ACER
European Union Agency for the Cooperation of Energy Regulators

ACER Decision on ERAA 2025: Annex III

DECISION No 06/2026
OF THE EUROPEAN UNION AGENCY
FOR THE COOPERATION OF ENERGY REGULATORS
on the European Resource Adequacy Assessment for 2025

Technical annex

24 April 2026

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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 2025 (‘ERAA 2025’) and complements the ACER Decision; the two should be read in conjunction. The technical annex supplements ACER’s assessment of ERAA 2025 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 2025 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 curtailment sharing feature implementation in ERAA 2025.

2. Fit-for-55 and renewable energy generation

This section evaluates the alignment of the ERAA 2025 assumptions regarding renewable energy deployment with EU-wide climate and energy policy objectives, specifically those established under the Fit-for-55 framework. ACER examines the consistency of ERAA 2025 with EU renewable energy targets, compares these assumptions with previous ERAA cycles, and benchmarks the data against Member States' National Energy and Climate Plans (NECPs).

2.1. Introduction

Pursuant to Article 3 of the ERAA methodology, the central reference scenarios must be consistent with national objectives and targets. As these national targets are derived from Union-wide objectives, ACER evaluates the alignment of the central reference scenarios with the broader Union policy framework. Given that hydropower capacity is projected to remain largely stable across the assessed horizons, this analysis focuses on solar and wind technologies, which represent the primary drivers for achieving renewable energy targets in the electricity sector.

Under the 'Fit-for-55' framework and the 2023 revision of the Renewable Energy Directive, a binding Union-level target of at least 42.5% for the share of renewable energy in the Union's gross final consumption was established for 2030, with the aim to reach 45%[1]. This target effectively calls for a significant increase of the renewable energy share in the electricity sector To reach this objective, the REPowerEU Plan identifies that the renewable energy share in electricity generation must increase to approximately 69% by 2030. This transition is supported by a benchmark of approximately 1,000 GW of combined installed wind and solar capacity (comprising 469 GW of wind and 530 GW of solar).

ACER observes that ERAA 2025 is broadly aligned with these Union-level benchmarks. For the 2030 target year, the assessment projects a total installed solar capacity of 654 GW and wind capacity of 392 GW, collectively exceeding the 1,000 GW benchmark.

Figure 1 illustrates the evolution of projected solar and wind capacity in the EU-27 under ERAA 2025 compared to the assumptions used in ERAA 2024. While the aggregate Union-level figures suggest alignment with policy objectives, ACER identifies specific discrepancies at the Member State level, which are addressed in the following subsections.

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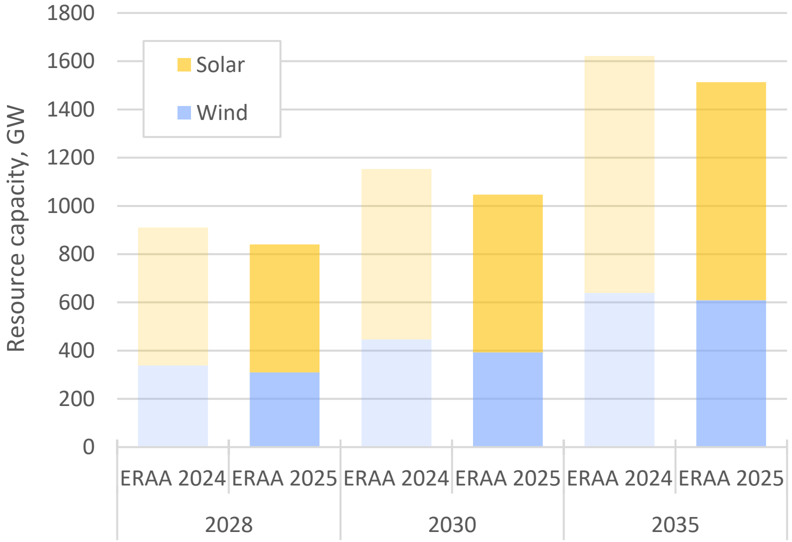
[1] For more information, see the European Commission's webpage on the Renewable Energy Targets.

Figure 1: Solar and wind capacity in EU-27: current vs previous ERAA

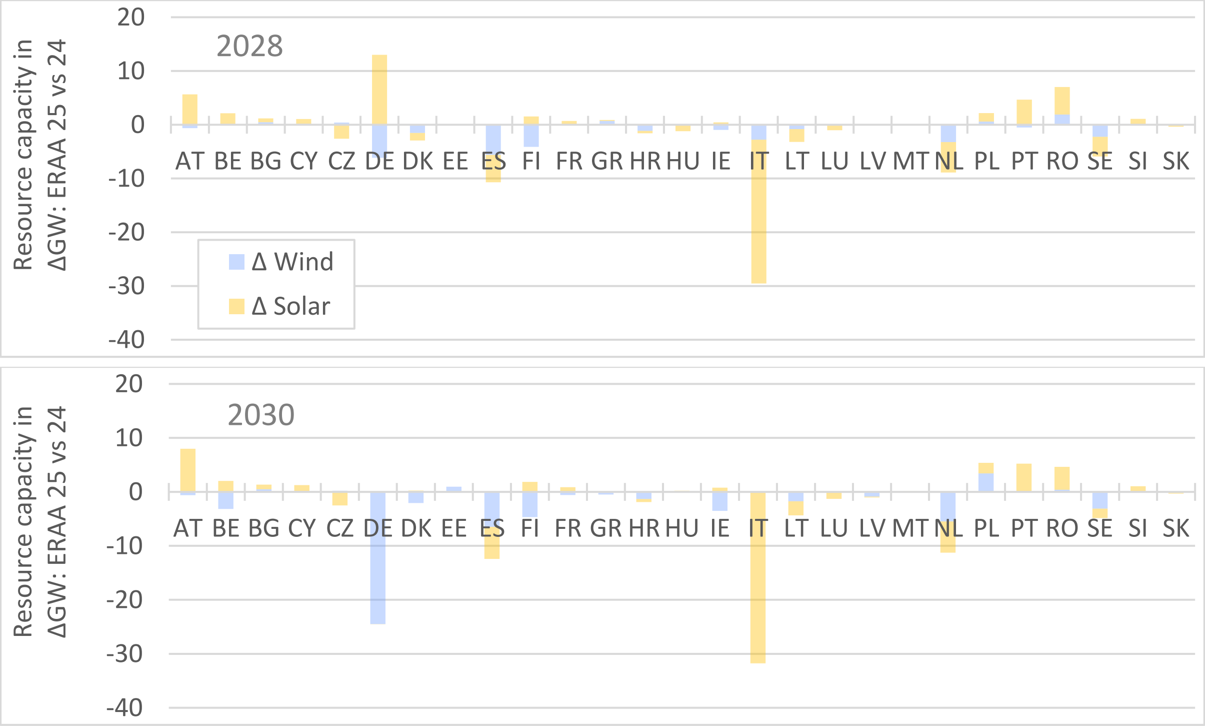


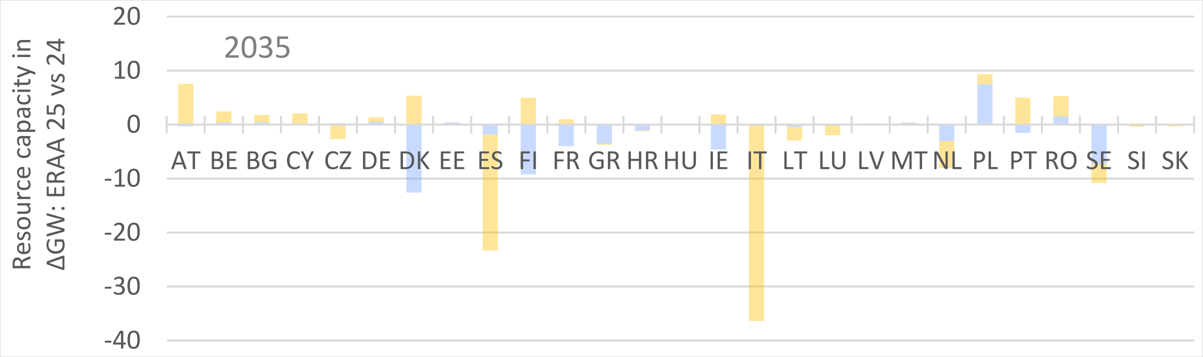
2.2. Comparison of ERAA 2025 with ERAA 2024

Overall, ERAA 2025 assumes lower total installed renewable capacity compared to the assumptions utilized in ERAA 2024 for both solar and wind technologies. This shift reflects divergent trends at the Member State level when comparing the current and previous assessment cycles. The detailed differences in installed renewable capacity per Member State between ERAA 2025 and ERAA 2024 are illustrated in Figure 2.

At the Union-level, the lower total installed solar and wind capacity projected in ERAA 2025 is primarily driven by reduced solar deployment assumptions in Italy and Spain, as well as downward revisions for wind capacity in Germany.

Figure 2: Differences in installed wind and solar capacity: ERAA 2025 vs ERAA 2024





Source: ACER analysis based on ENTSO-E's ERAA 2025 and ERAA 2024 data.

