European Resource Adequacy Assessment

2021 Edition

Annex 5: Country Comments

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 statement.

1 Austria

1.1 NTC scenarios

The results of the ERAA 2021 Net Transfer Capacity (NTC)-based simulations do not identify any adequacy concern in Austria even under stressed system conditions (e.g. reduced thermal capacity in the pan-European system). Security of supply is also ensured in the scenarios ‘EVA with/without Capacity Mechanism’ and ‘National Estimates with Low Thermal Capacity’. Nevertheless, we want to highlight that neither the ‘local matching constraint’ nor the ‘curtailment sharing’ rule (consistent with Chapters 6.8.1 and 6.8.2 of the Euphemia Public Description 2020) were applied in the NTC calculations. These rules might affect the Austrian results as a first impact was identified in the flow-based (FB) calculations where such principles were applied.

We would also like to highlight that when assessing the 2030 results for the ‘National Estimates with Low Thermal Capacity’ scenario, it is very hard to follow results for individual countries due to the drastic decrease in thermal generation capacity in Poland. Such extreme reduction strongly affects the adequacy indicators for the whole north and eastern-European region.

1.2 Economic Viability Assessment and Flow-Based Market Coupling

When interpreting FB results, it is noticeable that the selection of the FB domains (i.e. of the underlying list of Critical Network Elements and Contingencies; CNECs) has great importance and naturally affects the results. Within the ERAA 2021 proof of concept, it was certainly an insightful and useful exercise to investigate and elaborate on the different approaches available. Nonetheless, APG (Austrian TSO) sees as a key step forward the need to align on a single common and consolidated FB methodology for the calculations of the domains in the upcoming ERAA reports.

It is also important to stress that the published FB results are based on the ‘EVA without Capacity Mechanism’ scenario, which envisages a massive net retirement of thermal capacity up to more than 60 GW over the whole pan-European perimeter. The Economic Viability Assessment (EVA) was executed for the first time within the ERAA 2021 with some simplifications and will be further improved in future ERAA editions. The full implementation of the EVA in compliance with the ERAA methodology will follow ENTSO-E’s roadmap for ERAA development up to 2024. It follows that the EVA of the ERAA 2021 and its impact on the adequacy indicators have to be considered carefully when assessing the ERAA 2021 results.

To conclude, the ERAA 2021 FB results, as opposed to NTC simulations, already include a post-processing implementation of the ‘local matching constraint’ and the ‘curtailment sharing’ rule (consistent with Chapters 6.8.1 and 6.8.2 of the Euphemia Public Description 2020).

1.3 Input data quality

APG acknowledges the challenging work and the great efforts done by ENTSO-E and its member TSOs in collecting and maintaining the central dataset required by the ERAA assessment. As the ERAA 2021 process showed, having stable input data through the course of the whole process is of outmost importance. Proper data validation routines shall be guaranteed as changes of input data during the process jeopardisejeopardize the punctual and successful delivery of the ERAA.

2 Belgium

Previous adequacy studies performed for Belgium have all concluded that Belgium will face serious security of supply challenges as of 2025, due mainly to the phase-out of nuclear capacity and the energy transition evolutions in neighbouring countries. It was also established that this creates a significant need for new capacity as the existing capacity, in addition to ambitious assumptions regarding imports and future capacity developments such as Demand Response or renewable energy sources (RES), prove insufficient to cover the future needs.

In a recent study performed by Elia in June 2021 ('Elia study 2021', see footnote[1]), the adequacy need was again confirmed. This study, which closely follows the ERAA methodology, was the centrepiece for the Belgian authorities in the framework of the approval by the European Commission of a Belgian market-wide capacity remuneration mechanism (CRM) as of 2025. The European Commission approved the Belgian CRM on 27 August 2021.

2.1 General assumptions

The assumptions provided for Belgium in the ERAA 2021 are in line with those around the so called 'CENTRAL' scenario for Belgium for the target year 2025 and 2030, as defined in the 'Elia study 2021'. The main assumptions of this 'CENTRAL' scenario are based on the latest official targets and public information as outlined in Fig 3-3 of the 'Elia study 2021'.

2.2 Market capacity resource

For the 2025 and 2030 time horizons considered in the ERAA 2021, the assumptions for Belgium are in line with the recent 'Elia study 2021'. RES assumptions are based on the 'National Energy and Climate Plan' submitted by Belgium end of December 2018. The demand side response (DSR) and storage capacities are based on the 'Belgian Energy Pact' assumptions agreed upon by different Belgian authorities.

From 2025 onwards, no nuclear capacity is assumed in Belgium, in accordance with the planned nuclear phase-out.

For 2025, 2.4 GW of new capacity is assumed in the ERAA 2021. Such capacity relies on the assumption that it will be delivered under the CRM. Furthermore, it should be noted that in the 'Elia Study 2021', a volume of 3.6 GW new capacity has been identified as necessary to ensure an adequate Belgian system and to cover for uncertainties 'beyond the control' of Belgium.

2.3 Grid

Belgium has one of the highest interconnection capacities when compared with its peak consumption. Belgium's central location in Europe means that the country's import and export capabilities are defined following the principles of FB capacity calculation and capacity allocation within market coupling, as introduced by the European guidelines on Capacity Allocation and Congestion Management.

[1] https://www.elia.be/en/publications/studies-and-reports

The ERAA 2021 considers NTC simulations as main simulations for 2025 and 2030, which for Belgium provide an optimistic view on the ability of Belgium and its direct neighbours, notably France, The Netherlands, Germany and the United Kingdom, to receive imports during single and simultaneous scarcity situations.

Since the beginning of 2020, the 'Clean Energy for all Europeans Package' has been in effect. As a consequence, 70% minimum Remaining Available Margins (minRAM) has to be offered to the market for commercial exchanges and by 31/12/2025 onwards, the 70% minRAM requirement has to be applied rigorously to all CNECs. The 70% minRAM requirement is duly considered for all Belgian borders and for all borders modelled within the FB modelling (c.f. Annex 4 for details) in the ERAA.

Regarding the 70% minRAM requirement within the NTC simulations and with respect to the Belgian borders, it is important to note that, according to Elia, it is not possible to properly verify this 70% minRAM rule within NTC simulations as no consistent Pan-EU methodology is available. Furthermore, Elia nowadays performs only FB simulations in all its national studies. Therefore, NTC results in the ERAA 2021 for Belgium should be considered with care.

2.4 Demand

The total electricity demand was elaborated by use of growth rates based on the economic projections from the Federal Planning Bureau and with additional electrification based on the National Energy and Climate Plan (NECP). The macro-economic projections from the Federal Planning Bureau were published in June 2020 and considered the expected effects of the COVID-19 pandemic known at that time.

Regarding energy efficiency assumptions, these were based on the ambition in the last version of the NECP (WAM scenario) and thus include the additional measures foreseen in the framework of the European energy efficiency targets for 2030.

Additional electrification (on top of the existing devices already considered in the total consumption) was added by considering the consumption from additional electric vehicles (EVs) and heat pumps, as defined in the final NECP of Belgium published end of 2019.

