European Resource Adequacy Assessment

2021 Edition

Annex 1: Assumptions

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1 ERAA 2021 Scenarios

The starting point for a probabilistic adequacy assessment such as the present one is the definition of the study's scenarios. The scenarios of the European Resource Adequacy Assessment (ERAA) scenarios draw on the most up-to-date expectations for the selected target years, guided by policy frameworks and stakeholders' expert views. To this end, ENTSO-E carries out an extensive data collection exercise, during which Transmission System Operators (TSO) can provide their views and estimations of the trajectories of demand, resource capacities and grid elements. The input data gathered from TSOs, referred to as the 'National Estimates' scenarios, constitute ENTSO-E's Pan-European Market Modelling Database (PEMMDB). The data collection for the ERAA 2021 began in autumn 2020. Quality checks and reviews were carried out throughout this process, with updates integrated into the assessment until the start of main model runs in spring 2021. The impact of late updates, which could not be integrated in the assessment, was checked to ensure it would not distort the results.

A pan-European study naturally requires an extensive amount of input data, commonly calculated by respective TSOs and based on national policies and trends. The rules and assumptions used for the collection of these data for the ERAA 2021 are described in the 'Data collection guidelines' published by ENTSO-E. The 'National Estimates' scenarios of the ERAA 2021 were mainly based on the National Energy and Climate Plans available at the time of the data collection, considering a 40% reduction of greenhouse gas emissions by 2030. More recently, in July 2021, the 'Fit for 55' package was introduced and ENTSO-E will try to account it in the ERAA 2022 edition to the best possible degree.

For ERAA 2021, the economic viability assessment (EVA) was implemented on a single target year, i.e. 2025, for the two central reference scenarios required by the regulation, i.e. a scenario 'with Capacity Mechanisms (CM)' and 'without CM'. These two central scenarios are complemented in the ERAA 2021 with two additional reference scenarios, i.e. 'National Estimates' and 'National Estimates – Low Thermal'. These reflect the national estimates of TSOs with respect to installed capacities in both target years, with the latter expressing the uncertainty identified by TSOs in the commissioning and decommissioning of several thermal assets in their national power systems. Therefore, the ERAA 2021 includes 4 reference scenarios for TY2025 and 2 for TY2030:

1) National Estimate for TY2025 and TY2030, as collected from TSOs;
2) EVA without CM for TY2025: starting from the 'National Estimate' scenario, and updated through the application of EVA without CM;
3) EVA with CM for TY2025: starting from the 'National Estimate' scenario and updated through the application of an EVA with CM;
4) National Estimate – Low Thermal Capacity for TY2025 and TY2030, a scenario with reduced thermal capacity collected from TSOs.

'National Estimates' are bottom-up scenarios which serve as the basis for the construction of the EVA scenarios. During data collection, ENTSO-E guides TSOs through the assumptions of each scenario and the data required, aiming for a common understanding of all underlying assumptions and targeting a consistent data set among all modelled zones. However, for a number of scenario elements, specificities are present on each power system and thus TSOs might have different methodologies to estimate some inputs or validate the scenarios' compliance with the requirements of the ERAA methodology.

There are four scenario elements which deserve an elaborate description of the different view of TSOs and their impact on the ERAA 2021, i.e. the minimum 70% target of cross-zonal capacities, out-of-market measures available to TSOs, latest market reforms in each country, the evolution of trajectories for 10 years ahead and potential impact on adequacy. The sections below summarise TSOs' views on the aforementioned topics, whereas the detailed TSO feedback is appended to the end of this document.

1.1 Minimum 70% target for cross-zonal capacities

Article 16 (8) of the Electricity Regulation sets a minimum threshold of 70% for cross border capacity to be available for market participants. This relates to both net transfer capacities (NTC) and Flow Based (FB) parameters. For regions with a FB approach already implemented, it builds on a minimum Remaining Available Margin (minRAM) requirement. The compliance with the requirement is assessed by the NRA of each Member State.

For borders between EU members and non-EU members, the inclusion of 3rd country flows on the 70% RAM depends on the existence of an agreement between the Capacity Calculation Region and the 3rd country that shall also cover other topics such as the cost sharing of remedial actions. For the purpose of this exercise, it is considered that 3rd country flows are included in the 70% min RAM. The 70% requirement is currently not applicable between EU and non-EU borders and between non-EU borders (e.g. Albania, Bosnia Herzegovina, Serbia).

Regarding the FB simulations (c.f. Annex 4), the 70% is integrated in the modelling, ensuring that all EU–EU borders modelled with FB (mainly CORE region) comply with the 70% min RAM.

For more information on the border per border compliance, c.f. Table 11 in Appendix 2, provided at the end of this document.

1.2 Out -of-Market Measures

This chapter provides a systematic characterisation of out-of-market resources as provided by TSOs, e.g. which measures are considered out-of-market; which measures have not been considered available for adequacy purposes. In addition, a quantification of out-of-market measures that could address adequacy crises (e.g. a reduction of demand through voltage reduction), without necessarily modelling all of them, is also reported.

It should be noted that the notation of out-of-market measures varies from TSO to TSO. Among the measures considered out-of-market are:

- Strategic Reserves (e.g. Belgium, Finland, Malta, Sweden);
- Capacity reserve (e.g. Germany);
- Grid reserve (e.g. Germany);
- Lignite units in standby (e.g. Germany);
- Voltage reduction (e.g. Bulgaria, France, Ireland, Serbia, Slovenia);
- Optimising the number of transformers in operation (e.g. Bulgaria);
- Emergency power contracts with other TSOs (e.g. Bulgaria, Finland, France, Slovenia);
- Temporary use of disturbance reserve for adequacy issues (e.g. Finland, Sweden);
- Interruptible load contracts with large industrial consumers / out-of-market demand-side response (e.g. France, Germany, Poland);
- Eco-gestures (e.g. France);
- Use of operating reserves for adequacy issues instead of setting them aside for unknown events (e.g. France);
- Frequency Restoration Reserves (FRR; e.g. Germany, Latvia, Norway, Slovakia);
- Frequency Containment Reserve (FCR; e.g. Latvia, Norway, Slovakia);

- Special Network Equipment (e.g. Germany);
- Mothballed power plants / cold reserve (e.g. Lithuania, Serbia).

Controlled load shedding is used by TSOs as a very last resort after all out-of-market measures are exhausted.

The number of out-of-market measures at the disposal of TSOs varies from none (e.g. Albania, Bosnia and Herzegovina, Croatia, Estonia, Italy, Luxembourg, Netherlands, Portugal) to five or six types of out-of-market measures (e.g. France, Germany)

In Denmark, reserve/ancillary service capacity is normally considered out-of-market. However, as reserve requirements in Denmark in the ERAA are modelled as increased load, power plants conventionally delivering reserves are made part of the dataset and available on the market.

Norway does not consider strategic reserves from demand (demand manual FRR) as out-of-market, whereas it does consider other reserves (FCR, automatic FRR and production manual FRR) as out-of market.

For a detailed table on out-of-market measures per country or zones, please c.f. Table 8 in Appendix 1, provided at the end of this document.

1.3 Market Reforms

Market reforms referred to in Article 20(3) of the Electricity Regulation shall be considered in the ERAA scenarios. Most of these reforms are captured through the collected input data. In addition, TSOs responded to a qualitative survey regarding whether their country was impacted by specific national market reforms and how these were considered when providing the ERAA input data. TSOs also commented on the market reform plans that have not been considered, providing a proper justification.

A large share of countries report that no market reforms are foreseen. This can either be because Article 20(3) of the Electricity Regulation does not apply (e.g. Switzerland), or because no market reforms are deemed required as recent pan-European resource adequacy assessments have not pointed to any adequacy issues (e.g. Slovakia). Other countries expect to carry out a number of market reforms in the coming years, and are still assessing which measures would be applied and to what extent and how exactly their execution will affect the market situation (e.g. Bulgaria, Germany). Examples include reforms of pricing and price caps. Finally, multiple countries report that market reforms were already included in the data collected for the ERAA or will not significantly affect them (e.g. Greece, Hungary, Lithuania).

Some countries report that legislation is being implemented to support the development of renewable energy, the reduction of greenhouse gas emissions and/or the development of storage and demand-side response (e.g. Denmark, Germany, Italy), resulting in increased RES estimates in the ERAA.

1.3.1 Measures related to price caps

In Spain, a maximum price cap and floor have been modified for the wholesale market to +3k€/MWh and -500 €/MWh respectively, which is similar to multiple other countries in Europe[1]. Elia, the Belgian TSO, also remarks that reaching a price cap of 15k€/MWh in 2025, which is the default assumption in the ERAA 2021, should be considered with care, given the current level of the price cap and the rules for its increase. Therefore, it finds the considered sensitivity with the current value of 3k€/MWh very relevant. Furthermore, some TSOs suggest that certain market reforms should be modelled within the EVA (e.g. automatic increase

[1]https://ec.europa.eu/energy/sites/ener/files/documents/swd_2016_385_f1_other_staff_working_paper_en_v3_p1_870001.pdf

of price cap, implemented scarcity pricing functions) as additional sensitivities (e.g. Bulgaria, France) depending on the simulated market results.

1.3.2 Measures related to interconnection capacity

Slovakia will remove market barriers in the day ahead and intraday timeframe by joining the 4M Market Coupling (4M MC) countries, interconnecting with the Europe-wide Multi-Regional Coupling (MRC), integrating wholesale markets and increasing interconnection capacity with Hungary. Italy will increase interconnection capacity and promote European Market Integration.

1.3.3 Measures related to balancing energy and the procurement of balancing and ancillary services

The Baltics will introduce an ancillary services market after desynchronising from the Integrate Power System (IPS) and Unified Power System (UPS) synchronous system in 2025. This is, in turn, expected to constrain NTCs between Estonia and Latvia to some extent. The Finnish TSO expects significant market reforms within upcoming years as a consequence of an EU-wide harmonised balancing market, imbalance settlement and requirements for the procurement of reactive power. Market reforms in Italy will enable self-generation, energy storage and demand side measures. In Spain, demand-side facilities and storage facilities can participate in balancing services since January 2020 and will start participating in the redispatch market in 2022. The participation of independent aggregators in the markets is also foreseen for 2022. Sweden will transition to a 15-minute imbalance settlement period in 2024.

For a detailed table on the market reforms per country or zone, please c.f. Table 9 in Appendix 1, provided at the end of this document.

1.4 Evolution of trajectories

Being the first implementation of the ERAA, the ERAA 2021 focuses on two target years. Therefore, a qualitative understanding of the key capacity and energy mix evolution drivers (policy or not) for all 10 TY ahead can be insightful. This chapter provides, for example, information on whether main evolutions are characterised by a coal phase-out, RES deployment targets, demand side response (DSR) deployment, battery deployment etc.

Countries' energy mix trajectories are generally in line with national development plans, national studies and national energy and climate plans (NECP). Where NECPs are not yet available, TSOs' own estimates were used (e.g. Bosnia and Herzegovina).

