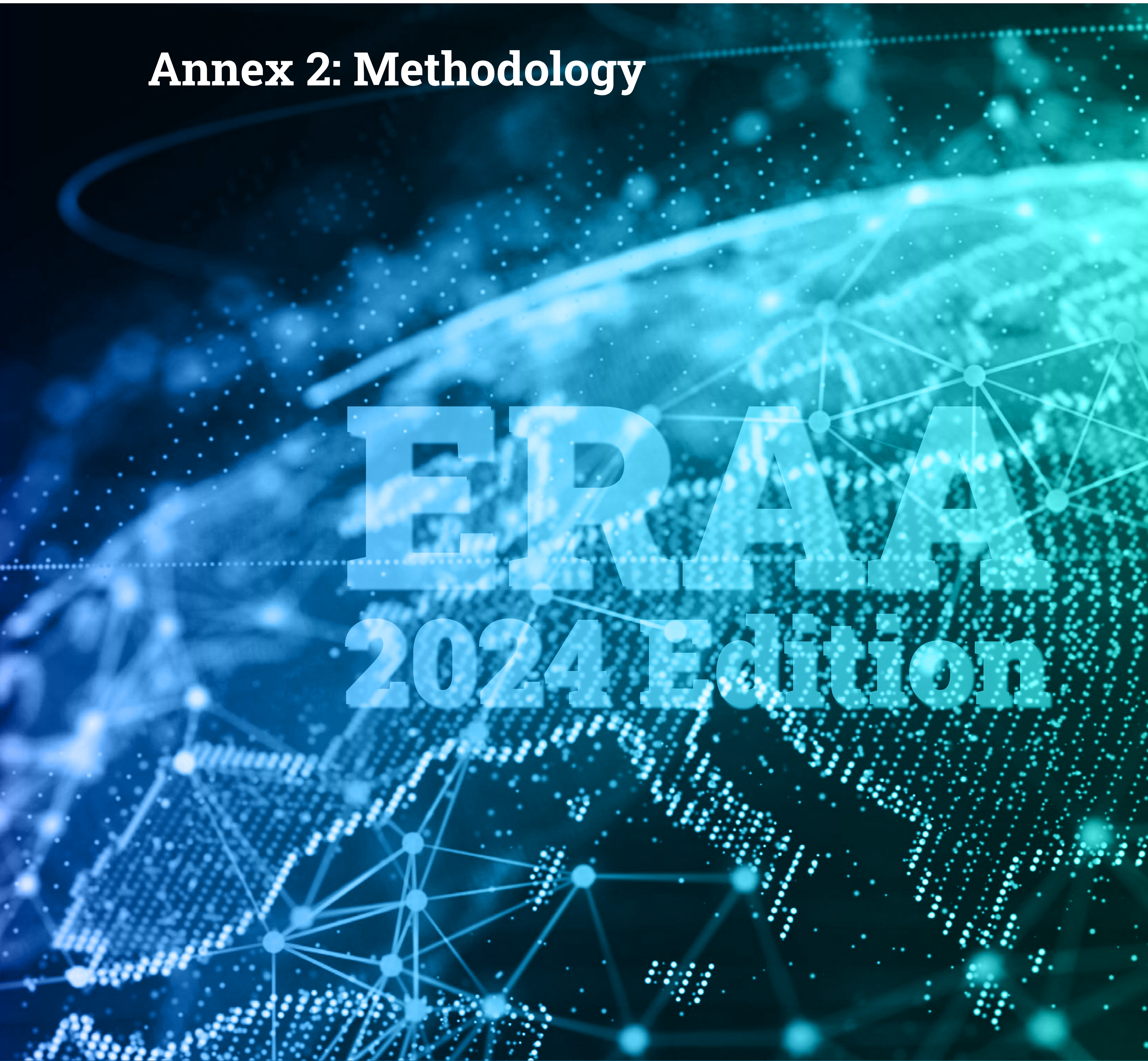
European Resource Adequacy Assessment

2024 Edition

Annex 2: 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 various 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 European Network of Transmission System Operators for Electricity (ENTSO-E) report – is to assess the adequacy of supply to meet demand in the medium term time horizon while considering interconnections between different power systems across the European perimeter, as illustrated in Figure 1.

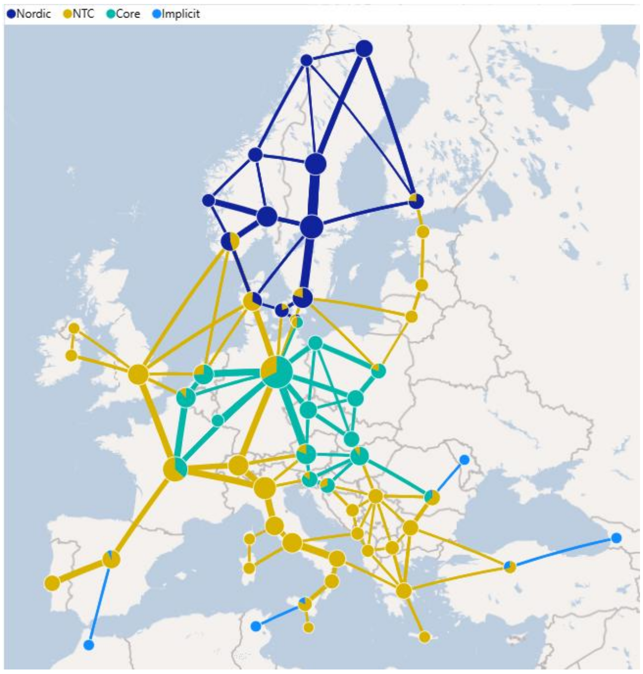

Figure 1: The interconnected European power system modelled in the ERAA 2024

The present European Resource Adequacy Assessment (ERAA) probabilistic methodology is considered a reference within Europe.

A large amount of detailed information is required to optimise and forecast a power system's operation. 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 2024 methodology and their impact on adequacy. The adequacy assessment considers – among others – generation, demand, demand-side response (DSR), storage, and network infrastructure.

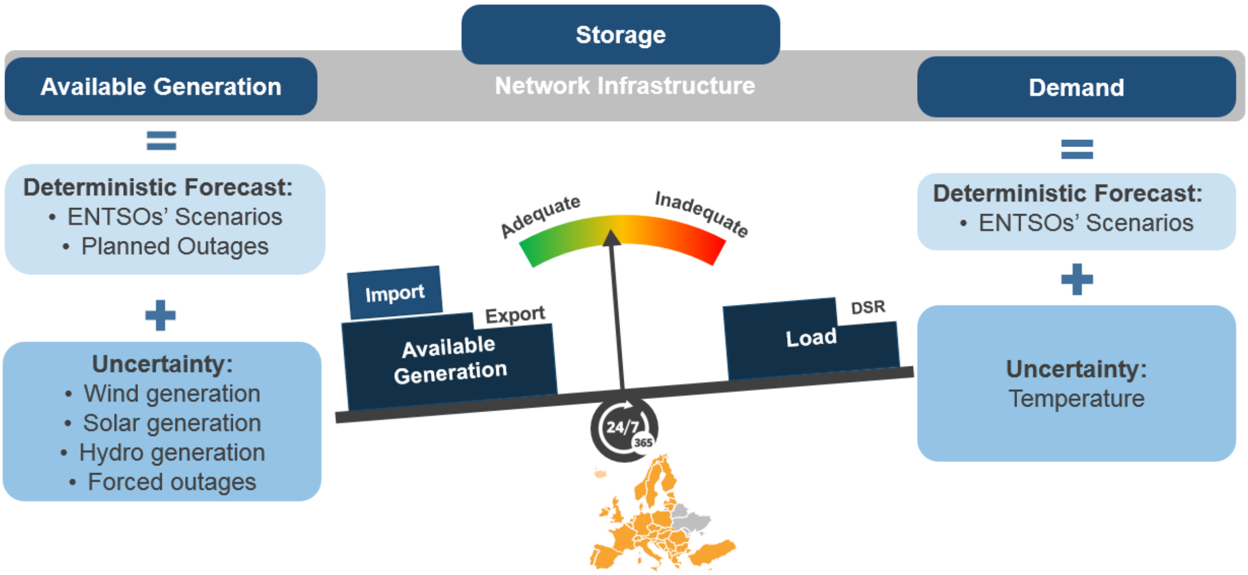

Figure 2: Overview of the ERAA 2024 methodological approach

1.1 Geographical scope and granularity

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) and for which the unit commitment and economic dispatch (UCED) problem is solved (more details can be found in Section Unit commitment and economic dispatch11.5). Non-explicitly modelled zones are market nodes for which detailed power system information is not available to ENTSO-E. For these zones, exogenous fixed energy exchanges with explicitly modelled zones are applied.

Overall, study zones in 35 countries are explicitly modelled in ERAA 2024. The ERAA accounts for interconnections between study zones and intrazonal grid topologies. Some countries are divided into multiple study zones according to the market setting in those countries (e.g. Greece, Denmark and Italy). Table 1 to Table 3 provide a list of explicitly modelled, non-explicitly modelled and non-modelled zones. Energy Island study zones are included.

Table 1: Explicitly modelled countries / study zones

Explicitly modelled member countries/regions and study zones			
Albania (AL00)	Finland (FI00)	Luxembourg (LUG1, LUB1, LUV1, LUF1)	Serbia (RS00)
Austria (AT00)	France (FR00)	Republic of North Macedonia (MK00)	Slovakia (SK00)
Belgium (BE00, BEOF)	Germany (DE00, DEKF)	Malta (MT00)	Slovenia (SI00)
Bosnia and Herzegovina (BA00)	Greece (GR00, GR03)	Montenegro (ME00)	Spain (ES00)
Bulgaria (BG00)	Hungary (HU00)	Netherlands (NL00, NLLL, NL60)	Sweden (SE01, SE02, SE03, SE04)
Croatia (HR00)	Ireland (IE00)	Norway (NON1, NOM1, NOS1, NOS2, NOS3)	Switzerland (CH00)
Czech Republic (CZ00)	Italy (ITN1, ITCN, ITCS, ITS1, ITCA, ITSA, ITSI)	Poland (PL00)	United Kingdom (UK00, UKNI)
Denmark (DKW1, DKE1, DKKF, DKNS, DKBH)	Latvia (LV00)	Portugal (PT00)	Türkiye (TR00)
Estonia (EE00)	Lithuania (LT00)	Romania (RO00)	

Legend: *Onshore study zones* *Offshore study zones*
Core FB Region *Nordic Region* *Other regions*

Table 2: Non-modelled countries/study zones

Non-modelled member countries/study zones	
Iceland (IS00)	Ukraine (UA00)

Table 3: Non-explicitly modelled countries/study zones

Non-explicitly modelled neighbouring countries/regions	
Morocco (MA00) – connected to ES00	Tunisia (TN00) – connected to ITSI
Moldova (MD00) – connected to RO00	Georgia (GE00) – connected to TR00
	Cyprus[1] (CY00)

1.2 Time horizon and resolution

The ERAA target methodology aims to identify adequacy risks up to ten year ahead and thus assists stakeholders in making well-informed investment decisions. ERAA 2024 considers the same number of target years (TYs) compared to ERAA 2023, i.e. four TYs (2026, 2028, 2030 and 2035). The choice of these four TYs is motivated by techno-economic trends and policy decisions relevant for the TYs assessed (e.g. the phase-out of certain generation technologies). Important trends relate to the phase-out of conventional generation technologies, the increase penetration of renewable energy sources and flexible assets (batteries, DSR, power to heat, etc.) and the increased electrification of demand.

An hourly simulation resolution – also referred to as an hourly market time unit (MTU) – has been adopted for all TYs and scenarios for the assessment. More information on the time resolution of each step can be found in Sections 10.5 and 11.1. Consequently, all input time series data for the

[1] Cyprus appealed for exclusion from ERAA 2024 according to Article 64 of Regulation (EU) 2019/943

UCED model are expressed in hourly intervals, e.g. renewable energy source [RES] generation, demand profiles and net transfer capacities [NTCs].. 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, which – like any model – is based on a set of assumptions. A non-exhaustive list of the main assumptions is provided below:

1) **Cost-driven dispatch decision:** The modelling tool dispatches available resources for specified time horizons by minimising the overall system costs.
2) **Perfect foresight**: Available RES energy, available thermal capacities (accounting for planned maintenance and forced outages (Fos)), DSR capacities, grid capacities (accounting for FOs), and demand are assumed to be known in advance with perfect accuracy, with no deviations between forecast and realisation. This also implies a perfect allocation of storage capacities (e.g. hydro storages) within the year.
3) **Demand is aggregated by study zone:** Individual end users or end user groups are not modelled.
4) **Demand elasticity regarding climate and price:** Demand levels are partly correlated with the weather. For example, temperature variations affect demand levels due to adaptations in the use of electrical heating/cooling devices. Part of the demand is modelled as explicit or implicit DSR, in which load can be reduced or shifted if energy prices are high (for more details, see Section 2.3.2). The remaining portion of energy demand is regarded as inelastic to price and will thus hold regardless of the energy price.
5) **Focus on energy markets only:** Only resources available to the market are accounted for in ERAA 2024. 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 during 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) **Non-market resources:** Non-market resources are considered a separate post-processing step of market simulations (e.g. strategic reserves).
7) **FOs only affect thermal generation and grid assets:** Power plants and grid assets are subject to FOs, which implies that their net generating capacity (NGC) is not continuously guaranteed.
8) **Planned maintenance of thermal units is optimised:** Planned maintenance of thermal units is scheduled in the least critical periods of the planning horizon, assuming perfect foresight of the demand and intermittent renewable infeed (i.e. periods with likely supply surplus rather than supply deficit). The maintenance optimisation methodology further aims to reflect the impact of different climate conditions.

9) **Some technical parameters of thermal generators are modelled in a simplified manner:** Technical parameters considered as having a low impact on adequacy are modelled in a simplified manner or are neglected (e.g. minimum uptime/downtime). Details on this are provided in Section 2.1.
10) **Flow-based (FB) modelling for the Core and Nordic areas:** In the adequacy model, grid limitations within the Core area (AT, BE, HR, CZ, FR, DE, HU, LU, NL, PL, RO, SK and SI) and Nordic area (DK, FI, NO, SE) are modelled using the FB approach, which mimics multilateral import/export restrictions. The remaining part of Europe is modelled via bilateral NTC exchange limitations.
11) **'Copper plate model':** The ERAA matches supply and demand – in addition to exchanges between study zones – without considering grid constraints within study zones.

2 Model components & granularity

The following chapter provides an overview of the different elements that are part of the power system model in ERAA 2024, their granularity and their characteristics.

2.1 Generation/resource side

Table 4 presents the categorisation and spatial granularity of the resource technologies considered.

Table 4: Classification of Resource units

Category	Technology	Aggregation
RES	Wind	Aggregated in Pan-European Climate Database (PECD) zones; onshore and offshore wind capacities are collected and modelled separately
	Solar	Aggregated in PECD zones; solar photovoltaic (PV), rooftop solar PV, concentrated solar (thermal) with storage and concentrated solar (thermal) without storage are collected and modelled separately
	Other RES	Aggregated in PECD zones
	Hydro without reservoir: RoR and pondage	Aggregated in market nodes
	Hydro with reservoir: Reservoir, open-loop pump storage plants (PSP), closed-loop PSP	Aggregated in market nodes
Non-RES	Coal	Unit-by-unit
	Gas	Unit-by-unit
	Lignite	Unit-by-unit
	Oil	Unit-by-unit
	Nuclear	Unit-by-unit
	Other non-RES	Aggregated in technology bands
Storage	Batteries	Aggregated in market nodes
DSR	DSR	Aggregated according to price/duration
Hydrogen	Fuel cells	Aggregated in technology bands
	Hydrogen-fired turbines	Unit-by-unit

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 PECD. Section 12 provides more information about the PEMMDB and PECD.

Additional standard parameters are also collected by ENTSO-E, known as the Common Data (e.g. FO rates per technology).

2.1.1 RES

As for wind, solar and other RES technologies, the total capacity installed at the 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 12.3.1). Planned and forced outages for RES technologies are already included in the hourly time series and therefore are not explicitly modelled.

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

The characteristics of Hydro technologies – namely run-of-river (RoR), Pondage, Hydro with traditional reservoir, Open-Loop PSP and Closed-Loop PSP – are described in separate Sections 2.1.4 and 6.1.

2.1.2 Non-RES

The models only account for units available in the market. Thermal units are dispatched according to their marginal production costs and other plant parameters, including associated costs for CO_2 emissions. No CO_2 emissions are considered for biofuel units. In addition, start-up costs are considered when reporting and assessing costs associated with each unit, although they are not included in the optimisation when determining the optimal dispatch, as this would require introducing binary variables in the mathematical formulation of the optimisation problem, thus increasing its complexity. Table 5 describes the consideration of unit-specific technical parameters as modelled, non-modelled, or simplified modelling as applied in ERAA 2024. Technical parameters assumed to have a significant impact on resource adequacy are explicitly or simplified modelled due to computational complexity. Parameters that are less relevant or have no impact on resource adequacy are neglected in the simulation.

Table 5: Summary of various parameters in the models

Parameter	Description	Accounted in EVA and/or adequacy step
Heat rate [GJ/MWh]	Amount of energy used by a power plant to generate one MWh of electricity	Modelled in both steps
FO rate	Likelihood of an unplanned outage	Modelled in both steps
Must-run [MW]	Hourly constraint for a single or group of units to produce at least a certain amount of MW.	Modelled in both steps
Min stable level [MW]	Minimal operation level of a unit	Not modelled
Derating [MW]	Hourly constraint for single or group of units to reduce the capacity offered to the market	Modelled in both steps
CHP revenue profiles [€/MWh_el/h]	Hourly profile by which the variable operations and maintenance (VOM) costs of the CHP unit are reduced	Modelled in both steps
Start-up time [h]	Time interval required to start a unit from 0 to a minimum stable level	Not modelled

Start-up cost [€]	Cost of starting a generating unit	Not explicitly modelled in optimisation, added in post-processing
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
Minimum up/down time [h]	Minimum time interval that a unit should be in / out of operation, frequently related to economic reasons	Not modelled

The impact of ramp rates and minimum 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 costs. Similarly, start-up times do not have a significant impact on adequacy results during normal operation due to the perfect foresight assumption. However, right after a forced outage of a unit and a subsequent scarcity, the availability of this unit may be further constrained by the start-up time even under assumptions of a perfect foresight. Nevertheless, as start-up time represents only a small fraction of the mean time to repair, its impact remains limited.

In addition to unit-by-unit thermal generators, the technology other non-RES technology 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 weather scenarios (WSs) and as such will be attached to the different PECD WSs 1-36. Available capacity profiles enable reducing computational difficulty by simplifying unit dispatch for smaller plants, while still considering reduced power output from planned maintenance or FOs.

Other non-RES usually aggregate small combined heat and power (CHP) units, waste incineration plants, non-dispatchable thermal generation, and any other plants that cannot be provided in a unit-by-unit resolution.

2.1.3 Batteries

Battery storages are increasingly adopted to introduce flexibility into the grid. This flexibility can either participate in the market (e.g. 'in-the-market' batteries) or not (e.g. 'out-of-market' batteries). All 'in-the-market' battery capacity is 'price-elastic' and explicitly modelled. Its dispatch is optimised within probabilistic modelling and the main parameters considered for this technology type are as follows:

- Installed output capacity (MW)
- Storage capacity (MWh)
- Efficiency (92% per cycle, or values provided by TSOs)
- Initial state of charge (default: 50%)

'Out-of-market' batteries are accounted as implicit DSR as described in Section 2.3.2 (together with electric vehicles (EVs) and heat pumps (HPs)) and can further be classified as either 'price-elastic' or 'price-inelastic'. The former are explicitly modelled while the latter are exogenously accounted for in the demand profiles based on information provided by TSOs. The open-Loop PSP and closed-Loop PSP storage technologies are described in the following section.

