European Resource Adequacy Assessment

2025 Edition

Annex 6 – Country Comments

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Disclaimer: This Annex aims to present specific national insights linked to the present ERAA, provided by TSOs on a voluntary basis. These insights reflect only the positions of the concerned TSOs who have submitted their comments and shall not be considered as ENTSO-E's statements.

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Austria

Adequacy Indicators

The range of adequacy indicators for Austria depicted in the ERAA 2025 report show non-zero potentially substantial values of LOLE and EENS for all the target years assessed (2028, 2030, 2033 and 2035). The range of average LOLE is in a range of 3 to 5h in the short term (2028) and marginally decreases in 2030 (2 to 3h). In the long-term, the LOLE reaches high values for the target years 2033 and 2035 with 4 to 12h and 4 to 13h respectively. These results show comparable expected adequacy levels compared to ERAA 2024 results in the lower boundaries of the LOLE ranges and highlight additional concerns and higher risk for security of supply in Austria in the higher boundaries, consistent with a more risk-averse approach in relation to the consideration of the price spikes in investment and decommissioning decisions in the EVA. Especially in the longer horizon (2033 and 2035), the LOLE values can go high above the 3h/year threshold taken as reference Reliability Standard (RS) for several Members States in Europe.

Ensuring security of supply in Austria, especially beyond 2030, remain challenging, despite a revision of the ERAA Central Reference Scenario (CRS) data, which included a reduction of the electrification targets, an increased foresight on the availability of the aging existing gas-fired fleet and an increase of the policy and climate targets for RES deployment (mainly solar PV and wind onshore) consistent with the Austrian NECP, as shown in the table below.

ERAA 2024 and 2025 CRS Data	2028	2030	2033	2035
Electricity Demand ERAA 24[1] [TWh]	82,0	89,0	-	107,0
Electricity Demand ERAA 25[2] [TWh]	77,4	82,7	86,1	90,2
Wind Capacity ERAA 24 [GW]	7,3	9	-	10,3
Wind Capacity ERAA 25 [GW]	6,7	8,4	9,4	10,0
Solar PV Capacity ERAA 24 [GW]	10,6	13,0	-	23,4
Solar PV Capacity ERAA 25 [GW]	16,3	21,0	27,0	31,0
Gas-Fired Capacity ERAA 24[3] [GW]	3,7	3,3	-	1,3
Gas-Fired Capacity ERAA 25[3] [GW]	3,7	3,3	2	1,8
PSP Capacity ERAA 24 [GW]	4,4	6,1	-	7,3
PSP Capacity ERAA 25 [GW]	4,3	6,1	7,5	7,5

[1] Electricity demand reports final energy consumptions, including grid losses and energy sector own consumption.
[2] Electricity demand energy consumptions, including grid losses.
[3]Gas-Dired Capacity excluding “Other non-RES” technology type.

Building on the experience matured in ERAA 2024, these results confirm that, despite the expected internal growth of RES capacity and the commissioning of key strategic hydropower projects, the expected growth of the electricity demand and the pervasive electrification of the industrial, heating and transportation sectors can pose significant challenges to maintain the highest desired level of domestic security of supply in Austria, given the high dependency on imports of scarce surplus generation during simultaneous scarcity event in the CORE region, as highlighted by the Causal Analysis in Annex 4. Therefore, the resilience of the system needs to be supported by securing availability of flexible resources, especially paving the way to a reliable and decarbonized system for Austria already in 2040.

APG (the Austrian TSO for electricity) closely monitors the domestic availability of resources to ensure resource adequacy in Austria in all time horizons, from the short to the mid-term and especially in the long-term perspective. Aside from the range of average adequacy indicators addressed above, particular attention needs to be reserved to the P95 values of Loss of Load Duration (LLD), indicating that 5% (27 out of 540) of the combined climate and outage scenarios assessed in ERAA have a number of load disruption hours higher or equal to the reported P95 value. The P95 indicators show an increase compared to ERAA 2024 with ranges that exceed 20h/year for all target years assessed, with concerning peak P95 values of 51/year in 2033 and 64h/year in 2035. Such adequacy indicators substantiate the sensitivity of the power system to several stressing factors such as (i) peak-load high dependence to the outdoor temperature profiles (e.g. due to residential heat pump loads) and (ii) increased risk of simultaneous adverse conditions from both demand and generation side (e.g. dunkelflaute events).

APG keeps monitoring the national level of adequacy to provide both the TSO and the national key stakeholders with tailored and complementary insights on the domestic adequacy indicators, complementary to the ones reported in the ERAA 2025 report, especially considering the peculiar characteristics of the Austrian power system, which cannot be properly reflected in a European reference study such as the ERAA. Highlighting possible future risks to the security of supply is crucial to ensure the timely preparation, planning and implementation of any potential necessary instrument enabling the required level of flexibility and adequacy resources are available when needed. Two necessary pre-conditions are the foundation of a legal basis to conduct a National Resource Adequacy Assessment (NRAA) and the establishment of a Reliability Standard for Austria. Both elements are foreseen as part of the ongoing drafting of the new national Power Act (ElWG).

Economic Viability Assessment

A key factor that affects generation resource adequacy is the economic viability of existing thermal generators. The EVA of ERAA 2025 indicates that between 190 MW and ca. 400 MW of existing CCGT and OCGT thermal generation capacity are at substantial risk of “early decommissioning” in the mid-term perspective (2028 - 2030) in relation to their economic viability. APG welcomes the improvements included in the EVA of ERAA 2025, such as the enhanced hurdle premiums for gas expansion candidates, as well as addressing in more details one aspect of the high uncertainty intrinsic to long-term investment decisions, by means of the introduction of the revenue cap as complementary risk aversion measure towards the investor’s reaction to price spikes, also substantiated by the corresponding consultation of market participants. The range of EVA results for Austria presented in the ERAA 2025 report are consistent with the current and foreseeable system operation, where a substantial part of Austria’s thermal generation capacity is already today maintained operational through a network reserve mechanism. APG monitors closely the availability of Austria’s thermal generation capacity, given its critical importance to ensure not only resource adequacy, but also a safe and secure operation of the national electricity grid. The current assumptions as well as the actual economic viability of such plants depict potential higher risk of mothballing or even early decommissioning over the next decade, highlighting the significance of complementary mechanisms to maintain enough flexible generation resources operational in Austria.

Belgium

Economic Viability Assessment

We refer here to the EVA results of ERAA 2025. These are based both on the total cost minimization approach and the revenue stream approach.

Since the observed economic decisions of the ENTSOE EVA protocol might not represent fully credible investor decisions, two different modelling approaches regarding risk aversion of investors are considered in ERAA2025: i) Hurdle premiums, updated to properly account for the volatility of revenues observed in ERAA 2025 simulations and ii) a revenue cap to account for the fact that investment which profitability is ensured by extreme price spikes, is typically not considered as a reliable investment by investors.

The results indicate that not all existing capacities subject to 'Life Time' Extension would be profitable and that the ones profitable rely on extreme price spikes to ensure profitability, if relying on revenues from the Energy only Market (EoM). "Net expanded capacity" as reported in Annex 5 refers to 'Life Time' extension units only

No expansion of new thermal capacity subject to EVA (expansion of nuclear is not considered in the EVA of ERAA) is found in the results. These results confirm the trend observed in Belgium over the past recent years, as there is no incentive for new build thermal capacity in Belgium, if relying on revenues from the Energy only Market (EoM).

These results confirm that CRM revenues are important to ensure the economic case of existing units and for the appearance of new thermal capacity both Belgium throughout the period 2028-2035.

Adequacy Indicators

The adequacy indicators for Belgium in the ERAA 2025 show values of LOLE > 3h (higher than the Reliability Standard for BE = 3h) for all the target years assessed (2028, 2030, 2033 and 2035) as eg indicated in Figure "Overview of adequacy risk compliance with established reliability standards" in the ERAA2025 Executive Summary. It is important to note that the data and assumptions for Belgium are coherent with the latest Adequacy and Flexibility study for Belgium (2026-2036),[1] considering the period of data freeze by ENTSOE (data collection end of 2024; Call for Evidence 31 March – 22 April 2025).

The results of all known CRM auction at the time of the data freeze by ENTSOE have been considered in the input data. Note however that the results of CRM auctions which have occurred after the data freeze period are not considered in the input data of ERAA2025. The LOLE >3h results confirms that the CRM is an appropriate and necessary measure to ensure the adequacy levels of Belgium but also highlights that the level of adequacy of Belgium heavily relies on the level of SoS and hence the assumptions of its neighbors (notably FR, DE, UK..) which are beyond Belgium's control. Therefore, a prudent approach is necessary regarding the level of SoS in Belgium. Furthermore, the results stress the importance of the Belgian CRM to ensure the desired level of adequacy in Belgium.

[1] https://issuu.com/eliagroup/docs/adequacy_and_flexibility_study_for_belgium_2026-2?fr=sZGQ5Njg2NjM5NTg

Bulgaria

Following the completion of the ERAA 2025 data submission, the Bulgarian Ministry of Economy released a revised version of the national NECP. This updated plan will be integrated into the ERAA 2026 data collection, ensuring that future assessments reflect the most current national policy framework and updated sectoral trajectories.

Bulgaria’s ERAA 2025 dataset is fully aligned with the previous NECP for demand, thermal capacity, and electrolysers for both 2030 and 2035. The NECP provides a long-term outlook up to 2050, but its five-year step structure required interpolation for intermediate ERAA target years, introducing minor smoothing across adequacy-relevant variables. All assumptions were validated with the national regulatory authority, ensuring consistency with officially approved national planning.

No significant deviations are reported between ERAA and TYNDP datasets for Bulgaria, supporting stable adequacy modelling across frameworks. Bulgaria is also not listed among countries expecting adequacy deterioration or improvement compared to ERAA 2024, indicating no major year-on-year adequacy shifts. With no policy or market-driven changes expected before November 2025, the dataset remains stable for the current assessment.

Overall, Bulgaria provides a consistent dataset, with predictable demand, RES, and thermal trajectories. The main modelling consideration continues to be the NECP’s limited temporal granularity, which required interpolation but does not materially affect adequacy robustness.

Czech Republic

Since the start of 2025, the Czech Republic is preparing the notification process of a capacity mechanism, which would help mitigate inadequacy issues, which are expected as early as 2028, with the possibility of first auctions during 2026. The Czech Republic has already taken initial steps in this matter and has prepared a Market Reform Plan defining the resource adequacy issue, which is currently under discussion with the European Commission. To proceed with this Market Reform Plan, it is necessary to determine the magnitude and structure of the missing capacity according to the ACER recommendations for adequacy assessment studies at the European and national levels. The Czech Republic is currently working on defining the required capacity level within capacity mechanisms to ensure resource adequacy. Due to the indicated timeframe, an accelerated negotiation procedure with the European Commission in accordance with the new Clean Industrial Deal State Aid Framework (CISAF) has been chosen. According to CISAF, the determination of the need for a capacity mechanism must be based on the latest available central reference scenario developed within the ERAA and approved by ACER. Therefore, the supporting material will be largely based on ACER-approved ERAA 2024 results, except several missing values (VOLL, CONE), which will be adopted from the latest national resource adequacy assessment. The results of ERAA 2025, especially the distribution of scarcity events and capacity addition needs are also analyzed in order to identify the Market Reform Plan needs.

Contrary to last year's edition, the input data for ERAA 2025, were largely based on the updated NECP, published in December 2024. The NECP features slightly more ambitious approach to RES development needed to achieve the EU climate goals.
The thermal resources' data were still provided according to the best estimate from operators, with many indicating earlier end of operations than provided in ERAA 2024. The demand prediction of the NECP indicates significantly slower growth of electricity consumption (73 TWh in 2035) compared to the best estimate from ERAA 2024 (83 TWh in 2035). On the demand side, the NECP prediction does not include the behind-the-meter consumption of prosumers, yielding a slight (1 TWh) underestimation of the total demand.

The results indicate significant issues with resource adequacy, with the LOLE values in all target years exceeding the Czech reliability standard (6.7 h/y). Compared with ERAA 2024, the LOLE values have increased sharply in nearly all target years (except 2028). The range of LOLE values generally increases with time, which shows the inability of new (gas and renewable) capacities to balance the coal phase-out effect. The expansion of nuclear capacities (2.5 GW planned by 2040) also mostly falls beyond the studied horizon of ERAA 2025.

There are significant risks regarding the expected development of the Czech energy mix. The EVA suggests an emerging capacity (760 – 900 MW) of Hydrogen CCGT plants in both 2033 and 2035, intended to gradually replace the remaining lignite capacity (1.7 GW), retired by 2028 due to non-rentability of coal-based power production. Despite the proposed rentability of Hydrogen CCGT plants – enabled by the large number of events with high price of electricity and the expected competitive price of hydrogen – it needs to be explicitly mentioned that hydrogen plants are still an emerging technology which is not prioritized by the investors (as indicated in the TSO input data, which do not include this technology at all). Furthermore, the emergence of Hydrogen CCGT plants also assumes that a robust hydrogen infrastructure has already been developed by 2033. The national hydrogen strategy for 2030 considers hydrogen production in Czechia for local industrial use and in longer time horizons the gradual development of infrastructure needed for significant

imports of green hydrogen. Therefore, although this technology may be considered by the investors, its emergence cannot be guaranteed. The more likely scenario is the development of similar capacity of CCGT plants supplied by LNG and supported by the newly developed capacity mechanism.
The wind capacity expected by the NECP appears to be significantly overestimated compared to recent trends, as there is no indication that the barriers inhibiting the wind development (mainly the NIMBY effect) are being overcome, despite an update in legislature aimed at designing acceleration zones for RES development and auctions for wind capacity support.