Italy exhibits the most significant absolute reduction in solar capacity across all target years, with decreases of 27 GW in 2028, 35 GW in 2030, and 37 GW in 2035. Spain also shows a substantial reduction in projected solar capacity for the 2035 horizon (21 GW). Adjustments to solar capacity assumptions for other Member States remain within ±10 GW. Collectively, compared to the ERAA 2024 assumptions, total Union-level solar capacity in ERAA 2025 is reduced by 40 GW in 2028, 52 GW in 2030, and 77 GW in 2035.

Regarding wind energy, the most pronounced reduction is observed in Germany, where projected capacity for 2030 is 24 GW lower than in the previous edition. Additionally, Denmark's wind capacity assumptions for 2035 reflect a 12 GW decrease. For most other Member States, changes remain within ±10 GW across all target years. On an aggregate Union-level, compared to ERAA 2024, total wind capacity in ERAA 2025 decreases by 28 GW in 2028, 53 GW in 2030, and 30 GW in 2035.

The underlying drivers for these variations are explored in further detail in Section 2.3, which benchmarks ERAA 2025 assumptions against NECP projections. For instance, the reduction in solar capacity in Italy between assessment cycles reflects the use of updated assumptions that are more closely aligned with the targets established in the national NECP.

2.3. Comparison of ERAA 2025 with the NECP projections

Following the comparative analysis with ERAA 2024, ACER evaluated the assumptions in ERAA 2025 against the renewable energy trajectories established in Member States' National Energy and Climate Plans ('NECPs')[2]. This benchmarking exercise is conducted to assess the alignment of the central reference scenario with national policy objectives, as prescribed by Article 3 of the ERAA methodology. ACER observes variable degrees of alignment between the ERAA 2025 assumptions and the NECP projections across Member States. As illustrated in Figure 3, the most significant absolute discrepancies in installed capacity are identified in the Netherlands, Spain, and Germany.

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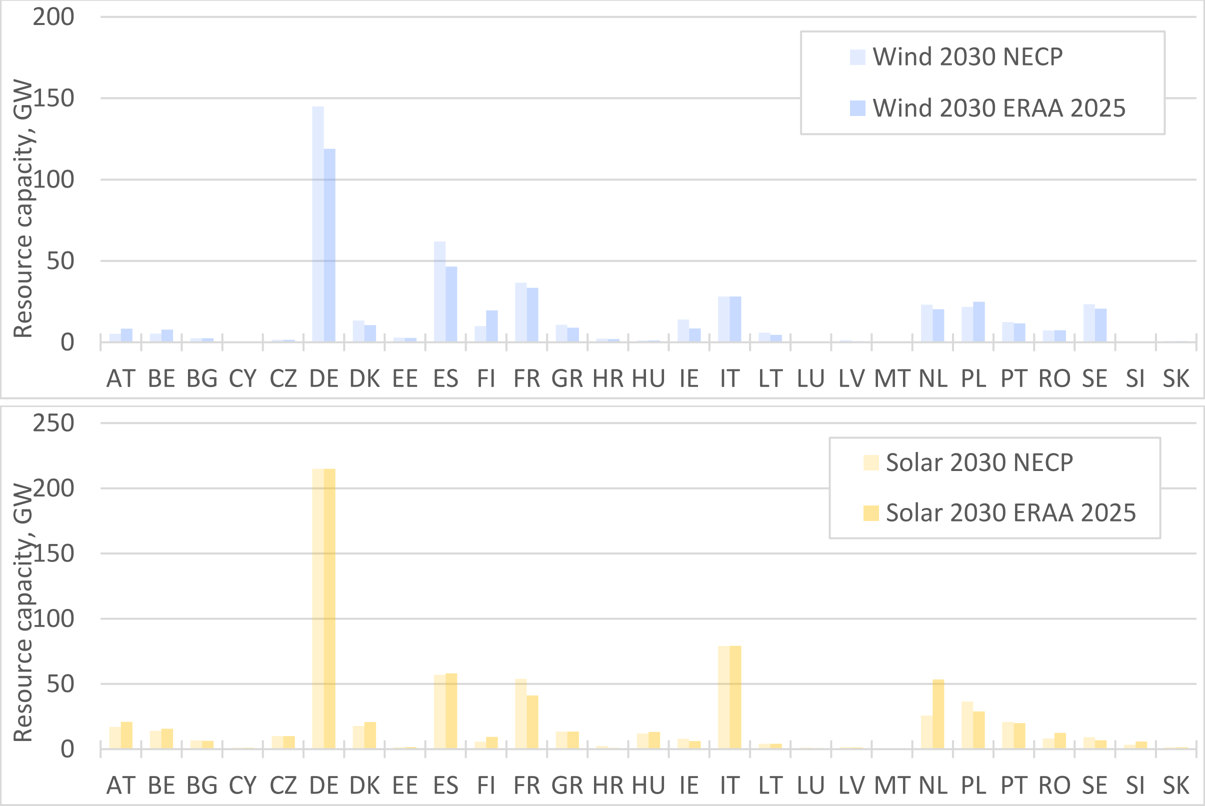
[2] The analysed data origin from the "NECP target" as stated on Ember's Live EU NECP tracker. The target represents national objectives, where they are available, or with second priority the scenario with additional measures (WAM). If neither are available in the NECP of a Member State, the with existing measures scenario (WEM) is showed.

Figure 3 Installed wind and solar capacities in 2030: ERAA 2025 vs NECP



The most pronounced absolute divergence concerns solar capacity in the Netherlands, where the ERAA 2025 assumptions exceed the NECP targets by approximately 28 GW. ACER notes that the assumptions for the Netherlands are derived from *Koersvaste Middenweg* scenario of the *Netbeheer Nederland Scenario's Editie 2025*, as detailed in ERAA 2025 *Annex 1 on Input Data & Assumptions*.

Conversely, for Germany, ERAA 2025 assumes approximately 25 GW less installed wind capacity compared to the NECP projections. These assumptions are based on the *Greenhouse Gas Projections* report of the Federal Environment Agency. Regarding Spain, ACER notes that wind capacity assumptions underwent downward revisions during the input data consultation process to exclude wind generation from the Spanish islands, which are not modelled in ERAA.

Aside from these specific outliers, ACER considers the ERAA 2025 assumptions to be broadly aligned with the national renewable energy targets defined in the NECPs. This general consistency supports the robustness of the central reference scenario in representing the likely evolution of the European power system in accordance with Union-wide policy objectives.

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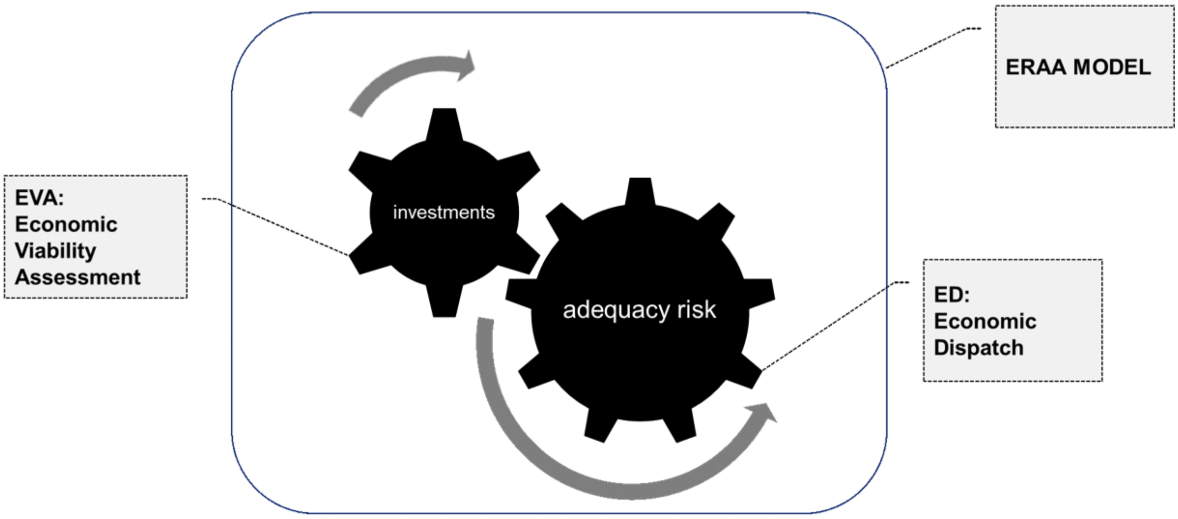
3. Economic viability assessment

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 2024 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 4: The ERAA 2024 model consists of two modules



The ERAA 2024 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 supplementary data regarding the adequacy risk indicators of the EVA and ED module runs with and without the implementation of curtailment sharing.

The following sections examine some of the key developments of the EVA in ERAA 2025 compared to ERAA 2024.

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 detail and assumptions in both modules, i.e. with the same level of hourly aggregation and for the same weather scenarios and outage patterns, as these are the underlying market conditions of ERAA.

Figure 5 shows the comparison of the average LOLE indicators between the EVA and ED module for all zones and all target years. Notable differences can be observed, with average increases ranging from 5.9h to 8.3h of LOLE depending on the target year considered. These differences highlight that perceived adequacy risks are not the same between the two modules, hence that scarcity situations and pricing are not accurately reflected in the EVA, distorting investment signals.