2.1.4 Hydro

Hydro capacities are aggregated by study zone and technology type. The availability of hydro energy inflows and additional hydro constraints in addition to the criteria for 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'). A key improvement in the hydropower modelling methodology for ERAA 2024 arises from the update of the PECD Hydro database, within which RoR and pondage was split into two distinct categories that now allow distinguishing between pure RoR and RoR with pondage capabilities, as well as small storages, as explained below.

Hydropower plants are now aggregated into five distinct technology categories:

1. RoR
2. Pondage
3. Reservoir (hereafter referred to as 'traditional reservoir')
4. Open-loop PSP reservoir
5. Closed-loop PSP reservoir

The RoR category aggregates non-dispatchable hydropower (river) plants whose generation profile follows the contingent availability of natural water inflows with negligible modulation capabilities.

The new pondage category – now separated from the pure RoR – instead collects fluvial or swell power plants with pondage capabilities, i.e. the possibility to leverage a dam or storage system ahead of the turbine inlet and thus leverage a certain degree of generation flexibility with respect to the natural water inflows. The pondage category also accounts for small daily storages, i.e. small reservoirs without pumping capabilities and with a ratio of reservoir size (MWh) to net generation capacity (MW) of less than 24 hours.

Major hydro storage plants without pumping capabilities are instead 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.

Hydropower generation is ruled by a set of constraints and parameters that define the maximum and minimum power available for turbine (or pumping) operations, including hydro natural inflows, minimum and maximum generation and reservoir level constraints. Due to the level of aggregation – i.e. aggregated capacity per technology type – FOs and maintenance requirements are implicitly reflected in the time series defining the maximum generation constraints. The data availability varies depending on the set of input data provided by TSOs for the specific 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 rather indicate the template and structure of the database itself.

[2] Hydropower modelling - New database complementing PECD

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

MW / GWh	RoR	Pondage	Trad. reservoir	Open-loop PSP	Closed-loop PSP
Hydro inflows	D	D	W	W	-
Max. power output	D	D	W	W	W
Min. power output	D	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	-	D*	W*	W*	-
Max. reservoir level	-	D*	W*	W*	-
Min. reservoir level	-	D*	W*	W*	-
Reservoir size	-	Y	Y	Y	Y
Turbine capacity	Y	Y	Y	Y	Y
Pump capacity	-	-	-	Y	Y
Size/capacity ratio [h]	-	≤ 24	>24	any	any

D: Daily	W: Weekly	Y: Yearly	-: Not applicable	■: Not modelled	* : Not modelled in EVA

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

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 power 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, derated by the frequency containment reserve (FCR) and frequency restoration reserve (FRR) hydro reserve requirements, if applicable. RoR generation is assumed to be non-dispatchable by definition, and thus daily inflows are turbined at a constant hourly output during the day. If a non-zero reservoir size is provided for the pondage category, such dispatch flexibility is granted according to minimum and maximum generation profiles, which can 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. These types of constraints can be retrieved from a detailed analysis of historical generation profiles, in addition to reflecting the combination of a wide range of restrictions, including minimum or maximum water flows from/to reservoirs or river damns due to environmental regulations, regulated levels of river or hydro storage flows due to regulated water use for navigation, agriculture or others, technical operational constraints of cascade reservoir systems and PSP plants, and any other peculiar constraint relevant for a specific study zone.

Reservoir level constraints are treated as discrete constraints to be enforced by the modelling tool at the beginning of each week, i.e. during 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 might sometimes lead to punctual infeasibilities in the UCED solution. Such infeasibilities frequently arise from the solver attempting to enforce the initial reservoir level (or minimum/maximum level) as hard constraints at the beginning of each week without sufficient flexibility. Therefore, two sets of minimum and maximum reservoir level constraints are collected, labelled as 'technical' and 'historical'. As the naming suggests, historical constraints include the minimum and maximum measured (weekly or daily) levels, while the technical constraints report operational limits of the reservoir that are independent from climatic conditions, e.g. safety operational levels, minimum water reserves for potable and agriculture uses, and others, which can never be violated. When infeasibilities or adequacy issues are detected, the solution adopted is to treat historical level trajectories as soft constraints, thus allowing the solver to violate them at a high penalty cost. Setting the penalty cost sufficiently high but still lower than the value of lost load (VoLL) ensures that the solver prioritises the dispatch of hydro resources and inflows during hours of generation scarcity to avoid energy not served (ENS) if potentially in conflict with historical reservoir trajectories. Technical constraints are instead treated as hard constraints regardless of the contingent dispatch or system status.

Minimum and maximum pumping are treated analogously to minimum and maximum power output constraints. Only limitations to the maximum pumping power are applied in the model. The other pumping 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 (weekly) energy constraints for pumping operations are deemed to be overly restrictive and unsuitable for the nature of the Monte Carlo 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.

2.1.5 Balancing reserves

Balancing reserves are power reserves contracted by TSOs that help to stabilise or restore the grid's frequency following minor or major disruptions due to unforeseen factors such as outages (generation or interconnection) or rapid demand changes. For each study zone, an amount of capacity equal to the total FCR and FRR capacity needs to be withheld from the energy-only market (EOM).

For ERAA 2024, TSOs could choose to account for balancing reserve requirements by thermal, renewable (wind and solar) and/or hydro units. For thermal units, known contracted capacities for reserves could already be deducted from the data reported by the TSOs. TSOs were also able to report FCR and FRR requirements that must be explicitly modelled and covered by the remaining available thermal and/or renewable fleet. These requirements are not already accounted for in the reported net generation capacities. Further details on this modelling can be found in Section 9.

Finally, TSOs were able to report reserve requirements that must be covered by hydro units. More specifically, FCR and FRR requirements can also be covered by reservoir, open-loop PSP and closed-loop PSP units. The full requirement can be covered by either one technology or a collection of them, depending on TSO reporting. Section 9 provides further insights into how the adequacy models account for reserve requirements provided by hydro.

2.2 Grid side

Like thermal capacities, TSOs provide forecasted available NTCs with an hourly resolution. The TSOs provide data divided into the high voltage alternating current (HVAC) and high voltage direct current (HVDC) categories, and NTCs are aggregated per border. Planned maintenance for transmission lines is integrated into the NTC hourly availability, as provided by TSOs. Transmission levels depend on deterministic planned outages and random forced outages, which are modelled in the same manner as for dispatchable generation resources. TSOs can report specific 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 comprise multiple poles, which are also explicitly modelled in the ERAA. For ERAA 2024, the default assumption has been one pole per line for HVAC interconnectors, if no data has been provided.

Due to the complexity of power systems, the consideration of multilateral interconnection restrictions – such as flow-based market coupling (FBMC) – becomes more important. Therefore, FBMC is implemented for the Core and Nordic CCRs.

2.3 Demand and flexibility

Most of the domestic demand is fixed and unaffected by endogenous market prices, making it inflexible. However, a portion of the demand is flexible and represented through explicit or implicit Demand Side Responses (DSRs). Implicit DSR includes the price-sensitive share of non-market demand side resources (EVs, HPs and household batteries). Table 7 summarises the above.

Table 7: Modelling of explicit and implicit DSR

	Examples	In the market?	Price-sensitive?	Modelling choice
Explicit DSR	Industrial DSR	Yes	Yes	Explicitly modelled
Price-sensitive implicit DSR	EVs, HPs, household batteries (out-of-market)	No	Yes	Explicitly modelled

Constraints on the maximum daily operating hours for DSR and the activation time of iDSR are included in the Economic Viability Assessment (EVA) and UCED.

2.3.1 Base demand

The base or inflexible demand comprises any fixed load and includes as separate components the price insensitive parts of EVs, HPs, optionally beyond the meter rooftop PV and batteries. The latter component would reduce the total net demand from a grid perspective.

TSOs can choose to either have ENTSO-E calculate the base demand time series on their behalf based on data provided by the TSOs or provide the time series themselves. ENTSO-E generates demand time series using a dedicated tool, i.e. the demand forecasting tool (DFT).

2.3.2 Price-sensitive demand-side flexibility

The categories belonging to ‘price-sensitive’ DSR are explicit DSR and price sensitive implicit DSR.

Explicit DSR capacity differs between study zones and between hours of the day. The dataset provided by the TSOs includes:

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

Each of the above parameters can be specified for different activation price bands, as either a market resource or strategic reserves (the latter is only considered in the ERAA adequacy simulations as a post-processing and if resources are already contracted and approved in the respective target year). From a modelling perspective, DSR is similar to any other generation asset, albeit with an activation price usually higher than the marginal cost of most other generation categories and with an availability rating that limits activated DSR capacity for a given hour.

The approach for the implicit demand side response (iDSR) implemented in ERAA 2024 aims to explicitly include the flexibility – with respect to endogenous market prices – expected from EVs, HPs and out-of-market batteries (oomB) in the market models (with due simplifications). An important input for this modelling approach is the share of price-sensitive consumers $\boldsymbol{R}$ among these consumer types. These vary between countries and are collected from each TSO as a best estimate. Based on this parameter, we can compute the amount of ‘price-sensitive EVs, HPs and oomBs’.

The price-sensitive share of oomB is included in the market model as a battery characterised by **installed charge/discharge capacity** and **storage size** (as directly reported in the data collected for oomB capacity) multiplied by the corresponding price-sensitive ratio $\boldsymbol{R_{oomB}}$. The example below illustrates the application of $\boldsymbol{R_{oomB}}$.

Assuming for a given study zone and TY:

- an oomB installed capacity of 350 MW;
- a storage capacity of 1,100 MWh; and
- a $\boldsymbol{R_{oomB}}$ of 5%.

The following would be explicitly modelled:

- **Charge/Discharge capacity** = Capacity x R_{oomB} = 350 MW x 5% = 17.5 MW.
- **Storage size** = Size x R_{oomB} = 1,100 MWh X 5% = 55 MWh.

In addition, the following assumptions are made:

- **State of charge (SoC)** initial and final level of the year = set to 50% by default.
- **Cycle efficiency** = set to 92% default value.

As for EVs and HPs, the methodology primarily leverages on the demand forecasts generated by the dedicated tool, as described in the previous section, which includes a base consumption for EVs and HPs. In the modelling tool, the price-sensitive share of EV and HP consumers ($\boldsymbol{R_{EV}}$ and $\boldsymbol{R_{HP}}$) can shift their demand within time windows to gain arbitrage and improve resource adequacy in times of scarcity. The energy within each time window must be balanced, i.e. energy cannot be shifted outside a time window.

Table 8 presents the start times of the time windows applied for EVs and HPs depending on the respective time zone (all times UTC). For HPs, there are four time windows per day, each covering six hours, while for EVs there are three time windows with two windows each covering six hours and an extended nighttime window covering twelve hours. The underlying assumption for the extended nighttime window for EVs is that most EVs are connected to the grid and not in driving mode during night time. The detailed mathematical formulation of the modelling of flexible EVs and HPs can be found in Appendix 2.

Table 8: EV/HP time windows

Time zone	StarttTime 1	Start time 2	Start time 3	Start time 4
STANDARD (UTC)	-/5am	7am/11am	1pm/5pm	7pm/11pm
UTC+1	-/6am	8am/12am	2pm/6pm	8pm/12pm
UTC+2	-/1am	9am/7am	3pm/1pm	9pm/7pm
UTC-1	-/4am	6am/10am	12pm/4pm	6pm/10pm

3 Overview of scenarios and calculations steps

This section provides an overview of the ERAA adequacy assessment process, which starts with collecting a large amount of raw input data processed to serve as input for the scenario computations. Preparing input data for all TYs and uncertain variables (e.g. WSs) is a major task for ERAA 2024. Figure 3 presents the following elements:

- The data are stored/generated in three databases/tools, namely the PEMMDB, PECD, and DFT and constitute the 'National Trend' scenario. For more information, see Annex 1.
- Some data are defined by TY, whereas other data are by WS (*N* WSs) or both TY and WS.
- 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 Section 11.4). Planned maintenance of grid assets is already included in the NTCs provided by the TSOs.
- Thermal capacity can be dispatched at will, whereas wind and 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 reference market modelling tool, which is further described in Figure 4. First, the input data and assumptions are fed into the EVA model to assess how likely generation capacities are to be retired, invested in, (de)mothballed, and/or extended in lifetime. Next, the EVA entry/exit of market capacity is included in the central reference scenario, followed by the Adequacy assessment with the Monte Carlo simulation to result in clear adequacy metrics.

National Trends Input calculation process

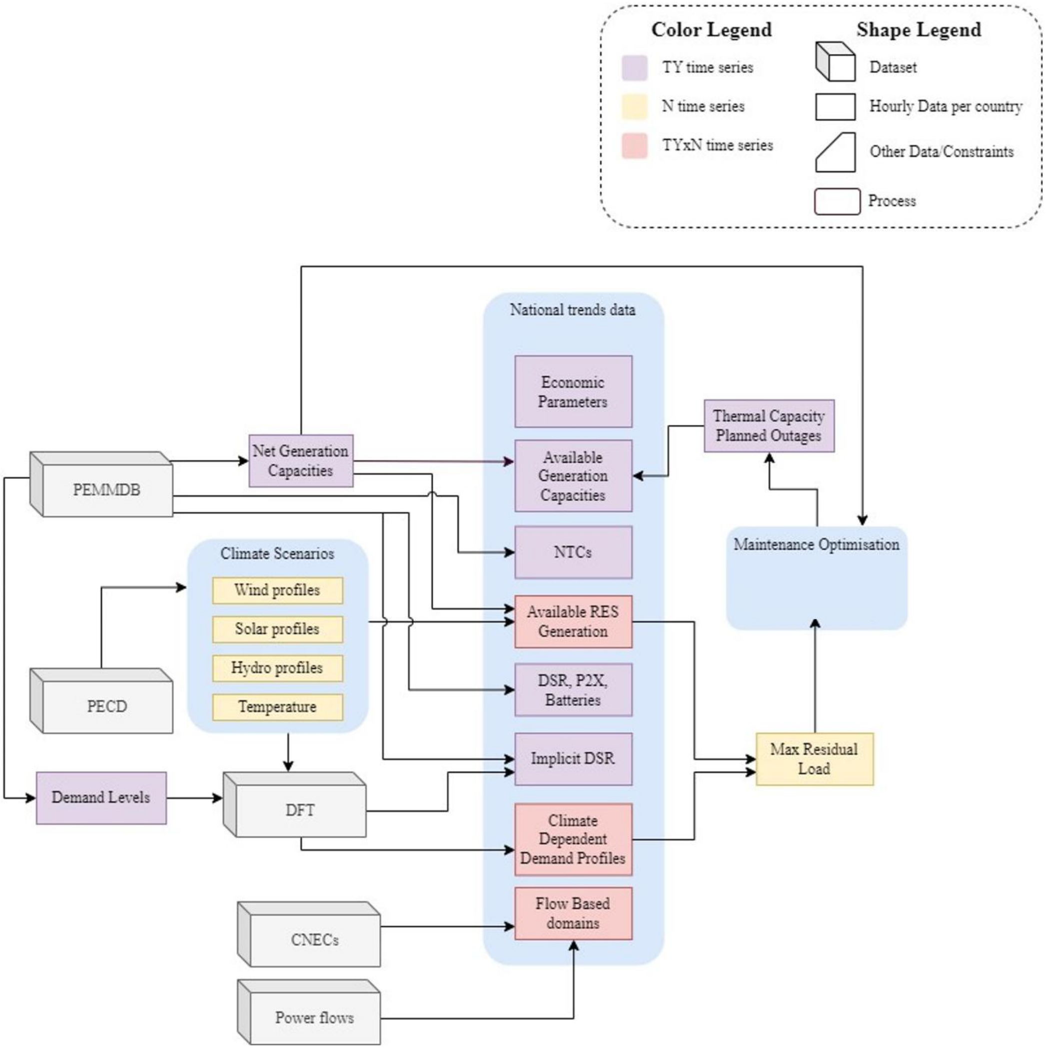

Figure 3: Overview of initial input data processing

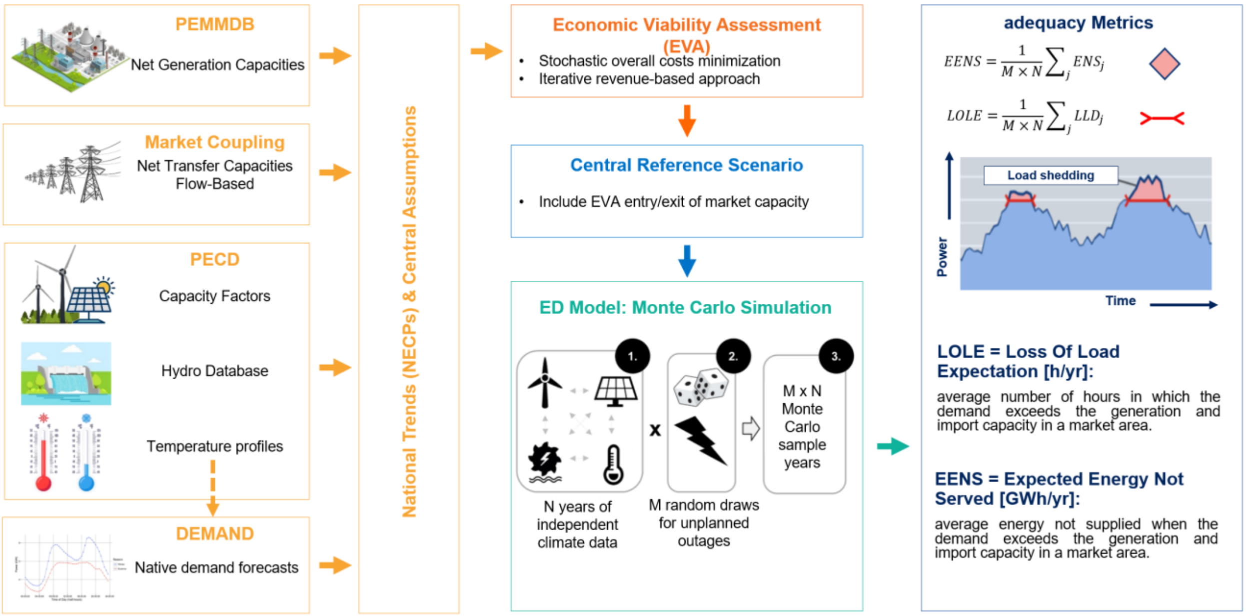

Figure 4 Multi-step ERAA approach

4 Flow-based domains calculation methodology

The ERAA target methodology requires implementing – where applicable – of an FB capacity calculation methodology (CCM) for cross-zonal trade. In the European day-ahead (DA) market for electricity, energy is traded within and across study zones. The market assumes no grid restrictions within a study zone, although there are **limitations** to the amount of energy that can be traded across study zones. One approach to account for these limitations is market coupling by NTC, in which the trades across any given border and market time unit do not affect exchange capacities on other borders in the market clearing process. By contrast, the FBMC approach considers interdependencies in the power system by allowing export from or imports to the study zones as long as monitored network elements are not overloaded, thus better representing the physical reality of the grid. The market coupling approach is currently defined by so-called capacity calculation regions (CCRs)[3].

Figure 5 shows the perimeter of the Core and Nordic regions, on which FB domains were calculated.

