ACER
European Union Agency for the Cooperation of Energy Regulators

ACER Decision on ERAA 2023: Annex III

DECISION No 06/2024

OF THE EUROPEAN UNION AGENCY

FOR THE COOPERATION OF ENERGY REGULATORS

on the European Resource Adequacy Assessment for 2023

Technical annex

2 May 2024

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1. Introduction

1.1. Scope of technical annex

The technical annex provides a detailed assessment of specific elements of the European Resource Adequacy Assessment 2023 (‘ERAA 2023’) and complements the ACER Decision; the two should be read in conjunction. The technical annex supplements ACER’s assessment of ERAA 2023 concerning the high-level requirements of the Electricity Regulation (as described in section 6 of the Decision). It provides additional background for ACER’s assessment. This annex is structured as follows:

- The second chapter focuses on the alignment of ERAA 2023 with the fit-for-55 target and renewable energy in particular.
- The third chapter details ACER’s assessment of the economic viability assessment (EVA).
- The fourth chapter focuses on the consideration of cross-zonal capacities in ERAA 2023.

2. Fit-for-55 and renewable energy generation

2.1. Introduction

Article 3 of the ERAA methodology stipulates that the central reference scenario needs to be in line with national objectives and targets. National objectives and targets stem from the EU-wide objectives and targets, implying that the central reference scenarios need to be aligned with the EU-wide policy objectives. This section examines the alignment of ERAA 2023 with the EU-wide policy objectives, in particular for renewable energy resources.

The current EU greenhouse gas emissions target for 2030 is to reduce emissions levels by at least 55% from 1990 levels (the so-called “fit-for-55”). To deliver this target the European Union has agreed to a binding EU-wide renewable energy target in the overall energy mix of at least 42.5% by 2030, with the aim to reach a 45% share.[1] This target effectively means almost doubling the share of renewable energy from current levels to 2030 and translates to an equivalent target at the high end of around 69% of electricity supplied from renewable energy resources.[2, 3]

2.2. Comparison of ERAA 2023 with ERAA 2022

In order to examine the alignment of the ERAA 2023 central reference scenario with the EU-wide policy objectives, ACER analysed the ERAA 2023 projections for renewable energy with the ERAA 2022 projections, as a first step. The analysis focuses on the target years 2025 and 2030, and solar and wind (onshore and offshore) technologies, in particular, that are expected to be the key technologies deployed for meeting the renewable energy targets. ACER notes that the ERAA 2022 scenarios were significantly misaligned with the EU climate and energy objectives regarding the development of renewable energy for a large number of Member States. This means that the ERAA 2023 projections for installed renewable capacity should in principle be higher than those for ERAA 2022. Figure 1 and Figure 2 present the differences in assumed renewable energy capacity between ERAA 2023 and ERAA 2022 for target years 2025 and 2030 respectively.

From the two figures, ACER observes that with limited exceptions, renewable energy capacity projections have increased across the timeframe and geography of the assessment. The main technology driving the changes is solar power, both in the short-term (i.e., 2025) and long-term (i.e., 2030), followed by onshore wind and to a lesser extent offshore wind. Similarly with last year’s analysis, renewable capacity increases are more pronounced for the long-term. This effectively indicates that ERAA 2023 assumes the pace of new developments will accelerate further out in the decade, compared to the next few years. Overall, ERAA 2023 assumes there is an additional 37 GW of installed renewable capacity in 2025 and an additional 150 GW in 2030, compared to ERAA 2022.

[1] For more information, see for example the European Commission’s webpage on the Renewable Energy Targets.

[2] According to the European Environment Agency, the share of renewable energy stood at around 22.5% in 2022, slightly up from the year before. In the power sector, about 40.7% of all electricity generated in the EU in 2022 came from renewable energy sources.

[3] According to the European Commission, to meet the RePowerEU target of a 45% share of renewables in total energy, the renewable energy share in the electricity sector would need to reach 69% by 2030.

Figure 1: Differences in installed renewable capacity between ERAA 2023 and ERAA 2022 for 2025

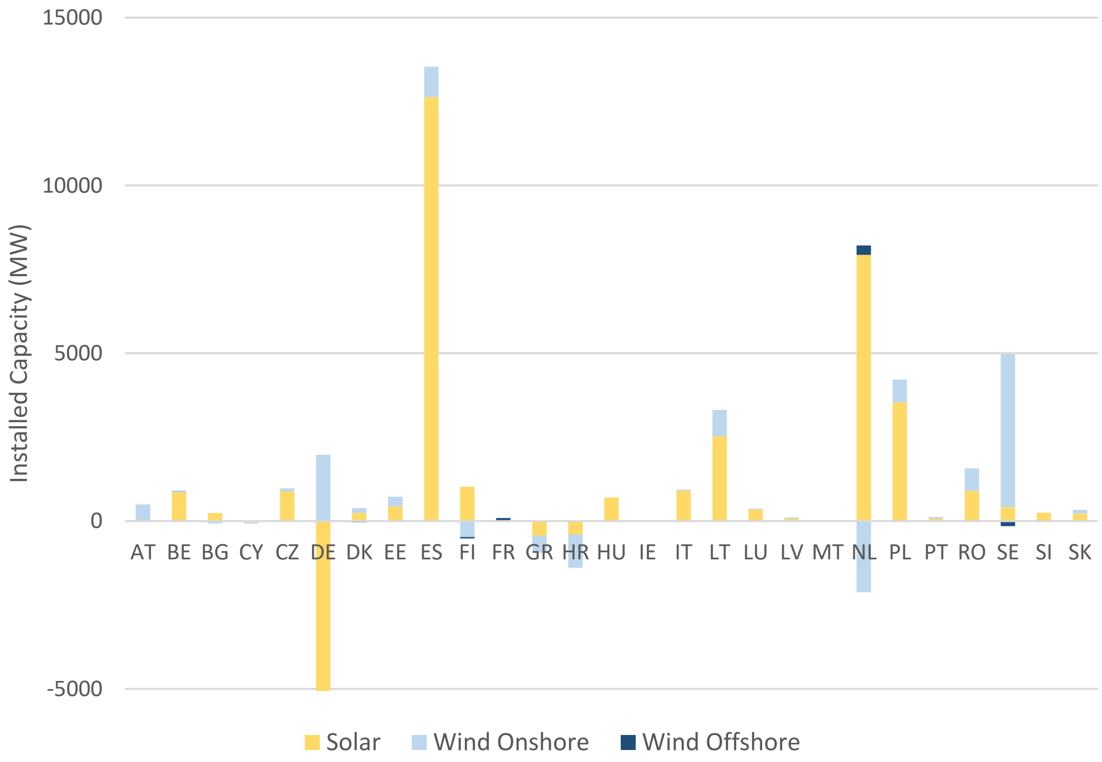
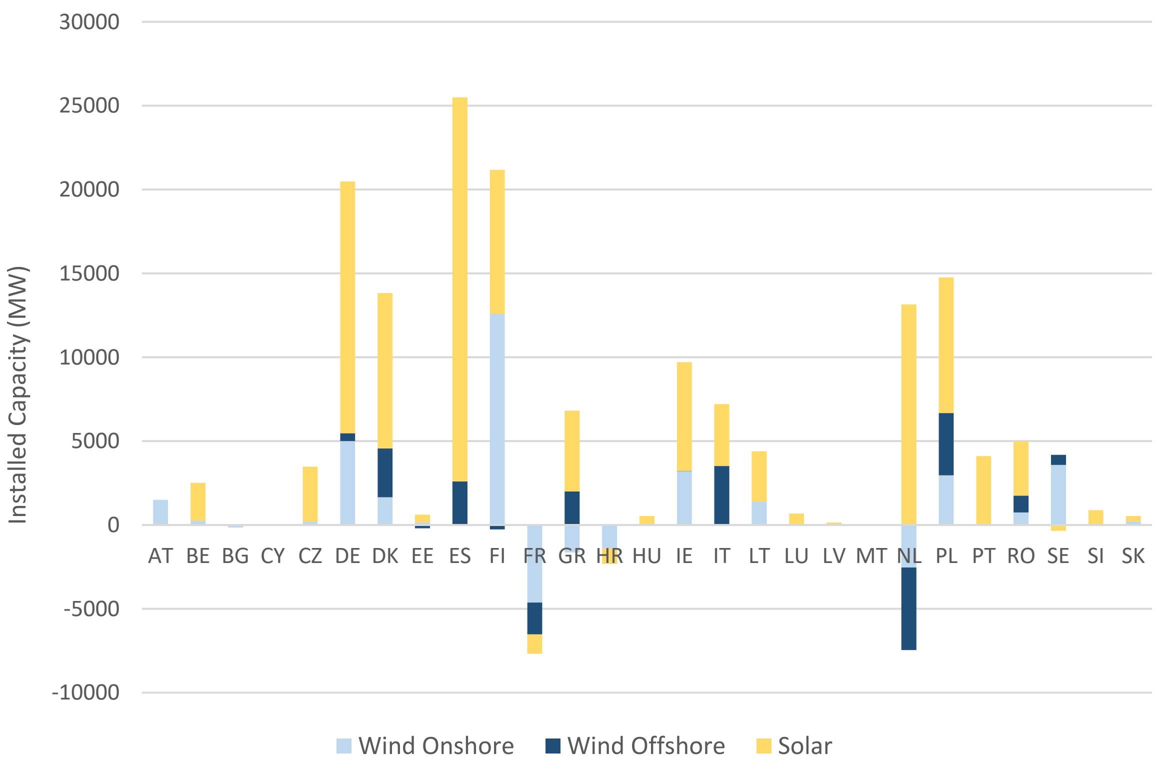


Figure 2: Differences in installed renewable capacity between ERAA 2023 and ERAA 2022 for 2030



Source: ACER analysis based on ENTSO-E's ERAA 2023 and ERAA 2022 data.

While not the focus of this section, ACER has also examined the changes in electricity demand between ERAA 2023 and ERAA 2022.[4] ACER's analysis shows that electricity demand projections have increased, especially for the long-term (i.e. 2030), by around 5% on average, compared to ERAA 2022. According to ERAA 2023, the main driver for this increase is higher electrification across Member States compared to ERAA 2022. Table 5 presents the results of this analysis for ERAA 2023 and ERAA 2022.

2.3. Comparison of ERAA 2023 with the draft National Energy and Climate Plans

In addition to the comparison with ERAA 2022, ACER analysed ERAA 2023 against the Member States' draft updated National Energy and Climate Plans (NECPs).[5] ACER notes that the draft NECPs only became available late in the process of developing ERAA 2023. As such, ENTSO-E could not have taken them into account while developing ERAA 2023. However, this analysis can provide useful information about the alignment of the ERAA 2023 central reference scenario with the pan-European renewable energy targets.[6]

The analysis focuses on target years 2025 and 2030, and solar and wind (onshore and offshore wind combined) technologies in particular. Figure 3 and Figure 4 present the relative differences in installed renewable capacity between ERAA 2023 and the draft NECPs for 2025 and 2030 respectively (in addition, Table 6 and Table 7 in the Appendix present the absolute differences in installed renewable capacity for the two target years). Due to limited availability of data at the time of conducting this analysis, the figures present a comparison for 20 Member States.

The two figures suggest that the ERAA 2023 scenario is on average largely consistent with the draft NECPs. The total differences in installed capacity are less than around 1% for both technologies and target years examined. For example, in 2030, the installed capacity of solar is lower by 1.2% in ERAA 2023, while that of wind is higher by 0.1% in ERAA 2023, compared to the draft NECPs for the entire geographical area examined.

Considering the Member State projections across the ERAA 2023 and draft NECPs, the alignment is more variable. For the majority of Member States (e.g., Germany, Greece, Romania) the projections are well aligned between the ERAA 2023 and their draft NECP. For some Member States, such as Finland, the Netherlands and Sweden, the ERAA 2023 assumes a greater deployment of renewable energy resources than the respective NECPs. On the other hand, for some Member States the assumed renewable energy capacities in ERAA 2023 are consistently lower than the draft NECPs. For example, the assumptions for Croatia, Hungary, Portugal and Slovenia are considerably lower (around or more than 20% lower for both wind and solar power) than the renewable energy goals set in the respective Member States' draft NECPs, with reference to 2030. In addition, the assumptions for Cyprus, France, Italy and Spain are also lower than the set NECP goals for both technologies in 2030, however, to a lesser extent. The projections for these Member States would have to be updated for next year's ERAA, so that they better align with the EU's renewable energy and, by extension, carbon emission reduction targets.