In summary, the results of ERAA 2025 indicate higher risks of inadequacy for Czech Republic than the previous edition. Contrary to the expectations from the input data, the significant decrease in demand does not balance out the expected decrease in capacities, indicating a Europe-wide lack of available capacity during hours of high demand. There are significant risks associated with the expected development of new capacities, mainly the Hydrogen CCGT plants suggested by EVA and the wind capacities predicted by the NECP. The results of ERAA 2025 will be considered in the ongoing Market Reform Plan.

Denmark

Submitted data for Denmark
The overall trends for Denmark have changed noticeable between the data submitted to ERAA 2024 and ERAA 2025. New political statements have been published regarding offshore wind plans in Denmark and additional postponing of the Danish energy island project at Bornholm, which means postponed interconnector capacities and offshore wind capacities.

Comment on the methodology and the results for Denmark
Over the next decade, Denmark is expected to become increasingly reliant on electricity imports during scarcity situations to ensure resource adequacy. Hence, the development in the resource adequacy situation across Europe, especially in North & Central Europe, is very important for Danish resource adequacy assessments. This trend is also reflected in the Danish NRAA25 and can be seen in ERAA 2025s results for Denmark. When the adequacy risk increases in Denmark's neighboring countries, the Danish adequacy risk increases as well and vice versa. This dynamic is especially visible between Denmark and Germany. The significant decommissioning of capacity by EVA in the short term, increases the adequacy risk across Europe, thus likewise affects the Danish adequacy results. Further, the EVA results show a commissioning of conventional gas power in Denmark, which potentially is not in accordance with the NECP-goal of climate neutrality in 2045[2].

In this year's EVA, two different methodologies to represent risk aversion are included: the "central reference scenario with the enhanced hurdle premium combined with a revenue cap" and the "central reference scenario with the enhanced hurdle premium only". Both approaches use an updated selection of Weather Scenarios and an increased Hurdle Premium compared to ERAA2024. The "central reference scenario with the enhanced hurdle premium combined with a revenue cap" additionally introduced a revenue cap reflecting additional measures.

For both outcomes of EVA, ERAA2025 identifies a higher adequacy risk compared to the previous edition. The combined risk aversion approach results in extreme LOLE-values of nearly 100 h/year in Denmark in 2035. This is a huge difference compared to outcomes of earlier ERAA editions, which had an order of size of 20 h/year. These increased values are a direct consequence of the methodological changes in EVA, especially the introduction of the revenue cap.

Energinet welcomes the fact that ENTSO-E has attempted to address the concerns from stakeholders, who have pointed out that investors in production capacity are not willing to base their investments on a few scarcity pricing hours in the day-ahead market. Energinet is dedicated to a thorough assessment of investment risks and recommends ensuring that methods reflect expected market conditions and thus recommends to further refine the method for the "central reference scenario with the enhanced hurdle premium combined with a revenue cap" approach, through further iterations and robustness checks.

The same is valid for the selection of weather scenarios for the EVA. The ERAA 2025 results are based on a selection of slightly warmer than average weather years, which could contribute to lower investments in the energy system. A broader set of representative weather scenarios should improve the EVA-ED-consistency and better capture system risks.

[2] https://www.stm.dk/statsministeriet/publikationer/regeringsgrundlag-2022/

Energinet welcomes the focus and ongoing work of representing curtailment sharing as precise as possible in the ERAA, compared to the algorithm used in the single day ahead market coupling (EUPHEMIA) and is looking forward to potentially seeing the method being further refined in the ERAA 2026.

Finland

In Finland, the adequacy of electricity supply faces its greatest challenges during the winter season, particularly during cold and calm weather periods with high demand and low wind generation. During these periods, Finland needs electricity imports to cover the peak demand, especially in case of forced outages or extreme cold. Therefore, most adequacy challenges are faced during the coldest years, which also drive up the average values for the adequacy indicators in Finland. This can be observed from the Annex 3 detailed results as high P95 values for the adequacy indicators, as well as Annex 4 from the high native demand percentiles as well as low availability of renewables during the scarcity events.

The adequacy risks in Finland have lowered in short-term due to commissioning of new Aurora Line interconnector but are seen to increase in mid- to long-term due to retirement of CHP capacity and increasing demand. The EVA results indicate that CHP capacity is at risk of being retired earlier than currently expected, which would lead to adequacy risks higher than the Finnish standard for system reliability (2.1 h/a) already by 2028. The results also show that adequacy risks increase by 2030 and are at highest in 2033 with LOLE up to 8–13 h/a (range depending on the method of analysing investor risk). By 2035 the risks stay high but are lowered due to commissioning of new interconnectors, however, these have been postponed for ERAA 2026 due to uncertainties in the timeline. In addition to the scarcity hours, Annex 4 details that the scarcity events are up to 1–4 GW. Also, the duration of the events is from single hours up to 56 hours with the duration increasing in the 2030s.

Overall, the adequacy risks identified in mid- to long-term are highly dependent on the development of the thermal capacity as well as demand and DSR. The increasing risks show that there is likely a need for measures to support adequacy in mid- to long-term, especially in the 2030s. Currently, Finland has a strategic reserve measure in place until 2032, however, no capacity is contracted to the reserve. Instead, the National Emergency Supply Agency has acquired the Meri-Pori coal power plant until the end of 2026 for so-called “crisis reserve”, which is an out-of-market reserve for severe disruptions and emergencies to guarantee security of supply. The detailed results of this report show that there is need for more flexible capacity in the system that can answer to the different needs in the system. To answer to the potential needs, the government established a working group that in June 2025 delivered a report on a non-fossil flexibility scheme. Fingrid perceives well-designed support scheme to ensure adequate electricity supply in Finland as a positive development.

France

General considerations – ERAA and NRAA
Given the importance now taken by ERAA exercises with regard to the justification of a capacity mechanism for a Member State, RTE considers that it is important to specify (i) the points of convergence but also (ii) the limits of the ERAA compared to what RTE considers as the state of the art and implements itself in its « Bilan Prévisionnel » for security of supply analysis on the French electricity system. These limits are likely to explain differences in results between ERAA and BP.

Both *Bilan Prévisionnel* and ERAA are based on the ACER methodology and therefore share the same fundamentals and have many similarities. In particular:

- they are largely based on information reported by TSOs in Europe,
- they cover a wide geographical perimeter,
- they provide a rigorous study of system adequacy in a central reference scenario,
- their analyses are based on a probabilistic optimization model (economic dispatch),
- they both conduct economic viability analyses (EVA).

However, some aspects of the implementation of this methodology differ, which can be explained by their different objectives. ERAA aims to provide a European-wide vision of the power system and its overall adequacy. It therefore adopts a broad, cross-country approach with some simplifications in the modelling.

ERAA is a reference study for assessing adequacy at European level, which directly feeds into the national adequacy studies conducted in France by RTE as part of its legal mandate. As a result, many of the assumptions used in RTE's forecast balances are taken directly from the ERAA.

On the other hand, the Bilan Prévisionnel presents a more precise and detailed view of the French situation and complements the ERAA by incorporating several specific features of the French electricity system and factors determining the security of France's electricity supply.

Firstly, it is necessary to consider the significant temperature sensitivity of the French electricity consumption, which requires specific modelling of the national power demand during extreme cold spells. Secondly, the significant share of nuclear power in the French mix means that security of supply is highly dependent on the availability of nuclear power plants, making it important to accurately represent the risks of nuclear unavailability in statistical terms. Finally, these specific characteristics have also historically led to very high variability in winter consumption peaks in France from one year to the next, resulting in considerable uncertainty as to whether price spikes will occur, depending on weather conditions.

This high level of uncertainty creates a significant risk to the revenues of the generation and demand-side capacities, which can have an impact on the decisions (investment, decommissioning, etc.) taken by operators. This issue of inter-annual revenue variability and the associated risk for capacity providers has long been identified and documented in France, particularly at the time of the implementation of the capacity mechanism in 2017.

These characteristics of the French electricity system therefore play an important role in the modelling used for the Bilan Prévisionnel developed by RTE, whereas they are often integrated in a more simplified manner in ERAA.

These differences (i) in implementation as well as (ii) in the underlying assumptions are sufficient in themselves to explain differences in results between BP and ERAA even if these differences are not systematic. RTE wishes in particular to point out:.

- A different climate database, with a wider statistical modelling of climate conditions, using 200 weather scenarios, to capture the effect of high thermosensitivity in France
- A broader modelling of uncertainties regarding nuclear availability, in order to capture the impact of forced and planned outages on the French security of supply
- A different approach to represent European Adequacy where economic viability for the french system is assesed in the BP under the assumption of no extensive over- or undercapacity with regard to their respective reliability standard.
- While the representation of risk aversion in the economic viability assessment (EVA) in ERAA25 is improved to be in line with concrete industrial practice of investment and operation decision-making process, it treats this as an exogeneous parameter and not as part of the overall model.

ERAA 2025 evolutions

RTE had identified in ERAA 2024 several critical points in ENTSOE's modelling, namely the lack of EVA/ED alignment, as a consequence of the low number of Weather Scenario modelled in the EVA, the critical lack of representativity regarding nuclear availability dispersion[3], and the size of flow-based domains.

The two latter issues have been addressed in this new edition of ERAA, as well as several other minor points. RTE salutes the progresses made in this new edition regarding the inclusion of spread in nuclear availability, the revised flow-based domains, as well as the revision of risk-aversion modelling. RTE believes these advances should be capitalized on and used for further ERAA editions.

Still, RTE believes that because of the inconsistencies between EVA and ED, and because of the single *without CRM* reference scenario, the results of ERAA must be read jointly with those of the upcoming French NRAA to properly assess the French security of supply.

Moreover, RTE salutes the inclusion of a Revenue-Based EVA dedicated Annex, which appears to give promising results and would allow for both better understanding of EVA results and, in future editions hopefully, a better grasping of investor risk-aversion. One of these implementations showcase the methodology and implementation of Revenue-Based EVA developed jointly by RTE and other TSOs.
For further editions of ERAA, RTE encourages the continuation of the improvement work, by taking into account even more variability in hypotheses, especially in the EVA. In general, RTE welcomes

[3] The results shown in proof of concept annex on nuclear availability of ERAA24 is a progress according to RTE, but RTE deplores it was relegated to an Annex and deprived of legal value, since it is only through quantitative, broad analysis that robust results can be attained.

the work currently underway in the ERAA Repurposing Task Force as it leads future editions towards greater methodological robustness.

The National Energy and Climate Plan

The updated version of the French NECP has been submitted to the European Commission mid-2024. It relies on three framework documents, the National Low-Carbon Strategy, the National Plan for Adaptation to climate Change and the Multiannual Energy Plan, under public consultation at the time of writing. These documents provide a roadmap for the energy sector in the coming years. The new NECP is also supported by RTE's latest National Resource Adequacy Assessment.

It integrates the *Fit for 55* package in the French energy roadmap, with ambitious RES development targets, but also carries a new nuclear strategy, with expectations of expanding lifetime of several nuclear units up to 50 years and the building of several new reactors. These developments support the target of decarbonisation through a rapid electrification of uses to reach *Fit for 55* targets and carbon neutrality by 2050.

Load forecast provided for 2028, 2030, 2033, 2035

After remaining stable over the past decade, the French electricity demand fell in 2022 (461 TWh, i.e. 12 TWh less than in 2019). This decrease happened after the COVID crisis and can be explained by a combination of sufficiency from consumers and high market prices.

In 2024, electricity consumption in France has stopped falling (+0.7% corrected consumption between 2024 and 2023 according to the latest national electricity balance).

In the medium term, French electricity demand is expected to rise from 2025 horizon, according to decarbonisation acceleration scenarios. The recovery of economic activity and the development of electricity as a decarbonisation vector is expected to counterbalance the effects of energy efficiency actions on the annual demand. Furthermore, to meet the *Fit for 55* target, RTE provided this ERAA with a reference load scenario, which was presented as well in the 2023 NRAA, the *Bilan Prévisionnel* (published in September 2023). This trajectory has been updated in 2025 for the new edition of the French NRAA: the next edition of ERAA will feature this updated load forecast. While slightly revised downwards, the conclusions remain unchanged.
Main drivers of this rising demand are:

- Approximately 9% of the French electricity demand dedicated to hydrogen production by 2035;
- Approximately 40% of the vehicle fleet and 20% of trucks will be electric by 2035;
- Increasing the share of electricity in heating systems and industrial processes.

Net generating capacity forecast provided for 2026, 2028, 2030, 2035

The scenario presented in the 2024 ERAA follows the NECP's evolutions on short term trajectories of electricity production:

- Accelerated development of RES (wind and solar capacities are multiplied by more than three in the next ten years);
- Concerning the last two coal units, Cordemais operator recently announced a full production stop by March 2027. For Saint Avold, the operator has announced a conversion of the power plant;
- The new Flamanville nuclear unit is gradually operating as of 2025;

- No commissioning of new thermal fossil units is authorised according to current regulation.

