European Resource Adequacy Assessment

2021 Edition

Annex 3: Methodology

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1 Introduction to the European resource adequacy assessment methodology

Adequacy studies aim to evaluate a power system's available resources and projected electricity demand to identify supply/demand mismatch risks under a variety of scenarios. In an interconnected power system such as the European system, this scope should be extended by considering the supply and demand balance under a defined network infrastructure, which can have a considerable impact on adequacy results. In this context, the focus of a pan-European adequacy forecast – as presented in the current report by ENTSO-E – assesses the adequacy of supply to meet demand on the mid-term time horizon while considering interconnections between different power systems across the European perimeter, as illustrated in Figure 1.

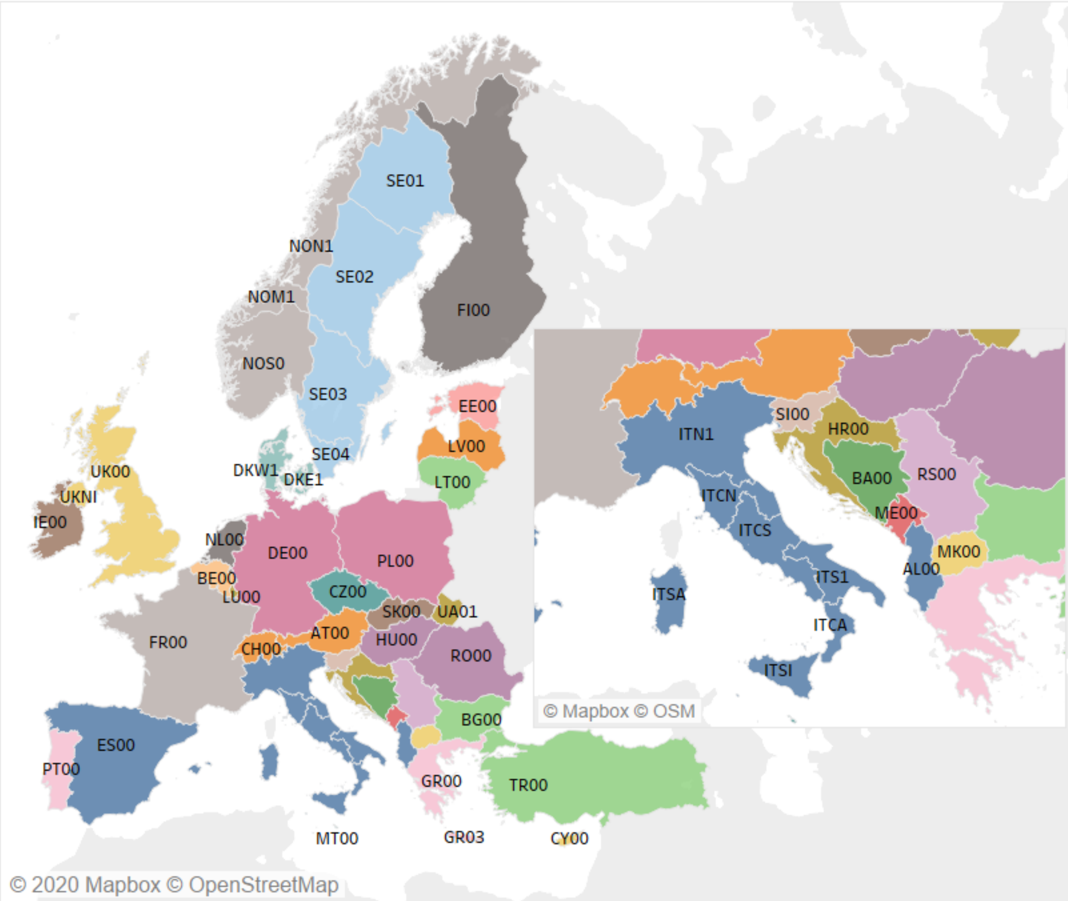


Figure 1: The interconnected European power system modelled in the ERAA 2021 (Note: Burshtyn Thermal Power Plant Island in Ukraine is also explicitly modelled in the ERAA 2021)

The present European Resource Adequacy Assessment (ERAA) probabilistic methodology is considered a reference within Europe. It is, however, not fully implemented to the extent defined in the 'Clean Energy for all Europeans' legislative package (see Section 7). Notably, both the ERAA 2021 scenarios and results should not be interpreted or utilised under this new legal framework. The roadmap towards the complete implementation of the ERAA methodology requirements can be found in the Executive Report, chapter 5.2.

To optimise and forecast a power system's operation, a large amount of detailed information is required. However, even with the best available data, the results are subject to considerable uncertainty and, therefore, result in a difficult decision-making process for market players.

Figure 2 illustrates the main elements of the ERAA 2021 methodology and their impact on adequacy. The adequacy assessment considers, among others, generation, demand, demand side response, storage and network infrastructure.

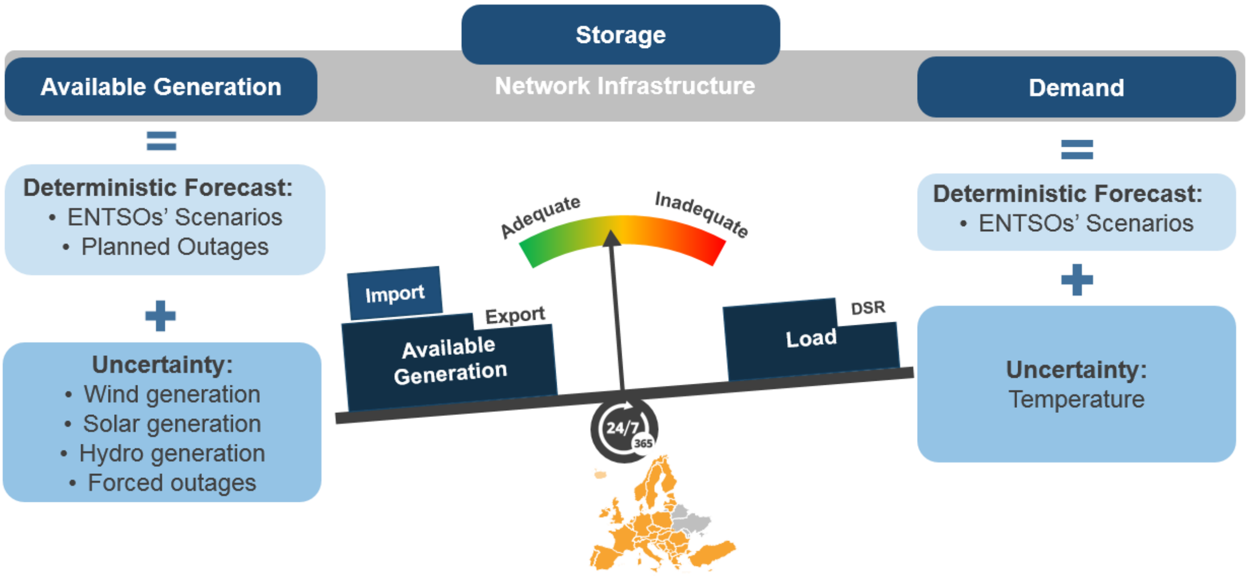


Figure 2: Overview of the ERAA 2021 methodological approach

1.1 Geographical scope

The present study focuses on the pan-European perimeter and neighbouring zones connected to the European power system. Zones are modelled either **explicitly** or **non-explicitly**. Explicitly modelled zones are represented by market nodes that consider complete information using the finest available resolution of input data (e.g. information regarding generating units and demand). Non-explicitly modelled zones are market nodes for which detailed power system information is not available to ENTSO-E. Only expected hourly exchanges between these market nodes and adjacent explicitly modelled nodes are considered.

In total, 56 bidding zones in 37 countries are modelled explicitly in ERAA 2021. The ERAA only models interconnections between market/bidding zones and makes an abstraction of intrazonal grid topologies. Some countries are divided into multiple zones according to the market setting in those countries (e.g. Greece, Denmark and Italy). Whereas Figure 1 illustrates all explicitly modelled zones of the ERAA 2021, Table 1, Table 2 and Table 3 provide a list of explicitly modelled, non-explicitly modelled and non-modelled zones. More details on explicitly and non-explicitly modelled zones are given in Geographical scope 1.1.

Table 1: Explicitly modelled countries / bidding zones

Explicitly modelled member countries/regions and bidding zones			
Albania (AL00)	Finland (FI00)	Republic of North Macedonia (MK00)	Slovenia (SI00)
Austria (AT00)	France (FR00)	Malta (MT00)	Spain (ES00)
Belgium (BE00)	Germany (DE00, DEKF)	Montenegro (ME00)	Sweden (SE01, SE02, SE03, SE04)
Bosnia and Herzegovina (BA00)	Greece (GR00, GR03)	Netherlands (NL00)	Switzerland (CH00)
Bulgaria (BG00)	Hungary (HU00)	Norway (NON1, NOM1, NOS0)	Turkey (TR00)

Croatia (HR00)	Ireland (IE00)	Poland (PL00)	Ukraine Burshtyn Thermal Power Plant Island (UA01)
Cyprus (CY00)	Italy (ITN1, ITCN, ITCS, ITS1, ITCA, ITSA, ITSI)	Portugal (PT00)	United Kingdom (UK00, UKNI)
Czech Republic (CZ00)	Latvia (LV00)	Romania (RO00)	
Denmark (DKW1, DKE1, DKKF)	Lithuania (LT00)	Serbia (RS00)	
Estonia (EE00)	Luxembourg (LUG1, LUB1, LUV1, LUF1)	Slovakia (SK00)	

Table 2: Non-modelled countries

Non-modelled member countries
Iceland (IS00)

Table 3: Non-explicitly modelled countries

Non-explicitly modelled neighbouring countries/regions		
Morocco (connected to ES00)	Russia (connected to FI00, LV00)	Tunisia (connected to ITSI)

1.2 Time horizon and resolution

The ERAA target methodology aims to identify adequacy risks up to 10-year ahead and thus assists stakeholders in making well-informed investment decisions. The ERAA 2021, as the first edition of a stepwise implementation, focuses on target years (TYs) 2025 and 2030 and considers techno-economic trends and policy decisions relevant for the assessed TYs (e.g. the phase-out of certain generation technologies).

An hourly simulation resolution, also referred to as an hourly market time unit (MTU), has been adopted for all TYs and scenarios. All input time series data for the unit commitment and economic dispatch (UCED) model (e.g. renewable energy source [RES] generation, demand profiles and net transfer capacities [NTCs]) are consequently expressed in hourly intervals. Data provided in a seasonal format by Transmission System Operators (TSOs) are transformed into hourly time series before being fed into the UCED model.

1.3 Modelling assumptions

The ERAA model is a simplified representation of the pan-European power system that – like any model – is based on a set of assumptions, which includes:

1) **Central planning for generation dispatch:** The modelling tool dispatches generation units for specified time horizons based on their marginal production cost and other plant parameters.
2) **Perfect information during the UCED problem:** Available RES energy, thermal capacities, demand-side response (DSR) capacities, grid capacities and demand are assumed to be known in advance with perfect accuracy; there are no deviations between forecast and realisation. Furthermore, perfect foresight is assumed for variables affecting optimal hydro dispatch.
3) **Demand is aggregated by bidding zone:** Individual end users or end-user groups are not modelled.
4) **Demand elasticity regarding climate and price:** Demand levels are partly correlated to the weather. For example, temperature variations will affect demand levels due to adaptations in the use of electrical heating/cooling devices. One portion of the demand is modelled as DSR, in which load can be reduced if energy prices are higher than the activation price. The remaining portion of energy demand is regarded as inelastic to price and will thus hold, regardless of the energy price. The latter

also includes new consumers, such as heat pumps and EVs, which are modelled assuming a price-inelastic consumption behaviour (see more details in chapter 6.2).

5) **Focus on energy markets only:** Only resources available to the market are modelled in the ERAA. Non-market resources, such as strategic reserves, are not modelled in the reference scenarios, but are quantified in the Annex 1. Adequacy is evaluated from a day-ahead/intraday market perspective. Lack of adequacy, the primary focus of the ERAA, should reflect the expectation that the system is not structurally balanced, at least in some hours and/or days. In addition, forward/futures markets or forward/futures contracts between market players are not modelled. As such, these do not influence modelled resource capacities.
6) **RES production depends on climate:** Solar, wind and hydro power generation directly depend on climate conditions.
7) **Forced outages (FOs) only affect thermal generation and grid assets:** A power plant net generating capacity (NGC) and a grid net transfer capacity (NTC) are not continuously guaranteed in a given TY. FOs are randomly generated for thermal assets and grid elements within the modelling tool, whereas planned grid outages are included in NTCs provided by TSOs. Lastly, FOs do not impact planned maintenance in any way.
8) **Upcoming FOs considered in UCED:** FOs are randomly generated but are known at the time of the UCED, with a look-ahead horizon of 1 day ahead. As such, the units are dispatched accordingly to avoid/minimise loss of load.
9) **Planned maintenances of thermal units are optimised:** Whereas FOs occur randomly over time, planned thermal unit maintenance is scheduled during the least critical periods, having perfect foresight of the demand pattern (i.e. periods with likely supply surplus rather than supply deficit). The maintenance optimisation considers country-specific restrictions such as the maximum number of units simultaneously under maintenance and is built on average climate conditions, i.e. an average climate year is selected for optimising planned maintenance profiles.
10) **Some technical parameters of thermal generators are modelled in a simplified manner:** Technical parameters considered to have a low impact on adequacy are modelled in a simplified manner or are neglected (e.g. minimum up/down time [h] restrictions that represent economical restrictions are not considered). Details on this are given in Section 3.1.
11) **NTC approach:** Electricity exchanges between market nodes are optimised as part of the UCED model optimisation and are limited by the respective NTC between the market nodes. The NTC approach considers only bilateral power flows without considering the impact of flows in neighbouring regions.
12) **Electrolysers are not modelled:** Electrolysers are not modelled explicitly as their impact on adequacy parameters is assumed to be negligible. In times of scarcity, electrolysers are assumed to consume no electricity due to high market prices. However, an implementation of electrolysers in the models is planned as part of the ERAA roadmap as part of the sectorial integration (see Executive Report, chapter 5.2).