Figure 5: Comparison of average LOLE between the EVA module and the ED module – Central scenario, all EU27 bidding zones except MT00, all target years

Figure 6 shows the comparison of gas technology capture prices[3] (i.e. volume-weighted revenues) between the EVA and ED modules. Values are lower in the EVA module across all target years. This analysis shows that the difference (in % increase) between both modules increases from roughly 22% in 2030 to 33% in 2035.

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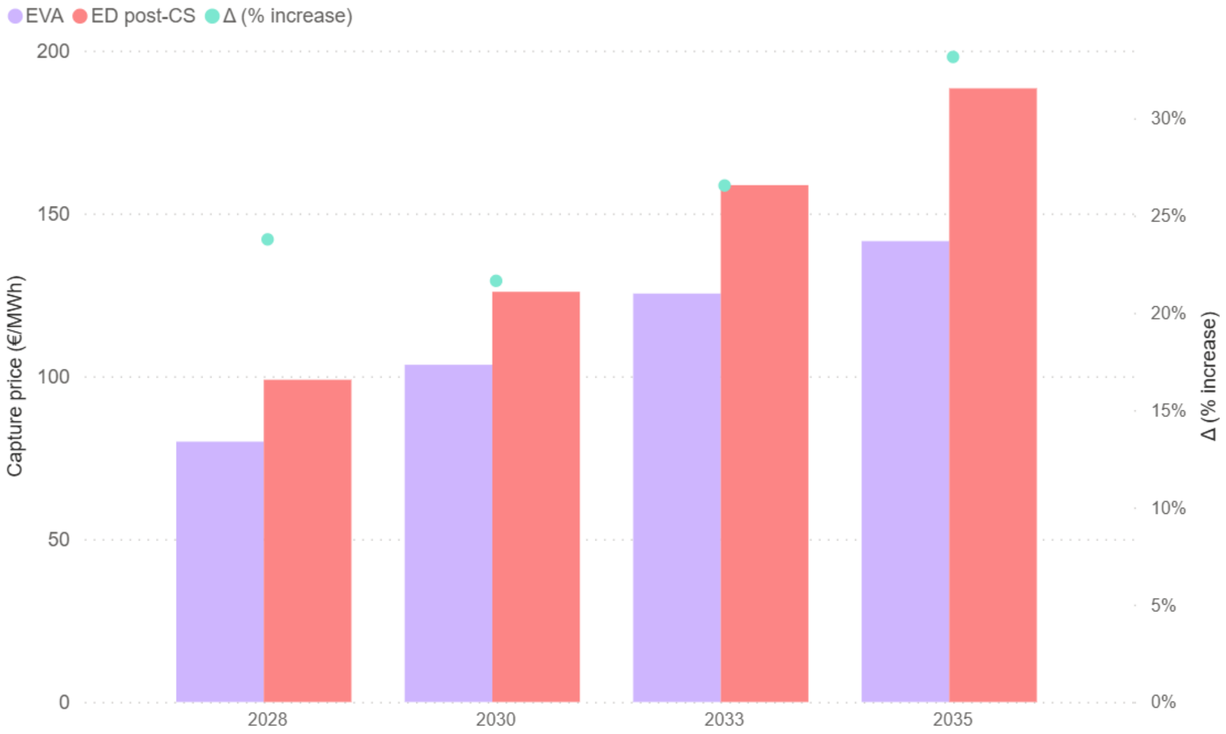
[3] ACER notes that, whereas the average capture prices increase along target years (for both, EVA and ED) it does not have an impact on consumer nor industrial electricity prices as gas generation is also decreasing over time. This analysis was developed just for the purpose of assessing the consistency between EVA and ED modules.

Figure 6 Average capture price (€/MWh) in EVA and ED models per target year for gas technology



The differences between the results of the EVA and the ED result from the combination of several simplifications introduced in the EVA module to cope with computational difficulties. The most important of these simplifications are the reduction of the modelled weather scenarios from 36 in the ED to 3 in the EVA, the different flow-based domains used, the divergent modelling of forced outages and the fact that local matching and curtailment sharing are only implemented in the ED module[4]. In future ERAA versions, ACER expects that revenues further align between the EVA and the ED.

3.3. Demand side response

Input (pre-EVA) DSR capacities for target years 2028/30/35 are plotted in Figure 7 for two ERAA editions: 2024 and 2025. EVA capacity expansions are also added on the top of the national estimates (pre-EVA). The largest absolute pre-EVA DSR capacity decrease can be observed in Germany, where capacity in 2035 declined from 6.6 GW in ERAA 2024 to 1.7 GW in ERAA 2025. For this and other target years, the DSR capacity reduction in Germany occurred during the public consultation process. On the other hand, the largest increase in pre-EVA capacity is observed in Sweden, rising from 1.7 GW to 4.4 GW in 2035. The reason for this change is not explicitly explained in the ERAA documentation. Sweden also records the largest additional DSR capacity introduced during the EVA modelling phase in both ERAA editions, with slightly more than 4 GW added in 2035.

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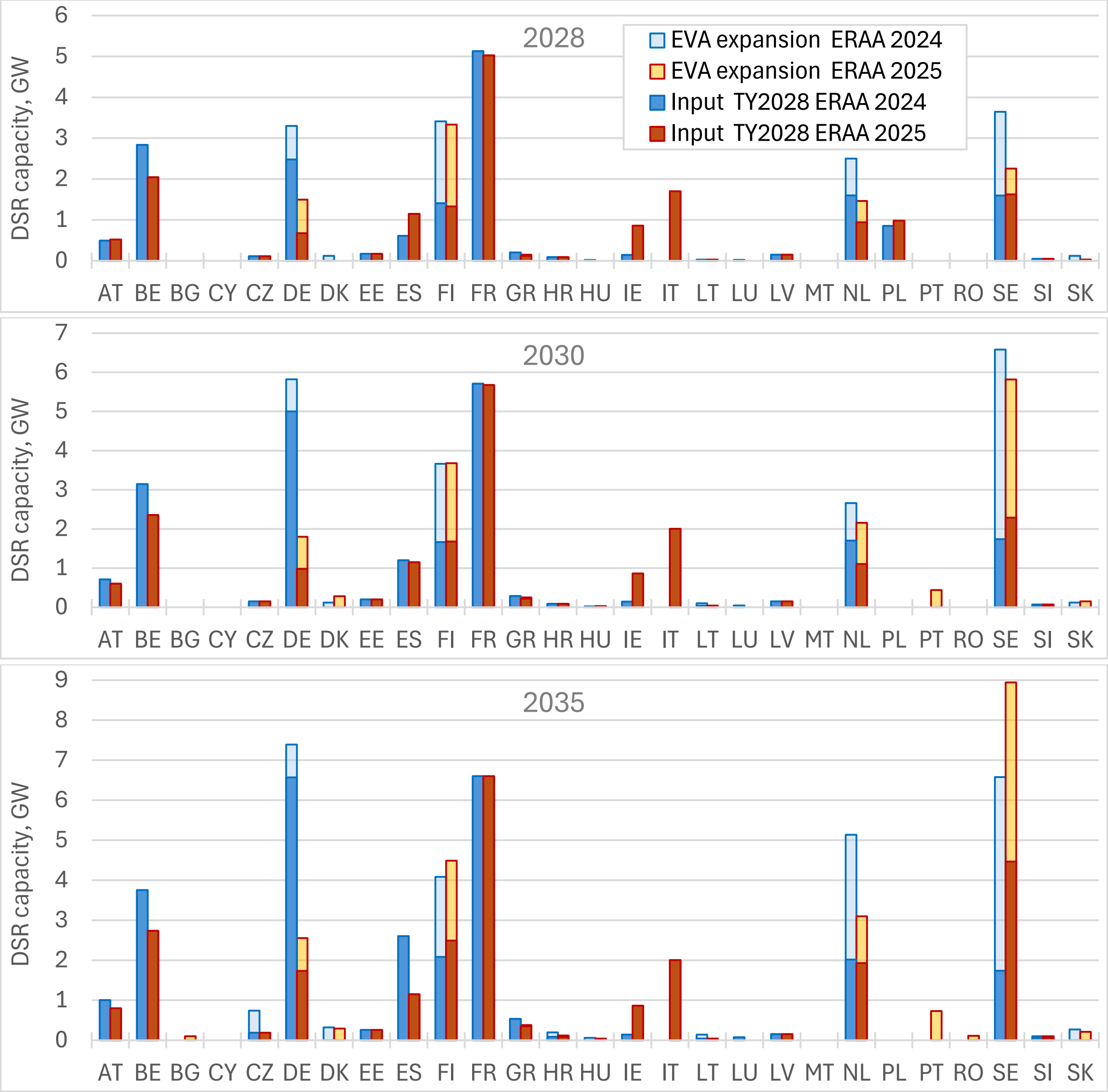
[4] There are other simplifications in the EVA that contribute to the mismatch between the EVA and the ED module. These include for example, the way aggregated capacity values form the EVA module are postprocessed to enable unit-by-unit consideration in the ED module, and the use of derating to model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

Figure 7 DSR capacity change: ERAA 2024 vs 2025



Most countries have potential DSR capacity to be deployed during EVA phase if deemed economically viable. However, Figure 7 shows that less than half countries gain extra DSR capacity during EVA modelling phase. The DSR expansion in EVA depends directly on assumed economic inputs – investment and operation costs – as well as on scarcity price events in the three weather scenarios modelled during the EVA phase. These both conditions may vary widely from one country to another and thus impact the DSR expansion decision.

