ACER
European Union Agency for the Cooperation of Energy Regulators

ACER Decision on the ERAA methodology: Annex I

Methodology for the European resource adequacy assessment

in accordance with Article 23 of Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity

13 March 2026

Contents

Whereas

(1) This document sets out the methodology for the European resource adequacy assessment (hereafter referred to as "ERAA") 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 (hereafter referred to as "Electricity Regulation"). This methodology is hereinafter referred to as the "ERAA methodology".

(2) The ERAA methodology takes into account the general principles and goals set out in the Electricity Regulation as well as in a broader EU regulatory framework, in particular:

(a) Regulation (EU) 2019/942 of the European Parliament and of the Council of 5 June 2019 establishing a European Union Agency for the Cooperation of Energy Regulators (hereinafter referred to as "ACER Regulation");

(b) Directive (EU) 2019/944 of the European Parliament and of the Council of 5 June 2019 on common rules for the internal market for electricity (hereinafter referred to as "Electricity Directive");

(c) 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 "RPR");

(d) Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management (hereinafter referred to as "CACM Regulation");

(e) Commission Regulation (EU) 2017/2195 of 23 November 2017 establishing a guideline on electricity balancing (hereinafter referred to as "EB GL");

(f) Commission Regulation (EU) 2017/1485 of 2 August 2017 establishing a guideline on electricity transmission system operation (hereinafter referred to as "SO GL");

(g) Commission Regulation (EU) 2017/2196 of 24 November 2017 establishing a network code on electricity emergency and restoration (hereinafter referred to as "E&R NC");

(h) Regulation (EU) 2018/1999 of the European Parliament and of the Council of 11 December 2018 on the Governance of the Energy Union and Climate Action (hereinafter referred to as "Governance Regulation");

(i) Regulation (EU) No 1227/2011 of the European Parliament and of the Council of 25 October 2011 on wholesale energy market integrity and transparency (hereinafter referred to as "REMIT");

(j) Commission Regulation (EU) 543/2013 of 14 June 2013 on submission and publication of data in electricity markets (hereinafter referred to as "Transparency Regulation");

(k) Report from the Commission to the European Parliament and the Council on the assessment of possibilities of streamlining and simplifying the process of applying a capacity mechanism under Chapter IV of Regulation (EU) 2019/943, in accordance with Article 69(3) of Regulation (EU) 2019/943, COM/2025/65 final (hereinafter referred to as "Streamlining Report");

(l) Communication from the Commission – Framework for State Aid measures to support the Clean Industrial Deal (Clean Industrial Deal State Aid Framework), C/2025/7600, OJ C, C/2025/3602, 4 (hereinafter referred to as "CISAF");

(m) The type and format of data and the methodology for TSOs' and DSOs' flexibility needs analysis approved by ACER Decision 05/2025 (hereinafter referred to as "Flexibility Needs Assessment Methodology" or "FNA Methodology");

(n) Methodology for calculating the value of lost load, the cost of new entry, and the reliability standard approved by ACER Decision 23/2020 (hereinafter referred to as "VOLL, CONE and RS Methodology");

(o) Technical specifications for cross-border participation in capacity mechanisms approved by ACER Decision 36/2020 (hereinafter referred to as "Technical Specifications").

(3) The responsibility to determine the general structure of its own level of security of supply is a Member State's right, pursuant to Article 194(2) of the Treaty on the Functioning of the European Union. The freedom for a Member State to set its own desired level of security of supply is also recalled in Recital (46) of the Electricity Regulation.

(4) The ERAA methodology contributes to an efficient achievement of the objectives of the Energy Union set out in Article 1(a) of Electricity Regulation, in particular with respect to security of supply, by providing an objective methodological basis for the assessment of resource adequacy concerns.

(5) The ERAA methodology ensures a realistic assessment, by requiring that the best forecast of the expected system state be used to assess resource adequacy.

(6) The ERAA methodology has been developed in line with the principles of the electricity market operation outlined in Article 3 of Electricity Regulation. In particular, the ERAA helps to ensure that safe and sustainable generation, energy storage and demand response participate on equal footing in the market (pursuant to Article 3(j) of Electricity Regulation), by requiring that all resources which contribute to resource adequacy are modelled.

(7) The ERAA aims to best reflect system development trends, including change of generation capacity mix, change of demand patterns, network development and others. The ERAA also aims to best reflect the expected trends in market design.

(8) The ERAA aims to provide reliable results and to reflect the realistic conditions of market and electric system operation.

(9) The ERAA aims to provide a consistent and comparable basis on a European level, gives key insights into the adequacy of supply to meet demand, and identifies resource adequacy concerns (and their causes). The ERAA results should help to inform the EU Member States (hereinafter referred to as "Member States"), national regulatory authorities (hereafter referred to as "NRAs") and stakeholders about the forecast level of security of supply in the EU. The ERAA results may also serve as a basis to consider different market design options pursuant to Articles 20 and 21 of Electricity Regulation.

(10) For the purpose of complementing the European resource adequacy assessment, Member States may also carry out national resource adequacy assessments pursuant to Article 24 of the Electricity Regulation. National resource adequacy assessments in accordance with Article 24 of the Electricity Regulation and the European Resource Adequacy Assessment in accordance with Article 23(5)(b) of the Electricity Regulation shall be 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. Based on their central reference scenarios, both the ERAA and NRAAs can identify adequacy concerns.

(11) Transparency and monitoring are essential for ensuring accountability of the European Network of Transmission System Operators for Electricity (hereafter referred to as “ENTSO-E”) in carrying out the ERAA and increasing stakeholders’ understanding of this exercise. To this aim, the ERAA methodology includes specific data publication and public consultation requirements, thereby not only enhancing transparency of the ERAA but also promoting transparent operation of ENTSO-E as mandated by Article 41(2) of Electricity Regulation. Furthermore, the ERAA methodology envisages information-sharing with the relevant NRAs to facilitate their joint regional oversight on cross-border issues pursuant to Electricity Directive.

(12) The ERAA methodology envisages suitable stakeholder engagement channels to ensure that all stakeholders and NRAs have the opportunity to provide transmission system operators (hereafter referred to as “TSOs”) 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 ERAA.

(13) In 2024, the Electricity Regulation was amended to improve the design of the Union’s electricity market.[1] Under Article 69(3) of the Regulation, the Commission was tasked with assessing how to streamline and simplify the application process for capacity mechanisms (CM) under Chapter IV and to request ACER to amend the ERAA methodology as appropriate. The Commission’s Streamlining Report of March 2025 formed the basis for ACER’s subsequent request to amend the methodology.

(14) Additionally, the Commission was tasked with developing proposals to simplify the process of assessing CMs. In August 2025, the Commission adopted the CISAF, establishing a fast-track approval process for CMs.

(15) The CISAF relies on ERAA to provide the necessary inputs for the computation of the CM-related parameters. The Streamlining Report recommended that the ERAA methodology should include a post-process to enable the direct identification of the capacity volume to procure for each bidding zone linked to the adequacy gap identified in the ERAA. Furthermore, the Report recommended that technology-specific de-rating factors should be made publicly available by ENTSO-E, with ACER’s oversight.

(16) Consequently, this methodology requires ENTSO-E to compute and publish, within each annual ERAA (“ERAA edition”), the CM-related parameters necessary for Member States that wish to make use of the CISAF fast-track CM approval process, including at least de-rating factors, adequacy gaps and total firm capacity needs for all modelled zones with an adequacy concern. Integrating the computation of the CM-related parameters within the ERAA provides several benefits. It ensures availability of these parameters to all Member States, enhances the transparency of the ERAA, and enables Member States to understand how their parameters are influenced by system developments and adequacy conditions in other countries. This approach is also the most efficient approach, since in this way parameters can be derived through standardised post-processing of ERAA outputs, without imposing undue computational burden on ENTSO-E and without requiring Member States to process the full ERAA datasets.

(17) Article 22(1)(c) of the Electricity Regulation stipulates that CMs must not exceed what is necessary to address adequacy concerns. This requires that the volume of capacity procured by a Member State appropriately considers the positive adequacy effects of CMs implemented in other Member States.

[1] 1 Regulation (EU) 2024/1747 of the European Parliament and of the Council of 13 June 2024 amending Regulations (EU) 2019/942 and (EU) 2019/943 as regards improving the Union’s electricity market design, OJ L, 2024/1747, 26.6.2024.

Within the ERAA, these cross-border interactions and their system-wide contribution to adequacy can only be captured in the central reference scenarios that include CMs (with-CM central reference scenarios). Deriving CM-related parameters from the with-CM central reference scenario is also essential for maintaining consistency with the calculation of maximum entry capacity, as set forth in the Technical Specifications. Therefore, this methodology provides that de-rating factors, adequacy gaps, and total firm capacity needs will generally be extracted from the with-CM central reference scenarios. The methodology therefore foresees a gradual implementation of the derivation of CM-related parameters from with-CM central reference scenarios, aligned with the progressive implementation of those scenarios across successive ERAA editions.

(18) Article 19e(1) of the Electricity Regulation requires that the regulatory authority, or another authority or entity designated by a Member State, must adopt a report on the estimated flexibility needs covering a period of at least the next 5 to 10 years at national level. Article 19e(1)(a) of the Electricity Regulation requires that this report must be consistent with the ERAA and NRAAs conducted pursuant to the Articles 23 and 24 of the same Regulation.

Article 1
Subject matter and scope

1. The ERAA methodology shall be used to identify resource adequacy concerns by assessing the overall adequacy of the electricity system to supply current and 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 Electricity Regulation.
2. The ERAA methodology shall fulfil the requirements of Article 23(5) of Electricity Regulation.
3. ERAAs shall have explicitly modelled systems covering at least the region composed of TSOs (i.e. at least the European Union). ENTSO-E shall continuously engage operators of other interconnected systems to establish and foster cooperation. If tightly interconnected neighbouring regions commit to cooperate on resource adequacy assessments, they should be modelled as explicitly modelled systems. Otherwise, the contribution of these systems to pan-European resource adequacy shall be considered through non-explicitly modelled systems.
4. The temporal and spatial granularity of the ERAA shall respect at minimum the granularity defined in the ERAA methodology. ENTSO-E shall carry out the ERAA on an annual basis in line with Article 23(4) of Electricity Regulation.

Article 2
Definitions and interpretation

1. For the purpose of the ERAA methodology, the definitions in Article 2 of Electricity Regulation, Article 2 of RPR, Article 2 of CACM Regulation, Article 3 of SO GL, Article 2 of EB GL, Article 2 of Transparency Regulation as well as Article 2 of Electricity Directive shall apply.

2. In addition, the following definitions and acronyms shall apply. In the event of any inconsistency between the following definitions and the definitions pursuant to paragraph (1), the latter shall prevail.

   (a) “adequacy gap” means for a given modelled zone, target year and scenario assumption basis, a quantity expressed in MW of equivalent firm capacity representing the additional capacity required, relative to the de-rated installed capacity in the corresponding without-CM central reference scenario, for that modelled zone to meet its applicable reliability standard, as determined in accordance with Article 12.

   (b) ‘annual fixed costs’ means costs incurred each year in the context of operation of a capacity resource once the capacity resource starts commercial operation, independently from the generated or curtailed (in case of DSR) energy volume;

   (c) ‘capacity calculation methodology’ (CCM) means the capacity calculation methodology expected to apply for the considered target year;

   (d) ‘capacity resource’ means any generation, storage or DSR asset which may bring resource adequacy benefit;

   (e) ‘capital expenditures’ (CAPEX) means the investment required to develop, construct or refurbish a capacity resource without considering the financial costs (e.g. interest costs) or the structure of financing (equity versus debt), i.e. the investment required if the capacity resource were to be built overnight at the current prices;

   (f) ‘central reference scenarios’ means the main scenarios defined pursuant to Article 3(2a), in line with Article 23(5)(b) of Electricity Regulation;

   (g) ‘CHP’ means combined heat and power;

   (h) ‘CM’ means capacity mechanism pursuant to Article 2(22) of the Electricity Regulation;

   (i) ‘CNEC’ means critical network element associated with a contingency used in the CCM. For the purpose of the ERAA methodology, the term CNEC also covers the case where a critical network element is used in the CCM without a specified contingency;

   (j) ‘CONE’ means cost of new entry in line with the CONE methodology;

   (k) ‘CONE methodology’ means the methodology for calculating the cost of new entry pursuant to TITLE 3 of the VOLL CONE RS methodology;

   (l) ‘CORP’ means cost of renewal or prolongation pursuant to Article 2 of the VOLL CONE RS methodology;

   (m) ‘demand’ means the total instantaneous electricity consumption observed in the transmission system, including transmission network losses;

   (n) ‘de-rated installed capacity’ means, for a given modelled zone, target year and scenario, the quantity of equivalent firm capacity attributable to installed capacity located in that modelled zone, calculated in accordance with Article 12(11).

(o) 'de-rating factor' means, for a given technology type, modelled zone, target year and scenario assumption basis, the parameter that quantifies the contribution of that technology, expressed in equivalent firm capacity, to meeting applicable reliability standard in that modelled zone for that target year with that scenario assumption basis, as determined in accordance with Article 12.

(p) 'DSR' means demand response pursuant to the Electricity Directive. In addition,

i. 'explicit demand-side response' (explicit DSR) means the demand-side flexibility that is actively offered into the market or procured as a service. It is represented as a dispatchable resource (i.e., a controllable reduction or shift of load) with an explicit activation rule. In modelling terms, it typically appears as an explicit decision variable subject to constraints, and may be treated analogously to a supply-side resource;

ii. 'implicit demand-side response' (implicit DSR) means the demand changes that occur passively through consumers' normal reaction to price signals or tariffs, without an explicit market bid or activation by an operator/aggregator. In modelling terms, it can be captured through altered demand levels or load shapes, or appear as a dispatchable resource;

(q) 'discount rate' expresses the time value of money and converts future cash flows 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;

(r) 'earliest entry year' means the first target year in which new capacity resources of a given technology may be assumed to enter the market in the Economic Viability Assessment. This year is determined to ensure that there is sufficient time for commissioning if an investment decision is made at the time of the ERAA study.

(s) 'earliest exit year' means the first target year in which existing capacity resources of a given technology may be assumed to exit the market in the Economic Viability Assessment. This year is determined to ensure that there is sufficient time for retirement or decommissioning, assuming that a decommissioning decision is taken at the time the ERAA.