2 Probabilistic assessment

As presented in the ERAA 2021 Executive Report, most member states monitor power system reliability through probabilistic adequacy indices, most commonly the loss of load expectation (LOLE). Thus, a modern adequacy assessment shall account for uncertain variables in the system and offer a probabilistic indicator of the adequacy situation under a number of plausible realisations of the uncertain system variables. The state-of-the-art methodology to calculate LOLE and expected energy not served (EENS) in adequacy studies is the so-called Monte Carlo (MC) simulation approach. The applied MC simulation consists of a large number of scenarios – each with a random realisation of unpredictable outages. These outages occur for generation and transmission assets. In the ERAA 2021, the random outages of assets are drawn for each modelled climate scenario. The combination of random outages and climate scenarios results in a large set of possible system states to be modelled. Results can then be assessed probabilistically, complying with the requirement of volatile modern power systems. This section presents the analysed indicators as well as the applied MC simulation and the convergence criteria.

2.1 Monte Carlo Adequacy Assessment

MC simulations are at the core of the ERAA. A set of different climate scenarios are defined, representing consistent historical climate years. Each climate year is then combined with multiple random forced outage realisations. Each forced outage realisation is drawn from forced outage distributions for both generation and interconnection assets. Each set of model runs that are executed for one climate year and for all related random forced outage realisations is referred to as an MC year.

As a first step, climate years from 1982 – 2016 are selected one-by-one (*N* climate years). Each climate year represents a consistent set of:

- Temperature-dependent demand time series;
- Wind and solar load factor time series;
- Time series for hydro generation, inflows, minimum/maximum generation or pumping capacity, and minimum/maximum reservoir level (where applicable);
- Climate-dependent time series for other RES and other non-RES generation.

Note that the above-mentioned climate year data might depend on the selected target year.

As a second step, multiple sets of random FO realisations (hourly time series) are generated for each climate year (*M* forced outage samples per climate year, where the quantity *M* is only known after model convergence is reached). The sets of FO realisations include FOs for thermal generation units, high-voltage direct current (HVDC) interconnections and some high-voltage alternating current (HVAC) interconnections. FO realisations do not impact the planned maintenance schedules. FOs are not modelled in the Economic Viability Assessment (EVA) model in the ERAA 2021. More details on the convergence can be found in Section 2.3.

The combination of *N* climate years and *M* forced outage realisations per climate year results in a total of *N x M* model runs. Each model run is optimised individually. Figure 3 illustrates the described MC approach for each TY studied.

For more information on input data, please refer to chapter 3 and Annex 1.

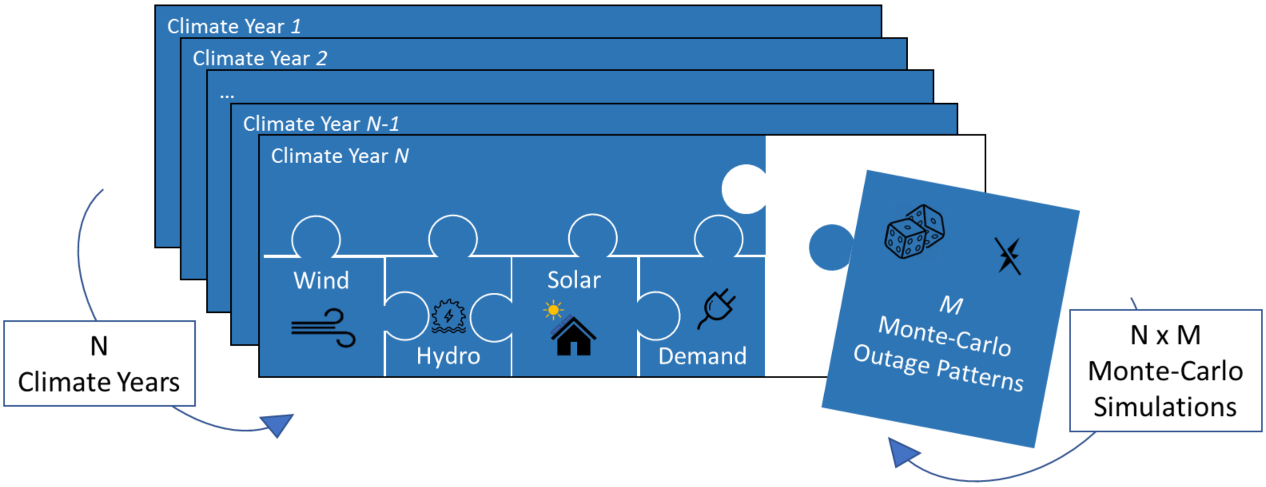


Figure 3: Monte Carlo simulation principles for a given target year

2.2 Adequacy Indicators

In probabilistic adequacy studies, the typical indicators for resource adequacy are either (1) the expectation of indicators (e.g. the EENS) or (2) a percentile of the independent indicator values (e.g. 95$^{\text{th}}$ percentile of the ENS values). The following indices are used to assess the adequacy levels for a given geographical scope and for a given time horizon:

- **Loss of load duration (LLD) [h] –** the duration in which resources (e.g. available generation, imports, demand flexibilities) are insufficient to meet demand. It does not indicate the severity of the deficiency (ENS). Note that the model has an hourly time resolution which therefore also transfers to the granularity of the LLD indicator.
- **LOLE [h] –** the expected number of hours during which resources are insufficient to meet demand over multiple scenario runs, i.e. climate years and/or FO realisations. LOLE can be calculated as the mathematical average of the respective LLD over the considered model runs, according to Eq. (2): For *J* the total number of considered model runs and LLD_j the LLD of model run *j*, then

$$LOLE = \frac{1}{J}\sum_{j=1}^{J} LLD_j. \qquad (2)$$

- **ENS [GWh]** – the sum of the electricity demand which cannot be supplied due to insufficient resources. For a geographical scope with multiple nodes, ENS refers to the total ENS of all its nodes. A null ENS suggests that there are no adequacy concerns.
- **EENS [GWh]** – the electricity demand which is expected not to be supplied due to insufficient resources. For a geographical scope with multiple nodes, EENS refers to the total EENS of all its nodes. EENS can be calculated as the mathematical average of the respective ENS over the considered model runs, according to Eq. (1): For J the total number of considered model runs, and *ENSj* the Energy Not Served of model run *j*, then

$$EENS = \frac{1}{J}\sum_{j=1}^{J} ENS_j. \quad (1)$$

2.3 Model Convergence

FO realisations may have an impact on model results depending on the specific demand and supply situation assumed in the given MC run. A major power plant experiencing a FO might, for example, lead to severe adequacy risk in a high-demand and low-renewable-energy-production situation, whereas it might have a negligible impact in a high-renewable-energy-production situation. Model run results might thus differ significantly. Figure 4 illustrates this aspect, showing a schematic histogram of the ENS over 700 MC realisations.

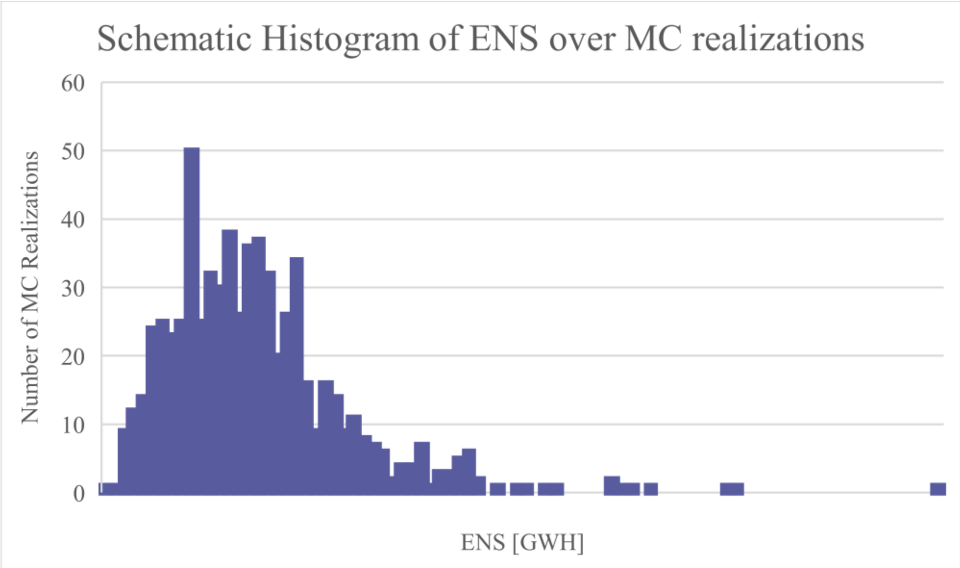


Figure 4: Schematic histogram of the ENS over 700 MC realisations. Each histogram bin covers a range of 5 GWh ENS and contains the number of MC realisations which lie within the respective ENS range.

To obtain robust results, the impact of additional MC realisation results on the existing results should be small or negligible and thus have limited/no impact on the convergence metrics. It can then be said that the model has converged.

In the ERAA 2021, the convergence of the models is calculated in several steps. Following a set of model runs, the models' convergence is assessed and, in the event the convergence is not reached, additional simulations using new FO realisations are launched.

Whereas the results provided in the Executive summary and Annex 2 are presented for each region separately, the convergence of the ERAA 2021 models is assessed using the relative change of the coefficient of variation α derived from the ENS of the entire geographical scope, as defined by Eq. (3):

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

where $EENS$ is calculated over all MC realisations completed at the moment of assessment and $\mathrm{Var}[EENS]$ is the variance of the expectation estimate (i.e., $\mathrm{Var}[EENS] = \frac{\mathrm{Var}[ENS]}{N}$).

Figure 5 provides an example of the evolution and the relative change of the coefficient of variation of an MC model in function of the number of MC realisations. No significant changes in α occur past a certain number of MC realisations, meaning no significant changes in averaged results are expected and thus no additional MC realisations are needed to improve results. In the ERAA 2021, no explicit simulation stopping criterium is set for the coefficient of variation. The decision of whether or not to launch additional model runs is based on a compromise between the relative change in α and the required computational time. Annex 2 offers an insight of the coefficient of variation and its relative change versus increasing number of MC simulations for the different ERAA 2021 scenarios.

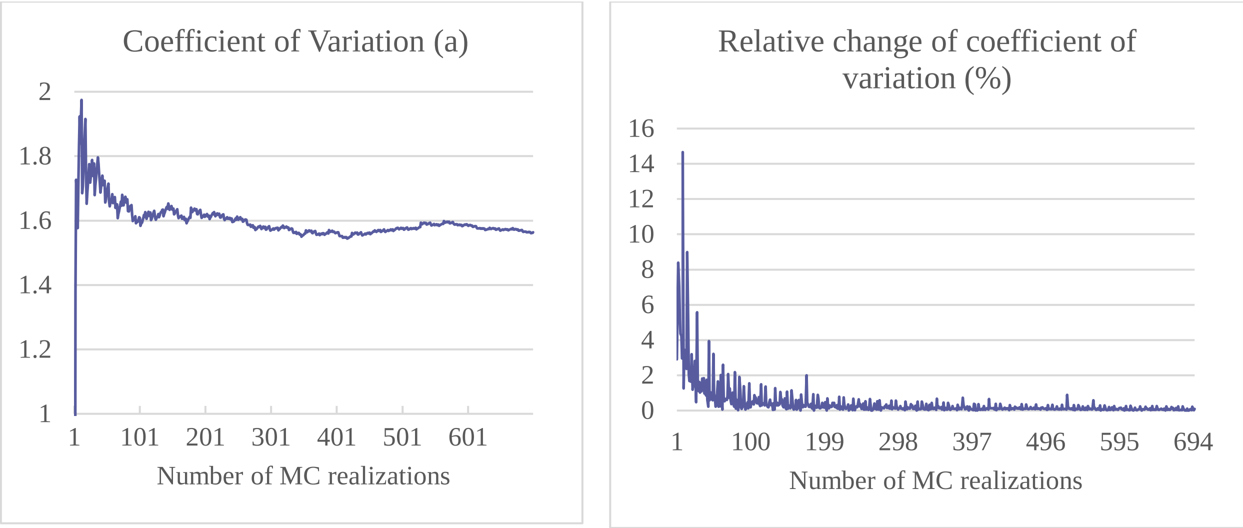


Figure 5: Example of α evolution and its relative change with an increasing number of MC samples for a converging model

Notably, certain inputs and parameters can have a significant impact on the results of those adequacy indices and their convergences, including:

- Hydro power modelling;
- NTCs;
- The use/absence of extreme, yet realistic, historical climatic years;
- Outages and their modelling, including both maintenance and FOs[1].

3 Main inputs and uncertainties

3.1 Generation/Resource side

In the ERAA 2021, generation units are classified as RES, Non-RES, storage and DSR. Table 4 shows the categorization and spatial granularity of considered generation technologies.

Table 4: Classification of generation units

Category	Technology	Granularity
RES	Wind	aggregated in PECD zones; onshore and offshore wind capacities are collected and modelled separately
	Solar	aggregated in PECD zones; solar PV and solar thermal with and without storage are collected and modelled separately

[1] To understand the impact of FOs, which are random by definition, it is important for all of the tools to use one commonly agreed upon maintenance schedule. This maintenance schedule should respect the different constraints specific to the thermal plants in different countries, as provided by TSOs.

	Other RES	aggregated in PECD zones
	Hydro RoR and Pondage	aggregated in market nodes
	Hydro with traditional reservoir	aggregated in market nodes
Non-RES	Coal	unit-by-unit
	Gas	unit-by-unit
	Nuclear	unit-by-unit
	Other Non-RES	aggregated in technology bands
Storage	Batteries	aggregated in market nodes
	Open-Loop PSP	aggregated in market nodes
	Closed-Loop PSP	aggregated in market nodes
DSR	DSR	aggregated in price bands

Generation data are provided by TSOs through the Pan-European Market Modelling Data Base (PEMMDB). Climate-dependent data such as hydro inflows, solar and wind generation time-series are included in the Pan-European Climate Database (PECD). Chapter 8 gives more information about the PEMMDB and PECD. If any relevant input parameter is missing, default values known as Common Data collected by ENTSO-E are used.