1.4.1 Demand trends

Most countries report an expected growth in demand, driven by:

- Electrification of transport (e.g. Austria, Denmark, Estonia, Finland, France, Germany, Italy, Lithuania, Luxembourg, Malta, Netherlands, Norway, Portugal, Spain, Sweden, Switzerland);
- Electrification of heating, i.e. installation of heat pumps and/or electric boilers (e.g. Austria, Denmark, Finland, Italy, Lithuania, Luxembourg, Malta, Netherlands, Switzerland);
- Increase in the number and/or scale of data centres (e.g. Austria, Denmark, Germany, Malta, Norway, Spain);
- Installation of electrolysers (e.g. Austria, Sweden);
- Electrification of industry (e.g. Austria, Finland, Germany, Italy, Netherlands, Norway, Sweden, Switzerland);

- New industries, e.g., battery factories (e.g. Norway);
- The occurrence of extreme weather events (e.g. Spain).

In general, most TSOs expect a significant growth in demand for electricity between 2020 and 2030. Electrification in various sectors (e.g. heating, transport and industry) is an important driver for demand growth frequently stated by TSOs.

Some countries explicitly report considering currently witnessed demand levels and growth rates (e.g. Albania, Bosnia and Herzegovina), or, similarly, effects of the COVID-19 pandemic in their projections (e.g. Belgium, Greece, Slovakia, Slovenia).

1.4.2 Resources, including storage and DSR

Countries' estimate of resource capacity trajectories build on national development plans, national resource adequacy assessments and NECPs. For some countries, the NECP is sufficiently detailed to provide information on all resource technologies, which can lead to some simplified or conservative assumptions. This is, for example, the case for Bulgaria regarding the development of battery storages and DSR.

The main drivers for a growth in resource capacity appear to be the significant development of RES, along with growth in storage and DSR. Even if thermal new entries can also occur, the decommissioning of thermal power plants is an important driver for reductions in resource capacities. Fuel switching appears to be a less significant phenomenon.

Drivers for resource capacity growth are:

- Construction of (hydro) storage (e.g. Albania, Belgium, Croatia, Greece, Hungary, Italy, Lithuania, Netherlands, Slovenia, Sweden);
- Development of RES, i.e. solar, wind and/or hydro power plant (e.g. Albania, Austria, Belgium, Croatia, Denmark, Estonia, Finland, France, Greece, Hungary, Italy, Latvia, Lithuania, Malta, Netherlands, Norway, Portugal, Serbia, Slovakia, Spain, Sweden);
- Development of DSR, in turn partially driven by electrification and price volatility (e.g. Belgium, Croatia, Finland, France, Lithuania, Luxembourg, Sweden);
- Commissioning of new gas-fired power plants (e.g. Albania, Greece, Hungary, Italy);
- Commissioning of new nuclear power plants (e.g. Finland, France, Hungary, Slovakia).

Drivers for resource capacity reductions are:

- Decommissioning of fossil fuel power plants (e.g. Austria, Finland, Italy, Lithuania, Portugal, Serbia, Spain);
- Decommissioning of nuclear power plants (e.g. France);
- Coal phase-out (e.g. Denmark, Finland, France, Germany, Hungary, Ireland, Italy, Netherlands, Portugal, Spain);
- Lignite phase-out (e.g. Germany, Greece, Ireland);
- Nuclear phase-out (e.g. Belgium, Germany, Spain, Sweden).

Drivers for fuel switching are:

- Coal-to-gas fuel switching (e.g. Denmark);

- Increasing biofuel share in existing power plants (e.g. Estonia).

It should be noted that an increase in solar power generation does not necessarily contribute to adequacy in all countries as consumption peaks typically occur during winter for countries in the north of Europe.

1.4.3 Grid

Grid capacity values are in line with national grid development plans, regional plans and the development plan of an integrated European electricity market (e.g. Bosnia Herzegovina, Croatia, Hungary, Spain). Multiple countries mention an – frequently significant – increase of interconnector capacities in the period 2020–2030 (e.g. Bosnia Herzegovina, Denmark, Finland, France, Germany, Greece, Hungary, Italy, Lithuania, Portugal, Serbia, Slovakia, Sweden). In some countries or market zones, internal grid reinforcements are foreseen, which also sometimes increase interconnection capacity. For Belgium, we refer to its latest Federal Development Plan for further details.

Spain reports its grid needs further development to reach the interconnection targets and is thus promoting several new interconnectors with France and Portugal. The Bay of Biscay Gulf project, not considered built yet in 2025, will improve adequacy in the following years, although not sufficiently to offset the nuclear phase-out plans.

1.4.4 Impact on adequacy

The impact of the presented trajectories evolutions on adequacy is summarized for many countries below:

- A positive impact on adequacy (e.g. Hungary, Slovakia);
- No significant impact on adequacy (e.g. Bosnia and Herzegovina, Greece, Italy[1], Norway, Serbia, Spain);
- An uncertain impact on adequacy (e.g. Estonia, Ireland, Malta, Poland, Serbia, Sweden);
- A negative impact on adequacy (e.g. Belgium, Croatia, Czech Republic, Denmark, Germany, Netherlands, Portugal, Switzerland).

Some more specific comments were made by the Belgian TSO, noting that considering NTC simulations for the reference scenarios in 2025 and 2030 leads to a rather optimistic view on the ability of Belgium and its direct neighbours to import during simultaneous scarcity situations.

For a detailed table on the trajectories' evolution per country or zone, please c.f. Table 10, Appendix 1 provided at the end of this document.

2 Demand profiles

In the context of the ERAA 2021, demand or load is active power required by any end user installation/appliance connected to the grid that may not be moved to another point in time but that may be reduced using DSR or may be curtailed. For more details on demand, please refer to the demand methodology. Electric vehicle and heat pump demand profiles are considered fixed in the ERAA 2021 and are thus included in the demand profiles.

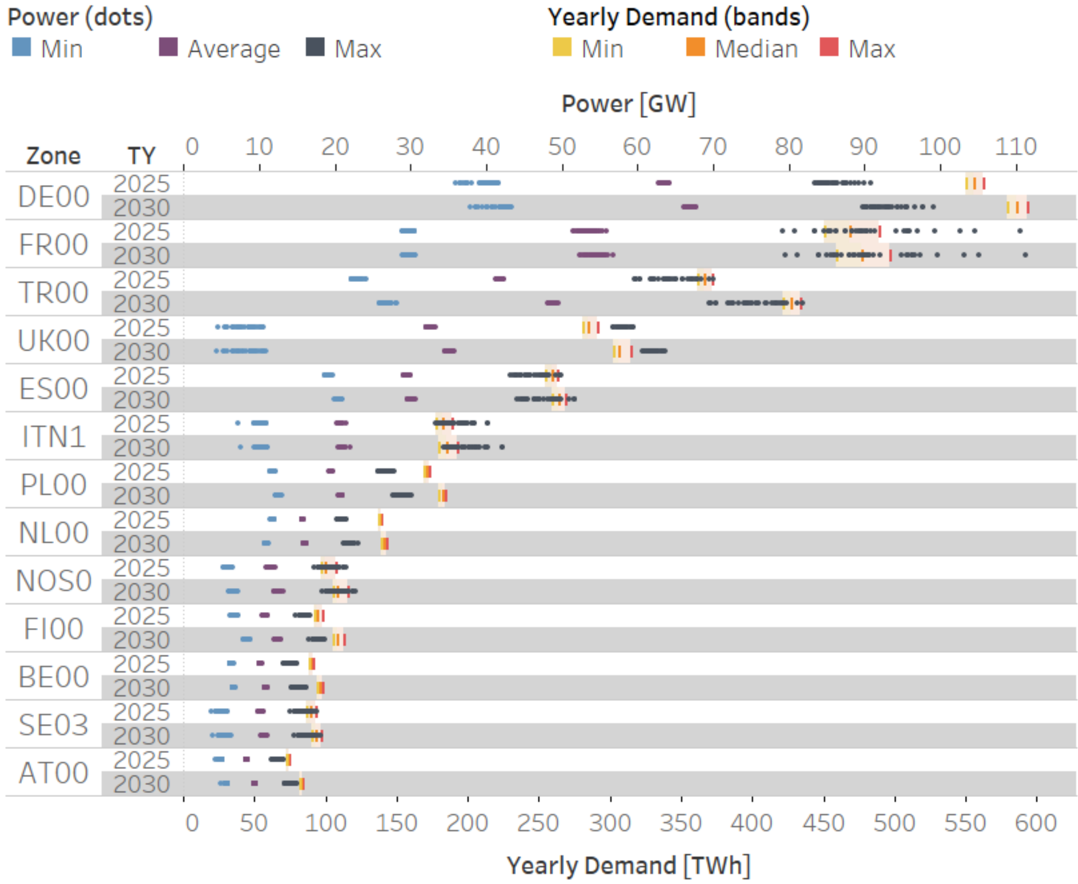
[1] If all investments in the National Transmission Grid envisaged in Terna's Development Plan are realized and that all scenario assumptions hold true

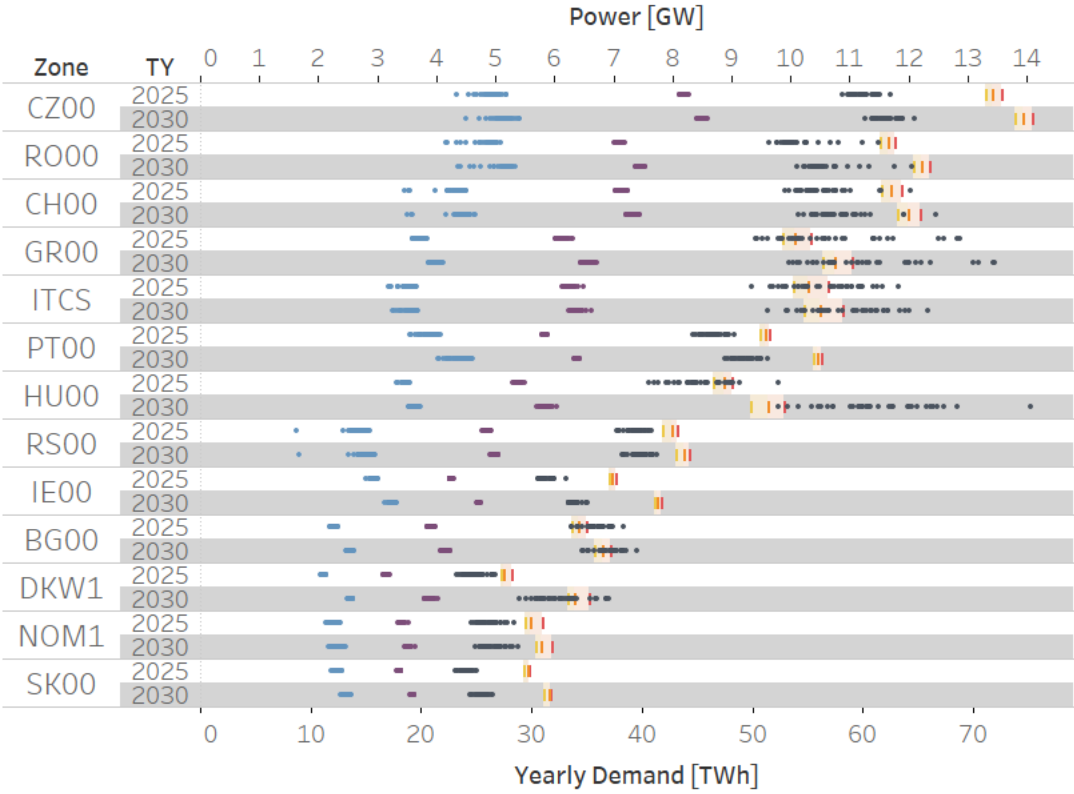
High demand levels – especially peak demand levels — coincide with moments of higher inadequacy risk. Figure 1 shows yearly demand (YD) values as well as hourly demand values by market zone and Target Year (TY). More precisely, the figure shows the minimum to median and median to maximum yearly demand ranges across all 35 Climate Years (bars) and the minimum, median and maximum/peak hourly demands across the 35 climate years (dots). The countries are ranked according to the maximum yearly demand of all CYs and TYs in descending order.