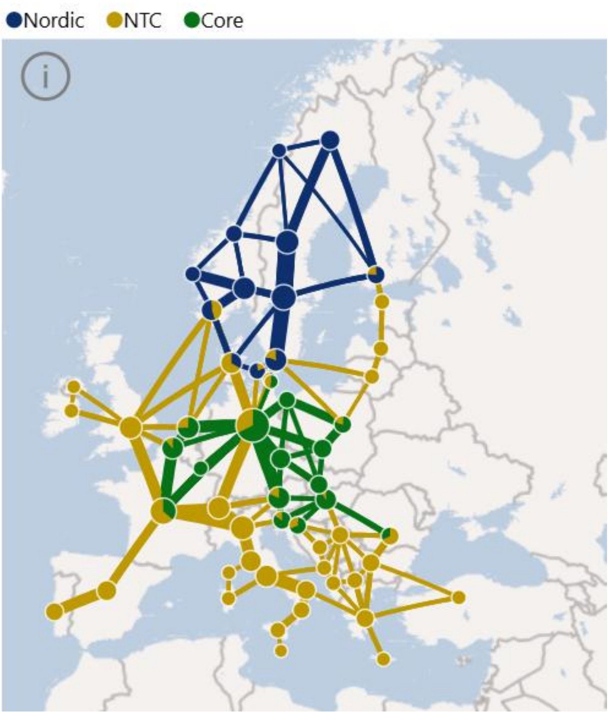

Figure 5: Core Capacity Calculation Region

The present section describes the FB concept and then Core and Nordic methodologies for computing FB domains. The ERAA 2024 uses individual FB domains for each TY.

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[3] https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32015R1222 , https://www.entsoe.eu/network_codes/ccr-regions/

4.1 FB domain concept description

In broad terms, an FB domain describes the solution space for the net positions of individual study zones in a given CCR for a given market time unit. In other words, it defines the limitation for exchanges between study zones in that CCR. It also enables accounting for external flows (to neighbouring countries) or internal DC line flows.

An FB domain is defined by a set of linear constraints derived from linearised equations in the network models (analysing active power flow) across monitored network elements. A change in study zone net position directly translates into the power flow change on the respective network element. This relation is represented by power transfer distribution factors (PTDFs).

Monitored network elements considered as critical network elements (CNEs)[4] in the capacity calculation can be both within and across study zones. Specific requirements apply for the consideration of internal network elements. By including relevant contingencies, the N-1 security constraints of the grid can be represented. This results in a list of CNECs, i.e. a list of CNEs combined with relevant contingencies under which particular CNEs are monitored. For each CNEC, a margin available for cross-zonal trade (MACZT) is defined, which restricts the power flow on the CNEC. This in turn will be the limiting factor for net positions of study zones in the form of FB domains.

As explained above, the constraints of an FB domain are given by the CNEC power flow definition on the left-hand side and their respective capacity margin on the right-hand side. Thus, an FB domain comprises linear constraints in the form of inequalities. In the conceptual FB domain given in Table 9, there is a linear constraint in which *A, B* and *C* correspond to the net positions of study zones or flows and/or set points of selected external flows to the CCR, internal HVDCs and selected phase-shifting transformers (PST) within the CCR:

$$-0.3A + 0.25B + 0.1C \leq 150 \text{ MW}$$

In FB with standard hybrid coupling (SHC), A, B and C correspond to the net positions of CCR study zones A, B and C with respect to the other study zones included in the CCR. However, these variables can also refer to setpoints of selected external flows into the CCR (AHC), the setpoints of HVDCs internal to the CCR (evolved flow-based, EFB) and selected PSTs within the CCR. Whereas in SHC, the FB domain only models the impact of exchanges between CCR study zones on CNECs, in AHC the impact of the interconnectors between CCRs is added to the model. The PTDFs (-0.3, 0.25 and 0.1 in this example) for AHC borders refer to the sensitivity of the flow on a CNEC to a change in flow over this AHC border. In EFB, similarly to AHC, the sensitivity of CNEC flow to setpoints of DC elements within the CCR are considered.

With the resulting set of constraints, the market simulation model can set the CCR net positions, the setpoints of DC elements and the bilateral exchanges over non-Core borders while respecting the maximum flows allowed on all CNECs. Note that while the NTC constraints between CCR study zones are completely replaced by FB constraints, NTC values remain constraining for the maximum flows over the AHC elements themselves.

[4] ACER Decision on the Core CCR TSOs' proposals for the regional design of the day-ahead and intraday common capacity calculation methodologies

Table 9: Conceptual FB domain example

Critical network element	Contingency	Critical network element and contingency	Influence of the net position on the flow on each line (PTDF matrix)			MACZT (MW)
			A	B	C	
Line 1	None	CNEC 1	-30%	25%	10%	150
	Contingency 1	CNEC 2	-17%	35%	-18%	120
	Contingency 2	CNEC 3	15%	30%	12%	100
Line 2	None	CNEC 4	60%	25%	25%	150
	Contingency 3	CNEC 5	4%	-15%	4%	50
...	...	...	...	...	...	...

The constellation of non-redundant constraints can be described as a 'convex hull', forming an n-dimensional polytope. The dimensions correspond to the columns of the FB domain matrix. In the example in Table 9, the dimensions are given by A, B and C.

In order to visualise a domain or compare between different domains, it can be useful to project the polytope onto a two-dimensional plane, which is comparable to casting the shadow of a three-dimensional object onto a wall. However, the computational complexity of creating the projection increases with the number of dimensions as it requires enumerating the vertices of the full polytope.

When referring to the 2D projection of an FB domain, the polygon displayed shows all admissible values for the two dimensions considered but it does not show the implication of these values on the variables of the remaining dimensions. As an example, we assume a simplified three-dimensional domain with the shape of a cube as described in Table 10. Its projection onto the dimensions A and B – shown in Figure 6 – makes it clear that this assignment forces C to adopt a net position of 0 in this example.

Table 10: Cube-shaped FB domain

CNEC ID	A	B	C	RAM
‘1	1	1	1	1
‘2	1	1	-1	1
‘3	1	-1	1	1
‘4	-1	1	1	1
‘5	1	-1	-1	1
‘6	-1	-1	1	1
‘7	-1	1	-1	1
‘8	-1	-1	-1	1

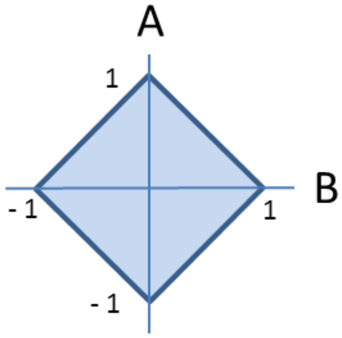

Figure 6: 2D projection of cube-shaped domain for C=0

4.2 FB domain computation steps for Core CCR

The process of computing the Core FB domains can be summarised in six steps, as illustrated below:

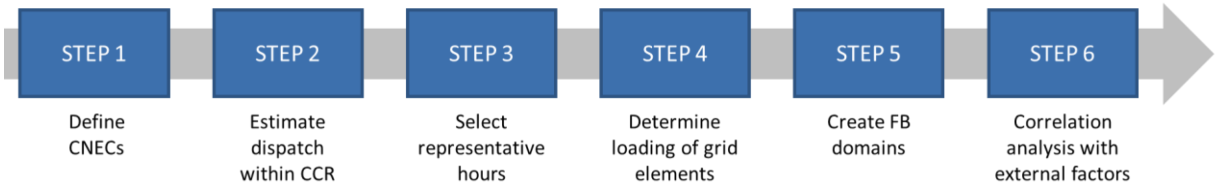

Figure 7: Steps for computing sets of FB domains for TY 2026

4.2.1 CNECs definition (step 1)

In the first step, a list of CNECs that potentially limit cross-zonal trade is defined. As mentioned above, a CNEC is a combination of a CNE with a contingency that refers – for example – to overhead lines, transformers or underground cables.

4.2.2 Computation of initial market dispatch within CCR (step 2)

The hourly market dispatch within the studied CCR in addition to exchanges with Study Zones outside of but connected to a given CCR is computed and given to the grid model as an initial market dispatch to perform load flow analysis and compute FB domains.

4.2.3 Selection of representative hours (step 3)

Given that calculating FB domains is computationally-intensive, it is impractical to calculate for each hour of each WS of the initial market simulation. To overcome this limitation, a selection of representative hours from the input market study is made on which FB domains will be calculated.

The selection of representative hours is based on a clustering process and provides a set of statistically representative, differentiated timestamps, to calculate domains that are both meaningful (representative of a sufficient number of hourly situations) and different (to provide a wide range of possible network constraint situations).

The clustering is based on the hourly flows on the monitored CNEs without contingencies, which are a good proxy of the final shape of the FB domains. The process to perform the clustering is as follows:

- A load flow simulation is run on a representative grid model for each hour of the selected WSs considering the initial market dispatch computed before, i.e. ERAA 2023 results. Consequently, the hourly flows on CNEs are computed (without simulating contingencies).
- The optimal number of clusters and the clusters themselves are computed based on the flows on CNEs, using a k-medoid clustering approach (see below for details). This results in identifying the representative hours across the selected WSs on which the FB domains will be calculated.

The optimal number of clusters is selected based on the computation of two clustering statistics, namely the total within sum of square (WSSs) and the silhouette. These indicators are calculated for different numbers of clusters to determine the optimal number, maximising the consistency within one cluster and the difference between clusters. This led to the selection of three clusters for winter hours and three for summer hours, resulting in four FB domains to be computed.

A simplified FB domain is also computed based on a single representative time stamp for summer hours and for winter hours (each). This simplified FB domain is not a subset of the full FB domain described above.

4.2.4 Reference loading of grid elements (step 4)

The reference loading of grid elements is calculated for representative hours by performing a load flow calculation on the input grid model (full load flow calculation).

4.2.5 FB domains computation (step 5)

Step 5 describes the computation of the FB domains for each representative hour, identified in step 3. The FB domain calculation begins with the PTDF matrix, which is derived from the grid model and allows for linear power flow calculations. The PTDF matrix represents all changes to flows over the CNECs in response to injections in individual network nodes in the detailed grid model. This PTDF matrix provides nodal granularity and incorporates all network nodes represented by columns. A generation shift key (GSK) is required to allow for a zonal representation in accordance with the European study zone configuration. The GSK is a matrix that carries information regarding how the nodal power injection changes if the net position of a study zone moves up or down. Multiplying the nodal PTDF and GSK matrices results in a zonal PTDF matrix. Finally, the matrix is augmented by columns representing either DC links or exchanges with external CCRs that are modelled as ARC. This concretely means that PTDFs are calculated for each CNEC for each represented DC link (currently the Alegro HVDC link) and for NTC borders between a Core and a non-Core study zone. This enables representing the sensitivity of CNEC flows within the Core region to the flows on the represented DC links and the NTC borders between Core and other CCRs. This step concludes the left-hand side of the FB domain constraints (PTDFs).

To establish the right-hand side of the constraints (remaining available margins; RAMs), the MACZT on each CNEC must be known. Its size depends on the physical active power transmission capacity, the base or 'reference-flow' loading, and the flow reliability margin of the CNEC, as well as the minimum legal requirements for cross-zonal trade. Step 5 also includes a non-costly remedial action optimisation through PSTs, aiming to increase the size of the domain in its narrower dimensions. The outcome of this step might therefore differ depending on the actual constraining CNECs, which are linked to the CNEC list used to build the domain.

Once zonal PTDFs and the RAMs have been computed for each CNEC, a post-processing is performed to adjust RAMs to comply with the 70% requirements. The 70% regulation (Regulation 2019/943, Article 16) prescribes a minimum margin of the physical cross border capacity that needs to be made available to cross-border trade. For this purpose, first the net positions of all study zones (within and outside of the Core region) are set to 0 (using the PTDFs previously calculated), and for each CNEC it is checked whether the resulting flow is lower than or equal to 30% of the RAM of the CNEC. If this is not the case, the RAM is increased until the flow in this situation reaches 30% of the RAM for all CNECs.

This process within the FB domains computation methodology ensures that the Core domains computed are compliant with the 70% rule.

As the final part of Step 5, post-processing to the FB domains can be adopted for better handling. For this an algorithm to reduce the number of (pre-solved) FB constraints is applied, to identify and remove the constraints that have a negligible impact on the FB domain.

This is achieved in an iterative procedure as follows:

1. For each FB constraint cx in the given FB domain, quantify impact of removing it, as a product of min/max net position ratios (before and after removal of cx).

$$Domain\ Impact\ (cx) = \prod_{\forall zone} \frac{NP_{zone}^{max}(with\ cx)}{NP_{zone}^{max}(withour\ cx)} \cdot \prod_{\forall zone} \frac{NP_{zone}^{min}(with\ cx)}{NP_{zone}^{min}(withour\ cx)}$$

2. Remove the FB constraint that has the lowest domain impact.
3. Repeat steps 1 and 2 until the lowest FB domain impact becomes non-negligible (higher than tolerance of 1%).

As a result of the aforementioned procedure, number of constraints can be reduced with a negligible impact on accuracy. This significantly reduces the complexity and shorten the computation times.

4.2.6 Defining when each FB domain should be used (step 6)

Step 6 defines the final part of the FB methodology and describes how the FB domains computed are chosen for each hour in the adequacy assessment models.

First, a random forest classification algorithm is trained to identify conditions under which each FB domain is more likely to be representative. Total load and RES generation (solar, wind, hydro RoR generation) are considered as main conditions influencing FB domains, called determinants. Each determinant is considered at a study zone level. A large set of determinant data is built considering conditions in each hour of the cluster (identified in step 3), which specific FB domain represents. With this dataset, the random forest classification algorithm identifies distinguished conditions under which each FB domain is representative.

Subsequently, to identify which FB domains should be chosen for every timestep of a prospective study, the trained random forest classification algorithm is applied for all possible conditions in a given prospective study. During this step each timestep of each weather scenario is analysed by the algorithm considering determining conditions (total load, RES generation). By analysing the data, the algorithm identifies which FB domain would best fit the conditions of that timestep. The process is repeated for every timestep of the prospective study.

4.3 FB domain computation steps for Nordic CCR

The process of computing the Nordic FB domains follows a similar process with a few differences that make it distinct from calculating FB domains in the Core region. The steps for calculating FB domains in the Nordic countries is summarized below.

4.3.1 Create a common grid model

For the Nordic CCR, each country develops and maintains a grid model of their control area for each target year (2026, 2028, 2030, and 2035). Note that for the 2024 ERAA report, not all models were up to date in time. For the Swedish and Norwegian grid, updated models for 2025 and 2030 were slightly adjusted and used as a proxy for TY 2026, 2028, and 2035. The Danish and Finnish grid models were not up to date. After preparing TY grid models, a common Nordic model was developed as an input to subsequent market and power flow studies.

4.3.2 CNEC selection

After developing a common grid model, each TSO in the Nordic CCR modelled market and power flow outcomes to identify flow patterns and congestions to compile a list of CNECs for calculating PTDFs and RAMs, including cross-border connections. Note that each time the grid plan for a TY is updated, changing the topology of the common grid model, the list of CNECs must be recalculated.

4.3.3 Update electricity market scenario modelling datasets

TSOs within the Nordic CCR collaborated to compile a list of input market outcomes and subsequent power flows for calculating FBMC parameters. This was undertaken in a scenario-based manner, where Stattnett's most recent long-term market analysis (LMA 2022) was taken as a basis.

4.3.4 Calculate FB domains

The first step into calculating the FB domains was to first forecast the marginal cost of water as an important input for forecasting the dispatch of hydro power in the Nordic CCR. This was completed using stochastic dynamic programming and then calibrated manually after verification by simulation. Next, the market dispatch was forecasted for 29 weather scenarios. The market dispatch was solved in three hour increments, giving 56 market outcomes per week. The power flows from these market dispatches were used to calculate a static PTDF matrix and 2912 RAM domain for each target year. 1999 was taken as an "average" climate year and representative demand. These FB domains were post-processed with a MACZT 20% of RAM requirement.

4.3.5 Review and deliver FB domains for the ERAA

Finally, the FB domains were reviewed by checking the resulting power flows and power prices to ensure that they are within reasonable expectations when compared to historical data.

5 Maintenance profiles calculation methodology

The main goal of periodic maintenance is to reduce the risk of unplanned unavailability of thermal capacity during potential times of scarcity – typically during periods of high load.

Hourly maintenance profiles for thermal units are calculated centrally by ENTSO-E for most study zones on a TY basis. In case TSOs can provide better-informed maintenance profiles due to better knowledge of the specificities of their power system, these are considered in the models instead of central calculations. Maintenance profiles are calculated for each thermal generation unit for each TY. Maintenance of renewables, other non-renewables, and storage units is considered and reflected in the respective infeed and availability time series of these generators.

The objective of the ENTSO-E maintenance optimisation methodology is to maximise the available thermal capacity during potential times of scarcity. Using the annual planned outage rates[5] of each unit, maintenance outage periods are scheduled on a yearly horizon using an objective function aiming to level the weekly capacity margin[6] per market node. Levelling the capacity margin can be achieved as described in Figure 8, minimise the risk of ENS.

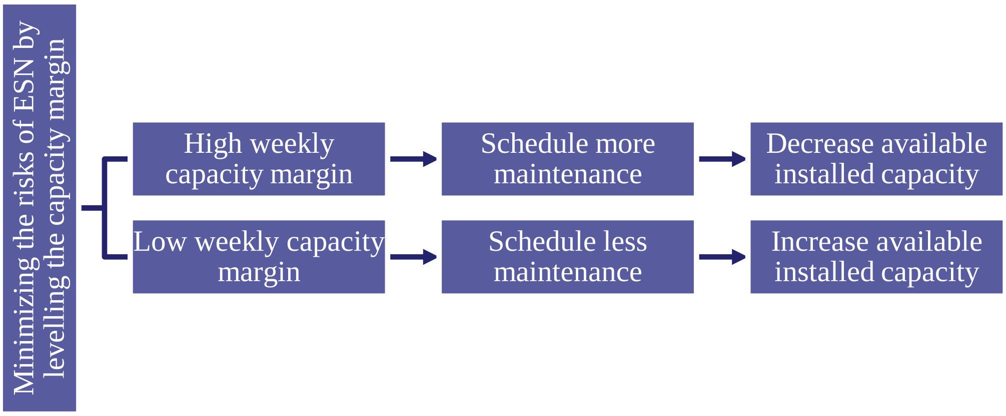

Figure 8: Levelling capacity margin with maintenance optimisation

The underlying load profile for maintenance planning is a residual load profile as it is expected that producers will consider a certain level of renewable infeed when planning future maintenance. The load profile is obtained stepwise:. First, a synthetic profile is computed by taking the minimum infeed of intermittent renewables over all WSs on an hour-by-hour basis. Subsequently, the latter is added to the hourly firm capacity of other generation units as given by the TSOs. Finally, the resulting profile is subtracted from the synthetic demand profile computed by taking the maximum native demand over all WSs on an hour-by-hour basis to yield the residual demand. This ensures that renewable infeed is accounted for to optimise the maintenance of thermal generation. The

[5] Total number of days per year required for maintenance
[6] Difference between peak load and available installed capacity during a given week

maintenance profiles are optimised on a country-by-country basis (in practice, cross-border interconnection capacities are not considered).

The resulting maintenance profiles – as determined by the above methodology – have been consulted with the respective TSOs. This allows the TSOs to amend and shape the maintenance profiles with specific knowledge not captured by the methodology.

Sections 10 and 11 provide more details on how these profiles are used in the EVA model and the adequacy model .