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[4] Specifically, ACER has compared the annual demand for each Member State (average annual demand across all climate years) for 2025 and 2030 between the two consecutive ERAAs.

[5] European Commission's National energy and climate plans page.

[6] For the ERAA 2022 Decision, ACER compared the ERAA 2022 renewable capacity assumptions with the European Commission's fit-for-55 scenario. In the absence of updated NECPs, the European Commission's fit-for-55 scenario presented a relevant reference point to evaluate the alignment of ERAA 2022 with the new targets for renewable capacity.

Figure 3: Relative differences (%) in installed renewable capacity between ERAA 2023 and the draft Member State NECPs for 2025

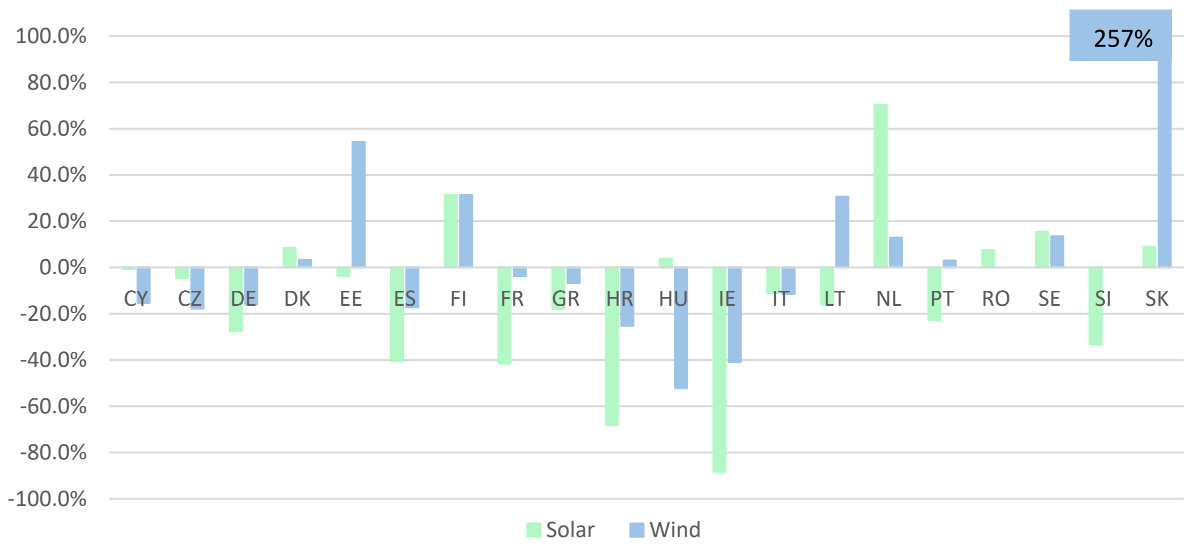
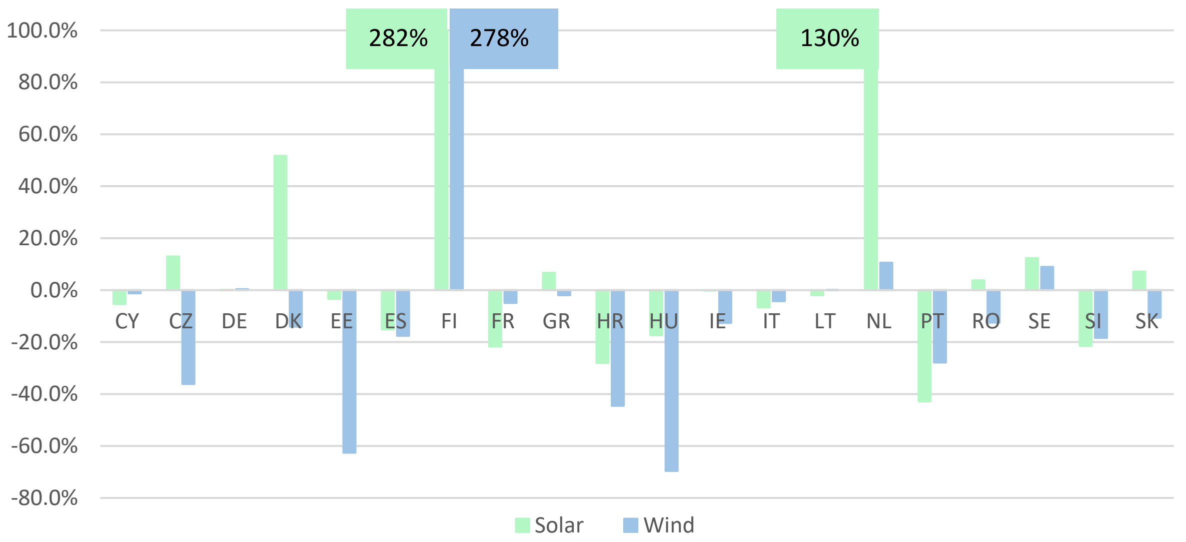


Figure 4: Relative differences (%) in installed renewable capacity between ERAA 2023 and the draft Member State NECPs for 2030



Source: ACER analysis based on ENTSO-E's ERAA 2023 data and renewable energy target data from Ember's Live EU NECP tracker for Member States. The relative difference is calculated with the draft NECP data as reference.

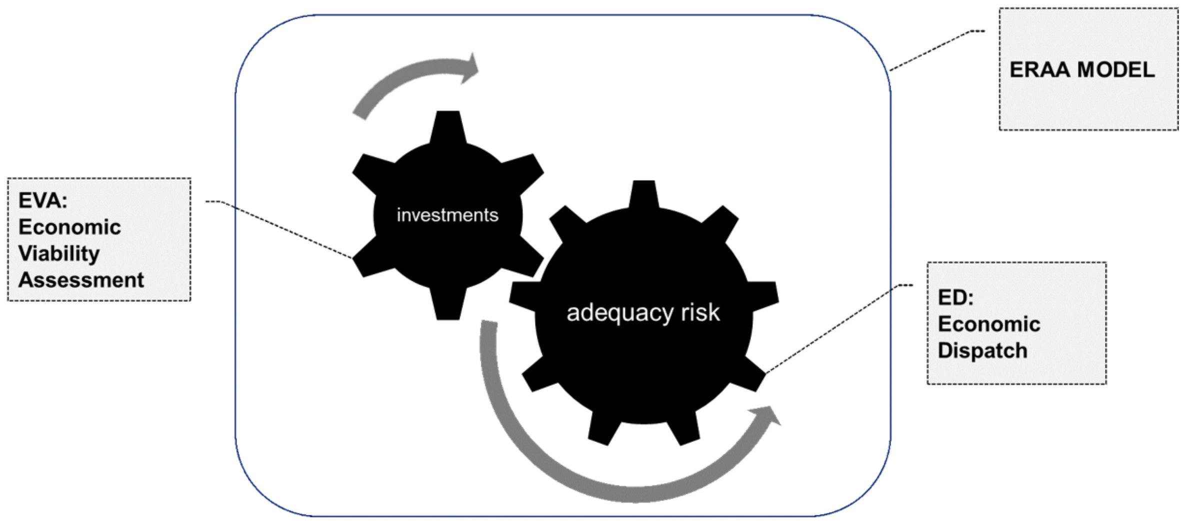
Notes: Figure 3 and Figure 4 present data only for Member States that have set renewable energy targets for wind and solar for 2030, based on Ember's Live EU NECP tracker. Where renewable energy targets for 2025 are lacking, ACER has interpolated between installed capacities as of 2022 and the 2030 targets as provided on Ember's website, to derive 2025 renewable energy targets.

3. Economic viability assessment

3.1. Introduction

The purpose of the economic viability assessment (EVA) is to assess economic decisions about entry and exit of capacity resources in the electricity market, based on expected revenues and associated costs. As in previous editions of ERAA, ERAA 2023 formulates the EVA as an optimisation problem that minimises total (fixed and operating) system costs. The output of the EVA module in terms of capacity available in the system for the modelled time horizon is the input of the economic dispatch (ED) module that is used to estimate adequacy risks.

Figure 5: The ERAA 2023 model consists of two modules



The ERAA 2023 describes the methodology of the EVA in Annex 2 (Chapter 10) and presents the results of the EVA in some detail in Annex 3. In addition, and upon ACER's request, ENTSO-E provided ACER with clarifications regarding the methodology and supplementary data regarding the adequacy risk indicators of the EVA and ED module runs with and without the implementation of curtailment sharing (see data in the Appendix)[7].

The following sections examine some of the key developments of the EVA in ERAA 2023 compared to ERAA 2022.

[7] The LOLE and expected energy not served (EENS) indicators of the economic dispatch module with and without the implementation of the curtailment sharing elements, and the EVA can be found in the Appendix – Table 1 and Table 2 Table 1: Central scenario: loss of load indicator in hours per year from the ED module with and without the implementation of curtailment sharing, and from the EVA.present the values of the indicators in the central scenario, whereas Table 3 and Table 4 present the values in the sensitivity (called "scenario B" in the Report).

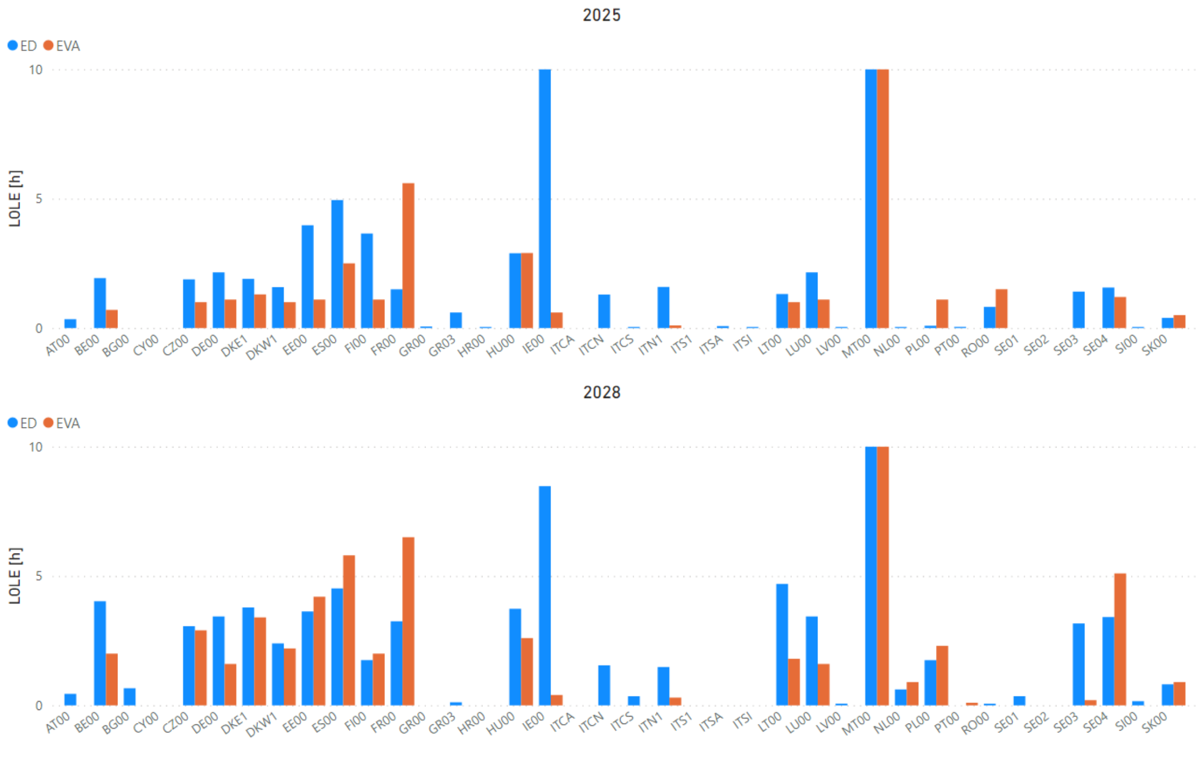
3.2. Consistency between the EVA and the economic dispatch modules

The consistency between the EVA module and the economic dispatch (ED) module is vital for the validity of the ERAA. The EVA aims to predict the level of new investments and market exits that can be expected based on market conditions. Ideally, this assessment would be performed at the same resolution in both modules, i.e. with the same level of hourly aggregation and for the same climate years and outage patterns, as these are the underlying market conditions of ERAA.