3.1.1 Non-RES

As shown in Table 4 above, major thermal units are modelled on a unit-by-unit basis. Only units available on the market are considered for the adequacy simulation. Thermal units are dispatched according to their marginal production costs and other plant parameters, including associated costs for CO_2 emissions. The cost of CO_2 emissions is set to 0 Euro/MWh for biofuel units. In addition, start-up costs are considered when a unit must be started. The following table describes the consideration of unit-specific technical parameters as modelled, non-modelled or simplified modelling as applied in the ERAA 2021. Technical parameters assumed to have a significant impact on resource adequacy are modelled explicitly or simplified. Parameters that are less relevant or have no impact on resource adequacy are neglected in the simulation.

Table 5: List of modelled and non-modelled technical parameters of thermal units

Parameter	Description	Consideration
Forced Outage Rate	Likelihood of an unplanned outage.	Modelled
Must-run [MW]	Hourly constraint for single or group of units to produce **at least** a certain amount of MW.	Modelled
Min Stable Level [MW]	Minimal operation level of a unit.	Modelled
Derating [MW]	Hourly constraint for single or group of units	Modelled

	to reduce the capacity offered to the market.	
Start-up Time [h]	Time interval required to start a unit from 0 to Min Stable Level.	Simplified
Ramp Rates [MW/h]	Limitation on the increase / decrease of the generation level within one hour for a unit that is already dispatched.	Not Modelled
Min Up / Down Time [h]	Minimum time interval that a unit should be in operation / out of operation. Frequently related to economic reasons.	Not Modelled
Balancing Reserve Procurement	Balancing reserves that are procured to serve for operational stability purposes.	Modelled

The impact of Ramp Rates and Min Up / Down Times on adequacy indices are negligible due to the perfect foresight assumption in the simulations. Scarcity situations are anticipated in advance, and units are ramped sufficiently early to cope with any adequacy risk and the associated high cost. Start-up Times are modelled in a simplified manner, only right after the occurrence of a forced outage of a unit. In these times, Start-up Time limitations can have an impact on adequacy as the outage withholds the unit from starting in advance.

In addition to unit-by-unit thermal generators, the technology Other Non-RES comprises multiple bands of aggregated Non-RES technologies for each market node. Similar smaller plants are grouped together by technology, price and efficiency, and can be given a must-run status. TSOs are free to provide time series of aggregated capacity with an hourly derating profile if relevant. Available capacity profiles can also be provided for different climate years and will as such be attached to the different PECD climate years 1982 – 2016. Available capacity profiles enable a reduction in computational difficulty by simplifying unit dispatch for smaller plants, while still considering decreased power output from planned maintenances or forced outages.

Other Non-RES usually aggregates small CHP units, waste incineration plants, non-dispatchable thermal generation, and any other plants that cannot be provided in a unit-by-unit resolution.

3.1.2 RES

As for Wind, Solar and Other RES technologies, the total capacity installed at PECD zone level is specified and corresponds to the sum of all plant-by-plant and aggregated capacities. In addition, hourly generation curves can be assigned to individual units and/or aggregated capacity provided by TSOs. Solar and wind generation are climate dependent and result from solar irradiance and wind conditions, respectively (see Section 6.3.2). Planned and unplanned outages for RES and Other RES are already included in the hourly time series and are therefore not explicitly modelled.

The available power of RES and Other RES is injected into the grid at no cost or curtailed following the optimisation model's decision.

RES technologies Hydro run-of-river (RoR) and Pondage and Hydro with traditional reservoir are described in a separate section 4.2.5.

3.1.3 Storage

Battery storages are increasingly adopted as a means to introduce flexibility into the grid. This flexibility can either participate in the market or be used behind the meter. Market-participating batteries are explicitly modelled and their dispatch is optimised within the probabilistic modelling. The main parameters considered for this technology type are as follows:

- Installed output capacity (MW);
- Storage capacity (MWh);
- Efficiency (default: 90% per cycle).

Non-market participating batteries are not explicitly modelled but exogenously included in the demand profiles based on information provided by TSOs. Storage technologies Open-Loop PSP and Closed-Loop PSP are described under the hydro section 3.1.5.

3.1.4 DSR

A part of demand is explicitly modelled as price-elastic DSR, whereas the majority of demand serves as a fixed input and is assumed to be inelastic to electricity prices generated by the model.
DSR capacity differs between market nodes and between hours of the day. The dataset provided by the TSOs includes:

- the maximum DSR capacity [MW];
- the day ahead price [EUR/MWh];
- the actual availability [MW] for all hours of the year;
- the maximum number of hours the DSR source can be used per day (default: 24 hours).

Each of the above parameters can be specified for different price bands, either as a market resource or as strategic reserves (the latter is not considered in the adequacy simulations of the ERAA). From a modelling perspective, DSR is equal to any other generation asset but with an activation price that is higher than the marginal cost of most other generation categories and with an availability rating that limits the actual DSR capacity in any given hour.

3.1.5 Hydro

Hydro capacities are aggregated by bidding zone and technology type. The availability of hydro energy inflows and additional hydro constraints as well as the criteria for the capacity aggregation are available and defined in the pan-European Hydropower Modelling Database complementing the PECD[2] (also referred to as the 'PECD Hydro database').

Hydropower plants are aggregated into four distinct technology categories:

1. RoR and pondage;

[2] Hydropower modelling - New database complementing PECD

2. Reservoir (hereafter referred to as 'traditional reservoir');
3. Open-loop PSP reservoir;
4. Closed-loop PSP reservoir.

The RoR and pondage category accounts for the RoR generators with swell RoR, pondage and small daily storages, i.e. without pumping capabilities and with a ratio of reservoir size [MWh] to net generation capacity [MW] smaller than 24 h. Major hydro storage plants without pumping capabilities are merged into the traditional reservoir category. PSPs are differentiated between basins with natural inflows, i.e. the open-loop PSP reservoir, and PSPs without natural inflows, i.e. the closed-loop PSP reservoir.

The maximum and minimum power available for turbining are constrained by hydro inflows, minimum and maximum generation and reservoir level constraints. Forced outages or maintenance of hydro technologies are included in the (weekly) maximum generation constraints. Data availability varies depending on the input data provided by TSOs for the peculiar generation mix of the market nodes within their control areas. It follows that the data in Table 6 are not fully available for all market nodes but are, rather, an indication of the template and structure of the database itself.

Table 6: Key hydropower data and constraints per aggregated technology type

MW / GWh	ROR & Pondage	Trad. Reservoir	Open-Loop PSP	Closed-Loop PSP
Hydro inflows	D	W	W	-
Max. power output	D	W	W	W
Min. power output	D	W	W	W
Max. generated energy	-	W	W	W
Min. generated energy	-	W	W	W
Max. pumping power	-	-	W	W
Min. pumping power	-	-	W	W
Max. pumped energy	-	-	W	W
Min. pumped energy	-	-	W	W
Deterministic res. level	-	W	W	-
Max. reservoir level	-	W	W	-
Min. reservoir level	-	W	W	-
Reservoir size	•	•	•	•
Turbine capacity	•	•	•	•
Pump capacity	-	-	•	•
Size/Capacity ratio [h]	≤ 24	>24	any	any

D: Daily	W: Weekly	- : N/A	■ : Not modelled

In what follows, a detailed description is given of the modelling assumptions and the hierarchy of the constraints collected in the table above.

Hydro Inflows – available as cumulated daily or weekly energy lots – are equally distributed over 24 or 168 hours respectively, given the hourly resolution of the UCED simulation. Depending on the hydropower category, inflows are immediately dispatched (e.g. pure RoR generation) or stored within the hydro reservoirs and released according to the optimised reservoir management performed by the modelling tool. If available hourly inflows exceed the dispatch needs or the maximum reservoir level trajectories, the modelling tools can decide to spill (i.e. dump) the inflow surplus.

Minimum and Maximum Generation (output power or energy) constraints regulate the hourly hydropower dispatch. If not explicitly provided, minimum power is assumed to be equal to zero and maximum generation is set to be equal to total installed capacity. RoR generation is assumed to be non-dispatchable by definition; thus, the daily inflows are turbined at a constant hourly output during the day. If a non-zero reservoir size is provided for the RoR and pondage category, such dispatch flexibility is granted according to minimum and maximum generation profiles, which reflect both the non-dispatchable RoR and the dispatchable swell or pondage share of the aggregated capacity, respectively. Minimum and maximum generated energy constraints represent weekly limitations to the energy output that are enforced in an intertemporal manner, i.e. the total generation over the whole week has to be lower (or higher) than the maximum (or minimum) energy constraint for the respective week.

Reservoir Level Constraints are treated as discrete hard constraints to be enforced by the modelling tool at the beginning of each week, i.e. on the first hour of the week. Nevertheless, the intrinsic complexity of optimising hydropower generation from hydro reservoirs characterised by climate-dependent and/or seasonal constraints and inflow patterns may sometimes lead to punctual infeasibilities in the UCED solution. Such infeasibilities frequently arise from the solver trying to enforce the initial reservoir level (or minimum/maximum level) at the beginning of the week without sufficient flexibility. When these issues are detected, the solution adopted is usually to allow the solver to account for the reservoir level trajectories as soft constraints which can be violated at a high penalty cost. Setting the penalty cost sufficiently high but still lower than the VoLL ensures that the solver prioritises the dispatch of hydro resources and inflows during hours of generation scarcity to avoid ENS if potentially in conflict with hard reservoir constraints.

Minimum and Maximum Pumping are treated analogously to minimum and maximum power output constraints. In the ERAA 2021, only limitations to the maximum pumping power are applied in the model. The other pumping hydro constraints – marked in blue in Table 6 – are neglected and excluded from the hydropower modelling methodology. In particular, minimum power as well as minimum and maximum energy constraints for pumping operations are deemed as too restrictive and not suitable to the nature of the MC adequacy simulations, in which PSP plant operations shall be left as a flexible decision variable to be optimised by the solver according to the contingent availability of resources and endogenous marginal prices.

3.1.6 Balancing Reserves

Balancing reserves (or ancillary services) are power reserves contracted by TSOs that help stabilise or restore the grid's frequency following minor or major disruptions due to factors such as unforeseen plant outages or higher loads. Although they are fundamental to a power system's stability, only replacement reserves (RR) are considered available for adequacy purposes in the ERAA. Indeed, the ERAA measures structural inadequacies that manifest in time steps of 1 hour or longer and does not analyse what occurs within each hour. To avoid scheduling operational reserves (FCR and FRR) for time steps of 1 hour or longer – thus making them unavailable for their initial purpose – the latter are kept aside for operational purposes. The following Table 7 summarises the different balancing reserves and how they are treated in the model.

Table 7: Consideration of Balancing Reserves in the ERAA 2021

Balancing Reserve type	Consideration
FCR	Unavailable capacity

FRR	Unavailable capacity
RR	Modelled as available capacity

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

3.2 Grid side

Like thermal capacities, TSOs provide forecasted available NTCs with an hourly resolution. The TSOs provide data divided in the categories HVAC and HVDC, and NTCs are aggregated per border. Planned maintenance for transmission lines was not centrally optimised in the ERAA 2021 but was considered integrated into the NTC hourly availability, as provided by TSOs. Transmission levels depend on deterministic planned outages and random FOs, which are modelled in the same manner as for generation resources. TSOs can report specific Forced Outage Rates (FOR) per interconnector. Standard assumptions of 0% for HVAC and 6% for HVDC are applied if TSOs do not provide specific FOR values. Interconnectors between market zones can consist of multiple poles, which are also explicitly modelled in the ERAA. Random outages on these interconnectors are drawn per pole (i.e. at borders with multiple poles, an outage of one pole does not reduce the NTC to zero).

Apart from bilateral interconnector constraints, the following constraints are also considered in the ERAA 2021:

- Gross export/import limit, constraining the sum of exports/imports from the considered market area
- Country position net import and export limit, setting a lower and upper bound for the net balance of the market area. This is typically related to the minimum amount of inertia that a country needs to maintain, i.e. the minimum number of units spinning in their system to be operationally stable and running within operationally safe levels.

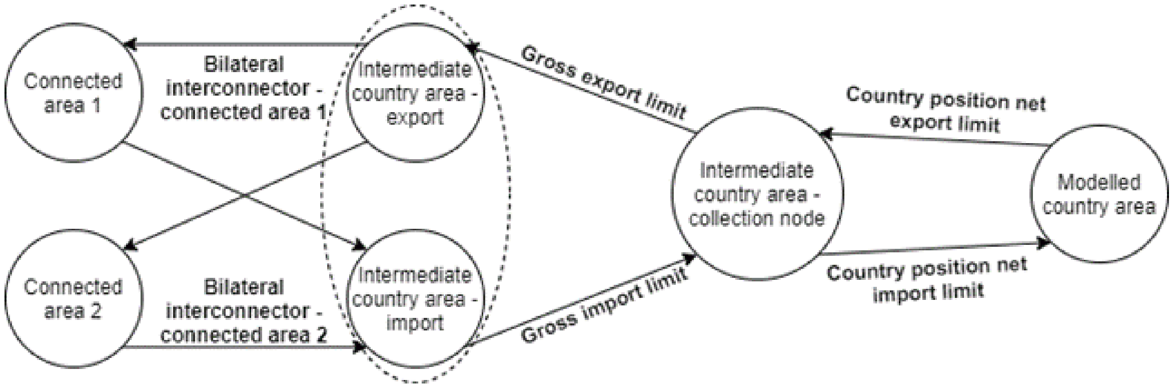


Figure 6: Modelling of gross import and export limits together with country position import and export limits

In Figure 6, bilateral interconnectors are modelled as usual. The only difference from conventional interconnectors is that they are coupled to intermediate export and import areas instead of to a modelled price area directly. The intermediate country import and export areas are, in turn, connected to an intermediate country area collection node through two unidirectional interconnectors representing the gross import and export limits.