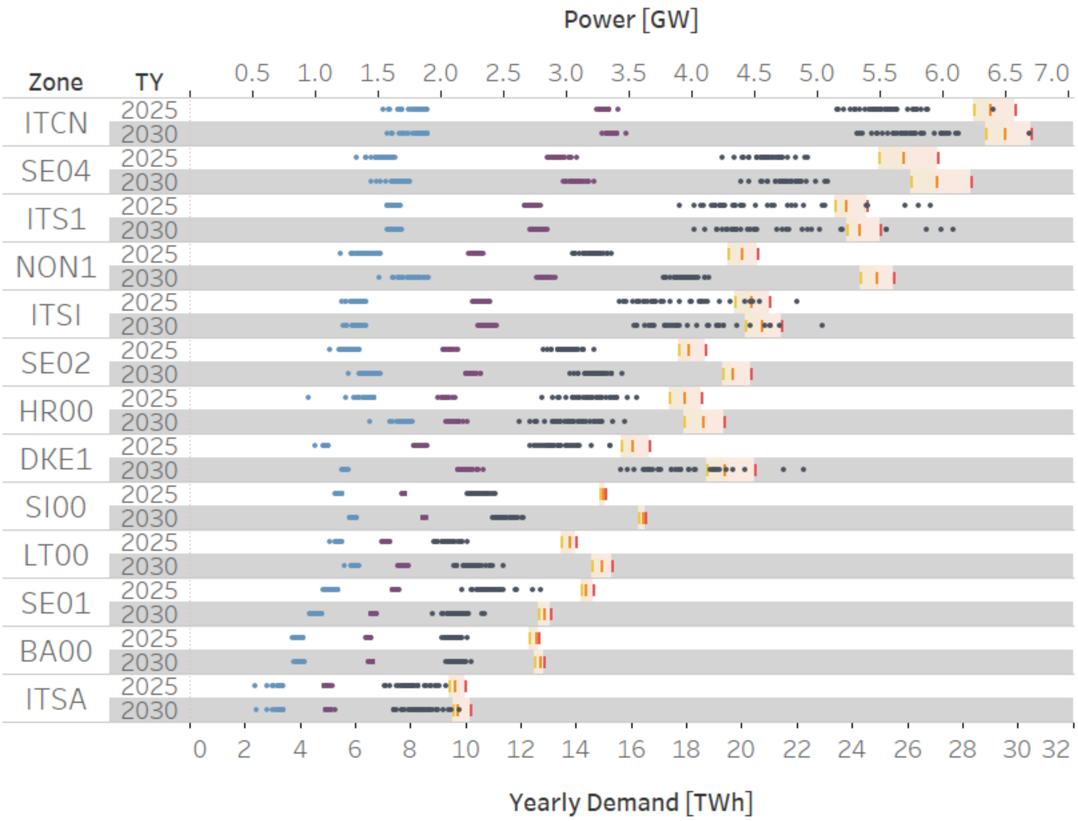
The demand profiles generated for TYs 2025 and 2030 combine historical data from 2012 – 2016 (some market zones use additional historical data) and are forecasted based on the climate years from 1982 – 2016 (c.f. demand methodology).

In general, the impact of CYs on a market zone's yearly and hourly demand values (i.e. the variability CYs cause in TWh and GW terms) is proportional to the zone's yearly demand levels. In other words, the higher the yearly demand level, the higher the variability on yearly demand and hourly demand values. All market zones are forecasted to have an increase in yearly and maximum hourly demand levels between TY 2025 and TY 2030.

All the countries are forecasted to have their minimum, median and maximum YD levels increase from TY 2025 to TY 2030. As shown in the bar plots, Germany (DE00), France (FR00) and Turkey (TR00) are forecasted to have the largest YD levels and the highest peak demand (PD) levels for both TYs. Turkey (TR00), Germany (DE00) and the UK (UK00) are forecasted to have the largest YD and PD increases from TY 2025 to TY 2030.




Power [GW]
Zone
TY
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14
CZ00
RO00
CH00
GR00
ITCS
PT00
HU00
RS00
IE00
BG00
DKW1
NOM1
SK00
2025
2030
0 10 20 30 40 50 60 70
Yearly Demand [TWh]


Power [GW]
Zone
TY
0.5 1.0 1.5 2.0 2.5 3.0 3.5 4.0 4.5 5.0 5.5 6.0 6.5 7.0
ITCN
SE04
ITS1
NON1
ITSI
SE02
HR00
DKE1
SI00
LT00
SE01
BA00
ITSA
2025
2030
0 2 4 6 8 10 12 14 16 18 20 22 24 26 28 30 32
Yearly Demand [TWh]

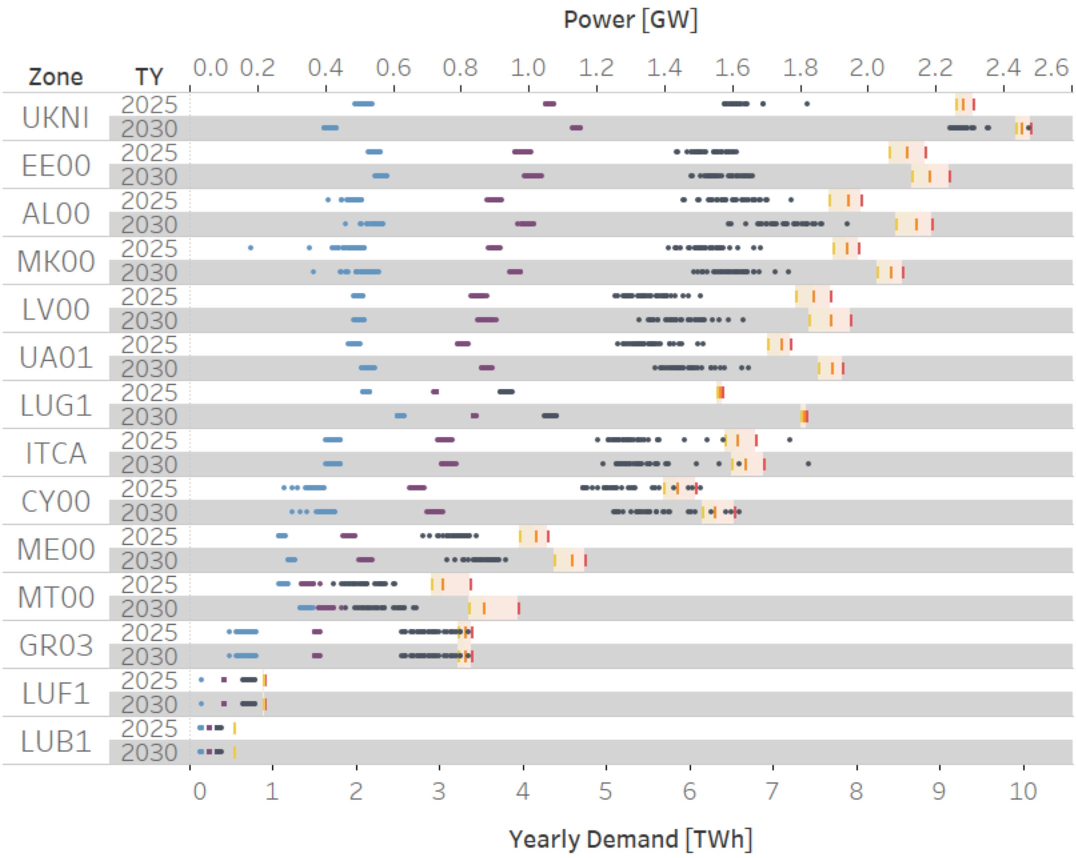


Figure 1: Yearly demand [TWh] and peak demand [GW] across 35 climate years by market zone for TYs 2025 and 2030

3 Climate Data

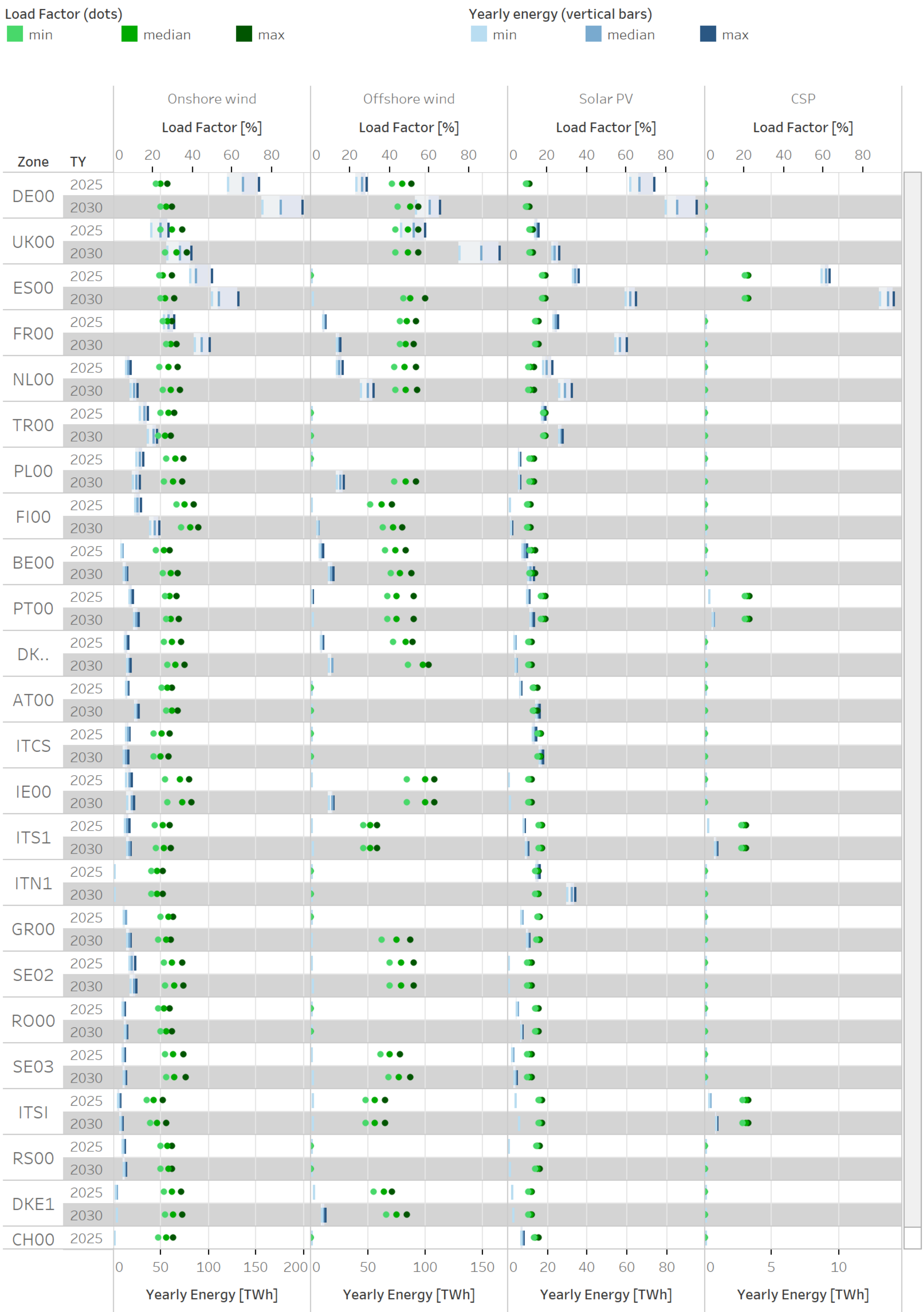
Climate data is a pivotal dataset for any power system assessments. The European power system is well interconnected and the situation in one area can affect the situation in another. Hence, a comprehensive dataset is necessary, describing possible operational conditions across Europe in different moments of the year (including day) and in different areas. First, this dataset has to be sufficiently spatially and temporally granular to represent variability in space (e.g. Pan-European average temperature is not suitable for all Bidding Zones individually) and in time (e.g. annual average temperature is not suitable to represent what can occur in different seasons). Second, climate data as a whole has to be coherent[1], ensuring that it represents reasonable situations in space (e.g. the temperature in neighbouring Bidding Zones should be similar) and in time (e.g. temperature from one hour to another does not change drastically). The Pan-European Climate Database (PECD) was developed to meet these requirements and was used in the ERAA 2021 assessment. PECD is, in essence, based on historical reanalysis data, which means that possible operational conditions are based on historically occurring situations and should be considered as a collection of weather variables or energy variables which are derived from weather variables.