(t) 'ECG' means electricity coordination group;

(u) 'economic dispatch' (ED) means a mathematical optimisation model as described in Article 7;

(v) 'economic lifetime' means economic lifetime pursuant to the CONE methodology;

(w) 'economic viability assessment (EVA)' means a model assessing the viability of capacity resources, informing decisions on retirement, mothballing and re-entry, renewal/prolongation and new-build of capacity resource as described in Article 6;

(x) 'energy-only market' (EOM) means the markets for electricity, including over-the-counter markets and electricity exchanges, markets for the trading of energy, balancing and ancillary services in all timeframes, including forward, day-ahead and intraday markets, but excluding CMs;

(y) 'energy not served (ENS)' means, for a given MTU and modelled zone, the energy which is not supplied due to insufficient capacity resources to meet the demand;

(z) ‘equivalent firm capacity’ means a common capacity metric, expressed in MW, used to compare the contribution of different resources to resource adequacy and to express adequacy-related capacity values for modelled zones. One MW of equivalent firm capacity corresponds to the contribution to resource adequacy of one MW of perfectly reliable reference technology.

(aa) ‘ERAA edition’ means ERAA conducted for a given year. For example, ERAA 2026 edition means ERAA conducted for the year 2026.

(bb) ‘ERAA report’ means the scenarios, sensitivities, assumptions and results of the ERAA for the purpose of Article 23(7) of the Electricity Regulation.

(cc) ‘expected energy not served’ (EENS) means, in a given modelled zone and in a given time period, the expected ENS;

(dd) ‘explicitly modelled systems’ means electric systems which are modelled in detail. These systems shall be modelled considering each element of the probabilistic model set in the ERAA methodology;

(ee) FCR means frequency containment reserves pursuant to SO GL;

(ff) ‘fixed costs’ means the sum of the CAPEX (annualised based on WACC) and the annual fixed costs of a capacity resource;

(gg) ‘flow-based’ means the flow-based approach pursuant to CACM Regulation;

(hh) ‘flow-based domain’ means a set of constraints that limit the flow-based cross-zonal capacity;

(ii) FRR means frequency restoration reserves pursuant to SO GL;

(jj) ‘GSK’ means generation shift key pursuant to CACM Regulation;

(kk) ‘load factor’ means the power generated (respectively consumed) by a given generation (respectively consumption) unit, divided by the installed capacity of the generation unit (respectively the maximum demand consumed);

(ll) ‘loss of load expectation’ (LOLE) means, in a given modelled zone and in a given time period, the expected number of hours in which resources are insufficient to meet the demand;

(mm) ‘MC’ means Monte Carlo (i.e. related to the Monte Carlo method);

(nn) ‘MC sample year’ means one realisation of possible future states of the modelled power system resulting from the combination of sampling different stochastic variables;

(oo) ‘market-based capacity resource’ means any capacity resource available in the system complying with market rules and commercial agreements and participating to the Internal Market for Electricity. This includes inter alia all capacity resources participating in CMs which are allowed to participate to the EOM;

(pp) ‘Member State’ means EU Member State;

(qq) ‘modelled zone’ means either a bidding zone, a country or another geographic area that is explicitly modelled in the ED. A modelled zone cannot be larger than a bidding zone or a country;

(rr) 'Modelled zone with an approved CM means a modelled zone for which, in order to ensure compliance with its reliability standard, capacity is to be procured in the considered target year under a CM approved by the Commission in accordance with Union State aid rules pursuant to Articles 107, 108 and 109 of the Treaty on the Functioning of the European Union.

(ss) 'MTU' means market time unit pursuant to Transparency Regulation;

(tt) 'near-scarcity MTU' means an MTU in which any increase in load in the considered modelled zone would result in additional ENS.

(uu) 'NECP' means an integrated national energy and climate plan pursuant to the Governance Regulation;

(vv) 'NECP notification deadline' means the date by which Member States are required to notify to the Commission either:

(a) their NECPs pursuant to Article 3(1) of the Governance Regulation, or

(b) updates of their latest notified NECPs pursuant to Article 14(2) of the Governance Regulation.

(ww) 'net generating capacity' (NGC) of a generation unit means the maximum net active electrical 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 (climate etc.) and full availability of fuels; and

iii. for hydro, solar and wind units, 'normal conditions' means the nominal availability of primary energies (i.e. water, solar or wind conditions).

(xx) 'net transmission capacity (NTC)' means the coordinated net transfer capacity approach pursuant to CACM Regulation;

(yy) 'non-explicitly modelled systems' means electric systems which are not explicitly represented in the modelling framework in detail, and which are directly interconnected with an explicitly modelled system;

(zz) 'out-of-market capacity resource' means any capacity resource which is not market-based. Out-of-market capacity resources include capacity resources of strategic reserves;

(aaa) 'PECD' means pan-European climate database;

(bbb) 'PEMMDB' means pan-European market modelling database;

(ccc) 'perfectly reliable reference technology' means a technology that is continuously available at its rated capacity and not subject to forced outages, planned outages or energy constraints.

(ddd) ‘pivotal target year’ means a target year for which the ERAA explicitly performs economic viability and ED simulations, rather than deriving results through interpolation.

(eee) ‘planned outage’ means a state of a capacity resource 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;

(fff) ‘PST’ means phase-shifting transformer;

(ggg) ‘PTDF’ means power transfer distribution factor;

(hhh) ‘RCC’ means regional coordination centre pursuant to Electricity Regulation;

(iii) ‘reference firm capacity’ means, for a given modelled zone, target year and scenario, the quantity of equivalent firm capacity available to meet demand in that modelled zone, including both domestic capacity and adequacy contributions from other modelled zones, as determined in accordance with Article 12(9).

(jjj) ‘remaining available margin’ (RAM) means the available margin of a CNEC, pursuant to CACM Regulation;

(kkk) ‘Reliability standard’ means the measure of the necessary level of security of supply, pursuant to Title 4 of the VOLL, CONE and RS methodology.

(lll) ‘RES’ means energy from renewable sources pursuant to Electricity Directive;

(mmm) ‘revenue’ means any income that a given capacity resource receives;

(nnn) ‘RR’ means replacement reserves pursuant to SO GL;

(ooo) ‘RS methodology’ means the methodology for calculating the reliability standard pursuant to Title 4 of the VOLL, CONE and RS methodology;

(ppp) ‘scenario’ means the quantitative description of a plausible future of the power generation, transmission and demand systems based on a collection of drivers;

(qqq) ‘scarcity MTU’ means an MTU in which ENS is strictly positive.

(rrr) ‘scenario assumption basis’ means the set of high-level policy and system assumptions underlying a scenario. For central reference scenarios, this corresponds to the Trends and Projections scenario assumption basis or the NECP scenario assumption basis.

(sss) ‘scenarios with the NECP scenario assumption basis’ means both the NECP scenario without CM and NECP scenario with CM.

(ttt) ‘scenarios with the Trends and Projections scenario assumption basis’ means both the Trends and Projections scenario without CM and Trends and Projections scenario with CM.

(uuu) `sensitivity’ means a change in a scenario stemming from the variation of one (or very few) input parameter(s) that would not involve significant changes in other input parameters or in the overall scenario;

(vvv) ‘strategic reserve’ means a type of CM in which designated capacity resources are not available in the EOM and are only dispatched when TSOs are likely to exhaust their balancing resources to establish an equilibrium between demand and supply;

(www) ‘study time period’ means the time period covered by the ERAA;

(xxx) ‘submission year’ (SY) means the year when ENTSO-E submits the ERAA results to ACER for approval, in line with Article 10(2);

(yyy) ‘TFEU’ means Treaty on the functioning of the European Union;

(zzz) ‘target year’ (TY) means a year simulated within the ERAA;

(aaaa) “Total firm capacity need” means a quantity expressed in MW of equivalent firm capacity that a modelled zone needs, in a given target year and scenario assumption basis, in order to meet its applicable reliability standard, as determined in accordance with Article 12.

(bbbb) ‘TYNDP’ means ENTSO-E’s ten-year network development plan;

(cccc) ‘unplanned outage’ means a state of a capacity resource when it is unavailable in the power system and the unavailability was not planned;

(dddd) ‘variable cost’ means variable cost pursuant to Article 2 of the VOLL, CONE and RS methodology;

(eeee) ‘VOLL CONE RS methodology’ means the methodology pursuant to Article 23(6) of the Electricity Regulation, approved by ACER Decision No 23/2020;

(ffff) ‘VOLL methodology’ means the methodology for determining a single estimate of the value of lost load pursuant to Title 2 of the VOLL, CONE and RS methodology;

(gggg) ‘WACC’ means WACC pursuant to Article 2 of the VOLL CONE and RS methodology.

(hhhh) ‘With-CM scenarios’ means the central reference scenarios that account for future CM revenues. This includes both the Trends and Projections scenario with-CM and the NECP scenario with-CM. These scenarios capture the effects and revenues of already awarded contracts and additional capacity expected to be procured under approved CMs, as specified in Article 3(3i).

(iiii) ‘Without-CM scenarios’ means the scenarios that do not account for future CM revenues. This includes both the Trends and Projections scenario without-CM and the NECP scenario without-CM. These scenarios exclude future revenues from CMs, while taking into account capacity volumes already contracted under approved CMs, as specified in Article 3(3h).

3. In the ERAA methodology, unless explicitly stated otherwise,

   (a) the singular also includes the plural and vice versa;

   (b) references to paragraphs within an article shall be interpreted as pertaining specifically to the corresponding paragraphs of that article, while references to articles shall refer to the articles of the ERAA methodology.

(c) the table of contents and headings are inserted for convenience only and do not affect the interpretation of the ERAA methodology; and

(d) 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 2a
Target years

1. The ERAA shall cover each year of the study period, starting from SY+1 up to and including SY+10. For SY+1, the ERAA may refer to the results of the seasonal adequacy assessment conducted pursuant to Article 9 of the RPR.
2. ENTSO-E shall select at least four pivotal target years, which shall be explicitly modelled. Any additional target years beyond four shall be selected after consulting ACER, the European Commission, Member States and the relevant RCCs.
3. Among the pivotal target years, ENTSO-E shall include target years that are multiples of five (e.g. 2030, 2035), except where such a year corresponds to SY+1.
4. The remaining pivotal target years shall be selected by ENTSO-E, after consulting ACER, the European Commission, Member States, and RCCs, so as to ensure:

   (a) the availability of results for the delivery periods needed for the computation of the maximum entry capacity by the relevant RCCs pursuant to Article 26(7) of the Electricity Regulation.

   (b) adequate coverage of the ten-year horizon, by ensuring that:

      i. at least one pivotal target year covers the short-term horizon (SY+2 or SY+3);
      ii. at least one pivotal target year covers the mid-term horizon (SY+4 to SY+7); and
      iii. at least one pivotal target year covers the long-term horizon (SY+8 to SY+10).

Article 3
Scenario framework

1. The ERAA shall be based on projected demand and supply covering the pivotal TYs selected pursuant to Article 2a.
2. ENTSO-E shall collect data to define the projected demand, supply and grid assumptions according to the requirements set out in Article 5.

2a. The ERAA shall rely on the following central reference scenarios as specified in paragraphs (5) and (5a):

   (a) NECP scenario without CM;

   (b) NECP scenario with CM;

   (c) Trends and Projections scenario without CM;

   (d) Trends and Projections scenario with CM;

3. The baseline data serving as the starting point for the scenarios with the NECP scenario assumption basis shall be derived from the national projected demand, supply and grid outlooks prepared by each individual TSO in accordance with Article 5, and subject to the principles set out in paragraphs (3a) and (3g).

3a. The assumptions of the scenarios with the NECP scenario assumption basis shall be consistent with existing and planned national policies, including:

(a) national objectives, targets and contributions, and other projections contained in the NECPs, as referred to in Article 3 of the Governance Regulation, including policies related to coal phase-out, nuclear, RES development, storage, electric vehicles, sectoral integration, DSR and energy efficiency measures. Scenario assumptions shall align with the latest NECP-based TYNDP scenario.

(b) best estimates regarding the state of the grid taking into account the most recent TYNDP and the most recent national development plans.

3b. The baseline data serving as the starting point for the scenarios with the Trends and Projections scenario assumption basis shall be derived from the national projected demand, supply and grid outlooks prepared by each individual TSO in accordance with Article 5, subject to the principles set out in paragraphs (3c) to (3g).

3c. The following general principles shall apply to the scenarios with the Trends and Projections scenario assumption basis:

(a) The scenario shall be consistent with the biennial reporting of Member States pursuant to Article 17 of the Governance Regulation, and, where available, taking into account more recent verified information or data reflecting updated realised outcomes.

(b) The effect of existing policies shall be considered as reflected in historical trends. Additional adjustments for existing policies shall be applied only for measures whose impact on the trends is expected to materialise after the ERAA data collection.

(c) For policies not yet implemented, the scenario shall reflect the best estimate of their expected impact, provided this estimate is supported by concrete implementation measures; and

(d) The scenario shall be consistent with the best estimate of the expected evolution of the electricity system. It shall not incorporate assumptions that are more conservative or more optimistic than those supported by recent, observable demand, supply and network trends in the energy transition.

3d. The following principles shall apply to the modelling of supply in the scenarios with the Trends and Projections scenario assumption basis:

(a) The ERAA shall develop separate forecasts for each asset type.

(b) For each modelled zone, the ERAA report shall describe the overall approach to forecast the projected evolution of electricity supply. That description shall be supported by concrete and, where available, quantifiable, evidence based on at least one of the following:

i. historical deployment trends; and/or

ii. data on new grid connection requests or investment plans, and/or

iii. detailed policy developments expected to influence asset deployment, such as the adoption, amendment or withdrawal of support schemes or regulatory measures. Where such developments are relied upon and are not already reflected in historical trends, the ERAA report shall indicate the policy developments considered and how their impact has been reflected in the supply forecast. Targets or policy objectives without concrete implementation measures shall not constitute sufficient justification.

Alternatively, the ERAA report may refer to an external source that provides equivalent level of detail on the supply forecast methodology and assumptions, including the relevant part of a national resource adequacy assessment.

3e. For the Trends and Projections scenario assumption basis, ENTSO-E shall describe in the ERAA report the approach and main assumptions used to forecast the projected evolution of electricity demand for each modelled zone. That description shall be supported by concrete and, where available, quantifiable, evidence based on at least one of the following:

(a) historical demand trends; and/or

(b) data on new demand connection requests or investment plans; and/or

(c) changes in relevant demand indicators (e.g. number of electric vehicles); and/or

(d) detailed policy developments expected to influence the demand trend, such as the adoption or amendment of measures affecting electrification, energy efficiency, or demand-side participation. Where such developments are relied upon and are not already reflected in historical trends, the ERAA report shall indicate the policy developments considered and how their impact has been reflected in the demand forecast. Targets or policy objectives without concrete implementation measures shall not constitute sufficient justification.