The PEMMDB database does not contain data regarding the generation portfolio, demand and other parameters necessary to model the countries of the non-ENTSO-E region; hence, it is not possible to explicitly model exchanges with these countries. For this reason, exchanges with non-ENTSO-E regions are not an output of the simulation driven by the market but are entered as a fixed input into the model in the form of annual hourly data series. This is referred to as non-explicit modelling.

Due to the increased complexity of power systems, consideration of multi-lateral interconnection restrictions, such as FB modelling, become more important. FB modelling is currently investigated as a proof-of-concept in the ERAA 2021 and will replace NTC modelling in the future, as planned in the ERAA roadmap (see Executive Report, chapter 5.2). Insights on the on-going work of FB modelling are provided in Annex 4.

3.3 Demand side

Hourly demand profiles are a crucial element of a resource adequacy study. The methodology used by ENTSO-E is based on an external tool, i.e. TRAPUNTA, which is designed to overcome the limitations of traditional approaches by enabling the reconstruction of entire daily load profiles. The idea is to isolate significant load components via a mathematical analysis of the available integral load profiles. The mathematical approach followed by TRAPUNTA enables the extraction of a set of few orthogonal basis functions that can be used for reconstructing different load profiles for the same node, incorporating:

- Prediction of the whole daily load profile;
- Analysis of the changes in the whole daily load profile during the year;
- Identification of dependencies associated to different groups of days;
- Identification and representation of bank holidays in specific market nodes;
- Identification of seasonal trends, such as daylight-saving time and summer vacation period.

In addition to a load prediction based on climatic variables (and groups of days), TRAPUNTA allows the user to correct these predictions based on information and estimates about other load components. In particular, the user can include predictions about electric vehicles, sanitary water, air conditioning fraction, air conditioning load, heating heat pumps fraction, heating heat pumps load, batteries impact, additional base loads, and energy demand increase.

As a detailed description of the demand forecasting tool and the specific modelling decisions for ERAA exceeds the scope of this Annex, a stand-alone document accompanies this publication to provide all information necessary for the readers to understand this complex task (cf. ‘Demand Forecasting Methodology’).

4 Adequacy assessment methodology

4.1 Maintenance profiles calculation

Optimised maintenance profiles are an important deterministic input as they can significantly impact available generation capacity. A single maintenance schedule per scenario is determined by a modelling tool and fed into all modelling tools to ensure comparability of results.

Maintenance profiles are only generated for thermal units with a unit-by-unit resolution (see Table 4). For that purpose, TSOs can either provide unit-specific parameters for the maintenance optimisation or they can predefine an hourly ready-made outage pattern. The maintenance of renewables, other non-renewables and storages are considered to be included in the collected infeed time series of these generators.

For generation resources without a predefined maintenance profile, the annual planned outage rate provides the total number of days per year required for maintenance. Maintenance outage blocks are then scheduled on a yearly horizon using an objective function that aims to level the capacity margin per market node. The capacity margin is determined as the difference between peak load and available installed capacity. Levelling the capacity margin is therefore equivalent to increasing available installed capacity (i.e. scheduling less maintenance) when the weekly peak load is high and decreasing the available installed capacity (i.e. scheduling more maintenance) when the weekly peak load is low to minimise the risk of not meeting peak load. Consequently, maintenance will be moved away from weeks with a high weekly peak load and will be concentrated around weeks with a low weekly peak load. The resulting distribution of maintenance is consequently translated back to the maintenance schedules of individual units.

For each market node, the load profile corresponding to CY 2007 is used to construct maintenance schedules using the capacity margin levelling approach described above. Wind and solar feed-in are disregarded in the capacity margin calculation as their generation can vary considerably from one climate year to another and, therefore, can have a significant impact on the resulting maintenance schedule. Similarly, interconnector exchanges between market nodes are also disregarded. Maintenance is consequently optimised for each bidding zone separately.

As for the future ERAA, it is planned to extend the maintenance optimisation by considering more climate years, wind and solar feed-in and interconnection flows. Investigations on this are currently on-going.

Apart from the maintenance duration, multiple maintenance constraints can be applied to individual units. The maintenance restriction date guarantees that no maintenance is planned in a certain period. Other constraints apply to groups of units in a market node, such as the specified maximum/minimum number of units that can be scheduled for maintenance for the period as defined by the respective TSO.

The following table gives an overview of the different parameters that can be provided in the PEMMDB and for which target years these parameters have been considered.

Table 8: PEMMDB parameters and the target years for which they are considered

Parameter	Target year Considered
Planned outage: annual rate (number of days)	2025 & 2030
Planned outage: annual rate (number of windows)	2025 (2030: fixed with 1 window)
Planned outage: minimum number of hours per window	none[3]
Planned outage: Winter (ratio of annual number of days)	none[3]
Maintenance restriction starting date	2025
Maintenance restriction end date	2025
Max. Number of units on maintenance	2025 & 2030

[3] can currently not be implemented due to limitations of the reference modelling tool.

Visual representation of the total capacity per market area during the year can be found in Annex 1, chapter 2.1.

4.2 Forced outage profiles

Forced outage rates (FOR) are fundamental parameters in probabilistic simulations. They represent the probability of a power plant or an interconnection being out of service unexpectedly for a period of time. These parameters must be set up carefully considering the amount of capacity (thermal generation and transfer capability) they can put out of service. FORs are expressed as a single percentage for each generation unit or interconnector. FORs are provided for both target years 2025 and 2030 and may vary between the two years according to interconnection and power plant upgrades or renewals.

FO profiles represent the core of the MC simulation as described in section 2.1. They are generated randomly within each modelling tool for each stochastic element in the simulation. In the ERAA 2021, stochastic elements to be considered are unit-by-unit generators and interconnection lines. The following parameters are provided by TSOs to describe the outage behavior:

- FOR – i.e. the likelihood of a forced outage;
- Mean Time To Repair – i.e. the duration of a forced outage
  (default: line – 7 days; Nuclear unit – 7 days; Gas & Coal unit - 1 day).

FORs are considered for each single thermal unit and depend on the plant's technology and peculiar characteristics. If, for a specific thermal unit, no FOR is provided by the TSO, a default value based on the best historical estimation for the technology is used. The same mechanism is applied to interconnections.

Based on the parameters mentioned above, FO profiles are drawn, which describe the hourly availability of each stochastic element of the system. FOs can have a significant impact on resource adequacy due to their uncertain nature. Therefore, it is important to draw a large number of possible outage realisations and assess their impact.

4.3 Storage optimisation

The modelling tool performs an additional optimisation step for storage assets after the generation of the FO pattern and before the UCED optimisation. Available storage energy is optimised on a weekly time resolution. Energy is stored in times of sufficient supply and is made available for discharging in times of simultaneous high demand and low available generation. Simultaneously, exogenously provided weekly hydro energy targets constrain the optimisation.

4.3.1 Hydro storage optimisation

Hydro storages represent the most complex element of storage optimisation. They are constrained not only by hourly available generation capacity and storage capacity but also weekly reservoir level limitations. These constraints represent historical or technical minimum and maximum reservoir levels per week as provided by TSOs. Figure 7 displays an example of minimum and maximum reservoir level trajectories together with the initial and final reservoir level given as an input to the modelling tool.

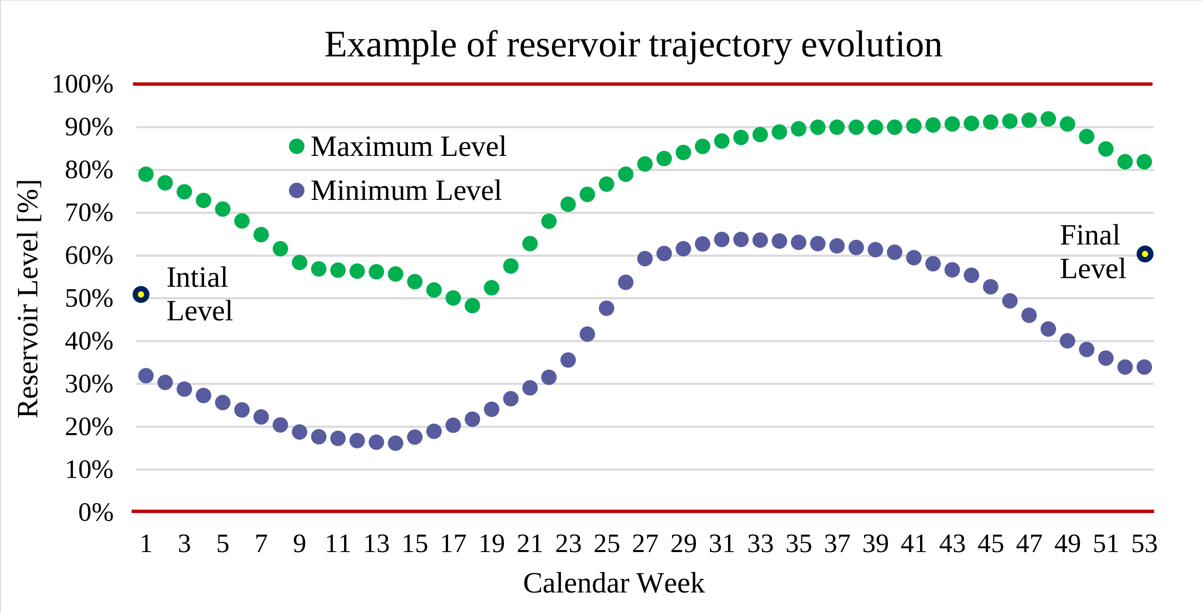


Figure 7: Example of reservoir trajectories and constraints

Alternatively, TSOs can also provide deterministic weekly trajectories per climate year to pre-define the reservoir level at the beginning of each week. As minimum and maximum reservoir trajectories provide more flexibility to the system, they are preferred over deterministic climate-dependent weekly trajectories in the event that both are provided. When both are missing, 0% and 100% of the total reservoir size act as continuous maximum and minimum hard constraints during the whole simulated timeframe. The initial reservoir level is taken as the fixed trajectory value at week 1 as provided by TSOs. If not available, the average between the minimum and maximum level trajectory at week 1 is taken. If both data are missing, 50% of the reservoir size is assumed as the standard value. Analogously, TSOs can provide fixed trajectory values for the final reservoir level. If the value is not available or not consistent, standard values as the mean between minimum and maximum reservoir constraints, or 50%, are assumed.

Apart from reservoir level constraints, multiple additional parameters limit the operation of hydro power plants, as summarised in Table 6 of section 3.1.5. The standard cycle efficiency (pumping – turbining) is assumed equal to 75%.

A pre-optimisation step for hydro storages occurs within the modelling tool at a coarser time granularity prior to the hourly UCED optimisation (see section 4.4). In this pre-optimisation, the available energy profile of hydro storage assets is optimised in daily energy lots so that hydro resources are saved and stored in the reservoirs over the year and made available to each daily UCED sub-problem related to the corresponding electricity needs of each bidding zone. The preoptimisation of reservoirs allocates the available energy from hydro storage assets in an optimal manner over the year, so that system costs (=generation costs) are minimised.

4.3.2 Batteries

Battery data are provided by TSOs, categorised as in-the-market batteries and out-of-the-market batteries. Only in-the-market batteries are modelled in the ERAA 2021 process. Therefore, behind-the-meter battery storages (integrated with PV systems) are not considered in the ERAA. Batteries are characterised by two parameters, namely output capacity measured in MW and storage capacity measured in MWh. The initial battery charge (at the start of the simulation) is assumed to be 50% of the storage capacity. In addition, the battery charging efficiency is assumed to be 90%, i.e. for 1 MWh taken from the grid, 0.9 MWh is stored in the battery and 0.1 MWh is lost. The discharge efficiency was assumed to be 100%. This principle is illustrated in Figure 8.

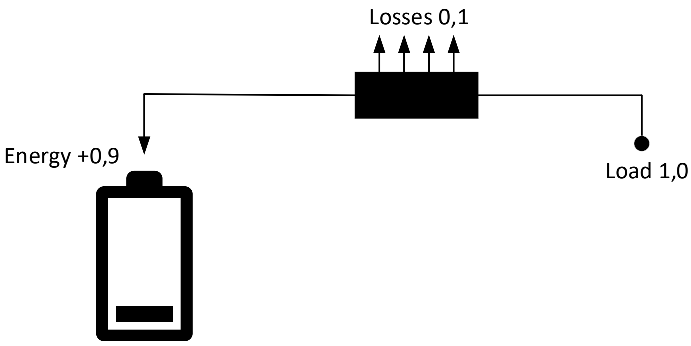


Figure 8: Illustration of the battery charging process

The energy consumed by the batteries (demand) is valued at market price, whereas energy supplied from the battery to the market is valued at zero cost (cost is already covered from the charging). The overall optimisation target is to operate batteries in a way that minimises total system costs, i.e. discharge at high electricity prices and charge at low electricity prices.

4.3.3 P2X

In the current PEMMDB version, P2X data only covers power-to-gas devices (electrolyzers). Electrolyzers are excluded from the adequacy simulation in the ERAA 2021 as they are assumed not to consume electricity in scarcity situations when prices are relatively high, thus having a negligible impact on adequacy indicators. At the same time, investigations are on-going as to how electrolyzers could be included in future ERAAs in a simplified manner.

4.4 Unit Commitment and Economic Dispatch

The UCED optimisation is a two-step approach with a system cost minimisation target, i.e. it strives to minimise the sum of electricity production costs under the constraint that electricity consumption must be fulfilled. In the first step, an annual optimisation for the target year is done to account for inter-temporal constraints that may span over the whole year (e.g. end-of-year reservoir targets and upper and lower weekly reservoir limits). This includes the hydro optimisation, as described in chapter 4.3.1. In this pre-optimisation, multiple hours are aggregated and optimised in blocks to deal with the large optimisation problem in a reasonable computation time. The optimised maintenance schedule for thermal units as seen in chapter 5.4.1 is anticipated and considered by the pre-optimisation.

The outcome of this first optimisation step consists of more granular daily target values for objects with annual constraints. In the case of hydro units, this results in daily reservoir targets that are set as soft boundaries to the total hydro energy available over the day for the subsequent more granular optimisation step.