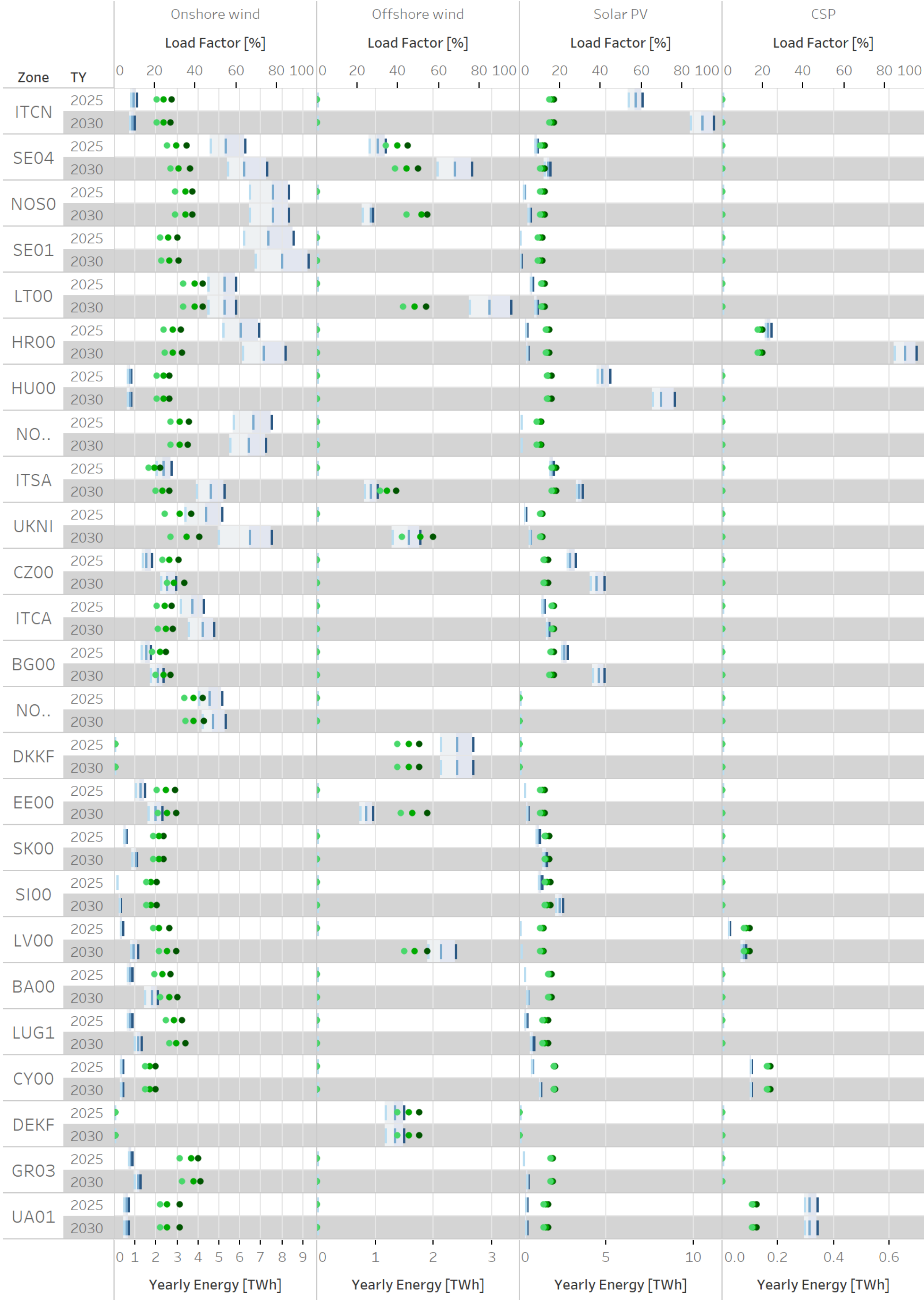
Figure 2 below shows the minimum, median and maximum yearly available RES energy that can be generated by these technologies and injected in the grid under all climate years, provided there is sufficient demand, as well as the derived load factors (assuming 100% of the available energy is injected in the grid). The available

[1] Often referred as ‘spatial and temporal correlation’.

energy is calculated based on the installed capacities of the reported technologies and wind & solar load factor profiles. Consequently, for a given TY, an installed capacity increase would increase the available energy proportionally while keeping the load factors unchanged. As these technologies do not assume any energy storage, if specific hours demand is too low to absorb a portion of the available energy, the latter will be curtailed.

As suggested by the figure, the available yearly energy is higher for wind technologies than for solar technologies, and the impact of the CYs is more pronounced for wind technologies. In general, offshore wind is the technology with the highest load factor.


Load Factor (dots)
min
median
max
Yearly energy (vertical bars)
min
median
max
Onshore wind
Offshore wind
Solar PV
CSP
Load Factor [%]
0 20 40 60 80
Zone
TY
DE00 2025 2030
UK00 2025 2030
ES00 2025 2030
FR00 2025 2030
NL00 2025 2030
TR00 2025 2030
PL00 2025 2030
FI00 2025 2030
BE00 2025 2030
PT00 2025 2030
DK.. 2025 2030
AT00 2025 2030
ITCS 2025 2030
IE00 2025 2030
ITS1 2025 2030
ITN1 2025 2030
GR00 2025 2030
SE02 2025 2030
RO00 2025 2030
SE03 2025 2030
ITSI 2025 2030
RS00 2025 2030
DKE1 2025 2030
CH00 2025
0 50 100 150 200
0 50 100 150
0 20 40 60 80
0 5 10
Yearly Energy [TWh]



Onshore wind
Offshore wind
Solar PV
CSP
Load Factor [%]
Zone
TY
ITCN
SE04
NOS0
SE01
LT00
HR00
HU00
NO..
ITSA
UKNI
CZ00
ITCA
BG00
NO..
DKKF
EE00
SK00
SI00
LV00
BA00
LUG1
CY00
DEKF
GR03
UA01
2025
2030
Yearly Energy [TWh]

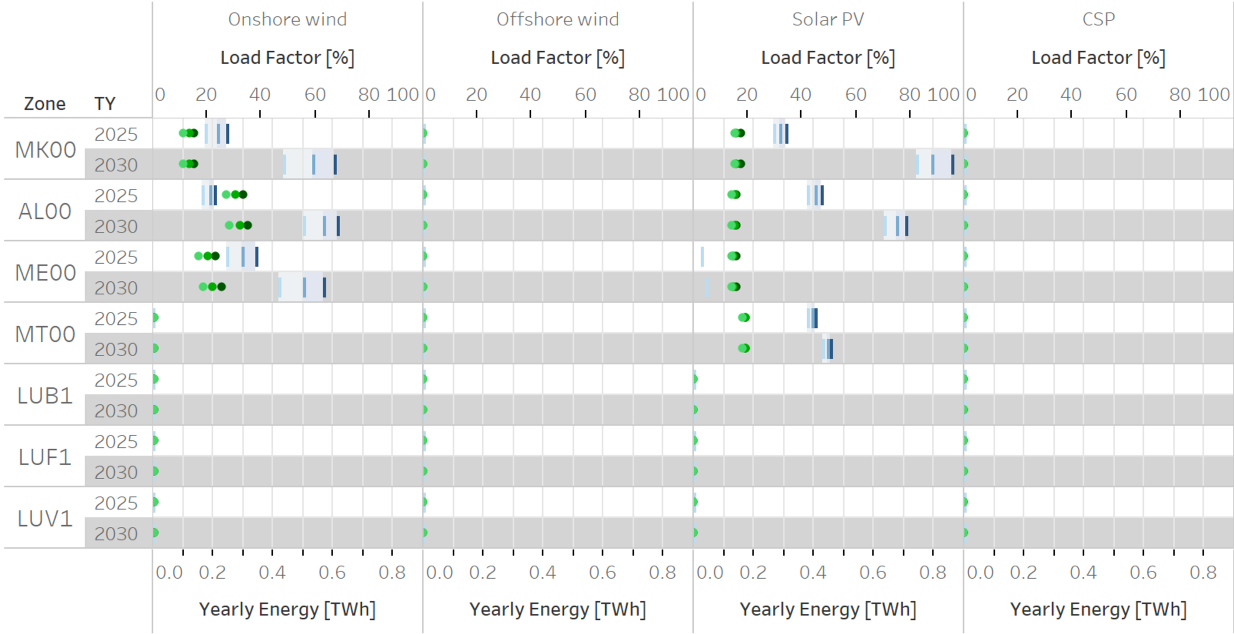
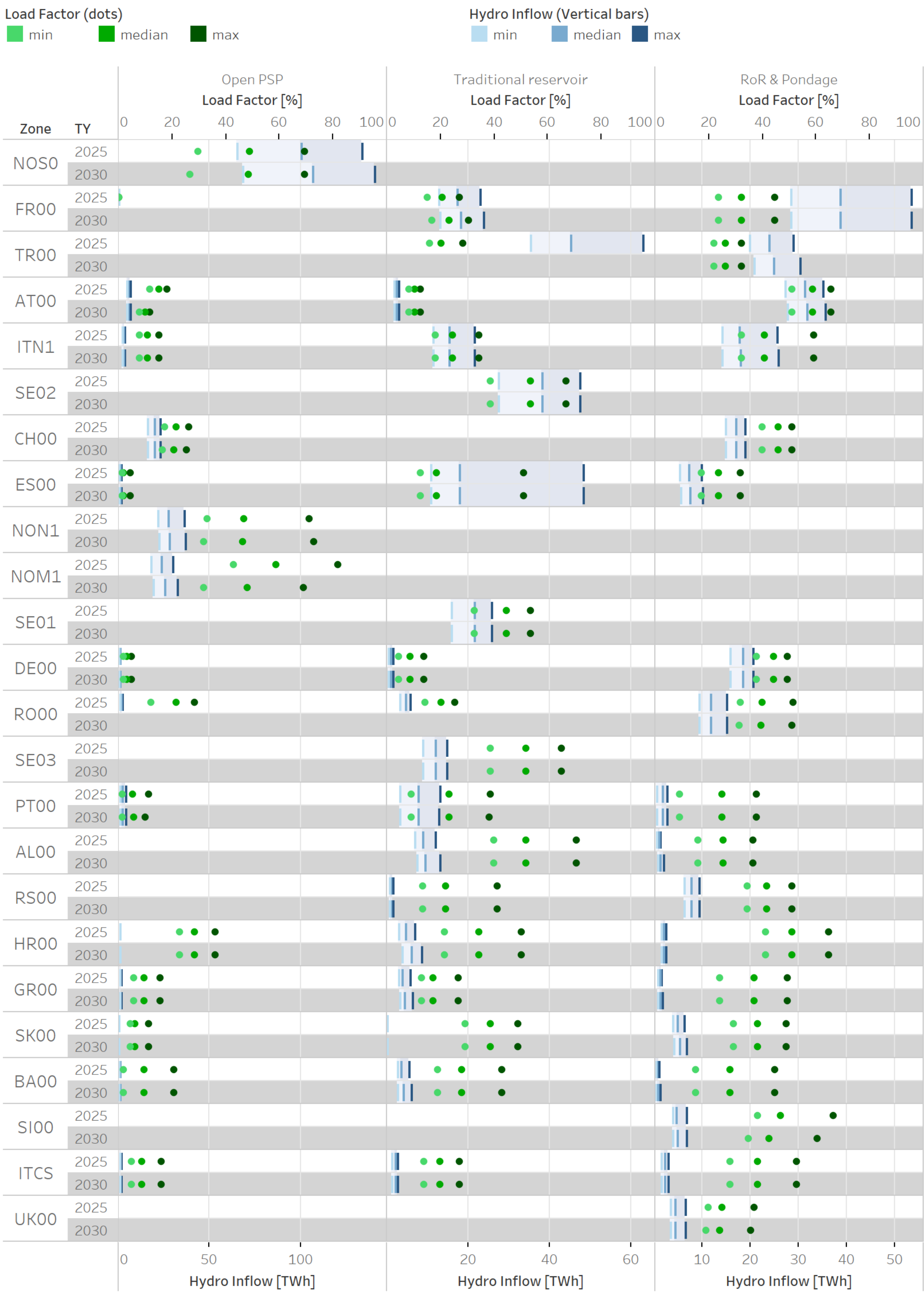