Figure 6 shows the comparison of the LOLE indicators between the EVA and ED module for all target years. With the exceptions of some modelled zones the results show low to moderate differences between the two modules. Notable differences, above 5 hours, are encountered for Ireland for target years 2025 and 2028, Malta for all target years, as well as for Cyprus, the Czech Republic, Germany, Hungary and Luxembourg for target year 2033.

The differences between the results of the EVA and the ED are the outcome of a number of simplifications introduced in the EVA module to cope with computational difficulties. The most important of these simplifications are the reduction of the modelled climate years from 35 in the ED to 3 in the EVA (discussed in section 3.5), the modelling of market coupling using the net transfer capacities (NTC) instead of the flow-based approach (discussed in section 4), divergent modelling of forced outages and the fact that local matching and curtailment sharing are only implemented in the ED module[8].

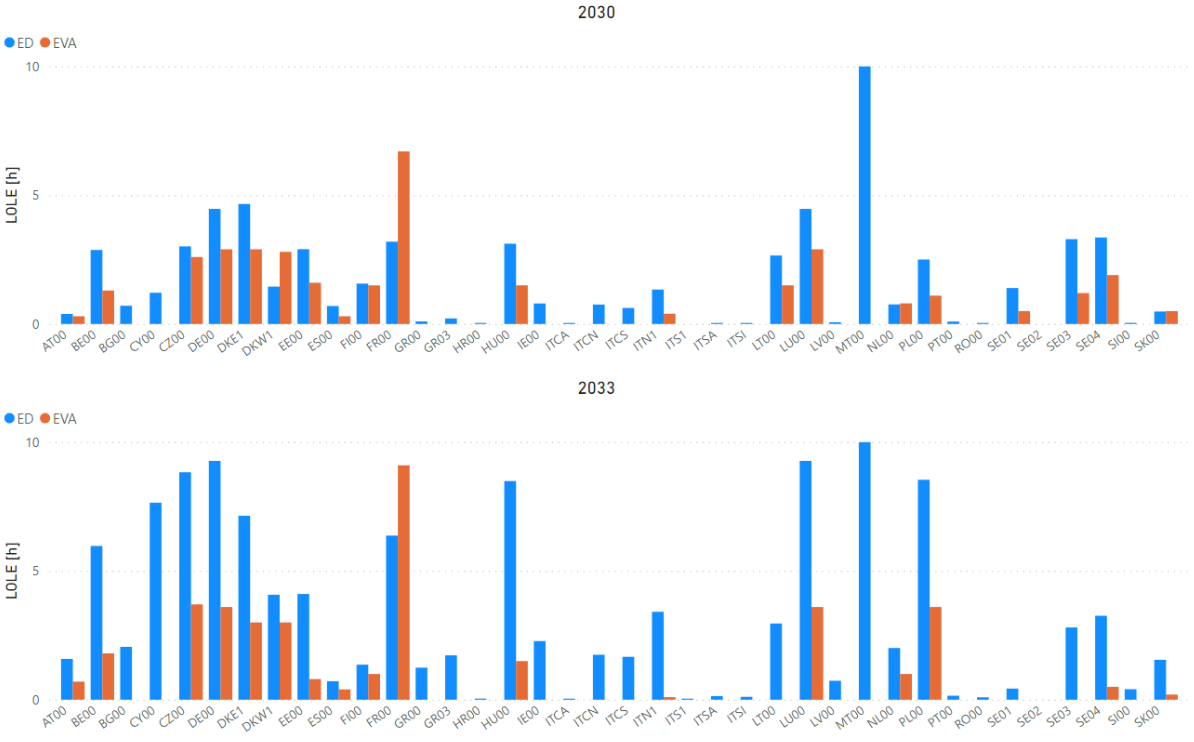
Figure 6: Comparison of LOLE between the EVA module and the ED module – Central scenario, target years 2025 and 2028



Note: for readability, the chart shows values of the LOLE indicator of up to 10h. Where in absolute terms, the values are higher than 10h, the heights of the bars are shown as 10h or -10h. Exact LOLE values can be found in Table 1 in the Appendix.

[8] There are other simplifications in the EVA that contribute to the mismatch between the EVA and the ED module. These include for example, the way aggregated capacity values form the EVA module are postprocessed to enable unit-by-unit consideration in the ED module, and the use of derating to model maintenance profiles in the EVA.

Figure 7: Comparison of LOLE between the EVA module and the ED module – Central scenario, target years 2030 and 2033



Note: for readability, the chart shows values of the LOLE indicator of up to 10h. Where in absolute terms, the values are higher than 10h, the heights of the bars are shown as 10h or -10h. Exact LOLE values can be found in Table 1 in the Appendix.

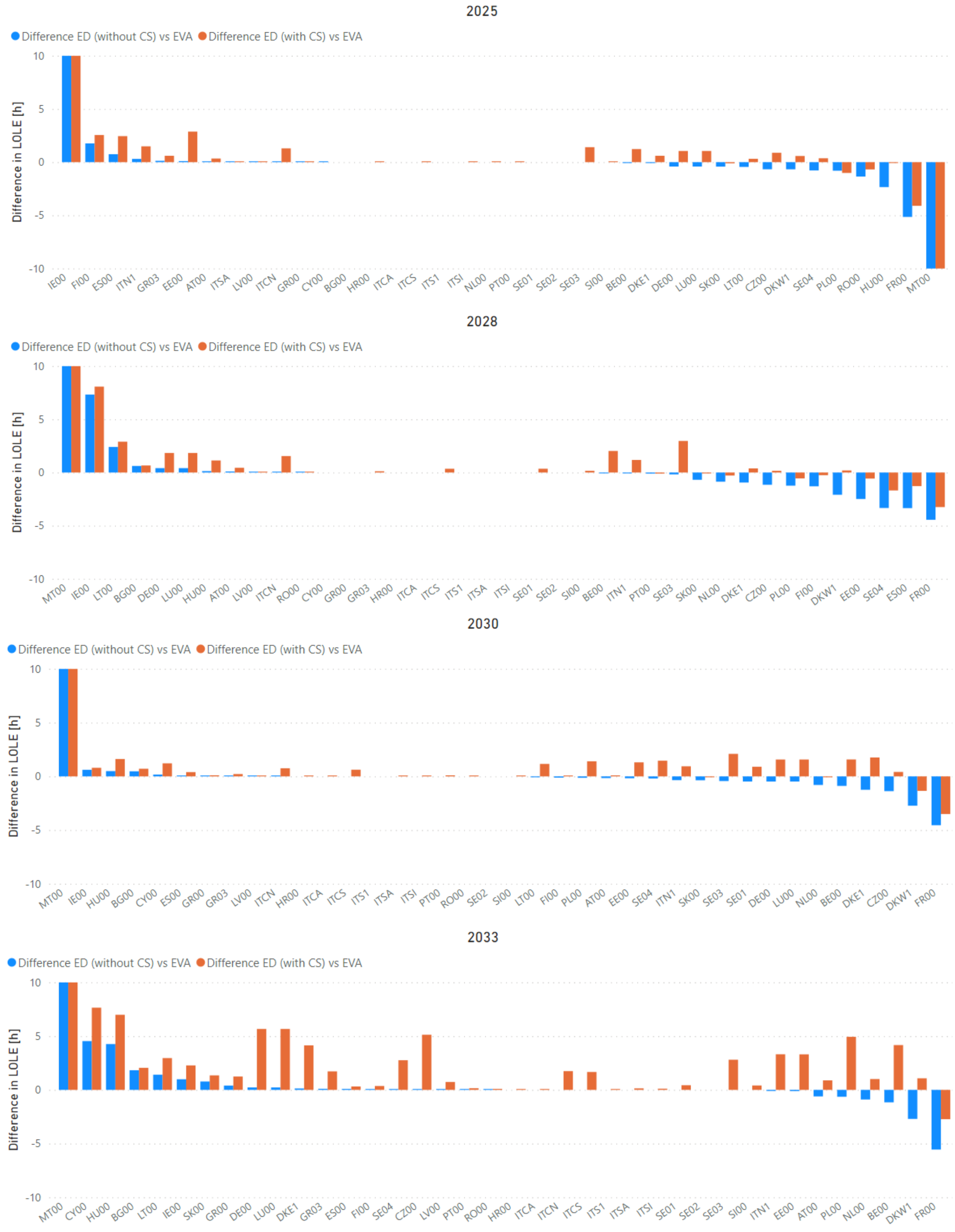
3.3. Curtailment sharing

Analysis of ERAA 2022 results indicated that the implementation of local matching and curtailment sharing features in the ED module was a key driver for the resulting inconsistencies between the ED and the EVA[9]. Local matching and curtailment sharing have been modelled differently in ERAA 2023 compared to ERAA 2022. First, local matching has been integrated into the ED module. Second, the curtailment sharing feature is modelled in a way that its impact is restricted to reallocating flows without altering the initial dispatch of the system's assets thus affecting only those cases (hours) for which ENS occurs. ENTSO-E provided to ACER results before and after the implementation of the curtailment sharing in the ED module (Figure 8 and Table 1). Analysis of this data shows that the new approach reduces the overall differences between the EVA and the ED, compared to ERAA 2022[10]. However, there are still some cases where differences are substantial, especially for target year 2033. There are also some elements that need further investigation and possible adjustments in the modelling of curtailment sharing by ENTSO-E. Examples are the significant change in LOLE across modelled zones as a result of a relatively minor sharing of curtailment or the change in LOLE in Cyprus, where one would not expect to see changes. ENTSO-E provided further explanations regarding these observations that indicated that they do not compromise the overall modelling approach. However, ACER still recommends that ENTSO-E improves the performance of the curtailment sharing feature in ERAA 2024.

[9] See section 3.2 of Technical Annex of the ERAA 2022 Decision.

[10] For comparison, see Figure 7 of Technical Annex of the ERAA 2022 Decision.

Figure 8: Differences between the LOLE from the ED module with and without the implementation of curtailment sharing, and the LOLE from the EVA. – Central scenario, target years 2025, 2028, 2030 and 2033



Note: for readability, the chart shows differences of up to 10h. Where in absolute terms, the differences are higher than 10h, the heights of the bars are shown as 10h or -10h. For IE00, the differences in target year 2025 are 358.7h (ED without CS vs EVA) and 369.6h (ED with CS vs EVA). For MT00, the differences are -497.0h and -504.2h in 2025, and 58.1h and 58.2h in 2028, and 26.8h (ED without CS vs EVA) and 27.1h (ED with CS vs EVA) in 2030, and 48.5h and 50h in 2033.

3.4. Stochastic formulation

The EVA module keeps the stochastic model formulation as in ERAA 2022 i.e. the model seeks to minimise the total system cost considering the probabilities of occurrence of the three representative climate years[11]. The total system cost consists of the fixed and operating costs, including the cost of energy not served, incurred in all examined years under all climatic conditions of the three modelled climate years.

The EVA models explicitly the four target years, 2025, 2028, 2030 and 2033. Contrary to ERAA 2022, intermediate years are not modelled explicitly in the EVA. Instead, their impact to capacity entry and exit decisions is taken into account in a simplified manner by considering the intermediate years as identical to the modelled year preceding them[12]. The impact of non-modelled years in the capacity entry or exit decision is modelled by including in the cost minimisation problem cost components for the non-modelled years that are equal to the cost components[13] of the precedent modelled year. The cost components are discounted to account for the depreciation of the assets.

The new approach allows ENTSO-E to remove two of the main simplifications of the EVA module of ERAA 2022. First, the optimisation problem is now solved in a single run over the whole time horizon[14]. Second, it allows to solve an hourly model, considering 24 hours per day, compared to only 18 hours in ERAA 2022. At the same time, the new approach does not capture the system dynamics of intermediate years within the ERAA horizon[15].

ERAA 2023 also introduces an improved representation of the investment costs by considering costs incurred after the study horizon, i.e. after 2033, and until the end of the economic lifetime of the relevant assets. It does so by assuming that the costs of future years (both in terms of capital expenditures, fixed annual costs and generation costs) are identical to the costs of the last modelled year and using appropriate depreciation factors. This approach is an improvement of the modelling of investment decisions especially for the last years of the study horizon. However, the effects of dynamic parameters of the period beyond the study horizon, such as the evolution of demand, fuel and CO_2 prices and the evolution of the maximum clearing price, are still not captured in the EVA.

3.5. Choice of representative climate years

ERAA 2023 models only three climate years in the EVA to cope with computational complexity. It considers the same climate years as in ERAA 2022, i.e. 1985, 1988 and 2003[16]. Considering the mismatch between the EVA and the ED module results in ERAA 2022, ERAA 2023 recalibrates the

[11] The choice of climate years is the result of the ERAA 2022 clustering approach. The probabilities used in ERAA 2023 are recalibrated to account for consistency gaps identified in ERAA 2022.