3.4. Dependence of EVA outcomes on input parameters

Objective function of the cost-minimization EVA

As detailed in Section 10.4 of Annex 2: Methodology of the ERAA 2025 Report, EVA employs a multi-year optimization to determine the evolution of the European capacity mix. The module simulates decisions on commissioning, decommissioning, life-extension, and (de-)mothballing of resources (See

Section 6.2.4.1. of the Decision). This is achieved by minimizing the total system costs, formulated as the Net Present Value (NPV) of all future costs.

$$Minimize \sum (1+r)^{(1-y)}[Total\ cost_y]$$

Where:

- r is the applicable discount rate.
- y the year, and.
- $Total\ cost_y$ comprises the annuity of CAPEX for new entries, FOM costs for all units, and operational costs (short-term marginal costs and costs incurred by ENS) in year y.

Under this cost-minimization logic, the EVA adds capacity if the annualized cost of an entrant is lower than the expected system savings (primarily avoided ENS costs). Conversely, it retires capacity if fixed costs exceed the unit's expected market contribution. ACER notes that this "Social Planner" approach assesses economic viability based on total system savings rather than the actual revenue sufficiency of individual assets. Consequently, a unit deemed "viable" by the EVA may not recover its costs through market prices alone. This divergence is particularly acute because the pure and perfect competition assumptions required for equivalence between cost-minimization and revenue-based models (e.g., atomicity, free entry/exit) are not fully realized in the ERAA framework. Consequently, adopting a cost-minimisation approach for the EVA conditions the resulting capacity mix retained to run the ED.

Determination of the national Reliability Standard (RS)

Pursuant to Article 25(1) of Regulation (EU) 2019/943, Member States must establish a Reliability Standard based on the VOLL/CONE/RS Methodology. The RS is expressed as a Loss of Load Expectation (LOLE) threshold, derived from the ratio between the Cost of New Entry (CONE) and the Value of Lost Load (VOLL):

$$LOLE_{RS} = \frac{CONE_{fixed}}{VOLL_{RS} - CONE_{var}}$$

Where:

- $LOLE_{RS}$ is the LOLE threshold related to the reference new entry[5] as defined by Article 10 of the VOLL/CONE/RS methodology, in hours.
- $CONE_{fixed}$ is the best estimate of the fixed CONE pursuant to Article 15 of the VOLL/CONE/RS methodology, in local currency/MW.
- $VOLL_{RS}$ is the best estimate of the single VOLL for RS pursuant to Article 7 of the VOLL/CONE/RS methodology, in local currency/MWh.
- $CONE_{var}$ is the best estimate of the variable CONE pursuant to Article 16 of the VOLL/CONE/RS methodology, in local currency/MWh. $CONE_{var}$ may be neglected in case it is negligible compared to $VOLL_{RS}$

In that sense, the LOLE threshold represents the socio-economic optimum where the marginal cost of additional capacity (or, where relevant, a renewable/prolongation) equals the marginal reduction of EENS (computed as $LOLE * VOLL_{RS}$).

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[5] Under the assumption that this specific reference technology meets the criteria as set out in Article 10, 18, 19, and 20 of the VOLL/CONE/RS methodology

Implementation in the EVA

In a theoretically aligned framework, if the cost-minimizing EVA used the same VOLL and CONE parameters as the national RS calculations, the model would converge to LOLE levels exactly matching the RSs. However, ACER observes structural divergences in the ERAA 2025 implementation that prevent this alignment.

Divergences in VOLL and impact of price caps

Pursuant to the ERAA methodology, the assessment must reflect price formation restrictions, specifically market price caps. In ERAA 2025, these caps are set at €5,500, €6,500, €7,000, and €7,500/MWh for the target years 2028, 2030, 2033, and 2035, respectively.

These caps are significantly lower than the VOLL values typically used by Member States[6] to set their RS. Because the EVA minimizes costs using the Price Cap as the proxy for the cost of ENS, the optimization targets a different equilibrium point:

$$Pricecap < VOLL_{RS}$$

$$\frac{CONE_{fixed}}{Pricecap - CONE_{var}} > \frac{CONE_{fixed}}{VOLL_{RS} - CONE_{var}}$$

$$LOLE_{EVA} > LOLE_{RS}$$

Since the price caps are lower than the VOLL, the LOLE outcomes of the EVA are structurally and systematically higher than the LOLE threshold corresponding to the RSs. This creates a bias where the ERAA identifies adequacy concerns that result from the introduction of a price cap in the model rather than reflecting actual scarcity.

Divergences in CONE values and hurdle rates

While Article 5(10) of the ERAA methodology requires the use of the best estimates for CONE, the ERAA 2025 has applied harmonized values for gas and battery technologies to prevent spill-over effects, where bidding zones with low national CONE values (e.g., Belgium) captured most of the new investments. Furthermore, as noted in Section 6.2.2.6 of the Decision, CONE values, including hurdle rates, have increased compared to previous editions.

While these updates may reflect current inflationary and risk environments, they often deviate from the CONE values used in national RS calculations. In the cost-minimization logic, increasing CONE (notably via higher hurdle rates) necessitates a higher LOLE to justify capacity.

$$CONE_{fixed,updated} > CONE_{fixed}\ ; CONE_{var,updated} > CONE_{var}$$

$$\frac{CONE_{fixed,updated}}{Pricecap - CONE_{var,updated}} > \frac{CONE_{fixed}}{Pricecap - CONE_{var}} > \frac{CONE_{fixed}}{VOLL_{RS} - CONE_{var}}$$

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[6] See Figure 2 of ACER's Security of EU electricity supply: 2024 Monitoring report

$$LOLE_{EVA,CONE\ updated} > LOLE_{EVA} > LOLE_{RS}$$

This results in higher LOLE outcomes in the EVA. In that sense, ACER observed in the Decision that the increased hurdle rates for gas technologies in ERAA 2025 directly contributed to the reporting of increased adequacy risks.

Conclusion

ACER concludes that the current cost-minimization EVA setup structurally results in the identification of adequacy concerns. By optimizing against a price cap instead of VOLL that was used to determine the RS, the ERAA is bound to report LOLE levels[7] that exceed these RS, diminishing the utility of the assessment for identifying real-world adequacy threats.

Furthermore, ACER highlights a methodological impasse of the current EVA setup:

- If parameters remain divergent to those of national RS studies (as they are now), the ERAA will continue producing results that suggest systemic inadequacy.
- If parameters were perfectly aligned with national RS studies, the EVA would risk becoming tautological, merely confirming that the system converges to LOLE = RS without providing new insights into market dynamics or investment hurdles.

To resolve this, ACER reiterates that the shift toward a revenue-based EVA is essential. Such an approach would move beyond theoretical cost-optimality to estimate the actual economic viability of resources. For this to be robust, the model must accurately reflect all revenue streams available to capacity, including Capacity Mechanisms, forward hedging, and ancillary services, as listed in Article 6(9) of the ERAA methodology, as well as the best estimates of national CONE values.

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[7] Other parameters may influence the EVA outcomes, such as technical constraints applicable to thermal generation, potential of new investments, life-extension, or retirement, or limited optimization window to manage computational complexity. For brevity, these parameters were not discussed in this Annex

4. Curtailment sharing

Curtailment sharing (CS) is a feature of EUPHEMIA designed to achieve a fair distribution of ENS across market zones during scarcity situations. It is replicated in ERAA through an “integrated post-processing mechanism” as described in Section 11.7 of Annex II: Methodology of ERAA 2025.

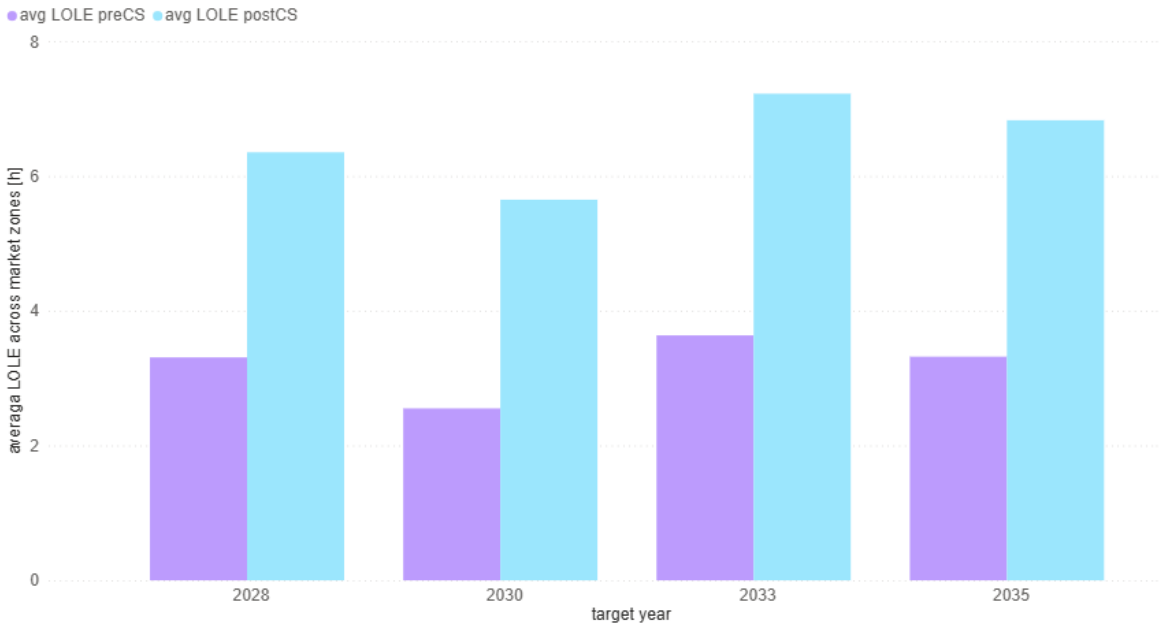
Based on data provided by ENTSO-E, ACER conducted an analysis to assess the feature’s impact and empirical robustness. The principal findings and resulting considerations are presented in the following paragraphs.