2.5 Market reforms

The following comments can be provided with respect to the market reforms mentioned in Article 20(3) of the Electricity Regulation and the assumptions taken in the ERAA 2021:

- Related 'to price caps':
    - The default assumption in the ERAA 2021 for the price cap is a value of 15k EUR/MWh, as recommended by ACER.
    - It should be noted that the current value of the price cap in the Single Day-Ahead Coupling (SDAC) is, however, lower and equal to 3000 EUR/MWh.
    - The evolution for the current value of the price cap to reach a value of 15k EUR/MWh from 2025 onwards should be thus considered with care.
    - Therefore, ENTSO-E has also considered a sensitivity with a current value of SDAC price cap of 3000 EUR/MWh in the simulations.

- Related to 'measures related to interconnection capacity' and to the 70% minRAM requirement, these requirements are duly considered within the FB simulations performed in the ERAA 2021.

- Finally regarding to ‘Measures which relate to balancing energy and procurement of balancing and ancillary services’, these aspects are considered in the assumptions made in the ERAA 2021 regarding the volumes of ancillary services and its consideration in the economic dispatch modelling.

Finally, and following Article 20(3) of the Electricity Regulation, the implementation plan of Belgium was published in 2020[2].

2.6 Out-of-market measures

No strategic reserve mechanism for Belgium is in place for the time horizons (2025, 2030) considered in the ERAA 2021.

2.7 Comments with regards to the ERAA EVA results

The EVA performed in this ERAA leads to significant economic retirement of capacities throughout Europe. Although the overall conclusions seem justified, it should be mentioned that the per-country results should be treated with care as investment decisions per country will be based on detailed assessments by capacity owners considering all national particularities which were out of the scope of this ERAA assessment.

It is therefore very important to highlight the following regarding the EVA ERAA 2021 results for Belgium:

  - 2.4GW new capacity is assumed as ‘present’ within the EVA in ERAA 2021, thus this capacity is only subject to FOM and not to CAPEX in EVA.
  - Therefore, this 2.4GW capacity is not retired in EVA; 2.4GW is assumed as ‘existing’ in Belgium in all the EVA results of the ERAA 2021 as its commissioning date is assumed to be prior to 2025.
  - Sanity checks performed on these EVA results confirm that if these 2.4GW capacity were to be assessed as truly ‘new built’, *i.e.* considering both FOM and CAPEX in the EVA, this capacity would not be viable and would be retired by the EVA. This confirms the assumption that this 2.4GW capacity is to be delivered under the CRM and that without a CRM, it will not be viable.

2.8 Comments with regards to the ERAA Adequacy results

2.8.1 Comments on 2025 results

- In the central reference scenario without capacity mechanisms (CMs), the simulated Loss of Load Expectation (LOLE) for Belgium is above the reliability standard, both for the base scenario and for all sensitivities. This confirms that Belgium will need to rely on a CRM to ensure its adequacy after the nuclear phase out in 2025.

- In the central reference scenario, considering the approved CMs, extra capacity is added in France, the United Kingdom and Italy. Furthermore, a need for ‘extra’ new capacity of 0.5 GW in addition to the already assumed 2.4 GW new-built is found for Belgium within the EVA iterations (see the ERAA report for details)
- These results support the observations that:
  - Belgium needs, at least, a ‘minimum’ of ~3.0 GW new capacity to ensure its adequacy, according to the NTC simulations in the ERAA 2021.

[2] https://economie.fgov.be/sites/default/files/Files/Energy/Belgian-electricity-market-Implementation-plan.pdf

  - Belgian adequacy heavily depends on the situation in its neighbouring countries as Belgium significantly relies on imports at times of scarcity.
  - We note that these results are based on NTC simulations, which provide an 'optimistic view' of situations of simultaneous scarcity between Belgium and other relevant neighbours France, Germany, The Netherlands etc...

- The FB simulations carried out in the framework of the ERAA 2021, which include the modelling of the curtailment sharing rules currently in place in the market coupling, indicate that the expected LOLE for Belgium would further increase compared to the NTC simulations. An ex-post check revealed that, to achieve the Belgian reliability standard, the additional capacity that needs to be added to the Belgian system increases to 1.2 GW (on top of the 2.4 GW of new-built capacity already assumed in the base case).
  - According to the FB simulations, Belgium thus needs a 'minimum' of ~3.6GW new capacity to ensure its adequacy.

- Finally, it should be noted that for the 'National Estimates with low thermal capacity' scenario, no specific reduction of thermal capacity data was provided for Belgium as Elia is of the opinion that such scenarios should be centrally built based upon an overall economic assessment. Nevertheless, a simplified viability check performed on this scenario revealed that the majority of the thermal technologies existing in Belgium would not be economically viable under the assumptions of installed capacity throughout Europe in 2025.

2.8.2 Comments on 2030 results

- Similar to the Mid-Term Adequacy Forecast (MAF) 2020, the 2030 simulations carried out for the ERAA 2021 are based on national assumptions collected, without applying an EVA. A simplified viability check performed on this scenario revealed that the majority of the thermal technologies existing in Belgium would not be economically viable under the assumptions of installed capacity throughout Europe assumed in 2030, both for the Base Case A 'National Estimates' and Base Case B 'National Estimates with low thermal capacity'.

The adequacy results therefore paint an overly optimistic view, and should be interpreted with care. Elia therefore considers that a similar disclaimer to MAF 2020 is applicable for the 2030 results of the ERAA 2021.

3 Czech Republic

The inputs reported for the ERAA 2021 for both target years are characterised by the significant growth in demand caused by electrification in the sector of transport (electromobility) and heating (heat pumps) without considering the possible additional consumption connected to hydrogen production. The coal phase-out is, according to NECP and other strategic policy documents, foreseen to occur by 2038 while being substituted partly by new Combined Cycle Gas Turbines (CCGTs) and the boost in RES deployment.

The ERAA 2021 National Estimate and National Estimates with Low Thermal Capacity scenarios show no critical adequacy issues for the Czech Republic (CZ) in 2025 and 2030. However, the EVA w/wo Capacity Mechanisms (CM) scenarios reveal quite an increase in the LOLE value stemming from the economical decommissioning of both existing and newly planned power sources that can no longer cover their fixed/operational costs. In the case of CZ, the EVA pulls almost the entire installed thermal capacity out of the market including those power plants allocated to provide ancillary services. In addition, after this economical retirement, the EVA scenarios lead to a slight increase in DSR. In our national sensitivity scenario aiming at the decommissioning of all lignite units earlier than by the end of 2033, the withdrawal of installed thermal capacity by 2025 does not reach such levels. For next ERAA editions we welcome further improvement of thermal phase-out modelling in the EVA. Moreover, we suggest considering taxonomy impacts on investment in gas power plants within the further development of the EVA methodology. Furthermore, by end of year 2021, the reliability standards should be defined, and it would be suitable to consider these while applying the EVA in future ERAA editions. Regarding imports, in the case of CZ it is not possible to exceed 10% of import dependence, which stems from Czech energy policy.

Even though FB is not a central reference scenario, high LOLE values, caused not only by applying the FB curtailment sharing but also by the fact that it runs on the top of the EVA without a CM approach, are creating caution. For the ERAA 2022, CEPS fully supports the development of the methodology in a manner that further works on curtailment sharing, and domain size is required to portray cross-zonal trade accurately. Furthermore, using the FB method over the scenario applying the EVA could lead to an increase of LOLE values in CZ.

