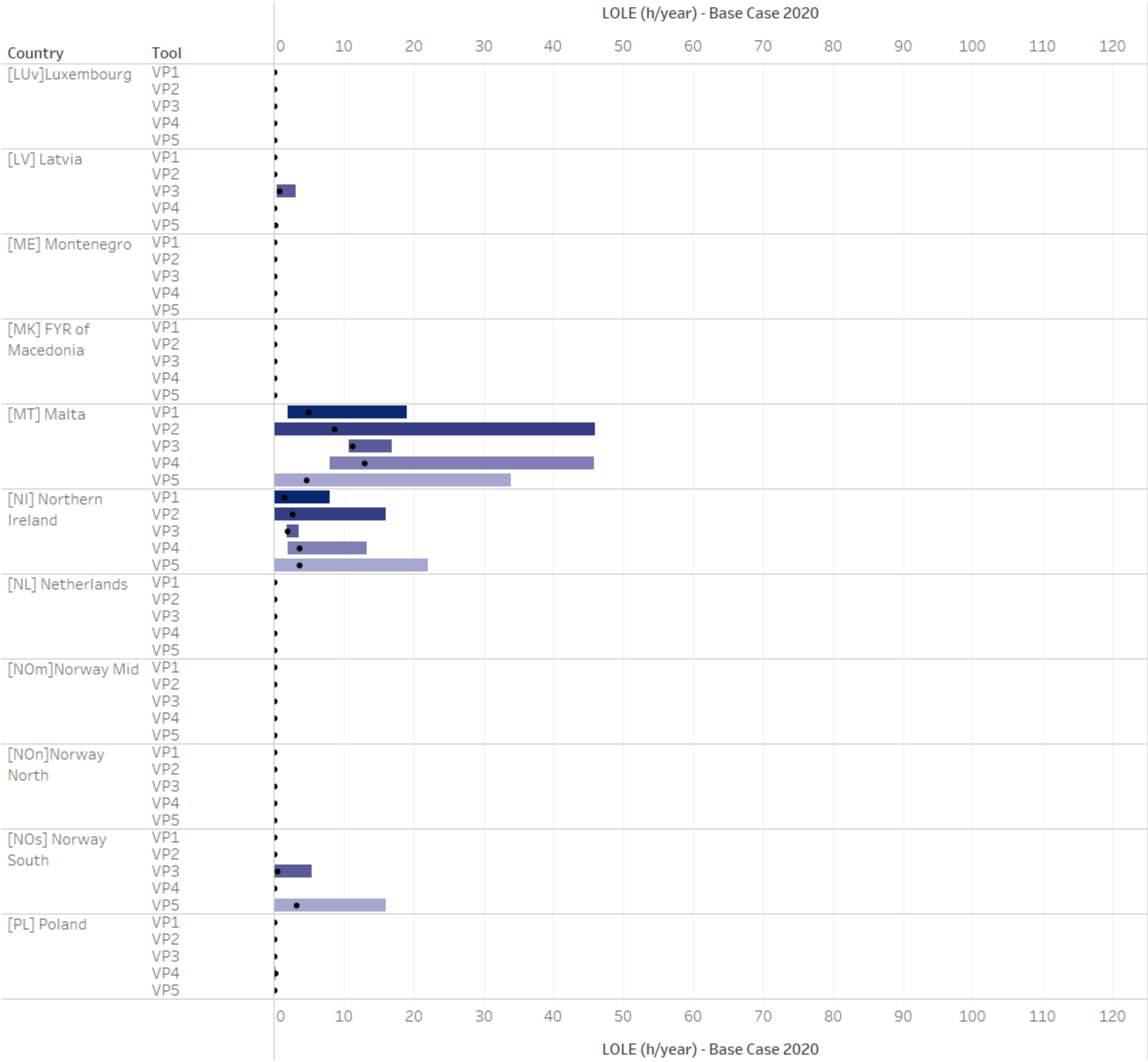
Figure 14 - Base Case 2020 - LOLE results by tool

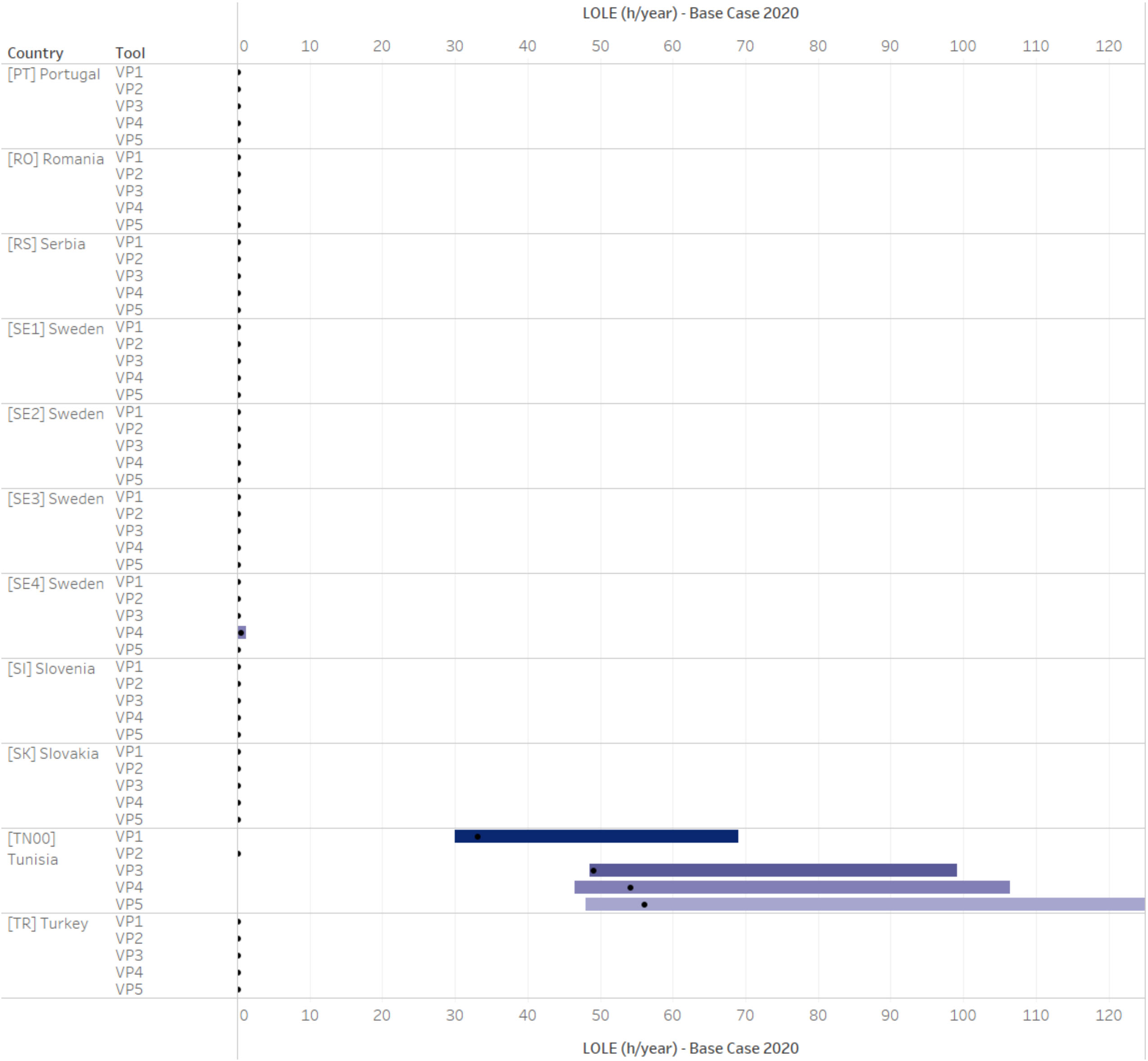




LOLE (h/year) - Base Case 2020
Country
Tool
[EE] Estonia
[ES] Spain
[FI] Finland
[FR] France
[GB] United Kingdom
[GR03] Greece Crete
[GR] Greece
[HR] Croatia
[HU] Hungary
[IE] Ireland
VP1
VP2
VP3
VP4
VP5
0 10 20 30 40 50 60 70 80 90 100 110 120
40 50 60 70 80 90 100 110 120 130 140 150 160 170


LOLE (h/year) - Base Case 2020
Country
Tool
0
10
20
30
40
50
60
70
80
90
100
110
120
[IS] Iceland
[ITcn] Italy Central North
[ITcs] Italy Central South
[ITn] Italy North
[ITs] Italy South
[ITsar] Italy Sardinia
[ITsic] Italy Sicily
[LT] Lithuania
[LUb] Luxembourg
[LUf]Luxembourg
[LUg] Luxembourg
VP1
VP2
VP3
VP4
VP5

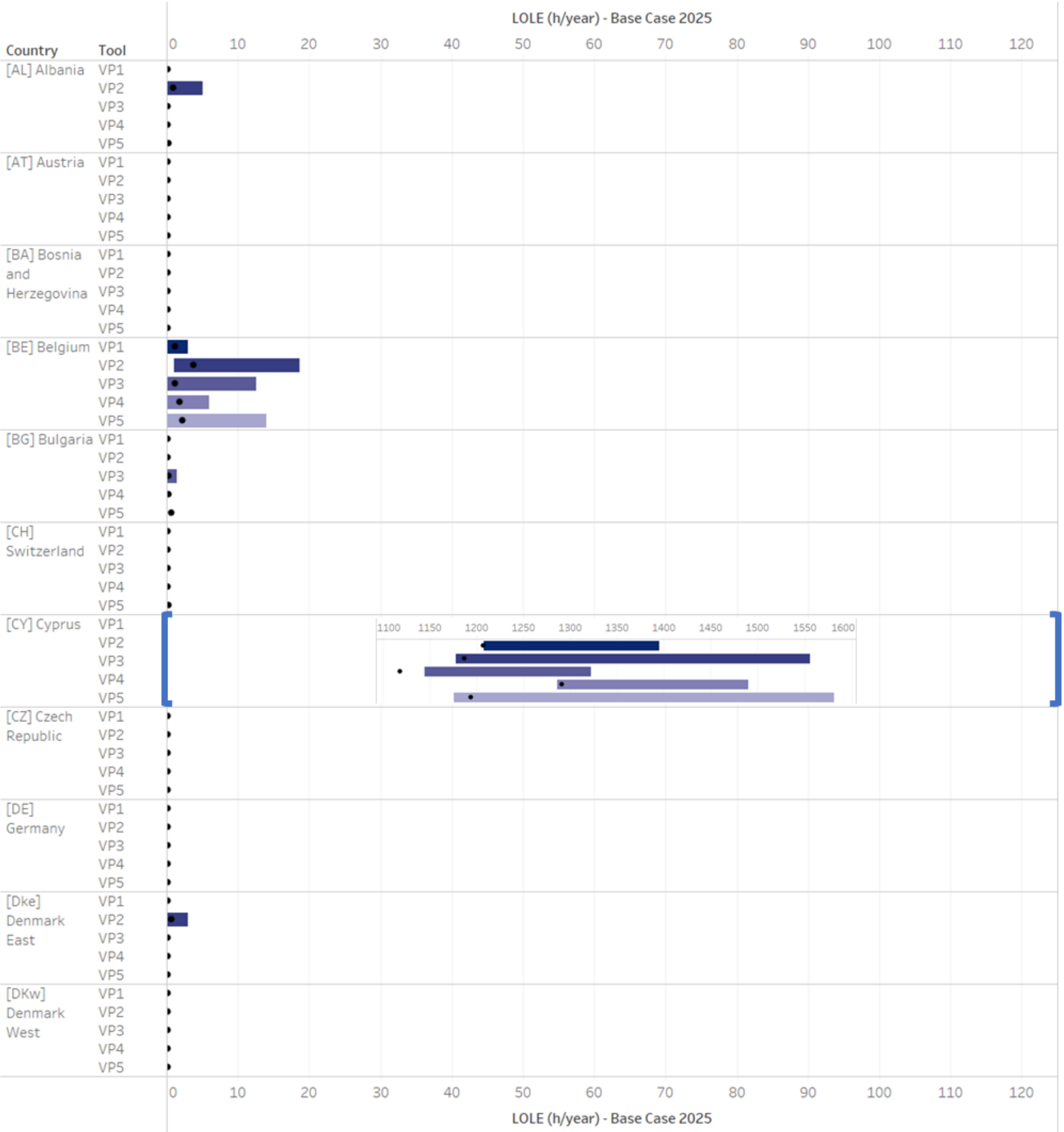

LOLE (h/year) - Base Case 2020
Country
Tool
0 10 20 30 40 50 60 70 80 90 100 110 120
[LUv]Luxembourg
[LV] Latvia
[ME] Montenegro
[MK] FYR of Macedonia
[MT] Malta
[NI] Northern Ireland
[NL] Netherlands
[NOm]Norway Mid
[NOn]Norway North
[NOs] Norway South
[PL] Poland
VP1
VP2
VP3
VP4
VP5


LOLE (h/year) - Base Case 2020
Country
Tool
0 10 20 30 40 50 60 70 80 90 100 110 120
[PT] Portugal
[RO] Romania
[RS] Serbia
[SE1] Sweden
[SE2] Sweden
[SE3] Sweden
[SE4] Sweden
[SI] Slovenia
[SK] Slovakia
[TN00] Tunisia
[TR] Turkey
VP1
VP2
VP3
VP4
VP5
LOLE (h/year) - Base Case 2020

2.1.2.2 Adequacy results in 2025

Compared to the 2020 scenario, MAF 2018 results for 2025 demonstrate better results for Bulgaria (due to the envisaged commissioning of new CCGT plants) and Finland, which experiences some risk of high LOLE in the 2020 scenario. On the other hand, a comparative increase in the LOLE values appears for Belgium, Italy, Ireland and Poland in the 2025 assessment.