Alternatively, the ERAA report may refer to an external source that provides equivalent level of detail on the supply forecast methodology and assumptions, including the relevant part of a national resource adequacy assessment.

3f. The following principles shall apply to the modelling of network infrastructure in the scenarios with the Trends and Projections scenario assumption basis:

(a) ENTSO-E shall consider the most realistic commissioning dates for network projects, taking into account the progress of the permitting and construction processes;

(b) Any deviation from the most recent TYNDP and national network development plan shall be justified in the ERAA report.

3g. The following principles shall apply to all central reference scenarios:

(a) In line with Article 23(5)(e) of the Electricity Regulation, the assessment shall anticipate the likely impact of the measures referred to in Article 20(3) of the Electricity Regulation. To this aim, the assumptions of the central reference scenarios shall align with the measures and actions defined by the Member States pursuant to Article 10(5) of the Electricity Regulation and with implementation plans pursuant to Article 20(3) of the Electricity Regulation;

(b) The MTU distribution of demand shall reflect the expected capability of consumers to shift consumption from scarcity MTUs to other MTUs. The assumptions on demand flexibility shall be clearly described in the ERAA report; and

(c) Where an ERAA edition contains both an NECP scenario and a Trends and Projections scenario, the ERAA report shall clearly describe the differences in the baseline data and assumptions used for each of those scenarios.

3h. For the without-CM scenarios, ENTSO-E shall model the evolution of the electricity system excluding any future revenues from CMs, while ensuring consistency with already awarded capacity contracts under CMs approved pursuant to Articles 107, 108 and 109 of the Treaty on the Functioning of the European Union.

3i. For the with-CM scenarios, ENTSO-E shall include already awarded capacity contracts under CMs approved pursuant to Articles 107, 108 and 109 of the Treaty on the Functioning of the European Union at the time of the assessment and additional capacity expected to be procured under approved CMs. In those scenarios, ENTSO-E shall model cross-border participation in CMs where technically feasible and in accordance with Article 26 of the Electricity Regulation.

4. For all central reference scenarios, the EVA shall cover the full set of pivotal target years and shall be performed on the baseline data described in:

(a) paragraph (3) for the scenarios with the NECP scenario assumption basis; and

(b) paragraph (3b) for the scenarios with the Trends and Projections scenario assumption basis.

The ERAA report shall clearly indicate whether and how the baseline data has been modified by the EVA. For consistency, the EVA may also be performed for the other scenarios and sensitivities.

5. The first ERAA edition published after an NECP notification deadline shall include, at a minimum:

(a) the Trends and Projections scenario without CM;

(b) the Trends and Projections scenario with CM; and

(c) the NECP scenario without CM.

Where, due to computational constraints, it is not feasible for ENTSO-E to run both without-CM central reference scenarios in that edition, ENTSO-E may instead limit itself to running the following scenarios:

(a) the NECP scenario without CM; and

(b) the NECP scenario with CM.

5a. All ERAA editions other than the one referred to in paragraph (5) shall include, at a minimum:

(a) the Trends and Projections scenario without CM; and

(b) the Trends and Projections scenario with CM;

6. ENTSO-E may complement the central reference scenarios with additional scenarios and/or sensitivities with European or regional relevance, e.g. to assess the robustness of the identified resource adequacy concerns. Such scenarios and/or sensitivities may be based on, inter alia, the following elements:

(a) different assumptions related to input data and scenario uncertainties, including different economic and policy trends relevant for resource adequacy;

(b) different electrification rates of the energy system, as one of the central drivers of the EU system transformation;

(c) impact of uncertainty in the deployment of electricity and wider energy system infrastructure including, but not limited to, investments in the electricity grid, infrastructure for the production, transport and storage of low-carbon fuels, as well as the transport and storage of CO2;

(d) assessments of the robustness of the identified investments within the EVA;

(e) variations on fuel, wholesale prices and/or carbon prices;

(f) consideration of extreme weather events and hydrological conditions;

(g) variations on cross-zonal capacities;

(h) alternative assumptions about CMs, e.g.

i. adding or removing CMs for some modelled zones;

ii. postponing the implementation of CMs, or prolonging CMs for some modelled zones;

iii. changing the type of CM for some modelled zones;

iv. delays in commissioning of new-build capacity contracted via CM auctions.

(i) presence of indirect restrictions to wholesale price formation, pursuant to Article 7(8) and (9) of the Electricity Regulation.

7. Definition and prioritisation of any additional scenarios and/or sensitivities pursuant to paragraph (6) shall be subject to public consultation by ENTSO-E. In particular, views of the Member States and relevant stakeholders on the evolution of the power system and the relevance of any proposed scenario and/or sensitivity shall be duly taken into account.

Article 4

Resource adequacy assessment

1. Modelling framework

(a) For pivotal target years, the resource adequacy metrics shall be estimated through the ED. Market entry and exit shall be modelled through the EVA. The ERAA shall apply a single modelling tool, in line with Article 23(5)(i) of the Electricity Regulation.

(b) For non-pivotal target years, the resource adequacy metrics shall be determined as follows:

i. for target years preceding the earliest pivotal target year, the resource adequacy metrics shall be set equal to those of the earliest pivotal target year;

ii. for target years following the latest pivotal target year, the resource adequacy metrics shall be set equal to those of the latest pivotal target year; and

iii. for target years between the earliest and latest pivotal target years, the resource adequacy metrics shall be derived by linear interpolation between the values obtained for the immediately preceding and immediately following pivotal target years.

As an alternative to linear interpolation, the resource adequacy metrics may be determined by performing ED simulations for those non-pivotal target years, using a realistic capacity mix based on the capacity mix of the surrounding pivotal target years.

(c) Resource adequacy shall be assessed using at least the following two probabilistic resource adequacy metrics: EENS and LOLE.

(d) The ERAA consists of the following major pillars: demand, supply, storage, and grid representation among different modelled zones.

(e) Within a given scenario, uncertainty is represented through the availability of capacity resources and network, and climate conditions.

i. Availability of capacity resources is represented through random unplanned outage patterns. Uncertainty of interconnectors is also represented through random unplanned outage patterns of interconnectors between different modelled zones, unless this effect is already included in the flow-based parameters considered within the flow-based approach and/or through the thermal capacity assigned to interconnectors.

ii. Data related to climate variables (i.e. hydro inflows, irradiance values, wind speeds and temperatures) are consolidated in the ENTSO-E PECD. The PECD comprises a set of hourly time series of climate variables for multiple years. The data set shall properly consider the inter-zonal and inter-temporal correlation of those climate parameters.

(f) The expected frequency and magnitude of future climate conditions shall be taken into account in the PECD, also reflecting the foreseen evolution of the climate conditions under climate change. To this effect, the central reference scenarios shall either

i. rely on a best forecast of future climate projections;

ii. weight climate years to reflect their likelihood of occurrence (taking historical or future climate projection into account); or

iii. rely at most on the 30 most recent historical climatic years included in the PECD.

Other scenarios and sensitivities may rely on climate data beyond the one used for the central reference scenarios, e.g. pursuant to Article 3(6)(f).

(g) Unless the modelling framework allows for a proper characterisation of unforeseen imbalances, the ED shall rely on a “perfect foresight” principle: under this assumption, forecast errors of wind, solar, hydro generation, of planned outages as well as of demand are ignored in the ED. Additionally, unplanned outages are assumed to be known in advance with the perfect foresight principle.

(h) The MTU shall be smaller than or equal to an hour.

(i) The spatial granularity of modelled zones shall be set at least by the smallest level between country and bidding zone, considering the bidding zone configuration expected for each target year. In addition, the specific geographical characteristics of the assessed perimeter shall be reflected in the ED model by explicitly modelling islands for which sufficiently qualitative and granular input data exist, for example the island of Crete.

(j) Non-explicitly modelled zones are represented by fixed time series of energy exchanges through interconnections.

2. Probabilistic assessment

(a) The ERAA shall use a probabilistic methodology to reflect the stochasticity of climate variables affecting supply and demand, as well as the expected availability of generation, storage and transmission resources.

(b) The MC method shall be used for probabilistically assessing the availability of capacity resources and transmission resources. It creates possible future states of the modelled power system by sampling a sequence of random outages of the relevant stochastic variables. Random outages represent different availability of capacity resources and transmission lines, which are subject to failures that cannot be predicted beforehand and may have a significant impact on resource adequacy.

(c) Modelling of outages shall reflect, where possible and applicable, the attractiveness for capacity resources to be available during MTUs when ENS is likely to occur.

(d) MC sample years shall combine the climate-dependent variables and random outages referred to in paragraph (1)(e), as follows:

i. Climate years, are first selected one-by-one;

ii. Each climate year is associated with random outage samples, i.e. randomly assigned unplanned outage patterns for at least thermal units, as well as for interconnectors;

iii. The combination of the climate years and the random unplanned outage patterns defines the MC sample years analysed. The number of MC sample years shall ensure convergence of the results, pursuant to paragraph (2)(e).

(e) The convergence of the Monte Carlo method shall be assessed by the coefficient of variation (α) of the ENS. It describes the volatility of the ENS in the Monte Carlo assessment. The coefficient of variation is defined by the equation below:

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

where $EENS$ is the expectation estimate of ENS over N, the number of Monte Carlo years, i.e., $EENS_N = \frac{\sum_{i=1}^{N} ENS_i}{N}$, and $Var[ENS_N]$ is the variance of ENS over N.

(f) A stopping criterion for the probabilistic assessment shall be enforced, under a sufficiently large number of Monte Carlo years, by comparing the relative increment of α with a given threshold value θ. In particular, for N sufficiently large, if

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

then increasing the number of Monte Carlo years would not increase the level of accuracy considerably. Consequently, the Monte Carlo analysis can stop.

(g) To indicate the reliability of resource adequacy assessment results, the following parameters shall be reported along with the results:

i. The number of analysed Monte Carlo years N;

ii. ii. The value of α as a function of N.

3. Demand:

(a) For each target year, demand shall be represented as a time series with a temporal resolution equal to the MTU. Demand shall be available at least at modelled zone-level, and may be available with a higher level of spatial detail. It shall be calculated based on historical demand time series and considering the stochasticity of climate variables, the impact of climate change, and projections of economic growth and penetration of new technologies (e.g. electric vehicles and heat pumps) for each target year.

(b) With respect to climate, demand shall be modelled considering at least load-temperature sensitivity using historical climate data or climate data derived from climate models. The demand sensitivity to climate may include other variables such as irradiation, wind speed or humidity, if proven relevant.

(c) Explicit and implicit DSR shall be considered in the assessment. The data related to potential for demand reduction, postponement or shifting shall be based on the best forecast in the modelled zone and within the concerned time period of the assessment.

i. Explicit DSR potential shall be structured in different price and volume bands, each characterised by a maximum activation capacity, maximum activation duration, unit activation price, as well as economic and technical activation and energy constraints. The activation 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 explicit DSR potentials and their activation curves shall be performed at least per modelled zone.

ii. Implicit DSR potential shall reflect the demand elasticity of the day-ahead market expected for the considered target year, based on best forecast.

iii. DSR shall be defined as either

1. DSR potential and initial installed capacity (for various activation prices) to allow the EVA to define the installed capacity and activation curve based on market entry and exit of DSR; or

2. Exogenous installed DSR capacity and activation curve.

iv. The choice of either option shall be properly justified and transparently communicated (see also Article 5(11)(c)). In case implicit DSR activation is not directly linked to time-variable electricity prices but rather to permanent incentive payments associated with a certain expected behaviour of customers at specific hours every day/week of the year, implicit DSR shall be modelled within ENTSO-E's demand prediction process, e.g. as time-dependent flexible demand bands.

(d) The proportion of each consumer's demand which is price-responsive, and which is excluded from calculating the single VOLL for RS pursuant to Article 7(2)(a) of the VOLL CONE and RS methodology, shall be included as DSR in the ERAA.

(e) Demand during charging of storage units shall be determined separately through the ED and shall be assumed to be price-responsive.

(f) Estimates on evolution of energy efficiency and its effects on demand curves as well as demand growth due to economic, technological and social developments shall be considered using annual best forecasts.

4. Supply

(a) Supply assumptions shall consider current status and best estimates of all available generation units in the system.

(b) All capacity resources and their contribution to flexible system operation shall be considered, in line with Article 23(5)(d) of Electricity Regulation.

(c) Supply shall be defined in terms of NGC. Any seasonal impact on generation capacity availabilities (e.g. CHP availabilities in summer and seasonal efficiencies) shall be considered (e.g. by introducing time series of availability or by modelling unavailability through the planned maintenance schedule). Constraints related to supply of other services (e.g. must-run of CHP) shall also be considered.

(d) Climate-dependent electricity generation, such as wind, solar and hydro generation, shall be based on modelled climate conditions, assuming perfect foresight in line with Article 4. The climate conditions used for climate-dependent generation and for climate dependent demand shall be consistent. Temperature impact on climate-dependent electricity generation (e.g. on the efficiency of PV panels, temperature sensitivity of thermal generation to air temperature, need of cooling water…) may be indirectly considered through the statistical information used to build the climate-dependent electricity generation models. Non dispatchable climate-dependent electricity generation shall be modelled by combining:

i. NGC for each technology, representing the expected market penetration of climate dependent electricity generation for the target year; and

ii. time-varying load factors reflecting the spatial and temporal dependency of climate-dependent electricity generation, as well as the evolution of technical characteristics of the relevant generation technologies in each target year.

(e) Availability of supply sources:

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

ii. Planned outages are modelled assuming perfect foresight in line with Article 4.

1. For the time period SY+1 - SY+3, planned outage schedules shall be prepared centrally by ENTSO-E, with support and inputs given by TSOs. These maintenance profiles may be calibrated using data published by owners of generation units pursuant to the REMIT, as well as technology specific constraints (e.g. maximum number of nuclear units in simultaneous maintenance);

2. For the time period SY+4 – SY+10, planned outage schedules shall be prepared centrally by ENTSO-E, with support and inputs given by TSOs. These planned outage schedules shall be optimised to avoid scheduling maintenance when ENS is likely to occur, while respecting relevant constraints such as maintenance period of each power plant, percentage of capacity that must undergo maintenance during the winter period, and technology specific constraints (e.g. maximum number of nuclear units simultaneously under maintenance). To preserve the representativeness of the results, assumptions on optimized planned outages may be refined to account for historical outage tendencies. Any such refinement shall be strictly limited to reflecting robust, well-documented patterns in historical outage behaviour, and only where these patterns remain demonstrably relevant in light of the expected demand profile and generation mix of the target year. Historical maintenance schedules shall not be replicated where they are inconsistent with future system conditions or would undermine the objective of optimising outages outside likely ENS periods.

iii. Unplanned outages of supply shall be considered in a probabilistic manner and assuming perfect foresight in line with Article 4, pursuant to paragraph (1)(e)(i) of this Article. Assumptions on outage rates per technology type and mean time to repair shall build on historical outage events in Europe. These assumptions may be refined to reflect how outage rates correlate with market signals.