4.1. Impact on adequacy outcomes

Impact on LOLE

The CS feature allocates ENS to bidding zones experiencing domestic scarcity (i.e., where domestic demand exceeds domestic supply and DENS > 0). By redistributing scarcity, the feature ensures that no single zone bears the full burden of a regional deficit if transmission capacity allows for sharing. It is important to note that, for such regions, the creation of ENS in a given hour results in an additional hour of scarcity, thereby increasing their final LOLE. Consequently, LOLE levels averagely double due to the CS feature as illustrated in **Error! Reference source not found.**8. Comparison per bidding zone in provided in Appendix 4: Detailed tables.

Figure 8 Pre and post-CS LOLE levels



Additionally, ACER’s comparison of pre- and post-CS simulations of the central reference scenario (See Section 6.1.1.3. of the Decision) confirms frequently extends scarcity to additional bidding zones. Considering all hours, all bidding zones, and all target years simulated, the number of newly affected bidding zones ranges from 0 to a maximum of 21. More specifically:

- In 49.4% of cases, 0 additional zones were affected
- In 50.6% of cases, at least one additional zones was affected
- In 32.7% of cases, at least 2 additional zones were affected.
- In 20.7% of cases, at least 5 additional zones were affected.
- In 4.2% of cases, at least 10 additional zones were affected

- In 1.7% of cases, the scarcity is shared among 19 or more additional bidding zones.

Error! Reference source not found.9 below presents the distribution of cases, expressed as the share of total scarcity hours, by the number of additional bidding zones that enter a scarcity situation following the application of the feature.

Figure 9: Distribution of cases by the number of additional bidding zones that enter a scarcity situation

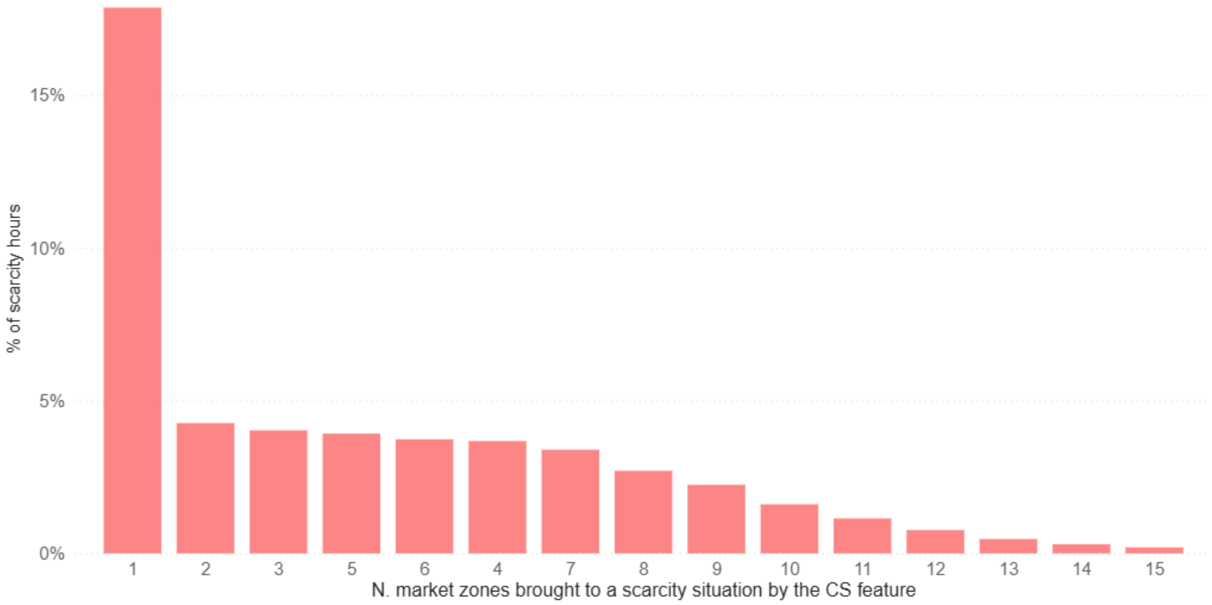
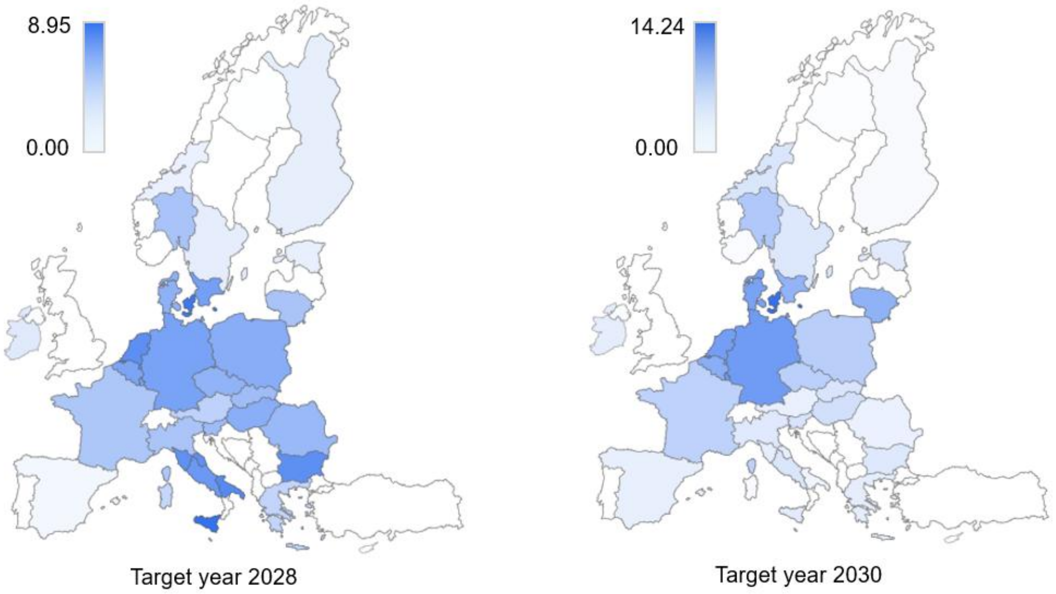


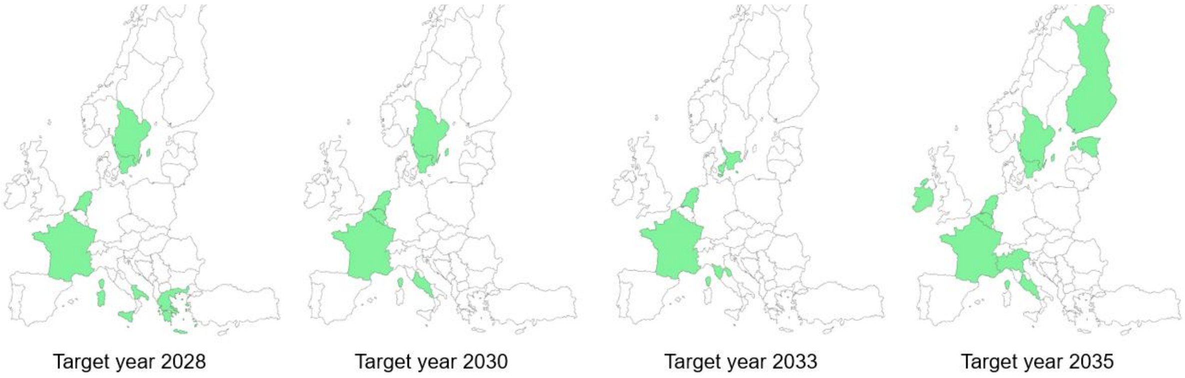
Figure 1010 maps how LOLE increase in target years 2028 and 2030. It shows that the impacted areas vary across years. In 2028, the effect is more pronounced in NTC domains (Italy and the South-East of Europe), whereas in 2030 the impact is primarily observed in FB domains (CORE and Nordic regions).