4 Denmark

The adequacy results for Denmark in the National Estimate scenario in the ERAA 2021 are roughly in line with the comparable results from the newest national adequacy assessment from Energinet.[3] The risk of lack of resource adequacy is increasing over the next decade in Denmark, especially in the Eastern part of Denmark (DKE). Over the next decade, it is expected that Denmark will become more dependent on electricity imports to secure resource adequacy. Hence, the development in the resource adequacy situation across Europe, especially in Northwestern Europe, is very important for Danish resource adequacy assessments. The ERAA 2021 gives, and forthcoming ERAA studies will give a very important insight into this development.

Even though the Danish input assumptions for the newest national resource adequacy assessment from Energinet[3] and for the National Estimate scenario in ERAA 2021 are in general quite aligned[4], there are some important differences to highlight. One significant difference is that manual frequency restoration reserve (mFRR) capacity is assumed to support Danish resource adequacy in the national study, whereas in the ERAA 2021 no balancing reserves are supporting resource adequacy. Another important difference for 2030 is that the national resource adequacy study contains two Danish energy islands and associated interconnectors, whereas the ERAA 2021 does not. However, the national resource adequacy study contains sensitivity analyses where the above-mentioned differences are aligned with the ERAA 2021. These specific sensitivity analyses from the national resource adequacy study and the National Estimate scenario in the ERAA 2021 show similar results.

Further differences exist between the ERAA 2021 and the newest national adequacy study from Energinet, but these will not be described in detail here. For example, the national resource adequacy study contains

[3] Every year, Energinet must perform national resource adequacy assessments according to Danish legislation. The latest version is Energinet's Security of Electricity Supply Report 2021 (edition for consultation): https://energinet.dk/El/Horinger/Hoeringer/2021-09-Hoering-af-redegoerelse-for-elforsyningssikkerhed-2021 (in Danish). The final version is available from mid November 2021 at https://energinet.dk/Om-publikationer/Publikationer.

[4] Both the National Estimate scenario in the ERAA 2021 and the national adequacy assessment from 2021 is based on Danish assumptions regarding generation capacities and demand from 'Analysis assumptions for Energinet 2020 (AF20)' from the Danish Energy Agency: https://ens.dk/service/fremskrivninger-analyser-modeller/analyseforudsaetninger-til-energinet.

more sophisticated modelling of Danish interconnectors, must-run constraints on Danish power plants and Danish demand profiles. The ERAA 2021 is based on the most up-to-date European data, whereas the newest national resource adequacy assessment from 2021 is based on MAF 2020 data for Europe in general.

National Estimate is only one of the scenarios analysed in the ERAA 2021. The results for the other scenarios in ERAA 2021 show a more stressed European resource adequacy. If future developments move more in the direction of these other scenarios, this will increase the risk of lack of resource adequacy in Denmark earlier than the results in the national study show. This is also what the ERAA 2021 results for Denmark demonstrate.

5 Finland

The underlying assumptions of the National Estimates scenario in ERAA 2021 reflect the expected future developments in the Finnish power system. Finland has been strongly dependent on imports for many years, but the Finnish power balance is expected to improve over the next years. From an adequacy perspective, however, Finland remains dependent on imports from neighbouring countries during periods of high demand and low wind power output. Therefore, the resource adequacy of neighbouring countries and associated interconnectors have a large effect on adequacy margins. This highlights the importance of current and future ERAA studies to have a comprehensive view of the developments in the interconnected European energy system. Overall, the ERAA 2021 results indicate that adequacy in Finland improves in the 2020s, which is in line with the comparable results from previous adequacy studies.

It is important to note that severe weather conditions and plant or interconnector outages can have a significant impact on adequacy in Finland. These have been considered in the ERAA methodology with the combination of climate scenarios and random outages. Comparing 95th percentile and average results per scenario in Appendix 2 shows that some climate years with possible outages are more challenging than what the average results indicate.

Regarding reliability standard, a government resolution set the standard to a LOLE equal to 3 h/year and EENS equal to 1800 MWh/year on 8 July 2021. The reliability standard was only considered in the modelling of the scenario with CM in case the adequacy indicators are higher than the standards set. Therefore, the reliability standard has no impact on the results of the analysis.

Regarding reserves modelling, Finland currently has a strategic reserve in use that, according to the methodology, was not included in the modelled capacity. Fingrid also has out-of-market back-up power plants to meet the fast disturbance reserve capacity requirement. These plants were included in the model but their impact on adequacy was offset by adding the reserve capacity requirement to the hourly consumption as described in the methodology. The back-up plants were set to activate only at very high prices to activate market-based capacity first. The applied modelling methodology for the Finnish back-up plants, however, increases power prices. This affects the EVA results, which indicates that gas capacity in Finland would be profitable in the scenarios. This does not affect the adequacy results of the National Estimates scenarios but affects the scenarios that apply an EVA. In both scenarios considering an EVA, the LOLE is seen to decrease slightly compared to the National Trends scenario.

Considering the modelling of Russian imports to Finland, part of the imports is modelled as a simplified fixed flow and part as a price-dependent generation capacity in Finland. There are uncertainties related to the impact of capacity payments on the Russian electricity markets and possible implementation of the Carbon Border Adjustment Mechanismcarbon border adjustment mechanism, which might reduce the imports and further have a negative effect on adequacy in Finland.

The capacity used for modelling Russian imports to Finland is excluded from the capacities published in the dataset for Finland. It is to be noted that the dataset, however, includes the out-of-market disturbance reserve capacity under the others non-renewable category, and peat-fired capacity in Finland is shown under the hard coal category.

6 France

6.1 The National Energy and Climate Plan

Since 2015, a new legal framework known as 'loi de transition énergétique pour la croissance verte' with its planning documents 'stratégie nationale bas-carbone' and 'programmation pluriannuelle de l'énergie' has been established to provide a roadmap for the energy field in the coming years.

In April 2020 the NECP, elaborated in these two documents[5][6], was officially passed by the energy ministry after a two-month public consultation.

6.2 Load forecast provided for 2025 and 2030

After remaining stable over the past decade, the French electricity demand fell sharply in 2020 (460 TWh, i.e. 13 TWh less than in 2019). This decrease was circumstantial and due to the health crisis, in particular due to its impact on to the industrial and tertiary consumption during the first lockdown. The conditions for an economic recovery remain uncertain, but a 'rebound' effect in electricity consumption is expected in 2021, linked to the rebound in economic activity.

In the medium term, French electricity demand is expected to increase, especially from around 2024 onwards. Indeed, the recovery of the economic activity and the development of electricity as a decarbonisation vector will more than counterbalance the effects of energy efficiency actions on the annual demand.

Main drivers with a rising effect on demand are:

- Approximately 5% of the French electricity demand dedicated to hydrogen production in 2030;
- Approximately 20% of the vehicle fleet will be electric in 2030;
- Increasing the share of electricity in heating systems and industrial processes.

The demand forecast of this ERAA is thus consistent with the French NECP and the projection assessed by RTE in its last adequacy report published in March 2021.