(f) Supply-side technical constraints shall be considered. These constraints may include minimum and maximum generating capacities, capacity requirements for system services (such as reserves or voltage support), capacity reductions due to mothballing, must-run constraints, annual run hour limits (e.g. for large combustion plants subject to operating restrictions or derogations under Directive 2010/75/EU on industrial and livestock rearing emissions and related best available techniques conclusions), time series of de-rating ratio (due to constraints which are not explicitly modelled in the ED), planned maintenance requirements, ramping capabilities, minimum run-time, start-up and shut-down times and, as long as relevant for the generation technology and consistent with the climate modelling approach, constraints on temperature dependency of thermal generation and constraints related to the need for cooling water.

(g) Energy constraints (such as for hydro) shall consider energy availability. For hydro generation modelling, the energy constraints may relate to water inflows, reservoir size or minimum energy release requirements due to environmental reasons and may require an ex-ante optimisation consistent with paragraph (5) of this Article.

5. Reservoir and storage

(a) Hydro reservoirs and pumped-hydro storage capacity resources shall be divided into different hydro technology types, consistent to the classification of capacity collected in the PEMMDB and the corresponding inflows (when relevant) provided by the PECD. The modelling of pumped-hydro storage units shall rely on specific modelling techniques, some of which include an ex-ante optimisation phase with a coarser time resolution than the timestep of the ED model (e.g. weekly or even seasonal decomposition, depending on the time resolution of the available inflow data or constraints). The hydro optimisation model shall respect the constraints prescribed and collected for the corresponding technologies, including for example upper and lower reservoir trajectories and minimum/maximum generation or pumping capacity. The hydro optimisation shall reflect:

   i. the expected operational principles applied for each target year by market participants which own and operate hydro storage; and

   ii. environmental or other technical constraints (e.g. on potable and agriculture uses) on the water resource.

(b) Batteries (including vehicle-to-grid) shall be considered within each modelled zone, based on best estimates for the concerned period of the assessment. Energy availability shall be based on energy storage capacities and charging-discharging constraints of the batteries. The ERAA shall consider:

   i. in-the-market batteries, which are large-scale battery capacities that are traded in day-ahead and intraday markets. In-the-market batteries shall be modelled similarly to pumped-hydro storage and shall be subject to the following constraints: maximum power, maximum energy storage, state of charge, charging/discharging efficiency; and

   ii. out-of-market batteries, which represent small-scale batteries typically managed behind the meter. Out-of-market batteries shall be modelled as peak-shaving units based on predefined peak-reduction ratios, which are a direct input to the demand prediction process.

(c) Other long-duration energy storage technologies can be considered, where technically feasible, for the modelled zones for which relevant capacity and robust data are available. Modelling of long-duration energy storage technologies should reflect expected operational practices, and may rely on one of the modelling approaches outlined in point (a) or (b), depending on the expected storage capacity.

6. Network

(a) For each target year, cross-zonal capacities shall reflect the expected CCM, taking operational security limits into account. In particular, cross-zonal capacities shall reflect the latest available information regarding MS 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. Cross-zonal capacities for the central reference scenarios shall also reflect the measures decided to reach electricity interconnection targets, according to the information available to the TSOs.

(b) Within NTC capacity calculation, NTCs shall limit the bilateral exchange between two explicitly modelled zones. These values shall reflect expected operational practices (which may include specific connection agreements) for the target year.

(c) Within flow-based capacity calculation, a flow-based domain shall be computed as follows, in line with the expected CCM:

i. ENTSO-E, based on TSOs' input data, shall coordinate the identification of CNECs during the data collection process pursuant to Article 5;

ii. definition of relevant node-to-hub PTDFs shall use grid models covering the flow-based area under consideration. At least one grid model per target year shall be used. European grid models from the TYNDP reference grid shall be used. These European grid models shall incorporate the relevant grid modifications expected to be operational by the different target times of the assessment;

iii. node-to-hub 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, PST settings, and other degrees of freedom expected to be reflected in capacity calculation;

iv. the capacity available for cross-zonal trade on a CNEC depends on the maximum admissible power flow at the considered MTU, defined as F . F may be implemented as a time-varying value in order to reflect varying relevant conditions; v. the selection of GSKs shall be in line with foreseen practices in the relevant capacity calculation region, taking into account any simplification necessary for the ERAA;

vi. zone-to-hub PTDFs shall be defined, combining node-to-hub PTDFs with GSKs for each MTU;

vii. RAM of each CNEC shall be estimated, including proper considerations on internal, loop and transit flows, as well as applicable minimum RAM requirements. The impact of coordinated validation of cross-zonal capacity on RAM should be taken into account;

viii. for all relevant CNECs, the (RAM, PTDFs) parameters shall define a collection of linear constraints for the ED. This total set of constraints shall be reduced to the set of constraints limiting the exchanges within the simulation. The reduced combination of relevant constraints shall form the final flow-based domain;

ix. The final flow-based domains shall be the linear constraints introduced in the ED model.

(d) Climate conditions and seasonal patterns that impact network constraints shall be considered when defining cross-zonal capacities. In particular, for each target year, cross-zonal capacities shall at least be estimated for winter and summer (following the seasons defined operationally by TSOs). For each MTU of each MC sample year, a set of cross-zonal capacity values shall be set based on the relevant variables (including climate, RES generation and demand) of the MC sample year for the considered MTU. A correlation analysis between the different cross-zonal capacities and the relevant variables shall be applied.

(e) If the CCM allows for specific allocation constraints, such constraints may further restrict cross-zonal trade (on top of the flow-based domains or NTCs). In this case, the constraint value shall be computed in line with the expected CCM.

(f) In the NTC approach, unplanned outages of interconnections shall be considered in a probabilistic manner, as per paragraph (1)(e)(i).[2] Assumptions on outage rates per line and mean time to repair shall build on statistical analysis of historical outage events in Europe.

6a. Reserves

(a) Reserve requirements shall be set separately for FCR, FRR and RR.

i. For each target year, the dimensioning of FCR and FRR, and the contribution of each TSO, shall reflect reserve needs to cover imbalances in line with Articles 153 and 157 of SO GL.

ii. Unless the modelling framework described in paragraph (1)(g) is able to model the use of balancing reserves in relation to unforeseen imbalances, FCR and/or FRR (or a part of these balancing reserves) may be deducted from the available capacity resources in the ED, by deducting their respective capacities from the available supply. However, the modelling of FCR and FRR shall comply with Article 7(7).

iii. RR shall be considered as capacity resource available in the ED. For each target year, the dimensioning of RR shall be consistent with Article 160 of SO GL.

7. Non-explicitly modelled systems

(a) Non-explicitly modelled systems shall be modelled as exogenous best estimates of cross-zonal exchanges on all borders with explicitly modelled zones. The cross-zonal exchanges shall be provided by TSOs having direct interconnections with those systems, and shall reflect expected market conditions and expected operational practices (including specific connection agreements) for the MTUs of each target year.

Article 5
Data collection

1. The ERAA data collection shall follow the ENTSO-E data collection framework principles:

    (a) ENTSO-E shall provide harmonised data collection guidelines to each TSO, to guarantee a coherent data collection process. Such guidelines shall specify the assumptions (including data template) to follow when providing data, in order to guarantee a standardised data preparation process and ensure that databases are built on consistent, transparent and common assumptions;

    (b) Some of the data requested from the TSOs is used by ENTSO-E as an input to generate centrally prepared datasets for the ERAA.

2. ENTSO-E shall coordinate the data collection process to prepare and consolidate the TSO input.

3. During the data collection process, ENTSO-E shall communicate with TSOs through delegated adequacy correspondents.

[2] In flow-based, unplanned outages of HVDC interconnectors are considered when computing the flow-based domain.

4. TSOs shall provide ENTSO-E with the data needed to carry out the ERAA, pursuant to Article 23(4) of Electricity Regulation. ENTSO-E shall clearly differentiate the origin of data used in its studies (Member States, TSOs, ENTSO-E assumptions, NRAs, DSOs, NEMOs, other/external, etc.). In addition, in case of inconsistency in the collected data, ENTSO-E shall request the relevant TSOs to disclose their data sources and shall define a consolidation mechanism in order to combine such data into a consistent dataset.
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 Electricity Regulation and respecting confidentiality of such data where required, in order for TSOs to set up or benchmark the scenarios of projected demand and supply and to provide relevant technical and economic assumptions for the EVAs.
6. For calibration purposes, ENTSO-E may also rely on other data collected in line with Transparency Regulation, such as e.g. historical wholesale prices.
7. In line with paragraph (4), to set up the flow-based modelling, TSOs shall either
   (a) Provide ENTSO-E with the input data required to compute centrally the flow-based domain pursuant to Article 4(6)(c); or
   (b) Define a list of relevant CNECs with PTDFs, Fmax and RAM pursuant to Article 4(6)(c).
8. Reserve requirements data collection per modelled zone shall consist of separate time series for FCR, FRR and RR, pursuant to Article 4(6a).
9. General economic parameters, such as evolution of fuel prices and CO_2 emission allowance price under the EU ETS (where applicable), shall be prepared centrally by ENTSO-E based on best available economic expertise at European level. These assumptions shall be consistent with the ENTSO-E's scenarios prepared for the TYNDP, but can use more up-to-date data where available, provided that such data are developed using a methodology that is consistent with the modelling principles and scenario construction framework applied in the TYNDP. These parameter values may be different among modelled zones.
10. Economic and technical data to perform EVAs shall be consolidated centrally by ENTSO-E based on best information available to ENTSO-E. The following data items shall be estimated per relevant technology and modelled zone:
    (a) CAPEX, expressed in EUR/MW;
    (b) Annual fixed costs, expressed in EUR/MW/year;
    (c) Short-term variable costs (EUR/MWh), efficiencies (%) and emission factors of CO2 (t/MWh);
    (d) WACC and discount rates;
    (e) (remaining) economic lifetime, and
    (f) earliest entry year, earliest exit year.

    The set of technical and economic data consolidated and adopted by ENTSO-E shall ensure the consistency and robustness of EVA results over the modelled perimeter and horizon, minimizing the risk of exogenous biases and inconsistencies. For the technologies used in ERAA which are also reference technologies for CONE or CORP, the economic and technical data used for ERAA (except for the WACC) shall be identical to the latest available best estimate used in the most recent CONE and CORP calculations pursuant to the CONE and RS methodologies, provided that such estimates are up-to-date.

Where ENTSO-E uses alternative economic or technical data, the ERAA report shall explain this choice and describe the values used, the methodology applied and the underlying set of assumptions. In particular, the EVA shall at least consider all reference technologies and all reference renewals/prolongations considered pursuant to Article 18 of the VOLL, CONE and RS Methodology.

For technologies, for which the CONE or RS methodology did not define technical and economic parameters, best estimates regarding technical and economic parameters required for the EVA shall be prepared centrally by ENTSO-E, based on best available economic expertise at European level.

11. Collected data shall originate from combined top-down and bottom-up collection processes. It shall be checked for completeness and consistency and eventually consolidated into a PEMMDB. The PEMMDB shall contain information on the network and market models for each modelled zone and target year. The PEMMDB shall at least include technical and economic data at modelled zone level for all the reference technologies considered during the calculation of CONE and CORP (according to the CONE and RS methodologies). More specifically, the PEMMDB shall contain the generic input dataset to the ED model. The PEMMDB shall include:

    (a) Generation data, consisting of, among others, RES and thermal generation NGCs, their predicted evolution over time, maintenance requirements, technical capabilities, fuel consumption, conversion efficiencies, mothballing predictions, RES and non-dispatchable fossil fuel generation time series. Thermal generation data shall be collected unit by unit, to the best availability. Wherever unit by unit data is not available, generation data shall be aggregated following the data collection guidelines and according to the standard data templates referred to in paragraph (1). Thermal power plant conversion efficiencies used in the model shall be based on fuel subtypes. RES capacities shall be provided per modelled zone, or using a more detailed geographic granularity. Both RES and non-dispatchable fossil fuel generation time series shall have a time resolution equal to the MTU;

    (b) Data on already awarded CM contracts, consisting of at least the type and volume of capacity resource contracted, the duration of the contract, the description of the delivery period and the annual amount paid to the contracted capacity during the whole duration of the contract;

    (c) Data on the current installed capacity and potential of (explicit and implicit) DSR and storage. Such estimates should build on input from relevant market parties and TSO data, and shall result in values that are differentiated for each modelled zone;

    (d) System reserve requirements separately provided for FCR, FRR and RR for each modelled zone, target year and MTU;

    (e) Demand predictions, built on historical hourly demand profiles and forecast adjustments. These components are the following:

        i. Historical demand time series (with a time resolution at least equal to the MTU) shall be collected from TSOs per modelled zone. ENTSO-E shall combine these historical demand time series with historical climate variables, in order to build demand predictions centrally. The predictions are then used to generate multiple time series for each target year to reflect different climate conditions.

        ii. A set of model parameters that allow for a characterisation of time series per modelled zone, target year and MTU where applicable. These include:

1. Annual demand per sector (industry, residential, services and transport) and per modelled zone shall be provided by TSOs as an aggregated forecast for each target year;

2. current and forecast number of electric vehicles for each target year, average effective usage with time differentiation, where possible (e.g. between seasons, months, weekends and weekdays), average efficiency (forecast consumption), share of fast and slow charging profiles (taking into account the geographical diversity of charging behaviour within the study time period). Deployment forecast of electric vehicles shall be defined by each TSO as part of the scenario building process, while vehicle-to-grid capabilities shall be based on best forecast;

3. current and forecast number of heat pumps, increase in thermal demand caused by heat pump additions, average values of coefficients of performance, threshold of coefficient of performance for switching (hybrid heat pumps);

4. current and forecast number of out-of-market batteries, their maximum total power, storage capacities, cycle efficiency, peak reduction and ramp rate reduction;

5. other forecast adjustments: other additional demand types (e.g. data centres);

6. calendars of holidays/weekdays/special days per target year;

7. other characteristics of relevant technologies that affect demand levels and shape (e.g. energy efficiency programs).

(f) NTC of bidding zone borders between explicitly modelled systems, and allocation constraints pursuant to Article 4(6)(e).