Figure 15 - Base Case 2025 - LOLE results by tool



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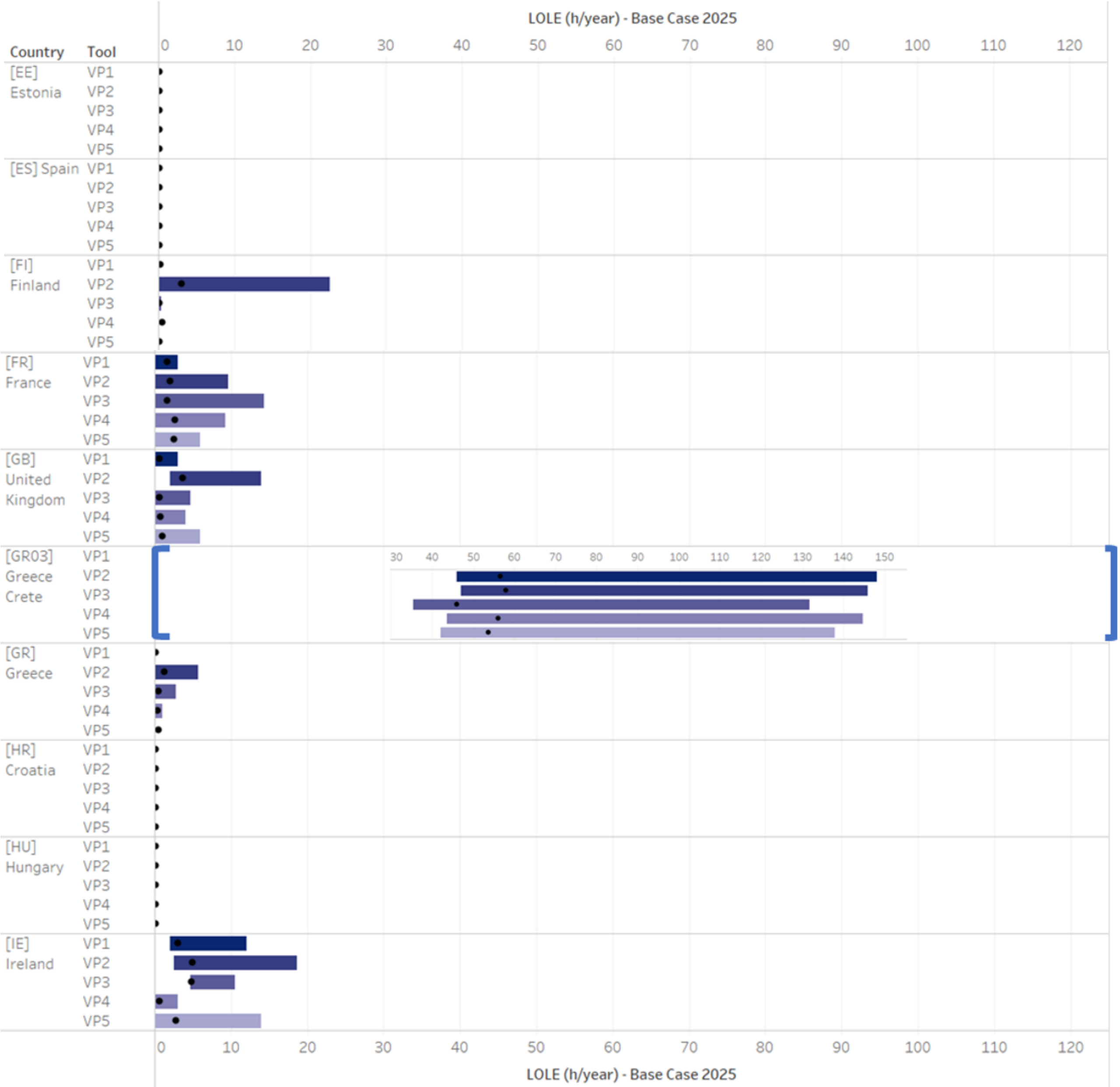

LOLE (h/year) - Base Case 2025
Country
Tool
0
10
20
30
40
50
60
70
80
90
100
110
120
[EE] Estonia
[ES] Spain
[FI] Finland
[FR] France
[GB] United Kingdom
[GR03] Greece Crete
[GR] Greece
[HR] Croatia
[HU] Hungary
[IE] Ireland
VP1
VP2
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VP5
30
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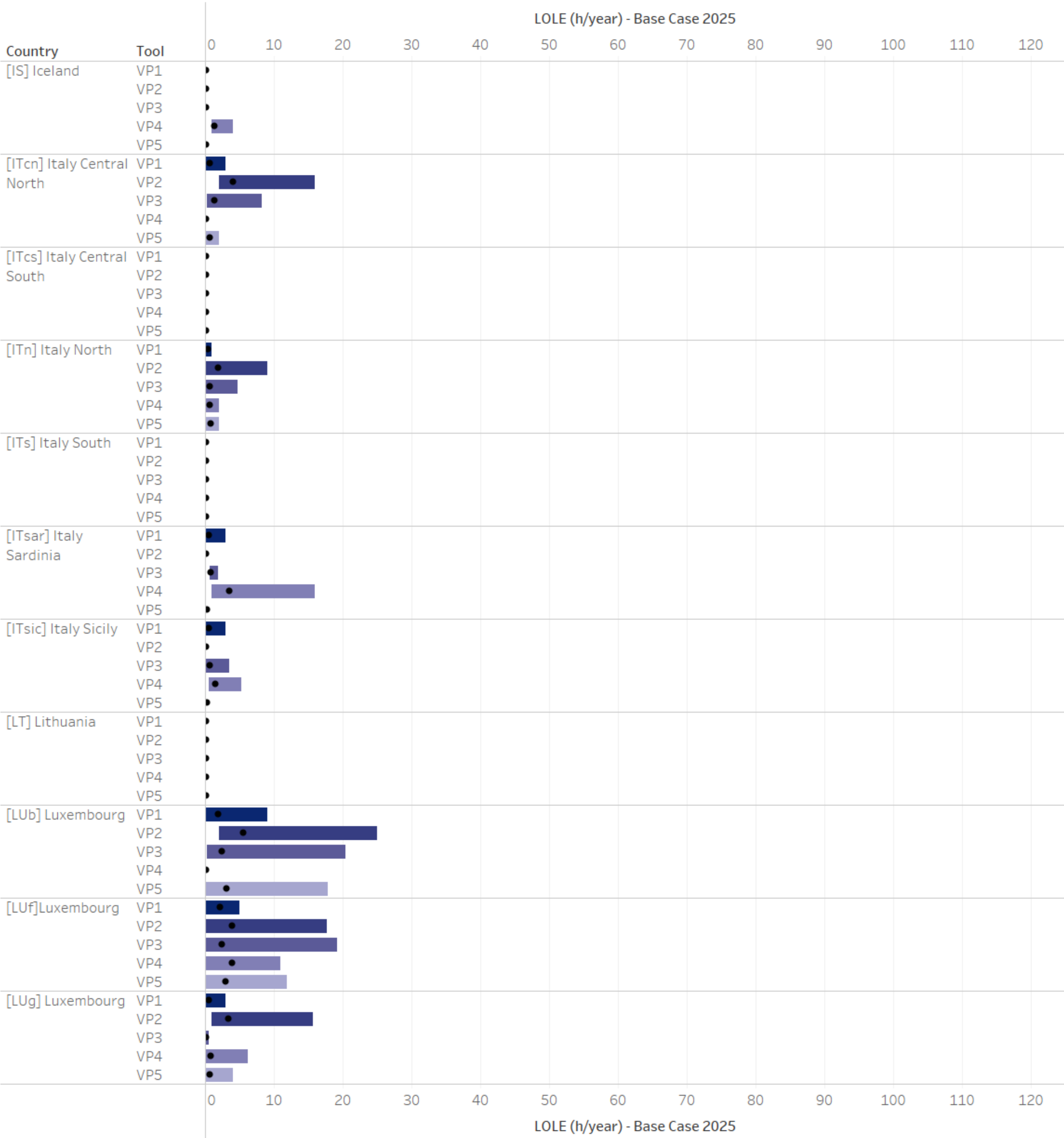
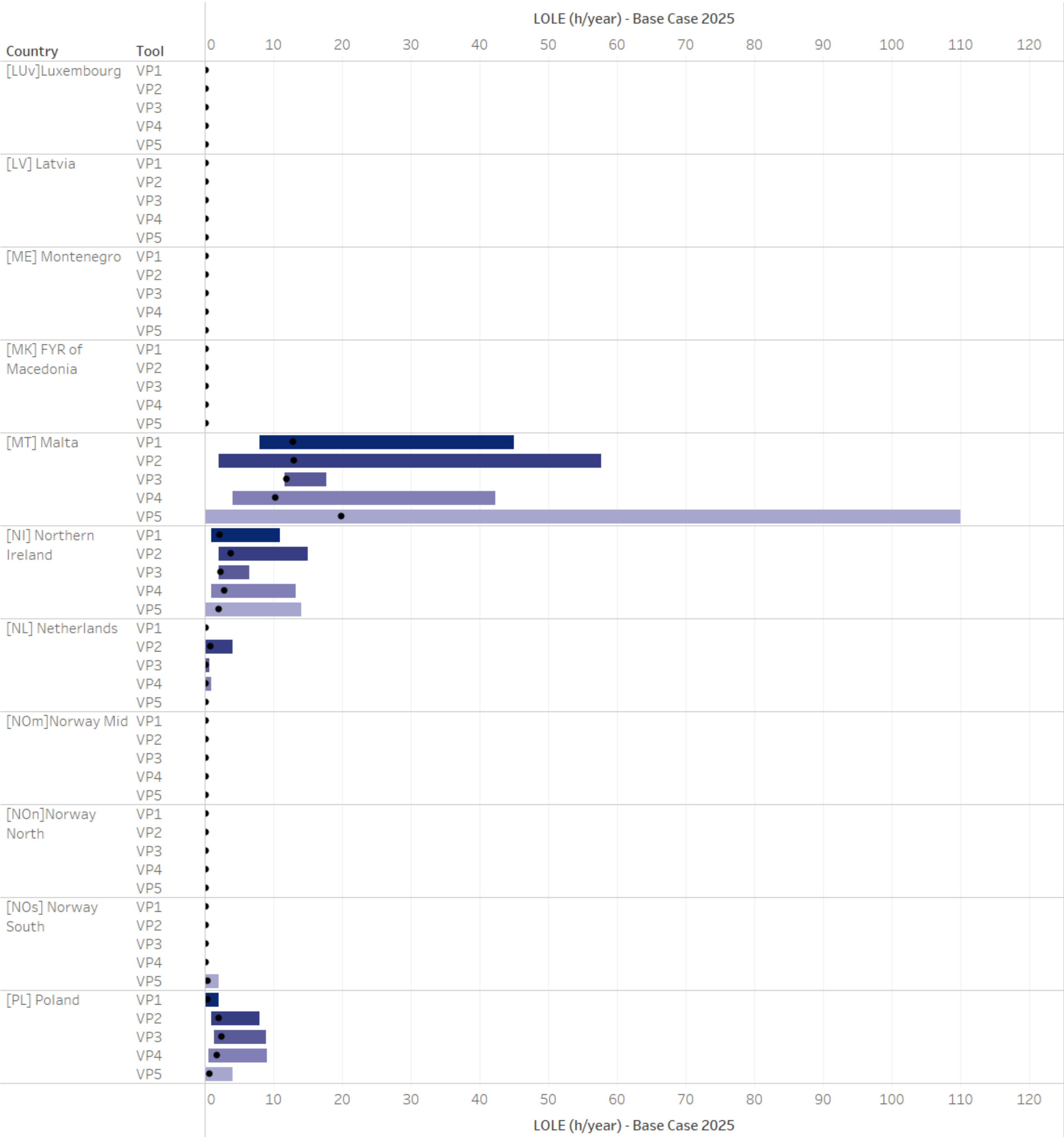
150