This trajectory has been revised upwards compared with the previous MAF, which was based on the last long-term national adequacy report (published in 2017). This update especially considers new climate regulations and the development of electricity uses (EVs, hydrogen production, etc).

6.3 Net generating capacity forecast provided for 2025 and 2030

The targets of the French NECP are reached within the central scenario of the ERAA 2021. The paramount evolutions for the French energy mix are:

[5] https://www.legifrance.gouv.fr/affichTexte.do?cidTexte=JORFTEXT000031044385&categorieLien=id
[6] https://www.ecologie.gouv.fr/programmations-pluriannuelles-lenergie-ppe

- Accelerated development of RES (wind and solar capacities are multiplied by more than three in the next ten years);
- Decommissioning of two of the remaining coal units by the end of 2022. The decommissioning of the last two coal units (Cordemais power plant) has been postponed to 2024, for security of supply concerns;
- No commissioning of new gas units, except CCGT Landivisiau in 2022;
- Commissioning of the new Flamanville power plant after 2022;
- Four nuclear units will be shut down between 2027 and 2030 (in addition to the closure of the two Fessenheim reactors that occurred in mid-2020) to reduce the nuclear share in electricity production to 50% by 2035. The NECP has also allowed the possibility of decommissioning two other units in 2025/2026, with conditions relating to security of supply and economic interest. RTE concluded in its latest national resource adequacy assessment (NRAA) that these conditions are not be likely to be met. Hence, these two additional closures have not been considered in this ERAA.

6.4 National view on adequacy and economic viability

RTE produces an annual risk assessment through its national generation adequacy report on a time horizon of five to ten years. Overall, the ERAA 2021 results seem to be in line with national elements published in March 2021[7].

The key messages from the NRAA were:

- Security of supply in France is under vigilance for the next three years, mainly due to the coal phase-out, the delayed commissioning of the new nuclear reactor, and the several nuclear outages planned during the next winters;
- Around 2025: a return to positive margins. The extent of the margins is, however, conditioned by (i) factors which may be uncertain (improved nuclear availability, achievement of national targets, etc.) and (ii) maintaining the French CM;
- In 2030, important positive margins can be reached but this remains highly uncertain as it relies on the assumption that France, but also its neighbouring countries, succeed in achieving all their national targets.

Although the ERAA 2021 results are globally consistent with the NRAA, several methodological approaches in the two analyses could lead to potential discrepancies:

- They do not use the same climate database. Although the one used in the French study models 200 potential forecasting climatic years (consistent with the effect of climate change for the next decade) with a full correlation between load, solar and wind conditions, the one used for the different studies at ENTSO-E (Seasonal Outlook, ERAA, TYNDP) is based on 35 historical climatic years (with a temperature detrending[8]).
- The nuclear availability in France is considered differently in both resource adequacy assessments. The French generation adequacy study combines a deterministic approach for all the planned outages (information shared via the official transparency channels – REMIT) for

[7] https://assets.rte-france.com/prod/public/2021-04/Bilan%20previsionnel%202021.pdf https://assets.rte-france.com/prod/public/2021-05/Bilan%20previsionnel%202021%20-%20annexes%20techniques.pdf

[8] See Annex 3

which each duration is probabilistically extended consistently with what has been observed in the past years, with a probabilistic one for the other outages. In the ERAA, the simulated availability of nuclear power plants considers uncertainty on the extension of the duration of outages in a deterministic manner instead of probabilistically.
- The FB approach, which is studied through a sensitivity in the ERAA, is modelled for the central scenario in the French national study.

Specifically for the EVA, RTE provided analyses with a significantly different approach, among others:
- Fewer Monte-Carlo years have been considered in the ERAA (< 10) than in the NRAA (200). This can lead to underestimating the high variability of the climatic conditions (renewable production, thermal sensitivity) and their impact on electricity prices.
- In the ERAA, investment and retirement of units are optimised deterministically on each scenario individually to meet the reliability standard. At the end, the average number of units by technology is taken over all scenarios to build the 'optimal' generation fleet. In the NRAA, RTE uses a standard stochastic approach, whereby investment and retirement of units are optimised over all scenarios (simulated all together) to meet the reliability standard and build the optimal generation fleet.
- Although the ERAA models the risk aversion via a modified weighted average cost of capital (WACC; based on fixed values), the EVA from the NRAA relies on statistical indicators of the revenue distribution allowed by using a high number of Monte-Carlo years.
- The NRAA also considers the dynamic constraints (start-up costs, start-up time, …) which have not been modelled in this ERAA.
- RTE has modelled the price caps consistently with the new regulation, being increased by 1000 €/MWh automatically 5 weeks after when market prices reach 60% of the current price cap. This has not been explicitly modelled in the ERAA.

Consequently, the results of this ERAA for France have to be treated cautiously and read jointly with the French last NRAA (also called 'Bilan prévisionnel') published in early 2021.

7 Germany

The ERAA 2021 report shows that, for the interconnected European energy system, resource adequacy in each country inter alia depends on the development of the energy system in its neighbouring countries. Therefore, the four German TSOs underline that regional coordination in decision making is necessary.

The underlying scenario assumptions of scenario National Estimates reflect the current legislation in Germany. The last nuclear power plants will be shut down in 2022, whereas hard coal and lignite-fired power plants must be shut-down by 2038 at the latest. The combined capacity of the latter must be reduced at least down to 30 GW by the end of 2022 and to 17 GW by April 2030. The German Climate Change Act was revised in August 2021 with more ambitious greenhouse gas reduction targets, which may lead to an acceleration of the phase-out of coal-fired power plants. It may also lead to an accelerated expansion of RES and the electrification of final energy consumption.

With its first implementation this year, the ERAA has taken multiple steps to comply with the ERAA Methodology requirements, while still representing an intermediate approach that requires improvement in the coming years to reach the necessary quality. The German TSOs acknowledge the improvements already achieved, but also see the following improvement potential for upcoming ERAA reports:

1. The ‘EVA - Economic Viability Assessment’ simulation run.

The EVA provides important insights on how the power plant park in Europe may develop without intervention from governments, i.e. a purely market perspective. It considers regional interactions and represents a valuable complementary scenario to TSOs’ National Estimates. Methodology wise, the implementation in the ERAA 2021 contains simplifications and assumptions that can have an important impact on the results. For example, a large number of units show a lack of economic viability, which is partly due to assumptions regarding ‘must-run’ profiles of units or disregarding other revenue streams such as heat or ancillary services. In addition, an integrated approach covering a large temporal horizon across the typical lifetime of units is required to model more realistic investment or retirement decisions. Considering the expected transformation process (e.g., expansion of renewable energy and electrification), anticipating this trend significantly influences an investment decision. By classifying the EVA scenarios as one of many reference scenarios, it highlights that the EVA results require assessment in comparison to the other scenarios. The substantial decommissioning in Germany (approx. additional 9 GW compared to National Estimates), already in 2025 provides a path which, from the perspective of the German TSOs, represents an extreme scenario with a considerably lower probability of occurrence. However, the German TSOs appreciate the enhancement of analysing a scenario resulting from an EVA.