(g) Flow-based domains as described in Article 4(6)(c).

12. The PECD shall include, at least per modelled zone level, the following data:

(a) temperature, irradiance, humidity and wind speed time series;

(b) wind power and PV load factor time series; and

(c) water inflows to hydro reservoirs.

The PECD shall build on “state-of-the-art” climate databases, using available re-analysis of historical data and climate projections where applicable. ENTSO-E shall periodically update the PECD within a timeframe compatible with the “state-of-the-art” to include re-analysis of recent historical data and/or synthetic data. The PECD shall be updated at least every 5 years, to account for the most recent climate data (e.g. more recent climate years and/or climate projections where applicable).

13. ENTSO-E shall estimate harmonised limits on maximum and minimum clearing prices (pursuant to Article 10(1) and (2) of Electricity Regulation), based on best available economic expertise at European level.

14. TSOs shall provide ENTSO-E with their best forecast on any indirect restrictions to price formation which are expected to significantly impact the ED or EVA (for those Member States applying indirect restriction to free price formation), as well as any related mitigating measures or actions pursuant

to Articles 10(4) and (5) and 20(3) of Electricity Regulation. For each declared restriction or mitigating measure, the TSO shall provide the timeline during which the restriction or measure is expected to apply, in line with measures and actions defined by Member States pursuant to Article 10(5) of Electricity Regulation and with implementation plans pursuant to Article 20(3) of Electricity Regulation.

15. TSOs shall provide ENTSO-E with information on approved CMs and other state-aid support mechanisms, and capacity contracts already awarded under these mechanisms for existing and new-build capacities. This information shall include assumptions on the type of CM, amount of de-rated capacity procured or expected to be procured and time duration of the CM. This information should allow to assess the share of the capacity within the PEMMDB relying on any CM, as well as the expected duration of any already granted CM contract within the study time period.

Article 6

Economic viability assessment

1. Pursuant to Article 23(5)(b) of the Electricity Regulation, the EVA shall assess the likelihood of retirement, mothballing, new-build of generation assets and measures to reach energy efficiency.
2. Subject to the constraints described in paragraph (8), and relying on the decision variables pursuant to paragraph (7), the EVA shall assess the economic viability of (groups of) capacity resources, pursuant to paragraphs (4), (4a) and (5). By way of simplification, ENTSO-E may instead apply an approach based on the minimisation of overall system costs in accordance with paragraph (6).
3. The evolution of capacity resources based on exogenous assumptions according to the national baseline data as described in Article 3 may be excluded from the EVA, i.e. the EVA may abstain from affecting these exogenous assumptions.
4. Where the EVA assesses the economic viability of capacity resources within the study time period, the economic viability of each capacity resource for a given target year shall be determined based on the difference between the revenues referred to in paragraph (9) and the costs referred to in paragraph (10).

4a. Where the EVA assesses the economic viability of capacity resources within the study time period, a capacity resource shall be considered economically viable if and only if the following condition is fulfilled, depending on the risk-aversion approach applied:

   (a) where investor risk aversion is represented through hurdle rates pursuant to paragraph (9e)(a), the capacity resource's expected return adjusted, where applicable, in accordance with paragraph (15), exceeds the applicable hurdle rate; or

   (b) where investor risk aversion is represented through an alternative approach pursuant to paragraph (9e)(b), the capacity resource's expected return adjusted in accordance with paragraph (9e)(b) and, where applicable, paragraph (15), exceeds the WACC.

5. Based on the economic viability of each capacity resource, the EVA shall:

   (a) keep existing economically viable capacity resources in the market;

   (b) consider re-entry of previously mothballed capacity if the mothballed capacity is viable;

   (c) consider removing or mothballing non-viable capacity resources from the model;

(d) consider renewing or prolonging viable existing capacity resources, if applicable; and

(e) consider adding new viable capacity resources.

6. Where ENTSO-E applies the simplification referred to in paragraph (2), and assuming perfect competition, the EVA may minimise overall system costs, i.e. the sum of:

   (a) fixed costs, as defined in the VOLL, CONE and RS methodology, based on data from Article 5(10); and

   (b) total operating costs resulting from the ED.

   In this case, the entry and exit decisions shall be assessed together for all capacity resources (as substitutional effects between capacity resources may occur).

7. For each target year and modelled zone, the EVA shall include the following decision variables:

   (a) decommissioning/mothballing of existing capacity resources;

   (b) investment in new capacity resources, such as generation, storage or DSR;

   (c) re-entry of mothballed capacity resources; and

   (d) renewal/prolongation of existing capacity resources.

8. For each target year, the EVA shall fulfil the following constraints:

   (a) the demand pursuant to paragraph (11);

   (b) the capacity resources and their technical constraints pursuant to paragraph (12);

   (c) the network constraints pursuant to paragraph (13);

   (d) the reserve requirements pursuant to paragraph (13a);

   (e) the market and regulatory constraints expected to apply pursuant to paragraph (14);

   (f) the earliest entry target year for new-build capacity pursuant to paragraph (16a) and the earliest exit target year for existing capacity pursuant to paragraph (16b).

8a. The representation of the business case of investors in the EVA shall reflect realistic investment behaviour in the electricity market. It shall include the consideration of the different revenue streams considered by investors as described in paragraphs (9) to (9d), and the representation of investor risk aversion in accordance with paragraph (9e), including the way investors consider extreme price events pursuant to paragraph (15).

9. For each scenario and sensitivity, and for each considered target year, the revenues of a capacity provider shall be equal to the sum of all relevant revenues expected to be collected by its capacity resources, as set out in paragraphs (9a) to (9c). Revenues shall be considered relevant if they are expected to influence the investment or operational decisions of market participants.

9a. The following revenue streams shall be considered relevant for all capacity resources expected to participate in the corresponding market segment:

   (a) revenues from the wholesale electricity market;

   (b) revenues from CMs, including:

      i. revenues from already awarded CM contracts, which shall be considered in both the with-CM and without-CM scenarios; and

ii. revenues from future CM contracts, which shall be considered only in the with-CM scenarios; and

(c) revenues from support schemes, subsidies, regulatory incentives, or other equivalent policy measures.

9b. The following revenue streams shall be considered relevant for the technologies specified:

(a) revenues from ancillary services (including frequency containment reserves, frequency restoration reserves and replacement reserves) for OCGT, CCGT, hydro storage, batteries and demand response;

(b) revenues from intraday market participation for storage technologies (hydro storage and battery storage).

9c. The following revenues shall also be considered relevant where they are expected to influence the economic viability of a capacity resource:

(a) revenues from electricity-related services other than those covered by paragraph (9b);

(b) revenues from services outside the electricity sector, such as heat supply;

(c) where the ERAA market time unit is hourly, additional revenues arising from the higher temporal granularity of day-ahead and intraday markets (15-minute products) compared to the hourly resolution of the ERAA EVA.

9d. The relevant revenues described in paragraphs (9a)-(9c) shall be calculated as follows:

(a) Wholesale market revenues shall be based on the prices derived from the ED results pursuant to Article 7(10). The wholesale market revenues shall reflect the probability-weighted average of simulated revenues across the Monte Carlo sample years. Where applicable and available before or during the submission year, forward market prices may be used to complement, refine or replace the ED-based revenues.

(b) Where the ERAA EVA explicitly represents intraday trading and/or a 15-minute market time unit, the intraday and sub-hourly revenues for storage and other flexible resources may be modelled endogenously. Where this is not the case, ENTSO-E may estimate the incremental value exogenously of (i) intraday and/or (ii) finer temporal granularity (15-minute versus hourly settlement) using extrapolation from historical data. Such extrapolation may be based on historical revenue uplift factors, computed per modelled zone and technology as the observed ratio between net revenues with intraday trading and finer time granularity, and net revenues under a day-ahead-only hourly benchmark. The methodology shall be documented per bidding zone, including data sources and assumptions. Alternative robust approaches may also be developed.

(c) Ancillary services revenues may be computed endogenously in the model where the ED explicitly represents the reservation and activation of ancillary services. Alternatively, net revenues from ancillary services may be estimated as an extrapolation of historical net balancing revenues. Historical net balancing revenues may be calculated as the sum of:

i. net reservation revenues, defined as the payments made by the TSO for the procurement of balancing capacity, net of the direct and opportunity costs of reservation incurred by balancing service providers; and

ii. net activation revenues, defined as the payments made by the TSO for the activation of balancing energy, net of the direct activation costs incurred by balancing service providers.

Where ancillary services revenues are estimated exogenously, ENTSO-E shall allocate those revenues to the relevant asset types or technologies in a manner consistent with their expected participation in balancing markets.

ENTSO-E may apply alternative approaches to estimate ancillary services revenues. For each bidding zone, ENTSO-E shall clearly describe the methodology applied, including the data sources and key assumptions, in the ERAA report.

(d) Revenues from services outside the electricity sector shall be based on the best available forecasts. As a simplification, where such revenues are expected to ensure the economic viability of the installed capacity or the achievement of the relevant capacity target, they may be assumed to do so without explicit revenue quantification. In such cases, the EVA shall not be required for the corresponding capacity resources;

(e) Revenues from support schemes, subsidies, regulatory incentives or other equivalent policy measures shall be based on the best available forecasts. As a simplification, where individual units benefit from such measures, or where specific installed capacity targets are defined for certain technologies pursuant to paragraph (9a)(c), these revenues may be assumed to ensure that the corresponding installed capacity targets are achieved without explicit revenue quantification. In such cases, the EVA shall not be required for the capacity concerned;

(f) Revenues from already awarded CM contracts. All generation and demand capacity holding CM contracts already awarded at the time of the assessment shall be deemed economically viable. The EVA shall not be required for such capacity resources;

(g) Revenues from future CM contracts. In any central reference scenario (or sensitivity) that includes additional CM-driven capacity to meet the reliability standard in the considered Member State and target year, expected CM revenues shall be taken into account based on the best available forecast of the expected CM functioning, in accordance with Article 5(15). As a simplification, where such potential CM revenues are expected to ensure that the installed capacity meets its economic viability criteria, they may be assumed to do so without explicit revenue quantification. In such cases, the EVA shall not be required for the corresponding CM-driven capacity.

9e. Risk aversion of market participants shall be reflected in the EVA based on approaches which align with best practices of relevant stakeholders, including market parties and investors. Inclusion of risk aversion in the EVA shall follow the principles set out in points (a) to (e):

(a) Investor risk aversion shall be reflected through technology-specific hurdle rates, consisting of (i) the reference WACC determined pursuant to the VOLL, CONE and RS methodology; and (ii) a justified technology-specific hurdle premium. In addition, a transparent and market-conform increase of the reference WACC may be applied to account for price risk, provided that the principles underlying such an increase are consistent with the WACC calculation guidelines set out in the VOLL, CONE and RS methodology. ENTSO-E shall ensure that this WACC increase does not result in double counting of risk relative to the technology-specific hurdle premium.

(b) Alternative risk-aversion metrics, such as Value-at-Risk or Conditional Value-at-Risk, may be applied where it is demonstrated that:

i. the alternative approach provides a representation of investor behaviour that is at least as robust as the use of hurdle rates pursuant to point (a); and

ii. the methodology is transparent and based on verifiable data.

Any such alternative approach shall be duly justified and documented in the ERAA report.

(c) The representation of risk aversion shall take into account the potential mitigation of exposure to price volatility through forward market hedging, for those EVA decision variables and asset types for which appropriate and sufficiently liquid hedging instruments are expected to be available.

(d) The simultaneous use or combination of multiple approaches shall not be permitted, except for the complementary treatment of extreme price events pursuant to paragraph (15).

(e) Other investment criteria, such as minimum expected payback period or debt service coverage ratio (DSCR), may only be included in the EVA where the same criteria are explicitly taken into account in the determination of CONE pursuant to the VOLL, CONE and RS methodology, and where their calibration is consistent with, and does not duplicate, the risk components already reflected in the WACC. Any such additional criteria shall be transparently documented in the ERAA report, including their parameterisation and their link to the CONE calculation.

10. For each scenario, modelled zone and target year, the costs of capacity resources shall be equal to the sum of all costs expected to be incurred by the capacity resources, consistently with the CONE and CORP calculation process according to the CONE and RS methodologies. These costs shall be computed based on the data described in Article 5(10). For scenarios with CM in the considered modelled zone, if the EVA relies on economic viability pursuant to paragraphs (4), (4a) and (5) and if the capacity resource receives CM payments pursuant to paragraph (9a)(b), the WACC may be reduced (if properly justified) to reflect the lower risk premium perceived by the capacity resource (due to a different risk allocation).

11. The demand for EVA shall reflect demand (excluding DSR insofar as it is represented separately in the modelling, to avoid double counting) for each target year and modelled zone pursuant to Article 4(3).

12. The generation, DSR and storage constraints shall be modelled in line with Article 4(3), (4) and (5). Furthermore, a maximum potential of NGC may be defined per technology, modelled zone and target year. In this case, the maximum potential of NGC shall be consistent with the capacity potential estimated for the new entrant and renewal/prolongation in the RS methodology.

13. The network constraints shall be modelled pursuant to Article 4(6).

13a. The reserve constraint shall be modelled pursuant to Article 4(6a).

14. The EVA shall reflect the following market and/or regulatory constraints:

(a) in modelled zones with CM for a considered target year, constraints related to CM payments for units exceeding the CO2 emission limits, as referred to in Article 22(4) of the Electricity Regulation;

(b) phase-out or restrictions of specific technologies, e.g. coal or nuclear;

(c) binding targets for the integration of specific technologies, e.g. RES or energy efficiency; and

(d) other market and/or regulatory constraints which are expected to apply in a target year, and which are expected to impact significantly the overall system costs or the economic viability of capacity providers. These constraints may include, inter alia, price restrictions, regulatory or policy restrictions on investments, regulatory or policy uncertainty.

15. The representation of investor risk aversion referred to in paragraph (9e) may be complemented by an additional approach aimed at better capturing investor behaviour in relation to extreme price events. This complementary approach shall:

(a) be consistent with state-of-the-art industry practice and ensure coherence with an economically sustainable business case;

(b) ensure a coherent consideration of risk;

(c) take into account the potential mitigation of exposure to the risks associated with extreme price events through forward market hedging, for those EVA decision variables and asset types for which appropriate and sufficiently liquid forward market instruments are expected to be available; and

(d) avoid any double counting of risks already reflected in the risk aversion approach applied under paragraph (9e).

The default for this complementary approach shall be a partial discounting of Monte Carlo sample years with the highest revenues. Alternative approaches may be applied where they provide a representation of investor risk that is at least as robust as partial discounting of the highest-revenue Monte Carlo sample years, and are duly justified and documented in the ERAA report.