LOLE (h/year) - Base Case 2025
Country
Tool
0 10 20 30 40 50 60 70 80 90 100 110 120
[IS] Iceland
[ITcn] Italy Central North
[ITcs] Italy Central South
[ITn] Italy North
[ITs] Italy South
[ITsar] Italy Sardinia
[ITsic] Italy Sicily
[LT] Lithuania
[LUb] Luxembourg
[LUf]Luxembourg
[LUg] Luxembourg
VP1
VP2
VP3
VP4
VP5


LOLE (h/year) - Base Case 2025
Country
Tool
0
10
20
30
40
50
60
70
80
90
100
110
120
[LUv]Luxembourg
[LV] Latvia
[ME] Montenegro
[MK] FYR of Macedonia
[MT] Malta
[NI] Northern Ireland
[NL] Netherlands
[NOm]Norway Mid
[NOn]Norway North
[NOs] Norway South
[PL] Poland
VP1
VP2
VP3
VP4
VP5


LOLE (h/year) - Base Case 2025
Country
Tool
0 10 20 30 40 50 60 70 80 90 100 110 120
[PT] Portugal
[RO] Romania
[RS] Serbia
[SE1] Sweden
[SE2] Sweden
[SE3] Sweden
[SE4] Sweden
[SI] Slovenia
[SK] Slovakia
[TN00] Tunisia
[TR] Turkey
VP1
VP2
VP3
VP4
VP5
LOLE (h/year) - Base Case 2025

2.2 Low-carbon sensitivity

Motivated by environmental policies, MAF 2018 incorporates a 'what-if' analysis to account for adequacy results in the year 2025 in case low-carbon policies lead to an accelerated reduction of thermal capacity. To this end, information regarding potential reduction in installed capacity and decommissioning of units was collected from TSOs. This is considered as a stress test, as the decommissioned high carbonized generation was not replaced by any other resource. The main results and input of this sensitivity analysis have been presented in the executive report. In total, 23.35 GW were removed from the 2025 base case scenario. In Table 4 and Table 5, the detailed results in terms of EENS and LOLE, including the P50 and P95 values, are presented for this sensitivity analysis.

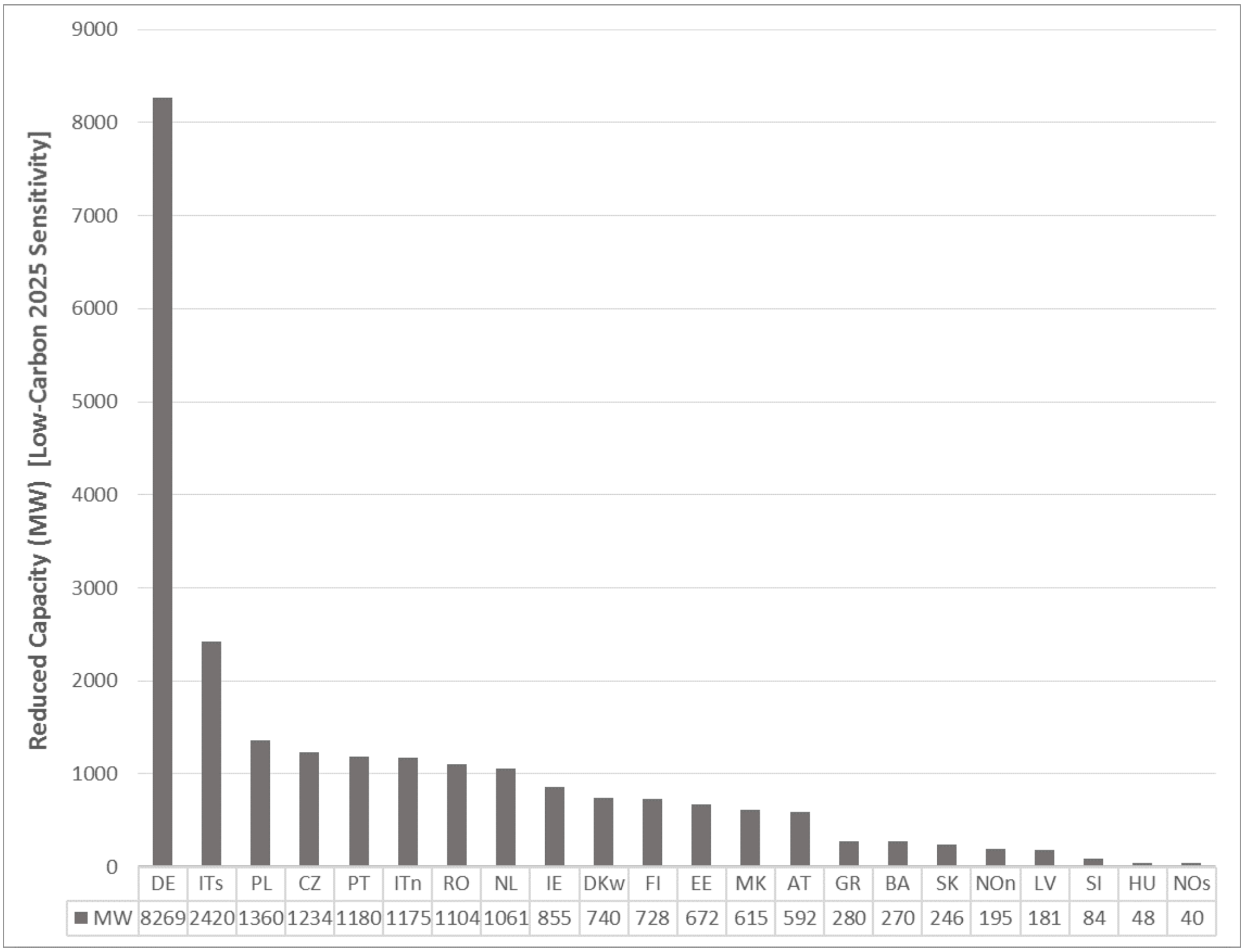


Figure 16:Generation capacity flagged as at risk of being decommissioned by 2025 and consequently removed in the low-carbon sensitivity

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Table 4: EENS results for low-carbon sensitivity 2025 by zone

Zone Code	EENS - Low-carbon Sensitivity 2025			
	EENS [GWh]	EENS / Annual Demand [%]	P50 [GWh]	P95 [GWh]
AL	0.8	0.009%	0.4	3.1
AT	0.6	0.001%	0.0	3.4
BA	0.1	0.000%	0.0	0.4
BE	34.2	0.040%	4.9	197.5
BG	0.2	0.001%	0.0	1.1
CH	1.1	0.002%	0.0	5.1
CY	147.2	2.132%	146.1	196.9
CZ	4.8	0.007%	0.6	25.2
DE	9.7	0.002%	0.3	52.6
DEkf	0.0	0.000%	0.0	0.0
DKe	1.9	0.012%	0.2	9.7
DKkf	0.0	0.000%	0.0	0.0
DKw	0.6	0.002%	0.0	2.8
EE	0.5	0.005%	0.0	2.7
ES	0.0	0.000%	0.0	0.0
FI	1.5	0.002%	0.0	8.2
FR	31.2	0.007%	0.0	171.7
GB	13.2	0.004%	2.5	71.7
GR	1.3	0.002%	0.3	6.1
GR03	4.0	0.115%	2.6	11.6
HR	0.2	0.001%	0.0	1.5
HU	0.9	0.002%	0.0	4.8
IE	28.3	0.090%	25.7	58.2
IS	0.3	0.000%	0.4	0.6
ITcn	6.2	0.017%	2.7	25.0
ITcs	0.3	0.001%	0.0	1.6
ITn	26.7	0.014%	4.2	135.4
ITs	0.0	0.000%	0.0	0.0
ITsar	0.5	0.005%	0.1	2.1
ITsic	0.3	0.002%	0.0	1.6
LT	0.7	0.005%	0.0	3.6
LUb	0.5	0.193%	0.1	2.2
LUf	1.7	0.137%	0.2	8.6
LUg	9.2	0.163%	2.6	45.5
LUv	0.0	0.000%	0.0	0.0
LV	0.2	0.002%	0.0	1.0
ME	0.0	0.000%	0.0	0.0
MK	0.6	0.007%	0.1	2.8
MT	0.7	0.024%	0.3	2.4
NI	2.9	0.031%	1.9	8.8

NL	5.7	0.005%	2.3	22.6
NOm	0.0	0.000%	0.0	0.0
NOn	0.0	0.000%	0.0	0.0
NOs	0.4	0.000%	0.0	2.1
PL	7.0	0.004%	3.1	28.4
PT	0.9	0.002%	0.0	4.5
RO	0.2	0.000%	0.0	1.3
RS	0.1	0.000%	0.0	0.5
SE1	0.0	0.000%	0.0	0.0
SE2	0.0	0.000%	0.0	0.0
SE3	0.0	0.000%	0.0	0.2
SE4	1.0	0.004%	0.0	4.2
SI	0.1	0.000%	0.0	0.5
SK	1.2	0.004%	0.2	5.7
TN00	0.3	0.001%	0.0	1.6
TR	0.1	0.000%	0.0	0.7

Table 5: LOLE [h/year] results for low-carbon sensitivity 2025 by zone

Zone Code	LOLE - Low-carbon Sensitivity 2025		
	LOLE [h/year]	P50 [h/year]	P95 [h/year]
AL	2.35	1.50	7.54
AT	0.67	0.00	4.40
BA	0.17	0.00	1.20
BE	12.28	2.95	60.26
BG	0.70	0.00	3.66
CH	0.88	0.00	4.83
CY	1205.60	1206.65	1488.69
CZ	6.02	1.50	29.72
DE	3.26	0.62	15.80
DEkf	0.00	0.00	0.00
DKe	3.94	1.23	20.29
DKkf	0.00	0.00	0.00
DKw	1.70	0.43	8.03
EE	1.82	0.16	8.88
ES	0.01	0.00	0.00
FI	3.25	0.13	17.83
FR	6.07	0.00	33.82
GB	5.02	1.95	24.66
GR	2.28	0.83	9.56
GR03	58.05	46.18	148.04
HR	0.29	0.00	1.98
HU	0.76	0.00	4.02
IE	92.72	87.95	165.50

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IS	0.41	0.40	0.80
ITcn	8.97	4.80	34.13
ITcs	0.61	0.02	3.43
ITn	8.59	2.26	42.68
ITs	0.01	0.00	0.00
ITsar	2.72	0.88	10.85
ITsic	1.24	0.29	5.95
LT	1.90	0.29	10.16
LUb	17.77	5.23	82.51
LUf	13.33	2.26	68.60
LUg	11.86	3.91	56.43
LUv	0.00	0.00	0.00
LV	0.97	0.08	5.23
ME	0.07	0.00	0.40
MK	1.39	0.42	5.85
MT	12.83	6.43	44.95
NI	20.77	16.81	55.41
NL	5.24	2.38	20.74
NOm	0.03	0.00	0.00
NOn	0.03	0.00	0.00
NOs	0.28	0.00	1.60
PL	9.33	6.32	27.90
PT	0.95	0.00	4.02
RO	0.44	0.00	2.20
RS	0.18	0.00	1.26
SE1	0.00	0.00	0.00
SE2	0.00	0.00	0.00
SE3	0.08	0.00	0.40
SE4	1.03	0.00	4.97
SI	0.27	0.00	1.94
SK	2.49	0.50	12.19
TN00	1.34	0.14	6.66
TR	0.11	0.00	0.80

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2.3 Level of imports during single and simultaneous scarcity situations

Interconnections are crucial for supporting adequacy in large systems. Specifically, interconnections can help to balance supply and demand on a broader geographical scope, thus allowing the deployment of benefits from statistical balancing effects in demand and variable renewable generation. Intuitively, when considering two interconnected countries there is a high chance that the two countries do not face the most critical ramp at the exact same time. This can be explained by uncorrelated climatic conditions and different periods of peak demand occurrence. Another factor can be time zone differences that cause time shifts of demand peaks. It is, thus expected that in a large number of situations, adequacy problems in a country will not be correlated with adequacy problems in neighbouring ones. In these cases, the importance of interconnectors is obvious as countries would be able to rely on imports from their neighbours to ensure their adequacy. We refer to these as **individual or single scarcity situations. In those cases, it is expected that countries will present import levels close to their maximum simultaneous importable capacity.**

On the other hand, 'critical or extreme situations' can occur which are highly correlated in time and geographical perimeter (e.g. cold spell, heat waves, large rain-snow storms, etc.). In those situations, a lack of available power might occur inside a geographical area encompassing more than one country. We refer to these as **simultaneous scarcity situations in a certain macro-area.**

Lack of power in these situations is typically related to the lack of available resources to generate the needed power in the specific macro-area[8]. Typically in those cases, although the adequacy problems are not linked to a lack of interconnection capacity, **the affected countries (part of the macro-area) might present import levels lower than their maximum simultaneous importable capacity. Such low levels of imports are, rather, related to a global/regional deficit of available power generation inside the perimeter encompassed by the countries in scarcity.**

Below, we have performed a detailed analysis of the results obtained for the 2020 scenario. For illustration purposes, we have focused on the area between France (FR), Great Britain (GB) and Belgium (BE) and analysed the hourly results of EENS vs 'Country Net Balance (Balance)'. Note that a negative (country net) balance corresponds to a country import. Furthermore, each dot in the figures below corresponds to an hourly situation, so 'Balance' and 'EENS' are provided in MW.

