European Network of
Transmission System Operators
for Electricity

entsoe

European Resource Adequacy Assessment - Methodology Proposal in accordance with Article 23 of the Electricity Regulation of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity (recast)

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Contents

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Whereas

This document is a proposal developed by the European Network of Transmission System Operators for Electricity (hereafter referred to as "ENTSO-E") regarding European Resource Adequacy Assessment (ERAA) Methodology (hereinafter also referred to as "Methodology") in accordance with Article 23(3) of Regulation (EU) 2019/943 of the European Parliament and Council of 5 June 2019 on the internal market for electricity (recast), hereinafter referred to as "Electricity Regulation".

(1) The Methodology takes into account the general principles and goals set in the Electricity Regulation as well as the European Union (EU) legal framework [Directive (EU) 2019/944 of the European Parliament and Council of 5 June 2019 on common rules for the internal market for electricity (hereinafter referred to as "Electricity Directive"), Regulation (EU) 2019/941 of the European Parliament and of the Council of 5 June 2019 on risk-preparedness in the electricity sector (hereinafter referred to as "Regulation (EU) 2019/941"), Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management (hereafter referred to as "CACM Regulation"), Commission Regulation (EU) 2017/1485 of 2 August 2017 establishing a guideline on electricity transmission system operation (hereafter referred to as "SO GL"), Regulation (EU) 2018/1999 of the European Parliament and of the Council on the Governance of the Energy Union and Climate Action (hereinafter referred to as "Regulation (EU) 2018/1999"), Regulation (EU) 2019/941 of the European Parliament and Council on risk-preparedness in the electricity sector (hereafter referred to as "RPR") and repealing Directive 2005/89/EC.

(2) One of the goals of the Electricity Regulation is to ensure the most effective and efficient provision of resource adequacy within the EU. A common approach—through this Methodology—in all adequacy assessments whether carried out at national, regional, or Union level is key to achieve this goal.

(3) Article 23(3) of the Electricity Regulation sets the legal basis and requirements for the Methodology developed by ENTSO-E. It shall be based on a common probabilistic adequacy assessment approach considering uncertainties of inputs – availabilities of exchange capacities, availabilities of power plants, variability of demand and renewable energy production – to identify the likelihood of national or simultaneous lack of resource adequacy in Europe or at regional level.

(4) Upon its adoption, ENTSO-E will use this Methodology, as required by Article 23(1) of the Electricity Regulation, to identify resource adequacy concerns by assessing the overall adequacy of the electricity system to supply current and projected demands for electricity at Union level, at the level of the Member States and, where relevant, at the level of individual bidding zones. ERAA shall be carried out on an annual basis covering a period of 1 - 10 years ahead. ERAA assesses the impact of system development trends on adequacy. System development trends include change of generation capacity mix, change of demand patterns, network developments and others. As a result of these assessments, policy makers and other relevant stakeholders might take actions to ensure that reliability standards are satisfied. Furthermore, it may also serve as indicator for market participants about potential business opportunities. ENTSO-E and its TSO members shall not be held responsible in case the hypotheses taken in this assessment or the estimations based on these hypotheses are not realised in the future.

(5) Complementary national resource adequacy assessments may be conducted, shall have a regional focus and shall be based on the Methodology detailed in this document. Article 24 of the Electricity Regulation specifies the principles for national resource adequacy assessments. Where the national resource adequacy assessment identifies an adequacy concern with regard to a bidding zone that was not identified in the ERAA, the national resource adequacy assessment shall include the reasons for

the divergence between the two resource adequacy assessments, including details of the sensitivities used and the underlying assumptions.

(6) Stakeholder interaction shall provide visibility and transparency on the scenarios, the assumptions, and the results as well as on the implementation of the Methodology for each ENTSO-E ERAA report. Sufficient interaction channels shall be provided to ensure that producers and other market participants have the opportunity to provide transmission system operators and ENTSO-E where necessary, with the relevant data to enable ENTSO-E to complete, compare and benchmark the data and assumptions used in the assessment.

(7) In conclusion, the Methodology contributes to the general objectives of the Electricity Regulation to the benefit of all market participants and electricity consumers.

Article 1
Subject matter and scope

This Methodology shall be used to identify resource adequacy concerns by assessing the overall adequacy of the electricity system and its ability to supply projected demand levels for electricity at Union level, at the level of the Member States and at the level of individual bidding zones, where relevant, in accordance with Article 23(1) of the Electricity Regulation.

The ERAA shall be based on a transparent methodology which shall ensure that the assessment:

a. is carried out on each bidding zone level covering at least all Member States;
b. is based on appropriate central reference scenarios of projected demand and supply including an economic assessment of the likelihood of retirement, mothballing, new-build of generation assets and measures to reach energy efficiency and electricity interconnection targets and appropriate sensitivities on extreme weather events, hydrological conditions, wholesale prices and carbon price developments;
c. contains separate scenarios reflecting the differing likelihoods of the occurrence of resource adequacy concerns which the different types of capacity mechanisms are designed to address;
d. appropriately takes account of the contribution of all resources including existing and future possibilities for generation, energy storage, sectoral integration, demand response, and import and export and their contribution to flexible system operation;
e. anticipates the likely impact of the measures referred in Article 20(3) of the Electricity Regulation;
f. includes variants without existing or planned capacity mechanisms and, where applicable, variants with such mechanisms;
g. is based on a market model using the flow-based approach, where applicable;
h. applies probabilistic calculations;
i. applies a single modelling tool;
j. includes at least the following indicators referred to in Article 25 of the Electricity Regulation: — ‘expected energy not served’, and — ‘loss of load expectation’;
k. identifies the sources of possible resource adequacy concerns, in particular whether it is a network constraint, a resource constraint, or both;
l. takes into account real network development;
m. ensures that the national characteristics of generation, demand flexibility and energy storage, the availability of primary resources and the level of interconnection are properly taken into consideration.

This methodology, after ACER approval or amendment, shall be adopted by ENTSO-E as the basis for the ERAA.

It shall also serve as a reference method, without prejudice to innovation going beyond it, for all other adequacy assessments, whether it would be national, regional or Union level. Regional and national adequacy assessments can take into account the particularities of national electricity demand and supply, use tools and consistent recent data that are complementary to those used by the ENTSO-E for the ERAA and, in assessing the contribution of capacity providers located in another MS to the security of supply of the bidding zones they cover.

The Methodology does not limit the geographical scope of the analysis. Adequacy assessments performed by ENTSO-E will cover at least a region composed of ENTSO-E members and other TSOs for which SO GL article 81 or article 106 is applicable. ENTSO-E shall continuously engage operators of other interconnected systems to establish and foster cooperation. If tightly interconnected neighbouring regions commit to cooperation on adequacy assessments, they should be modelled in the same level of detail as the core analysed regions. Otherwise, the contribution to Pan-European adequacy of those systems will be considered based on the assumptions of ENTSO-E's members having direct interconnections with those systems. Hereafter, those systems will be referred to as non-explicitly modelled systems.

Article 2
Definitions and interpretation

For the purposes of the Methodology, the terms used in this document shall have the meaning of the definitions included in Article 2 of the Regulation (EU) 2019/941, Electricity Regulation and Electricity Directive.

In addition, in this Methodology, unless the context requires otherwise, the following terms shall have the meaning below:

- Planned outage: state of an asset when it is not available in the power system and the outage was planned in advance. These outages include maintenance, mothballing and any other non-availabilities known at the time of data collection for the resource adequacy assessment.
- Unplanned outage (also called Forced Outage): state of an asset when it is not available in the power system and the outage was not planned.
- Non-explicitly modelled systems: electric systems which do not provide data for adequacy assessment, but are tightly interconnected with any member of ENTSO-E or any other electric system for which SO GL Article 81 or Article 106 is applicable. Contribution of those systems to the pan-European adequacy assessment shall be considered using assumptions provided by the TSO to which they connect to.
- Explicitly modelled systems: electric systems which are an integral part of the European power system and for which SO GL Article 81 or Article 106 is applicable. These systems shall be modelled considering each element of the probabilistic model set in this Methodology.
- Market-based measures: any supply or demand measures available in the system complying with market rules and commercial agreements. This includes all supply or demand measures which participate in Capacity Mechanisms (CMs) and are available on the energy market.
- Loss of Load Expectation (LOLE) in a given zone and in a given time period, is the expected number of hours in which resources are insufficient to meet the demand.

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- Expected Energy Not Served (EENS) in a given zone and in a given time period, is the energy which is expected not to be supplied due to insufficient resources to meet the demand.
- Net Generating Capacity (NGC) of a generation unit is the maximum electrical net active power it can produce continuously throughout a long period of operation in normal conditions, where: i) "net" means the difference between, on the one hand, the gross generating capacity of the alternator(s) and, on the other hand, the auxiliary equipment load and the losses in the main transformers of the power station; ii) for thermal plants "normal conditions" means average external conditions (weather, climate etc.) and full availability of fuels; iii) for hydro, solar and wind units, "normal conditions" refer to the usual maximum availability of primary energies, i.e. optimum water or wind conditions. The NGC of a country is the sum of the individual NGCs of all power stations connected to either the transmission grid or to the distribution grid.
- Coordinated Net Transmission Capacity approach/Net Transfer Capacity (NTC) model: a capacity calculation method based on the principle of assessing and defining ex-ante a maximum energy exchange between adjacent bidding zones as referred in Article 2 of the CACM Regulation.
- Flow-based approach/model: a capacity calculation method in which energy exchanges between bidding zones are limited by power transfer distribution factors and available margins on a critical network element as defined in Article 2 of the CACM Regulation.
- Flow-based Market Coupling (FBMC): a mechanism to couple different electricity markets, increasing the overall economic efficiency, while considering the available transmission capacity between different bidding zones using the flow-based approach/model as referred in Article 2 of the CACM Regulation.
- Value of Lost Load (VoLL): an estimation in €/MWh of the maximum electricity price that customers are willing to pay to avoid an outage, as defined in Article 2 of the Electricity Regulation.
- Capacity mechanism (CM): means a temporary measure to ensure the achievement of the necessary level of resource adequacy by remunerating resources for their availability, excluding measures relating to ancillary services or congestion management as referred in Article 2 of the Electricity Regulation.
- Strategic reserve: a CM in which resources designated as "strategic reserves" are not available on the energy market and are only dispatched in the case where the day-ahead and intraday markets have failed to clear and transmission system operators have exhausted their balancing resources to establish an equilibrium between demand and supply. Imbalances in the market during imbalance settlement periods where the strategic reserves were dispatched are settled to the highest value between the maximum value of lost load[1] and the intraday technical price limit, as referred in Article 10(1) of the Electricity Regulation.
- Reserve capacity: the amount of frequency containment reserves, frequency restoration reserves or replacement reserves that need to be available to the transmission system operator as defined in Article 2 of the Electricity Regulation.