Figure 2: Yearly available RES energy [TWh] and load factors [%] per market zone, TY and technology

Similarly, Figure 3 shows the minimum, median and maximum yearly energy content of water inflows of hydro storage technologies, which is either injected in the grid or being stored, under all climate years, as well as the derived load factors (assuming 100% of the available energy is injected in the grid). Contrary to wind or solar technologies, an installed hydro turbining capacity increase would only increase the available energy if associated with a new water catchment. The load factor is defined as the water inflow summed to the difference in reservoir levels between the beginning and end of the year over the energy produced under nominal turbining assumptions over the year. The figure shows the hydro categories run-of-river (RoR) and pondage, traditional reservoir and open pumped storage plant (Open PSP).


Load Factor (dots)
min
median
max
Hydro Inflow (Vertical bars)
min
median
max
Open PSP
Load Factor [%]
Traditional reservoir
Load Factor [%]
RoR & Pondage
Load Factor [%]
Zone
TY
NOS0
FR00
TR00
AT00
ITN1
SE02
CH00
ES00
NON1
NOM1
SE01
DE00
RO00
SE03
PT00
AL00
RS00
HR00
GR00
SK00
BA00
SI00
ITCS
UK00
2025
2030
Hydro Inflow [TWh]
Hydro Inflow [TWh]
Hydro Inflow [TWh]

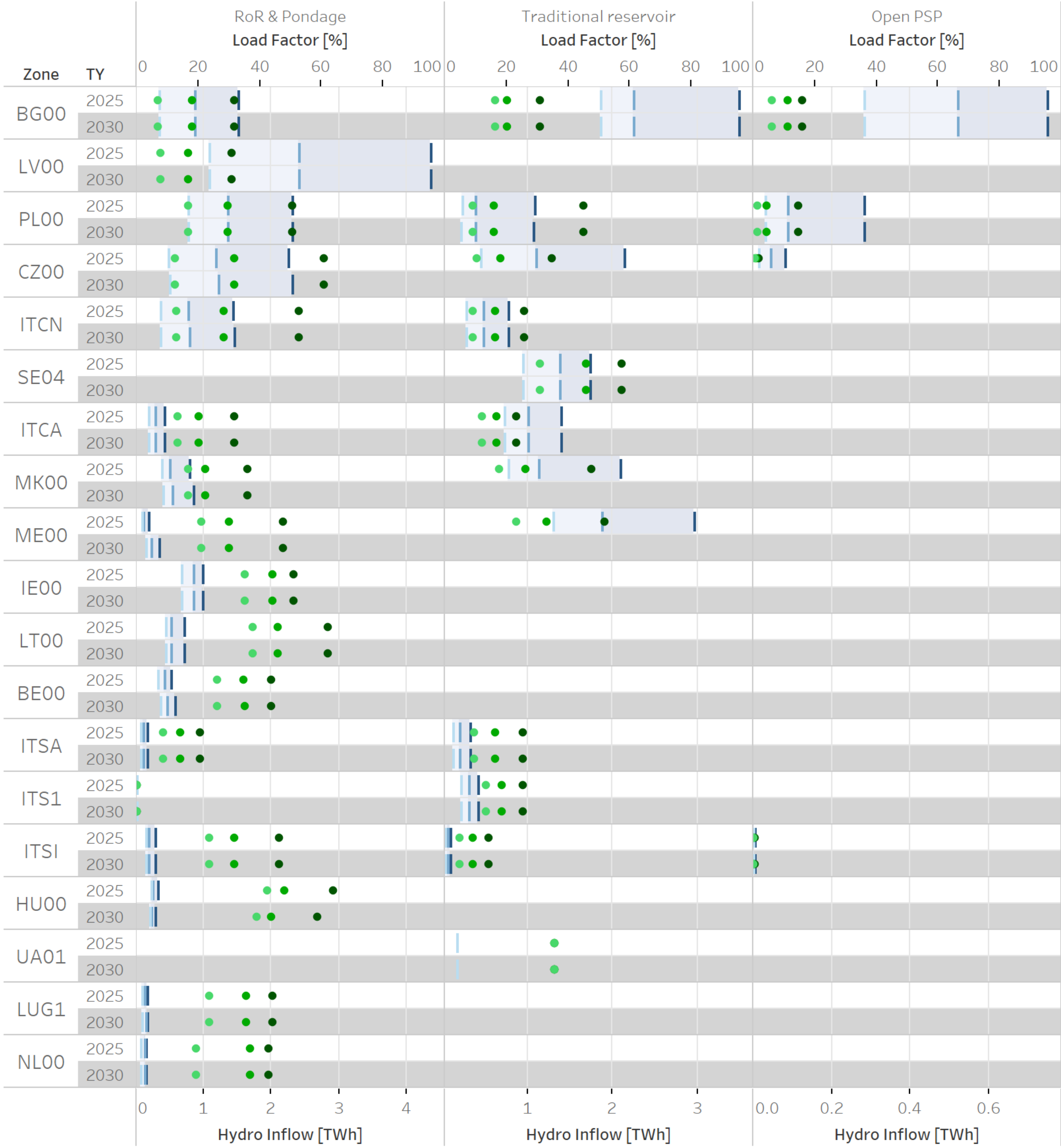


Figure 3: Yearly available hydro inflows [TWh] and load factors [%] per market zone, TY and technology

4 Resource capacities

In the context of the ERAA 2021, a resource is a market-participating unit or, more generally, a technology that may be managed/optimised to meet demand at any point in time. These include technologies injecting power in the grid and technologies reducing or shifting the demand to be met, such as DSR.

4.1 Resource capacities for "National Estimates" scenario

Thermal capacities are different for the various scenarios. As described in Annex 3, the 'National Estimates' and 'National Estimate with Low Thermal' scenarios use different thermal capacity assumptions whereas the 'without CM' and 'with CM' central reference scenarios are based on the 'National Estimates' scenario for the EVA step which modifies the resource capacities.

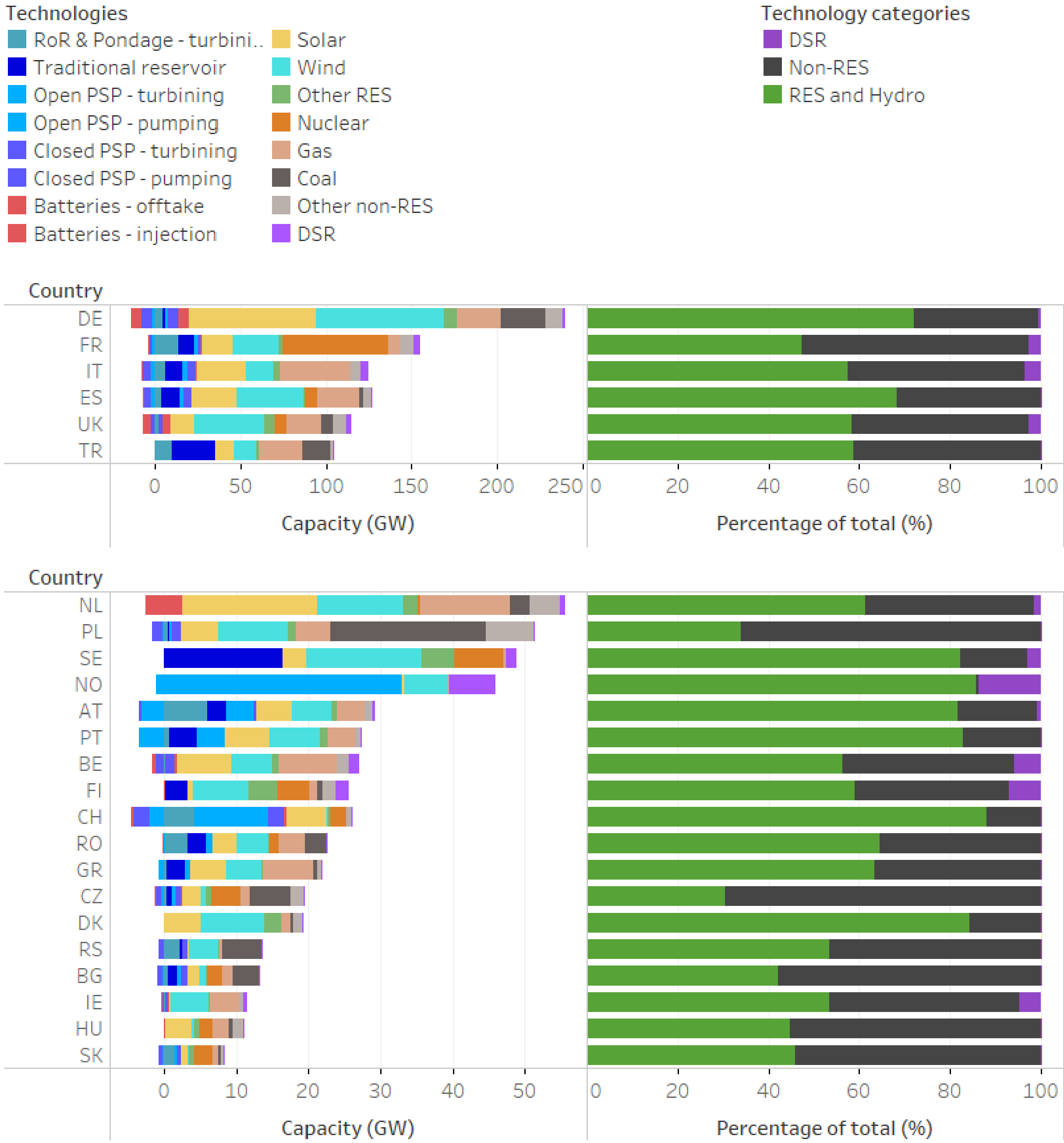
Figure 4 and Figure 5 show – for TYs 2025 and 2030 – the resource capacities (net generation capacity and DSR) by country and technology in the left part and the capacity mix of renewable energy sources (RES), non-RES and DSR capacities by country in the right part. Positive resource capacity values represent generation/injection/load reduction capacities, whereas negative values represent pumping/offtake capacities corresponding to PSP units and batteries. As shown in the installed capacities overview below, neither pumping capacities nor closed PSP or battery capacities are reported in the capacity mix calculations (c.f. RES / non-RES mix provided in %, Figures 4 and 5), as they first take off energy from the grid before injecting it again at a later time. Open PSP technology, however, is considered renewable as it also receives water inflows. Countries are ranked by decreasing order of the total injection capacity. The figures only show capacities commissioned before the start of the given period. Table 1 below summarises the technology aggregations and classifications performed.