Figure 10: Geographical repartition of LOLE increases due to CS - Year 2028 and 2030



The LOLE increases are crucial for the modelled bidding zones: for approximately 31% to 52% of the bidding zones that exceed their Reliability Standard in the final ERAA 2025 results, they only do so after the application of curtailment sharing. This highlights that many reported adequacy concerns are driven by the CS feature rather than initial system cost-optimisation. Figure 1111 and Table 1 table below present, for each target year, the bidding zones that are below the Reliability Standard prior to the application of curtailment sharing and exceed that threshold following its implementation

Figure 11: Map of bidding zones exceeding their RS due to CS - all target years



Target year 2028

Target year 2030

Target year 2033

Target year 2035

Table 1: List of bidding zones exceeding their RS due to CS - all target years

2028	2030	2033	2035
FR00	BE00	DKE1	BE00
GR00	FR00	FR00	EE00
ITS1	ITCS	ITCN	FI00
ITSA	NL00	NL00	FR00
ITSI	SE03	SE04	IE00
NL00	SE04		ITCS
SE03			ITN1
SE04			NL00
			SE03
			SE04

Impact on EENS

While the impact on the increase of LOLE is significant, the corresponding impact in terms of ENS is considerably more balanced. Curtailment sharing, as implemented in EUPHEMIA, redistributes ENS across bidding zones; consequently, ENS values both increase and decrease depending on the zone, resulting in a more balanced overall outcome.

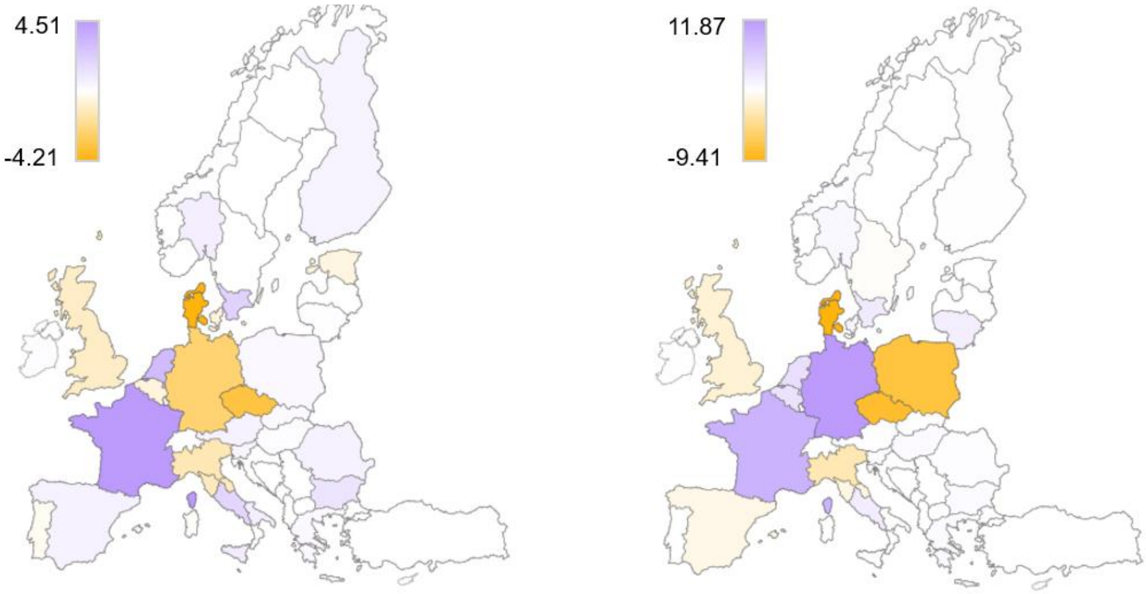
Table 2 below presents the annual variation of ENS (for absolute changes greater than 0.005 GWh) across bidding zones, together with Figure 1212 mapping 2028 and 2030.

Table 2: EENS evolution due to CS - all target years

2028		2030		2033		2035	
market node	ΔENS	market node	ΔENS	market node	ΔENS	market node	ΔENS
FR00	4.51	DE00	11.87	NL00	9.2	DE00	21.06
NL00	3.03	FR00	9.08	DE00	6.7	NL00	9.75
SE04	2.04	NL00	3.67	FR00	6.49	FR00	8.69
ITCS	1.81	BE00	3.28	SE04	2.92	BE00	5.48
BG00	1.2	SE04	2.33	BE00	2.84	LT00	2.35
ITSI	0.84	ITCS	2.15	LT00	2.51	ES00	1.92
NOS1	0.76	LT00	2.03	NOS1	2.19	SK00	1.78
ITS1	0.71	DKE1	1.19	ITCS	2.17	HU00	0.95
AT00	0.6	NOS1	0.81	ES00	1.16	SE04	0.89
RO00	0.59	GR00	0.62	HU00	0.9	EE00	0.88
ES00	0.58	HU00	0.59	SK00	0.81	GR00	0.86
FI00	0.54	BG00	0.5	NOM1	0.73	AT00	0.79
SI00	0.46	SI00	0.42	GR00	0.58	GR03	0.72
PL00	0.3	ITSI	0.41	EE00	0.49	NOM1	0.57
GR00	0.25	NOM1	0.36	GR03	0.46	SI00	0.51
SK00	0.23	RO00	0.3	BG00	0.37	FI00	0.44
IE00	0.15	GR03	0.29	SI00	0.31	ITSI	0.43
HU00	0.13	AT00	0.26	ITS1	0.26	LUG1	0.26
LT00	0.09	ITS1	0.25	ITSI	0.26	ITS1	0.22
NOM1	0.09	IE00	0.17	RO00	0.26	ITCS	0.14
UKNI	-0.02	LUG1	0.16	IE00	0.16	IE00	0.12
LUG1	-0.04	SK00	0.12	DKE1	0.11	LV00	0.08
ITSA	-0.1	FI00	0.08	LUG1	0.09	BG00	0.06
GR03	-0.15	ITSA	0.01	LV00	0.02	RO00	0.06
PT00	-0.19	EE00	-0.01	SE01	0.01	ITSA	-0.02
EE00	-0.52	UKNI	-0.02	NOS2	-0.03	SE03	-0.03
DKE1	-0.56	SE03	-0.21	UKNI	-0.04	UKNI	-0.17
BE00	-0.61	ES00	-0.86	AT00	-0.14	NOS1	-0.2
UK00	-0.98	ITCN	-1	FI00	-0.27	CY00	-0.72
ITCN	-1.11	UK00	-1.64	CY00	-0.36	ITN1	-0.85
ITN1	-1.29	ITN1	-2.94	ITCN	-0.9	DKE1	-1.3

DE00	-2.48	PL00	-7.45	UK00	-1.57	ITCN	-1.68
CZ00	-3.29	CZ00	-8.11	ITN1	-2.25	CZ00	-2.21
DKW1	-4.21	DKW1	-9.41	SE03	-3.61	UK00	-2.93
				CZ00	-4.56	PL00	-15.97
				PL00	-8.85	DKW1	-21.39
				DKW1	-11.03		

Figure 12: EENS evolution map - target year 2028 and 2030



Target year 2028

Target year 2030

On yearly basis, the number of market nodes exhibiting an increase in ENS exceeds the number showing a decrease. Certain zones, such as FR00 and NL00, display consistently strong increases across all years, whereas others, like DKW1 and CZ00, exhibit marked decreases.

A comparison of the impacts on LOLE and ENS indicates that there is no direct correlation between the two metrics. For example, DKW1 in 2030 records the largest decrease in ENS (−9.4 GWh) while simultaneously shows one of the largest increases in LOLE (+9.3 hours). This outcome does not reflect a lack of empirical robustness in the application of the feature; rather, it arises from the different dimensions captured by the two indicators in relation to curtailment sharing. Specifically, the variation in ENS reflects the net balance across all hours in which curtailment sharing produced a change in ENS, whether an increase or a decrease. By contrast, the variation in LOLE represents the number of instances in which ENS occurs in a zone (i.e., hours where ENS was zero prior to the application of curtailment sharing), without accounting for the magnitude of ENS in energy terms (GWh). Consequently, in cases such as DKW1 in 2030, the region experiences a substantial number of newly created scarcity hours, leading to a significant increase in LOLE, while the overall energy impact is dominated by reductions in ENS, resulting in a net decrease of the parameter.

Table 3 below summarizes the main variation of ENS [GWh] for all target years

Table 3 ENS variations summary statistics - all target years

Year	Sum ΔENS	Average ΔENS	Max ΔENS	Min ΔENS
2028	3.38	0.07	+4.51 *(FR00)*	-4.21 *(DKW1)*
2030	9.29	0.21	+11.87 *(DE00)*	-9.41 *(DKW1)*
2033	8.40	0.18	+9.20 *(NL00)*	-11.03 *(DKW1)*
2035	11.56	0.25	+21.06 *(DE00)*	-21.39 *(DKW1)*

The aggregate ENS variation across all bidding zones is positive, indicating that, at the European level, the curtailment sharing feature results in an overall increase in ENS. As explained by ENTSO-E in Annex II (paragraph 11.7) of ERAA 2025, this increase occurs when the post-processing application of curtailment sharing affects regions within the FB domain.

Specifically, the redistribution of flows introduced by the curtailment sharing feature deviates from the optimal “Flow Factor Competition” achieved in the main pre-CS ED simulation, which maximizes welfare. The application of curtailment sharing imposes new flow patterns across FB domain lines that are not welfare-optimal, as the optimization objective shifts from welfare maximization to the equalization of curtailment ratios. Within the network model, FB domain lines are represented as Critical Network Element Contingencies (CNECs) and are constrained by Remaining Available Capacity (RAM), which defines the maximum permissible physical load on each line. The redistribution of flows induced by curtailment sharing can therefore render RAM a binding constraint, limiting the Net Position (i.e., exports minus imports) of exporting zones experiencing domestic oversupply. The resulting reduction in exports leads to additional ENS at the system level.