[12] This means, that years 2026 and 2027 are considered identical to 2025, year 2029 to 2028 and years 2031 and 2032 to 2030.

[13] Annualised capital cost, fixed operation and maintenance cost and variable costs based on modelled operation.

[14] In ERAA 2022 the period was broken down into four smaller periods which lead to capacity entry and exit decisions being taken without a proper long term foresight.

[15] Based on the information included in the report and further exchanges with ENTSO-E, ACER was unable to verify whether the benefit of enabling the 24h/day and the single horizon model run counterbalances the impact of not-modelled intermediate years in capacity entry-exit decisions.

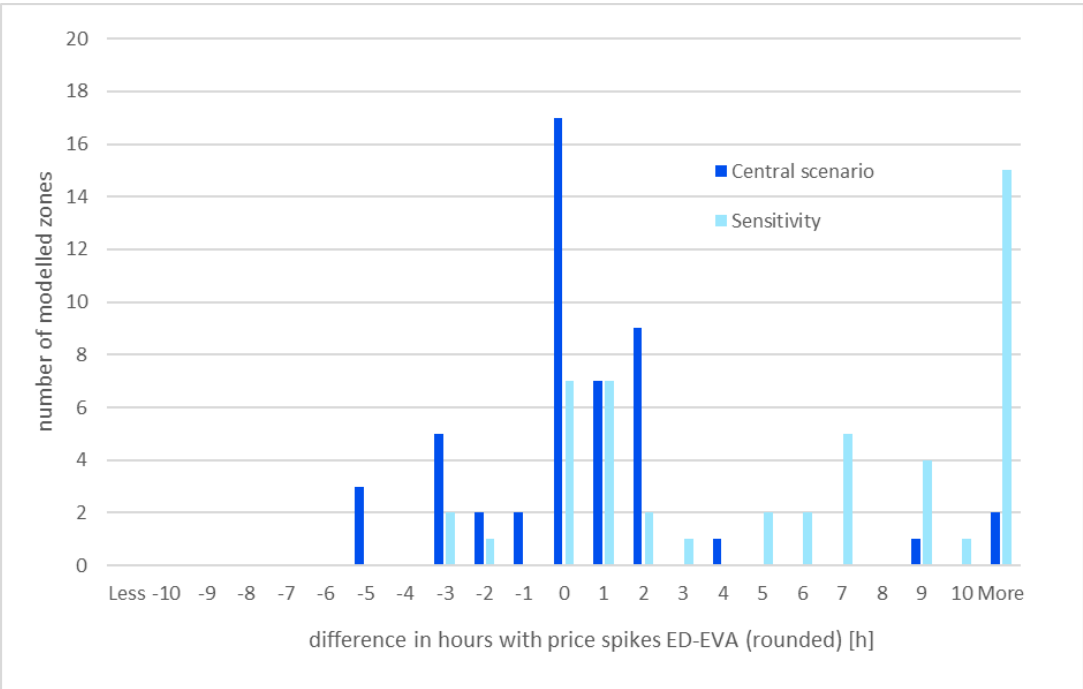
[16] The clustering approach in ERAA 2022 used the ED module for year 2030 to calculate the total system cost for all climate years. It then uses this information to formulate clusters of climate years, and eventually choose representative climate years from these clusters.

weight of each of these climate years in the central scenario to make the set more representative for the adequacy assessment.

Apart from the central scenario, ERAA 2023 includes a sensitivity (called "scenario B" in the Report). The sensitivity weights differently the three climate years used in the EVA. It does not use the recalibration of the central scenario that improves consistency between the adequacy indicators of the EVA and the ED module. Consequently, the sensitivity results in less capacity in the system compared to the central scenario, hence the risks identified in the ED are significantly higher.

Comparison between the results of the EVA and the ED between the central scenario (that uses the recalibrated weights) and the sensitivity (that uses the ERAA 2022 weights), verifies that the new approach improves the consistency between the two modules. For example, Figure 9 matches the modelled zones (49 zones in total) with the difference of the number of hours when price spikes (price above 90% of the maximum clearing price) occur between the EVA and the ED module for target year 2028[17]. When the ERAA 2022 weights are used (the "sensitivity") the yearly number of hours during which price spikes occur in the ED module is on average 7.5 hours higher than in the EVA module (average across the 49 zones). When the new weights are used (central scenario), this difference is reduced to 1.7h. Furthermore, in the central scenario, the difference in hours with price spikes between modules is close to zero (i.e. between -0.5h and 0.5h) in 17 zones, while in the sensitivity this is the case for only 7 zones. On the other hand, a difference of more than 10h (more than 10 more hours with price spikes in the ED module than in the EVA module) is observed in two zones in the central scenario (IE and MT), while in the sensitivity this is the case in 15 zones. The central scenario therefore leads to more consistent results.

Figure 9: Distribution of the difference of the number of price spikes between ED and EVA module, for ERAA 2022 (sensitivity) weights and for ERAA 2023 (central scenario) weights – target year 2028

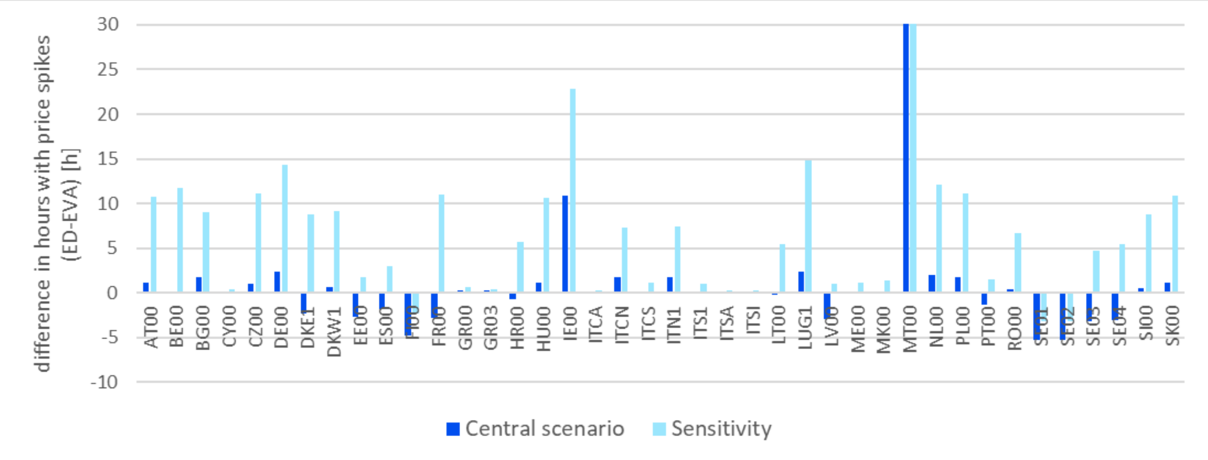


Note: On the x-axis, the histogram shows the rounded difference between the number of price spikes. The y-axis shows the number of zones, in each scenario, where a particular difference in the number of price spikes is observed. The figure only shows data for target year 2028, as the data on the number of price spikes in the ED module in the central scenario for target years 2025, 2030 and 2033 were not available to ACER.

[17] Data for target years 2025, 2030 and 2033 were not available. The average number of price spikes over all climate years is considered in the analysis.

Figure 10 shows the difference in the number of hours with price spikes between the two modules for the two scenarios per each EU bidding zone. The sensitivity shows far more considerable differences than the central scenario. From among the bidding zones in the EU, the central scenario results in a better consistency (i.e., lower absolute difference in the number of price spikes) in 34 zones.

Figure 10: Difference in the hours of price spikes between EVA and ED module in the central scenario and the sensitivity for target year 2028 per EU bidding zone

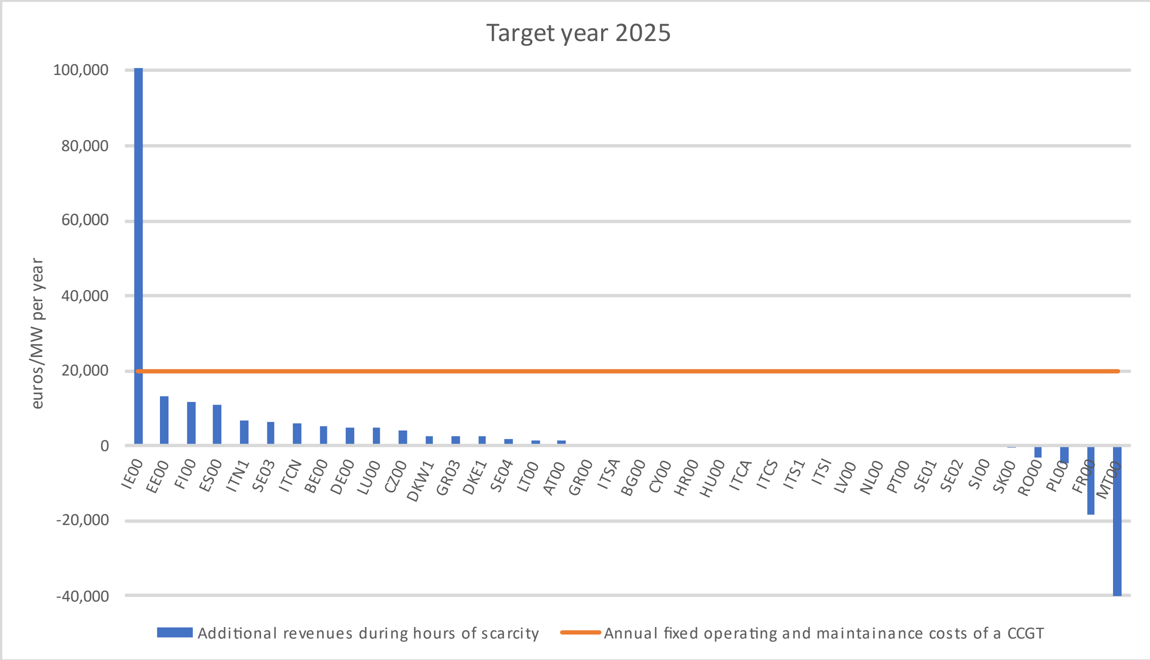


Note: the figure only shows data for target year 2028, as the data on the number of price spikes in the ED module in the central scenario for target years 2025, 2030 and 2033 were not available to ACER. For MT00, the values extend outside of the axis limits and are 70.3h for the central scenario and 59.7h for the sensitivity.

Figure 11 and Figure 12 show the difference in revenues during the additional hours when supply does not meet demand in the ED module compared to the EVA. The revenues are calculated as the product of the maximum clearing price in the target year and the LOLE. For illustrative purposes, the missed additional revenues are plotted against the default annual fixed operating and maintenance (FOM) costs of a CCGT (20,000 euros/MW per year[18]).

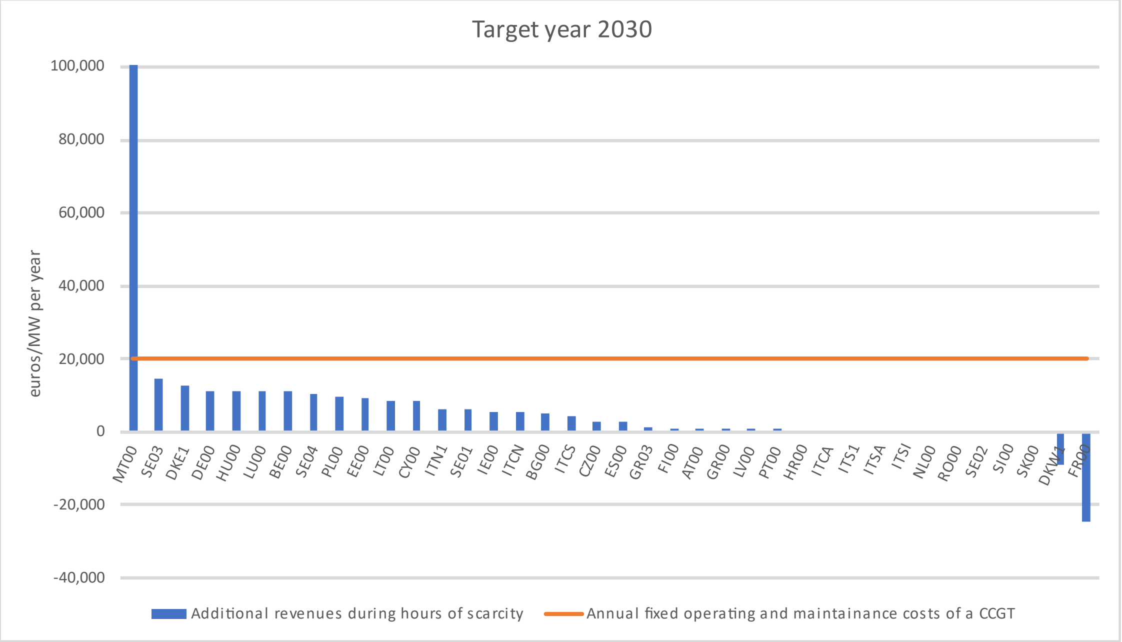
[18] EU Reference Scenario 2020, technical assumptions available here.