National view on adequacy and economic viability
The key messages from the NRAA, in the works and about to be published by late 2025 regarding adequacy in the policy target scenario are:

- Security of supply in France has improved and is expected to remain high within the couple next years should a capacity mechanism remain in place, to secure existing capacity.
- From 2030 on: a need for new capacities has been identified with electrification for decarbonisation, which can be fulfilled by several combinations of demand-side response and production. This capacity needs to be secured thanks to a capacity mechanism.

On a general basis, ERAA 2025 appears more aligned with the ongoing works for the current French NRAA on security of supply concerns in France than ERAA 2024. Both ERAA 2025 and the French NRAA for 2025 identify adequacy concerns from 2028 on to 2035, once taking into account the impact of the economic viability if there was no capacity mechanism.

As already mentioned, some technical simplifications of ERAA 2025 linked to the global complexity of calculations raise specific attention points. Mainly, the low number of Weather Scenarios used in the optimisation-based EVA (3) can lead to result instability, as one of these years only may carry drive for investment depending on the selection of the climate years in the study. Moreover, this precarious equilibrium between expansion costs and scarcity revenues may not represent fully a real risk-averse behaviour in capacity commissioning. RTE believes that the undergoing work on *revenue-based* approaches would support solving these limitations while being in line with the ACER methodology, and allowing for a higher number of Weather Scenarios.

Still, the results of this latest edition of ERAA are aligned with that of the upcoming French NRAA, as was already the case for ERAA2023 and 2022, identifying adequacy concerns in France throughout all temporal horizons. This questions the representativity of ERAA2024 results for France in this global trend.

Germany

Input data
The scenario input provided by German TSOs reflects the current legislation and policy targets in Germany at the time of the data collection (end of 2024). The scenario "With Additional Measures (WAM)" of the German National Energy and Climate Plan (NECP[4]) published in 2024 builds the framework of ERAA 2025. It is supplemented by the draft of the Scenario Framework for the German Network Development Plan[5] for Electricity (NEP 2037/2045 (2025)), and the legally mandated process on determining the need for grid reserve generation capacity for congestion management called "Systemanalyse 2025[6]". More relevant information about the input data and clarifications regarding the call for evidence of ERAA 2025 input data are elaborated further below.

Renewable energy sources
The development of RES capacities is based on short-term forecasts and project information while also taking into account policy targets. While the expansion of PV has increased in recent years and is on track, the expansion of onshore wind falls short of expectations and probably leads to an achievement of the target '115 GW in 2030' two years later.
The values for offshore wind capacities are based on actual project information. The target of 30 GW offshore wind in 2030 cannot be met due to project delays but will be made up one year later, what has been already communicated in the non-binding offshore agreements.
Due to the expectation of a less steep increase in electricity demand until 2030, there are public and political discussions about reducing the RES capacity targets in favour of the goal to supply 80 % of the electricity consumption by renewable energies. If this were implemented, it could result in a slower expansion of renewable energies in the future.

Demand
The electricity demand assumptions in ERAA 2025 are based on two mentioned national studies and align closely with the projections in Germany's National Energy and Climate Plan (NECP). For earlier target years, demand is lower compared to previous ERAA editions due to anticipated delays in electrification. The political target of 750 TWh gross electricity demand for 2030 is not expected to be reached before 2031.
Since the submission of ERAA input data, the German Federal Ministry for Economic Affairs and Energy (BMWE) has published a study[7] indicating that gross electricity demand in 2030 is expected to range between 600 and 700 TWh.

Coal phase out
The ERAA 2025 input data with regard to the decrease of coal-fired power generation capacities is similar to ERAA 2024 and represents the legally mandated phase-out by 2038. An accelerated phase-out by 2030 was not considered as there are no legal regulations planned to support this. Both planned decommissionings at the plant operators' own discretion and legally mandated decommissionings (also as result of decommissioning auctions) are taken into account. The remaining coal-fired power plants are subject to the EVA to maintain the possibility of an earlier and market-driven decommissioning.

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[4] Update of the Integrated National Energy and Climate Plan
[5] Network Development Plan Electricity | Network Development Plan
[6] Systemanalysen 2025
[7] BMWE Newsletter Energiewende | Monitoring report on the status of the energy transition

Gas and hydrogen power plants
In contrast to ERAA 2024, the input data for the ERAA 2025 does no longer consider the power plant strategy of the former Federal Government, because it is no longer pursued by the present Government in its previous form, but currently under revision.
For existing natural gas power plants, a fuel switch to hydrogen was modelled applying a technology adoption curve. By 2035, a share of about 50 % is reached which corresponds to 16.5 GW of hydrogen power plants. The ambition of the present Federal Government in May 2025 to enforce a fuel switch to hydrogen appears to be reduced. Therefore, the capacity of hydrogen power plants may be overestimated in ERAA 2025. Respectively the amount of natural gas power plants may be underestimated.

Reserves
Input data on German non-market resources contain:

- Capacity reserve: until 30 September 2026, a total contracted capacity of 1.1 GW of power plants is available for resource adequacy events. These power plants must be available within twelve hours. Currently, no capacity reserves have been contracted beyond that date.
- Grid reserve: This is used to resolve congestion and contains different types of power plants in Southern and Western Germany. It comprised a total capacity of 6.3 GW in January 2025.
- Special network equipment power plants: These are fast-starting power plants with an overall capacity of 1.2 GW, primarily intended to restore system security after a disturbance in the transmission grid and are available for curative redispatch. These units are not part of the reported data.
- Ancillary services: FCR of 564 MW and FFR of 2600 MW (positive).

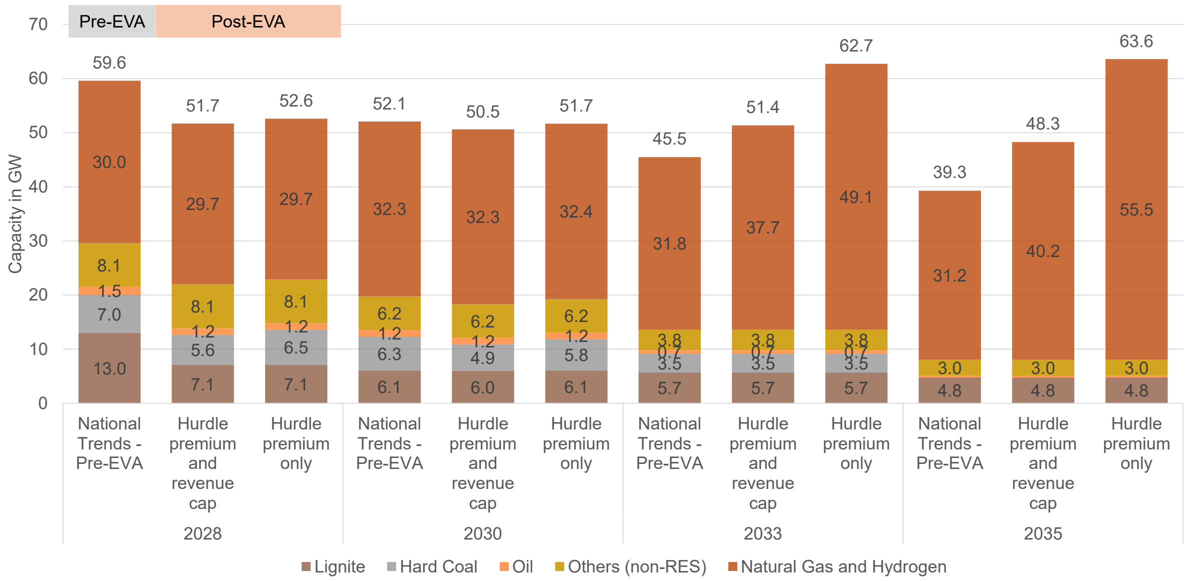
Home storage battery systems
Home storage battery systems are divided into two categories. Market participating batteries optimize their behaviour based on market prices, while out-of-market batteries optimize their usage based on households' self-consumption. While in 2028 only a small share is market-driven (0.7 GW of 22.7 GW) in 2035 this share is much higher (11.5 GW of 47.8 GW). This modelling is different to ERAA 2024, where it was assumed that also a part of self-consumption batteries will participate in the market during winter months.

Utility scale Batteries
In ERAA 2025, the installed capacity for utility scale batteries is based on national processes and a market survey on planned battery storage projects. In 2028, 14.3 GW utility scale batteries are assumed. This number grows to 28.1 GW by 2035. In line with national studies, these batteries have an average energy to power ratio of 2. As the developments in the utility scale battery sector are very dynamic, more recent estimations assume an even faster buildout.

DSR
ERAA 2025 models load shedding and load adding DSR, while shiftable DSR is not modelled. A part of the shiftable DSR has been assigned to load shedding DSR based on the recovery time. DSR processes with a very short recovery window have not been considered as flexible. In 2028 1.5 GW of load shedding DSR are assumed, this value rises to 5.3 GW in 2035.

Comments on the results
In ERAA 2025, no additional controllable capacity based on subsidies, as was envisaged in the draft of the German Power Plant Safety Act, is assumed, as capacity remuneration mechanisms (CRM)

and technology-focused tenders remain under political discussion. This exclusion significantly impacts economic viability and adequacy results.



The results of the EVA suggest a sharp decline in lignite and hard coal capacities, with market-driven decommissionings in 2028 and partially in 2030, driven by the changed residual load structure and reduced full load hours. After 2030, the legally mandated coal phase-out trajectory determines the remaining coal capacity. For units that stay in the system beyond 2030, low capacity factors impose a challenge on economic viability, as revenues increasingly depend on scarcity hours during extreme conditions. This uncertainty could accelerate early retirements of coal capacities ahead of EVA projections, further stressing adequacy.

The range of the EVA results highlights the uncertainty of market-driven investments in new capacity. Under the "hurdle premium and revenue cap" risk aversion approach, controllable capacity reaches 48.3 GW in 2035, whereas the "hurdle premium only" approach leads to a controllable capacity of 63.6 GW. Significant market-driven gas capacity expansion is visible from 2033 onwards. Even assuming a stronger risk aversion of investors, a market-driven addition of 5.9 GW of gas-fired open-cycle gas turbines occurs. Under the assumption of a higher risk tolerance, this figure rises to 17.3 GW. By the year 2035, an additional 2.5 GW (higher risk aversion) or 6.4 GW (lower risk aversion) is added, respectively.

The range of investments clearly illustrates that the absolute volume of market-driven capacity additions in Germany is more influenced by the modeling approach to investor risk behavior than in any other European country. At the same time, the results of previous ERAA editions, together with recent findings from the revenue-based EVA simulations, show that the regional distribution of investments in peaking capacity tends to vary considerably. When uncertainties related to actual investor behavior are added to the assessment, this further exacerbates the sensitivity to input data, methodological assumptions, and market conditions.

The LOLE values increase sharply under the "Hurdle premium and revenue cap" risk aversion approach: from 20.9 hours in 2028 to 30.8 hours in 2030, then jumping to 78.6 hours in 2033, and reaching 97.4 hours by 2035. In contrast, the "Hurdle premium only" approach remains at lower levels, rising from 14.3 hours in 2028 to 19.6 hours in 2030, 19.9 hours in 2033, and 24.0 hours in

2035, reflecting the combined effects of the ongoing coal phase-out and insufficient market-driven new builds.

The adequacy results show that with both risk aversion modelling approaches Germany fails to meet its reliability standard in any target year. Since the 2.77 h/year LOLE threshold is exceeded, the result of ERAA 2025 legitimates the introduction of a capacity mechanism in Germany.

Investment risks and market signals
Similar to ERAA 2024, the profitability of new gas units remains highly dependent on scarcity hours, which occur mainly under extreme climatic conditions. Without robust support mechanisms such as capacity remunerations, market-driven expansion under different investor risk aversion preferences appears insufficient to meet the reliability standard. Recent evaluations of electricity demand trajectories[8] present an additional challenge for planning the development of secured generation capacity. Due to the delayed and partially uncertain electrification of final energy consumption, the actual capacity need to ensure a reliable supply system constitutes a dynamic parameter that must be continuously recalculated and reassessed.