Conversely, when the redistribution of flows affects NTC domains (which are not modelled as CNECs) or when RAM constraints are not binding, the system-level ENS after curtailment sharing may remain equal to the pre-CS ENS. This theoretical behaviour seems to be confirmed by the results obtained in ERAA 2025: in target year 2028 is obtained the lowest increase of system-wide ENS and, looking back to the colour map showing the increasing level of LOLE, is possible to see how indeed in 2028 most of the new activation of ENS take place in the NTC domains (Italy and the South-East of Europe).

Impact on scarcity events duration

Finally, ACER has assessed the impact of the curtailment sharing feature on the duration of ENS events. Duration is defined as the number of consecutive hours in which a target market zone exhibits ENS.

The CS feature results in a substantial increase in ENS event duration in all assessed years, ranging from a minimum increase of +63% in 2033 to a maximum increase of +79% in 2030.

This outcome reflects the effect of the CS feature. Prior to its application, scarcity events are characterized by shorter durations and concentrated in a few bidding zones. With CS, scarcity conditions are longer and redistributed across multiple bidding zones.

4.2. Empirical robustness

Relying on the results of ERAA 2025 and additional data given by ENTSO-E, ACER conducted an empirical analysis to verify the robustness of the application of the feature. The main aspects taken into consideration being:

- Local Matching constraint
- Curtailment ratios equalization and minimization
- Evolution of system-wide ENS

Conjointly with the ERAA report submission, ENTSO-E provided ACER with both pre- and post-CS hourly curtailment ratio. As described in Annex II (paragraph 11.7) of ERAA 2025, these are defined as the ratio between hourly ENS and Domestic Energy Not Served (DENS), where DENS represents the difference between domestic demand and domestic supply and is greater than zero. ACER used these values to evaluate and verify the proper functioning of the curtailment sharing process.

ACER also conducted preliminary data validation checks on the dataset provided, specifically regarding:

- **The consistency of curtailment ratio values:** based on a sample of randomly selected observations, the reported curtailment ratios were compared with ratios independently calculated from the underlying ED simulation outputs (ENS, supply, and demand). The values were found to be consistent.
- **The assessment of data quality:** for all hourly samples, both pre-CS and post-CS, the alignment between curtailment ratios and ENS values was verified. The following issues were identified:
    - for target year 2028 of the pre-CS runs, the dataset contains only null values (all curtailment ratios equal to zero), despite the presence of ENS values for the post-CS runs.
    - for Luxembourg, ENS values are reported for bidding zone LUG1 in both pre-CS and post-CS scenarios; however, all corresponding curtailment ratios are recorded as zero, indicating a lack of correspondence.
    - for Croatia and Romania, valid curtailment ratios are available for the post-CS scenario, whereas only null values are reported for the pre-CS scenario, despite the presence of pre-CS ENS values.

Accordingly, the empirical analysis presented below excludes all observations for target year 2028 and omits the affected values for the three identified bidding zones (the resulting data gaps for the three nodes are limited in scope and are not considered to materially affect the analysis).

Local Matching constraint

Local Matching (LM) is a conditional constraint, active both in the pre- and post-CS simulations, that allows a zone to have ENS>0 only if it is in a domestic scarcity situation (i.e. domestic demand > domestic supply; DENS >0). According to this principle, the curtailment ratios, defined as the ratio between ENS and DENS should be in the range [0,1] if LM is correctly applied.

This alignment has been assessed using the curtailment ratio data provided by ENTSO-E, excluding target year 2028 due to missing information. The post-CS results show full compliance with the LM constraint, as no negative curtailment ratios are observed. By contrast, the pre-CS dataset exhibits an alignment level of 99.97%, with 607 instances of negative curtailment ratios. These deviations are primarily concentrated in AT00 (221 instances) and CH00 (208 instances).

In terms of ENS outcomes, this indicates that, excluding 2028, there are 607 instances across the Monte Carlo simulations in which the LM constraint is violated in the pre-CS dataset, leading to ENS in zones not experiencing domestic scarcity. In the post-CS dataset, full alignment with the LM constraint is achieved, and the previously identified 607 cases no longer exhibit ENS. Given the very limited share of affected observations (0.03% of the pre-CS dataset), the quantitative impact on the overall results is negligible.

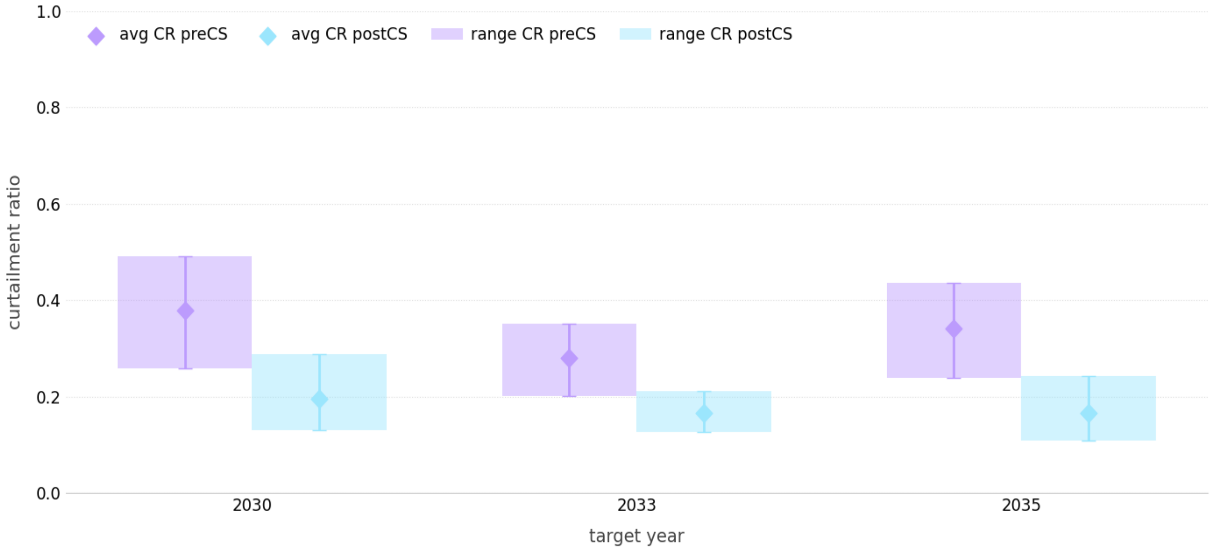
Nevertheless, these findings raise concerns regarding the empirical consistency of results across scenarios. Notably, all ENS events observed in Switzerland in the pre-CS simulations (with a maximum LOLE of 0.3 in 2030) occur in conjunction with LM constraint violations. As these violations are resolved in the post-CS scenario, no scarcity events are observed for that country after the application of CS.

Curtailment ratios equalization and minimization

The post-processing optimization of curtailment sharing aims to equalize and minimize curtailment ratios across bidding zones experiencing domestic scarcity. In order to verify such effect, ACER conducted an analysis relying on the curtailment ratios dataset given by ENTSO-E, therefore the target year 2028 is out of the scope due to missing data.

ACER first compared, for each target year, the level and dispersion of curtailment ratios across bidding zones within the same hours. To this end, ACER computed indicators on an hourly basis: for each hour

Figure 13: Boxplot of curtailment ratios - Year 2030, 2033, and 2035



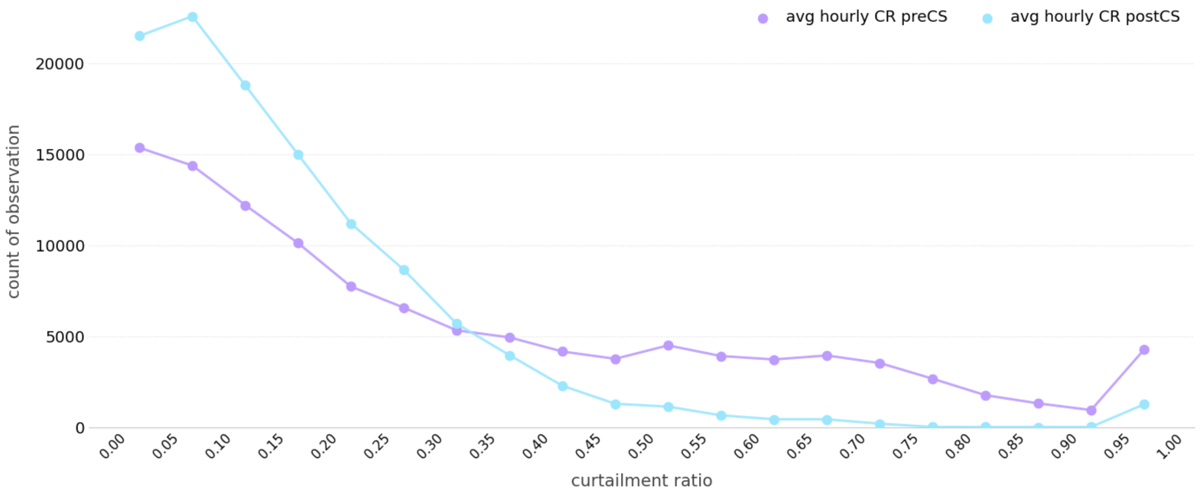
in which scarcity occurs, the average curtailment ratio across the affected bidding zones and the corresponding range between the maximum and minimum values, are calculated. These hourly results are then averaged over all scarcity hours to obtain representative values for each target year and represented in Figure 13.