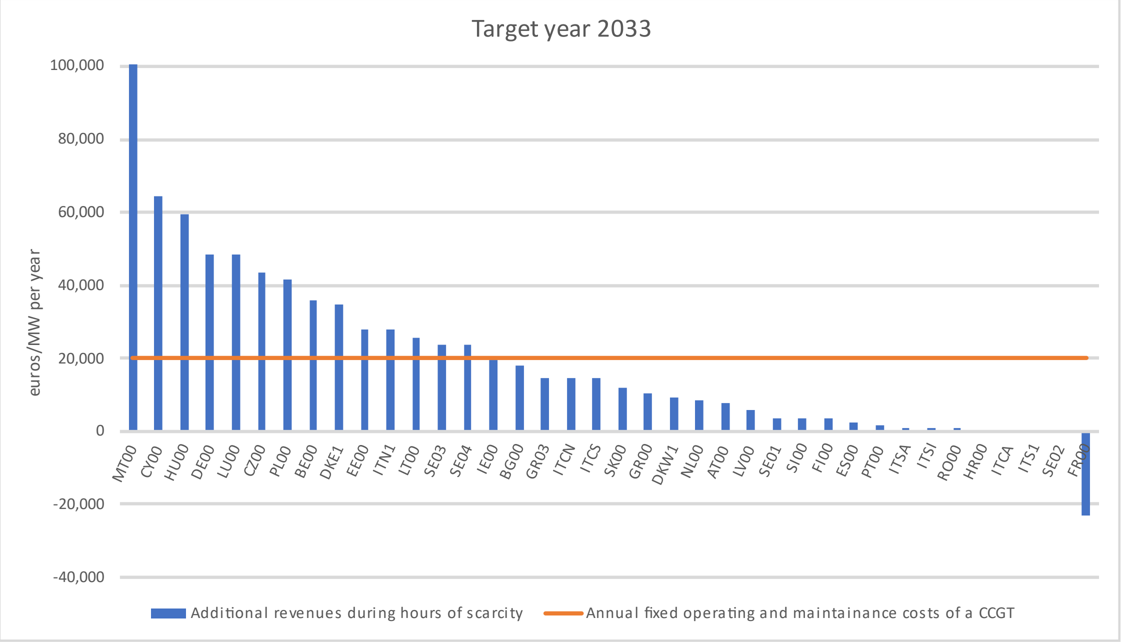
Figure 11: Estimate of the difference in annual revenues at times of scarcity between the ED module and the EVA (euros/MW) – Target years 2025 and 2028



Note: for readability, differences higher than +100,000 euros/MW are shown as +100,000 euros/MW, and differences lower than -40,000 euros/MW are shown as -40,000 euros/MW.

Figure 12: Estimate of the difference in annual revenues at times of scarcity between the ED module and the EVA (euros/MW) – Target years 2030 and 2033





Note: for readability, differences higher than +100,000 euros/MW are shown as +100,000 euros/MW.

For target years 2025 and 2030, the two target years that were also modelled in ERAA 2022, the additional revenues are smaller in ERAA 2023. Namely, in ERAA 2022,[19] the annual additional revenues were higher than the annual FOM costs of CCGTs in nine zones in TY 2025 and eleven zones in TY 2030, while in ERAA 2023, this was only the case for one zone in TY 2025 and one zone in TY 2030. While this analysis only focuses on the differences at individual bidding zone level[20], it is an

[19] See Figure 8 in the Annex of the ERAA 2022 Decision.

[20] In a flow-based market coupling framework a mismatch between supply and demand in one bidding zone could mean that other bidding zones also clear at the maximum clearing price.

indicator that consistency in the central scenario in ERAA 2023 has largely improved[21]. The additional revenues are more prominent in target year 2033, where the application of curtailment sharing shows the most substantial increase in the divergence of the LOLE between the ED and the EVA module (see Figure 8).

While differences between the LOLE from the ED module and the EVA show that in general the two modules are well aligned in the central scenario, there are still some modelled zones where the differences are exceptionally high (e.g. IE00, MT00)[22]. These differences may suggest that the clustering methodology results in years that are not equally representative for all zones of the system[23]. The primary purpose of the ERAA is to identify adequacy concerns that will inform Member States on the corrective actions they may need to adopt. Hence, it is important that the ERAA offers a representative assessment for all modelled zones.

This difference is high for Ireland, where the EVA resulted in a LOLE of 0.6 h in 2025 and 0.4 h in 2028, implying that investors would be willing to invest until less than one hour of scarcity occurred on an annual average. It also implies that investors believe they have invested in enough capacity so that they would expect less than one hour of scarcity to occur. In the ED, however, LOLE values of 370.2 h in 2025 and 8.5 h in 2028 were produced. This strongly indicates that the LOLE value of Ireland may be overestimated by the inconsistencies between EVA and ED, rather than a sign of insufficient market revenues to maintain a high standard of reliability. However, in this case, also given that the strong differences also persist in the sensitivity, the discrepancy seems to relate to the inconsistent approach to model forced outages of resources, including interconnectors, having a disproportionate effect on more isolated systems. In the ED module forced outages are modelled in a stochastic manner while in the EVA taking an average approach to outage patterns. This modelling choice seems to have a tempering effect on investments while can result to high risk in the ED.

The modelling challenges of the cost minimisation approach for the EVA and the resulting need to reduce the number of climate years is one of the main factors for the inconsistency between the risks perceived in the EVA and the outcome of the ED module. Although the re-calibration of the weights of the modelled climate years in the EVA improved the consistency, ENTSO-E should strive for further improvement. In this respect, ACER strongly recommends that ENTSO-E examines switching to the EVA approach defined in Article 6(2)(a), i.e. the ex-post comparison of costs and revenues of the relevant capacities, integrating all climate years into the EVA. This integrated approach is superior to the cost minimisation, as it considers the output of the ED module, ensuring consistency of the capacity entry and exit decisions with the estimated adequacy risks[24]. If this solution is not possible, or until it is implemented, ENTSO-E should implement measures to considerably increase the number of climate years considered in the EVA. ENTSO-E should assess the impact of the key modelling simplifications in the EVA with regards to the consistency issue[25]. In addition, ENTSO-E should assess whether clustering climate years based on indicators other than total costs (e.g. clustering based on risk indicators) would result in a choice of climate years that would be more suitable for ERAA.

[21] For example a similar analysis for the sensitivity (scenario B) shows less of an improvement since there are higher differences between the EVA and the ED module in annual revenues during supply-demand mismatches in more bidding zones.

[22] The differences are more pronounced after the implementation of the curtailment sharing. ENTSO-E should further investigate the impact of the curtailment sharing feature in the ERAA and whether the methodology should be further adjusted in order to limit any unrealistic results.

[23] This could relate to the limited number of years that were used (three) or to inherent characteristics of the clustering methodology. For example, one reason for the differences could be the fact that big modelled zones weight more in the total system cost than smaller ones. The clustering method will then choose years that are mostly representative for the big modelled zones. These years, however, could be less representative for smaller zones.

[24] ENTSO-E has been involved in the development of a model that shows promising results. For further details see link here.

[25] For example, a trade-off between increasing the number of modelled years and reducing the hourly resolution of the EVA.

3.6. Decision variables

ERAA 2023 considers decision options for commissioning, decommissioning, lifetime extension, mothballing and de-mothballing for gas, demand response and storage [26]. The same options except for new commissioning apply to coal, lignite and oil power plants. Nuclear and renewable power generation are considered to be completely policy driven. While this is largely true for the former, it is not totally true for renewable energy power generation plants, some of which are already competitive. Thus, ENTSO-E should consider enabling also market based renewable energy investments in future ERAA editions.

Endogenously modelled capacity expansion in the EVA module is normally constrained by upper levels of investment potential. Such constraints should reflect technical or economic potential or policy decisions. While these constraints do not necessarily mean that no capacity expansion takes place, as exogenously imposed capacity expansion is considered (e.g. policy driven renewable generation), their validity and realism need to be cross-checked. As an example, for France there is no possibility for any endogenous power generation capacity or demand response expansion (apart from the exogenous assumptions). Practically this implies that in France the market will not react in case of significant structural mismatch between supply and demand, i.e. there is no way to overcome an adequacy concern.[27] ACER recommends that the country assumptions are revised in subsequent ERAAs to avoid that those assumptions constitute an absolute impediment for new capacity to develop in the market, as such an impediment is neither realistic nor in line with the regulatory framework.

[26] At the same time, it considers other modelling choices, i.e. the reduction of explicitly modelled years to four, limit the scope of the mothballing/de-mothballing and life extension decision variables. Considering that these options are much cheaper than the new investments, this could have an impact in the final capacity stock.

[27] The assumption also puts in question the effectiveness of any adequacy measure other than demand curtailment since it implies that there is no room for neither capacity expansion nor implicit or explicit demand response.

3.7. Cost parameters

The EVA calculates total costs taking into account (annualised) capital cost (CAPEX) and fixed operating and maintenance (FOM) costs, as well as operating costs[28], including the cost for energy not served (ENS)[29]. Where possible ERAA 2023 uses cost parameters stemming from the relevant Member State studies, in line with Articles 6(6)(a) and 6(10) of the ERAA methodology. For the rest of the modelled zones ERAA 2023 uses default values for each technology calculated as the average of the relevant available data from these national studies[30].

3.8. Investment risks

Similarly to the approach in previous ERAA editions, ERAA 2023 considers a single value of technology specific hurdle premiums for all modelled zones[31]. As pointed out in the two previous ERAA decisions, these estimates are based on certain inputs and assumptions that are neither necessarily uniform across the EU; they are also not necessarily aligned with the assumptions of ERAA 2023[32, 33].

3.9. Maximum clearing price

According to Article 7 of the ERAA methodology, paragraphs 7(8) and 7(9), the assessment needs to reflect price formation during hours when scarcity occurs in a modelled zone, i.e. during periods of Energy Non-Served. The ERAA methodology further specifies that the price during scarcity periods should equal the harmonised maximum clearing price in line with Articles 10 of the Electricity Regulation, unless Member States apply any indirect restrictions to wholesale price formation.

Similarly to ERAA 2022, ERAA 2023 uses the results of ex-ante modelling using the ED module and the central scenario assumptions to estimate the evolution of the clearing price based on hourly marginal price estimates and taking into account ACER Decision 1/2023 on the harmonised maximum and minimum clearing prices for the day ahead market. However, ENTSO-E uses different climate years for each modelled target year in this ex-ante modelling. This results in omitting climate years, like 1985, that have a strong impact on price spikes and, hence, the results of the EVA and the ED module. This influences six out the ten modelled target years and results in an estimation of the maximum clearing price evolution that is not consistent with the rest of the ERAA. Furthermore, ENTSO-E did not verify

[28] Including variable operating and maintenance costs (VOM), fuel costs and cost for CO_2 emission allowances.

[29] ERAA 2023 assumptions on the cost of ENS, i.e. the maximum clearing price, are further assessed in section 3.9.

[30] Details provided in section 6.4 of Annex 1 of the Report. Similar to ERAA 2022, cost outliers impact the default value of cost parameters. This needs to be taken into account in next ERAA editions so that the default values are better estimates of real costs.

[31] The hurdle premium estimates are based on a methodology described in a report prepared for Elia, the Belgian Transmission System Operator (the report can be found here: https://www.elia.be/-/media/project/elia/elia-site/public-consultations/2020/20201030_200_report_professorboudt.pdf) The report includes a proof of concept implementation using information (inter alia) from Elia’s 2019 Adequacy and Flexibility study. ERAA 2023 uses hurdle rates values from Elia’s 2021 Adequacy and Flexibility study .

[32] According to the methodology any change of context, modelling setup or other factors such as market design may lead to different estimations of hurdle premiums. It is therefore necessary to assess consistency of the used hurdle premiums with the assumptions and context of each ERAA version.