It is possible to identify the following 3 regimes (A, B.1 & B.2, C):

- *A*: Triple simultaneous scarcity – hours when all 3 'GB+FR+BE' have EENS
- *B.1:* Simultaneous scarcity GB+FR– hours when 'GB+FR' have EENS
- *B.2:* Simultaneous scarcity BE+FR– hours when 'BE+FR' have EENS
- *C*: Hours when GB or FR are in 'individual' scarcity

Regarding the import levels (negative balance) during these regimes, we identify that:

- Situation *A* relates to lowest imports, much below the maximum simultaneous import capacity, in agreement with a 'resource scarcity' storyline of not having enough power regionally inside the area encompassed between these three countries.
- Situations *B.1* and *B.2* relate to mid levels of imports below the maximum simultaneous import– in agreement with a 'resource scarcity' storyline of not having enough power inside the area between the two countries considered (GB-FR B.1 and BE-FR B.2)

[8] For example, low or too strong winds, dry rivers reducing availability of hydro power or cooling capabilities of nuclear reactors, frozen rivers and roads limiting the transportation of fuels like coal or gas, extended low temperatures leading to unexpected large and long-lasting levels of electricity demand, etc.

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- Situation *C* relates to scarcity in FR, GB – EENS for those countries occurs individually while imports are close to the maximum simultaneous import for those countries FR ~ 12GW, GB ~ 4.5 GW. Furthermore, the adequacy problems of BE appear to be highly correlated with the 'resource scarcity' adequacy problems in FR and FR+GB.

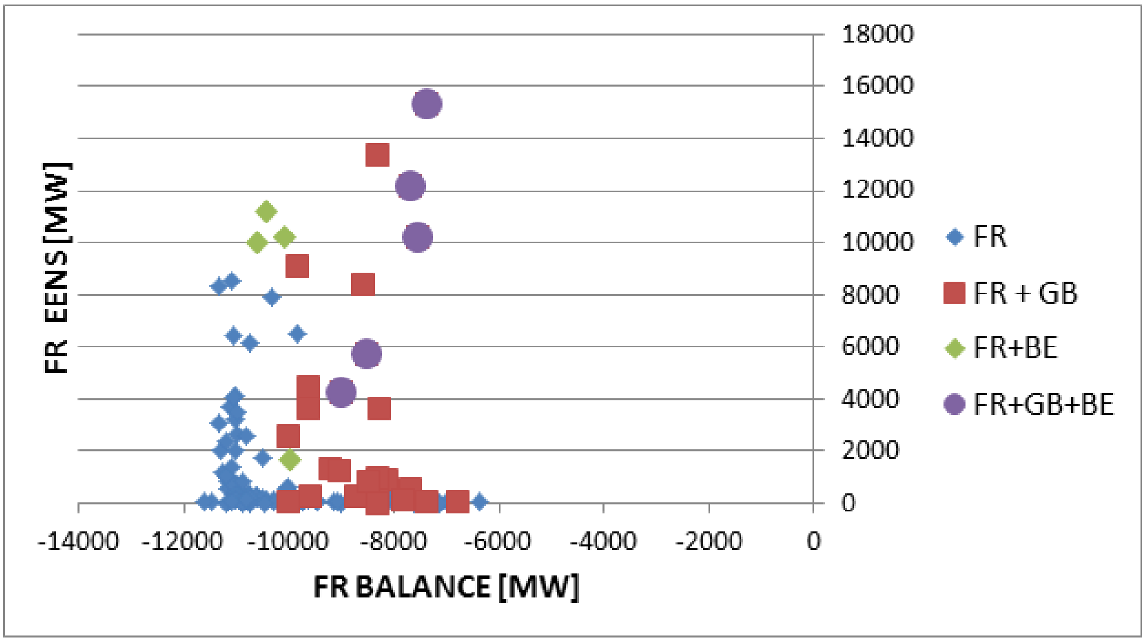

Figure 17: The impact of simultaneous scarcity events with a focus on FR. Negative balance corresponds to imports.

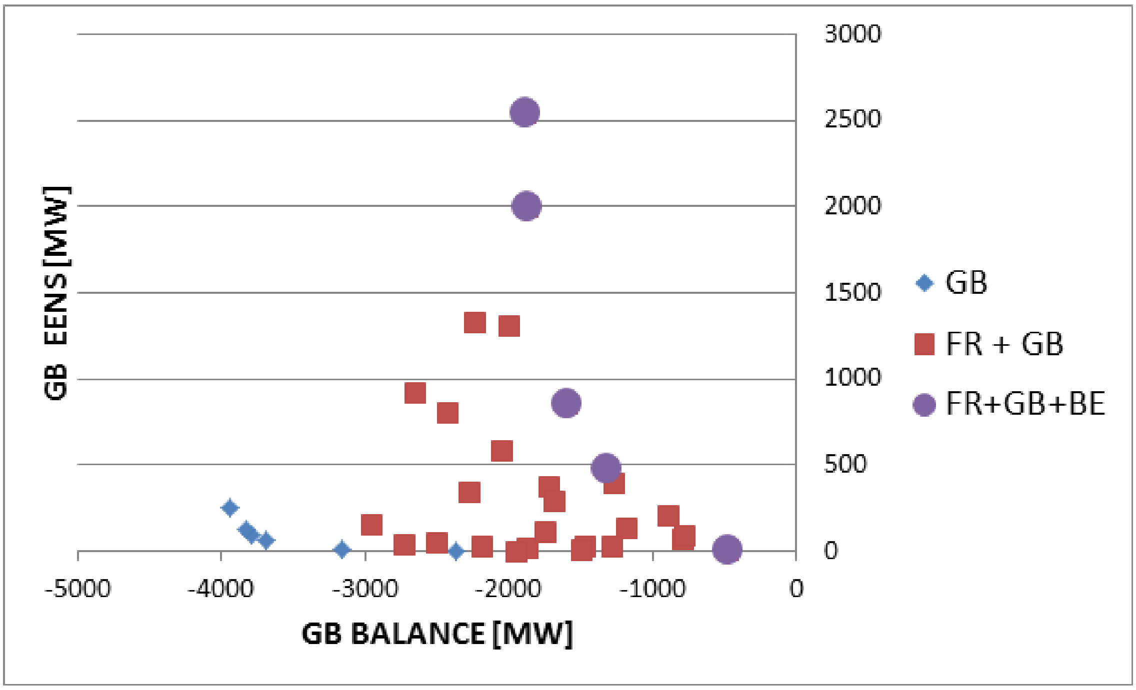

Figure 18: The impact of simultaneous scarcity events with a focus on GB. Negative balance corresponds to imports.

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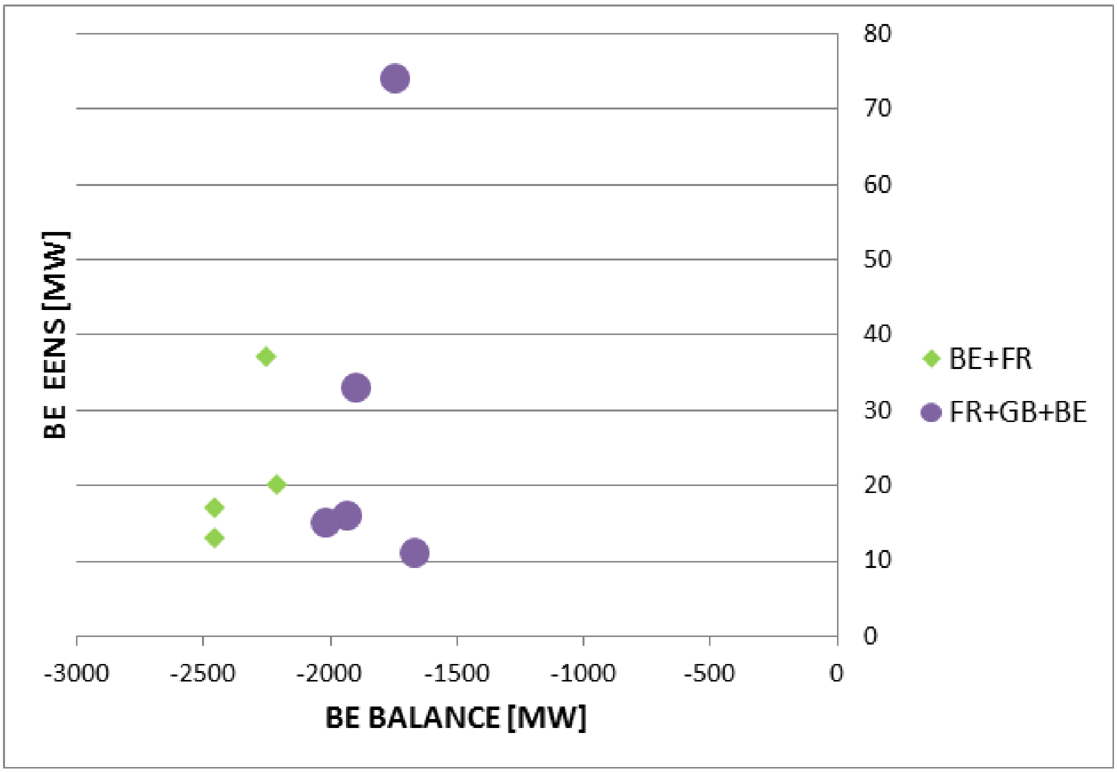

Figure 19: The impact of simultaneous scarcity events with a focus on BE. Negative balance corresponds to imports.

In conclusion, interconnectors contribution is of key importance in periods of scarcity. In case of single country scarcity, it is expected that the country in scarcity will import close to its maximum simultaneous importable capacity. In case of several countries' simultaneous scarcity, more moderate imports might thus occur despite sufficient interconnection capacity being available, due to lack of power resources within the scarcity area. However, still high imports should be expected towards the simultaneous scarcity (macro-) area.

2.4 Flow-based innovations

In this edition of MAF we have investigated different approaches for flow-based modelling which are presented in this section. At this stage, the outcomes of these innovative studies are qualitative only and confirm the need to invest more resources in further investigations.

2.4.1 2020 Flow-Based sensitivity for Continental Western Europe (CWE)

The FB approach implemented for the year 2020 follows the implementation of FBMC performed at the regional level by the PLEF study[9]. The approach for FBMC is an important step towards the more realistic modelling of operational planning in practice nowadays. In this approach, representative historical FB domains, considering the effect of grid reinforcements until 2019, are implemented for CWE countries (BE, FR, DE, NL) as a basis for modelling cross-border capacity. The different types of FB domains used represent several situations with different levels of congestion in the grid. Their implementation in the model is further

[9] Pentalateral Energy Forum, Support Group 2, 'Generation Adequacy Assessment', January 2018, http://www.benelux.int/nl/kernthemas/holder/energie/pentalateral-energy-forum

correlated to expected climate and consumption conditions of each day of the simulations, which are the main drivers for congestions in the grid.