[1] As referred to in Article 10(2) of Electricity Regulation

- Frequency containment reserves (FCR): the active power reserves available to contain system frequency after the occurrence of an imbalance as referred in Article 2 of the SO GL.
- Frequency restoration reserves (FRR): the active power reserves available to restore system frequency to the nominal frequency and, for a synchronous area consisting of more than one load-frequency control area, to restore power balance to the scheduled value as referred in Article 2 of the SO GL.
- Automatic FRR (aFRR): FRR that can be activated by an automatic control device.
- Manual FRR (mFRR): FRR that is manually activated.
- Replacement Reserves (RR): the active power reserves available to restore or support the required level of FRR to be prepared for additional system imbalances, including generation reserves as referred in Article 2 of the SO GL.
- Demand-side response (DSR):

  i) Explicit demand-side response (Explicit DSR): the change of electric demand of the final customer from their normal or current consumption pattern when directed to do so pursuant to an accepted offer to sell demand reduction or increase at a price in an organised market as referred in Article 2 of the Directive (EU) 2019/944, whether directly or through aggregation. DSR can consist of either foregone or shifted demand. Explicit demand response is considered in the supply curve as either a forward market resource, day-ahead or a balancing resource. ii) Implicit demand-side response (Implicit DSR): the change of electricity load by final customers from their normal or current consumption patterns, in response to time-variable electricity prices or incentive payments. Implicit DSR can either be self-directed or directed by an energy management service provider. Implicit demand-side response affects the demand curve. iii) The modelling of both types of DSR shall be considered in the same way in ERAA.
- Revenues: the amount of income that a given asset receives from the market. For the Energy-Only-Market (EOM) revenues for each hour are equal to simulated Market Price [€/MWh] multiplied by the Energy Produced [MWh];
- Capital Expenditures (CAPEX) or overnight cost: the investment required to develop, construct and refurbish a plant without considering the financial costs (e.g., interest costs) or the structure of financing (equity versus debt) i.e. the investment required if the plant were to be built in a single night at the current prices;
- Fixed Operational Expenditures (OPEX) or fixed Operations and Maintenance (O&M) costs: refer to the costs incurred in the context of operation of a capacity resource each year once the capacity resource starts operating, independently from the generated or curtailed energy volume.
- Fixed costs: refer to CAPEX and fixed OPEX/fixed O&M costs; Further hypotheses on discount rates (see below) are considered to convert CAPEX into Annuity values in the economic viability checks.
- Variable costs: refer to fuel costs, CO_2 costs and variable OPEX/variable O&M costs. Fuel and CO_2 prices shall be defined centrally, considering available economic expertise and projections in Europe. Variable OPEX/variable O&M costs are non-fuel operations and maintenance costs that includes cost of consumable materials (ammonia, limestone, water, etc.), production by-products handling (ash, slug, etc.) and maintenance costs that may be scheduled based on the number of operating hours or start-stop cycles of the plant;

- Policy-driven asset: generation, demand side response or storage asset for which investment is decided and executed based on the support from subsidies or incentives, as well as assets for which a policy is developed on a national level and for which investment decisions are therefore not solely depending on an economic trade-off and/or assets for which no new investments are possible due to e.g. a phase-out policy.
- Non-policy-driven asset: generation, demand side response or storage asset for which investment is decided and executed without any consideration of support from subsidies or incentives or policy considerations, hence relying on expected revenues from the market.
- Economic lifetime: the whole lifetime of an asset during which it is able to generate revenues, which may be equal or differ from the payback period representing the number of years within which the initial investment cost is expected to be recovered by rational investors. In this methodology it is assumed that the economic lifetime equals to the payback period.
- Construction time: represents the number of years needed between the moment the investment decision is taken and construction works start and the date of commissioning of the investment.
- Discount rate: expresses the time value of money and converts future cashflows to their equivalent present value via a discount factor, $k = \frac{1}{(1+r)^n}$, where r is the discount rate and n is the number of years after commissioning of the asset/plant. Multiplying the future cashflow by the respective discount factor *k* converts it to the equivalent value it would hold at the year of commissioning.
- Weighted Average Cost of Capital (WACC): is a calculation of the cost of capital of a firm – a for-profit business organization that provides professional services – in which each category of capital is proportionally weighted. All sources of capital, including common stock, preferred stock, bonds and any other long-term debt, are included in a WACC calculation.
- Annuity: Annualised CAPEX costs considering also weighted average cost of capital (WACC).

In this Methodology Proposal, unless the context requires otherwise:

− the singular indicates the plural and vice versa;
− the table of contents and headings are inserted for convenience only and do not affect the interpretation of this Methodology Proposal; and
− any reference to legislation, regulations, directive, order, instrument, code or any other enactment shall include any modification, extension or re-enactment of it then in force.

Article 3
Scenario Framework

1. The ERAA shall be based on projected demand and supply covering each year from Y+1 until Y+10, where Y indicates the year of the publication of the ERAA. The year Y+1 ERAA assessment shall refer to the results of the seasonal adequacy assessment pursuant to Article 9 of RPR.
2. ENTSO-E shall collect data to define the projected demand, supply and grid assumptions according to the requirements set out in Article 5.
3. The baseline data for the ERAA are the national projected demand, supply and grid outlooks prepared by each individual transmission system operator (TSO), considering:

a. National trends from the National Energy and Climate Plans (NECPs), as referred in Article 3 of Regulation (EU) 2018/1999, including trends related to coal phase-out, nuclear phase-out, renewable energy development and energy efficiency measures. For times between NECP publication and its update after 5 years, scenarios shall be aligned with the Ten-Year Network Development Plan (TYNDP) biennial scenario building relying on actualized data incorporating recent economic, demographic, political and technological trends;

b. Best estimates regarding the state of the grid in line with the TYNDP and the most recent national development plans;

c. Known trends/assumptions regarding mothballing, construction of new assets, existing contracts under current or past CMs and estimates on available capacity under current and planned CMs.

4. An economic viability check shall be performed on the baseline data according to Article 6, for the Central Reference Scenarios, referred to in paragraph Article 3 (5) below. Non-policy, non-viable resources, as defined in Article 6, on the market are removed and, relevant non-policy, viable new resources, as defined in Article 6, are added to the Scenario within the economic viability check. The ERAA shall show in a transparent way how the baseline data referred to in Article 3 (3) have been modified within the economic viability check.

5. The ERAA shall be performed for the following Central Reference Scenarios:

a. **Scenario with CM**: This scenario considers that CMs, as approved in accordance with the State Aid rules pursuant to Article 107, 108 and 109 of the Treaty on the Functioning of the European Union (TFEU) at the time of the assessment, provide additional revenues beyond the revenues from the EOM within the 10-year period covered by the assessment and with the purpose of ensuring that the reliability standard of the country is fulfilled. Constraints such as limits on capacities available (e.g. constraints on demand response), legal and administrative hazard, hazards with impact on availability, building delays, stop-loss limits, may however justify in specific cases that the Reliability Standard is not always fulfilled at any price.

b. **Scenario without CM**: This scenario considers that CMs, as approved in accordance with the State Aid rules pursuant to Article 107, 108 and 109 of the TFEU at the time of the assessment, do not provide additional revenues to resources, except when they already hold a CM contract granted in any previous auction of any existing or approved CM at the time of the assessment and in accordance with the State Aid rules pursuant to Article 107, 108 and 109 of the TFEU.

6. These two “Central Reference Scenarios” might be complemented by sensitivity studies to assess the robustness of the possible identified adequacy risks within the assumptions of these Central Reference Scenarios. Criteria for the definition of such sensitivities are amongst others: i) different assumptions related to input uncertainties, ii) impact of uncertainty in the deployment of grid investments; iii) assessments of the robustness of the identified investments within the economic viability check and iv) robustness of the results through variations on fuel and/or carbon prices.