Comparison with the NRAA
The German NRAA "Versorgungssicherheit Strom Bericht 2025[9]" was published on September 3, 2025. This report shows a net additional capacity need of 12.5 GW (total new build of 22 GW, compensating decommissioning of existing gas units) by 2035 in the central scenario, and 25.6 GW (total new build of 35.5 GW) in a second scenario characterized by delays in the expansion of renewable energy, demand flexibility, and interconnectors. Both scenarios anticipate an ambitious electrification rate and, at the same time, a high degree of demand flexibility. The assumed electrification rate is aligned with the legal and political targets in force at the time the scenarios were designed and is in a similar range to the assumptions considered for ERAA 2025. The high degree of demand flexibility considered in the central scenario leads to a market-driven decommissioning of installed capacity of stationary utility scale batteries from 1.6 GW in 2024 to 0.8 GW in 2035. In the sensitivity scenario, a slight increase to 2.0 GW by 2035 is observed. In comparison, 14.3 GW of utility scale batteries are projected for 2028 in ERAA 2025. This figure rises to 28.1 GW by 2035.
With the reported market-driven expansion, the security of supply can be guaranteed in both scenarios, i.e., after deployment of the considered out-of-market reserves, the German reliability standard of 2.77 h/year is met.
Adequacy results in both the German NRAA and ERAA 2025 largely depend on the economic viability of dispatchable capacities. Realistically reflecting risk aversion in market actors' entry and exit decisions is one key component. Differences in risk aversion (e.g., ERAA's revenue cap) help to explain why the German NRAA shows high market-driven investments in new gas units and early coal retirements, while ERAA 2025 differs from these results. Other differences between the two studies that further explain the discrepancies in results can be found both in the assumed exogenous input parameters and in the underlying modeling approaches. One example are the differences in the number and type (historical vs. projected) of weather scenarios considered in the adequacy assessment, as well as in those deemed as representative and, therefore, included in the economic viability assessment. In the German NRAA, only one historical weather year is taken into account for calculating the future capacity mix, whereas in ERAA 2025, three different projected weather scenarios are selected for this purpose in order to better reflect the variability of future weather conditions. Given the sensitivity of the EVA to such relevant factors as risk aversion and

8 BMWE Newsletter Energiewende | Monitoring report on the status of the energy transition
9 Versorgungssicherheit Strom Bericht 2025 | BMWE

weather projections, the German TSOs see value in exploring a greater number of alternative approaches as well as future projections. This broadens possible capacity developments and makes the impact on adequacy results more transparent and comprehensive.

Great Britain

The EVA assessment's projection of gas plant closures in Great Britain (GB) does not align with national adequacy requirements. NESO's internal modelling, particularly the CP30 adequacy analysis, indicates that approximately 35 GW of unabated gas capacity must remain operational in 2030 to ensure system reliability under a range of weather and demand scenarios. This figure is grounded in detailed probabilistic modelling that reflects the operational realities of GB's energy system and the critical role of gas-fired generation in maintaining flexibility and resilience.

As outlined in NESO's report "Resource Adequacy in the 2030s",[10] the modelling approach incorporates multiple weather years, demand profiles, and system stress conditions. The results consistently show that gas capacity remains essential for keeping Loss of Load Expectation (LOLE) values within statutory limits. These findings support the view that maintaining sufficient thermal capacity is key to ensuring a secure and reliable electricity supply through the transition period.

Since the publication of the July 25 resource adequacy report, FES have issued updated and higher demand forecasts, reflecting increased pressure from data centres. Consequently, the 35 GW of unabated gas capacity should now be regarded as a minimum requirement, with potential for upward revision to accommodate these new forecasts.

[10] https://www.neso.energy/about/our-projects/resource-adequacy

Hungary

MAVIR expected minor improvement in adequacy metrics compared to ERAA 2024, based on changes in demand and supply side forecasts. These changes and the underlying causes are presented in Annex 1. Despite this, results show that the adequacy situation is worse for the common target years of ERAA 2024 and 2025 (2028, 2030, 2035). This could be caused mainly by the updated risk aversion implementation in EVA, resulting in lower supply side capacities in all common target years both in Hungary and overall, in Europe. It is important to take this into account when assessing the results.

Ireland

Ireland and Northern Ireland together comprise the Single Electricity Market (SEM). This wholesale electricity market is designed to be compliant with the European Target Model. It aims to provide wholesale electricity at the lowest possible cost, ensuring that there is adequate supply to meet demand and to support long-term sustainability. The SEM incorporates a Capacity Market, with Capacity Auctions taking place annually.

The adequacy standard for Ireland is three hours of Loss of Load Expectation (LOLE)[11], as set by the Department of Climate, Energy and the Environment (DCEE) working with the Commission for Regulation of Utilities (CRU).

In early 2025, EirGrid provided inputs to the ERAA 2025 PEMMDB data collection, which were aligned with the latest national study, the 'All-Island Resource Adequacy Assessment 2025-34' (AIRAA25-34)[12].

The AIRAA25-34 is a collaboration between EirGrid and SONI, and is an assessment of resource adequacy across the island. The overall resource narrative is similar between the AIRAA25-34 and the ERAA25, but there are some differences due to different data freeze dates, and different methodologies.

LOLE(hrs)	TY2028	TY2030	TY2033	TY2034	TY2035
ERAA25 (ID34)	2.13	2.84	4.93		6.11
ERAA25 (ID37)	1.61	2.05	2.99		3.52
AIRAA25-34 (Base)	**3.2**	**2.3**	**3.8**	**3.6**	
AIRAA25-34 (Secure)	11.3	12.3	32.3	40.0	

The AIRAA25-34 results are shown in both the base and secure scenario – it is the Base scenario assumptions that match more closely with those of ERAA25. The secure scenario includes some extra security measures that are not included in the ERAA25, such as run-hour restrictions. EirGrid consider the Secure assessment is most prudent and should be considered as the central scenario for adequacy assessments, noting that capacity auctions remain the mechanism for determining specific auction requirements in the medium to long term.

At a national level, the AIRAA25-34 is showing Ireland to be outside of standard in 2028. However, there are out of market mitigation measures in place to address this, as reported in AIRAA25-34.

Note that the ERAA25 results are shown post-EVA, i.e. they have some capacity (approx. 400 MW by TY2035) removed due to the EVA process. However, the AIRAA25-34 methodology did not include an EVA (subsequent editions of AIRAA will develop the EVA process). Therefore the AIRAA25-34 (Base scenario) has slightly more capacity available, and typically has a better adequacy outcome.

[11] https://www.semcommittee.com/news/sem-24-051-2027-28-t-4-volumes-information-note
[12] https://www.eirgrid.ie/all-island-resource-adequacy-assessment

A second North South Interconnector is planned to increase grid capacity between Ireland and Northern Ireland, from October 2031. This is included in the ERAA25 assessment from TY2033 onwards, illustrating the benefits to adequacy on an all-island basis. This is consistent to the benefits shown in AIRAA25-34 for the all-island assessment.

A new interconnector is planned from Ireland to France. The ERAA25 includes this 700 MW interconnector from January 2028 onwards, as per data collection, and therefore includes the adequacy benefits of this new interconnector for the full year of 2028. However, project timelines have been updated, and it is now estimated that the commissioning date will be in Quarter 2 2028.

In both the Base AIRAA25-34 and ERAA25, LOLE is increasing as time progresses – this is mainly due to demand increasing. Note that if there are any delays to the expected capacity delivery (as per data collection in Jan 2025 for ERAA25), this would also affect the outcome.

Also, note that since the data collection (early 2025), the T-1 2025-26 and T-4 2028-29 capacity auctions have awarded capacity contracts that will improve our adequacy position when the new capacity is due to become available – this will be reported upon in the subsequent AIRAA 2026-35.

Italy

As highlighted in the Winter Outlook 2025–2026, Italy's current adequacy situation remains manageable, provided that imports from neighbouring countries during critical hours are available, albeit within limited levels. Overall, adequacy has gradually improved in recent years thanks to the additional capacity from thermal power plants and battery energy storage systems (BESS) awarded in the capacity market auctions.

However, looking ahead to the **medium- and long-term horizon, a significant adequacy risk could emerge**, primarily linked to the potential decommissioning of thermal power plants due to economic unsustainability.

ERAA 2025 underestimates the adequacy risk, as the analysis relies solely on the scenario of the cost based Economic Viability Assessment (EVA). The cost-based EVA takes the perspective of a Central Planner with perfect foresight, thereby underestimating the decommissioning risk of existing thermal power plants and overestimating the new entry capacity.

Annex 5 of ERAA 2025 presents the results of the **revenue-based EVA**, which indicates a possible **decommissioning risk of 22 GW by 2030** (Italy, Implementation A), compared to **18 GW** estimated under the cost-based approach.

ENTSO-E has not yet disclosed **the adequacy risk results for this post-EVA scenario under the revenue-based approach, namely its implications in terms of Loss of Load Expectation (LOLE). The revenue-based EVA remains the target for ENTSO-E, with further progressive results to be released at later stage. Already** under the cost-based approach, 9 hours of LOLE are estimated, which is well above the Italian reliability standard of 3 hours.

In light of these findings, it will be **essential to maintain a capacity mechanism in the coming years**. Such a mechanism will mitigate excessive decommissioning, trigger efficient asset renewal and replacement, and ensure that sufficient thermal capacity remains available to safeguard system adequacy.

Comparison between ERAA and NRAA

It is considered essential that the ERAA results are complemented by the Italian **NRAA ("Rapporto Adeguatezza Italia")**, which applies more detailed modelling and is therefore able to capture national specificities that cannot be fully reflected in a pan-European study.

Overall, the **national assessment provides a more critical view** of Italy's adequacy situation, for the following reasons:

1. **Higher decommissioning risk in the NRAA.** While ERAA 2025 adopts a cost-based EVA as the "default stream," Terna applies a revenue-based approach to evaluate the economic viability of power plants. In addition, the national EVA incorporates further details such as the CM outcome for repowered capacity, which offer 15-year only to the repowered portion of a power plant, leaving the remaining part exposed to a decommissioning risk.

2. **Representation of additional national specificities.** For computational reasons, the EU-wide analysis does not include all country-level details. By contrast, the NRAA integrates a more accurate representation of: (1) reserve provision, (2) storage constraints, and (3) network

constraints among Italian nodes, thereby reflecting observed operational limitations that occur in practice.

Lithuania

The input data applied in ERAA 2025 shows slight differences in adequacy results compared to results of ERAA 2024, as it integrates updated NECP data and reflects the changes in status of ongoing projects. ERAA 2025 considers an anticipated delay in the offshore wind project, resulting in an estimated reduction of 0.7 GW in installed capacity for each target year. Additionally, the increase in Lithuanian Latvian cross-border capacity in 2035 has been assessed.

The ERAA 2025 results indicate growing adequacy concerns, peaking in 2033 when LOLE reaches 35.58–46.95 hours per year. By 2035, risks remain significant but are mitigated by the commissioning of new cross-border lines with Latvia.

These trends suggest a need for measures to support adequacy in the medium to long term, particularly around 2033. A national adequacy assessment, complementing ERAA, is currently in progress. Results expected by mid-2026 will initiate future decisions on system reliability and capacity planning.

Malta

It is important to note that due to its specific electricity network characteristics, Malta does not have an electricity transmission system and although the generation has been opened for competition, there is currently no liquid wholesale electricity market on the island. The Maltese electricity system has been synchronised with the Italian electricity grid since April 2015 through the 225 MW HVAC 200kV interconnector.

We note that the introduction of out of market resources in the study significantly decreased the ENS and LOLE for the projected horizon.

Moldova

Although Moldova’s generation capacity availability ratio is relatively high and sufficient to cover its own consumption, the lack of natural gas may lead to adequacy risks.

Currently, MGRES TPP, the largest by far power plant (accounting for around 60% of available generation capacity), which previously covered most of Moldova's electricity needs — now supplies only the demand on the left bank of the Nistru River. It no longer supports the rest of Moldova’s grid, operating with only one unit that generates approximately 80–120 MWh.

On the right bank of the Nistru River, most electricity generation comes from thermal demand-side CHPs and renewable energy sources. However, the electricity generation capacity of CHPs is limited: during the winter, they can operate only as required for centralized heating demand, but in summer their output is very low, as there is only limited demand for centralized hot water.

Electricity purchases from MGRES TPP is not expected at least during the Winter 2025–2026 period, and Moldova is expected to face challenges in covering its demand, especially during peak hours. This deficit is planned to be addressed through imports via the RO–MD and UA–MD interconnections (when possible from the UA side). The granted NTC in the RO–MD direction is around 315 MW.

In the UAMD control block, capacity reallocation became possible after the launch of intraday capacity allocation: if the block’s total technical limit of 2100 MW is not fully utilized, the unused portion can be reassigned in intraday capacity allocation sessions to increase commercial capacity on individual borders — for example, raising the MD–RO import capacity from 315 MW up to around 600 MW. Currently Moldova heavily relies on the process of capacity relocation to ensure the possibility to import the required electricity, which can account to around 600MW.

However, if import opportunities from Ukraine are unavailable and no capacity reallocation occurs — especially in the near future (early 2026 after launch of intraday capacity allocation on UA-SK, UA-HU and UA-RO borders), when Ukraine may fully use its allocated cross-border capacity — Moldova will experience difficulties in covering its demand.

Moldova’s power system faces significant reliability challenges due to its limited flexibility in balancing production and consumption. A large part of the generation fleet consists of inflexible sources, such as demand-side CHPs and RES, which restricts the system’s ability to respond to rapid changes in demand or generation.

If the situation does not improve in the future, Moldova will continue to face serious risks to energy adequacy and reliability. Therefore, the development and implementation of electricity storage along with RES and new cross-border infrastructure projects have become crucial for the country.

Netherlands

Reflection on the ERAA 2025 results compared to previous ERAA editions and the Dutch NRAA
The ERAA 2025 results show a clear increase in LOLE and EENS for The Netherlands in both risk aversion EVA alternatives compared to previous ERAA editions. This is in line with an increased LOLE and EENS for the whole of the studied area in the ERAA. This is especially visible in the EENS results, increasing from 1 GWh to 9 GWh in 2030 and from 3 GWh to 20 GWh in target year 2035, when compared to the results with the results with hurdle premium only.