2. The modelling of new flexible consumers.

New consumers such as e-mobility or heat pumps are not yet considered in a flexible mode of operation. In the future, it might be feasible to model an electricity market-oriented mode of operation, at least for a share of flexible end consumers. The same applies to sector coupling technologies such as electrolysers, which are currently out of consideration in the ERAA 2021.

3. Dealing with the strategic reserve in Germany.

The strategic reserve in Germany is not included in any of the scenario results shown. On the one hand, this is due to the fact that the current legal basis for this reserve in Germany no longer exists in the years under consideration. On the other hand, the analyses determine the market LOLE that is achieved with market-based CMs. In contrast to the capacity markets, which are considered in the EVA run with CMs, the German strategic reserve (‘Capacity Reserve’) is solely intended for national reliability problems. It is therefore to be considered outside the market and consequently not used in this run. A basic assumption of the modelling in ERAA is that each unit included can be deployed for national and foreign scarcity situations. Nevertheless, to assess the effect of the German Capacity Reserve on the German LOLE, an ex-post analysis of the scenario with CM (2025 EVA with CM) conducted by the German TSOs determined a LOLE of 3.56 h/a for Germany with an assumed reserve capacity of 2 GW.

4. General input data quality improvement.

Input data quality is essential to obtain reliable results. European TSOs are already providing highly granular data in a high quality. However, with increasing RES shares in the system, uncertainty regarding their supply is growing. Therefore, it is important to guarantee the highest quality of this data. The Pan-European Climate Database (PECD) represents a good base for this but it should be continuously improved to include, for example, climate change, and also to benchmark RES profiles against historical feed-in. The same applies for demand which has a sensitive impact on adequacy.

5. FBMC, EUPHEMIA local matching constraint and curtailment sharing:

The integration of FB results can be classified as a first proof-of-concept approach. The transparent presentation of the result range in relation to the selection of CNECs shows that this is a very sensitive input data component which needs to be addressed in detail during the next implementations. At the same time, an implementation of the Euphemia concepts for local matching and distributing unserved energy (‘Curtailment Sharing’)”) is included in this proof of concept. This also results in an increase of the national LOLE values while only slightly increasing the sum of ENS across all countries. Considering this scenario helps to frame the preceding NTC results. Without representing the Euphemia Methodology, these show a minimum LOLE value that would increase with a fairer distribution of uncovered load. Therefore, the NTC-based results can be seen as an optimistic representation with respect to the LOLE values.

In total, the German TSOs support the approach of locating individual implementation steps in different scenarios during the ERAA implementation process. In this manner, a certain degree of uncertainty in methodological issues or the quality of input data is considered. However, the ERAA 2021 is a first prototype of a multiyear implementation process with the goal of reaching results as robust as possible over the next years until the assessment methodologies are fully implemented.

8 Greece

All national data provided for the ERAA 2021 study stems from the approved NECP and has been adjusted to the best knowledge of the TSO (IPTO) to reflect recent trends (mainly of demand and RES evolution).

The NECP has set ambitious targets regarding the penetration of RES, as well as energy saving measures. Despite the planned electrification of certain sectors (mainly transport), the energy saving measures are expected to maintain electricity demand at relatively stable levels. Furthermore, the NECP foresees the complete lignite phase-out until the year 2028, with the existing lignite units being gradually decommissioned by the end of 2023 and the new lignite unit which is currently under construction having switched to natural gas before 2028. At the same time, two new gas-fired CCGT units are expected to be in operation until the retirement of the existing lignite units. In addition, Additionally, a new hydro pumped storage unit (680 MW) and significant capacity of batteries are foreseen up to year 2030.

A Market Reform Plan was recently compiled and submitted to the EU for approval. The plan foresees numerous actions that will enhance the competition and functionality of the Greek energy market. Among others, the Plan foresees the enabling of DSR participation in the markets, however no data was provided for DSR (implicit or explicit) participation for the ERAA 2021 study as numerical values were not available. The capacity levels of DSR and their actual participation in the market (activation price and daily duration) are parameters with high uncertainty.

Under these assumptions, no adequacy concerns are identified in the ERAA 2021 for Greece for the years 2025 and 2030, whereas the EVA analysis performed for the year 2025 shows that the new lignite unit will face viability issues.

After the approval of the NECP, the Greek Government has decided to speed up the lignite phase-out, setting the year 2025 as a deadline. The expected viability issues of the new lignite unit, and the aforementioned government decision, has forced PPC to re-examine its plans for the new unit; however final decisions are pending. Moreover, the continuing increase in CO_2 prices caused severe viability issues for the existing lignite units, and PPC announced earlier in 2021 its intention to retire all of them before the end of the year. However, due to adequacy concerns and the ongoing gas crisis, this has not been realisedrealized. Currently, only one of the new CCGTs is being constructed and is expected to begin commercial operation in the beginning of 2022. Several CCGT units have been granted generation licenses and connection offers, but at the time of the data collection for the ERAA 2021 study, none of them appeared to have a firm business decision.

The above-mentioned uncertainties could raise significant adequacy concerns in the next years (2022–2024), especially if plans for lignite units retirement are realisedrealized, without coinciding chronically with the entry of the new units under construction.

Another main concern during this period, and possibly in the years after 2025, is the high dependency of the Greek system's adequacy on the ability to import significant volumes of energy during hours of scarcity. Currently, adequacy levels could be characterisedcharacterized as borderline sufficient as the system is extremely vulnerable to adverse climatic conditions and the availability of the existing resources (most of which are old units), thus rendering the reliance on imports crucial during adverse conditions. The replacement of the existing lignite units with new CCGTs will improve the overall availability of the resources but will not increase margins. Furthermore, the ability to import during scarcity hours in the future cannot be considered guaranteed due to the radical changes in the generation systems of the Balkan region.

More specifically, given the new Green Deal targets, the enforcement of EU Acquis in the Energy Community contracting parties (including removal of lignite subsidies, the opt-out of lignite plants, the ETS law and the prospect for gradual adherence in the EU ETS of non-EU Energy Community contracting parties), as well the enforcement of taxes on imports from non-EU countries depending on their carbon imprint (carbon border adjustment mechanism), it is highly unlikely that any new investment in hard coal or lignite units will be realisedrealized in either EU countries or non-EU countries as the investment risk would be substantial. Investment in new CCGT plants in the Wester Balkan countries faces limitations of gas supply and the lack of a gas market with sufficient liquidity. In light of these facts, most countries in the Balkan region are announcing earlier retirement of old coal/lignite or oil units and the simultaneous cancellation of numerous plans for new coal/lignite units. Given that most of these announcements were made after the ERAA 2021 data collection process, they have not been considered in this study; however the performed EVA analysis for the year 2025 has verified these decisions. Mass coal/lignite unit retirement and increased dependency on natural gas, especially in the near future, in the Balkan region could limit the ability of neighbouring countries to provide assistance in scarcity periods, especially if they are simultaneous.

Furthermore, the ERAA 2021 study assumes that the CEP 70% rule will be implemented by 2025, thus increasing NTCs in the whole region. In principle, this should be taken as granted as it is a binding target; however, for the Balkan countries it is questionable when this will be feasible due to difficulties arising from the ongoing efforts to include flows of third (non-EU) countries in the relevant calculations.