[33] Notably, ERAA 2023 uses lower hurdle premiums than ERAA 2022. Default values are 3% for batteries compared to 8.5% in ERAA 2022, 4.5 % compared to 6.5% for combined cycle gas turbines and 6.0% compared to 8.5% for open cycle gas turbines.

the results of this simplified approach by comparing them with the actual results of the ED module of ERAA 2023[34].

More importantly, ACER considers that ENTSO-E's assumption on the maximum clearing price are not aligned with the applicable regulatory framework. Similarly to ERAA 2022, ERAA 2023 omits the intra-day and balancing energy markets, both of which have different maximum clearing prices. This is particularly important for peaking resources that tend to operate for a limited number of hours, such as demand side response and open cycle gas turbines. In ACER's view, the ERAA should consider the technical bidding limits of at least the day-ahead and intra-day markets in conjunction.[35]

3.10. Demand side response

ACER considers that the level of simplifications is acceptable in ERAA 2023, but - given the enhanced role of DSR in an increasingly decarbonised power system - ACER recommends ENTSO-E to further improve the modelling of these resources in ERAA 2024:

Regarding explicit DSR, there is scope to improve the centralised ENTSO-E approach and better reflect the existing or future explicit DSR levels in the ERAA (e.g., DSR contracted through capacity mechanisms, beyond the duration of their contracts). Where national DSR assessments are used, ACER expects that ERAA 2024 provides more transparency on those inputs.

Regarding implicit DSR, future ERAAs would benefit from clear justifications about the basis for the assumed flexibility related to electric vehicles and heat pumps. ENTSO-E should also consider incorporating flexibility from other electricity uses. ACER also expects that ERAA will appropriately reflect the implementation of new support mechanisms for clean flexible resources (e.g., DSR and storage), including peak shaving products and flexibility support mechanisms.

[34] For example the increase of the maximum clearing price from 4500 to 6000 euros/MWh between 2025 and 2028 indicates three trigger events (trigger even means in general that the price in any bidding zone exceeds a value of 70% of the harmonised maximum clearing price in at least 2 market time units in at least 2 different days within 30 rolling days from the first price spike). However, information shared by ENTSO-E indicates several dozen (hundred if Malta is included) of cases with prices above 90% of the maximum clearing price in 2025 in European bidding zones.

[35] More details on this issue can be found in Annex I of the ERAA 2022 Decision.

4. Cross-zonal capacities

4.1. Introduction

This section focuses on the approach to cross-zonal capacities in the ERAA 2023 central reference scenarios. The review of cross-zonal capacity covers the following topics:

- Network developments taken into account in the context of capacity calculation;
- Capacity calculation methodologies; and
- Compliance of cross-zonal capacities with the so-called minimum 70% target.

4.2. Network development

Pursuant to the Electricity Regulation, the ERAA must properly take into consideration the level of interconnection, interconnection targets, and real network development (requirements of Article 23(5)(m), Article 23(5)(b) and Article 23(5)(l) respectively). Article 3 of the ERAA methodology specifies that the assessment must reflect best estimates about the future state of the network based on the latest national development plans and ENTSO-E's Ten-Year Network Development Plan (TYNDP). Article 4 of the ERAA methodology specifies the modelling framework for the electricity network.

The ideal configuration for the calculation of flow-based domains is a single market model that includes the network. However, ERAA 2023 considers two separate models, a market model and a grid model. In such a case, consistency between the two models is important for a robust calculation of flow-based domains. Therefore, the considered network must explicitly include:

- infrastructure developments within the capacity calculation regions where the flow-based calculation applies; as well as
- HVDC interconnectors tied to this perimeter, as the calculation implicitly models exchanges on interconnectors with regions where the NTC calculation applies.[36]

For the Core region, the ED module applies a flow-based approach, while the EVA module applies an NTC-based approach. The grid model used for the calculation of the flow-based domains is based on the assumed infrastructure for 2025 from the TYNDP 2020 National Trends scenario. If the investments taken into account differ between the two approaches, this can lead to a significant discrepancy between the EVA and the ED. In order to take into account the assumed network developments from 2025 onwards in the ED, ENTSO-E for ERAA 2023 uses a simplified approach where the flow-based domains of TY 2025 are expanded by increasing the RAM of each CNEC based on the trends identified in NTCs provided by the TSOs for the EVA.

ERAA 2023 details net import and export capacities used as input for NTC values for the target years 2025, 2028, 2030 and 2033, per Member State.[37] The approach used by ENTSO-E to consider the network developments from 2025 onwards in the ED is based on the following calculation steps:

1. Identification of NTC corners
2. NTC margins computation

[36] Regions where the NTC calculation applies should therefore reflect infrastructure developments on interconnectors shared with the capacity calculation regions where the flow-based capacity calculation applies.

[37] See Figure 8 of ERAA 2023 Annex 1 – Input Data & Assumption

3. NTC margin selection

According to the first step, NTC corners are identified as a list of unique possible Study Zone border combinations, which describe if a cross-border exchange is congesting cross-border interconnection. In the next step, for each CNEC and for each NTC corner a necessary RAM increase is computed to enable exchanges of that NTC corner. Subsequently, in the final step the NTC margin to be used in the FB domain expansion for each CNEC is selected as the 75th percentile from all NTC margins on a given CNEC. This NTC margin is then added to the RAM of the TY 2025 FB domains. These steps were performed for each CNEC of the TY 2025 FB domain, for the four seasonal FB domains per TY and for each of the TYs 2028, 2030 and 2033.

ACER acknowledges the improvement in ERAA 2023 compared to the ERAA 2022 regarding the consideration of network developments in the ED. Although the best approach would be to derive flow-based domains for every target year, ACER observes that this simplified approach can improve the consistency between the ED and the EVA regarding the network development representation.

4.3. Capacity calculation methodologies

4.3.1. Overall consistency between capacity calculation in the EVA and in the ED

To improve the consistency between the cross-zonal capacities of EVA and ED for the same target year in ERAA 2023, ENTSO-E has identified typical market positions in the flow-based market coupling in the ED module and used this information as additional input data in the EVA module that use NTCs. The approach used by ENTSO-E is based on the following steps:

1. Analysing Net Positions (NPs) in 2025 flow-based market coupling simulations in the ED module.
2. Taking the 99th percentile for export and 1st percentile for import values of NPs for each study zone.
3. Using the values from step 2 in the EVA as allocation constraints in complement with the TSOs' provided NTCs for 2025.
4. The values from step 2 are scaled according to the NTC development trends for future years.
5. Where the NPs of study zones are extremely low either for export or import, these are raised so that they do not restrict the export or import capability in the simulations.

This approach aims at providing a link between the flow-based domains computed from network models and used in the ED and the TSOs' provided NTCs used in the EVA. Therefore, the typical market positions, as derived from the ED market coupling simulations are taken into account, to a certain extent, through the allocation constraints in the EVA.

ACER acknowledges the improvement in ERAA 2023 compared to the ERAA 2022 regarding the link between the flow-based market coupling in the ED in one hand and the use of NTCs for the EVA in the other hand. In particular, this approach can be a temporary solution to improve the consistency between the ED and the EVA regarding the capacity calculation methodologies.

Next year's ERAA should include a more solid solution to ensure consistency between cross-zonal capacities in the two modules of the ERAA. The target should be to use flow-based market coupling in all modules consistently.

4.3.2. FB capacity calculation in the ED

Regarding the flow-based capacity calculation used in the ED in ERAA 2023, the methodology is the same as used in the ENTSO-E ERAA 2022. More information can be found in the technical Annex of ACER Decision No 04/2023, section 4.3.1.

4.3.3. Clustering of FB domains

Regarding the clustering of flow-based domains used in the ED in ERAA 2023, the methodology is the same as used in the ENTSO-E ERAA 2022. More information can be found in the technical Annex of ACER Decision No 04/2023, section 4.3.2, along with the recommendations for improvements.

4.4. Cross-zonal capacities and compliance with the minimum 70% target

4.4.1. Introduction

The Electricity Regulation introduced a minimum 70% target for capacity available for cross-zonal trade.

In 2019, ACER, regulatory authorities and the Transmission System Operators (TSOs) issued a recommendation for implementing the minimum margin available for cross-zonal trade (hereafter 'the Recommendation').[38] The Recommendation aims to ensure a harmonized implementation, monitoring and compliance assessment of the minimum 70% target. The Recommendation provides a concrete way to implement and monitor the achievement of the 70% target across the EU. In particular, the Recommendation clarifies the calculation of the margin available for cross-zonal trade (MACZT).

ACER's analysis of the compliance of cross-zonal capacity used in the ERAA 2023 with the minimum 70% target is based on this Recommendation, and on the results of the MACZT monitoring that ACER conducted for the year 2022.[39] ACER monitors the minimum 70% target on the bidding-zone borders within and between the EU's Member States, which should be met for all hours throughout the year.

The Electricity Regulation allows Member States to adopt transitory measures, i.e. action plans or derogations, to gradually reach the minimum 70% target. Action plans expire by the end of 2025, and include a gradual linear increase in cross-zonal capacity from the beginning onwards. As a result, these action plans are likely to have a limited (if any) impact on cross-zonal capacity in 2025. Depending on national regulatory authorities' decisions, derogations may apply in 2025 (or beyond).

The ERAA 2023 does not explain if any derogation to the minimum 70% target has been considered, and ACER expects that derogations will disappear once coordinated security analyses, and re-dispatching and countertrading, are fully implemented.[40] Consequently, ACER's review considers the 70% as the minimum target for all EU borders. Below, ACER presents its analysis to assess the levels of margin regarding the 70% minimum target.

The section focuses on the cross-border capacity on AC borders and assesses compliance with the minimum 70% target.[41, 42]

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[38] Recommendation No 01/2019 of the European Union Agency for The Cooperation of Energy Regulators of 08 August 2019.

[39] To the extent possible, i.e. when sufficient data allows for it.

[40] The methodology is currently being implemented in most of the regions and expected to be fully implemented by the end of 2024. For more information see ACER's webpage on Redispatching and countertrading.

[41] The analysis of DC borders revealed full compliance in the context of ERAA 2021. For a complete review of DC borders, see ACER's ERAA 2021 Decision.

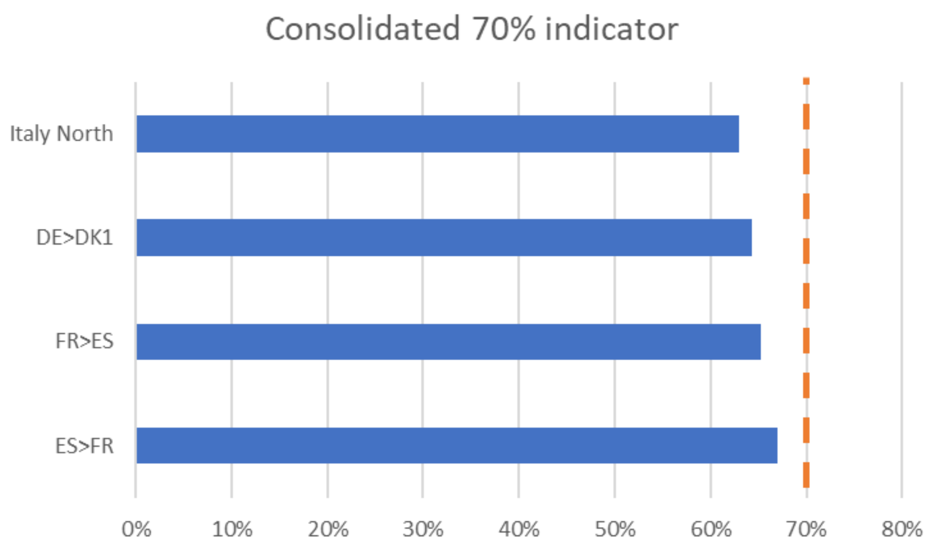
[42] For a detailed description of ACER's methodology for the assessment of NTC compliance with the 70% target, see Annex I of ACER's ERAA 2021 Decision, section 2.4.5.2.

4.4.2. NTC compliance with the minimum 70% target

Regarding the compliance of NTC borders with the minimum 70% target, no information is provided on how the 70% rule has been ensured, except for a high-level statement on their compliance. In the absence of further information on how the compliance is demonstrated, ACER carried out an assessment using high-level indicators based on ERAA 2023 NTCs for 2025 and on TSOs data provided in the scope of the ACER MACZT reports for 2022. The assessment has been used to identify the borders that require further attention with regard to the compliance with the 70% rule for subsequent ERAAs.