Table 1: Technology aggregations and classification used in installed capacity figures

Technology	Underlying technologies	Technology category
Hydro RoR & Pondage	*N.A.*	RES
Open PSP	*N.A.*	RES
Other RES	Geothermal, Marine, Small biomass, Waste	RES
Solar	PV, CSP	RES
Traditional Reservoir	*N.A.*	RES
Wind	Onshore wind, Offshore wind	RES
Coal	Hard coal, Lignite	Non-RES
Gas	Conventional, OCGT, CCGT	Non-RES
Nuclear	*N.A.*	Non-RES
Other non-RES	Heavy oil, Light oil, Shale oil, Other	Non-RES
DSR	*N.A.*	DSR
Battery	*N.A.*	*N.A.*
Closed PSP	*N.A.*	*N.A.*

According to Figure 4, Germany (DE), France (FR) and Italy (IT) are forecasted to have the highest resource capacity by TY 2025 and RES installed capacities account for a large proportion of installed capacities in these countries. The countries with the highest RES installed capacities include Germany (DE), Spain (ES) and Italy (IT), whereas the countries with the largest proportion of RES installed capacity include Albania (AL), Luxembourg (LU) and Norway (NO). France (FR), Germany (DE) and Italy (IT) are forecasted to have the highest non-RES installed capacities, whereas the countries with the highest proportion of thermal capacity are the Czech Republic (CZ), Poland (PL) and Cyprus (CY). Finally, DSR is expected to account for a small share of the resource mix of modelled countries. The countries with the highest DSR capacities are Norway (NO), Italy (IT) and France (FR), whereas the countries with the highest DSR shares are Norway (NO), Finland (FI), Latvia (LV), Ireland (IE) and Belgium (BE).

It is forecasted that for TY 2030, Denmark (DK) will replace Norway (NO) in the countries with the highest RES shares and Malta (MT) will supersede the Czech Republic (CZ) and Poland (PL) as the country with the largest non-RES shares, as seen in Figure 5.



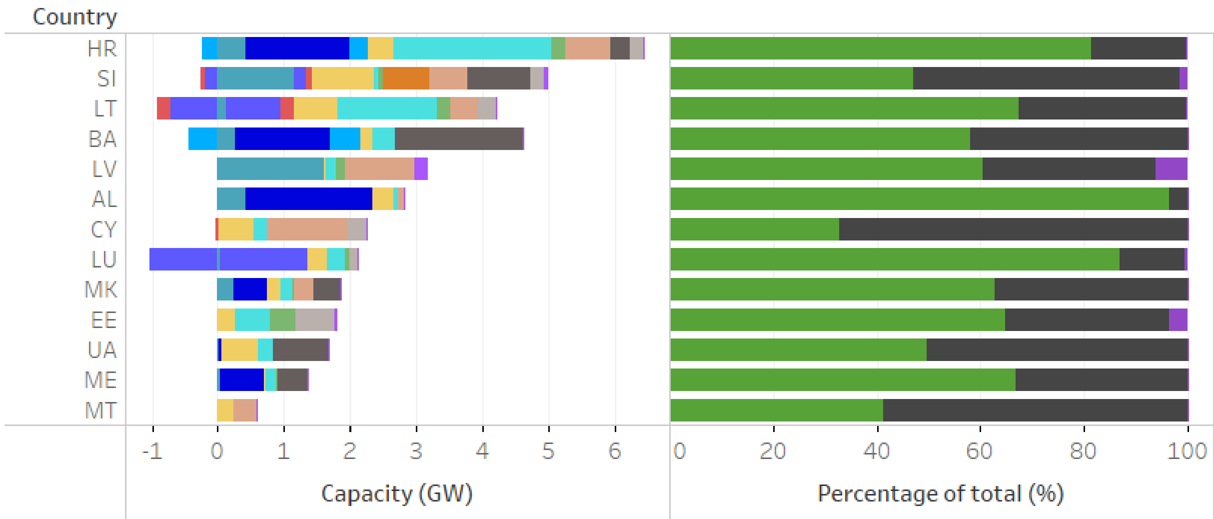
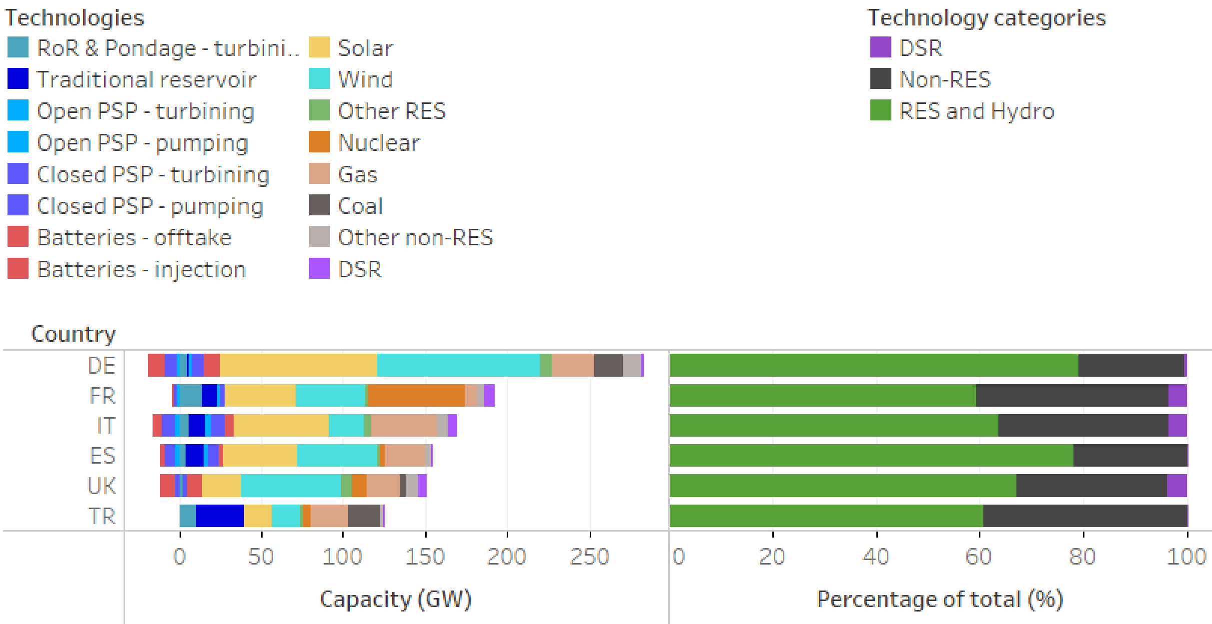


Figure 4: Resource capacity [MW] and capacity mix [%] by country for National Estimates TY 2025