More specifically, IPTO asked for 2020 and 2021 a derogation from the implementation of the minimum margin available for cross-zonal trade according to Article 16(9) of Regulation 2019/943 for the bidding zone border GR–BG to the SEE CCR. The main reason for this is the absence of the consideration of flows of third countries in the capacity calculation and the margin available for cross-zonal trade, and the insufficient potential for remedial actions to guarantee the 70% capacity criterion. The Coordinated Capacity Calculation Methodology does not consider the grid limitations of the neighbouring non-EU countries as well as potential remedial actions within their grid.

Cross border exchanges on GR's non-EU borders (Albania, North Macedonia and Turkey) significantly impact the cross-border capacity available on GR's EU border and vice versa. ACER'sACER recommendation provides that a consideration of third (i.e. non-EU member) country flows in capacity calculation and the calculation of the margin available for cross-zonal trade should be possible. IPTO and the rest of the TSOs of the SEE CCR have tried to make all necessary actions/activities to agree with third countries. However, it is not yet clear that such an agreement will be finalisedfinalized within 2021, causing the lack of legal conditions to consider the third countries flows during the determination of the binding target set in Article 16(8) of the Regulation 2019/943. The SEE TSOs in autumn 2020 sent an official request to their neighbouring third countries TSOs (OST, MEPSO, TEIAS, EMS), asking them to express their willingness to implement the 70% target on their borders with Greece, Bulgaria and Romania, with the response from these non-EU TSOs still pending. Recently, there has been an initiative between two RSCs with neighbouring non-EU TSOs, namely SELENE CC and TSCNET, to reach these non-EU TSOs through the non-EU RSC of the region, namely SCC, located in Belgrade. Their goal is to reach an agreement to apply common methodologies approved by the EU, starting from the Capacity Calculation Methodology. Note that after the agreements between the EU and non-EU TSOs of the region, the Capacity Calculation Methodology for the SEE CCR needs to be amended to include the participation of the non-EU TSOs and the application of the 70% capacity criterion. Finally, sufficient time should be given to develop the new methodology and IT implementation by the SEE RSC SELENE CC.

Looking towards the end of the decade, the number of uncertainties regarding the evolution of the system increase. The large-scale penetration of RES and the possible entry of new CCGTs will severely stress the viability of the older CCGTs, which could lead to unscheduled exits. The installation of batteries and the realisationrealization of the hydro pumped-storage unit cannot be considered guaranteed, and their realisationrealization is considered dependent on the existence of a support scheme. Demand could evolve at higher levels if the electrification of the various sectors is not effectively accompanied by energy saving measures. All and any of these issues could affect adequacy levels.

It is obvious that a Pan-EuropeanPanEuropean study such as the ERAA cannot consider all the uncertainties and particularities of each country and must focus on a limited number of Reference Scenarios, relying mainly on the best information available to each TSO at the time of the data collection. For this reason, all the above-mentioned uncertainties are considered in the new NRAA that will be published soon. The new NRAA is based on the same dataset as the ERAA 2021 study and aims to provide a complementary analysis to the ERAA 2021 on future adequacy levels and potential risks in Greece, under different conditions.

9 Ireland

Ireland and Northern Ireland together make up the Single Electricity Market (SEM). This wholesale electricity market is designed to be compliant with the European Target Model. It provides 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. These auctions can be for one year ahead, or up to 4 years ahead. Our inputs to the PEMMDB data collection reflect the best information available at the time of the collection, and therefore the most recent auction.

For the PEMMDB data collection in late 2020, we included some gas power plants that were successful in a previous auction, totalling almost 450 MW of capacity. We indicated on the data collection sheet that these were 'Uncertain' as they had yet to be built.

Subsequently (and after the data freeze for the PEMMDB), Eirgrid has been informed that approx. 600 MW of capacity (including the new gas units) have provided termination notices as of October 2021, after clearing from various capacity auctions. Ideally, the absence of these gas units should have been accounted for in ERAA's reference scenario 'National Estimate – Low Thermal Capacity'. However, the column of data where they had been marked 'Uncertain' was not used. Modellers instead choose the column for 'Delayed date of Commissioning' as an indicator for uncertainty in the 'Low Thermal Capacity' scenario. Therefore, an opportunity was lost to assess the declining adequacy situation in Ireland as a result of the termination of capacity from the Capacity Market. The ERAA presents no adequacy issues in Ireland.

Eirgrid carries out national adequacy assessments, as reported in the annual All-Island Generation Capacity Statement (GCS). As the data freeze for these studies is later than for the PEMMDB, the capacity that has terminated is not included in adequacy modelling in the latest GCS[9]. This and other differences in data input lead to differences in outcomes between the GCS and the ERAA. Furthermore, the GCS presents a number of alternative scenarios that cater for additional risk, including:

- Demand uncertainty, as has been recently experienced
- Decrease in generation availability
- Forecasted new generation failing to materialise

9 https://www.eirgridgroup.com/site-files/library/EirGrid/208281-All-Island-Generation-Capacity-Statement-LR13A.pdf

- Delay in building new capacity
- Emissions Limits (some plants that are due to close because of emissions limitations might close earlier than expected.)

Further to the operational requirements covered by ERAA to meet LOLE standards, additional capacity is required to facilitate transmission outage planning, in line with the standards that we plan and operate the transmission system to.

These 'Security of Supply' scenarios highlight the need for significant new capacity (at least 2000 MW) over the next decade to maintain our adequacy standard.

After the ERAA studies were complete, some issues came to light with regards to the handling of batteries in IE00 – they had been represented as providing more benefit to adequacy than had been intended. Subsequent limited modelling (with a more realistic benefit from batteries) showed that adequacy issues begin to appear in some studies. This will be carefully handled in the next ERAA, which we expect to show more significant adequacy problems ahead.

10 Italy

As required by current national regulation, Terna provides a yearly adequacy report in order to identify the mix of resources required to guarantee the respect of adequacy threshold (at present time 3 hours/year of LOLE). Like ENTSO-E's ERAA 2021, the national report includes an analysis for 2025 and 2030.

For year 2025, the results highlight the same critical issues for the bidding zones Sicily and Sardinia[10], related to the combined effect of two factors:

- insufficient transmission capacity with the mainland, which is increasingly important to guarantee the adequacy and safety of the islands in the face of the expected growth of intermittent renewable sources;
- the expected reduction in conventional generation capacity in the case of Sardinia due to the decarbonisation policies of the electricity system (coal phase out) and in the case of Sicily due to the presence of obsolete, polluting and economically inefficient generation plants (mainly oil-fired, identified on the base of the economic viability check performed).

The ERAA reports higher LOLE values (in particular for Sardinia) compared to the Terna adequacy report, mainly due to a different modelling approach for interconnection maintenance, which is better optimised in the national analysis: As in actual operation, the interconnection maintenance (expected unavailability) is planned when the residual load in Sardinia is low. Only the unexpected unavailability is a result of the Monte Carlo simulation and can happen at any time at a given probability.

The issues highlighted by both the ERAA and the national adequacy report can be resolved by the commissioning of the Tyrrhenian Link (new interconnection between Central South Italy and Sardinia as well as Sicily and Sardinia) and by ensuring a minimum level of dispatchable capacity (thermal resources and/or RES coupled with storage) in Sardinia. The latter objective can be achieved with the next Capacity Market auction.