Article 4
European Resource Adequacy Assessment – Description

1. **General**

a) The ERAA has a time horizon of 10 years ahead, with an annual granularity.

b) Adequacy shall be assessed using the following two probabilistic metrics: (1) the EENS and (2) the LOLE.

c) The adequacy metrics are assessed through a Unit Commitment and Economic Dispatch (UCED) model, referred to in this document as “the UCED model”. Regarding adequacy assessments, the UCED main focus is minimization of EENS as part of the system-cost minimization problem. The UCED also provides marginal prices as part of the outcome of the system cost-minimisation problem, which are relevant for the economic viability checks.

d) The adequacy assessment consists of three major pillars: demand (including DSR and system reserve requirements), supply (e.g. generation and storage units) and grid representation among different zones.

e) Uncertainty is represented through the consideration of random unplanned outage patterns of generators, interconnectors (as well as internal lines in case of direct impact on cross-border capacity) and different weather conditions. Data related to hydro inflows, irradiation, wind speed and temperature among others are consolidated in the ENTSO-E Pan-European Climate Data set (PECD). The PECD comprises a set of hourly time series of climate parameters for multiple years. Weather conditions and hydrological conditions shall represent a foreseeable distribution of the probability of each climate year in the future, taking into account the impact of climate change. Time series of PECD parameters are an output of climate simulation models while reanalyses of historical data are procured by ENTSO-E through external parties with a proven record on climate and meteorological modelling. The data set shall consider the inter-zonal and inter-temporal correlation of those climate parameters.

f) The UCED model shall be built on a “perfect foresight” principle with respect to variable parameters. Forecast errors of wind, solar, hydro generation, unplanned outages as well as of demand are ignored in the UCED model.

g) Market simulations shall be run with an hourly resolution.

h) The granularity of geographical zones shall be set at least by the smallest level between country and bidding zone, considering the official biding zone configuration and expected evolution at the moment of the assessment. In addition, the specific geographical characteristics of the assessed perimeter shall be reflected in the UCED model by explicitly modelling big islands, for example Corsica and Crete.

2. **Probabilistic Assessment**

a) The ERAA shall use a probabilistic methodology to reflect the stochasticity of climate parameters affecting supply and demand as well as the unexpected technically or economically constrained availability of generation, storage and transmission resources.

b) The Monte Carlo (MC) method shall be used for probabilistically assessing the availability of generation and transmission resources. It implies performing experiments by sampling a sequence of random outages of the stochastic variables. In ERAA, MC random samples represent different availability of generation assets and transmission lines, which are subject to failures that cannot be predicted beforehand and may have significant impact on adequacy. MC sampling is based on the Law of Large Numbers, according to which the average of the results obtained by performing the same experiment for a sufficiently large number of times, should converge to the expected value.

c) Monte Carlo simulations in ERAA shall be built combining the climate-dependent variables and random outages referred to in Article 4(1e) and Article 4(2b) respectively and shall be performed in the following way: climate years, including years considering realistic but extreme weather conditions and the effect of climate change, are first selected one-by-one. Each climate year consists of a combination of demand (accounting for the so called “temperature-load-dependency”, which however includes irradiance, wind speed among others as well), wind, solar and hydro inflow time-series. Each set of climate conditions is further associated with a relatively large number of so-called random outage samples, that is, randomly assigning unplanned outage patterns for thermal units and interconnections (HVDC and relevant HVAC, consistent with the methodology used for capacity calculation in accordance with the CACM Regulation). The convolution of climate years and number of random unplanned outage patterns defines the final number of Monte Carlo years analysed. The choice of the final number of Monte Carlo years shall ensure convergence of the results.

d) The convergence of the Monte Carlo method shall be assessed by the coefficient of variation (α) of the $EENS$ adequacy metric. It describes the volatility of the EENS adequacy metric in the Monte Carlo assessment. Coefficient of variation is defined by the equation below:

$$\alpha_N = \frac{\sqrt{Var[EENS_N]}}{EENS_N}$$

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

e) The number of Monte Carlo samples are sufficiently large if the relative increment of α value is lower than the given threshold Θ. In this case, increasing the number of Monte Carlo samples for the adequacy assessment would not increase the level of accuracy considerably, consequently, the Monte Carlo analysis can be stopped. In particular, for N sufficiently large:

$$\frac{|\alpha_N - \alpha_{N-1}|}{\alpha_{N-1}} \leq \Theta$$

f) To indicate the reliability of adequacy assessment results, these parameters shall be reported along with the results:

i. the number of analysed Monte Carlo scenarios;

ii. the values of α as a function of the number of analysed Monte Carlo scenarios.

3. **Demand**

a) Demand shall be represented as a time-series of the same time resolution as the UCED model. It shall be calculated considering the stochasticity of climate variables, economic growth and penetration of new technologies (e.g., electric vehicles and heat pumps) at the target year, based on historical demand time series and the impact of climate change.

b) Demand is modelled considering load- temperature sensitivity using historical climate data or climate data derived from climate models. The load-sensitivity relationship includes other variables such as irradiation, wind speed or humidity. While in the ERAA this data is aggregated to bidding zone level, national studies might include sensitivities that rely on climate data of higher spatial and temporal granularity.

c) Explicit and implicit DSR shall be considered in the assessment if such technology is considered as available, mature and competitive within the concerned period of the assessment. It can consist of a potential for demand reduction as well as demand postponement or shifting. The DSR potential shall be structured in different price and volume bands, each characterized by a maximum activation capacity (MW), maximum activation duration (h), marginal activation price (EUR/MWh) as well as economic and technical activation and energy constraints. The price and volume bands indicate the minimum price required to activate the corresponding volumes of DSR, hence constituting a DSR activation curve. The estimation of DSR potentials and their activation curves shall be performed per bidding zone. The economic viability check shall define the economic viable amount of such potential DSR that is to be finally included in the Reference Scenario capacity portfolio, taking into account the constraints referred in Article 6. For the avoidance of doubt, 'mature and competitive' refers to the existence of robust data upon the data collection process which allows to define: i) the potential for DSR, ii) one or several DSR price and volume bands iii) any technical or economical activation and duration constraints for each of the bands defined (e.g. energy constraints). Both DSR potential and DSR activation curves can either be given as input to the investment model referred to in Article 6 of the Methodology during the economic viability check, or be used to define DSR exogenously in the simulation. The choice of either option shall be based and communicated on the basis of transparent and fundamental arguments (see also Article 5(7c.7.(c))

d) Additional demand during charging of storage units is determined though the simulation model and shall be considered as an element responding to market signals. Such demand may result from pumped-hydro storage power plants, price-responsive batteries, power-to-gas units or electric vehicles among others.

e) It shall only be estimated to technologies that are used in practice or if there is consolidated evidence, e.g. through reports or political programs that these technologies may be mature and economically competitive and available within the analysed time-period (Y+1 to Y+10). Estimates on evolution of energy efficiency and its effects on demand curves as well as demand growth are considered using annual forecasts that are collected via the ENTSO-E central data collection process together with TSOs.

4. **Supply**

a) Supply assumptions shall consider best estimates of all available generation and storage units in the system, as well as available exchanges with non-explicitly modelled neighbouring zones.

b) Only market-based resources shall be considered. Any non-market resources, such as strategic reserves, shall not be considered in the central reference scenarios of ERAA. Their impact can be assessed through complementary sensitivity studies within national resource adequacy assessments in case an adequacy risk is detected in the ERAA, and should Member States wish to do so in accordance with Art 24 of the Electricity Regulation.

c) Supply shall be defined in terms of NGC.

d) Any seasonal impact on generation capacity availabilities (e.g. Combined Heat Power plant availabilities in summer and seasonal efficiencies) shall be considered, for example by introducing their availability by use of time-series for the installed capacity or modelling it through the planned maintenance schedule for the periods of unavailability.

e) Wind and solar generation shall reflect modelled weather conditions, respectively irradiance and wind speed. These weather variables are also correlated with temperature, through the climate database used. This allows to build a consistent input data for the assessment, since correlations between weather dependent generation and "temperature - dependent" demand are properly taken into account.

f) Availability of supply sources:

   i. Availability of power generation sources shall account for planned outages, system reserve requirements as well as forced outages.

   ii. Planned outages are modelled considering perfect foresight. Maintenance (planned outages) schedules shall be prepared centrally by ENTSO-E, with support and inputs given by TSOs. These shall be optimized to avoid as much as possible maintenance being scheduled at critical moments of scarcity. Furthermore, for the short-term period of 1-3 years, the maintenance profiles shall be calibrated to respect data published by owners of generation units, since these are obliged to transparently publish the latest information on the unavailability of the units in their fleet via the official transparency channel (REMIT), over a three-year time horizon.

iii. Forced outages of supply shall be considered in a probabilistic manner. Assumptions on outage rates per technology type and mean time to repair shall build on historical outage events in Europe.

g) Supply-side technical constraints shall be considered. These include, but are not limited to, minimum and maximum generating capacities, capacity requirements for system services (reserves, voltage support, etc), capacity reductions due to mothballing, must-run constraints, planned maintenance requirements, ramping capabilities, start-up and shut-down times.

h) Energy constraints (such as hydro) shall consider energy availability. For hydro generation modelling, the energy constraints can be related to water inflows, reservoir size or minimum energy release requirements due to environmental reasons. For bidding zones where vehicle-to grid technology is applied, energy availability shall be linked to energy storage potentials of EV battery.

i) Generation from Renewable Energy Sources (RES) shall be represented by two different elements: (1) RES net generating capacity for each technology, representing the market penetration of RES at the target year, (2) time-varying load factors reflecting the spatial and temporal dependency of RES generation on climatic variables as well as the evolution of RES technologies in the target year. The load factors are contained in the PECD database.

j) FCR and FRR shall be deducted from the available resources in the adequacy assessment, either by deducting their respective capacities from the available supply or by adding them to the load profile. Reserves are dimensioned to cover the unexpected imbalances resulting from second-by-second random variations of generation and load and to face a range of contingencies. When dimensioning reserves, it is assumed the system, on average, is balanced. These imbalances cannot be physically avoided as the predictability of demand and the controllability of demand and generation is limited. During an imbalance event there is a two-step approach to ensure the system frequency stays in the acceptable range to avoid system collapse: (1) Containment, where the Frequency Containment Reserves are activated to arrest the change in system frequency within a predetermined containment band after which (2) the Restoration process starts. During Restoration FCR is deactivated and replaced with FRR which drives the frequency back to the system setpoint. Frequency restoration process is mandatory, and should be done either through aFRR, mFRR or a combination of the two. The time to restore frequency is laid down in the SO GL to be equal to 15 minutes. As a non-mandatory process, RR could replace the activated FRR and/or support the FRR activation. RR reserves shall be considered as available capacity contributing to adequacy in the ERAA adequacy assessment.