Even more apparent is the rise in EENS and LOLE between the two EVA risk aversion alternatives. Removing generator income above 1000 euro/MWh for investment decisions, as is it the case in the results that include a hurdle premium and revenue cap, leads to a removal about 14 GW of gas capacity in study zones BE00, DE00, FR00 and NL00 combined, mostly because of reduced market-based gas capacity expansion in Germany. This shows that the EVA results are sensitive to modelled risk averse behaviour of investors but also that the adequacy of the electricity market in this region is sensitive to the occurrence of these additional investments.
Compared to the latest NRAA for the Netherlands, the *Monitor Leveringszekerheid 2025*, these ERAA results indicate a significant higher resource adequacy risk. The *Monitor Leveringszekerheid* 2025 was based on the European dataset of ERAA 2024, combined with the latest best estimate situation for the Dutch energy system for 2030-2035. The deviations in the results of *the Monitor Leveringszekerheid 2025* and the ERAA 2025 are a combination of:

- Different scenarios used for The Netherlands in the *Monitor Leveringszekerheid 2025* and the ERAA 2025 (see section below): NECP compliant (ERAA) versus 'best estimate' (NRAA) (see reflection on scenario data);
- Different EVA investor behaviour in this ERAA, that results in lower installed conventional generation capacities across Europe compared to previous ERAA. Since the Netherlands is strongly interlinked with its neighbours and does not have enough firm generation capacity to serve its own peak demand, any deterioration of generation capacity abroad strongly impacts the expected situation in the Netherlands as well and pushes up Dutch LOLE and EENS;
- Different application of curtailment sharing (see section reflection on application of curtailment management).

Reflection on the scenario data applied for The Netherlands in this ERAA
In line with ERAA requirements to use NECP compliant scenarios, TenneT submitted data for this ERAA based on the 'Koersvaste Middenweg' (steadfast middle course) scenario. A scenario developed jointly by TenneT and the other Dutch grid operators during 2024. More information on the scenario can be found here: [Netbeheer Nederland Scenario's Editie 2025 | Netbeheer Nederland]. Of all scenario's developed by the Dutch grid operators, the Koersvaste Middenweg scenario stays closest to existing national policies and related NECP targets. This results in a very high ambition level for growth in electricity demand and of electricity generation capacity of both renewables and conventional power stations.

However, given the current significant amount of grid congestion and other energy transition challenges, it is likely that the assumed speed of developments will not be fully met. The expectation is that electricity demand in the Netherlands will be lower than currently assumed in the analyses of this ERAA. At the same time, it is expected that some other developments regarding generation capacity like the continued use of some of the coal power stations based on biomass instead of coal after 2030, and like EVA based DSR expansions would not take place. TenneT intends to assess the net effect of these changes in more detail in the upcoming NRAA.

Reflection on the application of curtailment management

In ERAA 2025, the configuration for local matching and curtailment management (curtailment minimisation and curtailment sharing) remains unchanged compared to ERAA 2024. For the Netherlands, the level of allowed re-optimisation of curtailment sharing in ERAA 2024 compared to ERAA 2023 led to a higher LOLE, while EENS remained broadly comparable. The ERAA 2025 results confirm that Dutch adequacy indicators are sensitive to the curtailment-sharing configuration, both in terms of absolute LOLE and EENS values and in the way ENS is redistributed across countries.
TenneT supports the objective of reflecting the SDAC implementation of curtailment management and of ensuring a fair sharing of shortages in scarcity situations. I Investigations are still ongoing on European level to define which settings best reflect the actual implementation and TenneT considers the current curtailment-sharing settings in to be an evolving element of the ERAA methodology, which will be further tested and refined towards the target approach envisaged for ERAA 2026. TenneT intends to continue analysing the impact of alternative curtailment-sharing configurations in its own NRAA to better understand their impact on adequacy in the Netherlands.

Outlook on the next NRAA, the *Monitor Leveringszekerheid 2026*

The next version of the *Monitor Leveringszekerheid* is expected in June 2026. In this new version TenneT expects these EVA effects shown in the ERAA will be discernible as well, considering that the Netherlands is strongly interlinked with other European countries in which the resource adequacy situation seems to be deteriorating.

Regarding the scenario to be analysed in the NRAA, assumptions on foreign demand and installed capacity will be taken from ERAA 2025. However, for the Netherlands a different scenario will be applied that resembles the best estimate situation for the future Dutch electricity system, instead of a less likely NECP compliant scenario that was investigated in this ERAA. As result, the upcoming edition of the NRAA will consider i.e.:

- A slower development of electrification compared to ERAA, causing a lower peak demand.
- Latest information on installed generator capacities, following direct data provisioning of connected parties in autumn of 2025. This is expected to cause limited changes compared to the 2025 NRAA but could be lower than assumed in this ERAA especially due to the life extension of gas capacity in both EVA variants which will not be taken over in the NRAA.
- Lower amount of DSR capacities, as in this ERAA these were built out as result of the EVA step, which will not be applied in the NRAA.

Northern Ireland

Northern Ireland and Ireland together comprise the Single Electricity Market (SEM.) This wholesale electricity market is designed to be compliant with the European Target Model. It aims to provide wholesale electricity at the lowest possible cost, ensuring that there is adequate supply to meet demand and to support long-term sustainability. The SEM incorporates a Capacity Market, with Capacity Auctions taking place annually.

Throughout 2023 and 2024, SONI worked collaboratively with EirGrid, the Utility Regulator (UR) and the Commission for Regulation of Utilities (CRU) to develop the pathway for transitioning to the new methodology that aligns with Article 24 of the Regulation on the internal market for electricity (EU/2019/943). The first All-Island Resource Adequacy Assessment (AIRAA) covering the period 2025-2034 was published in early 2025. The second All-Island Resource Adequacy Assessment (AIRAA) covering the period 2026-2035 is due to be published in early 2026. It should be noted that differences may arise between ERAA and AIRAA publications due to differences in data freeze dates.

SONI provided inputs to the ERAA 2025 PEMMDB data collection, which were aligned with the latest published national study - this was the 'All-Island Resource Adequacy Assessment 2025-2034.[13]

In the table below, ERAA 2025 adequacy results are compared with the AIRAA25-34 results for LOLE. The LOLE results can be considered relative to the adequacy standard for Northern Ireland, which is 4.9 hours of Loss of Load Expectation (LOLE), as set by the Department for the Economy (DfE).

LOLE (hrs)	2028	2030	2033	2034	2035
ERAA25 (ID34)	0.85	2.03	2.88		5.46
ERAA25 (ID37)	0.61	1.06	1.15		2.95
AIRAA 2025-2034 Base	2.0	2.5	7.9	8.5	
AIRAA 2025-2034 secure	6.2	7.7	21.6	25.2	

Please note that the AIRAA base scenario accounts for regional constraints most notably annual run hour restrictions and can be compared with the ERAA results, noting variations in the model. The AIRAA also includes a prudent 'Secure Scenario' which analyses the system considering low imports and other operational requirements; this scenario shows Northern Ireland to be outside of the 4.9 hour LOLE standard across all years.

SONI considers the secure scenario as a prudent approach and should be taken into account for decisions relating to securing capacity for the continued secure and sustainable operation of the power system. Additional sensitivities are utilised to understand the impact of factors that have higher levels of uncertainty such as demand, renewable capacity, and storage forecasts.

Comparing ERAA 2025 to AIRAA 2025-2034 base, the general trends are similar, i.e. low adequacy concerns for the initial target years to 2030, and then an increasing LOLE for 2033 and 2035 due to increasing demand due to electrification of heat and transport. Some of the key differences between the ERAA and AIRAA study are outlined below:

[13] All-Island Resource Adequacy Assessment 2025-2034

1. AIRAA includes a more detailed assessment of run-hour limitations on some generators, reflecting a critical concern to security of supply in Northern Ireland and resulting in higher LOLE. SONI is actively supporting the Utility Regulator and relevant government departments in relation to mitigating risks related to run hour limitations on two new gas plants in Northern Ireland.
2. A second North South Interconnector is planned to increase grid capacity between Northern Ireland and Ireland. This is included in the ERAA25 assessment from TY2033 onwards, illustrating the benefits to adequacy on an all-island basis. This is consistent to the benefits shown in AIRAA25-34 for the all-island assessment.
3. Note that the ERAA25 results are shown post-EVA, i.e. they have some capacity (approx. 350 MW by TY2035) removed due to the EVA process. However, the AIRAA25-34 methodology did not include an EVA (subsequent editions of AIRAA will develop the EVA process). Therefore, the AIRAA25-34 (Base scenario) has slightly more capacity available and typically has a better adequacy outcome.

SONI notes that single electricity market capacity auctions are still an option to procure new generation which could address the capacity shortfalls.

Norway

Statnett has recently published an update of the Short-term Market Analysis (KMA 2025-2030). Despite some delays in electrification-processes, demand is expected to increase significantly. Based on the increased demand and a low production-increase, Norway is expected to go from a large energy-surplus to a more balanced situation. This leads to a tighter adequacy-situation, in where especially the dry-year-situation might be more stressed.

ERAA 2025 identifies some adequacy-issues in the bidding area NOS1 in the years 2030 to 2035. This is mainly based on high adequacy-risks in neighbouring countries (SE, DK) influencing the adequacy-risk also in one Norwegian price-area (NOS1/NO1), Statnett don't see the same adequacy-risk in Statnett's own analysis. We are currently investigating possible reasons for this difference, like the assumption of demand/production-growth, grid-modelling, flow-based modelling, increased reserves requirements or hydro-modelling-issues.

Poland

Input data description

The input data for Poland was valid during the data collection period with some adjustments after an input data public consultation finished in May 2025. The data for Poland took into account a dedicated scenario for the purpose of developing NECP and Energy Policy of Poland until 2040. This scenario includes the national vision for a low-carbon energy transition in the context of strengthening energy security and energy independence, as well as structuring Poland's contribution to the EU's 2030 climate and energy targets. Additionally, the data considered the necessary updates regarding:

- The dates of commissioning and decommissioning of thermal units already known to PSE.
- The information of the already concluded auction in Polish Capacity Market.
- Offshore projects submitted to PSE by investors.

According to the requirements, the data provided for ERAA 2025 takes into account information on already concluded contracts in Polish Capacity Market (CM). It includes results of all held, until moment of data collection, CM auctions i.e. delivery periods up to 2029. It does not include results or estimations for further years especially Target Year (TY) 2030, for which capacity auctions are already planned. The same assumption was applied to the already concluded contracts for DSR coming from CM, which means for TY 2028. Due to specific conditions of activation of Polish DSR, it was not a subject of the central simulation in ERAA 2024, however, it was used to reduce hourly ENS and LOLE results in post-processing. For information, PSE presents the result of this post-process also for TY 2030 below. Although the contracts on CM for these years are not yet concluded, PSE, observing the current interest in such DSR, expects at least to maintain the level of DSR capacity that has been already proven.

Results analysis

Following the final results of ERAA 2025, PSE has made in-depth analysis:

Main observation is the results of the EVA model, where it appears that the simplified application of perpetuity after the end of the planning horizon in the overall cost minimisation approach tends to over-estimate investment and under-estimate risk of capacity exit It has a major impact on the economic viability of Polish units. The perpetuity model does not take into account the real decommissioning dates provided by TSOs in the input data. The last year modelled within ERAA 2025 i.e. TY2035 repeats an infinite number of times and this TY due to high number of scarcity situations this TY has a significant impact on units' profitability. As a consequence, units may not be decommissioned despite of negative profits in earlier TYs. Thus it may underestimate the adequacy concerns in some bidding zones.

In the case of Poland, many coal units, due to end of their life cycle, are scheduled for decommissioning at the end of 2035 or close beyond 2035. For these units (and maybe others in Europe with similar conditions), the current perpetuity modelling has a direct impact on the unit's lifecycle revenues and their economic viability. For Poland, this results in an overestimation of coal units' capacity, which remain in the system in the ERAA 2025 time horizon, i.e. until 2035. PSE considers the appropriate implementation of the revenue-based EVA to resolve these concerns.

With regard to the new hydrogen units that appeared in the Polish power system after the EVA simulation, PSE agrees with the opinion expressed in Annex 3, according to which the suggested hydrogen-fuelled generation expansion should not be interpreted as a definite signal of investment viability. Rather, it highlights the need to expand dispatchable thermal units, whose fuel supply could realistically be either gas or hydrogen, depending on future fuel cost developments across scenarios.

As mentioned in the previous section, LOLE / EENS results are presented for Poland with and without DSR coming from CM in the table below:

Target year	Risk aversion assumption	LOLE [h]		EENS [GWh]	
		Before OMM	After OMM	Before OMM	After OMM
TY2028[1)]	HP & PC	18.06	13.34	23.23	17.69
	HP only	11.73	8.85	17.69	14.14
TY2030[2)]	HP & PC	23.25	19.26	38.02	31.17
	HP only	14.38	12.05	22.54	18.45
TY2033[3)]	HP & PC	38.75	n.a.	66.07	n.a.
	HP only	12.18	n.a.	21.47	n.a.
TY2035[3)]	HP & PC	48.95	n.a.	111.21	n.a.
	HP only	21.76	n.a.	56.59	n.a.