The UCED optimisation is then performed in smaller time steps (e.g. one day) to determine which units are dispatched at each hour of the optimisation horizon (TY) as well as the respective dispatch level for each unit. For the optimisation, a given TY is divided into several UCED optimisation time steps/horizons. Each resulting UCED problem is optimised based on its profiles of available thermal NGC, RES available energy, grid NTCs and demand. Subsequently, each UCED problem is given the final system state of the preceding UCED problem (used as the initial dispatching state for the current UCED problem). Indeed, optimising a given UCED problem with a different initial dispatching state while keeping other parameters unchanged may yield different results. Similarly, dividing a TY into a different number of UCED problems may also yield different results. The whole UCED optimisation process is visualised in Figure 9.

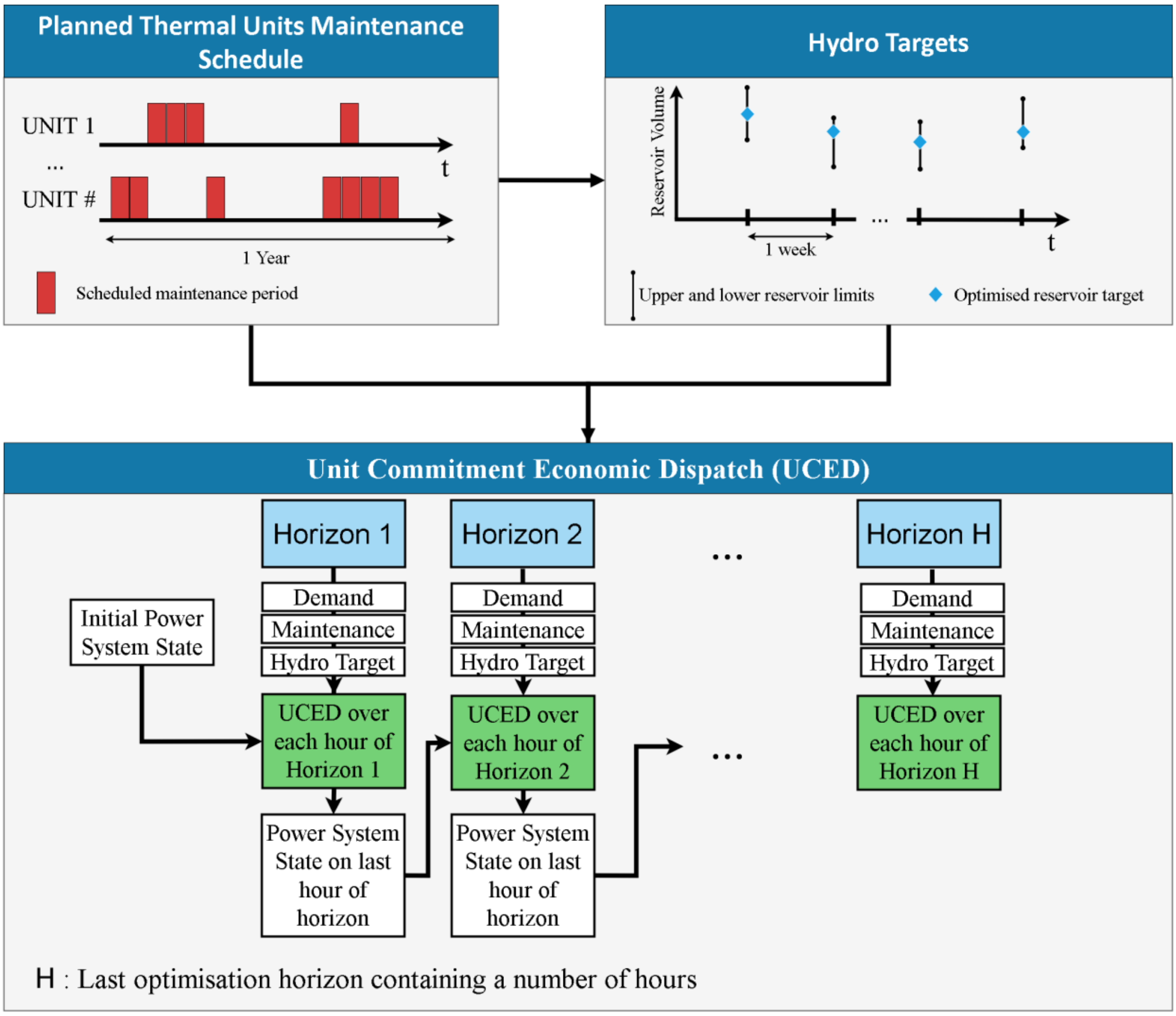


Figure 9: Illustration of the ERAA modelling process

The UCED optimisation problem solver employs flexible hydro storage resources such as reservoirs and PSPs to exploit marginal price gain opportunities from a total welfare perspective. The exogenously provided generation constraints and reservoir level trajectories are accounted by the solver. Water values or exogenous shadow prices for water are not explicitly accounted in the current hydropower modelling methodology. Final marginal prices are a direct result of the hourly optimisation of hydro storages and are set equal to the highest marginal cost (merit order) of the dispatched resources (e.g. RES, thermal, DSR, imports etc.) to cover the hourly domestic demand. As such, the residual load is matched with the least-cost available resource capacities and hydro resources and is sometimes referred to as ‘Hydro-Thermal’ optimisation. It follows intuitively that turbining occurs in times of high demand and/or low available generation (high marginal price), whereas pumping operations are allocated to hours of low demand and/or surplus of resources.

4.5 Detailed workflow

This chapter provides an overview of the ERAA adequacy assessment process. The process starts with the collection of a large amount of raw input data. Different tools then prepare these data to serve as input data for the MC simulation. In addition to the optimisation in the modelling tool as described in chapter 4.1 to 4.4, the preparation of input data for a number of target years and uncertain variables (e.g. climate years) is a major task for the ERAA.

Figure 10 and Figure 11 illustrate the current ERAA workflow to build and combine model inputs with the optimisation and convergence workflow.

Figure 10 illustrates the following elements:

- All required data are stored/generated in three databases/tools, namely the PEMMDB, PECD and TRAPUNTA. For more information, see Section 6.
- Some data are defined by TY, whereas some other data are defined by climate year *N* (climate years) or both by TY and climate year.
- A single modelling tool is used to optimise planned maintenance profiles for the thermal generation assets of each modelled market node (for unplanned maintenance, see Figure 11). Planned maintenance of grid assets is already included in the NTC availability by the TSOs.
- Thermal capacity can be dispatched at will, whereas wind and photovoltaic (PV) capacities depend on climate conditions during their operation. As such, the available wind and PV (power) generation can be injected at no cost (or curtailed following the optimisation model's decision).
- The datasets are fed into the market modelling tool.

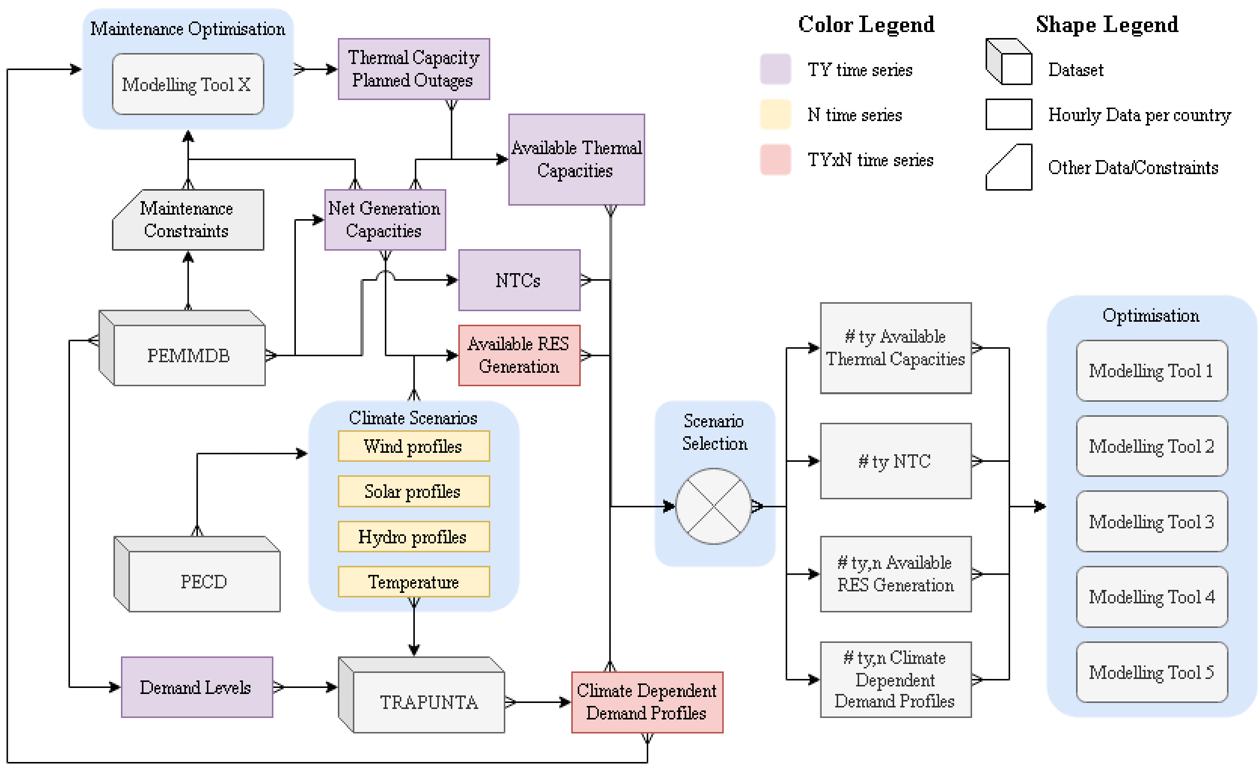


Figure 10: Model input building and combination.

Figure 11 below illustrates the following elements:

- The start of the simulations is carried out by feeding the five modelling tools with datasets for the first TY and climate year. Convergence is calculated ex-post for each tool separately, meaning that the calculation occurs after $N * M$ simulations for each TY, where M represents the number of random outage patterns.

- Reaching model convergence for a given TY is an iterative process. Initially, the modeller shall decide on a starting number of random outage patterns M to be generated by the modelling tool. The modelling tool generates its own distinctive patterns respecting a set of criteria and optimises the model for each pattern. If convergence is not reached, M is increased for the models that did not converge.

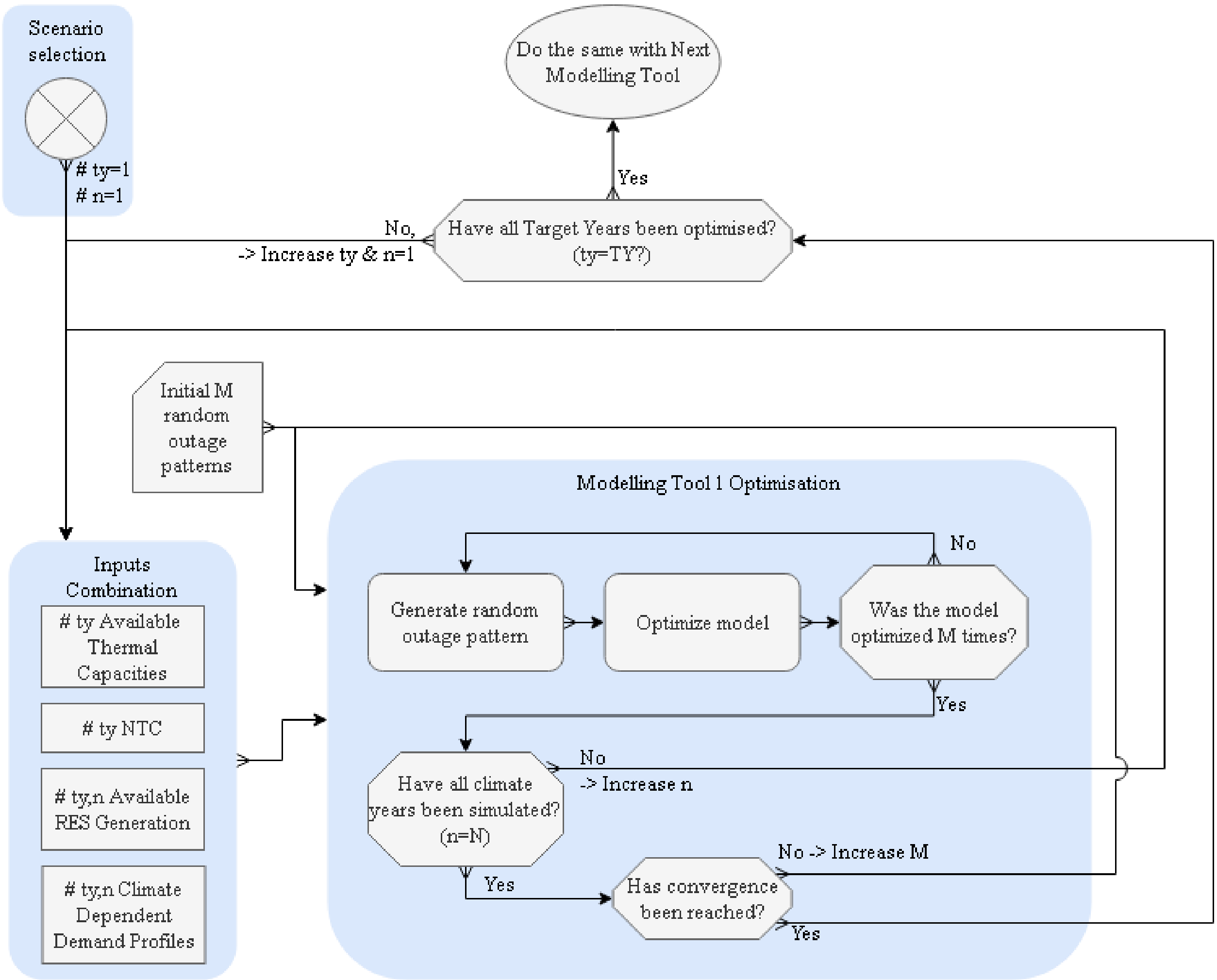


Figure 11: Model optimisation and convergence process.