Reserve sizing for FCR shall cover at least the reference incident of a synchronous area. FCR contribution by each TSO shall be based on the sum of the net generation and consumption of the TSO's control area divided by the sum of net generation and consumption of the synchronous area over a period of 1 year as set out in the SO GL. Within the analysed time-period (Y+1 to Y+10) in ERAA, dimensioning of FCR shall be based on the latest available historical data of generation and consumption.

Reserve sizing for FRR shall be carried out for each load-frequency block (hereafter referred as LFC block) and shall include at least the following main rules set out in the SO GL:

i. all TSOs of a LFC block shall determine the reserve capacity on FRR at least on a probabilistic methodology which shall be based on consecutive historical records that include at least one full year period ending not earlier than 6 months before the calculation date and shall take into account any expected significant changes to the distribution of LFC block imbalances or take into account other relevant influencing factors relative to the time period considered,

ii. positive/negative reserve capacity on FRR shall not be less than the positive/negative dimensioning incident of the LFC block which shall be determined as set out in the SO GL, and
iii. positive/negative reserve capacity on FRR or a combination of reserve capacity on FRR and RR shall be sufficient to cover the positive/negative LFC block imbalances for at least 99 % of the time, based on the historical records,
iv. the ratio of automatic FRR and manual FRR shall be determined by all TSOs of an LFC block to fullfil the frequency restoration control error target parameters laid down in the SO GL.

Within the analysed time-period (Y+1 to Y+10) in ERAA, dimensioning of FRR shall be based, at least, on the rules mentioned in point ii.

5. **Network**

a) Grid representation for zones within the "Coordinated Net Transmission Capacity" market-coupling approach shall be considered as copper plate networks (i.e. single nodes), coupled via cross-border capacities. Cross-border capacities are described by the NTC at each border. The NTC are defined such that system operational security constraints are respected, fulfilling the N-1 criteria.

b) According to Article 16 of the Electricity Regulation, NTC shall respect minimum requirements regarding capacity to be offered to the market, respecting operational security limits after deduction of contingencies, as determined in accordance with the capacity allocation and congestion management guideline adopted on the basis of Article 18(5) of the Regulation (EC) No 714/2009.

c) Network constraints are defined as the maximum exchange capacity constraints in case of NTC modelling. Furthermore, these may be complemented by constraints on total net exchanges, in case this is necessary to ensure safe system operation as well as specific connection agreements with neighbouring non-modelled systems.

d) Grid representation for zones within FBMC shall be considered following the methodology referred in Article 2 of the CACM. Therefore, the relevant grid constraints shall be captured by the flow-based approach performed in ERAA. Where applicable, the approach shall be consistent with existing capacity calculation principles, including requirements on selection of Critical Network Elements and Contingencies (CNEC) referred in Article 2 of the CACM and rules for the minimum capacity available for cross-zonal exchanges as referred in Article 16 of the Electricity Regulation.

e) The adequacy assessment shall consider the latest available information regarding Member State action plans for a linear trajectory pursuant to Article 15 or the minimum capacity pursuant to Article 16(8) as well as any temporary derogations granted as per article 16(9) of the Electricity Regulation regarding both NTC and FBMC approaches to define cross border capacities.

f) The flow-based approach shall be defined as follows:

i. Definition of relevant Power Transfer Distribution Factors (PTDFs) shall use grid models covering the flow-based area under consideration and suited for each target time of the assessment, i.e., each of the 10 target years. European grid models from the TYNDP reference grid shall be used incorporating the relevant grid modifications applicable to the different target time horizons of the assessment;

ii. PTDFs shall be defined for each of the different CNECs and for the relevant variables representing the net positions of each bidding zone under consideration, relevant HVDC flows, Phase Shifting Transformer (PST) settings, and other degrees of freedom that are given to the market under FBMC;

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iii. Network constraints shall be defined further through the Remaining Available Margin (RAM) of each CNEC, with existing capacity calculation principles as referred in Article 2 of the CACM, hence including proper considerations on internal, loop and transit flows;

iv. The capacity calculation should ensure the N-1 criterion is met at all times. The calculation of the PTDF and RAM thus accounts for the N-1 principle;

v. According to Article 16 of the Electricity Regulation, minimum margins shall be applied to the RAM for each relevant CNEC, respecting operational security limits of internal and cross-zonal critical network elements, considering contingencies, as determined in accordance with the capacity allocation and congestion management guideline adopted on the basis of Article 18(5) of the Regulation (EC) No 714/2009;

vi. Furthermore, these may be complemented by constraints on total net exchanges, if applicable to ensure safe system operations as well as specific connection agreements with neighbouring non-modelled systems;

vii. For all relevant CNECs, the (RAM, PTDFs) parameters define a collection of linear constraints to the variables to be optimized by the UCED model. Finally, this total set of constraints is reduced to the set of constraints limiting the exchanges within the simulation. This procedure leads to the final combination of relevant constraints forming the so-called flow-based domain.

viii. Finally, only the final set of limiting constraints, i.e. flow-based domains, shall be the linear constraints which need to be introduced in the UCED model tools for the ERAA assessment.

ix. Weather conditions and seasonal patterns that impact network constraints shall be considered when defining the exchange constraints within the flow-based approach. Time series of climatic years within the PECD will be used to model variability of the renewable generation, electricity demand, etc. The flow-based domains referred to in paragraph 5.f.viii) shall include representative groups of linear constraints, each group linked to given climate conditions and hence to a certain level of congestions in the network. A correlation analysis between the different domain groups and relevant climate variables (e.g. renewable generation/electricity demand) shall be applied when setting up the flow-based domains referred in paragraph 5.f.viii) in the UCED model.

g) Forced outages of HVDC interconnections in the NTC approach shall be considered in a probabilistic manner. Assumptions on outage rates per line and mean time to repair shall build on statistical analysis of historical outage events in Europe.

h) Load curtailment sharing principles currently applicable within the Day Ahead electricity market coupling algorithm, shall be considered both for Coordinated Net Transmission Capacity regions (under NTC modelling) as well as for Flow-based areas, within the UCED model. The aim of curtailment sharing is to equalize as much as possible the curtailment ratios between those bidding zones that are simultaneously in a curtailment situation.[2]

[2] Euphemia Public Description, https://www.epexspot.com/document/40503/Euphemia%20Public%20Description

Article 5
Data Collection

1. The ERAA data collection shall follow the ENTSO-E data collection framework principles: i) ENTSO-E data collection guidelines are provided to each national TSO, to guarantee a coherent data collection process. Such guidelines specify the assumptions that each TSO has to use when providing data to ENTSO-E; ii) Some of the data requested from the TSOs is used as an input for centrally prepared data at ENTSO-E level.

2. The process of data collection to prepare and consolidate all required input data shall be centrally coordinated by ENTSO-E. During this process, data is collected from the TSOs according to centrally prepared guidelines by ENTSO-E. Furthermore, the collected data is provided by TSOs by filling standard data templates prepared/provided by ENTSO-E in a coordinated manner. The established data collection guidelines guarantee a standardised data preparation process and ensure that databases are built on consistent, transparent and common assumptions.

3. Transmission system operators shall provide ENTSO-E with the data needed to carry out the ERAA.

4. Data used as input to the resource adequacy methodology is collected by ENTSO-E through its network of adequacy correspondents nominated at each member TSO. The data collection processes may evolve over time to follow technological advances while guaranteeing consistency with corresponding processes of the TSOs.

5. Producers and other market participants shall provide the TSOs with the relevant data regarding expected utilisation of the generation resources, pursuant to Article 23(4) of the Electricity Regulation, respecting confidentiality and transparency, in order for TSOs to set up or benchmark the appropriate scenarios of projected demand and supply and, especially, to provide relevant technical and economic assumptions for the economic viability checks.

6. In exceptional cases, ENTSO-E may also formally request data from external market parties such as National Regulation Authorities (NRAs), Distribution System Operators (DSOs), National Electricity Market Operators (NEMOs), power plant/asset owners or operators and other relevant stakeholders, should this data be: i) missing from the TSO data collection, and ii) be needed in order to set up the appropriate scenarios or assumptions for the resource adequacy methodology as outlined in Article 4.

7. Collected data originates from combined top-down and bottom-up collection processes. It is consolidated into a Pan-European Market Modelling Data Base (PEMMDB) – a data base that contains information on the network and market models in annual resolution. More specifically, PEMMDB contains the input dataset to the UCED model, i.e. any data processing is provided prior to the data entry in the database. The PEMMDB includes:

   a) Generation data, consisting of RES and fossil fuel net generation capacities, their predicted evolution over time, maintenance requirements, ramp capabilities, fuel consumption, conversion efficiencies, mothballing predictions and relevant data. For future years, there shall be a clear distinction between existing and added generation capacities. Thermal generation data shall be collected unit by unit, to the best availability. Wherever unit by unit granularity is not available, generation data shall be aggregated per generation technology. RES capacities are provided per bidding zone. Both RES and fossil fuel time series have hourly time resolution;

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b) Data on existing contracts for assets within the considered portfolio, which have been granted after auctions occurred within existing CMs before or at the time of the assessment;
c) Data on the potential of DSR, storage, etc. for which the final expected realization in the market shall be economically assessed within the economic viability check. If available to TSO through national economic viability checks, input from relevant national market parties or through national consultation processes, also forecasted available demand response shall be submitted by each TSO per bidding zone including the respective price bands (price of activation vs. capacity) and relevant activation constraints. TSO forecasts are important as they shall be used to calibrate and validate the outcomes of the investment model to be used for the economic viability check of Article 6 of the Methodology;
d) System reserve requirements, i.e., with respect to FRR, FCR and RR;
e) Demand predictions, built on historical hourly demand profiles and forecasted adjustments (e.g. electric vehicles, heat pumps, energy efficiency among others; their penetration along with their properties). These components are detailed in the following:

   -Bidding zone historical demand time series with at least hourly resolution shall be collected from TSOs. Such historical demand time series, together with historical climate variables are used to build demand predictions.