1) CM auctions already concluded, DSR applied by default
2) CM auctions not concluded yet, estimated value for the country comments only
3) Beyond the period of the existing CM in Poland

OMM - out of market measures
HP & PC – hurdle premium and lower price cap risk aversion assumption
HP only – hurdle premium and initial, central reference scenario with the enhanced hurdle premium only risk aversion assumption

Portugal

General appreciation
The Portuguese TSO (REN) highlights ERAA 2025 as an important step forward compared to the previous ERAA editions in terms of methodological implementation and development of capabilities, in a continuous effort to gradually improve the quality and value of the outputs, fruit of a collaborative framework between all parties, stakeholders, ENTSO-E and TSOs.

Nevertheless, REN has some concerns/comments regarding this ERAA 2025 exercise.

Input data
For ERAA 2025, REN provided input data based on the National Resource Adequacy Assessment Report (Portuguese NRAA) published in February 2025, RMSA-E 2024.[14] The "National Estimate" data is aligned with the Portuguese NECP[15] based "Trajetória Ambição" scenario as assumed in RMSA-E 2024.

In case of target year 2028, a conservative approach was assumed for the installed capacity in line with "Trajetória Conservadora – Sensibilidade à oferta".[16] In these scenarios, according to indications of the Portuguese Directorate for Energy and Geology (DGEG), CCGT "Tapada do Outeiro" is considered to be decommissioned by the end of 2030.

However, it is important to note that, at present, these scenarios involve significant uncertainty, arising from a current trend toward slower growth in supply compared to the projections in the Portuguese NECP, and an exceptional increase of demand requests for new electro-intensive consumer connections, all still subjected to confirmation at a later stage.

Short-term perspective (2025)
The ERAA, the Seasonal Outlooks and the Ten-Year Network Development Plan (TYNDP) aim to model and analyse possible events that could adversely impact the balance between supply and demand of power system in different time horizons ahead. The seasonal adequacy assessments, such as the Winter Outlook and Summer Outlook, assess the situation in the short-term period for the upcoming season (weeks to months ahead). The National Resource Adequacy Assessment (Portuguese NRAA) analyses also short-term periods.

The most recent **National Resource Adequacy Assessment Report (RMSA-E 2025)** is being currently developed and addresses electricity security of supply for Target Year 2026. Although not fully comparable with ENTSO-E studies in terms of methodology and assumptions, **on the expected study for year 2026, it is foreseen that there will be a risk of dependence of the Portuguese electric system on imports from Spain and a risk of noncompliance with the current national reliability standards, even in scenarios assuming that CCGT "Tapada do Outeiro" will remain in operation until the end of 2026.**

Under these conditions, some mitigation measures may be necessary to handle operational reserve needs and ensure security of supply in the Portuguese electric system, as listed below:

[14] https://www.dgeg.gov.pt/media/uu3dlpkj/rmsa-e-2024-vers%C3%A3o-final.pdf
[15] National Energy and Climate Plan 2030.
[16] Sensitivity analysis to lower installed capacities of wind and solar power.

#	Measures
Demand	Load reduction market product for eligible consumers with whom there are annual contracts for the provision of this service
Supply	Request for the activation of a support program with the Spanish System Operator
Demand	Occasional load shedding of non-priority consumptions, according to the protocol between the electricity transmission and distribution network operators

Regarding the 1st measure presented in the table, the Portuguese TSO performed a study in the beginning of the 4th quarter of 2025 in order to identify the load shedding requirements for 2026. This study was presented to the Portuguese NRA in order to perform an auction for this specific market product by the end of the present year.

ERAA 2025 results

ERAA focuses on the mid- and long-term horizon of 2 to 10 years ahead. The purpose of ERAA is to identify adequacy assessment concerns and serve as an action guidance, with a moderate uncertainty up to 5 years ahead, increasing to higher uncertainty beyond that time.

Economic Viability Assessment (EVA) results

The table below presents for Portugal a comprehensive analysis of Economic Viability Assessment (EVA) focused on global minimization of overall system costs. For each Target Year (TY), the decommissioned CCGT capacity and the DSR amount of expansion are presented, as well as the base values considered in the PEMMDB.
These EVA results are based on two different risk aversion approaches:

- Approach 1: enhanced hurdle premium combined with a revenue cap
- Approach 2: enhanced hurdle premium only.

Concerning results proposed by the EVA model for the Portuguese electric system, the impact of the chosen risk aversion approach is clear: the approach with the enhanced hurdle premium combined with a revenue cap (Approach 1) leads to a lower net revenue captured by CCGT's in the electricity-only market, thus a significant amount of CCGT capacity is considered not profitable and decommissioned; on the other hand, in approach with the enhanced hurdle premium only (Approach 2), the CCGT in general present higher net revenues, therefore the amount of unprofitable capacity is considerably lower.

EVA results for Portugal: decommissioned CCGT capacity and DSR amount of expansion

	TY 2028		**TY 2030**		**TY 2033**		**TY 2035**	
PEMMDB	3829 MW	0 MW	3829 MW	0 MW	2839 MW	0 MW	2055 MW	0 MW
EVA Approach	CCGT dec. [MW]	DSR exp. [MW]	CCGT dec. [MW]	DSR exp. [MW]	CCGT dec. [MW]	DSR exp. [MW]	CCGT dec. [MW]	DSR exp. [MW]
Approach **1**	-3060	0	-3060	+80	-2060	+100	-1270	+190
Approach **2**	-1770	0	-1770	+440	-770	+510	0	+730

In Approach 1, for all Target Years the EVA model presents as expected high CCGT possible decommissioning in the Portuguese electric system. In Approach 2, despite the different risk aversion assumption, the trend is very similar: in TYs 2028, 2030 and 2033, the EVA model also results in CCGT decommissioning, although with lower values in comparison with Approach 1. In TY 2035, the total CCGT capacity presented in the 'National Trends' scenario is viable in the electricity-only market.

Considering these results, it's possible to conclude that a significant CCGT capacity in the Portuguese electric system is expected to be not economically viable. Consequently, the implementation of a capacity payment mechanism may be needed in Portugal, given the crucial role that these generators play in electricity security of supply.

Regarding DSR expansion capacity identified in the two approaches, the EVA model presents a "similar" behaviour as for CCGTs: in Approach 1, only the DSR bands with lower activation prices are profitable; in Approach 2, even the bands with higher prices are activated in scarcity hours and nearly all the DSR potential[17] is deployed (e.g. 730 MW out of 855 MW in TY2035).

It's worth to note that expansion constraints/limitations introduced by neighbouring countries in some technologies can lead, as side effect, to a shift of DSR capacity expansion in Portugal, especially in Approach **2.**

Annex 5 presents a case study with results of two different models implementing a revenue-based EVA approach, that tries to evaluate the profitability of each unit in the electricity-only market under given conditions. The table below presents for Portugal a comprehensive analysis of the EVA results for each target year and type of implementation in terms of decommissioned CCGT capacity and DSR expansion capacity.

EVA results for Portugal: decommissioned CCGT capacity and DSR amount of expansion (CASE STUDY)

	TY 2028		**TY 2030**		**TY 2033**		**TY 2035**	
PEMMDB	3829 MW	0 MW	3829 MW	0 MW	2839 MW	0 MW	2055 MW	0 MW
EVA Scenario	CCGT dec. [MW]	DSR exp. [MW]	CCGT dec. [MW]	DSR exp. [MW]	CCGT dec. [MW]	DSR exp. [MW]	CCGT dec. [MW]	DSR exp. [MW]
Implementation A	--749	+50	-2240	+50	-1642 (-413 moth)	+50	--1250	+50
Implementation B	-990	0	-990	0	0	0	0	+262

It should be noted that only Approach 1 of the cost-based EVA is comparable with the revenue-based EVA implementations as the corresponding risk assumptions are aligned. For Portugal, implementation A presents a better alignment with Approach 1 for all TYs, with exception of TY 2028.

[17] DSR potential in Portugal is computed centrally by ENTSO-E as, for the time being, there is no official estimate of the evolution of this technology provided by the Member State.

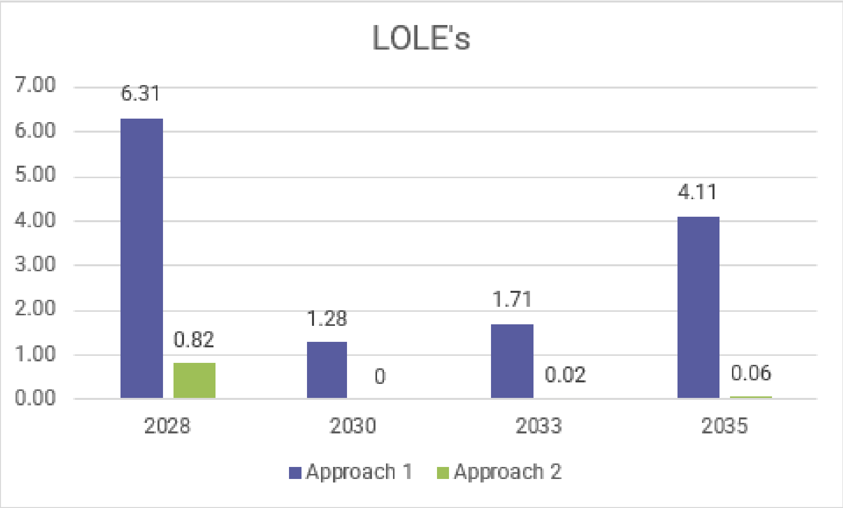
The differences between cost-based and revenue-based EVA can be explained by distinct methodological choices like unit clustering, maintenance granularity and market coupling modelling. **The impact of expansion constraints in larger neighbouring countries is also non negligible and can impact the results**.

From both EVA approaches (cost-based and revenue-based approaches) a high amount of non-viable CCGT capacity in Portugal can be concluded for the upcoming years.

Economic Dispatch (ED) results

Based on the EVA results ED simulations have been performed. The table below presents LOLE values from ED runs based on the cost-based EVA Approaches 1 and 2 for Portuguese electric system after curtailment sharing.

PT	LOLE	
post_CS	Approach 1	Approach 2
2028	6.31	0.82
2030	1.28	0
2033	1.71	0.02
2035	4.11	0.06



The results for the Portuguese power system show adequacy concerns in Approach 1 for TY 2028 and TY 2035[18]. For Approach 2 the results do not show adequacy issues. For TY 2030 and 2033 in Approach 1 and all TYs in Approach 2, the **low LOLE values are very different from the most recent NRAA (RMSA-E 2024) that identified resource adequacy concerns for Portugal.**

The main identified reasons for those differences are:

a) **Modelling of pumping consumption and hydro generation**, that assume much more pumping consumption in existing power plants than historically measured according technical hydro/pumping capabilities; and
b) **Assumption that 100% of NTC (Net Transfer Capacity) is always available for commercial exchanges with the Spanish system**. In real operation, the maximum power exchange capability is not available in all hours of the year.

This is linked to equitable pan-European modelling assumptions, and well as the tight ERAA 2025 timeline limiting the implementation of new model features. These aspects will be analysed in more detail in ERAA 2026.

[18] Assuming average reliability standard of 3 h/year since Portugal do not have a reliability standard publish according with ACER approved methodology.

Regarding hourly dispatch for Portuguese electric system from ED studies one can notice that due to differences in assumed electrolyser efficiencies between Portugal and Spain it could not replicate corresponding results which could be expected from the NRAA studies. These assumption are not expected to have impact in security of supply indicators, however, it is recommended to harmonise these input data in future ERAA studies to avoid possible distortion.

Furthermore, the installed capacity in central reference scenario for TY 2030, TY 2033 and TY 2035 is based on the delivery of targets presented in the revised Portuguese NECP. This plan describes the trajectories of the future capacity (renewables, storage and others technologies) and demand (electrification, energy efficiency) according to the EU's ambitious targets and represents the best available plan depicting the future of the energy system during the energy transition. However, this scenario does not take into account that delays may occur in the implementation of the measures described in the Portuguese NECP and that such delays could affect system adequacy. In this way, the adequacy results from ERAA 2025 studies for TY 2030, TY2033 and TY 2035 may be optimistic. To analyse these possible delays regarding the renewable expansion, the Portuguese NRAA presents other scenarios and sensitivities for these target years and shows some adequacy concerns to be taken into consideration complementarily to the ERAA results.

Finally, it is important to highlight the impact of expansion constraints introduced by larger neighbouring countries on small systems like Portugal. Such impact is especially visible in investment decisions taken by EVA model regarding DSR: as the expansion of several technologies is blocked or limited in other electrically connected countries, a shift of expansion capacity to Portugal can occur which may exceed the actual DSR potential in Portugal. In this context it needs to be noted, that there is neither official estimate of the evolution of this technology in NECP nor any CoNE study conducted by the Portuguese Member State to which the ERAA could have referred to. **The central DSR potential estimate in ERAA (855 MW) might be too high (recent auctions of load reduction market product in Portugal allocates values up to a maximum of ~400 MW although needs in the system are much higher).**

Complementary to the insights regarding the Portuguese resource adequacy provided by ERAA 2025 in a European context, national and regional assessments can provide deeper analysis of local constraints. The ERAA takes a pan-European approach that should be complemented by regional analysis outside the ERAA scope, e.g., the application of FNA (Flexibility Needs Assessment) methodology to quantify "ramping needs" and "short-term flexibility needs" indicators.