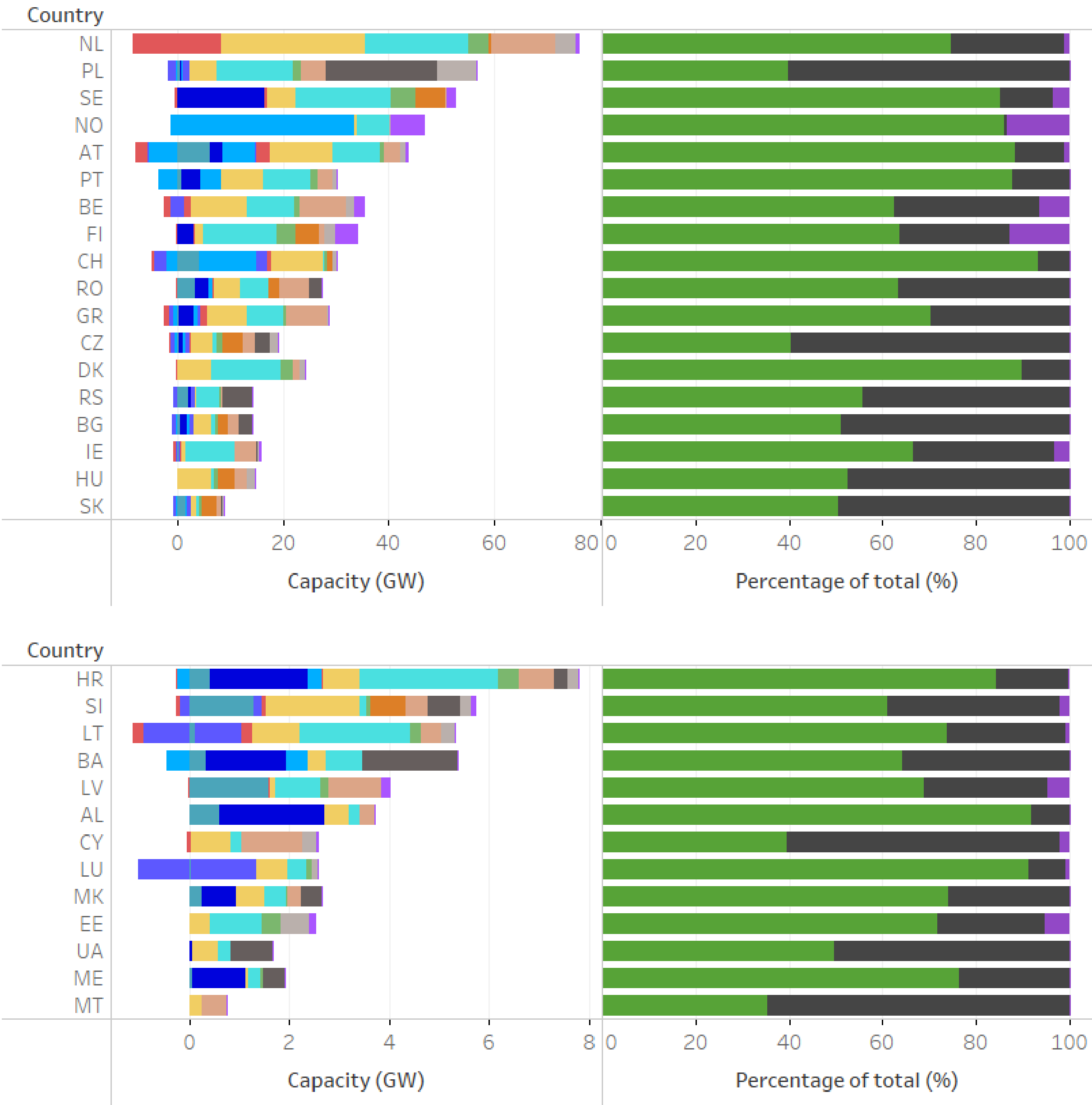
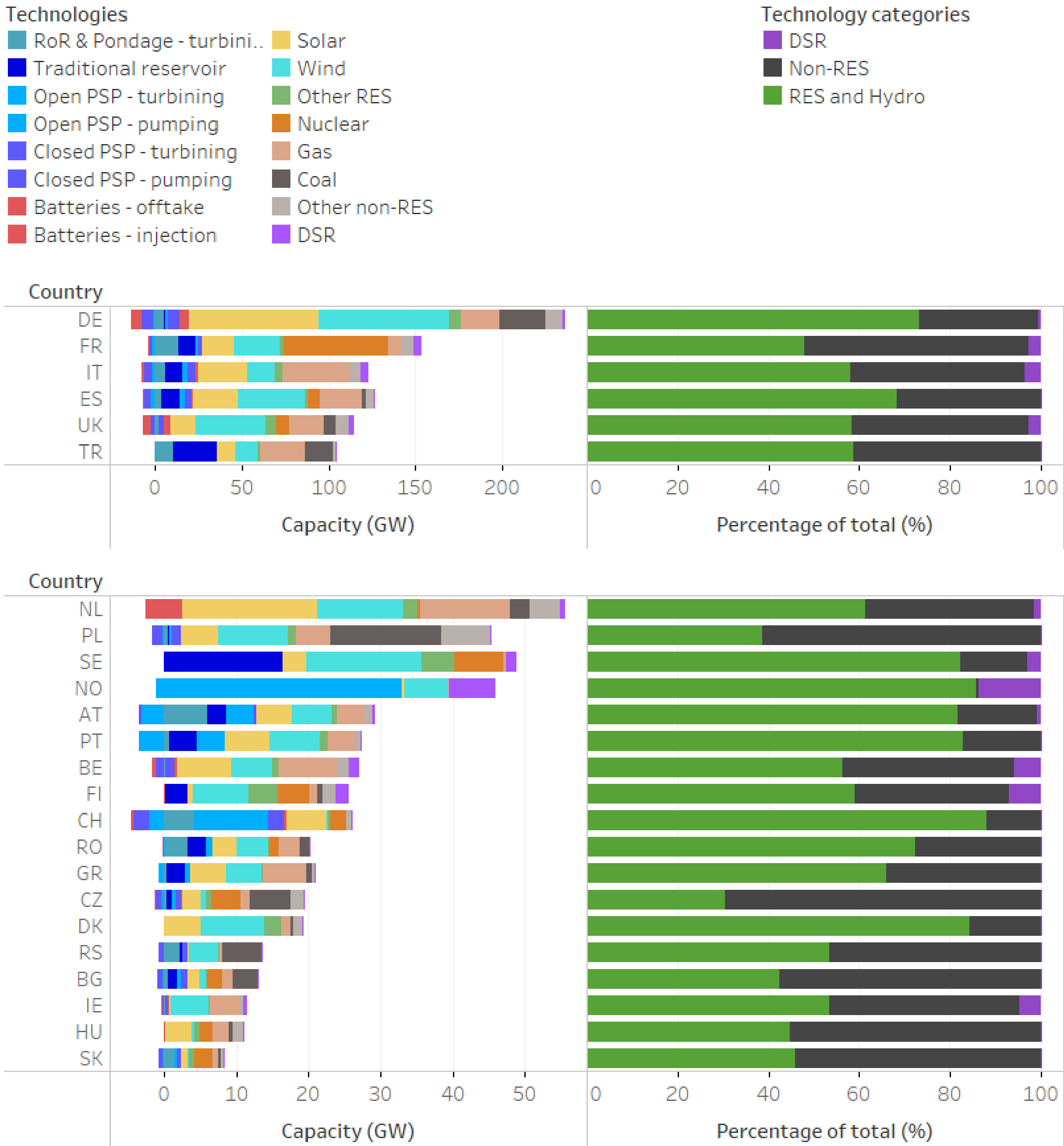


Figure 5: Resource capacity [MW] and capacity mix [%] by country for National Estimates TY 2030

4.2 Resource capacities for "National Estimates with Low Thermal Capacity" scenario

This section presents the resource capacities for the 'National Estimates with low thermal', 'Without CM' and 'With CM' scenarios. Figure 6 and Figure 7 show that the analysis made above for the 'National Estimates' scenario is still valid and, in addition, the countries with the largest reduction in thermal capacity are Poland (PL) with regards to coal capacity, Germany (DE) with regards to gas capacity and Romania (RO) with regards to gas and coal capacity.


Technologies
RoR & Pondage - turbini..
Traditional reservoir
Open PSP - turbining
Open PSP - pumping
Closed PSP - turbining
Closed PSP - pumping
Batteries - offtake
Batteries - injection
Solar
Wind
Other RES
Nuclear
Gas
Coal
Other non-RES
DSR
Technology categories
DSR
Non-RES
RES and Hydro
Country
DE
FR
IT
ES
UK
TR
0
50
100
150
200
Capacity (GW)
0
20
40
60
80
100
Percentage of total (%)
Country
NL
PL
SE
NO
AT
PT
BE
FI
CH
RO
GR
CZ
DK
RS
BG
IE
HU
SK
0
10
20
30
40
50
Capacity (GW)
0
20
40
60
80
100
Percentage of total (%)

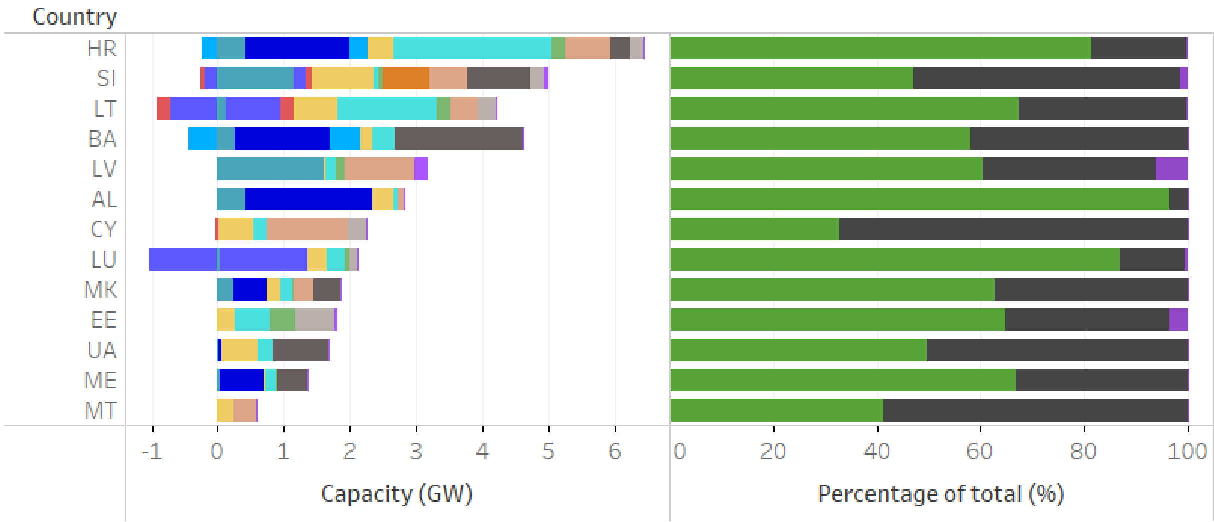
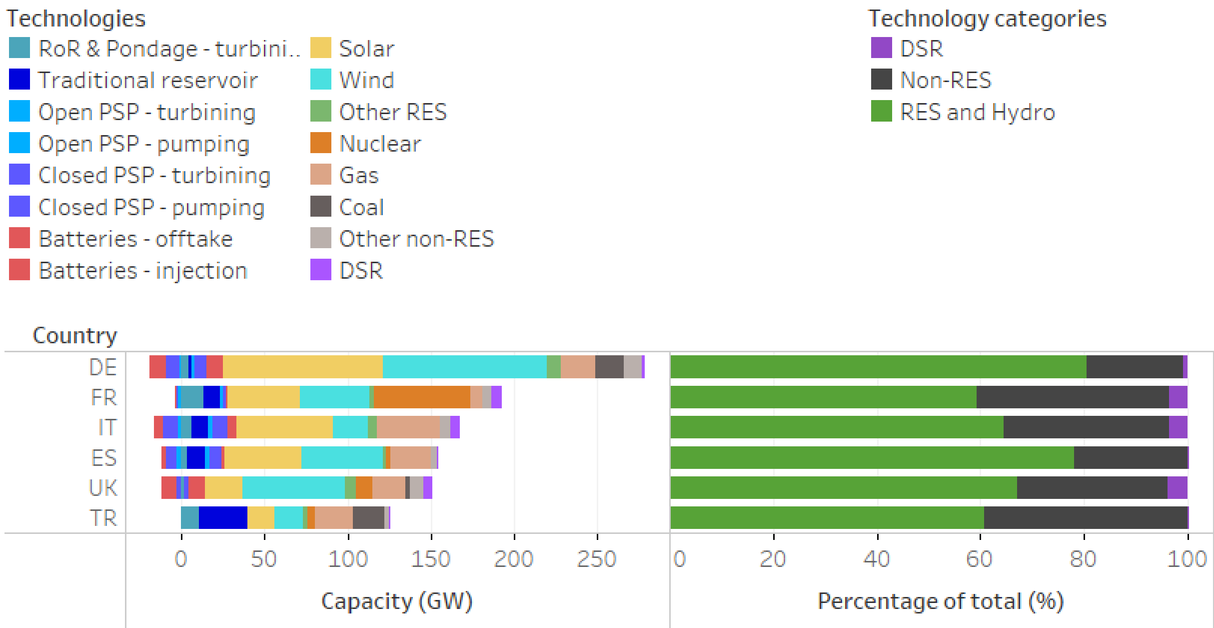


Figure 6: Resource capacity [MW] and capacity mix [%] by country for National Estimates with low thermal TY 2025