   -Demand forecasts further require a set of model parameters that allow for a characterization of time series:

   i. Forecasted annual demand per sector (industry, residential sector, services and transport) and per bidding zone is provided as an aggregated forecast for each year (in TWh);
   ii. Forecasted additional electric vehicles with regard to the base year, average effective usage (km/EV/day) with differentiation between weekend and weekdays, average efficiency (energy consumption in kWh/100 km), share of fast- and slow-charging profiles – taking into the account the geographical diversity of charging behaviour within 10 years of the assessment. EV forecast is defined by each TSO; Vehicle-to-grid capabilities shall be reported as far as they are available to each TSO through national consultation or the data collection processes;
   iii. Forecasted number of heat pumps added: thermal load increase caused by heat pump additions, Coefficient of performance (COP), COP threshold for switching (hybrid heat pumps);
   iv. Forecasted addition of batteries: Non-market participating batteries are considered with their maximum total power (MW), storage capacities (MWh), cycle efficiency (%), peak reduction (%) and ramp-rate reduction (%);
   v. Other forecasted adjustments: additional other load types (e.g. data centers) in MW.
   vi. Holidays/weekdays/special days calendars;
   vii. If not included in the list above, other relevant characteristics of relevant technologies that affect demand levels and shape.

f) NTC of bidding zone interconnections where relevant. FBMC borders are referred to in paragraph 9 below.

8. The PECD of ENTSO-E includes:

a) Wind power and PV generation capacity factor time-series used for the calculation of wind and solar generation;
b) Temperature, used for the calculation of demand time series along with irrandiance, humidity and wind speed data;
c) Water inflows to reservoirs for the calculation of hydro generation.
d) The used climate data shall build on "state-of-the-art" climate and weather databases, using available re-analysis of historical data and climate projections when applicable.

9. TSOs shall use the following data when setting up the flow-based modelling:
a) List of relevant CNECs;
b) PTDFs considering the relevant list of CNECs and all the relevant market hubs and other relevant variables, within the geographical area modelled within the flow based approach.
c) Phase Shifting Transformer settings and HVDC set position, shall be considered as possible variables if deemed relevant for the flow-based calculation;
d) Relevant limitations not associated with Critical Branches but relevant for the scope of the assessment (external constraints and Long Term Allocations and Nominations LTA/LTN if/while applicable);
e) Remaining Available Margin (RAM) for each CNEC, considering minimum levels of RAM on the list of relevant CNECs, in accordance with Article 16 of Electricity Regulation and Article 4 of the Methodology.
f) This data shall be calculated centrally within ENTSO-E and should rely to the maximum extent possible on data prepared by TSO flow-based expert groups both within ENTSO-E as well as within relevant RCCs. The methodology to calculate these parameters shall follow the principles referred in Article 2 of the CACM and rules for the minimum capacity available for cross-zonal exchanges as referred in Article 16 of the Electricity Regulation.

10. Reserve requirements shall be available per zone in NGC. Data collections shall consist of the following:
a) Reserve requirements for FRR, FCR and RR. Operational reserve requirements should be provided while avoiding risk of double-counting (e.g., FRR should not include FCR);
b) Reserve requirements shall be provided to allow different modelling approaches, consisting of reserve requirements modelled as additional load, deduction from available generating capacity, provision by storage units or demand response referring only to interruptible contracts that could be activated to contain system frequency after the occurrence of an imbalance;
c) FRR requirements shall contain manually activated reserve as well as automatically activated reserve requirements. FRR requirements should be divided into FRR that needs to be available by generation or storage units, and FRR that will be procured by reservoir or pumped storage hydro.

11. Economic and technical data to perform viability assessments should be consolidated centrally by ENTSO-E based on best available information to ENTSO-E and complemented by inputs from TSOs and other relevant stakeholders and market parties. The following data categories are needed per relevant technology:
a) CAPEX, expressed in EUR/MW;
b) Fixed OPEX/fixed O&M costs: fixed OPEX/fixed O&M costs shall be expressed in EUR/MW/year and variable OPEX/ variable O&M costs in EUR/MWh;
c) Short term variable costs including variable OPEX/variable O&M costs, fuel costs, efficiencies and CO2 prices;
d) WACC and discount rates

12. Best estimates regarding technical and economic parameters (carbon price developments, fuel developments, estimates of other parameters needed for the economic viability checks, assumptions on market price cap levels and the analysis of its likely evolution to the value of lost load, as referred in Article 10 of the Electricity Regulation, will be prepared centrally by ENTSO-E, based on available economical expertise at European level. This shall be consistent with the ENTSO-E scenarios prepared for the TYNDP.
13. Information on existing or planned CMs shall be considered within the collection of national data on generation, demand and storage assets and shall be provided by TSOs through the data collection process. This includes assumptions on capacity and time duration and may include any form of CM (strategic reserve, capacity payment, capacity auction, capacity obligation, reliability option, etc.). This information should allow to assess the share of the capacity within the Pan-European Market Modelling Data Base (PEMMDB) relying on any type of existing or future CM as well as the expected duration of any already granted CM contract within the Y+1 –Y+10 scope of the assessment.
14. Data collection guidelines and model assumptions shall be published either in the documentation of ENTSO-E major products or dedicated reports for further use and validation by other stakeholders.

Article 6
Economic viability assessments

1. The following process of the economic assessment as described in Article 6 aims to implement an ambitious, innovative but complex methodology. Hence it shall require a systematic implementation based on stepwise impact assessments of the different steps. The focus of such stepwise assessment shall be on both its feasibility as well as on the robustness and trustworthiness of the results. Its implementation will require a proof-of-concept stage according to the implementation roadmap presented in Article 10 and in any case validated by ACER and ENTSO-E. Should the implementation of the methodology as presented in Article 6 provide unreliable results, either due to data quality or implementation issues, the approach shall be updated, upon request either of ACER and/or ENTSO-E.

2. The European resource adequacy assessment shall include an economic assessment of the likelihood of retirement, mothballing and new-build of generation assets. The purpose of the economic assessment shall be the minimization of the overall system cost, including operational and investment costs. Any other relevant technological or economical restrictions as well as market regulations shall be formulated as constraints of the problem.

- The system costs consist of annualized investment costs, annual fixed costs, variable costs and the costs resulting from unserved demand. Differentiation between non-policy and policy units/technologies shall be performed when setting up the economic viability problem.
- Policy technologies are not subject to economic viability checks and shall be defined by exogenous assumptions, e.g. following policy decisions related to coal or nuclear phase-outs, development of renewable energy sources or investment decisions regarding other relevant policy-driven supply evolutions.
- Non-policy technologies are subjected to a verification of their economic viability. The following investment candidates shall be defined:
    - Decommissioning/mothballing of existing units categorized as non-policy;
    - Investment in new units categorized as non-policy.

National projected supply outlooks prepared by each individual transmission system operator should label the assumed existing or expected new-build capacity either as ‘policy’ or ‘non-policy’. Such categorization shall be based on transparent and fundamental argumentation.

The constraints to the economic assessment are, amongst others:

- The demand;
- Existing units and their respective lifespan within the relevant period of the assessment;
- Reserve requirements;
- Constraints or side-effects resulting from heat supply in case of CHP assets, when deemed relevant for electricity production and for non-policy labelled resources;
- Constraints related to emission limits of CO2 of fossil fuel origin per kWh, as referred to points (a) and (b) of Article 22(4) of the Electricity Regulation, if relevant;
- Relevant technological, economical, market and regulatory constraints might be further imposed in order to check the robustness of the solution found by this assessment;
- When deemed appropriate within the considered scenario framework, such additional constraints might be based on relevant considerations including price restrictions, imperfect information, regulatory uncertainty, regulatory restrictions on investments, risk-averse behavior by investors, uncertainty regarding input markets or other relevant externalities in the electricity market.
- Any such considerations shall be duly fundamented and their impact explained upon the discussion of the results obtained.

The decision variables of the economic assessment are:

- Investment in different generation and storage units defined within the problem as investment candidates (considering the complete lifetime of all assets);
- Investment in demand-side response technologies;
- The decision between temporary mothballing vs. final shut-downs of non-viable generation units. These shall be compared with exogenous best forecast assumptions regarding temporary mothballing vs. final decommissioning / shut-downs, within the national forecast referred to in Article 3 of the Methodology;
- The decision variables shall assess the economic viability of the assets within the period of the assessment from Y+1 to Y+10;
- Lifetime of the units shall be considered, together with WACC, in depreciating the CAPEX both for existing and new-built capacities within the period of the assessment Y+1 to Y+10;
- The assessment shall not provide any explicit results beyond the Y+10 horizon as adequacy assessments become less informative beyond Y+10 due to the intrinsic uncertainties regarding the evolution of the power system beyond 10 years ahead in time, altough boundary condition constraints based on the value of decision variables beyond Y+10 could be enforced.