Compared to previous MAF studies, an additional step has been implemented to comply with ERAA methodology requirements; namely, the selection of a single modelling tool whose results are taken as the reference ERAA results. One of the tools used in the aforementioned process was selected for the results included in the Executive Report and Annex 2, whereas the results of the rest of the tools are published in Annex 6, dedicated to giving more insights on the benchmarking process with multiple tools.

5 EVA Methodology

EVA is a step in the ERAA that assesses the viability of generation resources participating in an energy-only market (EOM). EVA is used to assess the adequacy in scenario with and without CMs. The EVA results in a valuation of generation resources to be retired or invested in per generation type and in each bidding zone. The current EVA is limited to a single year (2025[4]), while considering the full life span of the asset through annualised investment and operational costs. Extending the study horizon is foreseen in the target ERAA. Nevertheless, a qualitative economic viability assessment of generation technologies for the target year 2030 is provided.

5.1 Scenario with and without CMs

Throughout Europe, some Member States implement capacity mechanisms (CMs) in addition to the EOM to ensure viability of sufficient generation resources to reach the national reliability standard. To investigate the effect of CMs on adequacy, the EVA is first performed on a scenario without CMs to assess the economic viability of generation resources considering the EOM. Then, the scenario with CMs explores the effect of CMs on the viability of generation resources and on adequacy.

5.1.1 Scenario Without CM

In this scenario, the viability of generation resources participating in EOM are assessed. To do so, a long-term planning model is built that minimises the overall system cost[5]. The overall system cost equals the sum of investment costs of new generation resources, fixed and variable unit operations and maintenance (FOM) costs, and demand-side response activation costs, as well as the cost (welfare loss) of unserved energy. The key decision variables of the long-term model are (i) economic decommissioning of existing units and (ii) investment in new units[6]. Units with an awarded CM contract valid in 2025 are excluded from the EVA, this point is further clarified in Section 5.5.

5.1.2 Scenario With CM

The scenario with CM recalibrates the result of the scenario without CM by iteratively adding generation capacities in countries with CMs until their reliability standard is met (see Figure 12). The additional capacity is firstly acquired by removing capacity from the set of retired units in each bidding zone (BZ) in the scenario without CM, R_i, considering a priority for the units with lower FOM costs (if equal lower marginal cost). If the set of retired capacity is empty in the regarded BZ, additional capacity is acquired by adding to the list of units built, B_i, again considering it a priority for the units with lower FOM (if equal lower marginal cost). The amount of capacity removed from R_i or added to B_i in each iteration is proposed by the experts considering the ENS, LOLE and its difference from the reliability target in the related BZ[7].

[4] It is foreseen that a 10-year span will be assessed as from the ERAA 2024.
[5] Article 6.2 of the ERAA methodology acknowledges the use of overall system cost minimisation for the EVA, although as a simplification and assuming perfect competition
[6] Note that these variables are modelled linearly, and the long-term model is therefore kept as a linear programming model. This means the units can be partially decommissioned (invested). However, a 50% threshold is applied after EVA, i.e. if a unit is decommissioned (expanded) more than 50% it will be considered fully decommissioned (expanded) and if it is decommissioned (expanded) less than 50%, the unit is not decommissioned (expanded).
[7] To do this, a holistic view is taken by considering the regional effect of new capacity on the neighbours due to imports and exports.

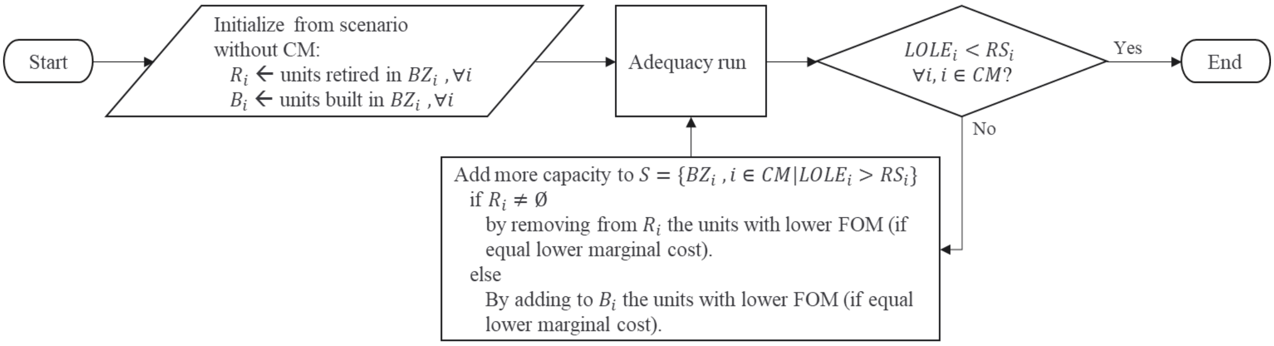


Figure 12: Process to find additional generation capacities in scenario with CM.

5.2 Risk

Following the ERAA methodology, the EVA aims to replicate as precisely as possible the actual decision-making process followed by investors and market players. According to one of the basic tenets of modern finance, investors generally show a certain level of risk aversion with respect to their decision process. This means investors typically demand a risk premium on investments, i.e. investments that increase the risk of their portfolio should also increase the expected return of the portfolio. Volatility and uncertainty with respect of the return on investment is a necessary condition of investment risk. ENTSO-E follows a recent academic study[8] of Professor K. Boudt (Boudt, 2021), which provides a theoretical and academic framework for investor behavior, considering the revenue distribution and downside risk stemming from the non-normality of the returns distribution as well as model and policy risk depending on technology and economic lifetime of the assets and within different scenarios. In Boudt (2021), hurdle premiums are set according to the deviation of actual returns from expected returns over a significant number of possible investment paths. These premiums are further calibrated considering the return impact of alternative scenarios considering standard CAPEX and FOM costs, but different levels of system adequacy, fuel prices, CO_2 prices, etc. Such calibration provides a robust yet pragmatic approach for the consideration of risk in adequacy simulations through the use of hurdle premiums. The hurdle rate equals the sum of the WACC[9] and the hurdle premium. The hurdle rate is then used to calculate the annuity of CAPEX, as follows:

$$Annuity_{CAPEX} = CAPEX \times \frac{Hurdle\ Rate}{1 - (\frac{1}{1 + Hurdle\ Rate})^{Lifetime}}$$

The hurdle rate also adjusts the FOM of existing units. As the FOM is a yearly cost, the annuity of FOM is calculated assuming a one-year lifetime.

$$Annuity_{FOM} = FOM \times \frac{Hurdle\ Rate}{1 - \left(\frac{1}{1 + Hurdle\ Rate}\right)^{1}} = FOM \times (1 + Hurdle\ Rate)$$

5.3 Reduction of Climatic Conditions

Expansion and decommissioning decision variables of the EVA model are long-term decision variables that take a single value for one year of the planning horizon. The long-term scope of these variables makes the EVA model a bulky model which requires a long running time and a significant amount of hardware resources to obtain a solution. Due to this fact and to limit the number of simulations, a direct approach is taken by

[8]https://www.elia.be/-/media/project/elia/elia-site/public-consultations/2020/20201030_200_report_professorboudt.pdf
[9] A reference industry-wide WACC of 5.53% is used in Boudt (2021).

solving the EVA model over a reduced number of CYs. A dedicated algorithm[10] is used to select representative CYs for the EVA model. This algorithm works as follows (selecting X number of CYs):

(i) Yearly hydro inflows are allocated on an hourly granularity and proportional to the net load (load minus solar and wind infeed).
(ii) An hourly residual load is computed considering solar/wind infeed, load and yearly hydro inflows.
(iii) The residual load for each macro region (Table 9), r, is derived.
(iv) For each combination, c, of X number of CYs, the difference in the mean, $\Delta^{\mu}_{c,r}$, and standard deviation, $\Delta^{\sigma}_{c,r}$, of residual load to the mean and standard deviation of the residual load of all CYs is calculated.
(v) A standardisation is applied to the $\Delta^{\mu}_{g,r}$ and $\Delta^{\sigma}_{g,r}$ values to have a mean of 0 and a standard deviation of 1; $\Delta^{\mu}_{c,r} \rightarrow I^{\mu}_{c,r}$, $\Delta^{\sigma}_{c,r} \rightarrow I^{\sigma}_{c,r}$.
(vi) A regional weighting factor, w_r, is applied for each macro region proportional to their load as compared to the European electrical load.
(vii) The euclidean distance of both indictors is calculated for each combination.

$$E_g = \sqrt{\sum_r w_r[(I^{\mu}_{c,r})^2 + (I^{\sigma}_{c,r})^2]}$$

(viii) The combinations with a Euclidean distance lower than 1 are selected.
(ix) K-Medoids score of each selected combination is computed assuming that the climatic years in each combination clusters all climatic years in X sets.
(x) The combination with the lowest K-Medoids score is selected.

Table 9: List of macro regions for selecting representative CYs

Macro Region	Bidding Zones									
Scandinavia	DKE1	DKKF	DKW1	FI00	NOM1	NON1	NOS0	SE01	SE02	SE03	SE04
Baltic countries	LV00	EE00	LT00								
Central west 1 FR–BE–NL	BE00	FR00	NL00								
Central west 2 DE–CH–AT–LU	DE00	DEKF	AT00	CH00	LUB1	LUF1	LUG1	LUV1			
South west	ES00	PT00									
Central east	CZ00	SK00	HU00	PL00	RO00						
GB–IE	UK00	IE00	UKNI								
South east	GR00	CY00	BG00	MK00	ME00	MT00	HR00	SI00	RS00	AL00	BA00
South central	ITCN	ITC1	ITN1	ITS1	ITSA	ITSI					

[10] Developed by ENTSO-E 'Bidding Zone Review' Task Force

5.4 Outages

5.4.1 Maintenance Profile – Planned Outage

The main goal of periodic maintenance is to ensure the availability of a power plant when electricity prices are expected to be high – typically during periods of higher load. Maintenance planning optimisation should ideally be integrated into the EVA model. However, this increases the number of decision variables of the EVA model and thus its complexity. To simplify this exercise, the maintenance modelling of existing units can be approximated, either by derating the available capacity of the units or by estimating maintenance windows. As stated in Section 4.1, an estimate of maintenance windows is available for existing units. For expansion candidates, a maintenance rate is applied as a derating factor of the generation capacity. The derating factor is inversely proportional to the load profile in a given region in order to make more generation capacity available during times of higher load and vice versa.

5.4.2 Forced Outage – Non-planned Outage

Forced outages were considered in the EVA model by simply derating NGCs and NTCs. This assumption is considered to avoid ramifying the EVA simulation over more MC years.

5.5 Expansion/Decommissioning Candidates

The supply sector makes up the units of different types, from thermal units to renewables, and extends to DSR and batteries. The economic viability of some units depends mainly on the EOM. Other units earn additional revenues by providing services to the system or are just protected by out-of-market measures/considerations. Moreover, some units depend on existing or planned CMs, and others serve as out-of-market reserves. Only units that mainly depend on the EOM serve as expansion/decommissioning candidates[11] for the EVA as explained further below; the others being excluded from the assessment.

- Thermal units (coal, lignite, oil and gas) will be the decommissioning candidates in the EVA. Nuclear units are excluded from the EVA because their future in the electricity system is largely determined by governments and policies rather than by pure market forces. Part of the thermal units already has an awarded CM or a policy contract in 2025 and are excluded from the EVA because their viability does not depend on the EOM anymore. Gas combined-cycle gas turbine (CCGT) and gas open-cycle gas turbine (OCGT) units (with 60% and 42% efficiencies, respectively) are considered as the expansion candidates among thermal units. CCGT and OCGT units are the most recent thermal technologies for load following and peak load electricity production, respectively. According to the EU Green Deal, new coal units, lignite units and oil units without carbon abatement technologies are unlikely to be built in the future as the investment risk would be substantial. Variants of these units with carbon capture systems are also examined as expansion candidates in the EVA. However, a simple comparison of total cost versus the operating hours in the year demonstrates that the variants with carbon capture systems cannot economically outperform the units without carbon capture systems considering higher CAPEX at the time of the study and the estimation of CO_2 price (40 €/ton) for the target year 2025.
- Government subsidies and European/national environmental goals currently play an important role in the expansion of renewable resources. Therefore, and because of the lack of location-specific

[11] There may be additional exogenous assumptions for why units cannot be retired such as locale considerations, national policies, support schemes and country specification. Therefore, any other unit labelled by TSOs as a 'policy unit' in the PEMMDB will not be a decommissioning candidate. Similarly, must-run units are not considered as decommissioning candidates.

CAPEX values, renewable units are not considered as expansion candidates. In other words, it is assumed that the expected renewable deployment trajectories collected from TSOs – based on national government policies – are the best estimate for the expansion of renewable resources.

- CHP units and batteries are not considered as decommissioning or commissioning candidates as only revenues from the energy market are investigated. Additional revenues received from flexibility services, heat supply or the steam and gas markets are not yet modelled in ERAA 2021. It solely relies on the data and the trajectories collected from TSOs.
- The EVA estimates the expansion of explicit DSR as the exploitable portion of technical explicit DSR potential. The technical explicit DSR potential by sector and for each region is first assessed by taking the historical yearly consumption of different sectors from Eurostat[12] and assuming equivalent annual full-load operating hours (e.g. 8760 h for all year long operation). The exploitable explicit DSR potential is a portion of this capacity as the whole industry cannot switch off for providing DSR service. ENTSO-E has consulted TSOs to propose meaningful DSR potentials for each bidding zone, starting with a proposed 35% exploitable ratio of the total DSR capacity per sector, for all industries except for construction. The activation price of DSR for the different sector is set as the value of lost adequacy derived from a study prepared by the CEPA for ACER[13]. The sectors are then clustered based on their activation prices to limit the number of bands used. The CAPEX and FOM are aggregated into a single annualised fixed cost by band. This fixed cost is derived from a French study published by the ADEME[14], where an annual remuneration for DSR is given by sector. Based on a mapping between the sectors defined in Eurostat and the ones defined in the study, fixed costs are defined for each band used in the EVA. The construction sector as well as the domestic sector are not considered in the potential calculation.

Table 10 summarises the expansion and decommissioning candidates among generation resources.