The analysis considers the percentage of hours for which the relative MACZT was above the minimum 70% target for 2022 per border, the percentage of average MACZT per border for 2022 for the hours for which the relative MACZT was below the minimum 70% target, the average 2022 NTC per border and the NTCs provided in ERAA 2023 for target year 2025. A high-level consolidated ranking indicator has been used to assess the compliance with the 70% target. The assessment suggests that several NTC borders appear to be on average above the 70% capacity. However, some borders appear to be close but below the 70% target. Figure 13 shows the borders that the consolidated 70% ranking indicator suggests are below the 70% target.

Figure 13: Assessment of the 70% minimum target based on the ERAA 2023 NTCs



Source: ACER calculations based on the ERAA 2023 NTCs and on TSOs data provided in the scope of the ACER MACZT report in 2023.

An important caveat underlying the above high-level analysis is that it is based on average annual values, therefore being above the 70% does not guarantee compliance with the 70% target across all hours. Such caveat implies that TSOs and ENTSO-E should ensure and justify compliance with the 70% target for all NTC borders and not only for the few ones displayed in the figure; the borders displayed in the figure solely indicate those for which the average gap between the average NTC values and the 70% target seems the highest.

Finally, for certain borders (BG-RO and BG-GR) there appears to be a big increase of NTCs between the average 2022 NTCs and the ERAA 2023 provided NTCs for the TY 2025, reaching 172% for the GR>BG border. It is not clear whether and how much the increase is attributed to new investments and/or increase of the offered capacity.

Overall, ACER highlights that ENTSO-E needs to ensure compliance with the 70% target for all borders, starting with the ones above displayed and improve the transparency on this topic in subsequent ERAAs.

4.4.3. Flow-based compliance with the minimum 70% target

For the flow-based capacity calculation that applies to the Core capacity calculation region (CCR) in the ED, ACER understands that compliance with the 70% minMACZT rule is ensured following two steps according to ERAA 2023:

1. First, net positions of all bidding zones (within and outside of the Core region) are set to zero; and
2. Second, ENTSO-E analyses for each Critical Network Element and Contingency (CNEC) whether the remaining available margin (RAM) amounts to 70% of the Fmax of each CNEC. If this condition is not met, the RAM is increased until the sum of the respective flow and reliability margin reaches a maximum of 30% of the Fmax for all CNECs.

ACER concludes that provided the above-described two-step approach is followed in a systematic and consistent manner, flow-based compliance with the minimum 70% target is correctly reflected in the flow-based calculations in the context of ERAA.

5. Appendix: Detailed tables

Table 1: Central scenario: loss of load indicator in hours per year from the ED module with and without the implementation of curtailment sharing, and from the EVA.

LOLE (hours/year) central scenario	Target Year 2025			Target Year 2028			Target Year 2030			Target Year 2033		
	ED without CS	ED with CS	EVA module	ED without CS	ED with CS	EVA module	ED without CS	ED with CS	EVA module	ED without CS	ED with CS	EVA module
AT00	0.1	0.3	0.0	0.1	0.4	0.0	0.1	0.4	0.3	0.1	1.6	0.7
BE00	0.7	1.9	0.7	2.0	4.0	2.0	0.4	2.9	1.3	0.6	6.0	1.8
BG00	0.0	0.0	0.0	0.6	0.7	0.0	0.5	0.7	0.0	1.8	2.1	0.0
CY00	0.0	0.0	0.0	0.0	0.0	0.0	0.2	1.2	0.0	4.5	7.6	0.0
CZ00	0.3	1.9	1.0	1.7	3.1	2.9	1.2	3.0	2.6	3.8	8.8	3.7
DE00	0.7	2.2	1.1	2.0	3.4	1.6	2.4	4.5	2.9	3.8	9.3	3.6
DKE1	1.2	1.9	1.3	2.5	3.8	3.4	1.7	4.7	2.9	3.1	7.1	3.0
DKW1	0.3	1.6	1.0	0.1	2.4	2.2	0.1	1.5	2.8	0.3	4.1	3.0
EE00	1.2	4.0	1.1	1.7	3.6	4.2	1.4	2.9	1.6	0.7	4.1	0.8
ES00	3.2	4.9	2.5	2.5	4.5	5.8	0.4	0.7	0.3	0.5	0.7	0.4
FI00	2.9	3.7	1.1	0.7	1.7	2.0	1.4	1.6	1.5	1.1	1.4	1.0
FR00	0.5	1.5	5.6	2.1	3.2	6.5	2.2	3.2	6.7	3.5	6.4	9.1
GR00	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.4	1.2	0.0
GR03	0.1	0.6	0.0	0.0	0.1	0.0	0.0	0.2	0.0	0.1	1.7	0.0
HR00	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HU00	0.6	2.9	2.9	2.7	3.7	2.6	2.0	3.1	1.5	5.8	8.5	1.5
IE00	359.3	370.2	0.6	7.7	8.5	0.4	0.6	0.8	0.0	1.0	2.3	0.0
ITCA	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
ITCN	0.0	1.3	0.0	0.0	1.5	0.0	0.0	0.8	0.0	0.0	1.7	0.0
ITCS	0.0	0.0	0.0	0.0	0.4	0.0	0.0	0.6	0.0	0.0	1.7	0.0
ITN1	0.4	1.6	0.1	0.2	1.5	0.3	0.0	1.3	0.4	0.0	3.4	0.1
ITS1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
ITSA	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0
ITSI	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0
LT00	0.6	1.3	1.0	4.2	4.7	1.8	1.4	2.7	1.5	1.4	3.0	0.0
LU00	0.7	2.2	1.1	2.0	3.4	1.6	2.4	4.5	2.9	3.8	9.3	3.6
LV00	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.1	0.0	0.0	0.7	0.0
MT00	518.3	511.1	1015.3	121.6	121.7	63.5	26.8	27.1	0.0	48.5	50.0	0.0
NL00	0.0	0.0	0.0	0.0	0.6	0.9	0.0	0.8	0.8	0.1	2.0	1.0
PL00	0.3	0.1	1.1	1.1	1.7	2.3	1.0	2.5	1.1	3.0	8.5	3.6
PT00	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.1	0.0	0.0	0.2	0.0
RO00	0.1	0.8	1.5	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.1	0.0
SE01	0.0	0.0	0.0	0.0	0.4	0.0	0.0	1.4	0.5	0.0	0.4	0.0
SE02	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SE03	0.0	1.4	0.0	0.0	3.2	0.2	0.8	3.3	1.2	0.0	2.8	0.0
SE04	0.4	1.6	1.2	1.8	3.4	5.1	1.7	3.4	1.9	0.6	3.3	0.5
SI00	0.0	0.0	0.0	0.0	0.2	0.0	0.0	0.0	0.0	0.0	0.4	0.0
SK00	0.1	0.4	0.5	0.2	0.8	0.9	0.1	0.5	0.5	1.0	1.6	0.2

Note: ED with CS values in TY2025 for Poland have been adjusted by ENTSO-E to reflect the DSR contracted for this year.

Table 2: Central scenario: expected energy not served (EENS) in GWh per year from the ED module with and without the implementation of curtailment sharing, and from the EVA.

EENS (GWh/year) central scenario	Target Year 2025			Target Year 2028			Target Year 2030			Target Year 2033		
	ED without CS	ED with CS	EVA module	ED without CS	ED with CS	EVA module	ED without CS	ED with CS	EVA module	ED without CS	ED with CS	EVA module
AT00	0.0	0.0	0.0	0.1	0.1	0.0	0.1	0.1	0.0	0.2	0.6	0.4
BE00	0.9	0.4	0.4	4.2	4.2	3.3	0.6	1.9	3.6	0.9	3.0	3.2
BG00	0.0	0.0	0.0	0.3	0.1	0.0	0.3	0.1	0.0	1.2	0.7	0.0
CY00	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4	0.4	0.0
CZ00	0.2	0.1	0.4	3.2	1.7	3.5	2.0	1.3	3.1	10.8	9.4	9.9
DE00	2.9	1.7	1.6	13.3	9.9	7.9	15.5	12.6	21.0	41.9	36.2	31.4
DKE1	0.6	0.8	1.1	1.9	2.2	3.0	1.9	3.8	4.6	3.7	7.5	4.3
DKW1	0.6	2.1	0.2	0.2	4.8	2.2	0.0	3.0	4.6	0.1	5.6	7.6
EE00	0.3	0.2	0.4	0.5	0.3	0.7	0.6	0.2	0.5	0.1	0.3	0.1
ES00	5.4	5.5	3.2	4.6	4.7	9.1	0.8	0.8	0.0	1.1	1.1	0.3
FI00	1.2	1.0	0.0	0.3	0.2	0.9	0.8	0.2	1.2	0.8	0.8	0.7
FR00	1.3	0.9	30.1	14.7	10.3	46.6	14.7	10.7	41.8	25.1	22.0	64.0
GR00	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.3	0.0
GR03	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0
HR00	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HU00	1.5	0.6	1.2	6.8	4.6	1.7	3.9	2.7	0.2	15.1	12.9	0.4
IE00	119.6	91.8	0.1	3.0	2.3	0.0	0.3	0.2	0.0	0.6	0.6	0.0
ITCA	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
ITCN	0.0	1.0	0.0	0.0	1.4	0.0	0.0	0.2	0.0	0.0	0.1	0.0
ITCS	0.0	0.0	0.0	0.0	0.2	0.0	0.0	0.1	0.0	0.0	0.1	0.0
ITN1	0.5	1.3	0.0	0.2	2.6	0.1	0.0	0.3	0.3	0.0	0.2	0.0
ITS1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
ITSA	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
ITSI	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LT00	0.2	0.1	0.4	1.2	0.6	0.6	0.9	0.4	0.8	0.8	0.4	0.0
LU00	0.0	0.0	0.0	0.2	0.1	0.1	0.2	0.2	0.3	0.5	0.5	0.4
LV00	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MT00	37.6	36.4	68.6	8.6	8.6	0.7	1.7	1.7	0.0	3.4	3.4	0.0
NL00	0.0	0.0	0.0	0.0	0.2	0.4	0.0	0.3	0.4	0.1	0.8	1.2
PL00	0.3	0.0	1.0	2.0	1.2	2.3	1.7	0.9	2.3	8.0	6.1	6.4
PT00	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RO00	0.1	0.0	0.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SE01	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.1	0.0	0.0	0.0
SE02	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SE03	0.0	1.7	0.0	0.0	5.7	0.0	0.8	5.6	0.3	0.0	1.2	0.0
SE04	0.3	1.3	0.0	3.0	3.8	7.1	3.1	3.2	5.6	0.8	1.8	0.0
SI00	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SK00	0.0	0.0	0.1	0.0	0.1	0.2	0.0	0.0	0.1	0.3	0.4	0.0

Note: ED with CS values in TY2025 for Poland have been adjusted by ENTSO-E to reflect the DSR contracted for this year.

Table 3: Sensitivity: loss of load indicator in hours per year from the ED module with and without the implementation of curtailment sharing, and from the EVA.