3. The **Economic Viability without CMs** check shall follow the following logic:

a) The Economic Viability procedure starts by considering exogenous assumptions based on national base line data as described in Article 3 of the Methodology. These national forecasts shall ensure quality and consistency with most recent national consultations and policies.

b) Within the above exogenous generation and demand assets, only non-policy technologies shall be considered as eligible for the economic viability check. Non-policy technologies refer here to technologies that exclusively rely on the energy-only market (EOM) revenues to ensure long-term investments. Technologies subject to national subsidies, support schemes, policies or incentives shall be considered as exogenous input and shall not be eligible in the ERAA economic viability check. These technologies might be assessed within national studies.

c) For countries with existing CMs, the economic viability assessment shall not take into account additional revenues to assets within a non-policy technology category as defined above, except when they already hold a CM contract granted in any previous auction of an existing or approved CM at the moment of the assessment.

d) Furthermore, within the above-mentioned non-policy technologies, all reported in-the-market capacities should be considered as eligible within the economic viability check (thus reported mothballed assets and proposed new-built assets by TSO shall be subject to the economic viability check, unless considered as policy assets under Article 6.2(c) of the Methodology).

e) The principles of the economic assessment framework of a scenario without CMs are:

For the given scenario and economic dispatch under a probabilistic simulation, the economic assessment, shall assess the likelihood of retirement, mothballing, and new-build of generation, storage and demand response assets, taking into account decisions based on the viability (or profitability) of the non-policy units under consideration.

Viability shall be defined as a function of the expected revenues (from EOM and any other relevant additional revenues if robust estimates exist on these), the variable costs, the fixed costs but also in terms of avoided costs (e.g. to take into account the possibility to mothball). In addition, revenues from CM shall be taken into account if the assets already hold a CM contract of an existing or approved CM at the moment of the assessment.

The expected revenues calculated for each asset shall reflect the current market design existing in each Member State. In particular, existing price caps on energy, including the provisions of Article 10 of the Electricity Regulation, and any existing contract within existing capacity markets shall be considered.

After economic dispatch under a probabilistic simulation, it can be observed that the distribution of revenues from all considered Monte Carlo years, including different climate conditions and outage scenarios, can be very skewed. In some cases, viability might rely on high price spikes occurring only within a small percentage of the analysed situations. To improve the viability assessment's robustness against these specific cases, the ERAA shall consider the effect of risk aversion towards price volatility and price spikes, considering state of the art experience in the industry.

Consideration of additional revenues due to scarcity pricing mechanisms shall be considered in ERAA only when a scarcity pricing mechanism is implemented and operational in a Member State. Therefore, a robust estimate exists and is provided upon the data collection on the extra revenues that such a mechanism is expected to provide through assumed backwards propagation of price signals into the day-ahead, intraday and long-term forward markets, triggered by short-term scarcity. ERAA economic viability checks will however not consider or assume any theoretical or academic scarcity pricing mechanism in any Member State beyond of what it is provided by the above-mentioned estimates relating to extra scarcity pricing related revenues.

Regarding additional revenues from for example heat-driven CHP production or ancillary services, if a robust estimate exists on the expected extra revenues and is provided upon the data collection by a TSO, it shall be considered in the economic viability within the ERAA assessment. To the extent possible, the estimation of expected revenues shall account for realistic operation within the functioning of either the EOM or the Ancillary Services Market of the concerned Member State. For ancillary services, the estimates shall only concern the Replacement Reserves (RR), these being the only part of the reserves contributing to adequacy (see Appendix 6 for details).

For the avoidance of doubt and regarding the above mentioned considerations of scarcity pricing or extra revenues from heat-driven CHP production and ancillary services, the concept of 'robust' implies here that such figures, when provided by TSO, are based on inputs from a national consultation process of data, as referred in Article 8 of the Methodology.

Furthermore, and due to the country-specific nature of these additional revenues, notably heat-driven CHP production or ancillary services, it might not be possible to reliably define these in the above-mentioned robust way needed for the ERAA. In that case, Member States might consider to tackle these aspects as part of the complementary national resource adequacy assessments pertinent to Article 24 of the Electricity Regulation. Robust estimation of such complementary revenues might be deemed a country-specific task by Member State and therefore beyond the scope of ERAA, therefore fulfilling the requirements of Article 24 (1a) of the Electricity Regulation of 'assumptions taking into account the particularities of national electricity demand and supply'.

f) The economic viability assessment procedure shall be integrated within the probabilistic economic dispatch assessment from the UCED model and its objective shall be to minimize the overall system costs considering operational costs and investment costs, in a probabilistic simulation.

- The economic viability assessment decisions shall keep non-policy assets in the model, if these assets are considered economically viable.

- The economic viability assessment decisions shall consider removing non-profitable non-policy assets from the model, if these assets are considered not economically viable.

- It is also possible for new assets within the different categories of non-policy technologies to be added, provided these assets are deemed viable within the economic assessment framework.

4. The **Economic Viability with CMs** check shall follow the same logic as Article 6(3) of the Methodology, also considering:

a) National projected supply outlooks prepared by each individual transmission system operator, indicating whether parts of the assumed existing or expected new-build capacity rely on remuneration from existing or planned but approved CMs in accordance with the State Aid rules pursuant to Articles 107, 108 and 109 of the TFEU. Hereby and in the following, only capacity remuneration mechanisms that allow capacity to participate in the electricity market are considered.

b) The economic assessment framework shall follow the principles described in Article 6(3), except for countries with existing or planned & approved CMs where the economic viability assessment shall also take into account additional revenues helping to ensure that the reliability standards are respected. Nevertheless, as referred to in Article 3(5)a, capacity limits (e.g. demand response), legal and administrative hazard, hazards with impact on availability, building delays and stop-loss limits, might justify in specific cases that the Reliability Standard is not always fulfilled at any price.

5. The stability and trustworthiness of the results of the economic viability assessment with respect to different assumptions (e.g. assumptions on costs, CO_2 prices, etc.) shall be studied with the objective to test the robustness of the scenarios resulting from the economic viability assessment. ENTSO-E shall ensure that

the endogenous assumptions of the model are consistent with relevant national policies, generation capacity forecasts and anticipation of feedback from national market parties, expressed upon the national consultations as referred in Article 9. In case of non-stability of the results within the mentioned sensitivity checks, the reliability of the relevant assumptions shall be assessed and when needed revised with non-purely economic considerations, in any case to strengthen the trustworthiness of the central scenarios proposed.

Article 7
Outputs and Results

1. Outputs of the adequacy assessment are provided in terms of EENS and LOLE for central reference scenarios and their sensitivities, with a spatial granularity which is the smallest level between country, bidding zone and control area, for each year from Y+1 until Y+10, where Y indicates the year of the publication of the adequacy assessment. For neighbouring bidding zones presenting EENS/LOLE, analysis of the different simultaneous scarcity regimes is performed. Different simultaneous scarcity situations at both regional and/or European level shall be indicated.
2. The source of the adequacy concerns shall be assessed via (i) the percentage of hours for any of the above scarcity situations to the total amount of scarcity hours and (ii) the analysis of imports during those scarcity events – considering all Monte Carlo years when there is scarcity.
3. The ERAA report shall strive to facilitate stakeholders' understanding regarding the inputs, data, and assumptions, and scenario development. This might encompass, amongst other, detailed figures and maps on renewable energy penetration, amount of unviable capacity, import/export levels, simulated newly-built capacity, mothballing, interconnector contribution, DSR, storage, self-generation contributions, energy efficiency measures, carbon price developments, etc.

Article 8
Stakeholder Interaction

1. Developing the proposals for the ERAA methodology, scenarios, sensitivities, assumptions and the report requires close interaction with the various stakeholders in each step of the process in a transparent, open, accessible, inclusive, efficient, and well-structured manner. The ERAA results provide a coherent and comparable basis on a European level, give key insights into the adequacy of supply to meet demand and contribute to the discussion on whether there is a need for CMs in the medium to long term for a variety of actors such as policy makers, TSOs, market participants, ministries, regulatory bodies and other national authorities and system users (among others).
2. Pursuant to Article 23(7) of Electricity Regulation, the ERAA methodology, scenarios, sensitivities, and assumptions as well as results of the assessment shall be subject to the prior consultation of Member States, the Electricity Coordination Group and relevant stakeholders and approval by ACER under the procedure set out in Article 27 of Electricity Regulation.
3. ENTSO-E shall facilitate opportunities through adequate interaction channels for all relevant stakeholders to contribute in each step of developing the proposals for the ERAA methodology, the scenarios, the assumptions, and results, through a transparent, open, accessible, inclusive, efficient, and well-structured process. Such channels shall include:

   a) stakeholder workshops and webinars to gather inputs and suggestions ahead of finalizing the proposals for the ERAA methodology and the report, and to address stakeholder questions;

b) web-based public consultations through the ENTSO-E consultation tool available on the ENTSO-E website;

c) visibility on forward planning for the next steps through the ENTSO-E Annual Work Program for each year ahead.

4. Consultations shall be planned by ENTSO-E on ERAA scenarios, assumptions, sensitivities and results:

4.1. A yearly consultation on assumptions and high-level definition of scenarios with their assumptions shall be published before the launch of simulations for the ERAA. This shall include at least CO_2 prices, fuel cost per technology and an overview of generation capacity per Member State. This process shall be closely aligned with the ENTSO-E TYNDP scenario framework biennial consultation process in the years when ERAA and TYNDP coincide with a view to avoiding duplication and ensuring data and scenario alignment between the ERAA and the TYNDP.

4.2. The exogenous capacity assumptions estimated by the TSOs shall receive stakeholder feedback through the processes of consultations of NECPs and national development plans within each MS and regional plans where relevant. In order to ensure coherent and consistent data quality and inputs, other available statistical sources or reports may be used as relevant from various national authorities, statistical databases and industry stakeholders, in compliance with Article 5(2) of the Methodology.