Table 10: Expansion and Decommissioning Candidates

Generation Type	Decommissioning Candidate	Expansion Candidate
Nuclear	FALSE	FALSE
Coal	TRUE	FALSE
Lignite	TRUE	FALSE
Gas	TRUE	TRUE
Oil	TRUE	FALSE
DSR	FALSE	TRUE
Renewables	FALSE	FALSE
CHP, Battery	FALSE	FALSE

[12] https://ec.europa.eu/eurostat/web/products-datasets/-/nrg_cb_e; Values from 2019 have been used.

[13] https://extranet.acer.europa.eu/en/Electricity/Infrastructure_and_network%20development/Infrastructure/Documents/CEPA%20study%20on%20the%20Value%20of%20Lost%20Load%20in%20the%20electricity%20supply.pdf

[14] https://librairie.ademe.fr/energies-renouvelables-reseaux-et-stockage/1772-effacement-de-consommation-electrique-en-france.html

6 Databases and Tools Used for the ERAA

The ERAA methodology uses data collected from TSOs or generated by internally developed tools, while also using assumptions collected by TSOs. The following sections describe the databases and tools used in the ERAA assessment. These databases are common with other ENTSO-E assessments such as TYNDP (Ten-Year-Network-Development-Plan), Seasonal Outlook, etc

6.1 Market modelling database (PEMMDB)

ENTSO-E uses a single source of supply-side and grid data across all its assessments (i.e. the PEMMDB containing data collected by TSOs on plant net generation capacities, interconnection capacities, generation planned outages, etc.). The database is aligned with national development plans and contains data about the power system according to the best knowledge of the TSOs at the time of data collection. The PEMMDB contains a highly granular unit-by-unit resolution of European power plants, their technical and economical parameters, their expected decommissioning dates and the forecasted development of RES capacities. Moreover, it provides an hourly time series of must-run obligations as well as the derating of thermal units. The data were collected for TYs 2025 to 2030 with a yearly resolution. For a better overview of the data collected under PEMMDB in the context of the ERAA 2021, please see the published 'data collection guidelines' at ENTSO-E website.

6.2 Demand Forecasting tool

Hourly demand profiles for most of the European countries are created centrally by ENTSO-E. ENTSO-E uses a temperature regression and load projection model that incorporates with uncertainty analysis under various climate conditions. The model comes in a software application developed by an external provider (TRAPUNTA). It is important to mention that some TSO members for the ERAA 2021 have provided their own hourly demand time-series directly to ENTSO-E, using their own demand forecasting tool, when this was required to achieve a sufficiently detailed and accurate representation of domestic demand.

TRAPUNTA allows electric load prediction to be easily performed, starting from data analysis of historical time series (electric load, temperature, climatic variables and other). Its overarching goal is to introduce an advanced forecasting tool which, eventually, will lead to a stronger harmonisation of forecasting activities and comparability of their outcomes provided by ENTSO-E members.

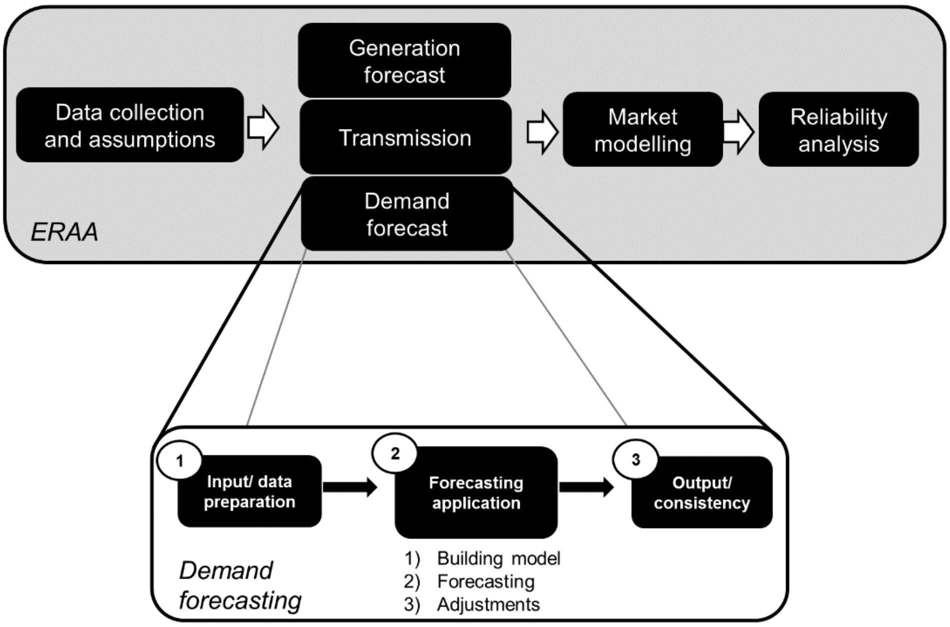


Figure 13: The embedding of demand forecasting in European resource adequacy assessment

Figure 13 shows the position of demand forecasting within the ERAA. As shown, it provides, together with generation capacity forecasts and transmission capacity information, fundamental input to market modelling. A more detailed description of input data, methodology and consistency checks are described in the relevant document published[15] alongside this report

6.3 Climate database (PECD)

6.3.1 Temperature detrending accounting for climate change

The ERAA makes use of climate variables for its simulations. Currently, only historical climate data are considered for ERAA simulations. These simulations extend to the next 10 years (currently up to 2030). Although climate data projections are in principle available, these are not presently used. An alternate, temporary solution is therefore required

The PECD used by ENTSO-E (currently v3.0) consists in a downscaling of the ERA-Interim climate reanalysis. Starting from the ERA-Interim geographical horizontal resolution of 75 km and temporal resolution of 6-hour, the climate variables are reproduced at 20 km and 1-hour resolutions, respectively. The database covers 1982–2016.

Using the climate data thus produced, the following energy variables are produced by different providers:

- Demand data;
- Wind and solar capacity factors;
- Hydropower data (RoR and water incomes to reservoirs, both expressed in terms of available energy).

The final goal is to update the PECD by the end of 2022, to provide a new dataset (PECD v4.0) suitable for long-term studies. This means PECD v4.0 should consider climate change and its effects on energy variables, and representative of the expected / foreseen climate up to 2050/2060. However, this work requires substantial changes to be implemented and on a relatively long timeframe.

[15] Link to the demand forecasting methodology:

6.3.1.1 Description of the context

The standard climatology reference period of a 30-year period is deemed as sufficient to represent the mean climate, but is not sufficiently long to sample extreme events. It is therefore critical for adequacy purposes to aim for sufficiently long periods, which shall include sufficient extreme events. In addition, updating the database to consider the latest available data is critical for demand modelling aspects. Therefore, a temporary solution (named PECD v3.1) was prepared for this ERAA 2021, whereas a longterm forward looking climate projection is foreseen from the ERAA 2023.

As a first step, the PECD temperature data were recently upgraded by *Météo-France* in late 2020 to use the latest reanalysis, called ERA5, and simultaneously extend the period to include up to 2019[16].

6.3.1.2 Temperature detrending as a temporary solution

The most applicable and promising solution to date with minimal impact on the current methodology and calculations was the computation of linear trends using the available data, which was prepared by Copernicus Climate Change Service (C3S) and applied to future years to extend the current period. To avoid mapping issues, a pragmatic approach was to target a specific year, namely 2025, meaning that each year in the current 1981–2019 dataset was adjusted to the year 2025. Consequently, years which are farther in the past will be subject to the largest trend adjustment compared to the more recent years.

Climate change causes trends in climate variables, both in the mean and in the variance. In the context of TSOs studies, both these trends are important. Thus, accounting for both trends, rather than just the trend of the mean, increases the confidence in the extrapolated signals. To analyse all months concurrently, the annual cycle is removed. In the present analysis, we adopt two different methodologies, one which involves considering all months together and another that considers months separately from each other.

Methodology 1 – All months together
To tackle the former methodology, namely when all months are considered simultaneously, in climate studies a common approach to calculating, and then removing, the annual cycle is to compute the average of individual monthly means, namely month by month. The annual cycle is then subtracted from the monthly average time series, thus obtaining monthly mean anomalies. The linear trend is then computed considering all months. The same approach is also applied to the standard deviation. The linear trend is then computed for all months together (taking their anomalies). Again, the same approach is taken for the mean values and the standard deviation.

Methodology 2 – Individual months
In methodology 2, months are considered separately from each other; there is no need to remove the annual cycle. The linear trend is computed for each month separately. Unlike in methodology 1, the different month-to-month linear trends might introduce jumps in the timeseries for adjoining months. To alleviate this issue, a smoothing is applied by generating an hourly timeseries from the (12) monthly linear trends (January to December) for each year.

6.3.1.3 Extrapolation of climate variables

Once the linear trend for the historical period is computed, the climate variables (just air temperature in this case) can be extended to the future period 2021–2030. Two extrapolation adjustment approaches are considered. The first uses only the (annual) mean linear trend (computed using monthly anomalies). The second is like the first but, in addition, the standard deviation is also adjusted, using the (annual) linear trend

[16] Despite the extended database available, the unavailability of hydro data restricted the use of climate years for the ERAA 2021 to years 1982–2016.

of the standard deviation. Consequently, four extrapolation estimates are computed for the year 2025 (two approaches for each of the two methodologies).

1. Methodology 1 – All months together – First approach – Extrapolation based on (annual) mean linear trend only, meaning: Adjust the (annual) mean by extrapolating a single (annual) linear trend based on monthly mean anomalies.
2. Methodology 1 – All months together – Second approach – Extrapolation based on (annual) mean and standard deviation linear trends, meaning: Adjust the (annual) mean and standard deviation by extrapolating a single (annual) linear trend based on monthly mean anomalies.
3. Methodology 2 – Individual months – First approach – Extrapolation based on monthly mean linear trend only, meaning: Adjust the (monthly) mean by extrapolating month-specific linear trends.
4. Methodology 2 – Individual months – Second approach – Extrapolation based on monthly mean and standard deviation linear trends, meaning: Adjust the (monthly) mean and standard deviation by extrapolating month-specific linear trends.

6.3.1.4 Results

Both Probability Density Functions (PDFs) and Cumulative Distribution Functions (CDFs) have been plotted for all cities and population weighted zones to check the results of the extrapolations are well behaved. Details can be downloaded on ENTSO-E ERAA 2021 webpage, input data. As an example, the PDFs and CDFs for the same Belgian zone (BE00) are plotted in Figure 14. Overall, approach four was still considered the most viable option.

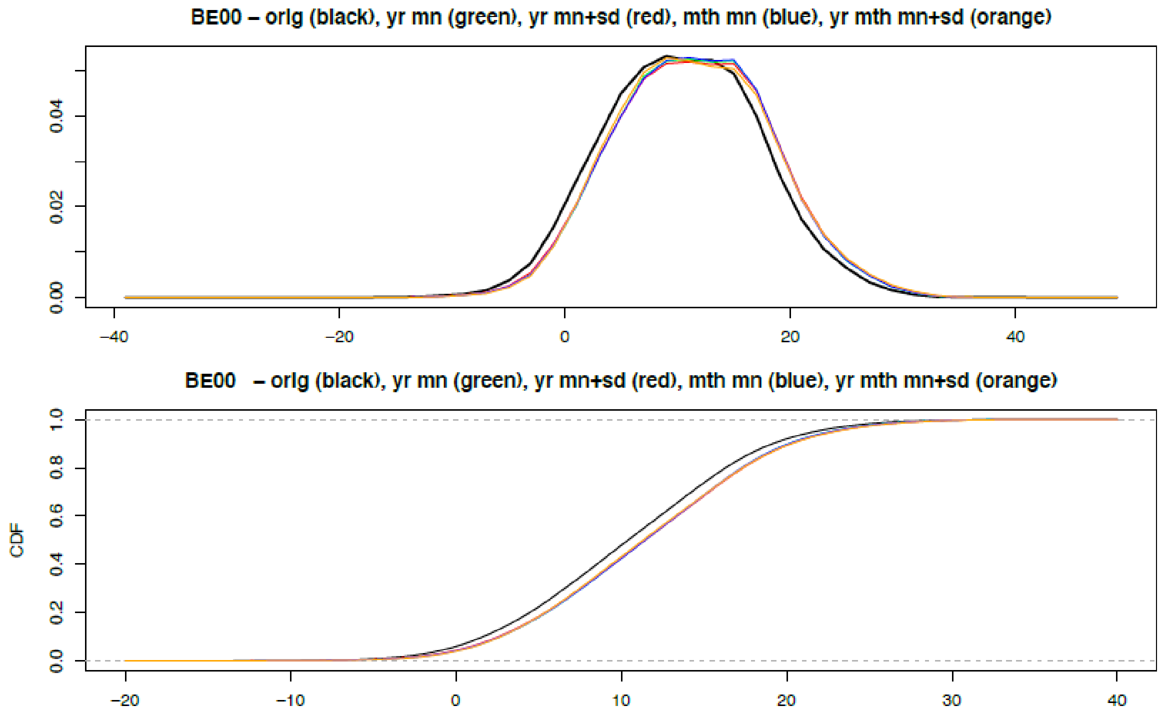


Figure 14: PDFs (top) and CDFs (bottom) for air temperature for a population weighted zone, in Belgium as an example, and reference year 2025 for the four extrapolation approaches: (1) mean yearly trend (green), (2) mean and standard deviation yearly trends (red), (3) mean monthly trend (blue), (4) mean and standard deviation monthly trends (orange). The baseline historical data (1981–2019) is shown in black.

6.3.2 Wind and Solar

The following paragraphs describe the PECD modelling update carried out in 2021. Both the meteorological data and the methods for transforming the meteorological variables to power generation are updated compared to previous PECD versions. The modelling is carried out using the Correlations in Renewable Energy Sources (CorRES) tool at DTU Wind Energy. The updates impact all the variable renewable energy generation time series: onshore and offshore wind, and solar photovoltaic (PV) and concentrated solar power (CSP).

All runs have the same geographical scope, with a split to onshore and offshore regions. All runs are with hourly resolution, covering years 1982–2019; except for the validation run, which covers 2015–2018.