More realistic modelling of cross-border exchange capacities means that the simulation results better reflect the tight situations observed in practice. This leads to a more realistic adequacy assessment of the region considered, compared to a constant NTC approach, as used in the main simulations in the MAF and as traditionally used in long-term planning studies.

An important evolution is the incorporation of the so called 'minimum remaining available margin (MinRAM)', which was considered in the FBMC approach presented in this section. The PLEF agreed a MinRAM level equal to 20% of the maximum allowed power flow, which is applied on each critical network element and contingency. The feasibility of the MinRAM application is currently verified by CWE TSOs for each day. The implementation of a MinRAM will provide more capacity for commercial exchanges inside the CWE flow-based market coupling. Planned grid development between 2018/19 until 2020 will play an important role for TSOs in this respect, so that commercial exchanges can be realized in a safe manner through the physical grid in real time.

The simulations for the 2020 case have been performed with the same two market tools used by TSOs in the PLEF study. Similar results were obtained by both tools. The implementation of MinRAM20% provides more capacity for commercial exchanges and, thus, has a positive effect on the adequacy results. Thus, the FB approach is generally in line with the base case results of the NTC approach for this particular study, leading however to a marginal increase in the LOLE and EENS values in countries around CWE (FR, BE, LU, GB in this case). The reason that the results of the FB simulation for 2020 are close to the NTC results is largely due to the effect of the MinRAM20% implementation. This was, e.g., not the case in the PLEF study, where no MinRAM20% was considered. Still the higher values of LOLE observed in FB than NTC, stem from the more accurate modelling of the network, which allows the model to capture the interdependencies between the commercial exchange of neighbouring countries and the physical flows occurring in the grid. Such interdependence is important when modelling, for example, cases of so-called 'simultaneous scarcity'.

2.4.2 2025 Flow-based sensitivity applied on a complete transmission model

The FB approach for the year 2025 was conducted on the whole Continental Europe perimeter using a complete transmission network model. The detailed grid model for Continental Europe (CGMES format) has been built in the framework of TYNDP 2018, including a detail of voltage levels from 100 kV up to 400 kV.

Table 6: CGMES network consistency

Element	Number
Nodes	19599
Transformers	9683
Lines	19454
Stations	8740
Generators	21129
Loads	10258

The complete transmission grid has been complemented using MAF data with respect to:

- Bidding Zones;
- Exchange limits among market areas (defined in 1.2.4.);

- Countries outside the network model but present in the MAF perimeter were modelled with bus-bar equivalents (the simplification has a low impact since most of the missing countries are connected with a HVDC link or in a radial position with respect to modelled countries);
- Hourly exchange time series associated to not modelled countries;
- Hourly demand time series;
- Identification of all generation in the network by typology and association with costs for thermal generation and time series for RES and imposed generation;

The size of the optimization problem to be solved is completely different between the MAF base case adequacy analysis and the one considering the network, due to the much higher level of detail entailed in the network representation (scale 1 to 10).
The integration of MAF additional data in the network model has been validated by reproducing MAF base case results with the same NTC approach, making the following assumptions:

- exchanges are variables of the optimization problem included in the balance equation of each market area;
- exchanges respect NTC limits;
- dispatching of generating units depends on costs and exchange limits.

After its validation, the complete network model has been used to apply a FB approach that considers:

- the impact of the distribution of generation and load in the network, on the interconnection lines and, therefore, on the exchanges ('flow equations');
- relaxed NTC limits derived from the thermal capacity of the interconnection lines considering a Transient Reliability Margin (TRM);
- dispatching of generating units depending on their costs and sensitivities on exchanges;
- monitoring[10] of interconnection lines and all 400 kV lines inside market areas, to avoid possible overloads (solved by economic re-dispatching, lowering the risk of additional load curtailment);
- additional sampling in the Monte Carlo process network elements faults (lines, transformers) rather than only generators and a subset of interconnection lines, as in the MAF base case.

Two approaches of FB simulations in 2025 were investigated:

- only interconnection lines (~200) are monitored to detect possible overloads
- the complete 400 kV perimeter (~4500 lines) is monitored along with the interconnections

The simulations have been tested for an ensemble of 100 MC years.

Preliminary conclusions from the comparison with the MAF reference case results for 2025:

- ✓ In the FB approach there is a higher system cost due to the effect of congestions on dispatching and the need for re-dispatching. This is because, in the FB approach, the optimization problem has to respect additional grid constraints, due to the 'flow equations'. These additional constraints also lead to higher EENS in the system in situations of scarcity;
- ✓ The number of market zones in scarcity situations (when EENS occurs) also increases from NTC to FB, because the bottlenecks observed in the NTC study can propagate in the FB one (in the form of loop-flows, transit-flows, etc.), when impedances are considered and the network representation is linked to generators and load locations;
- ✓ The computational time required for the MAF base simulation is considerably higher, depending on the monitored perimeter.

[10] A monitored line refers to a line that is ensured never to be overloaded (additional constraint). When the line is not monitored, only its impedance is considered.

The possibility to perform Monte Carlo simulations on the TYNDP complete network model while incorporating MAF data has been achieved, exploiting the available ENTSO-E data and applying FB methods to the entire continental Europe perimeter.

2.5 Impact of hydro constraints and its relaxation

Modelling and optimization of hydro generation is an arduous task and increases the complexity of the market modelling process. Furthermore, due to the use of five different tools during the MAF 2018 assessment, it is extremely relative to explore and compare the various ways that hydro optimization is performed by the different tools, in an effort to understand the impact on adequacy results and reach a better alignment among the tools.
Specific experiments were performed, which aimed at understanding the impact of relevant assumptions and hydro optimization constraints on the adequacy results. More precisely, after calibrating the models, a sensitivity analysis was performed, evaluating the following cases:

- Hydro generation is optimized, imposing strict constraints regarding weekly reservoir trajectory (referred to as ‘Strict Constraints’)
- Hydro generation is optimized, relaxing the constraints related to weekly reservoir trajectory and imposing monthly ones (referred to as ‘Relaxed Constraints 1’)
- Hydro generation is optimized, relaxing weekly reservoir constraints and only considering yearly initial and final reservoir levels (performed by one tool only – referred to as ‘Relaxed Constraints 2’)

Note that all other constraints and variables remained identical. In Figure 20 and Figure 21, the results for three zones are presented as an example to showcase the differences between the three approaches. The sensitivity is based on the 2025 base case scenario and was performed by two of the five tools , i.e. VP3 and VP5.

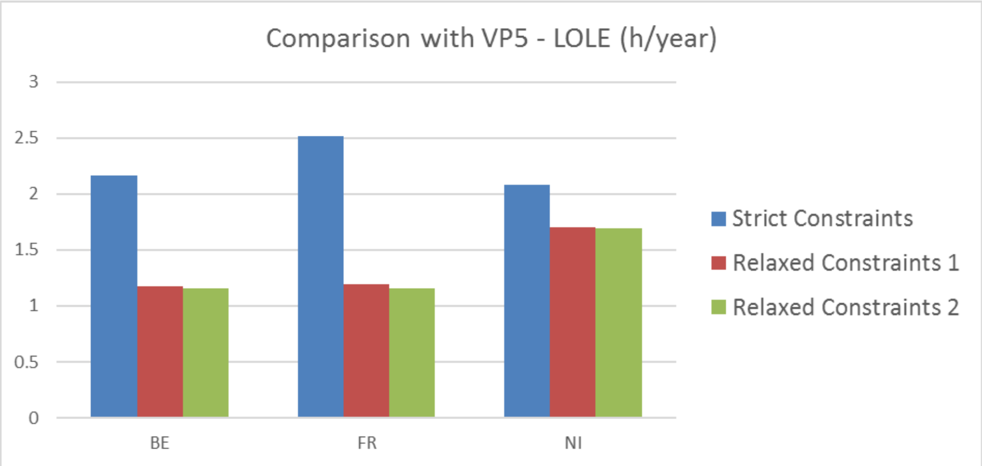

Figure 20: Hydro constraint relaxation for base case 2025 - Two relaxation levels of constraints (VP5)

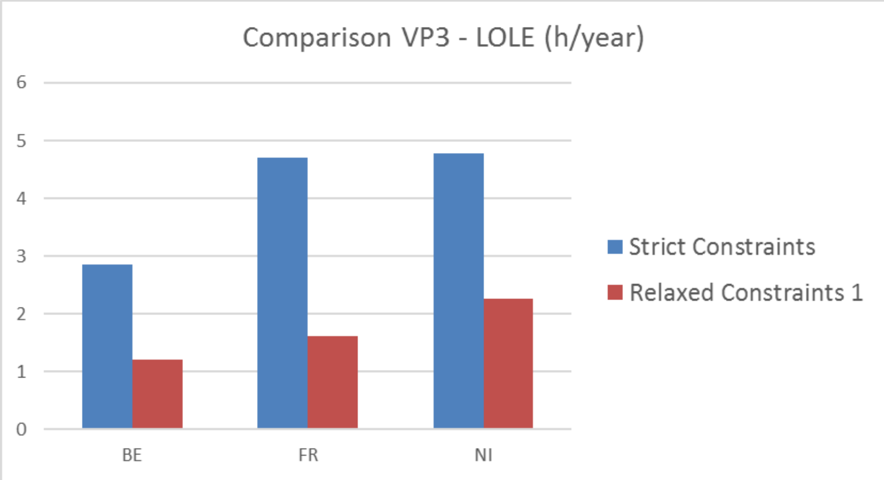

Figure 21: Hydro constraint relaxation for base case 2025 - Single relaxation level of constraints (VP3)

From Figure 20 and Figure 21, it is observed that imposing strict constraints regarding hydro weekly reservoir trajectory leads to more pessimistic results in terms of adequacy. The difference is considerable comparing the strictly constrained case with monthly relaxation, i.e. imposing the constraints on a monthly time scale (red bar), and even more so if constraints are not imposed at all (green bar). This result indicates how sensitive the model is on hydro modelling, but also highlights the importance of having different tools and calibrating them, since each tool applies a different methodology to model hydro.

2.6 Flexibility

In an energy system mainly driven by renewable energy sources, the fluctuating weather conditions directly impact the balance of generation and consumption of electrical energy. This balance is important to ensure safe system operation. Therefore, it is crucial to quantify the fluctuation of the renewable power generation as well as the demand volatility.

Although weather forecasts have become increasingly accurate, a perfectly accurate prediction is not possible. This naturally leads to uncertainty in terms of the expected power generation of solar and wind generators. On the demand side, climatic conditions play a minor role in the investigations of flexibility. A more significant impact is caused by the individual load profiles of each area. The natural behaviour, e.g. a demand peak in the evening caused by the simultaneous processes of all consumers in a region (cooking, heating, switch-on of electrical consumers) leads to a pronounced change in consumption from one hour to the next.

By subtracting the fluctuating generation from the demand curve, the **residual load** is calculated. The residual load describes the demand that is required to be covered by conventional and flexible power plants.

$$RL(h_i) = D(h_i) - W(h_i) - S(h_i) \qquad (6)$$

$D(h_i)$ … Demand in hour *i*

$W(h_i)$ … Wind generation (offshore and onshore) in hour *i*

$S(h_i)$ … Solar generation (PV and CSP) in hour *i*

A further analysis of the residual load quantifies the change from one hour to another and is referred as residual load ramps analysis.

$$R(h_{i,i+1}) = RL(h_{i+1}) - RL(h_i) \qquad (7)$$

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These calculation steps are performed with the MAF data set for each time step. The 99.9th percentile of the positive and negative residual load ramps are shown in Figure 22. This means that, on average, only 8 hours per year (0.1%) experience higher positive residual load ramps and only 8 hours per year (0.1%) experience higher negative residual load ramps.