[10] The LOLE value is bigger than MAF 2020 due to the fact the project SACOI 3 (increase of interconnection capacity between Sardinia and Italy Central North) have been postponed and is not anymore included in 2025 scenario.

For 2025, the national report also identifies adequacy concerns for the bidding zone Italy North. This is related to how the analysis values adequacy contributions from the Northern border which has significant import capacity from France, Switzerland, Slovenia and Austria. Terna underlines that the current European analyses need to evolve into a better representation of situations of simultaneous shortage of generation capacity in Europe. The recent experience occurred, for example, in January 2017 and September 2020 has shown that such a situation can lead to a risk of non-coverage of the load in Italy North. Terna's approach is based on a historical analysis of the actual foreign contribution and is therefore more conservative, thus showing adequacy concerns in terms of LOLE and ENS also in the Northern area.

The further implementation of the ERAA methodology (e.g. FB) in the next ERAA editions will contribute to a better representation of the adequacy contribution to neighbouring countries.

For 2030-time horizon, both reports, national and European, do not reveal major adequacy issues, provided that all investments in the National Transmission Grid envisaged in Terna's Development Plan are realised and that all scenario assumptions hold true. This includes a massive development of solar and wind generation capacity as well as the deployment of new storage capacity and the deployment of new dispatchable capacity in Sardinia required to replace the coal-fired generation being phased out.

11 Lithuania

National adequacy studies, performed by Litgrid for Lithuania, for normal conditions of the Baltic system synchronous operation in the Continental Europe grid after 2025 show similar results as the ERAA 2021.

After the identification of new RES targets and the clarification of information concerning the availability of existing conventional units in Lithuania, the RES targets and status of the existing generation have been updated in the ERAA 2021. The expected faster development of RES generating capacities and storage capacities will have a positive impact on system adequacy.

However, it is important to note that from an adequacy perspective, with an existing supply consisting of a generation mix and cross-border connections, Lithuania is dependent on imports from neighbouring countries. Considering that the main goal of the State is to integrate as much RES as is required to fully cover the electricity demand of Lithuania, and that there are no plans from investors to install any conventional generation, the energy mix of neighbouring countries has a huge impact on the adequacy margins, especially in periods with low RES generation.

For Lithuania as a small country, depending on very few large single supply sources corresponding to approximately 30% of peak demand, a coincident loss of supply could lead to serious adequacy issues. According to the Litgrid experts, the ERAA 2021 results might show too positive results, whereaswhile for decision making purposes the worst cases should be considered.

Today, old generation units play a huge role in ensuring adequacy in Lithuania, especially evaluating the geopolitical situation in the region, which are not viable in the market. Even though most of the capacity will be decommissioned by 2025, there is still a great deal of uncertainty about the future of the remaining fossil fuel generating capacities.

The results of the ERAA 2021 for Lithuania show a very small adequacy margin of LOLE to the defined 8 h/year in the Electricity Energy Law Art 18 (11)[11], so any changes in the neighbouring countries could have a crucial impact on Lithuania.

The Baltic system synchronisation with Continental Europe Networks in 2025 indicates an additional point from Litgrid's side to consider the ERAA 2021 results as very optimistic for Baltic system. A single failure of the grid component could lead to a desynchronisationdesynchronization from the European system and operation of the Baltic system in isolated mode for an uncertain period of time. Regarding such an event, the ERAA 2021 does consider the different Baltic system operation conditions, such as the drastic limitation of cross-border capacities, which play an important role in ensuring the Lithuanian and Baltic system adequacy. For that purpose, the Baltic system should require more internally available reliable generation capacity reserves which were taken out of the scope of the ERAA methodology approved by ACER.

We understand that the purpose of the ERAA 2021 is to assess the adequacy of the Pan-European system under normal electricity market conditions and does not cover failures that could lead to temporary disruptions of Baltic system synchronous operation with the Continental Europe Networks. However, the probability of the Baltics' isolated work is a concern for us and, in our view, is not considered by the ERAA 2021.

12 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 200 MW HVAC 200kV interconnector.

Out-of-market measures

Out-of-market resources, such as strategic reserves, are not considered within the ERAA as being available for adequacy purposes, which has a profound impact on the output of the models for Malta which yielded significant high values of LOLE and ENS. In Malta, there is as yet no real electricity market, and with just only one supplier the non-market measures are actually an integral part of the power system. A total generating capacity of 215 MW (38% of the thermal capacity in Malta),) which in the report waswere considered as non-market reserves and hence not included in modelling, is available for dispatching as required at any point to meet the local demand. The inclusion of these non-market measures in future editions of the ERAA study would reflect the state of Malta's power system in a more realistic manner and would inevitably decrease the risk of LOLE and ENS for Malta.

Interconnection Modelling: Adequacy and NTC

Malta implements an N-1 system/generation adequacy standard. This requires that even when losing the largest piece of power generation infrastructure (e.g. interconnector or gas facilities),) the system must be sufficiently resilient to meet the maximum electricity demand.

[11] https://e-seimas.lrs.lt/portal/legalAct/lt/TAD/TAIS.106350/asr

The expected increase in Malta's population, labour force and tourism is expected to drive energy demand even higher in the coming years. As a result of this expected increase in demand, Malta has carried out a national adequacy study with the aim of presenting cost-optimal solutions to meet the expected growth in electricity demand and tackle any projected future shortfalls. Based on the study, a decision was taken by the Government to invest in a second electricity interconnector.

A second Interconnector linking Malta to Sicily is expected to be commissioned in 2026, with an additional capacity of 200 MW. The ERAA study doesdo not include this additional capacity as information and the communication of such an increase was only made available after the data collection period.

Net revenues

Annex 2 provides results for revenues and costs by technology under the National Estimates scenarios. The revenues reported are disproportionately high for Malta compared to other bidding zones primarily due to the high amounts of ENS reported and the assumed VoLL of 15,000 EUR/MWh, which is used across all bidding zones. In reality, there is no wholesale electricity market in Malta and generators may not be able to gain additional revenue during periods of scarcity in the absence of a market. In situations where local generation sources are not able to satisfy demand, Malta would rely more on electricity imported over the interconnector with Sicily, whereas in the case interconnector imports are restricted, peak demand may be met by the strategic reserves.

13 Netherlands

TenneT values and appreciates the work of ENTSO-E on the development of the ERAA as defined in the Electricity Regulation as part of the Clean Energy Package. In particular, the methodological development and implementation of the EVA is a major and extremely challenging task.

According to the ERAA implementation roadmap, the EVA method is currently in its initial implementation phase and is expected to be fully mature in 2024. The method as applied in the ERAA 2021 has many simplifications regarding the data used and the modelling of the market mechanisms.

TenneT considers the current EVA method and outcomes as not yet a solid basis for the 2021 edition of the Dutch adequacy assessment and will use the National Estimates scenario from the ERAA 2021 instead.

14 Northern Ireland

Northern Ireland and Ireland together make up the SEM. This wholesale electricity market is designed to be compliant with the European Target Model. It provides wholesale electricity at the lowest possible cost, ensuring 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. These auctions can be for one year ahead, or up to 4 years ahead. Our inputs to the PEMMDB data collection reflect the best information available at the time of the collection.