LOLE (hours/year) sensitivity	Target Year 2025			Target Year 2028			Target Year 2030			Target Year 2033		
	ED without CS	ED with CS	EVA module	ED without CS	ED with CS	EVA module	ED without CS	ED with CS	EVA module	ED without CS	ED with CS	EVA module
AT00	0.2	0.9	0.0	0.1	0.8	0.3	0.2	0.6	0.2	0.3	2.6	0.3
BE00	1.4	6.3	0.6	4.0	9.8	1.3	1.7	7.3	1.0	6.7	19.3	2.7
BG00	0.0	0.0	0.0	1.7	2.3	0.1	1.1	1.2	0.0	4.4	4.5	0.0
CY00	0.0	0.0	0.0	0.0	0.0	0.0	0.3	1.6	0.0	6.0	9.3	0.0
CZ00	1.3	6.0	0.7	6.1	9.8	2.0	3.2	6.8	2.1	9.2	16.8	2.7
DE00	3.9	7.7	1.1	8.5	12.0	1.9	8.1	11.9	2.5	14.4	22.8	2.9
DKE1	3.8	6.8	0.7	6.9	10.1	5.5	4.8	11.2	2.1	10.3	19.7	2.6
DKW1	1.1	5.8	0.6	0.4	6.9	1.2	0.3	3.4	1.6	0.9	9.0	2.7
EE00	2.8	8.1	0.7	2.4	5.8	5.1	2.0	4.9	0.5	1.1	7.4	0.9
ES00	4.8	7.7	2.3	4.8	8.8	6.4	0.5	0.9	0.1	0.5	0.7	0.1
FI00	5.1	6.5	0.4	1.1	2.4	0.7	1.3	1.7	0.5	1.3	1.7	1.0
FR00	1.7	4.8	2.2	4.7	7.9	2.6	4.7	7.5	2.8	8.9	14.4	3.9
GR00	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.1	0.0	2.3	4.4	0.0
GR03	0.2	1.0	0.1	0.0	0.5	0.0	0.0	0.4	0.0	1.0	5.1	0.0
HR00	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0
HU00	2.4	8.0	3.0	7.6	10.5	1.7	5.4	7.7	1.4	12.7	18.0	1.6
IE00	358.2	371.6	0.5	13.0	16.5	0.3	0.7	1.1	0.0	1.1	2.6	0.1
ITCA	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0
ITCN	0.0	4.4	0.0	0.1	4.3	0.0	0.0	2.0	0.2	0.0	3.3	0.0
ITCS	0.0	0.0	0.0	0.0	0.9	0.0	0.0	1.8	0.0	0.0	3.1	0.0
ITN1	1.2	4.1	0.1	0.7	3.9	0.6	0.1	2.6	0.3	0.0	4.7	0.1
ITS1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
ITSA	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.2	0.0
ITSI	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0
LT00	1.4	3.7	0.3	5.9	7.4	0.8	3.0	5.0	0.7	4.1	7.1	0.2
LU00	3.9	7.7	1.1	8.5	12.0	1.9	8.1	11.9	2.5	14.4	22.8	2.9
LV00	0.0	0.1	0.0	0.0	0.0	0.1	0.0	0.1	0.0	0.1	1.1	0.0
MT00	507.8	502.4	1062.2	115.2	115.4	67.7	26.3	26.8	0.0	46.8	48.7	0.0
NL00	0.1	1.2	0.2	0.2	2.8	0.5	0.0	1.6	0.3	0.1	3.7	0.3
PL00	0.6	0.3	0.5	3.4	4.7	2.6	2.6	4.4	0.6	6.7	12.3	2.7
PT00	0.0	0.1	0.0	0.1	0.1	0.0	0.0	0.1	0.0	0.0	0.3	0.0
RO00	0.1	2.3	1.4	0.0	0.3	0.3	0.0	0.0	0.0	0.0	0.0	0.0
SE01	0.0	0.0	0.0	0.0	0.5	0.0	0.0	1.8	0.2	0.0	0.5	0.0
SE02	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SE03	0.0	4.4	0.0	0.1	7.6	0.1	0.8	6.6	0.4	0.0	4.9	0.0
SE04	1.7	4.8	0.5	3.9	8.1	3.9	3.3	6.9	1.0	1.1	6.8	0.2
SI00	0.0	0.5	0.0	0.0	1.0	0.1	0.0	0.3	0.0	0.0	1.0	0.0
SK00	0.7	3.5	0.6	1.3	2.5	1.1	0.5	1.4	0.9	1.7	2.5	0.6

Note: ED with CS values in TY2025 for Poland have been adjusted by ENTSO-E to reflect the DSR contracted for this year.

Table 4: Sensitivity: expected energy not served (EENS) in GWh per year from the ED module with and without the implementation of curtailment sharing, and from the EVA.

EENS (GWh/year) sensitivity	Target Year 2025			Target Year 2028			Target Year 2030			Target Year 2033		
	ED without CS	ED with CS	EVA module	ED without CS	ED with CS	EVA module	ED without CS	ED with CS	EVA module	ED without CS	ED with CS	EVA module
AT00	0.1	0.1	0.0	0.1	0.2	0.2	0.2	0.2	0.1	0.5	0.9	0.4
BE00	1.7	1.6	0.5	9.3	9.1	2.4	3.0	6.9	2.4	13.3	25.7	3.7
BG00	0.0	0.0	0.0	0.9	0.5	0.0	0.6	0.2	0.0	2.6	1.3	0.0
CY00	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.7	0.6	0.0
CZ00	1.0	0.8	0.3	14.1	9.2	4.1	6.9	5.2	4.1	25.2	21.2	7.0
DE00	21.2	12.0	3.7	55.9	47.2	7.7	70.9	58.0	21.9	160.3	141.4	33.0
DKE1	2.2	3.5	0.5	5.8	6.9	2.0	5.7	11.9	2.7	10.2	24.1	2.2
DKW1	1.7	8.4	0.4	0.6	12.3	1.5	0.2	6.8	2.4	0.7	15.7	4.5
EE00	0.8	0.5	0.2	0.7	0.4	0.6	0.7	0.4	0.2	0.2	0.6	0.1
ES00	8.1	8.2	4.8	9.0	9.2	16.3	0.9	0.9	0.1	1.1	1.1	0.1
FI00	2.4	2.0	0.1	0.7	0.5	0.4	1.2	0.4	0.4	0.8	0.8	0.7
FR00	8.9	5.5	12.3	37.2	26.7	21.7	38.4	29.8	20.5	73.4	58.9	33.6
GR00	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.9	1.6	0.0
GR03	0.1	0.1	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.2	0.8	0.0
HR00	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HU00	5.7	3.6	1.2	17.6	12.3	2.1	10.6	8.0	0.6	34.4	29.3	1.0
IE00	122.7	89.2	0.1	6.6	4.8	0.1	0.4	0.3	0.0	0.6	0.6	0.0
ITCA	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
ITCN	0.0	3.5	0.0	0.1	3.7	0.0	0.0	0.6	0.0	0.0	0.3	0.0
ITCS	0.0	0.0	0.0	0.0	0.8	0.0	0.0	0.5	0.0	0.0	0.3	0.0
ITN1	1.5	4.2	0.0	0.7	7.4	0.1	0.1	1.3	0.2	0.0	1.0	0.0
ITS1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
ITSA	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
ITSI	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LT00	0.5	0.2	0.1	1.8	0.7	0.3	2.2	1.0	0.4	2.5	1.4	0.0
LU00	0.3	0.2	0.0	0.7	0.6	0.1	0.9	0.8	0.3	2.1	1.8	0.4
LV00	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MT00	37.2	36.1	72.8	8.2	8.2	0.8	1.6	1.6	0.0	3.2	3.2	0.0
NL00	0.0	0.2	0.1	0.4	1.5	0.5	0.1	0.7	0.2	0.2	2.1	0.2
PL00	0.5	0.1	0.4	5.2	3.0	1.6	4.3	2.6	1.4	17.8	13.5	3.9
PT00	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RO00	0.1	0.2	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SE01	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4	0.0	0.0	0.0	0.0
SE02	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SE03	0.0	6.0	0.0	0.0	14.7	0.0	0.8	11.3	0.3	0.0	2.3	0.0
SE04	1.7	4.3	0.1	7.5	9.2	5.3	7.5	6.5	2.2	1.0	3.7	0.1
SI00	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SK00	0.2	0.2	0.1	0.3	0.2	0.2	0.1	0.1	0.1	0.5	0.4	0.1

Note: ED with CS values in TY2025 for Poland have been adjusted by ENTSO-E to reflect the DSR contracted for this year.

Table 5: Comparison of forecasted demand between the ERAA 2023 and ERAA 2022 central reference scenario for 2025 and 2030

	2025			2030		
Member State	**ERAA 2023 (GWh)**	**ERAA 2022 (GWh)**	**Relative difference (%)**	**ERAA 2023 (GWh)**	**ERAA 2022 (GWh)**	**Relative difference (%)**
AT	76140	75622	0.7	89780	90147	-0.4
BE	90920	91141	-0.2	115490	101454	12.2
BG	35390	37240	-5.2	37240	38000	-2.0
CY	5330	5770	-8.3	6210	6120	1.4
CZ	71220	71172	0.1	81770	75565	7.6
DE	570650	574392	-0.7	674130	649308	3.7
DK	41690	46807	-12.3	56960	59226	-4.0
EE	9200	9128	0.8	9900	9416	4.9
ES	255800	258680	-1.1	269550	262910	2.5
FI	90820	94049	-3.6	109810	107616	2.0
FR	470650	480320	-2.1	519610	524941	-1.0
GR	56280	56605	-0.6	70620	55449	21.5
HR	17500	17600	-0.6	18000	18540	-3.0
HU	57740	49046	15.1	65990	52650	20.2
IE	38480	39600	-2.9	45050	46500	-3.2
IT	327840	328982	-0.3	357460	344707	3.6
LT	14310	14119	1.3	17530	14955	14.7
LU	8510	8013	5.8	8940	9019	-0.9
LV	7900	7294	7.7	8730	7535	13.7
MT	3180	3010	5.3	3790	3410	10.0
NL	133650	124100	7.1	161780	153863	4.9
PL	169140	166898	1.3	189230	184744	2.4
PT	52270	51523	1.4	58800	55435	5.7
RO	56270	62229	-10.6	62940	65286	-3.7
SE	155580	150800	3.1	203190	187000	8.0
SI	16300	14716	9.7	18100	15666	13.4
SK	29980	29570	1.4	32230	31480	2.3

Note: Demand data for ERAA are estimated as the average of the annual demand values over all climate years. For Member States with multiple bidding zones the demand data are the cumulative demand for all bidding zones. The relative difference is calculated with the ERAA 2022 demand data as reference.

Table 6: Differences in installed renewable capacity between ERAA 2023 and the draft Member State NECPs for 2025

2025	Wind			Solar		
Member State	**ERAA 2023 (MW)**	**Draft NECP (MW)**	**Difference (MW)**	**ERAA 2023 (MW)**	**Draft NECP (MW)**	**Difference (MW)**
CY	170	200	-31	696	700	-4
CZ	617	750	-133	5159	5413	-254
DE	80459	95813	-15354	88448	122313	-33865
DK	8164	7900	264	5860	5400	460
EE	617	400	217	1060	1100	-40
ES	34817	42100	-7283	33699	56700	-23001
FI	8136	6200	1936	1873	1425	448
FR	26074	27063	-989	18185	31125	-12940
GR	5600	6000	-400	6569	8000	-1431
HR	1272	1700	-428	160	500	-340
HU	334	700	-366	7162	6900	262
IE	5249	8875	-3626	358	3063	-2705
IT	15303	17300	-1997	39954	44900	-4946
LT	2613	2000	613	3527	4200	-673
NL	13439	11900	1539	38683	22700	15983
PT	6488	6300	188	6478	8400	-1922
RO	5000	5000	0	4300	4000	300
SE	20643	18200	2443	3696	3200	496
SI	48	0	48	1200	1800	-600
SK	357	100	257	1088	1000	88

Table 7: Differences in installed renewable capacity between ERAA 2023 and the draft Member State NECPs for 2030

2030	Wind			Solar		
Member State	**ERAA 2023 (MW)**	**Draft NECP (MW)**	**Difference (MW)**	**ERAA 2023 (MW)**	**Draft NECP (MW)**	**Difference (MW)**
CY	198	200	-3	852	900	-48
CZ	958	1500	-542	11406	10100	1306
DE	145522	145000	522	215002	215000	2
DK	15556	18100	-2544	17744	11700	6044
EE	861	2300	-1439	1160	1200	-40
ES	51117	62000	-10883	64848	76400	-11552
FI	27242	7200	20042	10695	2800	7895
FR	35175	37000	-1825	42282	54000	-11718
GR	9800	10000	-200	13863	13000	863
HR	1442	2600	-1158	720	1000	-280
HU	334	1100	-766	9917	12000	-2083
IE	13978	16000	-2022	7987	8000	-13
IT	26911	28100	-1189	74601	79900	-5299
LT	6400	6400	0	5000	5100	-100
NL	25643	23200	2443	59317	25800	33517
PT	8946	12400	-3454	11675	20400	-8725
RO	7000	8000	-1000	8300	8000	300
SE	27133	24900	2233	7302	6500	802
SI	122	150	-28	2750	3500	-750
SK	715	800	-85	1500	1400	100

Source (Table 6 and Table 7): ACER analysis based on ENTSO-E's ERAA 2023 data and renewable energy target data from Ember's Live EU NECP tracker for Member States. The difference is calculated with the draft NECP data as reference.

Notes: Table 6 and Table 7 present data only for Member States that have set 2030 renewable energy targets for wind and solar based on Ember's Live EU NECP tracker. Where renewable energy targets for 2025 are lacking, ACER has interpolated between installed capacities as of 2022 and the 2030 targets as provided on Ember's website, to derive 2025 renewable energy targets.

6. List of Figures

7. List of Tables