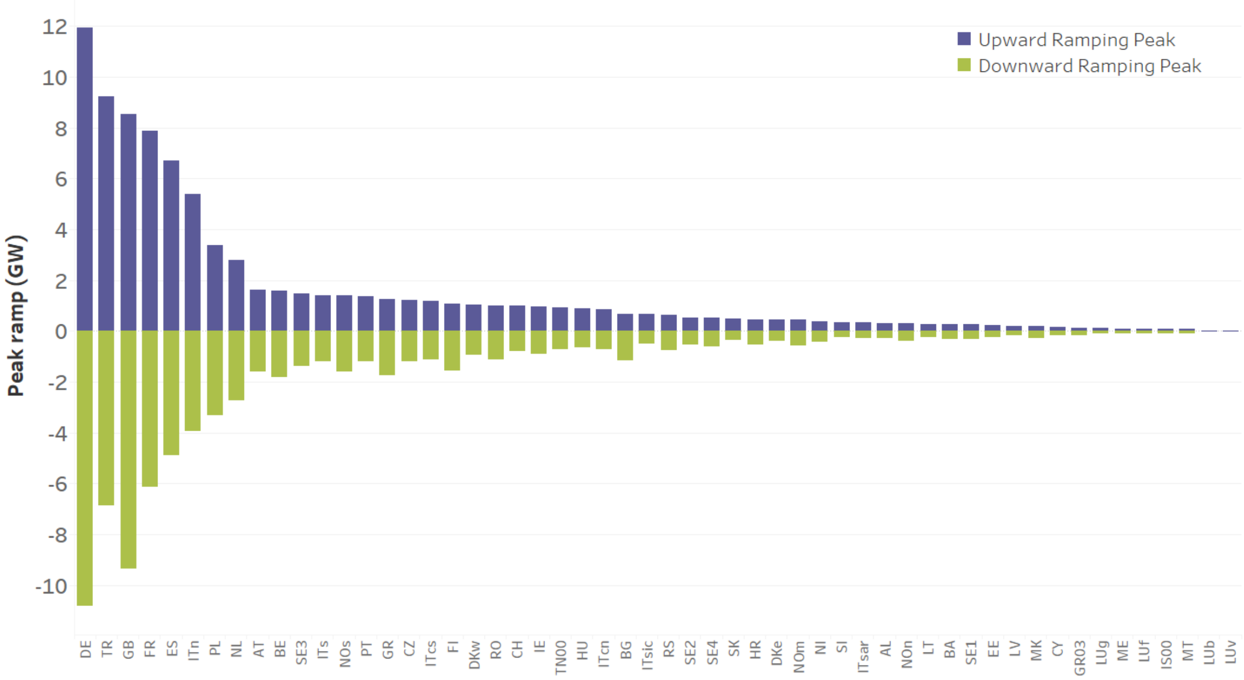


Figure 22: Hourly residual load ramps on a national basis (99.9th Percentile)

3 Market modelling tools used

3.1 ANTARES

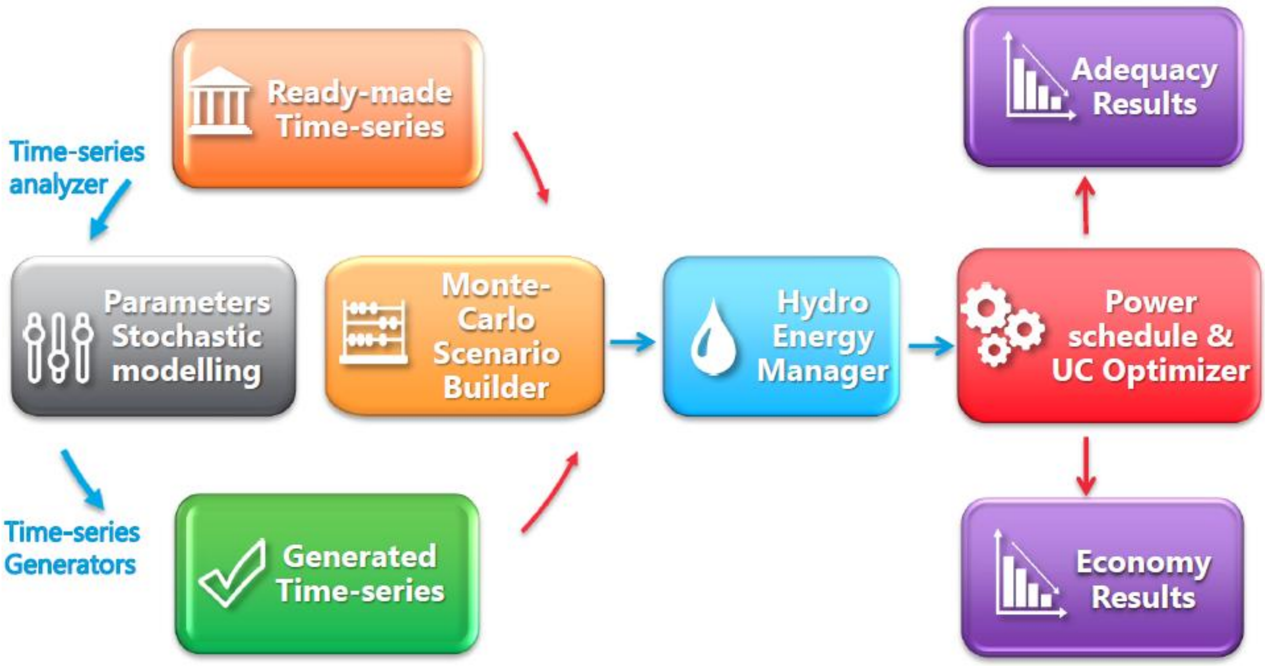
ANTARES - A New Tool for the generation Adequacy Reporting of Electric Systems – is a sequential Monte Carlo multi-area adequacy and market simulator developed by RTE. The rationale behind an adequacy or market analysis with a Monte Carlo sequential simulator is the following: situations are the outcome of random events whose possible combinations form a set of scenarios so large that their comprehensive examination is out of the question. The basis of the model is an optimiser connected in output of random simulators.

Antares has been tailored around the following specific core requirements:

a) Representation of large interconnected power systems by simplified equivalent models (at least one node per country, at most #500 nodes for all Europe)
b) Sequential simulation throughout a year with a one hour time-step
c) For every kind of 8760-hour time series handled in the simulation (fossil-fuel plants available capacity, wind power, load, etc.), use of either historical/forecasted time series or of stochastic Antares-generated time series

d) Regarding hydro power, definition of local heuristic water management strategies at the monthly/annual scales. Explicit economic optimisation comes into play only at the hourly and daily scales (no attempt at dynamic stochastic programming)
e) Regarding intermittent generation, development of ***new stochastic models*** that reproduce correctly the main features of the physical processes (power levels statistical distribution, correlations through time and space)

At its core, each Monte Carlo year of simulation calls for two different kinds of modelling, the first one being devoted to the setting up of a ***'Monte Carlo scenario'*** consisting of comprehensive sets of assumptions regarding all technical and meteorological parameters (time series of fossil fuel fleet availability, of hydro inflows, of wind power generation, etc.), while the second modelling deals with the economic response expected from the system when facing this scenario.
The latter necessarily involves a layer of market modelling which, ultimately, can be expressed under the form of a tractable ***optimisation problem***.
The former 'scenario builder' was designed with a concern for openness, that is to say to ensure the use of different ***data pools***, from a 'ready-made' time series to an entirely 'Antares-generated' time series.
The figure below describes the general pattern that characterises Antares simulations.



<u>Time series analysis and generation</u>
When ready-made time series are not available or too scarce (e.g. only a handful of wind power time series) for carrying out proper MC simulations, the built-in Antares time series generators aim to fill the gap. The different kinds of physical phenomena to model call for as many generators:

- The daily thermal fleet availability generator relies on the animation of a most classical three-state Markov chain for each plant (available, planned outage, forced outage)

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- The monthly hydro energies generator is based on the assumption that, at the monthly time scale, the energies generated in each area of the system can be approximated by Log Normal variables whose spatial correlations are about the same as those of the annual rainfalls.
- The hourly wind power generator is based on a model [5] in which each area's generation, once detrended from diurnal and seasonal patterns, is approximated by a stationary stochastic process.

The different processes are eventually simulated with the proper restitution of their expected correlations through time and space. The identification of the parameters that characterise at best the stochastic processes to simulate can be made outside Antares but this can also be achieved internally by a built-in historical time series analyser.

Economy simulations

When simulating the economic behaviour of the system in a 'regular' scenario (in the sense that generation can meet all the demand), it is clear enough that the operating costs of the plants disseminated throughout the system have a heavy bearing on the results of the competition to serve the load. As is known, the most simple way to model the underlying market rationale is to assume that competition and information are both perfect, in which ideal case the system's equilibrium would be reached when the overall operating cost of the dispatched units is minimal.

Altogether different is the issue of the time-frame for the economic optimisation: realism dictates that optimisation should neither attempt to go much further than one week (leaving aside the specific case of the management of hydro resources) nor be as short-sighted as a one-hour snapshot.

Put together, these assumptions lead, for economic simulations, to the formulation of a ***daily/weekly linear program***, whose solution can be found using the standard simplex algorithm.

Yet, since a very large number of weekly simulations are carried out in a row (52 for each MC year, several hundreds of MC years for a session) and considering the fact that many features of the problems to be solved may be transposed from one week to the next (e.g. grid topology), it proved very efficient to implement in Antares a variant of the ***dual-simplex algorithm*** instead of the standard algorithm. For each area of the system, the main outcomes of economy simulations are the estimates at different time scales (hourly, daily, weekly, monthly, annual) and through different standpoints (expectation, standard deviations, extreme values) of the main economic variables:

- Area-related variables: operating cost, marginal price, greenhouse gas emissions, power balance, power generated from each fleet, unsupplied energy, spilled energy.
- Interconnection-related variables: power flow, congestion frequency, congestion rent (flow multiplied by the difference between upstream and downstream prices), congestion marginal value (decrease of the overall optimal operating cost brought by 1MW additional transmission capacity).

Grid modelling

The tool offers different features which, combined together, provide a versatile framework for the representation of the grid behaviour.

- Interconnectors (actual components or equivalent inter-regional corridors) may be given hourly transfer/transmission asymmetric capacities, defined with a one-hour time step.
- Asymmetric hurdle costs (cost of transit for 1MW) may be defined for each interconnector, again with a one-hour time-step.

An arbitrary number of either equality, two-side bounded or one-side bounded linear constraints may be defined on a set of hourly power flows, daily energy flows or weekly energy flows. In parts of the system where no such constraints are defined, power is deemed to circulate freely (with respect to the capacities defined in [a]). In other parts, the resulting behaviour depends on the constraints definition. A typical choice consists of obtaining DC flows by using either PTDF-based or impedance-based hourly linear constraints. Note that the latter is a usually more efficient way to model the grid because it is much sparser than the former. Other constraints may be defined to serve quite different purposes, such as the modelling of FB domains defined at an hourly level or of pumped-storage power plants operated on a daily or weekly cycle.

Open-source approach

Since July 2018, Antares has been open-source. The source code of the software as well as its installer can be downloaded freely on Github: https://github.com/AntaresSimulatorTeam/Antares_Simulator. In parallel, a users' club has been created to offer support with training content, access to training sessions and maintenance.

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3.2 BID3

BID3 is Pöyry Management Consulting's power market model, used to simulate the dispatch of all supply and demand in electricity markets. Equally capable of covering both short-term analyses for trading and long-term scenarios, BID3 is a fast, powerful and flexible tool that provides comprehensive price projections in an intuitive and user-friendly interface.

What is BID3?

BID3 is an economic dispatch model based around optimisation. It models the hourly generation of all power stations on the system, considering fuel prices and operational constraints such as the cost of starting a plant. It accurately models renewable sources of generation such as hydro, reflecting the option value of water, and intermittent sources of generation, such as wind and solar, using detailed and consistent historical wind speed and solar radiation.

What is BID3 used for?

BID3 provides a simulation of all the major power market metrics on an hourly basis – electricity prices, dispatch of power plants and flows across interconnectors. BID3 can be run for both short term market forecasts and long term scenario analysis. It is the perfect tool to assess the market value of power plants under a range of situations, through outputs like market revenue, load factor, fuel and CO_2 costs, or the number of starts per year. These results can be computed for a single plant, or for an entire project portfolio for planning and investment purposes, assessing the effect of both internal decisions and a large range of external factors. BID3 can be used for the economic assessment of interconnectors, outlining flows and congestion rent, as well as socioeconomic and other commercial benefits. BID3 has a very detailed description of intermittent renewable sources, basing generation on historically observed wind speed and solar irradiation data.

BID3 combines state-of-the-art simulation of thermal-dominated markets, reservoir hydro dispatch under uncertainty, demand side response and scenario-building tools.