4.3. The Electricity Coordination Group (ECG) shall be consulted regarding the methodology, scenarios, sensitivities and assumptions. An overview of the preliminary results of the ERAA will be presented at the ECG as soon as available and preferably before the publication of the ERAA report.

4.4. Comments received from the ECG or other stakeholders during the consultation shall be incorporated into the respective edition of the ERAA as soon as practicable, while not delaying the annual publication of the ERAA.

4.5. The results of the ERAA depend strongly on the chosen scenarios and the quality of the data collected. ENTSO-E shall ensure through its public consultation on the scenarios, assumptions and sensititivies of the ERAA that producers and other market participants have the opportunity to check, compare and benchmark the data and the assumptions used in the assessment. For that purpose, they may be further asked to provide TSOs and ENTSO-E where necessary, with relevant data if deemed necessary and with the only purpose of ensuring that ENTSO-E uses robust and coherent inputs. The granularity of the data published shall be in compliance with ENTSO-E's data transparency guidelines.

4.6. The results of each ERAA, together with the assumptions on which they are based and the data related to the different scenarios, shall be made publicly available on the ENTSO-E website at the same time as the report is published.

5. Regarding approval, revision or amendments to the Methodology:

5.1 As set in Article 27(3) of Electricity Regulation, within three months of the date of receipt of the draft proposals, ACER shall either approve or amend them. In case of amendment, ACER shall consult ENTSO-E before approving the amended proposal.

5.2. ACER may request changes to the approved proposal at any time, pursuant to Article 27(4) of Regulation (EU) 2019/943. Within six months of the date of receipt of such a request, ENTSO-E shall submit a draft of the proposed changes to ACER. Within three months of the date of receipt of the draft, ACER shall amend or approve the changes.

5.3. ENTSO-E may also submit a request for updates to ACER, in case significant evolutions or new information would require updates of the Methodology. Any subsequent proposals for amendments to the methodology shall be consulted publicly as per the requirements of Article 27 of Electricity Regulation and submitted to ACER for approval or amendment.

6. While complying with the methodology framework, ERAA shall, to the extent possible, take advantage of latest innovations and improvements in terms of data accuracy, data granularity and computing power, in order to keep a state-of-the-art approach. ENTSO-E shall strive to keep awareness on innovations in Europe and globally, especially though interactions with universities, research institutions and industry experts.

Article 9
Process

The data collection and different stakeholder interactions, as described in Article 5 and Article 8 of the Methodology, will occur in the following order:

1. ENTSO-E provides data templates to each TSO and publishes data collection guidelines and model assumptions either in the documentation of ENTSO-E major products or dedicated reports for further use by other stakeholders;
2. TSOs fill in the data templates according to the data collection guidelines;
3. ENTSO-E collects the TSO data, executes data quality checks, centrally prepares and stores the data in the PEMMDB in order to be used later in the ERAA;
4. ENTSO-E prepares and consolidates economic and technical data to perform viability assessments centrally;
5. ENTSO-E organizes, in alignment with the TYNDP scenario framework biennial consultation process in the years when ERAA and TYNDP coincide, a consultation on yearly assumptions and high-level definition of scenarios with their assumptions before the launch of simulations for the ERAA.
6. The exogenous capacity assumptions estimated by the TSOs shall receive stakeholder feedback through the processes of national consultations of NECPs and national development plans within each MS and regional plans where relevant;
7. ENTSO-E consults the ECG regarding the scenarios, sensitivities and assumptions;
8. ENTSO-E executes the ERAA calculations and analyses the results;
9. ENTSO-E presents an overview of the preliminary results of the ERAA to the Electricity Coordination Group and relevant stakeholders as soon as available and preferably before the publication of the ERAA report;
10. ENTSO-E incorporates comments received from the ECG or other stakeholders during the consultation into the respective edition of the ERAA as soon as practicable, while not delaying the annual publication of the ERAA;
11. ENTSO-E publishes the report containing the results of each ERAA on the ENTSO-E website, together with the assumptions on which they are based and the data related to the different scenarios;
12. ACER may approve, revise or amend the ERAA results throughout the process as set in Article 27(3) of Electricity Regulation.

Article 10
Implementation

1. The ERAA methodology shall be used as the reference methodology for conducting the ERAA by ENTSO-E. The national resource adequacy assessments shall have a regional scope and shall be based on the ERAA methodology as per article 24 of the Electricity Regulation.
2. The ERAA methodology shall be implemented through a step-by-step, gradual process, where 'proof of concept' testing and impact assessment of the different methodological elements shall be ensured, prior to considering that any such methodological deployment within the ERAA methodology target is mature as an integral part of the ERAA report. Such approach shall also allow to strike the balance between accuracy and feasibility of the targeted improvements and facilitate an efficient implementation based on experience gathered through this step-by-step process.
3. This ERAA methodology provides the key principles and requirements to be considered as a basis to perform the European assessment. However, different requirements may be gradually deployed in each subsequent annual ERAA based on latest capabilities and improvements with respect to technical, data and computational capabilities and resources to ensure a state-of-the-art approach is followed.
4. Each ERAA report shall:

   a) consider the most up to date information and data available regarding Member State-level plans (NECPs) in the year of publication of the report;

   b) use the current bidding zone configuration of the year of publication of the report as well as the latest available assumptions regarding potential changes to that configuration for the 10-year horizon ahead;

   c) deploy the flow-based market modelling approach where applicable (e.g. where real time flow-based market coupling is implemented);

   d) deploy/include sectorial integration assumptions and modelling once the relevant European legislative framework regarding sector coupling has been established;

   e) deploy a yearly granularity resolution through a stepwise approach based upon testing and tool outputs have converged towards equally robust results;
5. Regional and national adequacy assessment studies shall inter alia use most recent data and assumptions which shall be as much as possible consistent with ENTSO-E data and which if deviating shall be complementary to the data used by ENTSO-E for the ERAA. Regional and national adequacy assessment studies shall follow the same ERAA stepwise implementation and deployment approach as ENTSO-E.

Article 11
Language

1. The reference language for this Methodology Proposal shall be English.

Appendix 1
Glossary

Acronym	Definition
aFRR	Automatic Frequency Restoration Reserve
CM	Capacity Mechanism
CNEC	Critical Network Elements and Contingencies
DSO	Distribution System Operator
EENS	Expected Energy Not Served
ENS	Energy Not Served
ERAA	European Resource Adequacy Assessment
FBMC	Flow-based Market Coupling
FCR	Frequency Containment Reserve
HVDC	High-Voltage Direct Current
Electricity Regulation	Electricity Regulation of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity (recast)
LOLD	Loss of Load Duration
LOLE	Loss of Load Expectation
Methodology	European Resource Adequacy Assessment Methodology in accordance with Articles 23 of the Electricity Regulation of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity (recast)
mFRR	Manual Frequency Restoration Reserve
MS	Member State
NEMO	Nominated Electricity Market Operator
NRA	National Regulatory Authority
NGC	Net Generating Capacity
NTC	Net Transfer Capacity
RR	Replacement Reserve
TFEU	Treaty on the Functioning of the European Union
TYNDP	(ENTSO-E) Ten-Year Network Development Plan

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Appendix 2
High-level information flow scheme

European Resource Adequacy Assessment (ERAA)

10-year ahead adequacy results
- Year-by-year adequacy in each zone
- Compliance with reliability standards
- Impact of different regulatory scenarios on adequacy
- Lack of generation and interconnection capacities

↓ Year-ahead adequacy results

Seasonal Adequacy Assessment

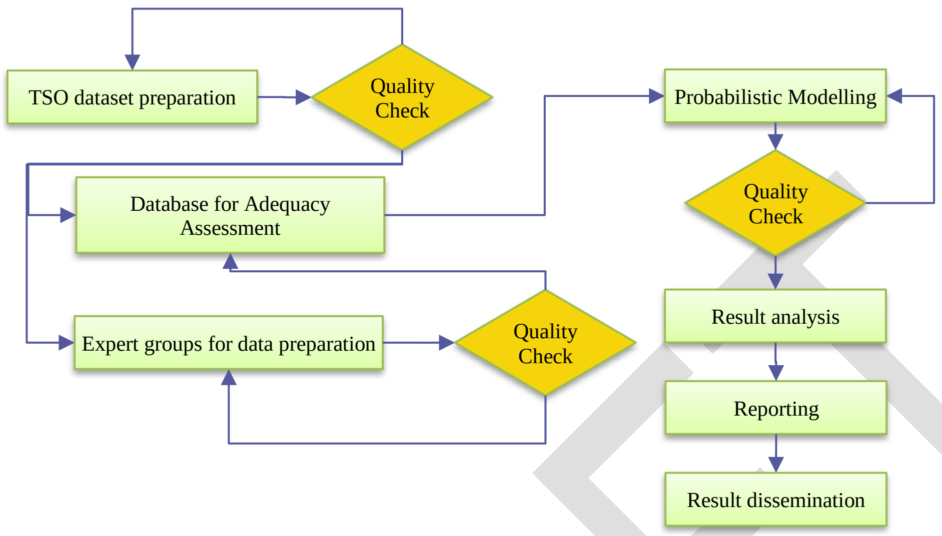
Intra-season adequacy results
- Updated adequacy
- Identification of most critical weeks and zones
- Assessment of available countermeasures
- Circumstances when risks exist

↓ Critical weeks and zones

Short-term Adequacy Assessment

Intra-week adequacy results
- Updated adequacy
- Identification of most critical moments
- Assessment of available countermeasures
- Trigger if regional assessment is needed

Appendix 3
High-level business process diagram



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Appendix 4
Principles of an economic viability assessment

In order to assess the viability of generation, demand response or storage capacities, relevant investment decisions have to be replicated and forecasted as far as possible. In general, investment decisions will depend on expected revenues in the energy-only market (EOM) plus potential additional revenue streams (for example, revenue streams from CMs, heat supply markets etc). In addition, there is a range of potential investment decisions available to market actors (e.g. new DSR, new gas units, new non-policy RES, unit decommissioning). The following aspects and interdependencies need to be considered in a viability assessment:

- The possibility to invest in different generation and storage technologies;
- The decision between temporary mothballing vs. final shut-downs;
- The possibility to invest in demand side management technologies;
- The impact of one investment on another / the interdependency of different investment options;
- An estimation of the revenue streams in the EOM;
- An estimation of possible other revenue streams and subsidies, especially related to heat supply and ancillary services; In this respect and due to its national specificity, ENTSO-E relies on estimates from each Member State;
- The impact of CMs as an additional revenue stream;

The estimation of revenues and prices of the EOM should consider price variations due to different weather years and power plant outages as these impacts are also known to market actors. A purely deterministic approach (potentially underestimating market prices) would not lead to a correct representation of the investors' revenue expectations.