16. The remaining economic lifetime (beyond the end of the study time period) of the capacity resources shall be considered, together with WACC, in depreciating the CAPEX (both for existing and new-built capacities) within the period of the assessment. The EVA may take boundary conditions into account, to reflect the expected costs and benefits of a capacity resource beyond the study time period.

16a. Where necessary to reflect realistic lead times for the entry of new-build capacity resources, ENTSO-E may define a technology-specific earliest entry year. Such an earliest entry year shall prevent the investment in new-build capacity of the considered technology other than that already included in the baseline data pursuant to Article 3, in cases where the time interval between the year of the ERAA edition and the relevant target year is insufficient for the investment to materialise. In determining earliest entry years, ENTSO-E shall take into account only the expected time between the final investment decision and commissioning, including construction and commissioning periods. The determination of earliest entry years shall be consistent with the auction schedule and delivery timelines of approved CMs in the relevant Member States.

16b. Where necessary to reflect realistic lead times for the exit of existing capacity resources, ENTSO-E may define a technology-specific or asset-specific earliest exit year. An earliest exit year shall prevent the EVA from selecting the mothballing or decommissioning of the relevant capacity resources other than those already included in the baseline data pursuant to Article 3, where the time interval between the ERAA edition year and the relevant target year is insufficient for such exit to be implemented.

16c. Pursuant to Article 23(5)(b) of the Electricity Regulation, which provides that the EVA assess the likelihood of retirement, (de)mothballing, and new-build of generation assets, the result of the EVA based on paragraph (2) may also be expressed as a likelihood of each of the decision variables listed in paragraph (7), as long as it ensures the computation of deterministic adequacy metrics.

(a) This approach shall assess the economic viability of (groups of) capacity resources pursuant to paragraphs (4), (4a) and (5) and may:

i. consider uncertainties in the reference cost assumptions pursuant to paragraph (10) and Article 5(10) (e.g. CAPEX, annual fixed costs), taking into account more detailed national-level data where available (e.g. next expected major overhaul);
ii. consider uncertainties in the hurdle rates pursuant to paragraph (9e)(a), taking into account the heterogeneity of investor and risk preferences;
iii. be used to check the robustness of the results of the approaches defined under paragraph (2), or applied independently.

(b) Existing and potential new-build capacity resources shall be classified into viability categories (e.g. very likely viable, possibly viable, unlikely viable) based on clearly defined and transparent thresholds. In case (additional) unviable existing capacity or viable new-build capacities are identified, the potential impact on adequacy indicators shall be assessed by mapping these categories to deterministic entry/exit assumptions in line with paragraph (4a) and either:

i. using these assumptions as a basis for a sensitivity analysis pursuant to Art 3(6)(d), or
ii. iterating the calculations to update the (central reference) scenario.

17. ENTSO-E shall study the stability and trustworthiness of the EVA results. ENTSO-E shall ensure that the assumptions of the model are consistent with relevant national policies, generation capacity forecasts and feedback from national market parties, e.g. expressed within the national consultations as referred in Article 9, and surveys pursuant to paragraph (18). In case of instability and/or untrustworthiness of the results, the reliability of the assumptions shall be assessed and, when needed, revised appropriately to strengthen the EVA. ENTSO-E may use the data collected pursuant to Article 5 to calibrate the EVA.

18. To ensure that the assumptions and methodologies applied in the EVA reflect real-world investor behaviour as closely as possible, ENTSO-E shall conduct, at least every three years, a survey of investors, utilities, financial institutions and other market participants. The survey shall, inter alia, collect information on additional relevant revenues other than those listed in paragraphs (9a) and (9b), earliest entry/exit year pursuant to paragraphs (16a) and (16b), and risk aversion practices pursuant to paragraphs (9e) and (15). ENTSO-E shall consult ACER on the proposed survey questionnaire.

Article 7

Economic dispatch

1. For each MC sample year (based on a given scenario or sensitivity), ENTSO-E shall run an ED to estimate ENS and to inform the EVA.

2. The ED shall assume perfect foresight of generation, storage and demand availability in line with Article 4. The window over which perfect foresight is assumed may depend on the considered technology.

3. The ED shall determine the dispatch of generation, storage and demand units in order to meet demand for every MTU of the MC sample year, while minimising the total system operating cost. The ED shall at least model individually each modelled zone; it may rely on a higher level of spatial detail. In this case, the input data shall be refined accordingly.

4. The total system operating cost shall include:

   (a) generation cost, including at least short-term variable cost, pursuant to Article 5(10);

   (b) DSR activation cost and demand elasticity;

   (c) storage operating cost; and

   (d) cost of ENS pursuant to paragraph (8).

5. The ED shall reflect the following constraints:

   (a) technical constraints of generation per modelled zone and MTU, pursuant to Article 4(4). The ED may reflect start-up and switch off decisions in detail, i.e. it may reflect a unit commitment economic dispatch, in order to improve the quality of the simulated dispatch;

   (b) demand (including DSR) per modelled zone and MTU, pursuant to Article 4(3);

   (c) available storage, including technical constraints, pursuant to Article 4(5);

   (d) planned and unplanned outages per modelled zone and MTU, pursuant to Article 4(2)(d)(ii);

   (e) available cross-zonal capacity per modelled zone border and MTU, pursuant to Article 4(6);

   (f) reserves and balancing requirements per modelled zone and MTU, pursuant to Article 4(6a); and

   (g) exchanges with non-explicitly modelled systems, pursuant to Article 4(7).

6. The ED shall consider that forced demand disconnection, as a non-market-based measure, is a measure of last resort, which shall be activated if all options provided by the market have been exhausted, or where it is evident that market-based measures alone are not sufficient to prevent a further deterioration of the electricity supply situation, in line with Article 16 of the RPR and with Articles 11(5)(b)(v) and 22 of the E&R NC and any other relevant national legislation related to load-shedding procedures.

7. In line with Article 22(2) of Electricity Regulation, the ED shall reflect that strategic reserves are to be dispatched only if a TSO is likely to exhaust its balancing resources to establish an equilibrium between demand and supply, without prejudice to the activation of capacity resources before actual dispatch in order to respect the ramping constraints and operating requirements of these capacity resources.

8. To ensure consistency with the EVA, the cost of ENS shall reflect price formation during MTUs when ENS occurs in a considered modelled zone, and shall be equal to the harmonised limit on maximum clearing price (pursuant to Article 10(1) and (2) of Electricity Regulation) unless indirect restrictions to wholesale price formation (pursuant to Article 10(4) and (5) of Electricity Regulation) impact price formation during MTUs with ENS in the considered modelled zone.

9. The ED should reflect price formation to estimate a price for each modelled zone and each MTU. In this case, the following elements shall be reflected, if they are expected to impact significantly the EVA or the ED:

(a) harmonised limits on maximum and minimum clearing prices pursuant to Article 10(1) and (2) of Electricity Regulation;

(b) indirect restrictions to wholesale price formation (and mitigating measures) pursuant to Article 10(4) and (5) of Electricity Regulation

(c) pursuant to Article 23(5)(c) of Electricity Regulation, the likely impact of measures adopted pursuant to Articles 10(5) and 20(3) of Electricity Regulation, including e.g. shortage pricing function for balancing energy; and

(d) the impact of cross-zonal capacity allocation (e.g. flow-based, adequacy patch or other demand-curtailment sharing expected to apply in single day-ahead coupling), in line with CACM Regulation.

The modelling of these elements may be simplified to ensure a feasible implementation.

10. The ED simulations shall provide the following results for each MC sample year and MTU:

(a) the total operating cost in EUR;

(b) for each (group of) generation unit, the production in MW;

(c) for each (group of) storage unit, the injection or withdrawal in MW;

(d) for each (group of) DSR unit, the activated DSR in MW;

(e) the change in demand due to demand elasticity in MW;

(f) for each modelled zone, the ENS before activation of out-of-market capacity resources, in MW;

(g) for each modelled zone, the ENS after activation of out-of-market capacity resources, in MW;

(h) for each modelled zone, the short-term marginal cost in EUR/MWh;

(i) for each modelled zone, the price in EUR/MWh (if price formation is modelled for the considered MTU according to paragraphs (8) and (9));

(j) for each modelled zone, the net position in MW;

(k) for each modelled zone border, the commercial cross-zonal exchange in MW; and

(l) for each CNEC, the physical flow in MW, and the shadow price in EUR/MW.

11. The ED simulations shall at least provide the following results for each target year:

(a) the EENS before activation of out-of-market capacity resources, in MWh;

(b) the EENS after activation of out-of-market capacity resources, in MWh;

(c) the LOLE before activation of out-of-market capacity resources, in h; and

(d) the LOLE after activation of out-of-market capacity resources, in h.

12. For each modelled zone, the activation of out-of-market capacity resources shall reflect scenario assumptions (e.g. related to presence of strategic reserve), expected operational TSO practices and applicable legal framework for the considered target year. The modelling of out-of-market capacity resources may be simplified to ensure a feasible implementation.

13. ENTSO-E may use the data collected pursuant to Article 5 to calibrate the ED.

Article 8

Identifying a resource adequacy concern

1. For a given target year and modelled zone, ENTSO-E shall identify a resource adequacy concern if and only if:
   (a) the relevant Member State or competent authority designated by the Member State (or Member States or competent authorities designated by the Member States in the case of cross-border modelled zones) has set a reliability standard for the target year and modelled zone pursuant to Article 25 of Electricity Regulation, based on the RS methodology; and
   (b) the reliability standard is not fulfilled for the target year for at least one central reference scenario. Where the reliability standard is defined solely as LOLERS by the relevant Member State (or Member States in the case of cross-border modelled zones), the reliability standard is not fulfilled for a target year and modelled zone, if the LOLE after activation of out-of-market capacity resources pursuant to Article 7(11)(d) is higher than the LOLERS (in at least one central reference scenario). When other criteria are used in the definition of the RS, the fulfilment of the RS should be established accordingly in a transparent manner.
2. Pursuant to Article 23(5)(k) of Electricity Regulation, for each resource adequacy concern identified pursuant to paragraph (1), ENTSO-E shall identify the possible source(s) of the resource adequacy concern. The possible source(s) of the resource adequacy concerns shall be assessed at least via:
   (a) the percentage of MTUs corresponding to ENS occurring simultaneously in multiple neighbouring modelled zones, to the total amount of MTUs with ENS; and
   (b) the analysis of generation, demand, cross-zonal capacity and cross-zonal exchanges of a modelled zone and its connected neighbouring systems during MTUs with ENS.

Article 9

Stakeholder interaction

1. While complying with the methodology framework, the ERAA shall, to the extent possible, take advantage of the latest innovations and improvements in terms of data accuracy, data granularity and computing power, in order to maintain a state-of-the-art approach. ENTSO-E shall endeavour to keep abreast of the latest innovations in Europe and globally, especially through interactions with academia, research institutions, industry experts and financial experts.
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 ECG and relevant stakeholders and approval by ACER under the procedure set out in Article 27 of Electricity Regulation.
3. ENTSO-E shall establish adequate interaction channels for all relevant stakeholders, including civil society, to contribute to 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) public consultations; and

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

4. ENTSO-E shall hold the following consultations on the ERAA methodology, scenarios, assumptions, sensitivities and results for each ERAA edition:

(a) A public consultation on assumptions and high-level definition of scenarios with their assumptions. This consultation shall be published and shall include at least prices of CO2 emission allowance, fuel prices, demand, DSR potential, storage, cross-zonal capacities and an overview of generation capacity by type of technology per Member State. In particular, exogenous assumptions shall be properly consulted. This yearly public consultation may align with the biennial consultation the ENTSOs' TYNDP scenario framework. For the scenarios with the Trends and Projections scenario assumption basis, the consultation shall also include a description of how the assumptions were established, including how observed historical trends were taken into account and how additional information and expected policy developments not already reflected in those trends were incorporated.

(b) The ECG shall be consulted regarding the ERAA methodology, scenarios, sensitivities and assumptions. ENTSO-E shall present an overview of the preliminary results of the ERAA to the ECG as soon as available and before the publication of the ERAA report.

(c) Comments received from the ECG or other stakeholders during the public consultation shall be considered in improving the ERAA. These comments should not delay the annual publication of the ERAA, unless they seriously challenge the credibility or acceptance of the ERAA results. ENTSO-E shall provide a reply to the stakeholders' comments received during the public consultation for each ERAA edition.

(d) The results of the ERAA depend heavily on the chosen scenarios and the quality of the data collected. During the public consultation on the scenarios, assumptions and sensitivities of the ERAA, ENTSO-E shall ensure that all stakeholders have the opportunity to check, compare and benchmark the data and the assumptions used in the assessment.

(e) In line with Article 11, the results of each ERAA edition, together with the assumptions on which they are based and the data related to the different scenarios and sensitivities, shall be published on ENTSO-E's website as the ERAA report.

5. All ENTSO-E's consultations shall comply with Article 31 of Electricity Regulation.

Article 10

Assessment process

1. The data collection and different stakeholder interactions, as described in Article 5 and Article 9, shall occur in the following order:

(a) ENTSO-E shall publish data collection guidelines and model assumptions and shall provide them along with data templates to each TSO;

(b) TSOs shall fill in the data templates according to the data collection guidelines;

(c) ENTSO-E shall collect the TSO data, execute data quality checks, prepare and store the data in the PEMMDB;

(d) ENTSO-E shall prepare and consolidate economic and technical data to perform EVAs;

(e) ENTSO-E shall publicly consult on each ERAA edition, pursuant to Article 9(4)(a);

(f) ENTSO-E shall consult the ECG regarding the scenarios, sensitivities, input variables, assumptions, and on the option for a Member States to opt-out from the calculation of CM-related parameters pursuant to Article 12(1);

(g) ENTSO-E shall execute the ERAA calculations and analyse the results;

(h) ENTSO-E shall present an overview of the preliminary results of the ERAA to the ECG and relevant stakeholders as soon as available and preferably before the publication of the ERAA report;

(i) ENTSO-E shall incorporate comments received from the ECG or other stakeholders during the consultation into the relevant edition of the ERAA, pursuant to Article 9(4)(c);

(j) ENTSO-E shall publish the report containing the results of each ERAA edition on the ENTSO-E website, together with the assumptions on which they are based and the data related to the different scenarios, pursuant to Article 11 and the CM-related parameters pursuant to Article 12.

2. By 1 November each year, ENTSO-E shall submit the ERAA report to ACER for approval pursuant to Article 23(7) of Electricity Regulation.