6 Long-term storage optimisation

The modelling tool performs an intermediate optimisation step for large storage assets before the UCED optimisation. Available storage capacity is optimised so that energy is stored in times of sufficient supply and made available for discharging in times of higher demand and/or lower available generation. Such a pre-optimisation step occurs within the modelling tool at a coarser time granularity than the hourly UCED optimisation (described in Section 11.5) as the optimal management of storage resources requires much higher foresight and planning at a seasonal or even yearly level. In this (pre-) optimisation phase, the available energy in storage assets and any cumulated exogenous energy flows (e.g. natural inflows for hydro storages) are optimally pre-allocated in (e.g. daily) energy lots so that energy resources are saved and made available to each daily UCED sub-problem related to the corresponding electricity needs of each study zone, which allows minimising system costs, i.e. resource dispatch costs. The contingent hourly dispatch of the energy available in storage assets is then finally optimised within each sub-problem of the UCED starting from the pre-optimisation targets, which are refined and concretised into the final daily generation based on the contingent availability of the other dispatchable and non-dispatchable resource capacities. Consistent with the assumption of perfect market and non-opportunistic behaviour of market players, storage assets never set the marginal price when entering the merit order, but are rather dispatched as zero-cost resources that exploit marginal price gains by storing energy during hours at low(er) marginal prices (e.g. collecting inflows in hydro reservoirs or by direct power infeed through pumping or battery charge) and releasing energy during hours at high(er) marginal prices.

6.1 Hydro storage optimisation

Hydro storage represents the most complex element of storage optimisation. It is 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 9 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.

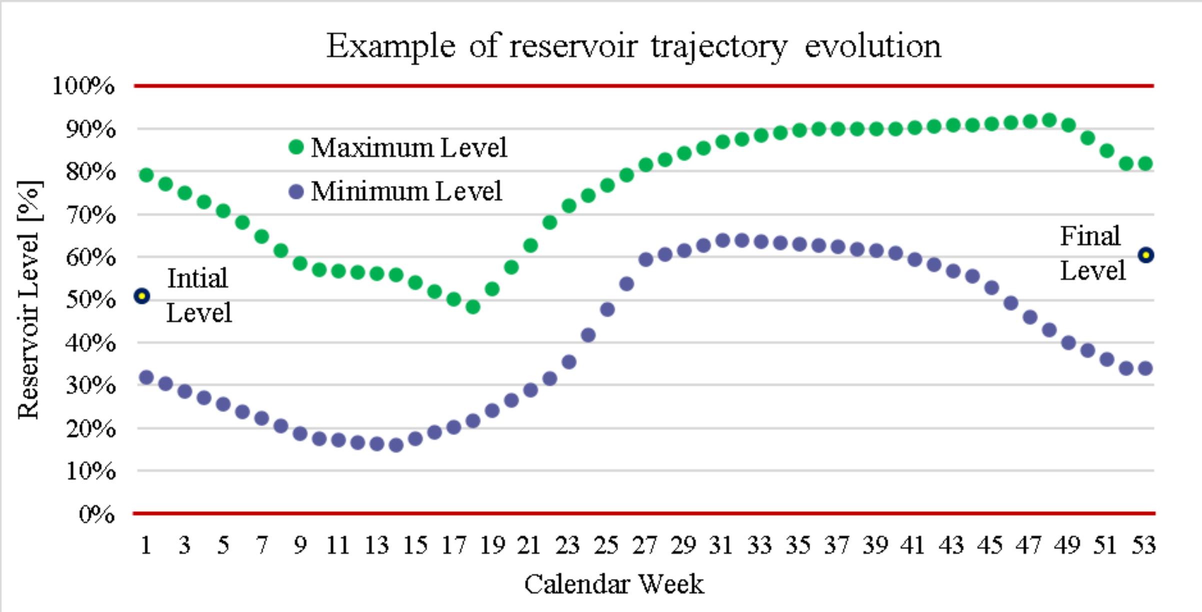

Figure 9: Example of reservoir trajectories and constraints

Alternatively, TSOs can also provide deterministic weekly trajectories per WS 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 if both are provided. If neither the minimum and maximum trajectories nor the deterministic start/end levels are provided, 0% and 100% of the total reservoir size act as continuous maximum and minimum hard constraints during the entire simulated timeframe.

The initial reservoir level (WS specific) 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 (historical before technical) is taken. If both pieces of data are missing, 50% of the reservoir size is assumed as the standard value.

Consistently, the final reservoir level is taken as the fixed trajectory value at week 52 or 53. If not available, the initial reservoir level of the following WS (e.g. 2007 for the simulated WS 2006) is selected. In the absence of fixed weekly reservoir levels, the average between the minimum and maximum level trajectory at week 52 is taken. If all data for reservoir levels are missing, 50% of the reservoir size is assumed as the standard value.

In addition to reservoir level constraints, multiple additional parameters limit the operation of hydro power plants, as summarised in Table 6. The standard cycle efficiency (pumping – turbining) for PSPs is assumed to be equal to 75%.

In the EVA, due to the computational complexity a reduced set of hydro storage constraints is taken into account, as indicated in Table 6. Constraints with a limited impact on price formation and thus investment behaviour have been omitted.

6.2 Batteries

Battery data are provided by TSOs and – as described in Sections 2.1.3 and 2.3.2 – comprise 'in-the-market' (mostly large-scale) and 'out-of-market' batteries (mostly household). 'In-the-market' batteries are price-sensitive and are explicitly modelled, while 'out-of-market' batteries are exogenously included in the demand profiles based on information provided by TSOs, e.g. typical consumption pattern for household batteries.

The 'in-the-market' capacities are aggregated and modelled mainly using 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 according to the values provided by TSOs (or default to 92%). For example, charging efficiency set at 90% means that for 1 MWh taken from the grid, 0.9 MWh is stored in the battery and 0.1 MWh is lost. The discharge efficiency is assumed to be 100%. This principle is illustrated in Figure 10.

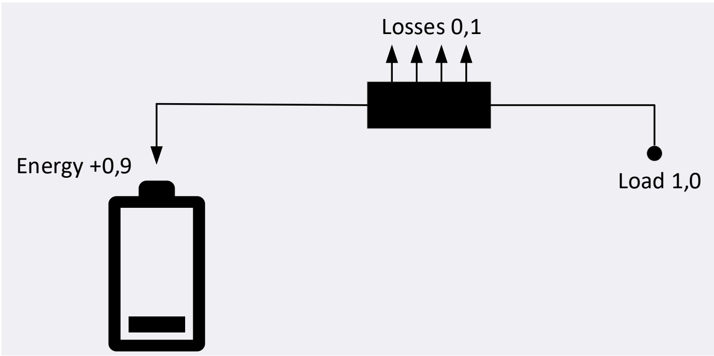

Figure 10: Illustration of the battery charging process

The energy off taken from the grid by the batteries (demand) is valued at market price, whereas energy injected from the battery to the market is valued at zero cost (the cost is already covered by the charging). The overall optimisation target is to operate batteries to minimise total system costs, i.e. discharge at high electricity prices and charge at low electricity prices.

7 Sector coupling (P2X)

Electrolysers use the surplus electricity mainly generated in RES to produce hydrogen, which can then be used in various ways, e.g. as a fuel to re-generate electricity, in the transport sector, or for heat generation. Only the water electrolysis production process has been modelled in a simplified manner in ERAA 2024 as it is the only production method that mainly relies on electricity. The electrolysis units were modelled as an additional demand activated below a threshold price, defined in the equation below:

$$P_{act} = P_h * \eta * 3.6$$

Where: P_{act} – electrolyser activation price [€ / MWh]
P_h – hydrogen price[7] [€ / GJ]
η – hydrogen production efficiency[8] [%]
3.6 - conversion factor MWh to GJ (1MWh = 3.6GJ) [MWh/GJ]

The adoption of such assumptions translated into the activation price of electrolysers in the range of 45–71 € / MWh depending on the TY and electrolysers' efficiency. Schematically, this principle is shown in Figure 11, which shows that the electrolyser starts producing hydrogen if the price of electricity drops below the electrolyser activation price.

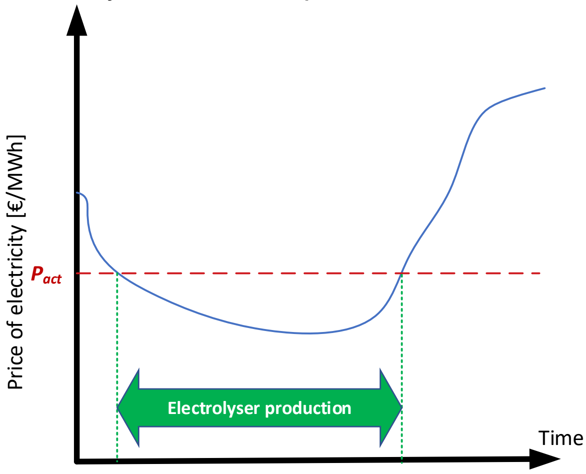

Figure 11: Activation price approach

The hydrogen prices are computed in accordance with Section 6.1 in Annex 1.

[7] The hydrogen price was assumed in the range of 21.69 - 23.47 € / GJ depending on the target year (see Annex 1, Section 6.1)
[8] Hydrogen production efficiency was adopted based on data provided by the TSO and ranged between 58 % and 84%, with a default of 68% (see Annex 1, Section 12.1).

8 CHP dispatch optimisation and heat credits

In some market zones, CHP units account for a large share of installed capacity. It is crucial to account for heat generation revenues when evaluating the economic viability of CHP units. These revenues directly contribute to the overall profitability of CHP units, which are often designed to meet both electricity and heat demands. Ignoring these revenues can lead to underestimating the unit's economic potential and might skew decisions regarding its operation or decommissioning. Additionally, CHP units operate with a unique must-run profile to ensure heat supply, which might result in power generation even when electricity prices are low. Without factoring in heat-related revenues, the assessment would overlook the added value that CHP units bring to the energy system by providing necessary heat, which can justify their continuous operation even during periods of low electricity demand. Therefore, including these revenues offers a more accurate picture of CHP units' economic viability, fostering better-informed decisions regarding their role in the energy mix.

The 'heat credit method' was introduced first time for the ERAA 2022 study, alongside the existing must-run approach[9], to address the aforementioned problems, namely (i) the need to reflect the marginal cost of CHP units in the electricity price and (ii) the necessity for some CHP units to be eligible for endogenous decommissioning—. For the heat credit method, revenue profiles are provided for individual units in hourly granularity. These profiles are calculated based on an approach using PEMMDB data, measured historical times series of district heating demand, and standardised data from pre-processed Eurostat statistics (see Figure 12).

The 'heat revenue tool' is shown in Figure 12. Using typical full load hours and the thermal capacity of each unit, slices of the overall heat demand time series are assigned to specific units. Combined with heat prices, each CHP unit receives a profile with revenues per MWh of electricity generated.

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[9] Due to limited TSO or literature data availability for CHP units, the heat credit approach is only applied to public district heating CHP units only. The must-run approach is applied to other types of heat networks such as industrial heat networks, special district heating constructs or heat generation from waste incineration.

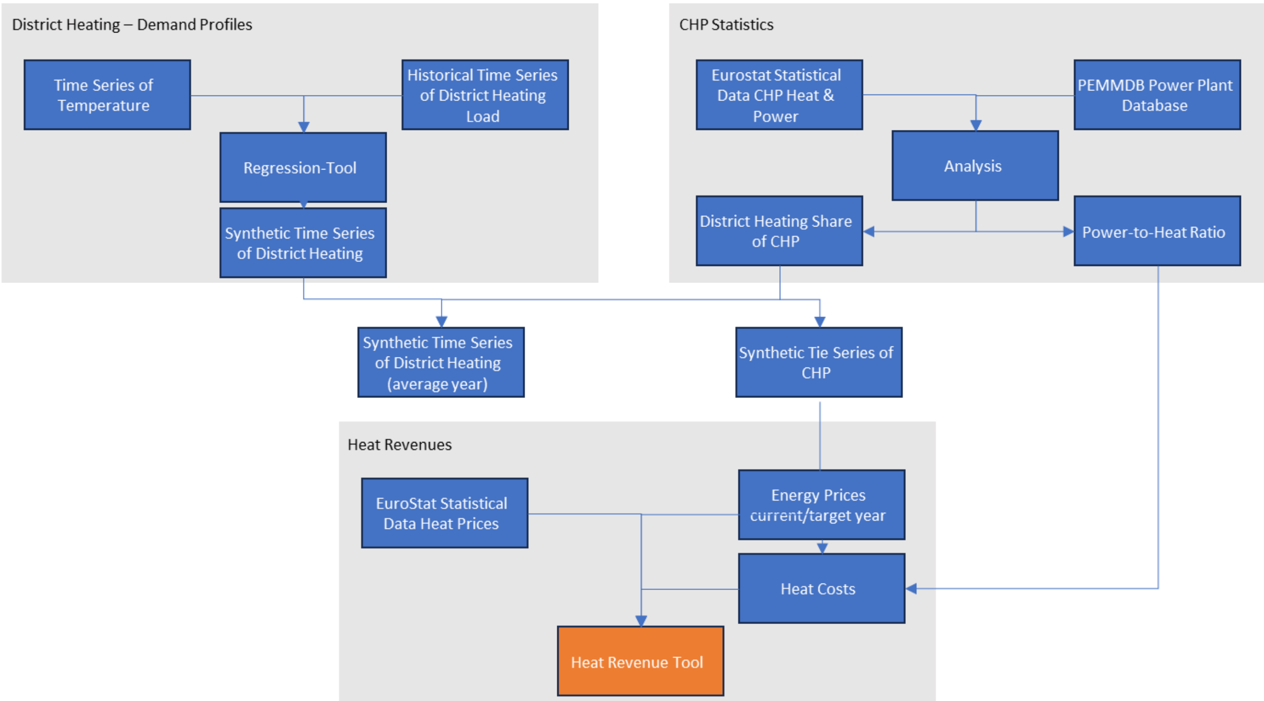

Figure 12: Heat revenue tool: Input data and calculation methodology

Missing TSO data are complemented using Eurostat statistical data[10] as shown in Figure 12. A mean heat demand profile is calculated and used with all the WSs to minimise the amount of data processed,.

Figure 13 shows the resulting stacked CHP unit dispatch (right graph) derived from the total district heating demand (left graph). The share of heat plants is not shown as these units are not modelled in the ERAA.

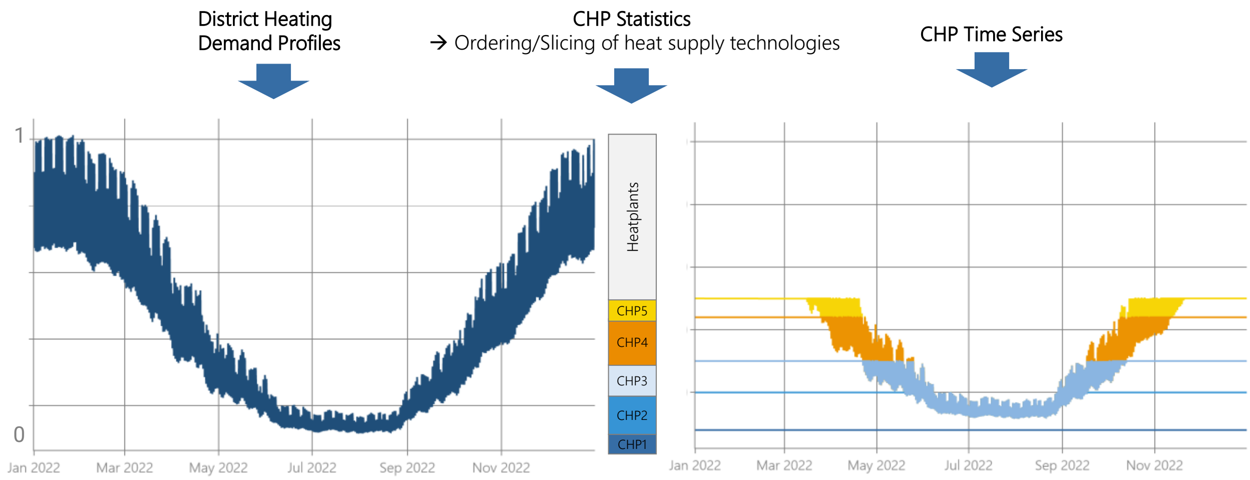

Figure 13: Illustration of splitting the heat demand between various CHP technologies

[10] Eurostat data browser: https://ec.europa.eu/eurostat/databrowser/product/view/nrg_bal_c?lang=en

The revenue profiles are derived from a thermal demand time series based on TSO-provided power-to-heat ratios and heat prices. Statistical data are used for any missing TSO values, with the exception of heat revenues, for which it is assumed that revenues correlate with the costs of heat supply provided by natural gas-fired heat plants. Therefore, heat revenues are dependent on the evolution of the gas price scenario.

In the total system cost optimisation, the heat credit method implies that CHP units have lower marginal costs at heat demand times. These units thus switch left in the merit order and their profitability is more advantageous due to additional revenues for heat supply than a similar unit (with the same technological configuration and fuel type) without heat extraction.

9 FCR and FRR Balancing reserves

For each study zone, an amount equal to the total FCR and FRR capacity needs to be withheld from the EOM. From a modelling perspective, reserve requirements for balancing purposes can be accounted for by withholding generation capacity from the wholesale market or increasing hourly demand (‘virtual consumption’) and in both cases by the quantity of reserve requirements set by the member states. The capacity withholding approach was adopted in ERAA 2024 as it has the advantage of not distorting the energy balance and the resulting market prices as ‘virtual consumption’ is not added.

Any reserve requirement quantities not directly withheld in the thermal generation capacities by the TSOs in the collected data are accounted for by procuring thermal capacities or reducing renewable production profiles or reducing the maximum hydro generation depending on TSO preference.

If the TSO requests balancing reserve procurement from thermal, the respective capacity must be held back from the wholesale market. TSOs can withhold the thermal capacity of specific units for reserve requirements by reporting derated maximum unit generation capacities during the data collection. Another method is to specify the reserve requirement which should be covered by thermal units, after which the model identifies the cheapest possible method of providing the reserves from the units available to procure the balancing reserves. The decision is based on the calculated prices of capacity procurement as the dual values of the reserve requirement constraint. The available thermal units for providing balancing reserves have been assumed to be all thermal units within the given zone, except the thermal units with inelastic production profiles.

In some countries, reserves are provided by hydro units. In these cases, reserve requirements are modelled by capping the maximum hydro generation of either reservoir, open-loop pumped storage, closed-loop pumped storage units or a combination of them, depending on the data reported by TSOs. The maximum generation value is calculated by subtracting the constant reserve capacity demand to be provided by the hydro unit from its turbining capacity.

In some countries, reserves are provided by renewable units. In such cases, reserve requirements are modelled by derating the maximum renewable generation of onshore wind, offshore wind, solar units, or a combination of them, depending on the data reported by TSOs. The maximum generation value is calculated by subtracting the constant reserve capacity demand to be provided by the renewable unit from its production profile, capping it a zero. This capping ensures no negative production profiles can occur in hours with low or no renewable production.

10 EVA methodology

The EVA step assesses the viability of capacity resources[11] participating in the EOM[12]. This is assessed using a long-term planning model to minimise the total system costs[13]. The key decision variables of such a long-term model aim to identify the economic-optimal (least-cost) evolution of resource capacity over the modelled horizon. This assessment therefore delivers insights, per each study zone and over the TYs, on the resource capacities that are likely to be (i) retired, (ii) invested in, (iii) (de)mothballed, or (iv) extended in lifetime. The decision variables attributed to available resources depend on the specific technologies and fuel types of generation assets, in addition to country-specific data where applicable, e.g. thermal units eligible for (de)-mothballing or life extension (see Section 10.2 for more details about the EVA's scope).