For all three target years for which data are available, the application of the feature results in a lower average curtailment ratio, indicating overall minimization, and a narrower range across bidding zones, reflecting increased equalization. The magnitude of these changes is quantified below.

Year	reduction average CRs	reduction range CRs
2030	-48%	-32%
2033	-41%	-44%
2035	-52%	-33%

ACER also examined how the feature affects the distribution of curtailment ratios within the interval [0, 1]. To this end, all the hourly average curtailment ratio values across market zones for the target years 2030, 2033, and 2035 were pooled and grouped into intervals of width 0.05. The number of observations within each interval was then counted to derive the distribution presented below.

Figure 14: Distribution of average hourly curtailment ratios – cumulative Year 2030, 2033 and 2035



A comparison of the two distributions shows that, after the application of curtailment sharing, curtailment ratios are more concentrated at low values. In fact, post-CS observations are predominantly located in the lower part of the range, with a high number of cases between 0 and 0.15 and only limited occurrences above 0.45, resulting in a more concentrated distribution. By contrast, pre-CS ratios display a broader spread across the interval. Although their frequency generally declines as the ratio increases, higher values remain comparatively more common, with a relatively stable number of observations in the range between 0.50 and 0.75. This distribution analysis, together with the results on average levels and ranges, provides empirical confirmation of the expected functioning of the curtailment sharing process: hourly curtailment ratios across market nodes become both lower and more closely aligned.

As illustrated in the previous section about the impact of CS on LOLE, this outcome is achieved through the activation of additional bidding zones experiencing domestic scarcity. These zones enter scarcity conditions more frequently, thereby increasing their LOLE, but they typically exhibit relatively low ENS volumes and, consequently, low curtailment ratios. Their participation therefore contributes to the overall reduction and convergence of curtailment ratios across the system.

Evolution of system-wide ENS

The CS feature is implemented through a post-processing optimization. From a theoretical standpoint, this implies that the total hourly ENS aggregated across all bidding zones should remain unchanged between the pre-CS and post-CS values. However, as discussed in the analysis of ENS impacts, when the feature affects the FB domain it may lead to an increase in ENS, as the redistribution of flows departs from the welfare-optimal “Flow Factor Competition” achieved in the main pre-CS economic dispatch simulation.

On this basis, it is theoretically consistent for system-wide ENS to remain unchanged or to increase following the application of CS; conversely, a decrease in system-wide ENS would not be expected. An empirical analysis was therefore conducted to verify whether the observed results are consistent with this theoretical expectation. To exclude minor numerical differences potentially arising from data rounding in post-processing, the assessment focuses on cases where the system-wide ENS decrease exceeds a threshold of 0.5 MWh. The comparison of hourly ENS values between pre-CS and post-CS scenarios yields the following variations:

- In 2.4% of cases, system-wide ENS decrease by more than 0.5 MWh;
- In 1.04% of cases, system-wide ENS decrease by more than 1 MWh;
- In 0.96% of cases, system-wide ENS decrease by more than 25 MWh;
- In 0.84% of cases, system-wide ENS decrease by more than 100 MWh;
- In 0.18% of cases, system-wide ENS decrease by more than 500 MWh;
- The minimum value of system-wide ENS variation obtained is -601 MWh.

These results show that only a limited share of observations exhibits non-negligible reductions in system-wide ENS. The proportion decreases from 2.4% for reductions exceeding 0.5 MWh to 1.04% for reductions exceeding 1 MWh, indicating that such deviations have a limited influence on aggregate indicators and are not visible in average system-level results.

To illustrate these observations, ACER identified an hour in target year 2030[8] (13 December, hour 6, Monte-Carlo sample: WS 25 and FO 2). In this instance, the pre-CS ENS was concentrated in two Italian zones (ITCN and ITSA). Following the application of the CS feature, the ENS was redistributed across five bidding zones, as described in Table 4.

Table 4: Example of ENS reduction post-CS

Bidding zone	ENS pre-CS	ENS post-CS
ITCN	2196.7	418.8
ITSA	460.6	87.8
ITCS		278.0

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[8] 13 December, hour 6, Monte-Carlo sample: WS 25 and FO 2).

ITN1		1283.0
ITSI		209.6
Total	**2657.3**	**2277.3**

Critically, in this specific hour, the aggregate system-wide ENS decreased by 380 MW. This outcome is counter-intuitive and contradicts the intended functioning of the post-processing mechanism. Furthermore, a detailed review of the generation data for this sample reveals an 823 MW increase in gas-fired generation within the ITN1 bidding zone during the post-CS run. ACER notes that the availability of this additional 823 MW of capacity post-CS implies that significant generation resources remained unutilized during the initial pre-CS optimization, despite the presence of scarcity in neighbouring zones. It is unclear why the primary ED simulation designed to minimize total ENS failed to dispatch this available capacity.

Such occurrences suggest that the interaction between the primary ED and the CS may not be fully optimized or that underlying constraints are being applied inconsistently between the two steps. Consequently, ACER recommends in its Decision that ENTSO-E clarifies these cases in future ERAA editions.

5. Appendix: Detailed tables

Table 5 Summary statistics – Impact of CS on LOLE outcomes

Year	Total LOLE increase across Europe	Average LOLE increase per BZs	Maximum LOLE increase
2028	143.11	3.04 **(+92%)**	8.95 *(ITSI)*
2030	136.32	3.10 **(+121%)**	14.24 *(DKE1)*
2033	165.08	3.59 **(+99%)**	11.84 *(NL00)*
2035	164.96	3.51 **(+106%)**	14.25 *(NL00)*

Table 6: LOLE increase per bidding zone

2028		2030		2033		2035	
market node	ΔLOLE	market node	ΔLOLE	market node	ΔLOLE	market node	ΔLOLE
ITSI	8.95	DKE1	14.24	NL00	11.84	NL00	14.25
DKE1	8.49	DE00	9.98	EE00	11.72	GR03	13.57
ITS1	7.36	LUG1	9.98	DE00	10.67	DE00	12.18
NL00	7.1	NL00	9.66	LUG1	10.67	LUG1	12.18
BG00	7.07	DKW1	9.3	LT00	10.5	BE00	10.04
ITCN	6.98	BE00	8.17	SE04	9.32	DKE1	9.4
ITCS	6.45	LT00	7.72	NOS1	9.3	DKW1	9.21
SE04	6.05	SE04	7.55	DKW1	9.2	CZ00	8.97
DE00	5.86	NOS1	5.47	GR03	8.47	SK00	8.78
LUG1	5.86	PL00	4.88	BE00	8.02	EE00	8.19
BE00	5.7	CZ00	4.74	SK00	5.98	LT00	6.41
GR03	5.5	FR00	4.5	NOM1	5.9	SE04	6.04
PL00	5.16	HU00	3.15	DKE1	5.76	FR00	4.6
HU00	5.15	GR03	3.01	CZ00	5.26	AT00	3.64
DKW1	4.89	SI00	2.7	FR00	4.65	SE03	3.51
CZ00	4.82	SK00	2.63	SE03	3.83	HU00	3.23
RO00	4.44	ITCS	2.57	PL00	3.59	PL00	2.52
SI00	4.26	NOM1	2.56	HU00	3	ITCS	2.47
SK00	4.17	SE03	2.28	ITN1	2.9	SI00	2.39
NOS1	3.73	BG00	2.22	ITCS	2.27	LV00	2.36
LT00	3.71	ITN1	2.18	LV00	2.22	ITSI	2.22
ITN1	3.69	EE00	2.03	IE00	2.11	ITN1	2.12
FR00	3.57	ITSI	1.96	AT00	1.91	NOM1	2.04

AT00	2.84	GR00	1.75	ES00	1.9	ES00	1.88
GR00	2.64	IE00	1.71	SI00	1.88	NOS1	1.85
ITSA	2.53	ITCN	1.67	GR00	1.76	IE00	1.76
IE00	1.3	ES00	1.55	BG00	1.63	GR00	1.7
SE03	1.11	AT00	1.45	ITCN	1.55	FI00	1.54
FI00	1.04	RO00	1.37	ITSI	1.38	ITCN	1.52
EE00	1.02	ITS1	1.01	FI00	1.26	UKNI	1.28
NOM1	0.88	ITSA	0.52	RO00	0.97	ITS1	1.01
ES00	0.53	FI00	0.52	ITS1	0.86	CY00	0.55
UKNI	0.12	UKNI	0.36	NOS2	0.57	BG00	0.54
PT00	0.03	NOS2	0.34	CY00	0.54	ITSA	0.4
LV00	0.03	SE01	0.19	UKNI	0.53	SE01	0.26
NOS3	0.03	CY00	0.19	NON1	0.44	RO00	0.2
SE01	0.02	LV00	0.09	ITSA	0.37	NON1	0.15
NON1	0.01	NOS3	0.08	SE01	0.35	HR00	0.01
		NON1	0.03	HR00	0.01	MD00	0.01
						NOS3	0.01

6. List of Figures

7. List of Tables