3. No later than 1 month after ECG consultation on the input variable and assumptions referred in paragraph (1)(f), ENTSO-E shall publish the final assumptions and input variables used in the central reference scenarios.

Article 11

Transparency requirements

1. ENTSO-E shall ensure full transparency of the ERAA in line with its obligation to operate in full transparency towards stakeholders and the general public, required by Article 41(2) of Electricity Regulation. In particular, ENTSO-E shall publish on its website all relevant documentation pertaining to the ERAA which shall enable stakeholders to understand inputs, data, assumptions, and scenario and sensitivity development.

1a. ENTSO-E shall ensure that any ERAA report published prior to ACER decision pursuant to Article 27 of the Electricity Regulation, includes a clear disclaimer stating that the report is a preliminary draft. This disclaimer must indicate that the report is subject to approval and potential amendments by ACER. Upon the issuance of ACER's decision, ENTSO-E shall ensure that the published version of the ERAA report is replaced with the version amended and approved by ACER.

1b ENTSO-E shall include in the ERAA report, for each modelled zone and target year, a statistical distribution of the duration of ENS events observed in the ED simulations. ENTSO-E may present this information by grouping ENS events into duration ranges and indicating the share of ENS events falling within each range, or by applying any other method that provides an equally clear and informative representation. The information shall be published in a manner that allows Member States and stakeholders to understand the nature and frequency of short- and long-duration ENS events that may occur in the assessed scenarios.

1c For every without-CM scenario computed in an ERAA edition, ENTSO-E shall include in the ERAA report, for each modelled zone and target year, the amount of capacity that is not subject to the EVA and the reasons for such exclusion. ENTSO-E shall provide separate quantities for at least the following categories:

(a) subsidised capacity as referred to in Article 6(9a)(c);

(b) capacity receiving other electricity-sector revenues that ensure economic viability, as referred to in Article 6(9c)(a); and

(c) capacity receiving revenues from outside the electricity sector that ensure economic viability, as referred to in Article 6(9c)(b).

These quantities shall be reported separately for each relevant technology types referred to in Article 12(3).

2. For each ERAA edition, ENTSO-E shall publish on its website the ENTSO-E data collection guidelines pursuant to Article 5(1)(a);

3. For each ERAA edition, ENTSO-E shall publish on its website at least the following input data for each scenario and sensitivity:

   (a) high level indicators of relevant temporal granularity per modelled zone to enable a comparative analysis, characterising both the demand and the supply side. These indicators shall include at least the total demand targets and peak demand, including their compound annual growth rate over the modelled pivotal years, as well as the evolution of nominal generation capacities at least by technology type (including DSR) and their storage size when relevant.

   (b) high level indicators of relevant temporal granularity and per modelled zone to enable a comparative analysis, characterising the underlying grid modelling and market coupling. These indicators shall include at least the evolution of NTC timeseries for the relevant borders over the modelled pivotal years, as well as Minimum and Maximum Net Positions of the Flow-Based domains for the modelled Flow-Based regions (e.g. CORE and Nordic).

   (c) high level assumptions, economic and technical data to perform the EVA pursuant to Article 6, with relevant temporal granularity and at least per modelled zone;

   (d) high level assumptions, economic and technical data to run the ED pursuant to Article 7, with relevant temporal granularity and at least per modelled zone;

   (e) the PECD pursuant to Article 5(12) (if not already publicly available);

   (f) the main assumptions underlying the modelling of the harmonised limits on maximum and minimum clearing prices pursuant to Article 10(1) and (2) of Electricity Regulation, in line with Article 5(13); and

   (g) any indirect restrictions to wholesale price formation and mitigating measures pursuant to Article 5(14), and Articles 10(4) and (5) and 20(3) of Electricity Regulation, for those Member States where this is applicable.

4. For each ERAA edition, ENTSO-E shall publish on its website at least the following output data for each scenario and sensitivity:

(a) aggregated outputs from EVA, at least with yearly temporal granularity and per modelled zone;

(b) for each MC sample year and modelled zone, the prices (if generated by ED), marginal costs, net positions and ENS per MTU;

(c) for each MC sample year and modelled zone border, the cross-zonal exchanges per MTU;

(d) EENS and LOLE before and after activation of out-of-market capacity resources pursuant to Article 7(11) for the study time period, for each modelled zone with yearly temporal granularity;

(e) for each target year and modelled zone, the distribution (including the average) of total ENS and LOLE over all considered MC sample years;

(f) for each target year and modelled zone, the distribution (including the average) of net position of the modelled zone during MTUs when ENS is positive over all considered MC sample years, pursuant to Article 7(10);

(g) for each target year, the number of analysed MC sample years and the value of the coefficient of variation (α) of the EENS metric pursuant to Article 4(2)(e);

(h) for neighbouring modelled zones with a positive EENS or LOLE, an analysis of the different situations when ENS simultaneously occurs in modelled zones. Different simultaneous ENS situations at both regional and/or European level shall be indicated;

(i) for each MC sample year and modelled zone, the dispatch results per MTU, aggregated by technology and their availability;

(j) the inputs referred to in Article 5 for which default values across bidding zones are used.

5. In case of instability or untrustworthiness of EVA results, ENTSO-E shall clearly describe and justify in the ERAA report the additional (or revised) assumptions enforced to strengthen the trustworthiness of the EVA, as referred to in Article 6(17).

6. Each ERAA report shall include any policies, measures or actions which, while not modelled in the ERAA, are expected to significantly impact resource adequacy concerns. These shall include:

   (a) actions to eliminate or, if not possible, to mitigate the impact of that policy or measure on bidding behaviour, pursuant to Article 10(5) of Electricity Regulation; and

   (b) measures to eliminate any identified regulatory distortions or market failures, as defined by Member States pursuant to Article 20(3) of Electricity Regulation.

   The ERAA report shall qualitatively assess how the aforementioned elements not modelled in the ERAA may impact ERAA results.

7. The level of detail of published data shall be consistent with the level of implementation of the ERAA methodology at the time of publication, in line with Article 13. The published data shall include the list of additional data items available upon request.

8. Where ENTSO-E identified as confidential a set or a subset of data (or information) to publish, ENTSO-E may publish the relevant data (or information) in such aggregated form which still preserves their confidentiality. When publishing the aggregated data (or information), ENTSO-E shall explain why publishing the data (or information) required would cause harm.

9. Upon request and for each ERAA edition, ENTSO-E shall provide ACER with all the information necessary for the purpose of carrying out ACER's tasks pursuant to Article 23(7) of Electricity

Regulation, unless ACER has already requested and received such information, in line with Article 3(2) of the ACER Regulation.

10. Upon request, for each ERAA edition and for each simulated central reference scenario and/or sensitivity, as applicable, ENTSO-E shall provide all additional relevant information to Member States, including their designated authorities or entities that are responsible for the NRAAs and flexibility needs assessments, for the purpose of the execution of the tasks pursuant to the FNA methodology, Articles 19e and 24 of the Electricity Regulation.
11. ERAA data shall be shared between ENTSO-E and RCCs. In particular, for each ERAA edition, ENTSO-E shall provide RCCs with all the relevant information for the calculation, on annual basis, of the maximum entry capacity available for cross-border participation in CMs pursuant to Article 26(7) of Electricity Regulation.
12. Upon request and for each ERAA edition, ENTSO-E shall provide the NRAs with all the information necessary for the purpose of carrying out regional cooperation tasks pursuant to Article 61(2)(c) of Electricity Directive.

Article 12

CM-related parameters supporting fast-track state aid procedure

1. For each modelled zone and target year with an identified resource adequacy concern pursuant to Article 8(1) in the without-CM central reference scenario, ENTSO-E shall compute and include in the ERAA report the following CM-related parameters:
   (a) de-rating factors for each technology type referred to in paragraph (3);
   (b) the adequacy gap; and
   (c) the total firm capacity need.

   This paragraph does not apply to modelled zones for which the Member State, within three months after the ECG consultation under Article 10(1)(f), requests ENTSO-E not to compute these parameters.

2. ENTSO-E shall compute the parameters referred to in paragraph (1) for the Trends and Projections scenario assumption basis. Where, pursuant to Article 3(5), the Trends and Projections central reference scenarios are not produced in a given ERAA edition, ENTSO-E shall compute the parameters referred to in paragraph (1) for the NECP scenario assumption basis for that edition. In all other cases, ENTSO-E may also compute the parameters referred to in paragraph (1) for the NECP scenario assumption basis. For the purpose of this Article, references to scenarios shall mean the central reference scenarios with the corresponding scenario assumption basis.
3. For the purposes of paragraph (1), point (a), ENTSO-E shall compute de-rating factors for all technology types that are able to deliver their output continuously for at least one hour, including, as a minimum:
   (a) energy-constrained technologies, including storage assets with a duration between one and eight hours and hydro storage;
   (b) demand response resources with a duration between one and twelve hours;
   (c) weather-dependent technologies, including solar, onshore wind, offshore wind and run-of-river; and
   (d) all thermal technologies modelled in the ERAA.

Where new types of assets emerge, including but not limited to longer-duration storage, ENTSO-E shall also compute de-rating factors for those assets.

4. ENTSO-E shall compute the parameters referred to in paragraph (1) as follows:

   (a) for pivotal target years, those parameters shall be computed in accordance with paragraphs (5) to (16);

   (b) for non-pivotal target years, those parameters shall be derived from the values computed pursuant to point (a) for pivotal target years, in accordance with points (i) to (vi):

      i. where CM-related parameters have been computed for the earliest pivotal target year, the parameters for any preceding target years shall be set equal to those of that earliest pivotal target year;
      ii. where CM-related parameters have been computed for the latest pivotal target year, the parameters for any subsequent target years shall be set equal to those of that latest pivotal target year;
      iii. for non-pivotal target years between two pivotal target years for which CM-related parameters have been computed, the parameters shall be determined by linear interpolation between the values obtained for the immediately preceding and the immediately following pivotal target years;
      iv. for non-pivotal target years between two pivotal target years where CM-related parameters have been computed for only one pivotal target year, the de-rating factors for each technology type shall be set equal to those of the pivotal target year for which CM-related parameters have been computed;
      v. for non-pivotal target years between two pivotal target years where CM-related parameters have been computed for only one pivotal target year, the adequacy gap shall be determined by linear interpolation between:
         1. the adequacy gap obtained for the pivotal target year for which CM-related parameters have been computed; and
         2. an adequacy gap equal to zero for the pivotal target year for which CM-related parameters have not been computed;
      vi. for non-pivotal target years between two pivotal target years where CM-related parameters have been computed for only one pivotal target year, the total firm capacity need shall be determined by linear interpolation between:
         1. the total firm capacity need obtained for the pivotal target year for which CM-related parameters have been computed; and
         2. the reference firm capacity of the without-CM central reference scenario, calculated pursuant to paragraph (9), for the pivotal target year for which CM-related parameters have not been computed.

5. For modelled zone z, target year t and scenario s, the adjustment capacity $AC_{z,t}^{s}$ shall represent the capacity of perfectly reliable reference technology that would need to be added in modelled zone z in target year t, on the basis of the ED simulations of scenario s, in order for that modelled zone to meet its applicable reliability standard. The adjustment capacity shall be computed as follows:

   (a) ENTSO-E shall construct an ENS monotone series by collecting, for modelled zone z and target year t, all ENS values across all Monte Carlo sample years of the ED simulations of scenario s for scarcity MTUs, and ordering those values in descending order.

   (b) ENTSO-E shall calculate the reliability standard index K_z as the product of:

i. the reliability standard applicable to modelled zone z, expressed as a number of scarcity MTUs per year; and
ii. the number of Monte Carlo sample years used in the ED simulations of scenario s.

(c) The adjustment capacity $AC^{s}_{z,t}$ shall be equal to the ENS value located at position K_z in the ENS monotone series constructed pursuant to point (a).

6. For a given technology type, target year, modelled zone and scenario assumption basis, the de-rating factor shall represent that technology's contribution to resource adequacy and shall be determined as follows:

(a) for a modelled zone with an approved CM, de-rating factors shall be computed in accordance with paragraph (7) on the with-CM scenario with that scenario assumption basis;

(b) for a modelled zone which does not have an approved CM and for which a resource adequacy concern has been identified in the with-CM central reference scenario with that scenario assumption basis, de-rating factors shall be computed in accordance with paragraph (7) on the with-CM scenario with that scenario assumption basis. For the purpose of this computation, and where relevant for the de-rating factor approach applied under paragraph (7), ENTSO-E may adjust the calculation to reflect the expected contribution of technologies if the modelled zone were aligned with its reliability standard. Such adjustment may be performed either:

i. by post-processing the ENS results to account for the adequacy gap determined in accordance with paragraph (12)(b); or
ii. where technically feasible, by performing an additional calibration, limited to the relevant modelled zone, to align the forecast level of resource adequacy with its reliability standard in the considered target year.

7. For the calculation of de-rating factors for a given technology type i, modelled zone z, target year t and scenario s, ENTSO-E shall select one of the approaches set out in points (a) to (d). For a given technology type, the selected approach shall be applied consistently across all modelled zones and target years, and shall be described in the ERAA report.

(a) For all technology types, de-rating factors may be computed using the effective load-carrying capability (ELCC) method as follows:

$$DF^{s}_{i,z,t} = \frac{\Delta \mathrm{EENS}^{s}_{i,z,t}}{\Delta \mathrm{EENS}^{s}_{ref,z,t}}$$

where

- $\Delta \mathrm{EENS}^{s}_{i,z,t}$ is the reduction in EENS in modelled zone z and target year t resulting from the addition of 1 MW of the assessed technology type i in that modelled zone, in scenario s; and
- $\Delta \mathrm{EENS}^{s}_{ref,z,t}$ is the reduction in EENS in modelled zone z and target year t resulting from the addition of 1 MW of a perfectly reliable reference technology in that modelled zone in scenario s.

The computation shall be performed using the same modelling assumptions, input data and settings as those applied in the ED simulations of scenario s.

(b) For a thermal technology i, de-rating factor may be computed as:

$$DF_i = 1 - FOR_i - EPM_i$$

where:

- FOR_i is the forced outage rate of technology type i. Where appropriate, this rate may also reflect risks associated with fuel availability constraints; and
- EPM_i is the expected planned maintenance rate during scarcity MTUs. By default, $EPM_i = 0$, unless evidence justifies the occurrence of planned maintenance during scarcity MTUs.