Figure 14 indicates which inputs from the National Trends are used for the EVA step. In ERAA 2024 FB modelling has been introduced in the EVA to increase the consistency between the EVA and the adequacy models. Parts of the geographical scope where FB modelling has been introduced are modelled with simplified domains to cope with the computational complexity.

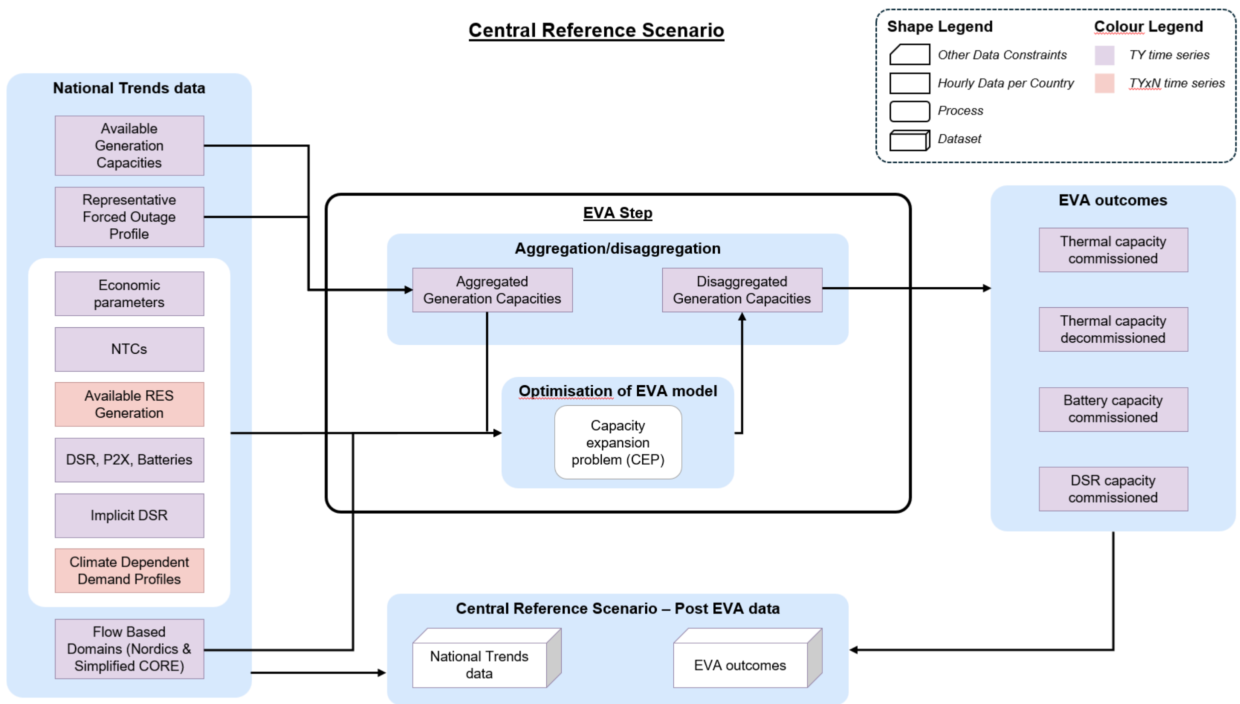

Figure 14: Overview of the inputs and outputs of the EVA step.

[11] Generation resources include storage units, e.g. batteries.
[12] Units with a CM contract awarded are excluded from the EVA for the duration of their contracts.
[13] Article 6.2 of the ERAA methodology acknowledges the use of overall system cost minimisation for the EVA, albeit as a simplification and assuming perfect competition.

10.1 Geographical scope

Resource capacity changes as a result of the EVA step are only allowed in explicitly modelled study zones (see Table 1), accounting for fixed exogeneous energy exchanges with non-explicitly modelled study zones.

10.2 EVA technology scope

Only units that mainly depend on the EOM revenues are included in the EVA scope[14]. In addition to decommissioning and new market entries, generation resources are eligible for lifetime extension[15] or mothballing/demothballing[16]. Table 11 summarises the decision variables of the EVA .

Table 11: EVA decision variables

Technologies	Decommissioning	Life Extension	New Entry
Gas	✓	✓	✓
Lignite/hard coal/oil	✓	✓	
DSR			✓
Battery			✓

Additionally, new entry decisions are limited by expansion constraints as elaborated in Sections 6.4.1 and 6.5 in Annex 1.

10.3 Capacity scoping

The EVA might use slightly different resource capacities as a starting point compared to the National Trend scenario, i.e. TSOs projections. The differences come from:

- Simplifying assumptions made on the decommissioning dates of the units subject to EVA. A unit subject to EVA is considered fully commissioned or not at all during a given year, whereby it cannot be commissioned or decommissioned at another moment than at the beginning of the year. The cut-off date is chosen as 1 July of any given year. A unit whose decommissioning date is before this date is not considered at all during the year of its decommissioning, otherwise it is considered to be commissioned for the entire year of its decommissioning and effectively decommissioned the next year.

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[14] There might be additional exogenous assumptions for why units cannot be retired such as local 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 or units with a CM contract in place are not considered as decommissioning candidates.

[15] Lifetime extension implies replacing or upgrading key elements of the asset to avoid a unit's retirement at the end of its initially calculated economic lifetime.

[16] (De-)mothballing is a common practice in the power sector that puts the unit in a temporary state of preservation with reduced fixed costs to return back in service later when market conditions improve.

- Neglection of secondary fuels: for units with primary and secondary fuels, the primary fuel is assumed to apply to all of the unit's installed capacity.

10.4 Non-consecutive target years

ERAA 2024 collected data for four non-consecutive TYs of 2026, 2028, 2030 and 2035. However, given that the EVA is an integrated model over multiple years for the 2026 – 2035 horizon.it is assumed that non-TYs are duplicates of the latest available TYs. For example, non-TY 2027 is assumed to have the same load, generation capacity, network constraints, etc. as TY 2026.

The net present value (NPV) of capital expenditure (CAPEX) and fixed operations and maintenance costs (FOM) in the case of commissioned capacities are discounted uniformly over the represented years. For example, if OCGT capacity is commissioned in the first TY – which in fact represents the years 2026 and 2027 – the CAPEX and FOM are discounted, assuming a uniform increase of the capacity from 2026 until 2027, i.e. a half increase of the capacity in each year. This methodological decision is a compromise between assuming all fixed costs already from 2026 onwards or only from 2027 onwards. This approach is taken to have a fair representation of financial parameters throughout the entire horizon.

10.5 Multi-year EVA optimisation function[17]

The EVA simulation is performed over multiple years. The total costs of the system in consecutive years are totalled in the EVA simulation by calculating the NPV of all future costs. A discount factor is applied to translate costs incurred in the future years to the present day value, as follows:

$$Minimize \quad \sum_{y} (1+r)^{(1-y)} \left[Total\ cost_y\right]$$

where: r – discount rate [%]

The total cost is equal to the sum of investment costs of new resources capacity (including a risk premium; see Section 10.12), fixed and variable unit operations and maintenance costs (including a risk premium; see Section 10.12), and DSR activation costs, in addition to the cost of curtailed energy represented by fictitious generators with the marginal cost equal to the market price cap (see Section 10.10).

The resource capacity build cost represents the overnight cost of building a new unit, i.e. the all-in capital cost as per the commissioning date. Building a new resource means spending a 'lumpy' capital cost with the expectation of benefiting from the favoured market conditions until at least the economic life of the resource. However, the economic life might exceed the modelled time horizon of the EVA, which is ten years ahead. To resolve this, the build cost $CAPEX$ is converted to an equivalent annual charge, which is applied in the year of build and every subsequent year.

[17] The detailed formulation of the EVA optimisation model can be found in Appendix 1.

$$Annuity = CAPEX \times \frac{WACC}{1 - (\frac{1}{1 + WACC})^{Lifetime}}$$

where: $WACC$ – Weighted average cost of capital
$Lifetime$ – Economic lifetime of the unit
$CAPEX$ – Capital expenditure

However, having a finite time horizon (of ten years) and considering the annuity for new build units forces the model to build generators with low build costs even if their marginal generation costs are high because the average generation cost between build years and the end of the planning horizon – including build costs – will be lower for such generators. To resolve this, we assume that the last year of the planning horizon is repeated an infinite number of times while the annuity is considered in the objective function but only for the economic lifetime of generation units. Table 12 shows the discount factor applied to each year of a ten-year planning horizon assuming a discount rate of $r\%$, and showing the perpetuity applied to the final year.

Table 12: Discount factor applied to each year of a ten-year planning horizon with perpetuity assumption in the final year

Year	Formula
1	$1/(1+r)^{(1-1)}$
2	$1/(1+r)^{(2-1)}$
3	$1/(1+r)^{(3-1)}$
4	$1/(1+r)^{(4-1)}$
5	$1/(1+r)^{(5-1)}$
6	$1/(1+r)^{(6-1)}$
7	$1/(1+r)^{(7-1)}$
8	$1/(1+r)^{(8-1)}$
9	$1/(1+r)^{(9-1)}$
10	$1/(1+r)^{(10-1)} + (\frac{1}{(1+r)}^{(10-1)})/r$

In the above basic formulation, perpetuity – i.e. an implicitly infinite horizon – is assumed despite the fact that the EVA model has a finite horizon. In this way, the objective function is expanded by the yearly costs – including the annualised build costs – after the final year of the horizon.

10.6 Weather scenario selection and reduction

Uncertainty is integrated into the multi-year model through the introduction of weather scenarios (WSs), presenting three possible evolutions of climate and twelve weather conditions in each of these climatic evolutions, hence resulting in a total of 36 WSs[18]. Given a collection of WSs, the EVA model finds the optimal solution using a stochastic approach. This means that the optimal

[18] More details in Annex 1 – Section 3

entry/exit decision of resource capacities – making up the $Fixed\ cost$ – is made by considering several possibilities of operational conditions, i.e. a set of weather scenarios WSs with their related possibilities ω_{WS} as follows:

$$Total\ cost_y = Fixed\ cost_y + \sum_{WS} \omega_{WS}[Operational\ cost_{y,WS}]$$

However, as formulated in Section 10.5, the EVA – especially when adopting the overall cost-stochastic modelling approach used in ERAA 2024 – is a complex and computationally-demanding exercise. Therefore, it is necessary to reduce the number of WSs introduced. Due to this fact and to limit the number and duration of simulations, a direct approach is taken by solving the EVA model over a reduced number of WSs.

The reduction of the set of WSs is based on statistical properties. It was opted to reduce their number through an optimisation process aiming at minimising the distribution difference in revenues of thermal units between the full set of WSs and the selected subset, based on pre-EVA economic dispatch (ED) results. This analysis is performed once *ex-ante* of EVA simulations, and selected WSs do not change during the protocol. The selection of WSs is performed on TY 2030 only.

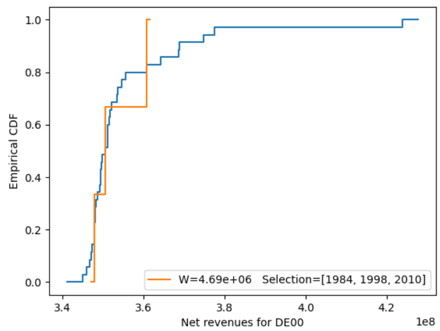
For a selected technology in a selected study zone, we define proxy revenues as the revenues that a perfectly dispatchable technology with variable production cost $SRMC$ would make, with λ_h hourly prices:

$$R_{proxy,tech,BZ} = \sum_h \max(\lambda_{h,BZ} - SRMC_{tech}, 0)$$

We then aim to minimise the Wasserstein distance between the revenue proxy distribution for each technology and study zone. For a single distribution, the Wasserstein distance can be understood as the difference between the *empirical cumulative distribution functions* (eCDFs). For a full set S and subset S_k, this distance can be understood as the area between the two curves:

$$W(S, S_k) = \int |eCDF(S) - eCDF(S_k)|$$

$eCDF(S)$ $eCDF(S_k)$



Each technology can be evaluated separately, although the selection must consider the relative importance of each study zone in terms of it economic impact on Europe. Hence, within the selection we use weights based on the residual load of each study zone, as the residual load is a first-order driver for economic indicators, and that reflects climate impact.

$$LW_{BZ} = \frac{Residual\ Load_{BZ}}{\sum_{i \in all\ BZ} Residual\ Load_i}$$

The selection starts by selecting an array of candidates of subsets S_k. In ERAA 2024, the size of the candidate subsets is set to three in order to limit computation time in the EVA model. Since this results in only $\binom{36}{3} = 7{,}140$ size 3 candidates, all of them can be tested.

The best candidate subset is the one minimising the total score as follows:

$$S^* = \min_{S_k} \sum_{BZ} LW_{BZ} \sum_{tech} W_{tech,BZ}(S, S_k)$$

To improve the representativeness of the selected subset of WSs with regard to post-EVA economic dispatch (ED) results, weights are computed for each of the selected WSs based on revenues for thermal units extracted from post-EVA economic dispatch (ED) simulations. For the computation, the weighted sum of revenues of the selected subset of WSs is set to be equal to the arithmetic mean of the full set of WSs. The computation of weights is performed on TY 2035 only.

10.7 Unit aggregation

To reduce the size of the EVA model, generators are aggregated according to their main characteristics of node, technology, fuel and techno-economic parameters. This simplification is possible because (i) a uniform derating of NGCs in the EVA model based on FORs is considered instead of random draws of outage patterns, and (ii) the EVA model is solved in a linearised manner.

As adequacy models use unit-by-unit data, it is necessary to post-process the aggregated EVA outcomes to increase the granularity. For this purpose, a uniform derating approach is applied in which the capacity of all units belonging to the same technology is derated homogeneously and proportionally to their installed capacity in the adequacy model according to the EVA results.

This linear derating approach guarantees the best matching between EVA and adequacy models (i.e. it preserves maintenance patterns across models), and it avoids arbitrary decisions regarding which units are decommissioned. Although units would not be partially decommissioned in the real world, the goal of the EVA is not to determine which units are decommissioned but rather the overall capacity viable per technology in each study zone.

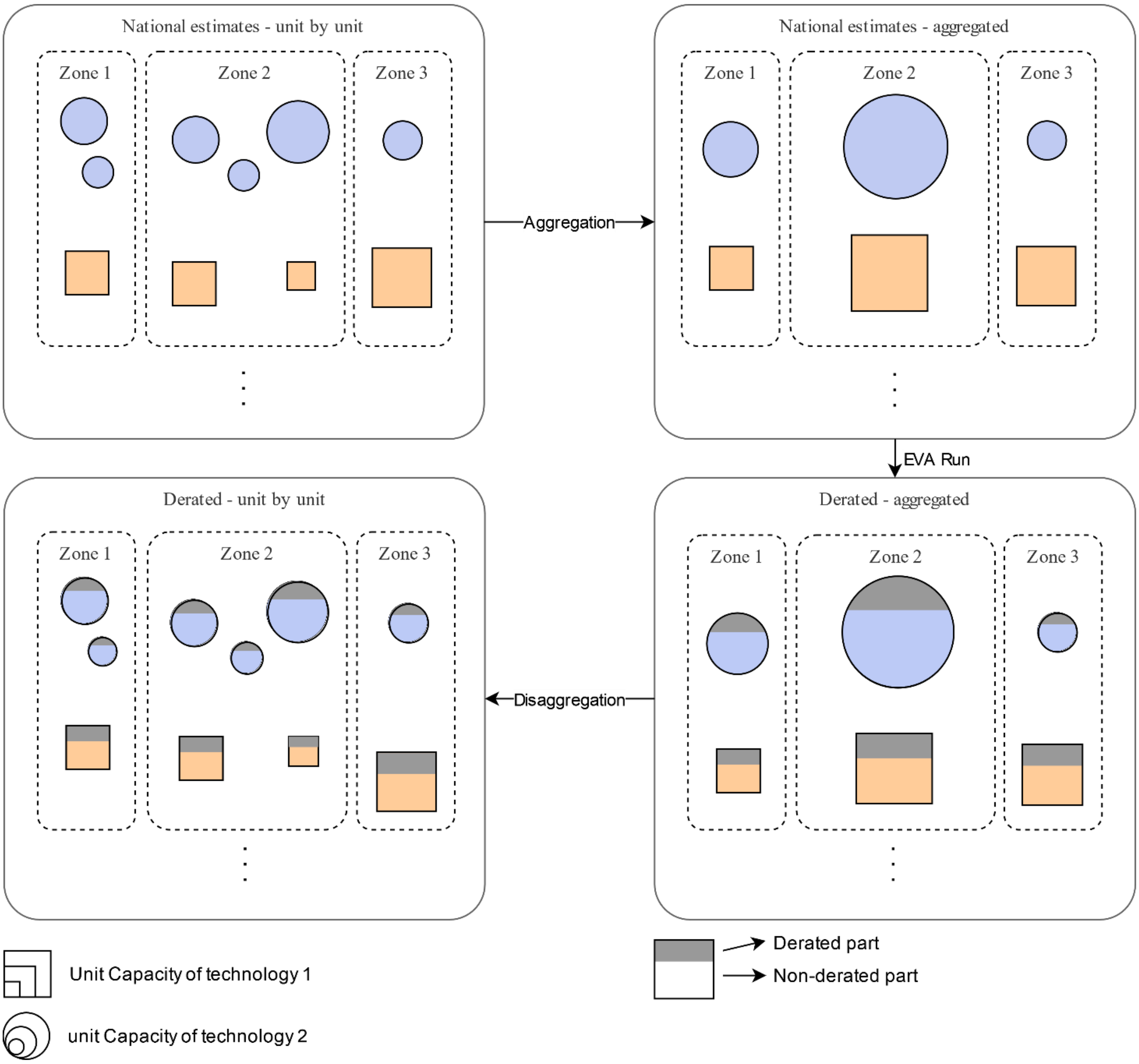


Figure 15: EVA unit aggregation process

10.8 Maintenance profiles

The maintenance modelling of existing thermal units is simplified compared to the adequacy step by derating the available capacity of the units to reduce computational complexity. The derating of existing thermal units is based on the maintenance patterns calculated for the adequacy step. The derating is applied to the aggregated units following the same logic as explained in Section 10.6.

For expansion and life extension candidates, a maintenance rate is applied as a derating factor of the generation capacity of some generation technologies. The derating factor is inversely proportional to the load profile in a given region to make more generation capacity available during times of higher load, and vice versa.

10.9 Modelling of forced outages

The methodology to compute FOs for generating units has been improved compared to previous ERAA cycles. Instead of a simple arithmetic, average a representative outage pattern is applied in the EVA model. For this purpose, ED simulations are performed for each target year at the unit level before units are aggregated into the EVA, as shown in Figure 15. During this process, a representative outage pattern selection is performed. This allows the simulation tool to generate a mathematical model with multiple random forced outage profiles. Out of these profiles, the tool selects one that is most similar to others, making it a representative outage pattern. In this iteration of ERAA, a set of fifteen outage samples was generated, which was then reduced to a single representative sample.

After the ED run the availabilities of all units (non-profile based thermal units that are set to have a forced outage rate during the data collection) are converted into the corresponding EVA aggregated units, which essentially creates derating profiles based on a representative forced outage pattern. The result is a more realistic and accurate derating curve for the units compared to the simple arithmetic average used in previous ERAA publications. This method produces a plausible set of profiles that more accurately represent the Fos of power plants. Additionally, this approach ensures greater consistency between the ED and EVA ERAA modules.

As for NTCs, a derating equal to the line specific forced outage rate (FOR) is applied in the EVA model to account for forced outages. For borders where FB modelling applies, no additional FOs are taken into account since outages are already implicitly considered in FB domains.