Key features:

i. Sophisticated hydro modelling, incorporating stochastic Dynamic Programming to calculate the option value of stored water.

ii. Detailed modelling of intermittent generation, such as wind and solar, allowing users to understand the impact of renewables and requirements for flexibility.

iii. Advanced treatment of commercial aspects, such as scarcity rent and bidding above short-run marginal cost.

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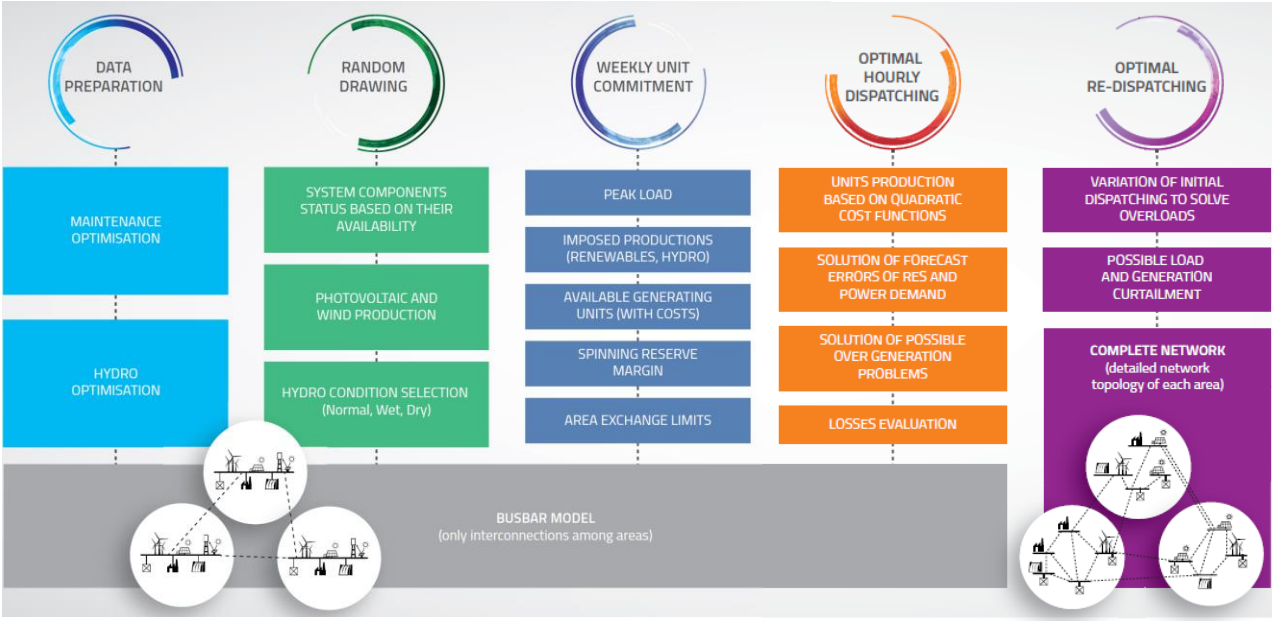
3.3 GRARE

GRARE (Grid Reliability and Adequacy Risk Evaluator) is a powerful computer-based tool of Terna, developed by CESI[11], that evaluates reliability and economic operational capability using a probabilistic Monte Carlo analysis.

GRARE has been developed to support medium and long-term planning studies and is particularly useful for evaluating the reliability of large power systems, modelling in detail the transmission networks.

The tool is developed to take advantage of a high performance multi-threaded code and it is integrated into the SPIRA application that is designed to perform steady-state analyses (e.g. load-flow, short-circuits, OPF, power quality) and is based on a network database of the system being analysed.

The calculation process is performed as a series of sequential steps starting from a high-level system representation and drilling down to low-level network details. Thanks to the ability to couple the economic dispatch of the generation with the complete structure of the electrical network, GRARE is able to offer a unique support for the planning and evaluation of the benefits related to network investments.



The **complete network model** (lines, generators, transformers, etc.) includes different voltage level detail, and the power flow derived from generation dispatching to feed the load is obtained by applying a DC load flow with the possibility of obtaining power losses and voltage profile estimation. Starting from a complete network model, GRARE is able to automatically obtain simplified bus-bar models to complete unit commitment and market analyses where the network detail is not needed. The analysis of the full network model allows for the feasibility of the economic dispatching to be verified and the necessity to apply a re-dispatching or load shedding to operate the network in accordance with security criteria.

[11] www.cesi.it/grare

Algorithm and main optimisation process

- The time horizon is a single year with a minimum time unit of one hour. Many Monte Carlo Years can be simulated, each one being split into 52 weeks, with each week independently optimised.
- The Probabilistic Monte Carlo method uses statistical sampling based on a 'Sequential' or 'Non Sequential' approach.
- Monte Carlo convergence analysis to verify the accuracy of the results obtained.
- Optimised Maintenance schedule based on residual load distribution over the year.
- Reservoir and pumping hydro optimisation, mindful of water value as an opportunity cost for water in respect to other generation sources.
- Different hydro conditions managed (dry, normal, wet).

System model

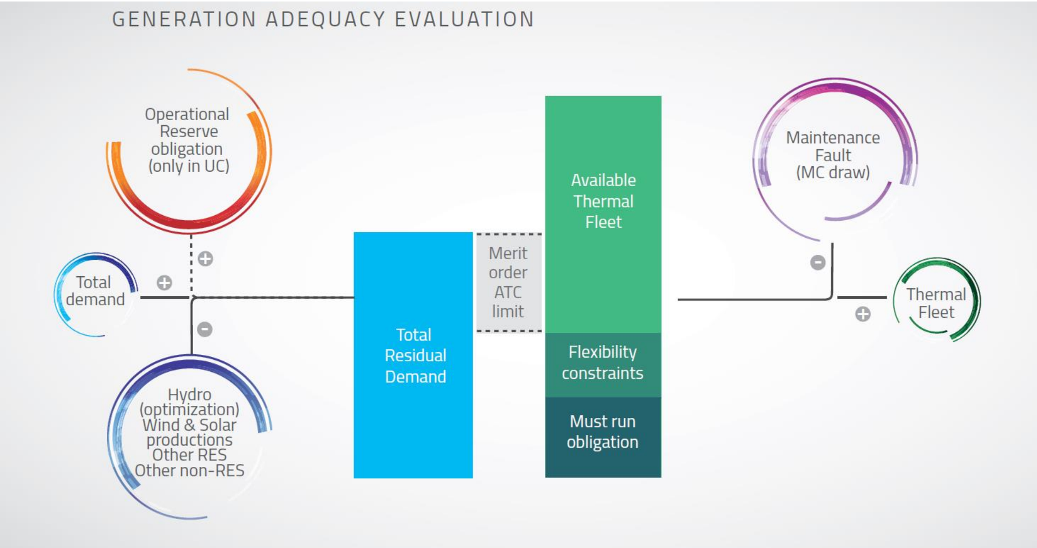
- Network detail to represent each single area (grid dimension up to 5,000 buses). A DC load flow is calculated and an estimate of voltage level can be obtained using the Sauer algorithm.
- Area modelling to optimise Unit commitment and Dispatching consistent with transfer capacities.
- Unit Commitment and Dispatching with a Flow or NTC-based approach.

Market analyses

- Single year day-ahead market analysis with area modelling detail, but with no Monte Carlo drawings.
- The general restrictions of the Unit Commitment such as minimal uptime and downtime of generation units are considered for each optimisation period.
- Dispatchable units characterised by power limits, costs, must-run or dispatching priority, power plants configurations, start-up and shutdown flexibility, and CO2 emissions.

Adequacy analyses

- System adequacy level measured with Reliability Indexes (ENS, LOLE, LOLP).
- Renewable production calculated by a random drawing starting from producibility figures.
- Operational reserve level evaluation, considering the largest generating unit, uncertainty of load and RES forecast, and possible aggregation of area and fixed percentage of load.
- Demand side management as rewarded load to be shed with priority without any impact on adequacy.
- Over-generation management with possible priority on generation to be reduced.



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Main applications

The high level of versatility and flexibility of the GRARE tool has been appreciated in Europe first and then in several countries globally. The program has been developed to be applied in the design phase for the Italian framework and it is now used for ENTSOE-E adequacy studies. Various TSO/Institutions have benefited from the potentiality of the tool by using it directly or through specialist consultancy services.

- Designed for technical analyses of large electric systems.
- Evaluation of electric systems
- Generation & Transmission adequacy.
- Optimal level of RES integration.
- Cost Benefits Analysis for network reinforcements and storage, which factors in Security of Supply, network overloads, RES integration, network losses, CO2 emissions and over-generation.
- Calculation of Total Transfer Capacity of interconnections.
- Generation reward evaluation for the Capacity Remuneration Mechanism.
- Point Of Connection and sizing for new power plants.

3.4 PLEXOS

PLEXOS, developed by Energy Exemplar, is a sophisticated power systems modelling tool. It uses mixed integer optimisation techniques to determine the least cost unit commitment and dispatch solution to meet demand, while respecting generator technical-economic constraints.
Advanced Mixed Integer Programming (MIP) is the core algorithm of the simulation and optimisation.

PLEXOS 4.0 was first released in 2000. It is used by utilities, system operators, regulators and consulting firms for:

1. Operations
2. Planning and Risk
3. Market Analysis
4. Transmission (Network) Analysis

PLEXOS features:

1. State-of-the-art optimisation-based engine using latest theories in mathematical modelling and game-theory
2. Co-optimises thermal and hydro generation, transmission and ancillary services given operational, fuel and regulatory constraints
3. Dispatch and pricing solutions are mathematically correct, robust and defensible
4. Applies optimisation across multiple timeframes
5. Benchmarked against real market outcomes and existing large-scale models

Solving Unit Commitment and Economic Dispatch ***using MIP***

Unit Commitment and Economic Dispatch can be formulated as a linear problem (after linearisation) with integer variables representing generator on-line status.

Minimise Cost = *generator fuel and VOM cost + generator start cost*
+ contract purchase cost –contract sale saving
+ transmission wheeling
+ energy / AS / fuel / capacity market purchase cost
–energy / AS / fuel / capacity market sale revenue

Subject to:

1. Energy balance constraints
2. Operation reserve constraints
3. Generator and contract chronological constraints: ramp, min up/down, min capacity
4. Generator and contract energy limits: hourly / daily / weekly / …
5. Transmission limits
6. Fuel limits: pipeline, daily / weekly/ …
7. Emission limits: daily / weekly / …
8. Others

Hydro-Thermal planning

Particularly important for the MAF studies was the co-ordination of Hydro-Thermal planning. The goal of the hydro-thermal planning tool is to minimise the expected thermal costs along the simulation period. The PLEXOS Integrated Energy Model offers a seamless integration of phases, making it possible to determine:

1) An optimal planning solution in the medium-term
2) Then use the obtained results in a detailed short-term unit commitment and economic dispatch problem with increased granularity.
E.g. weekly targets as constraints filter down to produce hourly electricity spot prices.

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3.5 PowrSym

PowrSym is a probabilistic Monte Carlo tool developed by Operation Simulation Associates, Inc., used to model the operation of large interconnected electricity production and transmission systems[12]. The supply may consist of power and heat production units, wind, solar and (pumped) hydro resources. The simulation uses an equal incremental cost computation method to optimally dispatch hydro, thermal and other resources, subject to grid constraints. In principle, PowrSym can model an unlimited number of grid nodes and generation stations. In current practice, PowrSym models have been built for up to 1000 grid nodes and 5000 generating stations with 100 or more generating units per station. The base optimizing periods are weeks or months, with the possibility of using different time steps, e.g. one hour or 10 minutes.

Input Data

The input for PowrSym consists of two parts: time series data, and description of generator and grid characteristics. Time series data include loads, solar resources, wind resources, and certain other data[13]. System characteristics such as generating unit data and grid constraints are not time series but may change by week or season. Input data is prepared using database facilities and/or spreadsheets. While a large amount of data is required to set up a base case, it is very easy to make data changes for various scenarios of the base case.

Planned Maintenance Schedule

PowrSym may accept a planned maintenance schedule as input, or may use an internal maintenance scheduling algorithm to scheduled required planned maintenance optimally, or a combination of two. The planned maintenance scheduler produces an output file for use in other models or to maintain consistency across study scenarios.

Treatment of uncertainties by using Monte Carlo Scenarios and Climate Dependent Time series

PowrSym uses a Monte Carlo simulator to include the effects of uncertainties on generating unit availability, transmission link capacity, and variants in loads and hydro, solar and wind availability. These may be used in combination with pre-defined climate dependent time series. In FB grid mode, Monte Carlo draws are used to select the FB equations by date. A specified number of scenarios, driven by random number selection, are selected for simulation.