Romania

Changes in the adequacy results from ERAA 2024 to ERAA 2025 for Romania, in line with the other European countries, indicate growing adequacy concerns, reflecting both the input data changes due to the updated NECP and status of the new projects commissioning, as well as the consequences of the new investor risk aversion scenarios applied for the Economic Viability Assessment phase.

For both EVA approaches, "Combined Risk Aversion" and the "Hurdle Premium only", ERAA2025 identifies the highest adequacy risk for Romania in the short to medium term, driven by a significant decommissioning of thermal capacity, both on lignite and gas, due to economic unviability, additional to the planned retirement of one nuclear unit in Cernavoda for lifetime extension.

Thus, the results of the EVA suggest a potential market-driven early retirements of the remaining lignite units (850 MW) in 2028 and 2030, driven by the residual load pattern and reduced full load hours. Also, the range of the EVA results in all target years highlights the uncertainties related with the economic unviability of the expected new gas units.

The ERAA2025 results indicate the adequacy risk trends for Romania: peaking in 2028 when LOLE reaches 7.59–13.30 hours/year on average, with the highest of 49.05-57.05 hours/year in extreme scenarios (95th percentile) and being partly mitigated by the commissioning of new renewable generation capacity and new nuclear units in the following years, with the average LOLE figures going below 2 hours/year.

These trends highlight the need for additional analysis to identify the generation capacity required to ensure a reliable supply system in Romania, particularly in the 2027-2030 period. A national adequacy assessment, complementing ERAA, is currently in progress, assessing the national specificities that cannot be fully captured in ERAA. It is to be mentioned that, compared to ERAA2024, the results of this latest edition of ERAA are more aligned with the security of supply concerns identified by the ongoing Romanian NRAA.

The results of the previous and current ERAA illustrate that the expectable available generation capacity evolution on the market and consequently the adequacy metrics are highly sensitive to the modeling approach considered in EVA to capture the *actual* investors behavior as well as to the selection of the representative weather scenarios and all cost-related elements, including fuel and CO2 prices.

Therefore, in order to improve the consistency of the adequacy assessment and better reflect real market conditions in the future ERAAs, there is a need for a further consolidation of the risk aversion modelling as well as of the EVA representative weather scenarios and cost-related data.

Slovakia

The ERAA 2025 LOLE / EENS results for Slovakia are noticeably higher than in previous edition of ERAA. Target years 2028 and 2030 show manageable values of LOLE, but with slightly higher EENS than in ERAA 2024. These values seem non-problematic, but hourly values of ENS, or at least peak values of ENS per target year, would provide more insight. For target years 2033 and 2035 the *central reference scenario with the enhanced hurdle premium combined with a revenue cap* value of LOLE indicates potential adequacy risk with non-negligible EENS. In Slovakia, a reliability standard has not yet been set, however we consider the values of LOLE and EENS worthy of attention, and the scenarios will be analysed within the national adequacy study.

The ERAA results may be slightly distorted, as the real development of wind power plants in Slovakia is not so optimistic as expected in the NECP and in ERAA 2025, since the current installed capacity is almost 0 MW and the NECP expects 750 MW in 2030. Development of solar energy is, however, increasing much more, than NECP expectations. On the other hand, the demand also may not increase as is expected in NECP. The impact of these different assumptions will be further analysed in the national adequacy study.

Spain

General overview of the ERAA 2025

The timely delivery of ERAA every year is important from the adequacy monitoring perspective, especially during the transition to a more decarbonized power system and an electrified economy, which has been possible in the 2025 edition thanks to the consolidation of the improvements achieved in previous editions. Red Eléctrica also finds very valuable that ERAA includes again a scarcity analysis that helps to understand and validate the results.

ERAA 2025 has focused on the representativity of the results through a new investor behavior consideration, an element that has been considered a limitation in previous editions as reliance on a few hours at very high prices in order to retain existing capacity or even to trigger an important volume of new capacity has been questioned by a wide range of stakeholders. According to the results, the consideration of higher risk aversion for new investments through a higher hurdle premium (as feedback received from consultations under the ERAA framework) already has a considerable impact, which is especially representative when combined with a revenue cap that also affects the viability of existing capacity subject to decommissioning. This lower net effect of the economic viability assessment across Europe then translates into higher risks when adequacy is assessed, which is necessary to achieve the economic equilibrium in the new conditions and explains the higher indicators when compared to previous editions.

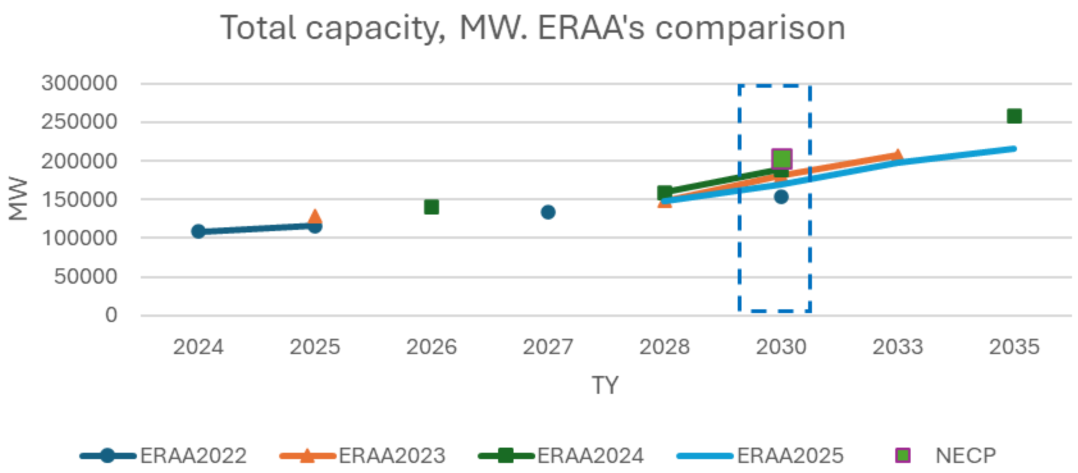
Also showing the adequacy indicators as a range of results is probably a better representation of what adequacy assessments aim: to provide indications of the expected capability of the system to supply a certain demand. Unfortunately, this cannot be represented through one single value, and probably a set of different values can better capture some of the uncertainties. In this sense, Red Eléctrica finds special value for adequacy monitoring to consider results, and understand the divergences, from different scenarios, editions and assessments as complementary in order to have a broader picture of possible future states of the system and take better informed decisions. In this sense, the results for the Spanish peninsular power system confirm the conclusions of previous ERAA and NRAA[19] editions and make evident it is important to keep monitoring adequacy in future assessments, and to introduce a capacity mechanism in the Spanish peninsular power system as a key planning measure, necessary to achieve the required level of system adequacy.

Spanish assumptions for the ERAA 2025

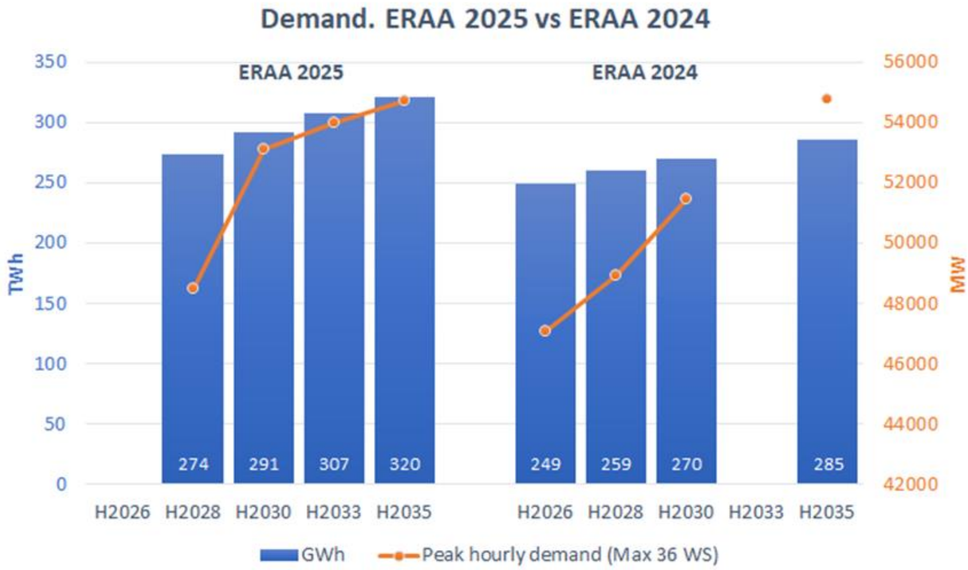
As in previous ERAA processes, Red Eléctrica has provided input data to create a scenario that best represents the expected reality of the Spanish system and respects the data collection guidelines. For the short and medium term (2026, 2028), the scenario is based on the most reliable information available to the TSO from market participants and on the recent evolution of installed capacities and issued permits. For the long term (2030, 2035), the data reported combines two key aspects. On the one hand, these two horizons have been defined in line with the final version of the NECP. On the other hand, the scenario reflects the current situation of the Spanish peninsular power system regarding new storage capacity: most of the expansion of storage foreseen in the NECP is subject to additional incentives, such as through a capacity market. However, to apply such a remuneration mechanism, an adequacy concern must first be identified. Therefore, in the ERAA 2025 pathway, only the volume of capacity that has already received some form of public support has been considered (which represents a reduction in capacity compared to the NECP and ERAA

[19] National resource adequacy assessment performed by Red Eléctrica as complement to the ERAA: https://www.ree.es/en/operation/system-development/studies-forecasts

2024). This assumption is in line with the recent Spanish National Resource Adequacy Assessment (NRAA).
Regarding the evolution of the rest of projected resource capacities, the largest increases occur in renewable generation, particularly onshore wind and photovoltaic, which grow in each target year. Offshore wind and solar thermal power are expected to develop mainly from 2030 onwards. Nuclear capacity is projected to gradually decline over the horizon in accordance with the current official schedule, while the combined-cycle fleet is assumed to remain stable.
The following chart summarizes Red Eléctrica's effort to provide the best possible information so that ERAA results are as consistent as possible with Spain's reality.



In terms of demand, an acceleration of the electrification process is expected in the medium and long term, in line with the NECP and endorsed by the important volume of demand connection agreements and requests for new connections received under the ongoing grid development plan (see the figure below). In ERAA 2025 demand levels for 2030 are aligned with the NECP which was published in mid-2024, constituting a relevant increase with regards to demand levels considered in ERAA 2024. An additional relevant aspect to consider regarding demand is that in ERAA 2025, peak demand is mainly observed across all WS during the winter period, in contrast to ERAA 2024, where there was a higher occurrence of peaks in summer according to WS. The evolution of electrolysers is aligned with that of the NECP and ERAA 2024: it is assumed to have an important evolution, although assumptions consider an electricity price driven operational mode demand that therefore has no impact on adequacy, while peak hours won't have attractive market prices for decarbonized H2 production. SRAD (Spanish acronym for "automatic demand reduction system") type demand side response was kept at the contracted value, while the historical maximum potential of 2600 MW is considered for additional demand side response expansion during the economic viability assessment step.



Cross-border capacities for the Spain–France border imply that no additional interconnectors will be available until 2030 beyond the HVDC Bay of Biscay project, while Navarra–Landes and Aragón–Atlantic Pyrenees would be only available outside the ERAA 2024 analysis period.[20] For the Spain-Portugal border, the proposed cross-border capacities already consider the future interconnector Beariz-Ponte de Lima since 2025. As in ERAA 2024, Balearic Islands and Ceuta have been considered as implicit regions, as well as Morocco.

Finally, reserve requirements are expected to increase slightly across the horizon, in line with operational scenarios that have recently occurred and suggest that as variability grows an increase of reserves is needed for system security.

The incorporation of future improvements in the data due to improvements in the dataset or new requirements must be monitored to be able to include them adequately and thus allow the comparison of results between the different analyses of the ERAA to be understood. In this sense, many of the assumptions that were included in the recent NRAA as differences with the ERAA 2024 have also been considered in ERAA 2025 for a better alignment and coordination of the assessments, such as the consideration of lower storage capacities, the weekly capacity for closed pumped storage, separation of 2 hour and 4 hour batteries, outage rate of combined cycles aligned with last available historical values, and the consideration of the Balearic Islands and Ceuta as fixed exchanges with the Peninsular system that cannot face ENS.