10.10 Price cap evolution

The value of the price cap holds first-order of importance when assessing the energy market viability of resource capacities. Price caps exist in markets mainly for technical reasons, in the interests of consumer protection and to prevent of potential anti-competitive practices. The current maximum clearing price of the DA market is 4,000 €/MWh. According to ACER's decision 2023/01[19], in the event that the clearing price exceeds 70% of the harmonised maximum clearing price for single day-ahead coupling (SDAC) during at least two days within each rolling 30-day period, the latter shall be increased by 500 €/MWh the next day. However, if a transition period of 28 days is defined before the increase is applied for, this shall be applied in all relevant study zones 28 days later. During this period, no further price adjustments can be initiated.

The dynamic increase of market price caps described above cannot be modelled endogenously within the available market modelling tools used in ERAA 2024. Therefore, the yearly evolution of the DA price cap for all the TYs was estimated in a simplified manner, comprising the following steps:

[19] ACER Decision 01-2023 on HMMCP SDAC - Annex 1.pdf (entsoe.eu):
https://www.acer.europa.eu/Individual%20Decisions/ACER%20Decision%2001-2023%20on%20HMMCP%20SDAC.pdf

(i) Building a set of ten WSs representing the horizon from 2026 until 2035 (i.e. 26 WS sets) using the available historical data from 1982 to 2016 (35 years) across 20 FO patterns (i.e. 26 × 20 = 520 multi-year scenarios).

(ii) Extracting hourly marginal prices for all Monte-Carlo samples and all study zones from the ERAA 2023 ED results for 2026.

(iii) Considering a starting price cap of 4000 €/MWh on 1 January 2024 and mimicking a dynamic price cap increase, applying ACER's rule based on the hourly marginal prices.

(iv) Computing a mean price cap value for each year of the study horizon.

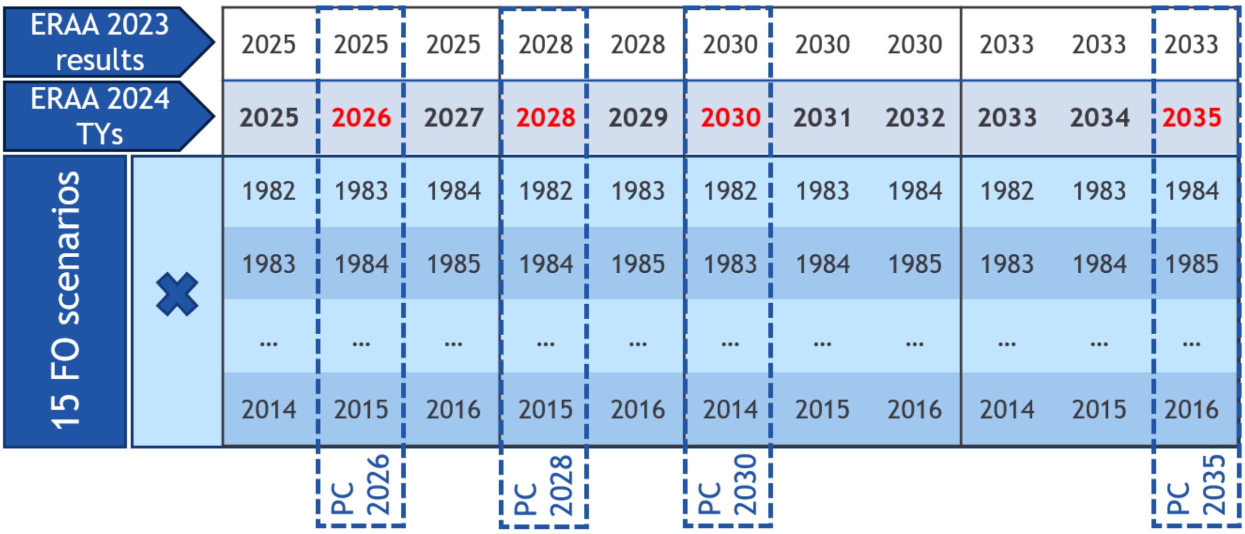


Figure 16: Ten-year scenarios considered for estimating the price cap evolution from 2025 until 2035

These new price caps are then set as fixed input values for EVA and adequacy simulations.

10.11 Investor risk aversion

Following the ERAA methodology, the EVA shall aim to replicate the decision-making process followed by investors and market players. Investors generally show a certain level of risk aversion regarding 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 of the revenue projections, as well as the policy and scenario landscape which might affect the return on investment – are intrinsic conditions of investment risk in the electricity market. The ERAA approach relies on a theoretical and academic framework for investor behaviour[20], merging concepts from utility and prospect Theory. The rationale behind this approach is to overcome the limitations of a pure traditional capital asset pricing model (CAPM), which is not suitable alone considering the non-normal distribution of returns and downside risk stemming from the non-normality of the revenue (and price) distribution, in addition to the model and policy risk. All such elements cannot be properly captured using a pure weighted average cost of capital (WACC) "base" model. The approach prescribes a transparent increase of the WACC (compliant with Article 6.9.iii.a of the ERAA

[20] Source: https://www.elia.be/-/media/project/elia/elia-site/public-consultations/2020/20201030_200_report_professorboudt.pdf

methodology) using a "hurdle premium" which is specific to the technology and economic lifetime of the assets and within different scenarios (Figure 17).

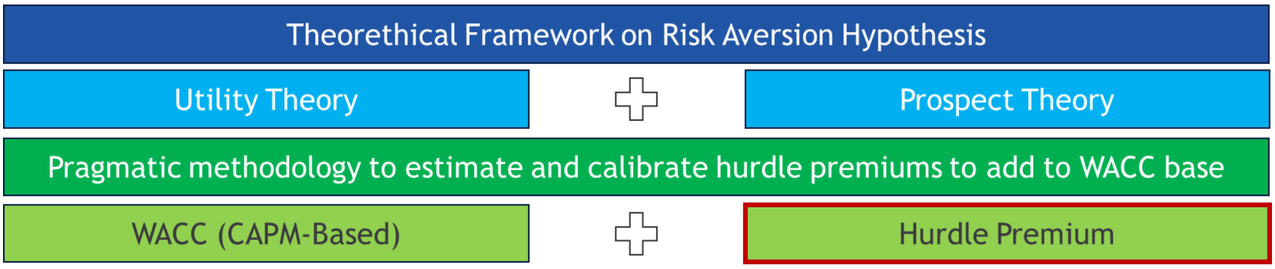


Figure 17 Theoretical framework on risk aversion hypothesis

Hurdle premiums are set according to the deviation of actual returns from expected returns over a significant number of possible investment paths. The level and range of hurled premiums primarily depend on two key drivers and how such risk drivers affect the specific technology:

1. The revenue distribution and the downside risk (under the simulation setup):
   - High price and revenue volatility in the distribution call for higher hurdle premium,
   - Intrinsically linked to the technology type and the merit order, e.g. higher for peak units compared to base load generators.
2. Additional risks such as model risk and policy risk:
   - Difficult to capture real investor behavior within the limited modelling framework and ruling assumptions.

These premiums are further calibrated, assessing the return impact of alternative scenarios considering standard $CAPEX$ and FOM costs but different levels of system adequacy, fuel prices, CO_2 prices, etc. While the hurdle premiums used have been calibrated on the Belgian electricity market[21], such values can be extrapolated to other markets, if (i) the model and policy risk are applicable and consistent, and (ii) the distribution and downside risk are similar. Given that both conditions are valid in the ERAA modelling framework, such a calibration of hurdle premiums provides a robust yet pragmatic approach for considering risk aversion in the EVA.

The implementation in the EVA works by leveraging specific "hurdle rates" per technology (and country where applicable), defined as:

$$HurdleRate = WACC + \ HurdlePremium$$

The hurdle rate is then used to calculate the annuity of $CAPEX$, as follows:

$$Annuity = CAPEX \times \frac{HurdleRate}{1 - (\frac{1}{1 + HurdleRate})^{Lifetime}}$$

The hurdle rate also adjusts the FOM of existing units. As the FOM (noted FOM^* in the equation) is a yearly cost, the annuity of FOM (noted FOM in Appendix 1) is calculated assuming a one-year lifetime.

[21] Source: [Boudt K., 2022, Analysis of hurdle rates for Belgian electricity capacity adequacy and flexibility analysis over the period 2024-2034]

$$FOM^{*} = FOM \times (1 + HurdleRate))$$

To summarise, under this framework, the investment in new capacity (or existing capacity) is economically viable when the expected return exceeds the hurdle rate assigned to such capacity, which is set equal to the cost of capital of a reference investor plus a hurdle premium. The latter serves as a cushion to compensate for the deviation of the “asset cost of capital” from the reference investor’s cost of capital based on the predicted project risk under the base scenario, and the model and policy risk related to the scenario ED outcomes within the probabilistic Monte Carlo assessment (e.g. non-normal revenue distribution and model risk) and the uncertainty on the evolution of the scenario landscape assumptions over the different TYs considered (e.g. policy risk).

The results under the base scenario of ERAA strongly depend on the assumptions that define the very central scenario (e.g. commodity prices, CONE values, weather scenarios, policy targets). Beyond the projected revenue distributions obtained from the simulations, investors would likely also consider alternative scenarios. These uncertainties can be only partially covered by means of the hurdle premium calibration, which is based on a pre-defined combination of quantitative and qualitative conclusions.

As an example, the expected returns of investors are likely to be a combination of returns of various adverse or favourable scenarios considered. The risk profile or “appetite” of each investor determines the “weight” that such investor attributes to adverse scenarios as compared to the base or favourable scenarios. The more negative the effect of a plausible adverse scenario, the higher the hurdle rate [21].

Since the expected return calculation used in the EVA of the ERAA is limited to the boundaries of using a single reference scenario, we shall reflect on the uncertainties that might or might not be captured through the hurdle premium calibration. Therefore, a periodical review and updates of the hurdle rates considered is recommended. Nevertheless, it becomes apparent that not all plausible risks relevant for investor decisions can be fully captured via the hurdle premium approach and its calibration, and thus additional and complementary risk aversion approaches – such as the ones presented in the ERAA methodology – shall be investigated in conjunction.

10.12 Centralised approach for estimating explicit DSR potential

As introduced in Annex 1, Section 6.5, a stepwise approach is used to determine the additional explicit DSR potential beyond the ‘National Trends’ assumptions depending on available country data. If no DSR potential is available from a published official VoLL/CONE study or national study for DSR reported by the TSO, a centralised bottom-up approach is used by ENTSO-E to determine any additional explicit DSR potential. Figure 18 illustrates the approach used.

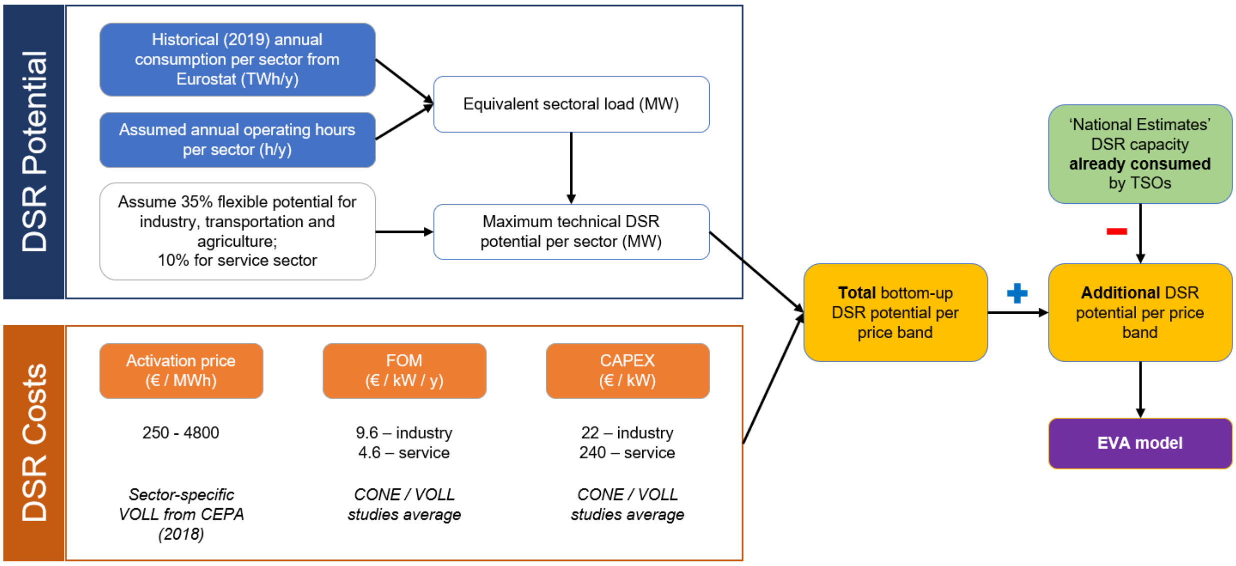


Figure 18: Overview of the explicit DSR potential estimation methodology

The maximum technical DSR potential (per industrial sector[22] per country) is estimated based on:

- annual sector electricity consumption from 2021 from Eurostat;
- assumed 8,760 operating hours per year (i.e. baseload);
- assumption on the flexible industrial, transportation and agriculture load (35%)[23];
- assumption on the flexible service sector load (10%); and
- no minimum threshold on the capacity of DSR from a given industry sector is applied to avoid the risk that the approach overlooks additional DSR capacity in smaller countries.

The potentials are combined with assumed cost parameters, based on the following sources:

- sector-specific VOLL values from CEPA (2018) as a proxy for the activation price[24];
- FOM value derived from the available VoLL/CONE studies, whereby an average is made across the VoLL/CONE studies where DSR is a reference technology and used as a single value for DSR potential; and
- CAPEX value, following the same approach as for the FOM.

To prevent the double-counting of DSR capacity, the DSR capacity accounted for in the 'National Trends' scenario is subtracted from the maximum technical DSR potential for each country.

This simplified bottom-up approach is necessary given the lack of high-quality consistent EU-wide datasets for DSR. However, due to the stepwise approach applied this year, this fallback is applied to a few countries across Europe. Twenty-nine study zones have DSR potential, eleven of which have national studies or TSO-estimated DSR potential and six have a VoLL/CONE study. As more

[22] Residential DSR is not consider in the centralised approach.
[23] Due to limited data on the flexible share in the literature, this assumption was set in ERAA 2023 by adjusting the flexible share until the total DSR potentials approximately matched the estimated potentials from available national studies. As a sanity check of this 35% assumption, the calculated total DSR potential per country as a share of peak demand fell in the range of 10% – 20%, comparable with other studies.
[24] CEPA (2018), Study on the estimation of the value of lost load of electricity supply in Europe

VoLL/CONE and national DSR studies become available, ENTSO-E will endeavour to use these in future years for the ERAA and to improve the modelling of DSR.

11 Adequacy assessment methodology

The objective of the ERAA adequacy study is to calculate the risk of security of supply of the post-EVA scenarios by calculating LOLE and EENS metrics (see Section 11.2 for the mathematical expression). A modern adequacy assessment accounts for uncertain variables in the system and offers a probabilistic indicator of the adequacy situation under several plausible realisations of the uncertain system variables. The state-of-the-art methodology in adequacy studies is the so-called Monte Carlo (MC) simulation approach. To avoid any confusion, the MC approach is not applied in the EVA step.

11.1 Monte Carlo adequacy assessment

The MC simulation applied comprises a large number of scenarios, featuring different asset FO realisations/draws for each given TY and WS. More specifically, these FOs occur for the thermal generation and transmission assets (HVDC and HVAC interconnections), and their impact on the installed capacities are known during the UCED step (see Section 11.5). The combination of random outages and climate scenarios results in a large set of possible system states to be modelled for each TY. The results can then be assessed probabilistically, which is well-suited for the modern volatile power systems. The detailed process is described below.

The process starts by defining the climate scenarios, representing consistent historical WSs. WSs from 1982 to 2016 are selected one-by-one (*N* WSs). Each WS 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); and
- climate-dependent time series for other RES and other non-RES generation.

Note that the aforementioned WS 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 WS (*M* forced outage samples per WS, where the quantity *M* is only known after model convergence is reached). FO realisations do not affect the planned maintenance schedules (more details on the convergence can be found in Section 11.6).

Each model run is executed for one WS and one random forced outage realisation, referred to as an MC year. The combination of *N* WSs and *M* FO realisations per WS results in a total of $N \times M$ model runs. Each model run is optimised individually. Figure 19 illustrates the MC approach described for each TY studied.

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

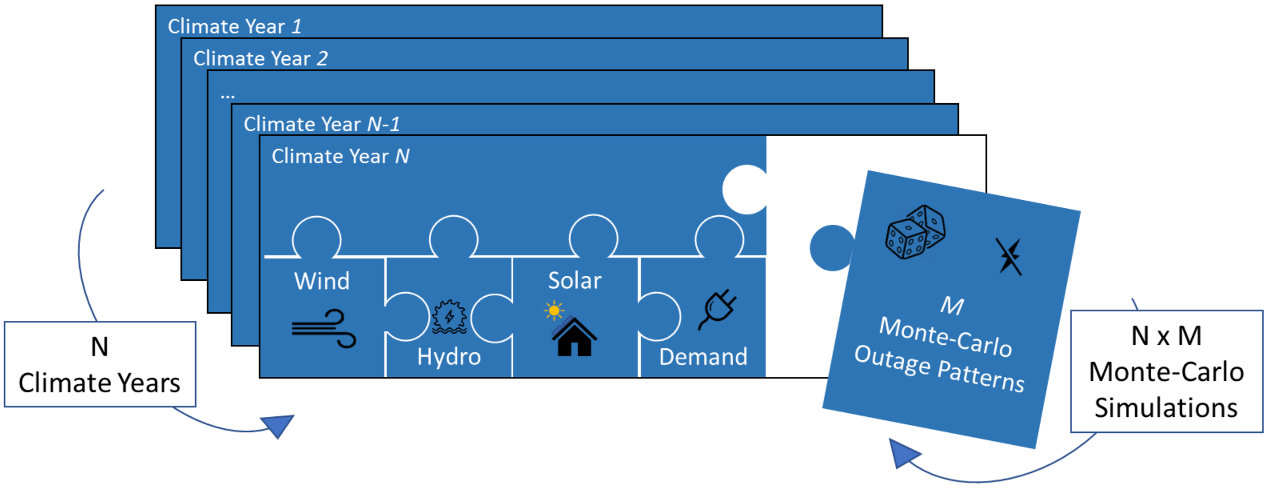


Figure 19: Monte Carlo simulation principles for a given target year

11.2 Adequacy indicators

In probabilistic adequacy studies, the typical indicators for resource adequacy are either the expectation of indicators (e.g. the EENS) or a percentile of the independent indicator values (e.g. 95th percentile of the ENS values). The following indices are used to assess the adequacy levels for a given geographical scope and 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. This 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. WSs and/or FO realisations. LOLE can be calculated as the mathematical average of the respective LLD over the considered model runs, according to Eq. (1), in which J is the total number of considered model runs and LLD_j is the LLD of model run j:

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

- **ENS [GWh]:** The sum of the electricity demand that 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 that 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. (2), n which J is the total number of considered model runs, and ENS_j is the energy not served of model run j:

$$EENS = \frac{1}{J}\sum_{j=1}^{J} ENS_j \qquad (2)$$

Note that the final adequacy indicators in ERAA 2024 reflect the impact of the curtailment sharing implementation in the adequacy assessment, as described in Section 11.7.