6.3.2.1 Wind

European wind power plant (WPP) installations given per plant are used (thewindpower.net); these installations include installed capacity, hub height, number of turbines and turbine model. We also use a turbine power curve database (thewindpower.net). A generic wake loss model developed at DTU Wind Energy is used when the layouts of the plants are not known. This model is a deep neural network (machine learning [ML]) regression trained on the wake losses of 1000 wind power plants with different layouts, number of turbines and installed capacities. The ML wake model predicts the wake losses as a function of wind speed as a time series for each plant in the modelled onshore wind fleets.

Detailed wake modelling for future installations and offshore wind installations is performed by optimising a wind plant layout to maximise the turbine spacing within a specified plant area. The detailed wake modelling then predicts the wake losses as a function of wind speed and wind direction.

Onshore wind runs
The different onshore wind run setups are shown in the table below. The Validation run is used when comparing to measured data (where WPP fleet changes in time). All other runs are simulated with a fixed fleet, modelling either the existing or new installations, and multiple WPP technologies are considered for the future runs. Validation is focused on onshore wind, as a) measured data are available for multiple countries for multiple years; and b) Information about the existing WPP installations is quite extensive.

Table 11: Onshore wind run setups

Run type	Simulated meteorological years	WPP locations	WPP technology	Losses
Validation	2015-2018	Changed every year to match changing WPP installations	Known turbine types & hub heights (changed every year)	Wakes using ML. And 5 % for other losses & unavailability; these are further adjusted based on measured generation data.
Existing	1982-2019	All years with 2018 WPP locations	Known turbine types & hub heights (always 2018 fleet).	Wakes using ML. And 5 % for other losses & unavailability; these are further adjusted based on the Validation run.
Future: Repowering	1982-2019	All years with 2018 WPP locations	Hub heights remain the same as in Existing, but turbines are changed (3 types are simulated).	Wakes using ML. And 5 % for other losses & unavailability.
Future: New installations	1982-2019	Different locations for the different RGs (three RGs modelled).	3 hub heights & 3 turbine types -> 9 wind technologies. The layout of a plant of 50.4 MW with 14 turbines 3.6MW is optimized per technology.	Wakes using PyWake. And 5 % for other losses & unavailability.

Regarding PECD onshore wind CFs of the existing installations, it is notable some regions which do not have very high wind speeds show high CFs. This is because, in addition to wind speeds, the wind technology of the fleet impacts the CFs; e.g., in Finland, very high hub heights and modern low specific power turbines are utilised.

In the future technology runs, the CFs follow mean wind speeds in the regions more directly as a uniform wind technology is modelled in all regions per run. However, within each region, there is a significant difference between the different RGs. Note that whereas the lower specific power turbine at 150m hub height shows high CFs, the low specific power and high hub height also indicate a high CAPEX.

Offshore wind runs
The different run setups for offshore wind are shown in Table 12. All runs are simulated with a fixed fleet, modelling either the existing or new installations. Multiple offshore WPP (OWPP) technologies are considered for the future runs. Specific validation runs have not been carried out for offshore wind.

Table 13: Offshore wind run setups

Run type	Simulated meteorological years	OWPP locations	WPP technology	Losses
Existing	1982-2019	Existing & in-construction OWPPs (dataset from 2019)	OWPP with 210 MW consisting of 70 turbines of 3MW with specific power of 388 MW/m2.	Wakes using PyWake. And 5 % for other losses & unavailability.
Future	1982-2019	The best 10 % of all potential locations*	2 offshore wind turbine types, with generic 504 MW OWPP consisting of 28 turbines of 18 MW capacity in optimized layout.	Wakes using PyWake. And 5 % for other losses & unavailability.

*) For the North Sea, where offshore energy hubs are considered possible for the entire region, all locations are considered potential. For other Sea areas, max 100 km from shore are considered as potential locations.

6.3.2.2 Solar PV

The transformation to solar PV power generation uses PVLib library, with a specified generic PV module (Canadian Solar) and inverter (ABB). Generic models are used because we do not have a pan-European database of solar PV installations available.

The power generation model requires the time series of DNI and DHI, but also the wind speed and temperature to estimate the performance efficiency (or temperature driven losses). Furthermore, a given PV plant is localised in terms of longitude, latitude, altitude (for pressure estimation) and panel orientation (azimuth and tilt angles).

Solar PV runs
For solar PV, only one run is simulated to model both existing and future installations, i.e. no technology development is considered. Information about existing solar PV installations was not available; thus, a representative generic simulation setup is used. The best 50% of locations (in terms of mean irradiance) within a region are considered to represent solar PV installations in that region. For these locations, multiple tilt angles and orientations were tested. South-facing installations 15 degrees below the optimal tilt angle were found to give the highest correlation compared to measured data (FR, ES, DK and AT were tested). This was considered reasonable as large installations can be at the optimal tilt angle, but rooftop installations can often be placed at sub-optimal angles (generally lower angles than the optimal).

An additional solar PV run was carried out for Germany, using measured data provided by the German TSOs for model calibration. Based on this, an even lower tilt angle was used for Germany for these runs, suggesting an even larger share of rooftop installations than in the generic run described above. Specific validation runs have not been carried out for solar PV.

6.3.2.3 CSP

As in the previous PECD version, the CSP model consists of 3 parts: a solar field, a power block and a thermal energy storage. The main parameters required to model the performance are: (a) solar multiple, which is the ratio between the solar field capacity over the turbine capacity, (b) plant installed capacity; (c) turbine, storage charging/discharging efficiencies; and (d) energy storage capacity. The storage capacity is usually given in hours of rated capacity operation. The heat transfer fluid is modelled as a first order dynamical system characterised by a time constant responsible for a delay in the response between a change in DNI and power produced in a CSP plant.

CSP runs
The best 50% of locations (in terms of mean irradiance) are selected for possible installation locations. Two runs are performed in the CSP analysis, (1) CSP plants are simulated without energy storage, and (2) CSP plants with 7h of thermal energy storage. For case (2), the results are given in two time series, one representing the automatic energy dispatchment to use the energy storage as soon as possible after noon every day, or as a time series that includes the excess in power; these time series can be used based on ENTSO-E system-level modelling needs.

6.3.3 Hydro data

Available hydropower generation is an important factor in adequacy assessments as it can have a significant impact on results. Therefore, choosing the appropriate level of detail, evaluating distinct hydrological conditions, and better reflecting the interdependence of hydro generation and climatic conditions, including with other RES, is of great importance.

Since 2019, the PECD has been extended to include hydro generation data using a single source of coherent climatic data. Based on re-analysed data concerning hydro inflows, a standardised central methodology has been designed to map historical inflows of generation data and build a model to project hydro generation, including hydro RoR, hydro reservoirs and pump storage. In 2020, a further improvement was achieved by introducing a higher granularity of north-sea offshore zones and updating the zone configuration in Belgium. More information regarding the methodology and relevant assumptions are included in the document 'Hydro modelling description' which accompanies the MAF 2020[17].

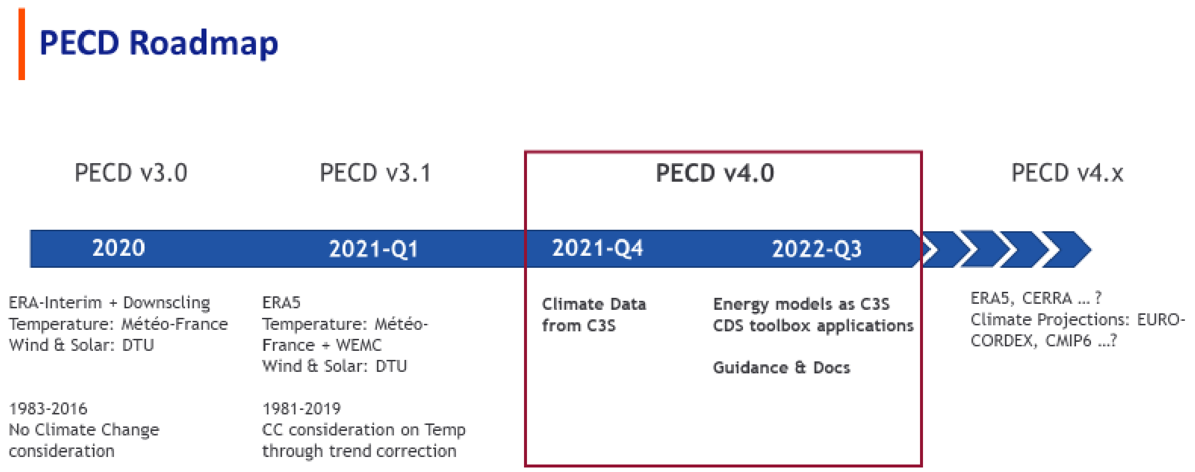
6.3.4 Future forward looking climate projection

As stated above, the PECD dataset will be updated by the end of 2022 to consider climate change and its effects on energy variables and be representative of the expected / foreseen climate up to 2050/2060. Consequently, the PECD v4.0 will become a large ensemble of public, updated and state of the art dataset, based on C3S:

- Climate information on the past and the future;
- Corresponding energy data (wind & solar) at different geographical resolutions, from flexible models;
- Guidance and methodology to select the right ensemble of data for a given application.

[17] https://www.entsoe.eu/outlooks/midterm/

The dataset will no longer be based solely on historical data but will include climate projections, several climate models and several greenhouse gas emissions scenarios. The implementation is delegated to C3S within their work programme, and ENTSO-E is acting as the main stakeholder / super-user.



7 Methodological limitations of the ERAA 2021

The current ERAA methodology relies on an advanced probabilistic market modelling approach. However, like every modelling approach, it has its inherent limitations. The goal is to remedy these limitations wherever possible for the next ERAA editions as part of the implementation roadmap (see Executive Report, chapter 5.2). These limitations are presented as follows:

- **Thermal asset planned maintenance optimisation:** Maintenance optimisation of thermal generation assets is performed independently for isolated market nodes (i.e. it does not yet include the grid infrastructure). It is also optimised based on a single reference climate year only, without considering the feed-in from wind and photovoltaic. Improvements are currently under investigation for future ERAA.
- **DSR limitations:** DSR is only modelled as demand reduction potential in the case of high prices, whereas shiftable load is not yet considered in the simulations. Shiftable load enables the re-scheduling of demand from a period with high prices to a period with lower prices (i.e. from a period with higher adequacy concerns to a period with lower adequacy concerns). For the moment, shiftable load, e.g. EV demand, is considered within the demand forecasting methodology (from periods with peak demand to periods with lower demand). Moreover, the current methodology considers that part of the demand is elastic to price but no other criteria (e.g. the generation mix of a given moment).
- **Static market price cap:** The market price cap is not dynamically modelled and is assumed to be the same for all regions and scenarios, equal to a proxy of the VoLL.
- **Thermal and grid assets are not affected by climate conditions:** In reality, thermal and grid assets capacities may vary with air temperature and humidity, for example.
- **Internal grid limitations within a bidding zone are not considered:** However, they have been further investigated in an FB study conducted as a sensitivity analysis (explained further in Annex 4). This topic requires further development and also needs to consider possible evolutions of the European market.

- **No FO sampling is done for RES[18] assets:** Contrary to thermal units, no random outage draws are considered for RES.
- **FOs are assumed to not affect planned outages:** Generation units' planned outages are usually scheduled months or years in advance. However, they may still change depending on the operational/contractual constraints of each plant owner/operator. In reality, if an FO occurs very close to a planned outage, the latter may be moved at a different moment or even merged with the FO.
- **Procurement of ancillary services:** As a simplified assumption, only balancing services as part of ancillary services are modelled by adding a fixed demand. This has an impact on the simulated market prices. It is planned to model ancillary service requirements more adequately in future ERAA editions.
- **Sectoral integration:** Sectoral integration technologies, such as technologies for power-to-gas and power-to-hydrogen conversions or power conversions to other mediums, are not accounted for.
- **Network:** The ERAA 2021, including the EVA, is built on the NTC approach for the representation of grid elements. A proof-of-concept study on FB implementation is published alongside this report in Annex 4.
- **Limited time scope consideration in the EVA:** The EVA is performed based on the profitability of a single target year (annuity). A consistent viability assessment should consider the whole lifecycle of a unit. Consideration of multiple target years in the EVA is planned for future editions of the ERAA.
- **Limited consideration of units in the EVA**: Only units that depend mainly on the EOM are considered as expansion / decommissioning candidates for the EVA. As more generation resources become candidates in future ERAAs, additional revenue streams will also be considered.
- **EVA and must-run units:** Must-run plants are typically CHP plants or plants linked to an industrial consumer. As the EVA cannot model these in the ERAA 2021, we assume that these units cannot be mothballed or retired. Explicit modelling of such units will be implemented in future editions of the ERAA.
- Due to a lack of data, **no refurbishment[19] and retrofitting of generation resources[20]** are considered in the EVA. Mothballing is also not considered as the EVA is only performed for a single TY (i.e. 2025).
- **No curtailment sharing in the NTC model:** Curtailments are modelled for each bidding zone individually. Notably, bidding zones neighbouring other bidding zones with LOLE might therefore not be correctly presented. Curtailment sharing according to the EUPHEMIA principles[21] shall be incorporated in future ERAA editions both for the FB and the NTC simulations.

[18] This includes hydro generation units.

[19] Countries currently do not report potential for life-extensions in a consistent way in the PEMMDB, which prevents a common and transparent approach to modelling overhauls endogenously in the EVA. Thus, for 2021 overhauls will not be modelled endogenously. Instead, the plan is to revise the PEMMDB template and data collection on this topic so that next year, a consistent approach can be applied in EVA 2022.

[20] No consistent approach is applied in the PEMMDB for e.g., coal plants which could be retrofit for biomass. Some countries (e.g. NL) assume certain coal plants are run with 100% biomass after a certain year. To model biomass retrofits endogenously, a consistent approach should be taken in the PEMMDB and the modelling. This is to be developed in future EVA study.

[21] Euphemia Public Description: https://www.nordpoolgroup.com/4adb91/globalassets/download-center/single-day-ahead-coupling/euphemia-public-description.pdf