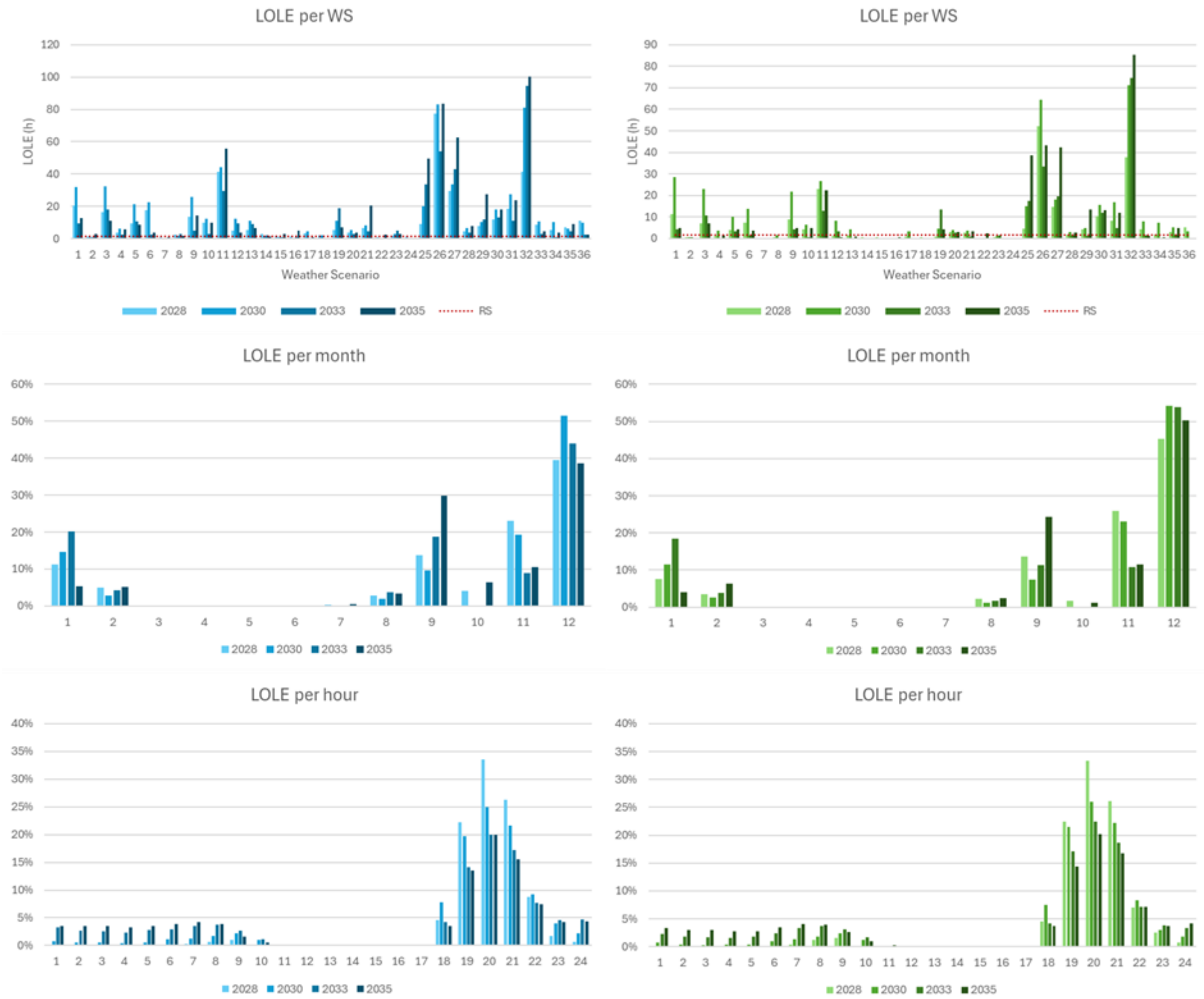
Economic viability assessment (EVA) results
Regarding the capacity modifications proposed by the EVA model for the Spanish peninsular power system, no decommissioning of combined cycles is observed. This difference with results of previous editions can be explained by the differences in terms of assumptions. With a similar generation fleet as the ERAA 2025, the NRAA that Red Eléctrica produced as a complement to the ERAA 2024 already showed a reduction of the unviable capacity from 9 GW identified in ERAA 2024 to 3.5 GW, which now is transformed into no decommissioning is due to the important increase of the expected demand considered in ERAA 2025. This tendency of a lower volume of unviable

[20] The values included in the model, in cases where the figures provided for a border by the TSOs involved differ, use the most conservative value (the minimum).

capacity is also observed in the additional results provided in ERAA 2025 under the revenue-based EVA case study.
In ERAA 2025, the EVA used for the central reference scenario also considers viable some battery expansion which is not observed in the revenue-based results and needs to be seen with carefulness, given the techno-economical characteristics of the default expansion candidate (mainly the 6 hour duration with a CAPEX of 1.5 MEUR/MW) may not be totally representative for the Spanish case currently as mostly 2 and 4 hour duration battery are being considered).

Adequacy assessment results
After the EVA results are applied to the initial set of data, the adequacy assessment is carried out. Spanish Reliability Standard (RS) expressed as maximum acceptable Loss of Load Expectation (LOLE) was approved in July 2025,[21] based on the CONE study released in October 2024,[22] and set at 1.5 hours per year.
The ERAA 2025 shows, under the given scenarios and methodological framework following the considerations set out by the Regulation EU 2019/943, a risk of adequacy issues above the reliability standard in the short (2028), mid (2030) and also long-term (2033, 2035). This message is different from the ERAA 2024 which only identified risks for 2028 but is in line with the results of the NRAA 2025 where adequacy risks were identified not only for the short term but also for the mid-term with a similar generation fleet as the ERAA 2025. Now ERAA 2025 confirms this for 2028 and 2030 and identifies potential adequacy risks for the first time also for 2033 and 2035 given the higher considered demand. The adequacy indicators obtained for 2030 in ERAA 2025 seem reasonable when compared to the additional simulations performed in the NRAA with all the combined cycle capacity that already showed non-zero values.
The following figure shows a detailed distribution of Energy Not Served in the Spanish peninsular power system for the different target years that allows to extract some key values and draw conclusions, also considering the scarcity analysis shown in Annex 4. The table below also shows a summary of the results and some additional interesting statistics. From this information, it is confirmed that risks typically appear during the evening hours of autumn and winter months. Also, it is observed that a very high proportion of weather scenarios has non-zero ENS and most of them face LOLE > RS, meaning that the system faces some structural lack of generation.

[21] Resolución de 7 de julio de 2025, de la Dirección General de Política Energética y Minas, por la que se fijan los valores del valor de carga perdida y el estándar de fiabilidad, de conformidad con lo previsto en el Reglamento (UE) 2019/943, del Parlamento Europeo y del Consejo de 5 de junio de 2019, relativo al mercado interior de la electricidad: https://www.boe.es/eli/es/res/2025/07/07/(2)
[22] Informe INF/DE/114/24 de 31 de octubre de 2024, de la Comisión Nacional de los Mercados y la Competencia, sobre la determinación del coste de nuevos entrantes (CONE) para la determinación del estándar de fiabilidad (RS): https://www.cnmc.es/sites/default/files/5650953.pdf

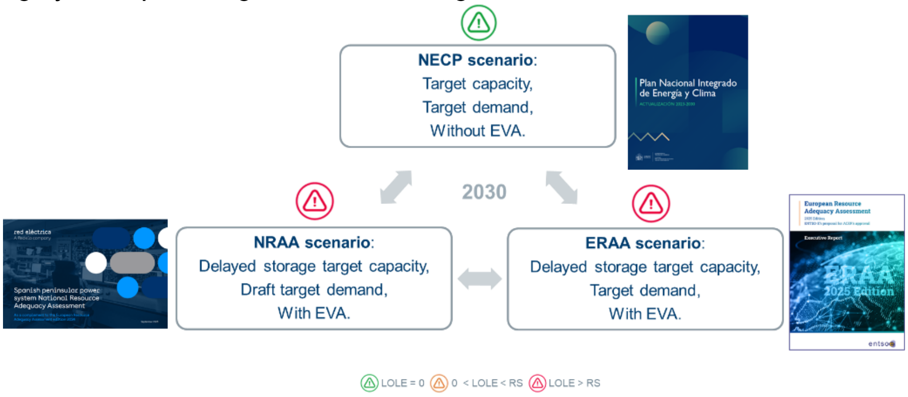


	2026	2030	2033	2035
LOLE (h/y)	**6.35 - 11.32**	**11.09 - 15.98**	**6.37 - 11.45**	**9.06 - 18.61**
WS LOLE<>0 (%)	100 - 100	92 - 97	78 - 92	89 - 97
WS LOLE>RS (%)	61 - 83	75 - 83	44 - 75	58 - 83
EENS (GWh/y)	9.87 - 16.65	22.67 - 35.66	11.21 - 20.44	16.91 - 36.41
Max ENS (GW)	8.27 - 9.76	10.33 - 12.46	11.98 - 12.26	10.95 - 11.26

Wrap up
The ERAA 2025 shows, under the given scenarios and methodological framework following the considerations set out by the Regulation EU 2019/943, a potential adequacy risk above the reliability standard in the short (2028), mid (2030) and also long-term (2033, 2035).

The Spanish NECP also includes an adequacy assessment for target year 2030 following the ERAA methodology (without applying an EVA), and Red Eléctrica recently published a NRAA as a complement to the ERAA 2024 reassessing target year 2030. This allows to compare, for this key target year, adequacy in three different scenarios and extract some key messages. While NECP shows that with 2030 target capacities the desired electrification level can be achieved, NRAA shows that if the storage targets set in the NECP are not achieved in the expected time, in case of decommissioning on the volume of non-economically viable thermal generation, adequacy risks would rise above the RS. Now ERAA 2025 confirms it and extends until 2035 after aligning the demand values with the updated NECP target value.

Therefore, a combined look of these three assessments allows us to understand the importance of implementing system planning measures that guarantee the achievement of the targets in time.



To sum up, ERAA 2025 results for the Spanish peninsular power system add to those already available from ERAA 2022, NRAA 2023, ERAA 2023, ERAA 2024 and NRAA 2025 making evident it is important to keep monitoring adequacy in future assessments, and providing robust justification to introduce a capacity mechanism in the Spanish peninsular power system as a key planning measure, necessary to achieve the required level of system adequacy. These mechanisms have in fact already been considered in the NECP as a measure to reach the targets. Further delays in their implementation will eventually critically increase the possibility of situations without sufficient system adequacy in the years analyzed in the light of the projected system evolution.

Sweden

The input data for Sweden is primarily based on the national short-term electricity market analysis and the long-term EP scenario, which assumes a high level of electrification. The projected increase in electricity demand is driven mainly by industrial electrification and hydrogen production. New national short-term and long-term assessments are currently being developed at Svenska kraftnät, incorporating updated assumptions on future demand and generation projections. Recent developments indicate that the expected short-term increase in demand will be postponed, as several industrial projects have been delayed.

In the EVA, a 440 MW CCGT unit in SE04 is being decommissioned in target year 2028. According to a decision by the Swedish National Electricity Preparedness Authority, this plant should be part of the Swedish electricity preparedness and remain in operation up to and including 2029. Considering the adequacy situation in SE03 and SE04, the unit could also be economically viable in later target years. This has an impact on the adequacy situation for target year 2028 and potentially also for later years.

The ED results indicate that the LOLE exceeds the reliability standard (1.0 hours/year) in SE03 and SE04, particularly in the later part of the study period. This reflects both the increasing electricity demand and the rising adequacy risk in nearby regions, as evidenced by simultaneous scarcity outcomes. Notably, the adequacy risk in SE03 and SE04 remains high despite a substantial expansion of DSR in the region. There is also some adequacy risk in northern Sweden (SE01), slightly above the reliability standard in the combined risk aversion scenario in target year 2035. Recent findings suggest that the results may have been affected by modelling limitations regarding hydro production and DSR in SE01. Svenska kraftnät does not foresee adequacy risk exceeding the reliability standard in SE01. Overall, the main observation is the increasing adequacy risk in SE03 and SE04 toward the end of the study period.

Switzerland

Although no adequacy issues have been identified for Switzerland in the present exercise, ERAA 2025 shows that adequacy indicators will remain tight in Europe in the coming years. The results of this adequacy study are based on the input assumptions coming from the Swiss “Scenario Framework for Electricity Network Planning” and the "Energy Perspectives EP2050+". Thus, their validity depends on the implementation of the generation and electrification targets according to these documents.

For the system adequacy not to deteriorate, the integration of Switzerland in the European grid must be ensured. Any reductions of the cross-border capacity between Switzerland and its neighbours will have adverse impacts on Switzerland and, potentially, on the whole region. To mitigate these effects, Swissgrid has entered into relevant agreements with the CCR Italy North, Core and Central Europe. To ensure the adequacy of the system in the long term, it is important to maintain at least the current cross-border capacity values even in the absence of an electricity agreement.

Ukraine

Electricity consumption in Ukraine decreased by approximately 30% in 2022 compared to 2021 and has remained at a relatively low level since. A gradual recovery is expected, with an average annual growth rate of around 1.5% over the medium-term horizon. However, consumption in 2025 and 2026 may be slightly lower than in 2024 due to the relocation of industrial enterprises from eastern to western regions of Ukraine, driven by the ongoing military aggression from Russia. This shift has been incorporated as an assumption in the national medium-term electricity demand forecast.

The medium-term development of electricity generation is projected to include a significant share of distributed generation. This will consist of small gas-fired units, consumer-owned solar installations, and battery energy storage systems. In the long-term perspective, further expansion of nuclear and renewable energy sources is anticipated. This direction is supported by the Ukrainian Government and relevant legislation.

Despite continuous barbaric attacks by Russia on Ukraine's energy infrastructure since 2022, the Ukrainian Power System has demonstrated resilience. Adequacy issues arise primarily in the aftermath of direct missile strikes on energy facilities.