11.3 Maintenance for market entries

As described in Section 10.8, maintenance profiles for thermal units references in the 'National Trends' scenario data are the output of a pre-optimisation step. For units entering the market as a result of the EVA step in the respective TY (de-mothballed, life extended, or new build units), no maintenance (planned) is considered as it is assumed that it will occur during times of oversupply and thus not significantly affect reliability standards. Nevertheless, these units are subject to FOs, as described in the following Section 11.4.

11.4 Forced outage profiles

The following parameters are provided by TSOs to describe the outage behaviour:

- 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 fundamental parameters for computing FO profiles. 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 interconnection capacity) that they can put out of service. FORs are expressed as a single percentage for each generation unit or interconnector and provided for individual TYs, reflecting power plant or interconnection upgrades or renewals.

FORs are on a unit-by-unit granularity for thermal units and depend on the technology and characteristics. In the absence of FORs provided by TSOs, a default representative value based on the given technology is used. A similar mechanism is applied to interconnections: for some interconnections, input data already explicitly consider outages, while in other cases random outages on interconnectors are drawn per pole based on FORs (i.e. at borders with multiple poles, an outage of one pole does not reduce the NTC to zero).

FO profiles are generated randomly within each modelling tool for each stochastic element in the simulation, namely resource units and interconnection lines. Based on the parameters mentioned above, FO profiles are drawn describing the hourly availability of each stochastic element of the system. They can have a significant impact on resource adequacy due to their uncertain nature. Therefore, it is important to draw a sufficient number of possible outage realisations to assess the impact on adequacy in expectation.

11.5 Unit commitment and economic dispatch

The unit commitment problem aims to discover an optimal combination of on/off decisions for all generating units across a given horizon. The on/off decisions must imply both a feasible solution and an optimal solution regarding the total system cost, including the cost of start-up and shutdown. The ED refers to optimising generator dispatch levels for the given unit commitment solution. The UC and ED are co-optimised such that the combined costs are minimised.

More specifically, 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 (being the main components of the costs: the fuel price, emission price and VO&M) under the constraint that electricity consumption must be fulfilled. In the first step, an annual optimisation for the TY is undertaken to account for intertemporal constraints that might span the whole year. Multiple hours are aggregated and optimised in blocks to deal with the large optimisation problem in a reasonable computation time. The constraints that apply to the unit commitment problem are mainly derating, annual maximum operating hours, start cost, must-run conditions (run-up rate or start profile, and run-down rate or shutdown profile), and energy limits (e.g. end-of-year reservoir targets and upper and lower weekly reservoir limits). This latter constraint (energy limits) includes optimising available hydro resources, as described in Section 6.1. The optimised maintenance schedule for thermal units computed as described in Section 10.8 is anticipated and considered by the pre-optimisation.

The outcome of the hydro optimisation step comprises 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/finer time steps (e.g. one day) to determine which units are dispatched for each hour of the optimisation horizon (TY) in addition to the respective dispatch level for each unit. For the optimisation, a given TY is divided into several UCED optimisation time steps/horizons. For each resulting UCED, the problem is optimised based on the hourly system state (demand, RES feed-in, available thermal generation, NTC / FB constraints). 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 might yield different results, likewise, dividing a TY into a different set of UCED problems. The entire UCED optimisation process is visualised in Figure 20.

Process for all TY

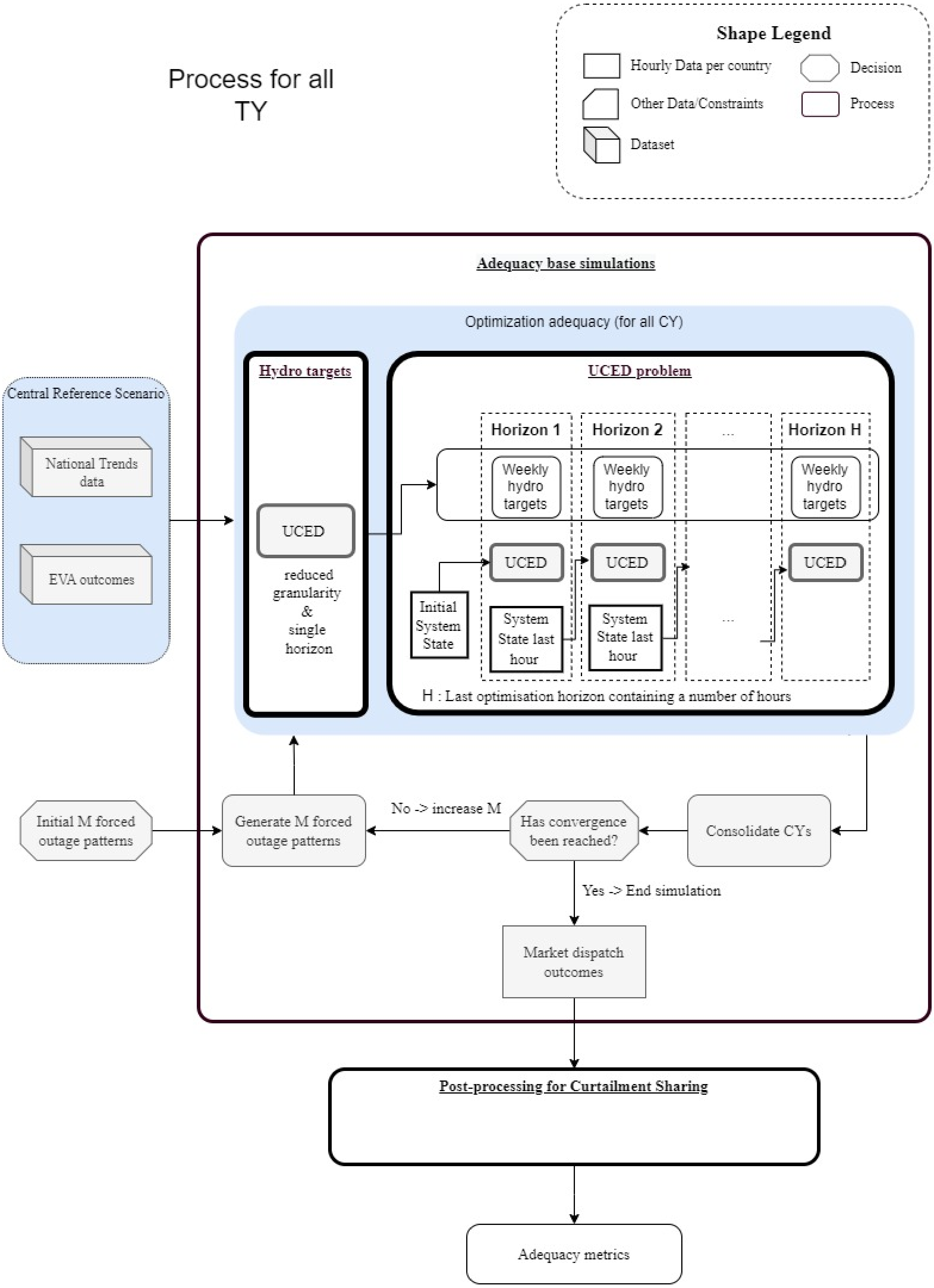


Figure 20: UCED problem

The UCED optimisation problem solver employs flexible hydro storage resources such as reservoirs and PSPs to exploit marginal price gain opportunities from a cost minimisation perspective. The exogenously provided generation constraints and reservoir level trajectories are accounted for by the solver. Final marginal prices are a direct result of the hourly optimisation of hydro storages and 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[25] 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 storage injection occurs in times of low capacity margins (high electricity prices), whereas storage offtake occurs in times with high capacity margins.

In a system with a high degree of flexibility (i.e. implicit DSR technologies, battery storage systems, hydro storage), the storage dispatch in scarcity periods can affect adequacy indicators[26]. It is therefore necessary to properly account for storage operation strategies in scarcity periods, in particular to avoid an arbitrary temporal distribution of ENS. In this study, a modelling approach minimizing the peak residual load has been applied. It is an integral element of this methodology that the total ENS volume and thus the system costs are not increased by the homogenized temporal ENS distribution.

11.6 Monte Carlo convergence

FO realisations might affect model results depending on the specific demand and supply situation assumed in the given MC year. For example, a major power plant experiencing an FO might 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. Therefore, model run results might significantly differ. Figure 21 illustrates this aspect, showing a schematic histogram of the ENS over 525 MC realisations.

[25] Demand minus supply from non-dispatchable generation resources (e.g. wind and PV).
[26] Gonzato, S.; Bruninx, K. Delarue, E.: The effect of short term storage operation on resource adequacy.

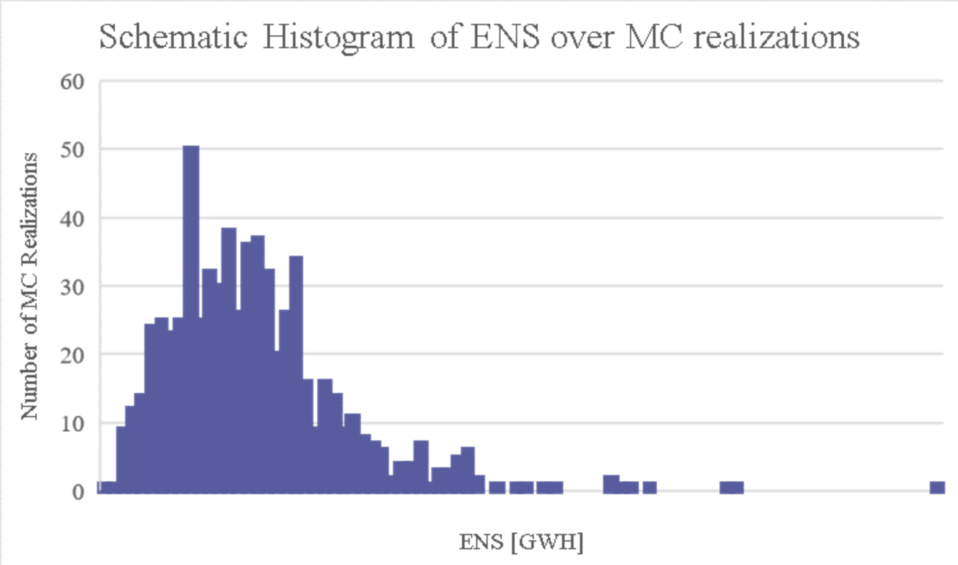


Figure 21: Schematic histogram of the ENS over 525 MC realisations.

Note: Each histogram bin covers a range of 5 GWh ENS and contains the number of MC realisations that 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 ERAA 2024, the convergence of the adequacy results is calculated in several steps. Following a set of model runs, the models' convergence is assessed and – in the event that the convergence is not reached – additional simulations using new FO realisations are launched, increasing *M*.

The convergence of the 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. $\mathrm{Var}[EENS] = \frac{\mathrm{Var}[ENS]}{N}$).

The left side of Figure 22 provides an example of the evolution and 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 that no significant changes in averaged results are expected and thus no additional MC realisations are needed to improve the results. No explicit simulation stopping criterium is set for α. The decision 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 3 offers an insight into the coefficient of variation and its relative change versus the increasing number of MC simulations for the different ERAA 2024 scenarios.

The right side of Figure 22 provides an example of the evolution and the relative change of the coefficient of variation of an MC model as a function of the number of MC realisations. No significant changes occur past a certain number of MC realisations, meaning that no significant changes in averaged results are expected and thus no additional MC realisations are needed to improve the results.

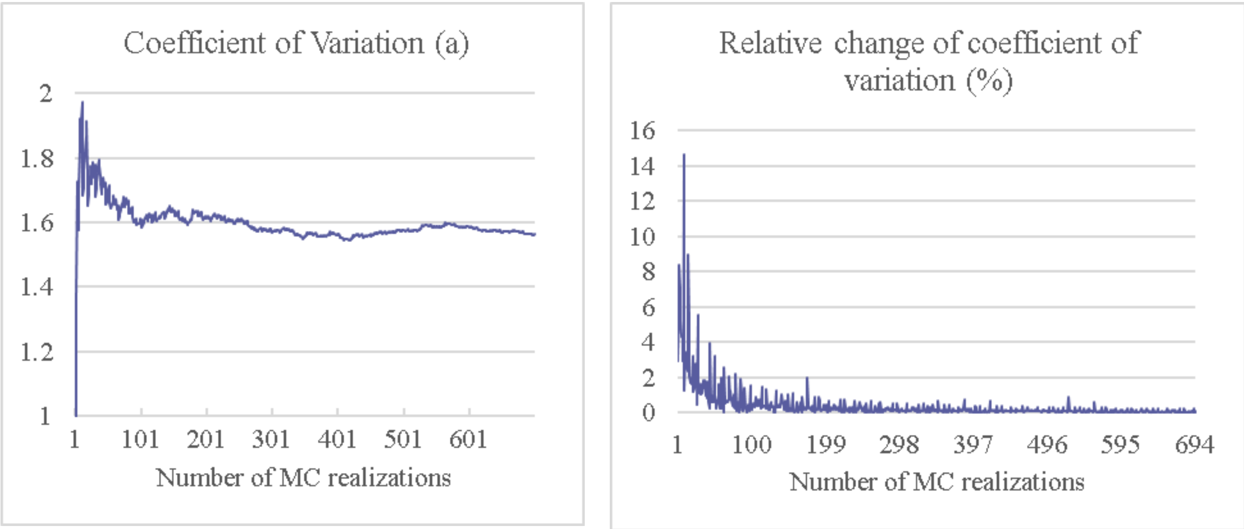


Figure 22: Example of α evolution and its relative change with an increasing number of MC samples for a converging model

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

- Hydro power modelling
- Commercial exchanges between countries
- The use/absence of extreme, yet realistic, historical WSs
- Outages and their modelling, including both maintenance and FOs[27]
- The number of units with outages in a country (more units lead to faster convergence)

11.7 Local matching and curtailment sharing

Local matching (LM) and curtailment sharing are implemented in the adequacy models in ERAA 2024 as described in the EUPHEMIA algorithm (PCR Market Coupling Algorithm). The curtailment rules are used in the operational FB market coupling algorithm to mitigate the effect of flow factor competition. These rules intervene when one or more countries experiences scarcity, i.e. there is ENS in the system. The solution implemented in EUPHEMIA within FBMC follows the curtailment sharing principles that already existed under the NTC. Two different rules are introduced, namely curtailment minimisation and curtailment sharing. Their main function involves minimising the ENS and equalising the curtailment ratios between the different study zones as much as possible. Moving away from the optimal solution – which is solely the minimisation of ENS towards a solidarity solution of ENS distribution – will result in a sub-optimal solution from the total welfare perspective.

[27] 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.

The curtailment rules (curtailment sharing and curtailment minimisation) explained below follow the market behaviour expected in (simultaneous) scarcity situations. In the ERAA, the 'curtailment of ^price-taking orders of demand' is referred to as a shortage or ENS.

11.7.1 Flow factor competition

If two possible market transactions generate the same welfare, the one with the lowest impact on the scarce transmission capacity will be selected first within FBMC. This also means that some buy (demand) bids with higher prices than other buy (demand) bids located in other study zones might not be selected within the FB allocation to optimise the use of the grid and to maximise the total market welfare. This is a well-known and intrinsic property of FB referred to as 'flow factor competition'.

Under normal FBMC circumstances, 'flow factor competition' is accepted as it leads to maximal overall welfare. However, for the special case where the situation is exceptionally stressed – e.g. due to scarcity in one or several study zones – 'flow factor competition' could lead to a situation where order curtailment takes place non-intuitively or non-fairly. For example, this could mean that some buyers (order in the market) that are ready to pay any price to import energy would be rejected whereas lower buy bids in other study areas are selected instead due to 'flow factor competition'. These 'pay any-price' orders are also referred to as 'price taking orders' (PTOs), which are valued at the market price cap in the market coupling.

Two situations tend to occur due to the implementation of the FBMC constraints:

1. ENS can be created for net exporting countries to find the lowest ENS for the FB area as a whole; and
2. countries with low 'flow-factors' are penalised with ENS to the benefit of countries with high 'flow factors', even if all these countries are simultaneously at the maximum market price cap.

Curtailment rules are introduced to correct market simulation results after implementing the FBMC constraints.

11.7.2 Local matching

Local Matching is achieved in EUPHEMIA through the LM constraint. EUPHEMIA enforces the LM of price-taking (buy) hourly orders with hourly orders from the opposite sense (sell) in the same study zone as a counterpart. That means that local PTOs are prioritized and matched with local supply, whenever the curtailment of PTOs can be avoided locally on an hourly basis.

In the ERAA, the LM constraint is implemented following two different rules:

1. Each study zone is allowed to export only the share of generation capacity exceeding its internal demand, hence, preventing net exporters study zones from having ENS.
2. Net importing countries should primarily use internal resources to cover internal demand, avoiding exports to countries driven by better flow factor competition.

The LM constraint should be enforced for all study zones in the welfare maximisation problem.

11.7.3 Curtailment sharing

To address the issues of 'flow factor competition' concerning PTOs, EUPHEMIA implements the curtailment sharing principle. Curtailment sharing aims to equalise the curtailment ratios between those study areas that are simultaneously in a curtailment situation and those that are configured to share curtailment as much as possible. In other words, curtailment sharing aims to 'fairly' distribute the curtailment (rejection of PTOs) across the involved market zones by equalising the curtailment ratios of each zone, defined as curtailed PTOs divided by the total volume of local PTOs.

11.7.4 Implementation in ERAA

To ensure that the implementation of curtailment sharing does not affect the adequacy results in terms of system ENS occurrences (hours with at least one study zone experiencing ENS), curtailment sharing is implemented as an integrated post-processing mechanism. Therefore, we perform the adequacy run and the post-processing run.

Economic dispatch run

The LM constraint is implemented in the economic dispatch run as a conditional constraint. The condition of activation is the surplus of generation in a study zone compared to the demand of the study zone for a specific hour. In addition to the LM constraint, a flow-factor competition (FFC) constraint is implemented in the economic dispatch run to ensure that the unserved energy for a specific country does not exceed the allowed unserved energy defined by the so called 'domestic energy not served' (DENS), i.e. the difference between domestic load and generation, due to FBMC.

<u>Local matching constraint:</u>

Mathematically, the condition is written as:

$$If\ NetPosition_{Region} - ENS_{Region}\ \geq 0\ or \sum Line_{Flows} - ENS\ \geq 0$$

Mathematically, the constraint is written as:

$$NetPosition_{Region} + Load_{Region} - Generation_{Region} \leq 0\ or \sum Line_{Flows} + Load_{Region} - Generation_{Region} \leq 0$$

<u>Flow-factor competition conditional constraint:</u>

Mathematically, the condition is written as:

$$If\ NetPosition_{Region} - ENS_{Region} < 0\ or \sum Line_{Flows} - ENS\ < 0$$

Mathematically, the constraint is written as:

$$NetPosition_{Region} \leq 0 \; or \; \sum Line_{Flows} \leq 0$$

Post-processing

The post-processing run is designed to take the solution of the economic dispatch run and ensure the equalization and minimisation of curtailment ratios (CS distribution) while ensuring that all grid constraints and local matching are respected.

The LM and FFC constraints in the post-processing run are based on the domestic energy not served (DENS) inherited from the economic dispatch run. The DENS can be simply defined as: demand-generation. Therefore, the LM is active if the DENS ≤ 0 and the FFC constraint will ensure that ENS ≤ DENS.

In order to share the ENS within the different study zones, a penalty involving a quadratic function is added to the objective function.

The quadratic function is defined similarly to EUPHEMIA as: **PTO volume * (rejected PTO ratio) ^{2}**

In the context of ERAA, the proxy for the PTO volume equals to the DENS. Hence, the curtailment ratio or PTO ratio equals to ENS/DENS.