Spinning and Operating Reserve

PowrSym features a detailed model of spinning and operating reserve with a variety of specification methods and constraints on the reserve contributions of individual generating units. Spinning reserve requirements must be met by un-dispatched capacity of on-line generating units. Operating reserve includes spinning reserve plus off-line quick-start generating units. Operating and spinning reserve requirements may be specified for any combination of system, transarea and control areas. Reserve requirements may be specified as a constant amount, a percent of load, the largest on-line unit or some combination of these amounts.

The contribution of each generating unit to reserves can also be controlled. A non-firm unit does not contribute to reserves - a firm unit does. A quick-start unit contributes to operating reserves while off-line. An upper bound may be placed on a unit's contribution, thus limiting its contribution when partially dispatched during low load periods. A lower bound may be placed on a unit's contribution to reserves, effectively preventing the unit from being fully dispatched unless reserve constraints must be violated. A summary report of spinning reserve violations is produced.

[12] The PowrSym tool also includes a detailed module to model supplies, transport and storage of different fuels
[13] PowrSym also has many options to model various types of demand side flexibilities

Hydro Scheduling

PowrSym respects the reservoir constraints of each hydro station. Reservoir constraints are specified as maximum level, minimum level, hourly inflow, and required levels at the beginning and ending of the simulation period (week or month). The model will allocate water and pumping across the simulation period, respecting reservoir levels and system requirements. The PowrSym hydro pre-scheduler will schedule the hydro generation and pumping across the period to levelize the loads in the area where the hydro is located. This pre-schedule may be left in place for the thermal optimization or the hydro thermal optimization may reschedule the hydro in a cost-optimal manner. For adequacy studies, PowrSym will skip the computationally intensive hydro-thermal optimization for periods in which unserved energy is below a specified level.

Hydro Thermal Optimization

The hydro thermal optimization schedules the hydro and the thermal resources across the period (week or month) to minimize production costs and unserved energy in the system. The thermal optimization creates a marginal cost curve for each hour of the period. The hydro generation and pumping is then scheduled against the array of hourly marginal cost curves to minimize total system costs, by using the so-called value of energy (water) method. This generally finds a more optimal hydro schedule than the pre-schedule going against only the loads, but is computationally intensive.

Final Optimization

PowrSym optimizes the unit commitment and dispatch of the thermal units using the method of equal incremental cost. The marginal cost for each hour is determined and units with operating cost less than the system marginal cost can be expected to be at full output during the hour. Units with higher marginal cost may be either offline or partially dispatched. The equal incremental cost theory applies not just to generating units, but also to interaction between the system areas subject to the grid constraints. For example, two interconnected areas will have the same marginal cost unless the link between the areas is at capacity. The grid model may be one or some combination of three methods. The three grid methods used are the NTC method, the PTDF method and the FB method. The model respects the power curve, heat rate curve, ramp rates, minimum up times and minimum down times of the generating units. Generating unit costs include fuel cost, operation and maintenance cost, and emissions-related costs. Wind and solar stations may be treated as either must-take stations or optionally curtailment can be allowed when necessary to meet minimum loads. The thermal optimization includes a robust operating and spinning reserve model.

Grid Model

PowrSym includes three distinct grid models which may be used individually or in combination allowing different models for different areas of a large system. The NTC model allows free flows between the areas limited only by link capacities, wheeling charges, hurdle costs, and link losses. The PTDF model utilizes transfer factors between each area and the defined centre area. Internally, the logic expands the transfer factors array to define the factors for exchange between each area and each other area. The third model is an implementation of the FB market coupling method used in CWE and uses constraint equations based on the net positions of selected areas to further bound the NTC model based on the FB model.

The grid model has three methods for the priority of scheduling flows. The first method schedules power flows incrementally from the surplus areas to the areas with the largest unserved energy in each hour. This method will tend to levelized unserved energy across the areas and results in minimum total unserved energy for the system. The second method is the opposite of the first; it schedules power flows incrementally from the surplus areas to the areas with the least unserved energy. The second method tends to concentrate the unserved energy in a few areas and minimizes loss of load hours but generally results in an increase of both system unserved energy and costs. The standard method combines the first method with some cost factors in an attempt to minimize total system costs.

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Combined Heat and Power Stations (CHP)
While the district and industrial heat requirements are often represented simply as minimum generation requirements on selected stations, PowrSym offers a fully integrated and optimized CHP model. In CHP mode, a time series of hourly heat loads are specified for each defined heat area and both CHP and heat boiler stations are assigned to each area. The heat rate functions for each CHP station are functions of both the electrical and heat loading of the station. The CHP model is fully integrated into the hydro-thermal-grid optimization, resulting in a global optimum for serving both the electrical and heat loads. The PowrSym output reports include costs, fuel consumption and emissions associated with heat production.

CWE flow-based calculations in PowrSym
PowrSym is able to incorporate the mechanism of the FBMC as applied in the CWE FB market coupling in the Monte Carlo economic dispatch optimisation.

- **Selection of the Flow-based domains**: On forehand each day of the reference year 2018/2019 is categorised based on the season, day of the week, French load, German wind generation, and German solar PV generation. Based on this category, a set of flow-based domains and the chances for specific domains are determined for each day. During the (Monte Carlo) simulations, one of the pre-selected domains is chosen with a weighted draw.
- **FB domains in PowrSym**: A FB domain consist of 24 lists of constrains, one for each hour, which reflects the physical network limitations. The constrains in one list describe together the space for exchange between the four CWE zones. In the simulations with FB domains, the tool selects for each hour a corresponding list and optimizes the flow with the given space or exchange. This in contrary to the non-FB calculations, which use fixed values for the interconnector capacities. The FB domains might both be less restricting and more restricting depending on the fixed interconnector capacities and depending on the used FB domains, and the direction and magnitude of the market power flows.

Reporting
PowrSym produces detailed output reports by hour, day, week, month and year. Output results include system reliability measures such as EENS and LOLE, emissions totals, fuel costs, fuel consumption, and other cost factors. Output reports include files designed for input into database and spreadsheet models allowing flexibility in the preparation of charts and graphics.

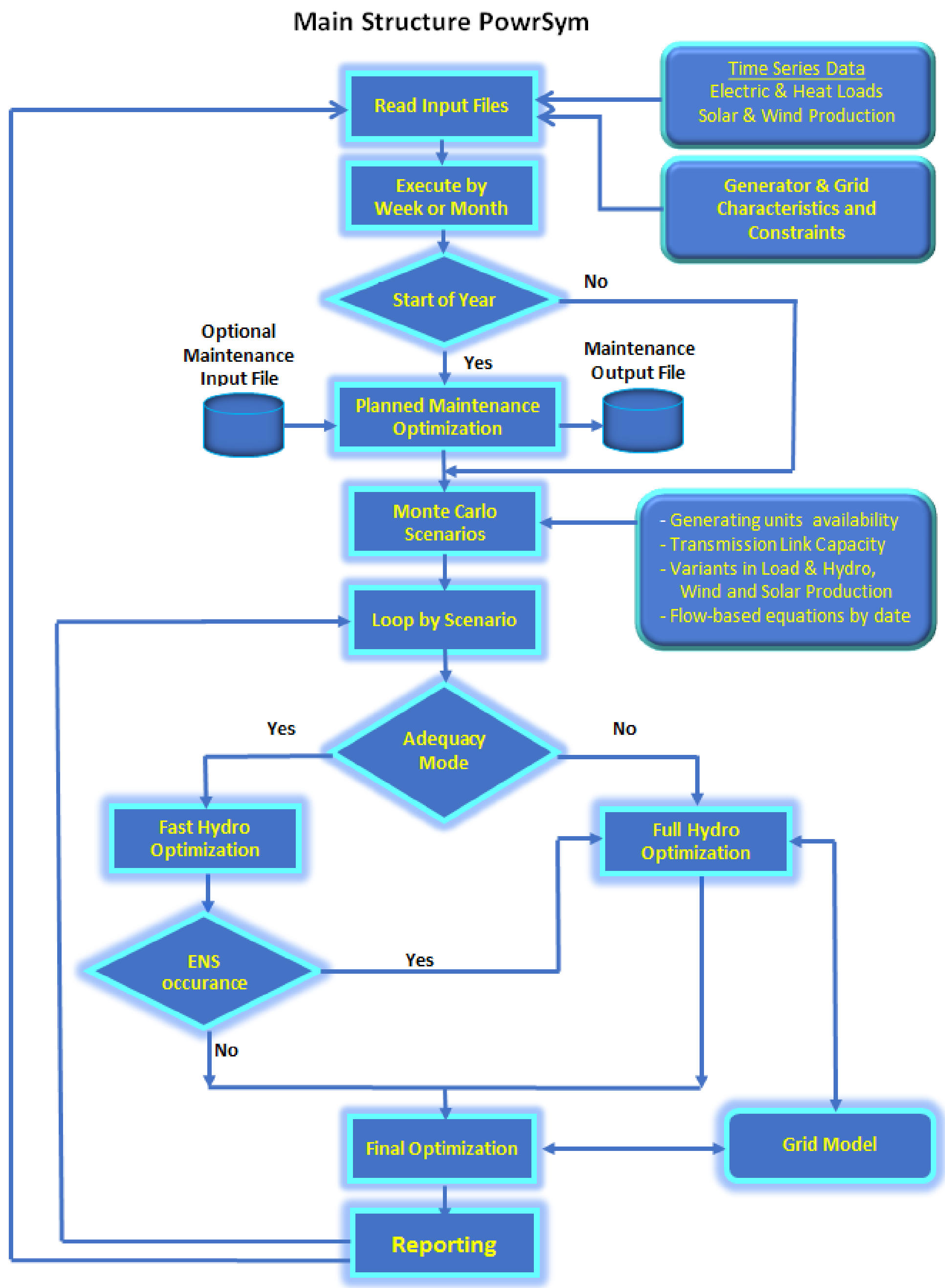

Figure 23: Main structure of PowrSym

4 Glossary

4.1 Zone codes and corresponding countries

AL	Albania	GR	Greece	MK	FYR of Macedonia
AT	Austria	GR03	Greece Crete	MT	Malta
BA	Bosnia and Herzegovina	HR	Croatia	NI	Northern Ireland
BE	Belgium	HU	Hungary	NL	Netherlands
BG	Bulgaria	IE	Ireland	NOm	Norway Mid
CH	Switzerland	IS	Iceland	NOn	Norway North
CY	Cyprus	ITcn	Italy Central North	NOs	Norway South
CZ	Czech Republic	ITcs	Italy Central South	PL	Poland
DE	Germany	ITn	Italy North	PT	Portugal
DEkf	Germany KF	ITs	Italy South	RO	Romania
DKe	Denmark East	ITsar	Italy Sardinia	RS	Serbia
DKkf	Denmark KF	ITsic	Italy Sicily	SE1	Sweden
DKw	Denmark West	LT	Lithuania	SE2	Sweden
EE	Estonia	LUb	Luxembourg	SE3	Sweden
ES	Spain	LUf	Luxembourg	SE4	Sweden
FI	Finland	LUg	Luxembourg	SI	Slovenia
FR	France	LUv	Luxembourg	SK	Slovak Republic
FR15	France Corsica	LV	Latvia	TN00	Tunisia
GB	United Kingdom	ME	Montenegro	TR	Republic of Turkey

4.2 Abbreviations

CCGT	Combined Cycle Gas Turbine
CGMES	Common Grid Model Exchange Specification
CHP	Combined Heat and Power
CWE	Continental West 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
HP	Heat Pump
HVDC	High Voltage Direct Current
IEA	International Energy Agency
LOLE	Loss of Load Expectation
LOLP	Loss of Load Probability
MAF	Mid-term Adequacy Forecast
MILP	Mixed-Integer Linear-Programming
NGC	Net Generating Capacity
NRA	National Regulatory Authority
NTC	Net Transfer Capacity

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OCGT	Open Cycle Gas Turbine
OPF	Optimal Power Flow
PECD	Pan-European Climate Database
PEMMDB	Pan-European Market Modelling Database
PLEF	Pentalateral Energy Forum incl. (AT, BE, CH, DE, FR, LU, NL)
PTDF	Power Transfer Distribution Factor
PV	Photovoltaics
TYNDP	Ten Year Development Plan
VP	Voluntary Party (refers to a market modelling tool)