When evaluating a scenario, the viability assessment shall be performed for both existing and anticipated generation capacity.

Both the assumptions as well as the methodology are subject to continuous improvement in order to achieve more precision on predicting the generators' expansion and retirement decisions.

Especially during the initial implementation phase, counterchecking the results by TSOs will support the calibration and development of a suitable model.

The generation viability assessment shall be based on an economic model. Such a model incorporates all existing information as exogenous input (as for example information on ongoing power plant installations) and derives an endogenous solution for the remaining degrees of freedom (see Appendix 5 for details).

The development and application of such model is challenging, especially in the European framework. It is therefore considered as a mid-term target that is to be reached by yearly improvements of generation viability assessments, following both systematic impact assessments of the proof-of-concept as well as by assessing the robustness of the results within any given ERAA report.

Appendix 5
Principles about risk aversion metrics

In order to verify the economic viability of the assumptions used to set up the Reference Scenarios of ERAA, the study shall include an 'economic viability test' based on expected inframarginal rent of assets. Inframarginal rent (the operational profit without taking into account the fixed operational cost) are assessed using a probabilistic approach, simulating yearly (Monte Carlo years) inframarginal rent according to several hundreds of different generation patterns of renewables (over different climate years) and forced outages.

Inframarginal rent estimates based on these Monte-Carlo simulations could be ranked from the lowest to the highest. The ranking consists of 100 percentiles, where e.g. the P01 represents the lowest revenue and P100 the highest revenue.

In this appendix ENTSO-E addresses the reasoning behind the proposed choices for the ERAA methodology. More specifically, this appendix presents the following arguments:

- A basic average expected revenue cannot adequately reflect investors' risk perception and aversion, due to the inframarginal rent distribution skewness and the lack of information on extreme events; and
- When making an investment decision, an investor will adopt a prudent approach with respect to the inframarginal rent distribution provided in the adequacy study;
- The methodology and its implementation shall capture these considerations and focus on two main drivers: i) maturity of the method & robustness of the results ii) feasibility of the calculation;
- Construction Time and Economic Lifetime considerations need to be considered carefully;
- Risk aversion relates to investment decisions for both Generation and Demand Response assets.

Capacity operators and investors bear a financial risk regarding the economic profitability of their assets as a result of uncertainty surrounding fluctuating energy levels and capacity prices.

Increased RES penetration and a rapidly evolving interconnected system will bring increased volatility to the power system which in turn might present both new opportunities as well as additional difficulties and risks to investors.

In the power sector, investors often push project developers to deliver projects whose likely viability is based on conservative estimates. In other words, viability is determined by the project's ability to mitigate the impact of extreme and hard-to-model events rather than basing it purely on the basic average of the total revenues which might be highly dependent on occurrence of prices spikes.

Therefore, ENTSO-E considers that economic viability modelling should capture investors' risk averse behaviour in economic viability tests. In doing so, ENTSO-E will consider the following, during the period agreed for implementation of the economic viability framework:

- Review and consider 'state-of-the-art' risk metrics/methods when considering the calculation of the expected revenues.
- The impact on the methodology after the introduction of such risk metrics needs to be assessed carefully. Systematic impact assessments will be needed to assess:
    - (i) the maturity of the proposed method;
    - (ii) the feasibility of the viability assessment to be performed/computed by addition of such methodological layer;
    - (iii) robustness of the results and quantification of the risk-averse metrics.

- Therefore, it may be necessary to explore different strategies during the implementation of the methodology. Some non-exhaustive examples are given:
  - (i) incorporating risk metrics through linear constraints in the economic viability problem
  - (ii) using metrics in the estimation of strategies to reduce price volatility risk after analysis of the results of the economic viability
  - (iii) Other relevant metric and state-of-the-art methods than mentioned above can be explored and will have to be thoroughly assessed during the implementation phase. Some further examples include utility functions and Capital Asset Pricing Model (CAPM).

The electricity industry requires high capital investment costs. Therefore, any risk aversion is automatically linked to how these capital costs should be recovered and remunerated. Risk aversion from this perspective can be very significant if the construction period and economic lifetime are equal to or greater than 10 years.

Risk averse behaviour however must also be expected and thus considered on the demand side, specifically considering DSR and demand-flexible customers/assets, as those customers do not / will not always act ‘rationally’ i.e. cannot always be expected to take the most cost-effective option.

For demand flexible customer and investments related to DSR, aversion to risk can also exist due to the capital intensiveness of the investments required, financial risk due to interrupted commercial or industrial activity, inflexibility of a certain part of demand, complexity to technically materialize customers’ economic willingness to react to high prices or simply because customers have other priorities in relation to willingness to pay and market responsiveness.

With regards to DSR at very high price levels, it is also uncertain whether the theoretically-derived, most cost-effective option truly reflects a customer’s willingness to pay or if it is simply forcing a customer to disconnect once they are unable to pay the offered price. In the former case, DSR is a service based on the customers’ freedom to choose while it could be argued the latter might restrict customers’ decision-making power.

Amendments request by ACER might be initiated, as referred to in Article 8(5) of the Methodology, in order to incorporate into the methodology description any of above-mentioned considerations should the systematic impact assessment and continuous checks performed by ENTSO-E throughout the implementation process conclude that a given methodological item has reached the level of maturity necessary to be considered as an integral part of the ERAA assessment methodology.

Appendix 6
Reserves

Reserves are aimed at ensuring maintaining the frequency at 50 Hz. The reserves are dimensioned to cover the unexpected imbalances resulting from second-by-second random variations of generation and load and to face a range of contingencies. When dimensioning reserves, it is assumed the system, on average, is balanced.

A lack of adequacy reflects the expectation that the system is structurally imbalanced, at least in some hours and days, e.g. during peak loads or low renewable feed-in periods. The hours for which a structural lack of adequacy is present are aggregated as LOLE (Loss of Load Expected). In such cases it may be tempting to use reserves to partially address inadequacy. However, this would mean they would not be available for their intended purpose in the event where an imbalance event occurs. This could result in severe violations of the frequency quality criteria set up in legislation that reserves are obligated to meet, given the lack of means left in the system with the technical characteristics (e.g. activation delay) needed to safeguard these frequency criteria. The fundamental criteria governing frequency reserves is stipulated in the SO GL.

A concrete and recent example:

> It was seen in Great Britain on the 9th of August 2019 that the system experienced an instantaneous loss in generation capacity resulting in severe low frequency disconnections. As the country had assigned scheduled reserves to cover normal operational demand, these were unavailable to arrest the frequency drop. Similar results will occur if frequency reserves are eroded for operating margin instead of being used for frequency containment and restoration. Frequency reserves are required to ensure that the frequency containment and restoration policy is met, while in this example, this was not the case.

ENTSO-E considers it important not to confuse measures planned to cope with predictable imbalances with those designed for unplanned contingencies. While FCR is dimensioned to cover the biggest imbalance incident in the synchronous area, in Continental Europe FRR is dimensioned to cover the biggest imbalance incident in the LFC Block and to cover 99% of observed, historical imbalances. RR is optional and is meant to replace/complement FRR. In addition, FRR capacity is dimensioned for each LFC Block to fulfil the frequency target requirements according to the SO GL. If a country were to hypothetically use FRR to cover partially or entirely its generation adequacy needs, then FRR (automatic/manual) would need to be over-dimensioned to cover these extra needs to not violate its frequency target requirements, these being determined annually. Even if reserves are over-dimensioned there is no way TSOs can guarantee that these are able to cover all imbalance incidents simultaneously as most of these events are unplanned, by definition.

Concerning FRRs, there is no differentiation between mFRR and aFRR in the sense that both are meant to restore system frequency within 15 minutes after an imbalance incident as stipulated in the SO GL for the Continental European Synchronous Area. The SO GL further mandates that reserves in general are not meant to balance the system for longer than 15 minutes, unless in exceptional circumstances, so-called contingency events.

Since adequacy issues are predictable in general, they do not count as exceptional circumstances. The probabilistic dimensioning of FRRs does not take these adequacy events into account unless these events have happened at a statistically significant rate. By design, LOLE has to be less than 1% of the annual operating hours. As FRR covers 99% of all unbalanced cases, leaving 1% intentionally uncovered, the LOLE is both statistically insignificant and outside the scope of FRR dimensioning.
With variable generation increasing one can expect a rise in unpredictable imbalance events. As such, it is critical to keep reserves to mitigate unexpected fluctuations.

The conclusion of ENTSO-E is that no FCR and FRR frequency reserves should be assumed for mitigating generation adequacy problems.