The penalty grows more quickly with increased curtailment, and hence equilibrium can be expected where curtailment ratios are equalized, while perfect equalization of curtailment is limited due to the existing grid constraints.

12 Databases and tools used for the ERAA

The ERAA methodology uses data collected from TSOs, generated by internal tools using TSO assumptions/data and solutions co-developed with other entities. The following sections describe the databases and tools used in the ERAA assessment. These databases are commonly used with other ENTSO-E assessments such as the Ten-Year Network Development Plan (TYNDP), Seasonal Outlook, etc.

12.1 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 in addition to the derating of thermal units.

12.2 Demand forecasting toolbox

ENTSO-E centrally creates hourly demand profiles for most European countries using a temperature regression and load projection model incorporating uncertainty analysis under various climate conditions. The Demand Forecasting Toolbox (DFT) comes in a software application developed by an external provider (Sia Partners). It is important to mention that some TSOs have provided their own demand time series to be used by ENTSO-E, using their own DFT.

12.3 Pan-European Climate database (PECDv4.1)

The Pan-European Climate Database (PECD) is at the core of ENTSO-E prospective studies. Seasonal Outlooks, ERAAs and TYNDPs all require climatic information at high spatial[28] and temporal resolution, to assess the effects of weather variability on the European power system. Other users in the energy sector also use the PECD.

To date, the different versions of the PECD have used climate reanalysis (ERA5 and ERA-interim earlier). Re-analysis can be seen as a kind of optimal interpolation of all existing observations for

[28] high spatial resolution is needed for wind speed and solar radiation, to accurately model the local effects for wind and solar capacity factors, even though the information is then aggregated at PECD zones or study zones level.

a long period, obtained by assimilating these observations in a climate model[29]. However, climate change should be considered when estimating the future potential of variable renewable resources, such as wind, solar, and hydro, as well as the impact of temperature on electricity demand. This has only been partially achieved by the statistical de-trending temperature dataset in the historical re-analysis data used in previous ERAAs.

In 2022, ENTSO-E signed a memorandum of understanding (MoU) with the European Center for Medium Range Weather Forecasts (ECMWF), which implements the EU Copernicus Climate Change Service (C3S). C3S has issued a contract led by Inside Climate Service, working with the Danish Technical University (DTU) and Mines ParisTech in which the new versions (4.x) of the PECD are developed. These new versions still include data from the past (referred as the historical period or "historical stream") but now also include information about the future, based on projections from climate models from the CMIP6 exercise[30], referred to as the "projection stream".

The PECD version 4.1 has been used for the ERAA 2024 study. The full dataset – named "Climate and energy related variables from the Pan-European Climate Database derived from reanalysis and climate projections" – is available on the C3S Climate Data Store[31]. The data store contains an interface to download the dataset and a complete documentation of the solution. Meanwhile, exact datasets used in ERAA 2024 can be accessed on ENTSO-E website along the respective study publication.

12.3.1 What does the full PECD4.1 dataset contain?

As mentioned above, PECD4.1 contains historical re-analysis data (data of the historical years), called the historical stream (HIST) and projected data for the future, called the projection stream (PROJ-)

- HIST: Contains 42 weather scenarios, based on 1980-2021 ERA5 re-analysis (PECD4.2 will include data until mid-2024, and then annual updates will be made)
- PROJ: Contains 153 weather scenarios based on 2015-2065 calendar years assessed under one greenhouse gases emission scenario (SSP2-4.5) with three climate models

SSP2-4.5 greenhouse gas emission scenario has been chosen by ENSTO-E, for its alignment with the current emissions. This emission scenario is thereby the most probable for the coming years considering the nations' climate commitments. Nevertheless, the greenhouse gas emission scenario selection is considered not to be essential because the differences between the various emission scenarios are only evident from around 2035-2040, as the climate of the next 10 to 20 years will mainly be determined by the greenhouse gasses already emitted in the atmosphere.

[29] An explanation on what is historical climate reanalysis can be found on C3S youtube channel - https://www.youtube.com/watch?v=FAGobvUGl24&ab_channel=CopernicusECMWF

[30] The 6th Climate Model Intercomparison Project (CMIP6), is the ensemble of climate projections that constitutes the core of the scientific literature exploited in the AR6 Synthesis Report: Climate Change 2023 — IPCC of the Intergovenmental Panel on Climate Change (IPCC)

[31] C3S datastore with PECD 4.1 - https://cds.climate.copernicus.eu/datasets/sis-energy-pecd?tab=overview

The three climate models used in PECD4.1 are CMCC-CM2-SR5 (ECS=3.52°C), EC-Earth3 (ECS=4.30°C) and MPI-ESM1-2-HR (ECS=2.98°C). These were selected by C3S and validated by ET Climate from around twenty climate models available based on following criteria:

- The horizontal and temporal resolution of the models (the finer the better).
- The availability of simulations for all the 4 SSP scenarios (SSP1-2.6, SSP3-7.0 and SSP5-8.5 will be included in the next version PECD4.2 early 2025).
- The structural differences among the models (to avoid choosing models that have common biases or behaviors).
- The equilibrium climate sensitivity (ECS[32]) of the models, which measures the diversity of the models' response to climate change. It indicates the temperature increase after an equilibrium state is reached.

The dataset is composed of weather and energy variables as follows (including their short names), and described in details in the Confluence web page mentioned above:

Table 13: Time resolution for different data types

Climate data	**Energy data**
Hourly resolution	*Hourly resolution*
• 2m air temperature (TA) • Population weighted temperature (TAW) • Wind speed at 10 m (WS10) • Wind speed at 100 m (WS100) • Global surface solar radiation downward (GHI)	• Wind power onshore (WON) • Wind power offshore (WOF) • Solar PV generation (SPV) • Concentrated solar power (CSP)
Daily resolution	*Daily resolution*
• Total precipitation (TP)	•
Weekly resolution	*Weekly resolution*
•	• Hydropower reservoirs generation energy (HRG) • Hydropower reservoirs inflow energy (HRI) • Hydropower run-of-river generation energy (HRO) • Hydropower run-of-river inflow energy (HRR) • Hydropower run-of-river with pondage generation energy (HPO) • Hydropower run-of-river with pondage inflow energy (HPI) • Hydropower open-loop pumped storage inflow energy (HOL)

The energy conversion models – which allow transforming the climate information into renewable energies generation – are either physical models (wind, solar PV, and solar CSP) or statistical models (hydropower). All details of these models can be found on the Confluence web page as mentioned earlier. It should be noted that in the case of hydropower, the statistical (random forest) models need observed data (generation and/or inflow) for the training phase. As this kind of data

[32] Carbon Debrief (2018): Explainer: How scientists estimate 'climate sensitivity' https://www.carbonbrief.org/explainer-how-scientists-estimate-climate-sensitivity/

is available at country level on the Transparency Platform, the conversion models are also only at country level.

12.3.2 What subset of PECD4.1 is used in ERAA2024?

In ERAA 2024, 36 climate projections were chosen due to computational time and power implications. Data of all three climate models were used, although period for each climate model was shortened to the twelve years between 2025 and 2036 ensuring that they are representative of all TYs of ERAA 2024.

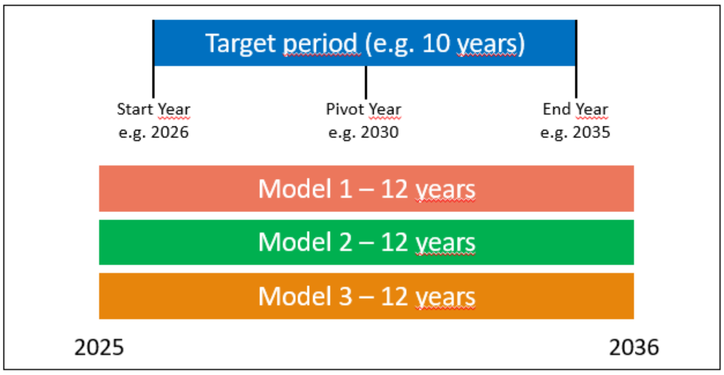


Figure 23: Climate projections in the ERAA 2024

According to international standards and recommendations from the World Meteorological Organization (WMO), the **representative climate for a given year is a 30-year period surrounding the given year**. For example, to represent the climate for 2035, the correct period to consider would be 2021 to 2050 (or 2020 to 2049). A twenty-year period can also be considered, although, in principle, no less than 20 years should be taken into account to fairly represent natural variability.

In addition, the international scientific community also strongly recommends using multiple climate models to consider the uncertainties due to each model's formulation and approximations. Hence, data of all three models were used in ERAA 2024.

Furthermore, for EVA simulations dataset had to be reduced even further, with Section 10.6 describing how a subset of 36 weather scenarios used in ERAA 2024 was further reduced for the EVA.

Appendix 1: Detailed EVA optimisation function

The detailed formulation of the EVA optimisation model is presented in this appendix, formulated as follows:

$$Minimise \quad \sum_{y\ in\ Y} (1+r)^{(1-y)} [Total\ cost_y]$$

$$Total\ cost_y = Fixed\ cost_y + \sum_{sc\ in\ CY} \omega_{sc} [Operational\ cost_{y,sc}]$$

$$Fixed\ cost_y = \sum_{n\ in\ BZ} \{ \sum_{g\ in\ G_n^{new}} [(Annuity_g + FOM_{g,y}) \times p_{y,g}^c] + \sum_{g\ in\ G_n^{ex}} [FOM_{g,y} \times (P_g - p_{y,g}^d)]\}$$

$$Operational\ cost_{y,sc} = \sum_{n\ in\ BZ} [\sum_{\substack{g\ in\ G_n \\ t\ in\ T}} SRMC_{g,y} \times p_{y,sc,g,t} + \sum_{t\ in\ T} PC_{sc} \times l_{y,sc,n,t}]$$

$subject\ to$:

$$p_{y,sc,g,t} \le P_g - p_{y,g}^d \qquad for\ all\ y, sc, t, n\ and\ g\ in\ G_n^{ex}$$

$$p_{y,g}^d \ge p_{y-1,g}^d \qquad for\ all\ y > 1, n\ and\ g\ in\ G_n^{ex}$$

$$p_{y,sc,g,t} \le p_{y,g}^c \qquad for\ all\ y, sc, t, n\ and\ g\ in\ G_n^{new}$$

$$p_{y,g}^c \ge p_{y-1,g}^c \qquad for\ all\ y > 1, n\ and\ g\ in\ G_n^{new}$$

$$\textstyle\sum_{g\ in\ G_n^{new}} (p_{y,g}^c - p_{y,sc,g,t}) + \sum_{g\ in\ G_n^{ex}} (P_g - p_{y,g}^d - p_{y,sc,g,t}) \ge BR_n \qquad for\ all\ y, sc, t, n$$

$$\textstyle\sum_{g\ in\ G_n} p_{y,sc,g,t} + l_{y,sc,n,t} + \sum_{i \to n} f_{y,sc,i,t} - \sum_{i \leftarrow n} f_{y,sc,i,t} = Load_{y,sc,n,t}\ for\ all\ y, sc, n, t$$

$$f_{y,sc,i,t} \le F_{y,i,t} \qquad for\ all\ y, sc, i, t$$

where:

Sets/indices

n	Index representing study zones
CY	Set of climatic scenarios
sc	Index representing climatic scenarios
G_n	Set of all generation resources in study zone n, existing and new candidates
G_n^{ex}	Set of existing generation resources in study zone n
G_n^{new}	Set of new candidate generation resources in study zone n
Y	Set of the years in the planning horizon
y	Index representing the years of the planning horizon
g	Index representing the generators
T	Set of time steps in each year
t	Index representing the time steps
i	Index representing interconnections ($i \rightarrow n$: default direction of the interconnection is importing to study zone n, $i \leftarrow n$: default direction of the interconnection is exporting from study zone n)

Variables

$p_{y,sc,g,t}$	Generation level of unit g in year y, climatic scenario sc and time step t – [MW]
$f_{y,sc,i,t}$	Flow in interconnection i in year y, climatic scenario sc and time step t – [MW]
$p_{y,g}^c$	Capacity of the new generator g – [MW]
$p_{y,g}^d$	Capacity decommissioned from the existing unit g – [MW]
$l_{y,sc,n,t}$	Load not served in year y, climatic scenario sc, in study zone n and time step t – [MW]

Parameters

r	Discount rate [ratio]
$Annuity_g$	Annuity of the new generator g including risk premium – [€/MW]
$FOM_{g,y}$	Fixed operating and maintenance cost including risk premium – [€/MW/year]
$P_{\boldsymbol{g}}$	Capacity of the generator g – [MW]
$F_{y,i,t}$	NTC of interconnection i in year y and time step t [MW]
$SRMC_{g,y}$	Short-Run Marginal Cost – [€/MWh]
PC_y	Wholesale market price cap used for the year y – [€/MWh]
ω_{CY}	Probability of each climatic year scenario
BR_n	Balancing reserve requirement in study zone n – [MW]
$Load_{y,sc,n,t}$	Load level in year y, climatic scenario sc, in study zone n and time step t – [MW]

The $Fixed\ cost_y$ comprises build cost annuity (including the cost of mothballing and de-mothballing and the cost of extending the life of a unit) and FOM costs for new commissioned units and FOM cost of an existing unit (or a reduced value in case the unit is mothballed).

The $Operational\ cost_{y,sc}$ comprises operation costs of producing electricity and the cost of unserved energy. In scarcity periods, the market price is assumed to reach the price cap.

Appendix 2: Mathematical Formulation of flexible EV and HP consumer (implicit DSR)

The following section presents the underlying mathematical formulation of the implicit DSR (EVs and HPs) modelling approach developed within the ERAA working group. Such a formulation was translated pragmatically into the modelling methodology, compatible with the characteristics and features of the market modelling tools used for the ERAA. The formulation largely follows the approach introduced in a study[33] published by APG.

The demand time series are provided in hourly granularity and the ED problem is solved in discrete hourly time steps. The 'demand' mentioned in the rest of the chapter shall always be intended as referring to the share of price-reactive demand peculiar to HPs or EVs, respectively. We define the time index t denoting the time step δ, with $t \in \mathcal{K} \coloneqq \{1, \dots ,8760\}$.

For each δ, two decision variables are introduced, $p_i^{\mathrm{DSR}}(t)$ and $e_i^{\mathrm{DSR}}(t)$, which can be interpreted as follows:

- $p_i^{\mathrm{DSR}}(t)$: Curtailed (i.e. reduced) or increased demand of demand object i due to price-sensitive time-shifting of the demand at time step t.
- $e_i^{\mathrm{DSR}}(t)$: Amount of energy of demand object i that still has to be served or has already been served at time step t.

The consumptive limitations of the flexibility resources – quantified by the respective time series – require defining the following constraint:

$$\underline{p_i}^{\mathrm{DSR}}(t) \le p_i^{\mathrm{DSR}}(t) \le \overline{p_i}^{\mathrm{DSR}}(t),$$

with $\overline{p_i}^{\mathrm{DSR}}(t)$ and $\underline{p_i}^{\mathrm{DSR}}(t)$ denoting the maximum demand that can be curtailed at time step t, and the maximum curtailed demand that can b²e shifted to time step t, respectively. For the amount of energy shifted to a later point in time, we define the following two constraints:

$$\underline{e_i}^{\mathrm{DSR}}(t+1) \le e_i^{\mathrm{DSR}}(t+1) \le \overline{e_i}^{\mathrm{DSR}}(t+1), \text{ and}$$

$$e_i^{\mathrm{DSR}}(t+1) = e_i^{\mathrm{DSR}}(t) + \delta \cdot p_i^{\mathrm{DSR}}(t).$$

[33] Haas A., Iotti G., Petz M., Misak K., Methodological developments for European Resource Adequacy Assessments, 17. Symposium Energieinnovation, 16.-18.02.2022, Graz/Austria

Here, $\overline{e_i}^{\mathrm{DSR}}(t+1)$ and $\underline{e_i}^{\mathrm{DSR}}(t+1)$ represent the maximum energy demand that can be curtailed or shifted up to time step $t+1$, respectively. Finally, as an arbitrary boundary condition, we can define:

$$e_i^{\mathrm{DSR}}(1) = e^0,$$

where the superscript 0 refers to the initial condition.

To define discrete timeframes within which the demand can be shifted (either forward or backward), the profiles $\overline{e_i}^{\mathrm{DSR}}(t+1)$ and $\underline{e_i}^{\mathrm{DSR}}(t+1)$ should be such that there exist time steps in which the two bounds coincide, i.e. there exist $h \in \mathcal{K}$ such that:

$$\overline{e_i}^{\mathrm{DSR}}(h+1) = \underline{e_i}^{\mathrm{DSR}}(h+1) = e^{\mathrm{H}}.$$

Consequently, we define the subset $\mathcal{H}$ of all these points in time as:

$$\mathcal{H} \coloneqq \left\{ t \in \mathcal{K} \text{ s.t. } \overline{e_i}^{\mathrm{DSR}}(t+1) = \underline{e_i}^{\mathrm{DSR}}(t+1) = e^{H} \right\}.$$

Practically speaking, the elements of $\mathcal{H}$ define the boundaries of time windows within which the load can be shifted (i.e. the flexibility windows defined in the previous chapter). To ensure that all flexible demand is eventually supplied within each time window, bound by the time steps in $\mathcal{H}$, the boundary conditions are set equal to the initial condition, thus:

$$e^{\mathrm{H}} = e^0.$$

After introducing the constraints above, it is necessary to choose an appropriate set of parameters. Assuming that $\overline{p_i}^{\mathrm{DSR}}(t)$ follows the hourly demand time series of the corresponding iDSR element (e.g. HPs or EVs), it is necessary to define the remaining parameters $\underline{p_i}^{\mathrm{DSR}}(t)$, $\overline{e_i}^{\mathrm{DSR}}(t+1)$, $\underline{e_i}^{\mathrm{DSR}}(t+1)$, e^{H}, e^0 and $\mathcal{H}$.

To begin with, the set $\mathcal{H}$ is defined with arbitrary time windows of six hours, whereby it follows that $\mathcal{H} \coloneqq \{6, 12, 18, 24, \dots, 8760\}$. For the sake of simplicity let $e^0 = 0$, then:

$$\overline{e_i}^{\mathrm{DSR}}(t+1) \coloneqq \begin{cases} +\infty \text{ if } t \in \mathcal{K} \backslash \mathcal{H} \\ 0 \text{ if } t \in \mathcal{H} \end{cases}, \text{ and}$$

$$\underline{e_i}^{\mathrm{DSR}}(t+1) \coloneqq \begin{cases} -\infty \text{ if } t \in \mathcal{K} \backslash \mathcal{H} \\ 0 \text{ if } t \in \mathcal{H} \end{cases}.$$

To avoid negative values for $e_i^{\mathrm{DSR}}(t)$ the boundary condition $e^0 = e^{\mathrm{H}}$ can be shifted to an arbitrarily large positive number yielding the same effect (i.e. the default 50% SoC defined in the previous chapter). Finally, we can dimension $\underline{p_i}^{\mathrm{DSR}}(t)$ to allow for a maximum power absorption that matches the maximum demand curtailment in the same time window. Denoting two consecutive indices in $\mathcal{H}$ (e.g., 6 and 12) with h_i and h_{i+1}, then:

$$\underline{p_i}^{\mathrm{DSR}}(t) \coloneqq \max\left\{ \overline{p_i}^{\mathrm{DSR}}(\tilde{t}) \text{ s.t. } h_i \leq \tilde{t} \leq h_{i+1} \right\} - \overline{p_i}^{\mathrm{DSR}}(t), \forall k \in [h_i, h_{i+1}] \subset \mathcal{K}.$$