(c) For all technology types, de-rating factors may be computed as:

$$DF_{i,z,t}^s = \frac{1}{N_{ENS,z,t}^s} \sum_{m \in MTU_{ENS,z,t}^s} \frac{Output_{i,z,t,m}^s}{Cap_{i,z,t}^s}$$

where:

- $MTU_{ENS,z,t}^s$ is the set of scarcity and near-scarcity MTUs in modelled zone z and target year t from the ED simulations of scenario s.
- $N_{ENS,z,t}^s$ is the number of MTUs in $MTU_{ENS,z,t}^s$;
- $Output_{i,z,t,m}^s$ is the output of technology type i in modelled zone z in MTU m (in MW), in the ED simulations of scenario s;
- $Cap_{i,z,t}^s$ is the installed capacity of technology type i in modelled zone z for target year t, in the ED simulations of scenario s.

(d) For energy-constrained technologies and demand response, de-rating factors may be computed as:

$$DF_{i,z,t}^s = (1 - FOR_i) \cdot \frac{\sum_{e \in E_{ENS,z,t}^s} T_e \cdot C_{e,i}}{\sum_{e \in E_{ENS,z,t}^s} T_e}$$

where:

- FOR_i is the forced outage rate of technology type i;
- $E_{ENS,z,t}^s$ is the set of scarcity events in modelled zone z for target year t in the ED simulations of scenario s.
- T_e is the duration of scarcity event e, expressed as the number of consecutive scarcity MTUs; and
- $C_{e,i}$ is the contribution factor of technology type i to event e, defined as:

$$C_{e,i} = \min\left(1, \frac{T_{i,e}^{avail}}{T_e}\right)$$

where $T_{i,e}^{avail}$ is the available discharge duration at the start of scarcity event e, taking into account the energy limitation of the asset and, where relevant, its ability to recharge between successive scarcity events. As a simplification, ENTSO-E may assume that storage assets are fully charged at the beginning of each scarcity event. In such case, $T_{i,e}^{avail}$ shall be equal to the nominal storage duration of the asset.

8. Where appropriate, ENTSO-E may derive an additional set of de-rating factors that reflects alternative capacity mixes used to close the adequacy gap. In such cases, ENTSO-E shall:

   (a) identify a set of technically plausible alternative capacity mixes capable of covering the adequacy gap;

(b) compute, for each identified capacity mix, the corresponding de-rating factors in accordance with paragraph (7); and

(c) describe the identified capacity mixes and the resulting de-rating factors.

9. The reference firm capacity for a given modelled zone z, target year t and scenario s shall be calculated in accordance with point (a) where de-rating factors are computed pursuant to paragraphs (7)(a) or (7)(d) for any technology type. Where, for a given modelled zone and target year, de-rating factors are computed pursuant to paragraph (7)(b) and/or (7)(c) for all technology types, the reference firm capacity may be calculated in accordance with either point (a) or point (b).

(a) Demand-based approach:

$$F_{z,t}^{s} = \overline{D}_{z,t}^{s} + BC_{z,t}^{s} - \overline{ENS}_{z,t}^{s}$$

where:

- $\overline{D}_{z,t}^{s}$ is the average demand during scarcity MTUs across all Monte Carlo sample years for modelled zone z, target year t, in the ED simulations of scenario s;
- $BC_{z,t}^{s}$ is the capacity required to cover balancing needs in modelled zone z, target year t, and scenario s; and
- $\overline{ENS}_{z,t}^{s}$ is the average ENS during scarcity MTUs across all Monte Carlo sample years for modelled zone z, target year t, in the ED simulations of scenario s.

(b) Supply-based approach:

$$F_{z,t}^{s} = \sum_{i \in I_z} Cap_{i,z,t}^{s} \cdot DF_{i,z,t}^{s} + IMP_{z,t}^{s}$$

where

- I_z is the set of technology types in modelled zone z;
- $Cap_{i,z,t}^{s}$ is the installed capacity of technology type i in modelled zone z for target year t, as represented in the ED simulations of scenario s;
- $DF_{i,z,t}^{s}$ is the de-rating factor for technology type i in modelled zone z for target year t and scenario s, calculated in accordance with paragraphs (7).
- $IMP_{z,t}^{s}$ is the average (net) imports from other modelled zones during scarcity MTUs for modelled zone z, target year t, in the ED simulations of scenario s.

10. For a given target year and modelled zone, the total firm capacity need with a given scenario assumption basis shall be determined as follows:

(a) for a modelled zone with an approved CM, the total firm capacity need shall be equal to the reference firm capacity calculated pursuant to paragraph (9) on the with-CM scenario with that scenario assumption basis;

(b) for a modelled zone which does not have an approved CM and for which a resource adequacy concern has been identified in the with-CM central reference scenario with that scenario assumption basis, the total firm capacity need shall be equal to the sum of:

i. the reference firm capacity determined pursuant to paragraph (9) on the with-CM scenario with that scenario assumption basis; and
ii. the adequacy gap determined in accordance with paragraph (12)(b).

11. The de-rated installed capacity for a given modelled zone z, target year t and scenario s, $DRIC^{s}_{z,t}$ shall be calculated as:

$$DRIC^{s}_{z,t} = \sum_{i \in I_z} Cap^{s}_{i,z,t} \cdot DF^{s}_{i,z,t}$$

where

- I_z is the set of technology types in modelled zone z;
- $Cap^{s}_{i,z,t}$ is the installed capacity of technology type i in modelled zone z for target year t, as represented in the ED simulations of scenario s; and
- $DF^{s}_{i,z,t}$ is the de-rating factor for technology type i in modelled zone z for target year t and scenario s, calculated in accordance with paragraphs (7).

12. For a given target year and modelled zone, the adequacy gap, expressed in equivalent firm capacity (MW), with scenario assumption basis b shall be determined as follows:

    (a) for a modelled zone with an approved CM, the adequacy gap shall be equal to:

    $$GAP^{b}_{z,t} = DRIC^{with-CM,b}_{z,t} - DRIC^{without-CM,b}_{z,t}$$

    where $DRIC^{with-CM,b}_{z,t}$ and $DRIC^{without-CM,b}_{z,t}$ are calculated pursuant to paragraph (11) for, respectively the with-CM and without-CM central reference scenarios with scenario assumption basis b;

    (b) for a modelled zone without an approved CM for which a resource adequacy concern has been identified in the with-CM central reference scenario with scenario assumption basis b, the adequacy gap shall be equal to the adjustment capacity determined in accordance with paragraph (5) and applied on the with-CM scenario with that scenario assumption basis.

13. For a modelled zone that does not have an approved CM and for which no resource adequacy concern has been identified in the with-CM central reference scenario, ENTSO-E shall, for that modelled zone and target year compute the parameters referred to in paragraph (1) as follows:

    (a) the adequacy gap shall be equal to the adjustment capacity determined pursuant to paragraph (5) on the without-CM scenario;

    (b) the total firm capacity need shall be equal to the sum of:

        i. the reference firm capacity determined pursuant to paragraph (9) on the without-CM scenario; and
        ii. the adequacy gap determined in accordance with point (a).

    (c) the de-rating factors shall be computed in accordance with paragraph (7) on the without-CM scenario. For the purpose of this computation, and where relevant for the de-rating factor approach applied under paragraph (7), ENTSO-E may adjust the calculation to reflect the expected contribution of technologies if the modelled zone were aligned with its reliability standard. Such adjustment may be performed either:

        i. by post-processing the ENS results to account for the adequacy gap determined in accordance with point (a); or
        ii. where technically feasible, by performing an additional calibration, limited to the relevant modelled zone, to align the forecast level of resource adequacy with its reliability standard in the considered target year.

14. For the ERAA 2026, ERAA 2027 and ERAA 2028 editions, where ENTSO-E encounters duly justified computational difficulties that prevent the execution of the with-CM scenario, the parameters referred to in paragraph (1) shall be computed pursuant to paragraph (13) for all modelled zones with an identified adequacy concern in the without-CM central reference scenario.

15. As an alternative to the approach set out in paragraphs (5) to (13), ENTSO-E may instead determine the parameters referred to in paragraph (1) on the basis of a reliability standard adjusted scenario. In that reliability-standard-adjusted scenario, ENTSO-E shall simultaneously adjust, in each modelled zone for which a reliability standard applies, the capacity so that each such modelled zone meets its applicable reliability standard, while keeping all other modelling assumptions, input data and settings unchanged compared to the corresponding central reference scenario.

16. Where ENTSO-E uses the reliability-standard-adjusted scenario pursuant to paragraph (15), ENTSO-E shall compute the parameters, for each modelled zone and target year referred to in paragraph (1), as follows:

    (a) the total firm capacity need shall be equal to the reference firm capacity calculated pursuant to paragraph (9) on the reliability-standard-adjusted scenario pursuant to paragraph (15);

    (b) the adequacy gap shall be calculated in accordance with paragraph (12)(a), treating the reliability-standard-adjusted scenario as the with-CM central reference scenario for the purposes of that calculation; and

    (c) the de-rating factors shall be computed in accordance with paragraphs (7) on the reliability-standard-adjusted scenario pursuant to paragraph (15).

Article 13
Implementation of the methodology

1. For the ERAA 2026 edition, ENTSO-E shall apply Annex I of ACER Decision 24/2020, subject to the transitional provisions set out in paragraphs (2) and (3).

1a. This ERAA methodology shall apply to the ERAA 2027 edition and to all subsequent editions, subject to the transitional provisions set out in paragraphs (4) to (7).

2. In the ERAA 2026 edition, ENTSO-E shall compute and publish in the ERAA report the CM-related parameters pursuant to Article 12, provided this does not delay the delivery of the ERAA report.

3. By way of derogation from Annex I to ACER Decision 24/2020 for the ERAA 2026 edition, ENTSO-E may:

    (a) refrain from performing the sensitivity on the restriction of price formation referred to in Article 3(7) of Annex I of ACER Decision 24/2020;

    (b) refrain from estimating revenues from (i) other electricity-related services, as referred to in Article 6(9)(b) of Annex I of ACER Decision 24/2020, and (ii) services outside the electricity sector, as referred to in Article 6(9)(c) of Annex I of ACER Decision 24/2020, if ENTSO-E is not yet in a position to robustly estimate them by the time it is needed for the ERAA 2026 edition;

(c) explicitly model only a subset of pivotal target years pursuant to Article 2a and estimate resource adequacy metrics for non-pivotal target years in accordance with Article 4(1)(b);

(d) run a with-CM central reference scenario only as a proof-of-concept, and publish it as a separate study, outside the ERAA 2026 report, no later than six months after the submission of the ERAA 2026 report; and

(e) apply the Trends and Projections scenario assumption basis in place of the NECP scenario assumption basis.

4. In the event that ENTSO-E encounters computational difficulties that prevent the production of the Trends and Projections scenario with CM for ERAA editions preceding the ERAA 2029 edition, ENTSO-E may limit the modelling of that scenario as follows:

   (a) in the ERAA 2027 edition, to the earliest pivotal target year only; and

   (b) in the ERAA 2028 edition, to the earliest pivotal target year and to one additional pivotal target year selected as the most relevant for the computation of the maximum entry capacity.

5. For the purpose of constructing the with-CM central reference scenario for a given scenario assumption basis, ENTSO-E may apply the following simplified procedure:

   (a) ENTSO-E shall compute, for each modelled zone that (i) has an approved CM; and (ii) displays an adequacy concern in the corresponding without-CM central reference scenario, the maximum capacity that may be added, as the adjustment capacity determined pursuant to Article 12(5) on the basis of the corresponding without-CM central reference scenario;

   (b) ENTSO-E shall use as the starting point the without-CM central reference scenario with the same scenario assumption basis;

   (c) ENTSO-E shall add, in each modelled zone referred to in point (a) that does not meet its applicable reliability standard, an incremental capacity not exceeding 10% of the maximum capacity computed pursuant to point (a);

   (d) on the basis of the incremental capacity added pursuant to point (c), ENTSO-E shall re-run the ED simulations;

   (e) ENTSO-E shall compute the resource adequacy metrics on the basis of the ED simulations referred to in point (d);

   (f) where all modelled zones meet their applicable reliability standards, the resulting outcome shall constitute the with-CM central reference scenario; where one or more modelled zones do not meet their applicable reliability standards, ENTSO-E shall repeat the steps set out in points (c) to (e) until all modelled zones meet their applicable reliability standards.

   Where ENTSO-E applies the simplified procedure referred to in this paragraph, it shall analyse the performance of the procedure in bringing all the modelled zones referred in point (a) to their reliability standard, and shall identify methodological improvements for subsequent ERAA editions. Based on these analyses, the 2028 ERAA report shall be complemented by ENTSO-E's assessment of the simplified procedure in which they recommend whether it should be continued in the subsequent ERAA editions.

6. Paragraphs 6(8a)-6(9e) and 6(15) concerning the representation of investor business case shall be implemented no later than in the ERAA 2028 edition. In preparation for their implementation and as part of the ERAA 2027 edition, ENTSO-E shall:

(a) conduct a survey of transmission system operators to ascertain whether they perform analyses to estimate additional revenues derived from ancillary services and intraday markets, either within the framework of their national resource adequacy assessments or through other processes, including but not limited to tariff determination; and

(b) assess how to estimate the additional revenues referred to in point (a) for modelled zones whose transmission system operators do not currently carry out such analyses. This assessment shall identify the approach to be applied, including, as appropriate, one or more of the following:

    i. inferring revenue estimates from modelled zones where such analyses are performed, including through interpolation or other technically robust methods; and/or
    ii. applying, for those modelled zones, a methodology based on an approach used by one or more transmission system operators, or a methodology developed by ENTSO-E, to estimate such revenues.

7. No later than three months after the approval of this amended ERAA methodology by ACER, ENTSO-E shall publish an implementation plan that outlines the prioritisation and timeline for implementing new methodological elements, in accordance with the timelines set out in this Article. ENTSO-E shall review the implementation plan after each ERAA edition, taking into account the most recent information regarding the technical feasibility of implementing the respective methodological elements, both individually and in combination. Where ENTSO-E considers that amendments to the implementation plan are necessary, it shall amend the plan after consulting Member States, ACER and relevant stakeholders. Any amendment shall remain consistent with (a) the timelines and requirements set out in this Article and (b) the most recent ACER decision on the annual ERAA.

8. ENTSO-E shall assess whether the implementation of the ERAA methodology may lead to cybersecurity risks. If it is the case, ENTSO-E shall report on such risks (and potential mitigation measures) to ACER without undue delay.

9. ENTSO-E may suggest potential improvements of the ERAA methodology to ACER. Irrespective of any suggestion from ENTSO-E, ACER may request amendments to the ERAA methodology pursuant to Article 27(4) of Electricity Regulation.

Article 14

Language

1. The official language for the ERAA methodology shall be English.