SONI carries out national adequacy assessments, as reported in the annual All-Island GCS[12].

[12] https://www.soni.ltd.uk/media/documents/EirGrid-Group-All-Island-Generation-Capacity-Statement-2019-2028.pdf

Whereas no adequacy risks are identified in either the ERAA or GCS for Northern Ireland, SONI has completed a range of adequacy sensitivity studies to assess the risk to security of supply in Northern Ireland. The studies presented provide an indication of Northern Ireland's adequacy position based on a range of credible risk, low plant availability, delay to contracted capacity, loss of interconnection support, and outages or run-hour limitations on large generating plant.

15 Poland

In the case of Poland, the *National Estimates* scenario is based on the National Policy until 2040 official document[13].

The *National Estimates with Low Thermal Capacity* scenario should be treated as a kind of stress test scenario, where only hard coal / lignite central dispatch units with already concluded contracts on the Capacity Market are considered for the year 2025 and 2030. The remaining units, in this scenario, are early decommissioned without a verification of their economic viability and the need for capacity in the system.

It is worth saying that the capacity of hard coal / lignite units, planned for being decommissioned, achieve level of c.a. 6 GW in 2025 and c.a. 17 GW in 2030. As a result, the significant and unacceptable level of loss of load expectation (LOLE) can be observed in this scenario for Poland, especially in year 2030, which affects neighboring zones as well. This shows the necessity and – compared to the value of lost load – a business case for a big amount of additional, dispatchable, generating capacity. This capacity can be assured by the balanced sum of existing coal and lignite generating units, not being decommissioned, and new generating (e.g. gas fired) units. In this situation decommissioning of existing high-emitting units would be feasible and economically justified only in case of commissioning new zero- and low-emitting units with the equivalent capacity.

16 Portugal

As required by the current Portuguese national legal framework, REN collaborates with the Directorate-General for Energy in the elaboration of the annual National Adequacy Assessment Monitoring Report to identify the mix of resources required to comply with the reliability standards in force: Probabilistic Load Supply Index ≥ 1 and LOLE ≤ 5h/year. The most recent National Adequacy Assessment Monitoring Report (RMSA-E 2021) addresses the horizon 2022–2040.

On that report (RMSA-E 2021[14]), for year 2022 (not included in the ERAA 2021 analysis), the decommissioning of all existing coal power plants before the end of 2021, as well as the delays expected in the construction of new large hydro power plants (initially expected in 2022) to 2023, results in non-compliance with the current national reliability standards. Under these conditions, some mitigating measures may be necessary to handle operational reserve needs and ensure security of supply, as listed below:

#	Measures

[13] https://www.gov.pl/web/klimat/polityka-energetyczna-polski

[14] https://www.dgeg.gov.pt/media/hp5p13zr/rmsa-e-2021.pdf

(Supply)	Request for the activation of a support program with the Spanish System Operator
(Demand) [15]	Load reduction, using the load shedding service for eligible industrial consumers with whom there are annual contracts for the provision of this service in the market
(Demand)	Occasional load shedding of non-priority consumptions, according to the protocol between the electricity transmission and distribution network operators, in the event of non-compliance with the instructions referred to in the previous measure by interruptible consumers.

For the targets years 2025 and 2030, the ERAA 2021 results for 'National Estimate' and 'National Estimate – Low Thermal Capacity', i.e. adequacy assessment without an EVA, is according to the Portuguese RMSA-E 2021.

The EVA for year 2025 induces a significant potential capacity decommissioning in the Iberian Peninsula. Nevertheless, the conclusion should be treated carefully on a country level as investment decisions must be based on detailed assessments, considering national specificities.
For target year 2025, in the scenario 'EVA without CM' (i.e. adequacy assessment of the updated 'National Estimate' scenario, following an EVA without CM and considering a VoLL of 3k€/MWh and CO2 of 40€/ton), the decommission of 990 MW of thermal capacity in Portugal fulfils the proposed national reliability standards in the ERAA 2021 study. Nevertheless, in RMSA-E 2021, a sensitivity analysis performed to study this thermal decommission results in non-compliance with the current national reliability standards for target year 2025.

Regarding the 70% minRAM requirement within the NTC simulations and with respect to Portugal the medium/long-term NTC values do not consider the 70% minRAM requirement yet. The available values were calculated in joint studies with the neighbouring TSO previous to the publication of this rule. New studies considering more recent information on future scenarios are planned; these will also consider the 70% minRAM requirement.

In terms of balancing reserves, the current Portuguese methodology is not aligned with the ERAA methodology and REN is concerned about the reserves contribution for adequacy assessment, namely modelling of Replacement Reserves (RR) as available capacity. For REN, the general concept of unserved energy means that the electricity supply is not able to face electricity demand due to lack of adequacy (related to load and generation balance on the day-ahead market) or lack of reserves (to face unexpected variations on power system in real time, e.g. variation in load, wind, solar, forced outages, etc). Therefore, if reserves are used for adequacy assessment purposes, thesethose will not be available to face all system reserve needs in real time. If a TSO follows the approach of keeping aside automatic Frequency Restoration Reserve (aFRR), mFRR and Strategic Reserves from its adequacy assessment but, conversely, considers that RR is available for that same purpose, it is creating an increased risk of imbalance of the European power system due most likely to a lack of reserves and, therefore, an implicit deterioration of security of supply standards.

[15] According to a recent government announcement, the first demand measure is expected to be finished by the end of 2021 and replaced by a market product for demand reductions. In this context, being a market measure it will have priority over all other measures.

REN highlights that the ERAA 2021 is a first approach for the ERAA methodology, with a certain degree of uncertainty in terms of methodology and quality of input data. In the next studies, until the assessment of the methodologies is fully implemented, efforts will be made, with stakeholder engagement, to improve the approach.

17 Sweden

New flow patterns may reduce network capacity between certain bidding zones, which may reduce adequacy in the Southern regions of Sweden beyond the results reported in the ERAA 2021. Some regional network constraints may also impose local adequacy issues. Due to this, Svenska kraftnät conducts more detailed national resource assessments to complement the results from the ERAA. The Nordic power system is hydro dominated, which also requiresrequire adapted models to model flows and hydro constraints.

Svenska kraftnät publishes these assessments in a short-term (the next 5 years) and long-term (target years 2035 and 2045) market analysis. These assessments do not currently meet all of the requirements from Article 24 in Regulation (EU) 2019/943, but they are a good complement. For the near future, the identified adequacy in the short-term analysis is comparable to that of this study. However, they show dependency on DSR or some other measure to maintain adequacy from 2035 onward due (mainly) to the electrification of the industry sector. For periods when Sweden is experiencing adequacy issues, the ability to support other countries may be limited.

Sweden has a strategic reserve with a capacity of 562 MW in price area SE04 which is contracted until March 2025 and can be used for adequacy problems within this period. A portion of the disturbance reserve (gas turbines) might be able to help resolve adequacy problems temporarily, although this is not its intended purpose.

A reliability standard (measured in LOLE) for Sweden has been proposed and is currently under review. It is not yet approved.