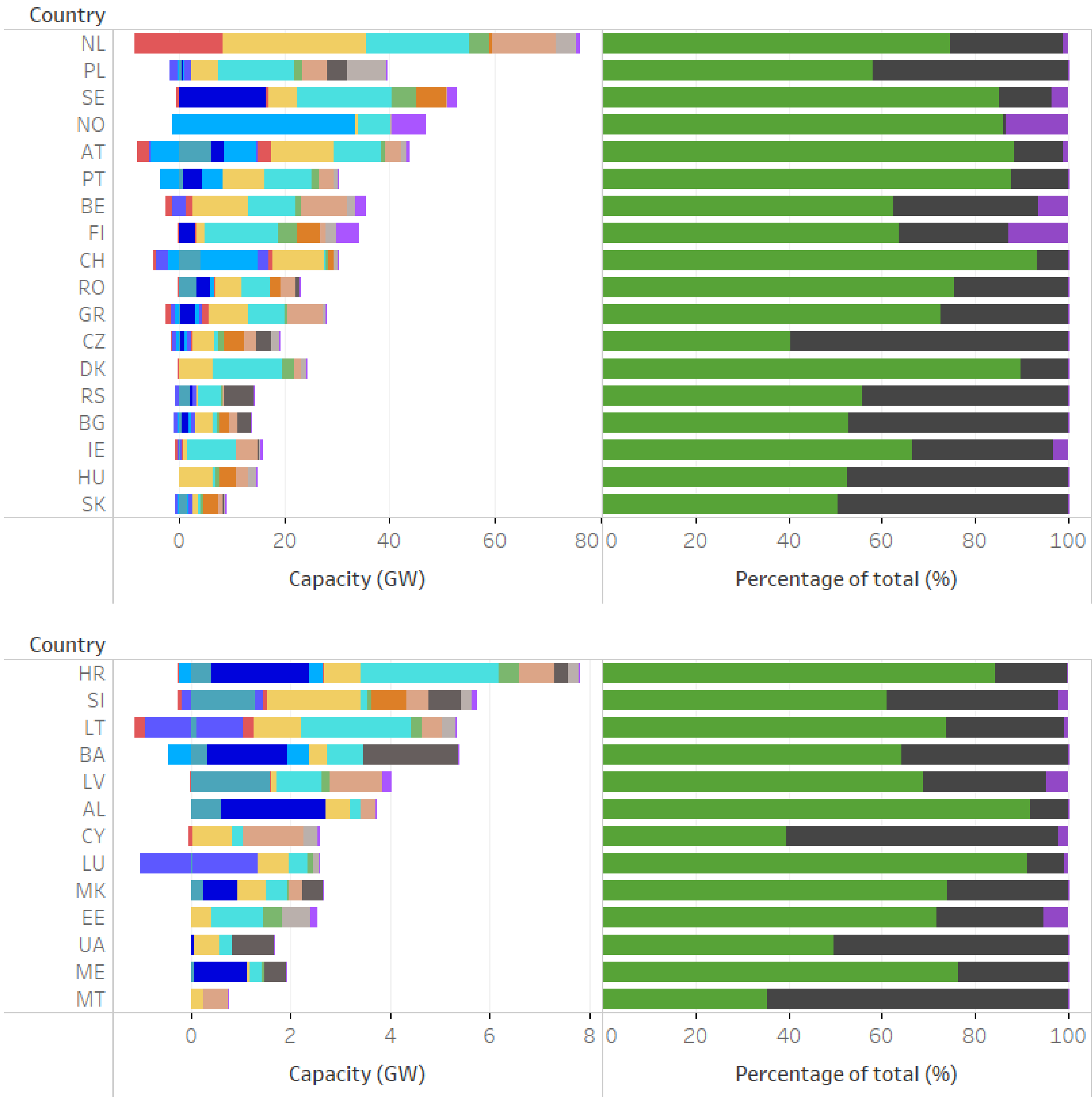


Figure 7: Resource capacity [MW] and capacity mix [%] by country for National Estimates with low thermal TY 2030

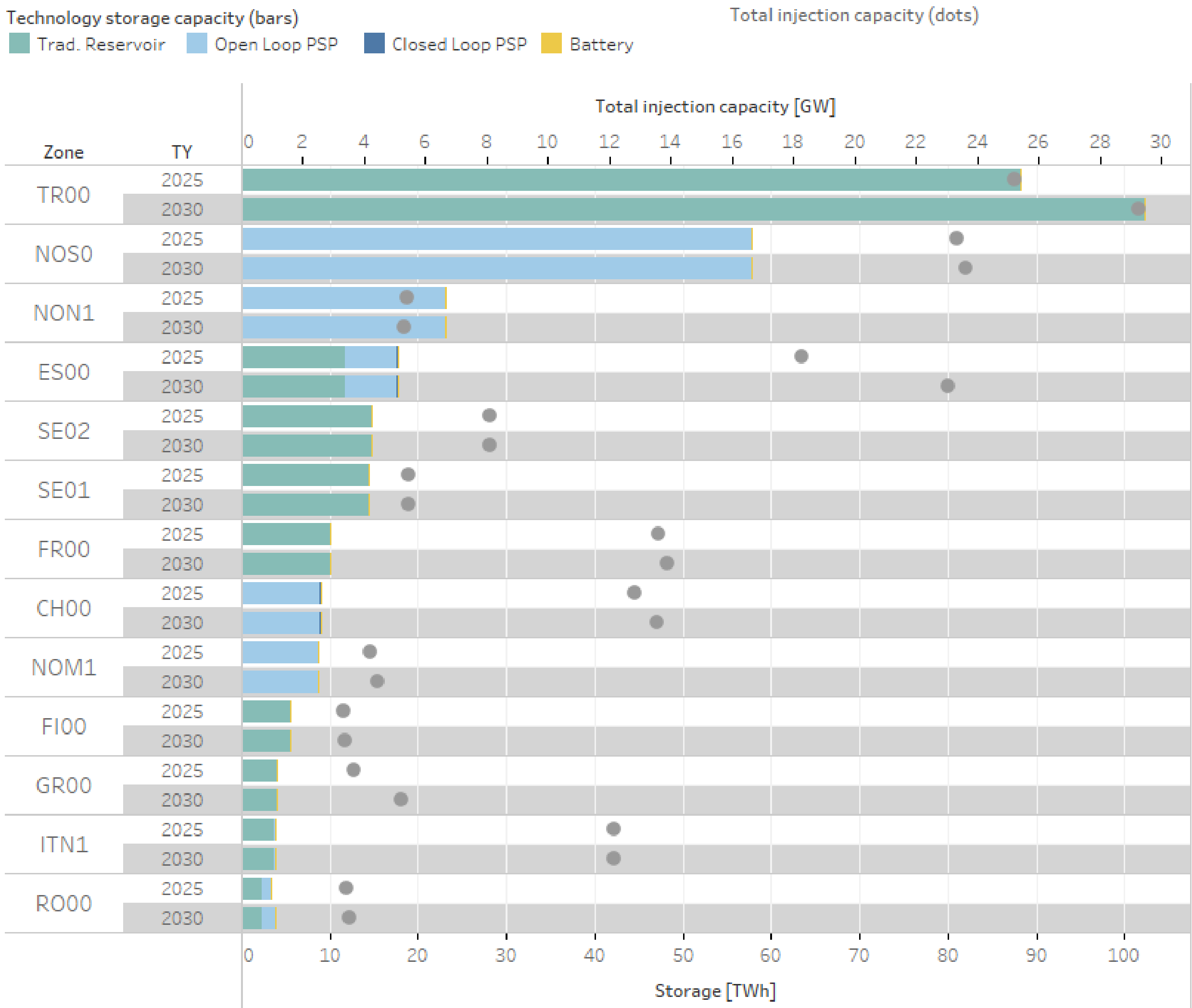
4.3 Storage capacities

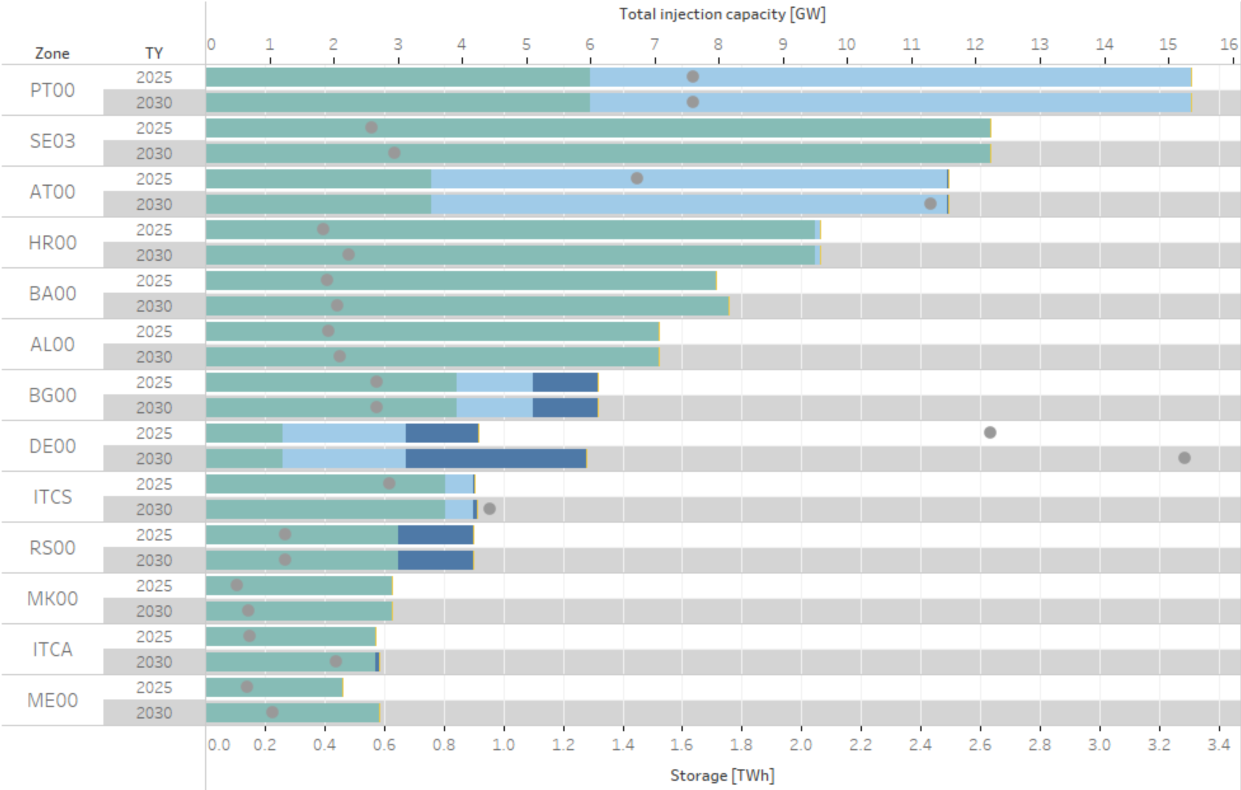
Figure 8 shows the energy content of the storage capacities (stacked bars) expressed in TWh for each storage technology, as well as the total injection capacity of these technologies (dots) expressed in GW per market zone and target year. The market zones are ranked according to their highest total storage values of any given TY.

The vast majority of the total storage capacity in Europe is composed of hydro technologies and, more precisely, traditional reservoirs and open PSPs, whereas closed PSPs and batteries only represent a small proportion of the overall storage capacity. Countries with the biggest storage capacity are Turkey (TR00), followed by Norway (NOS0 & NON1). The storage capacity in most countries is stable between 2025 and 2030, with the exception of Turkey whose storage capacity increases significantly. Due to a mistake in the data collected, the battery storage capacities used in the models in Ireland (IE00) and Northern Ireland (UKNI) are greater than the actual forecasts by a factor of 1000 (i.e. than the values shown in the figure).

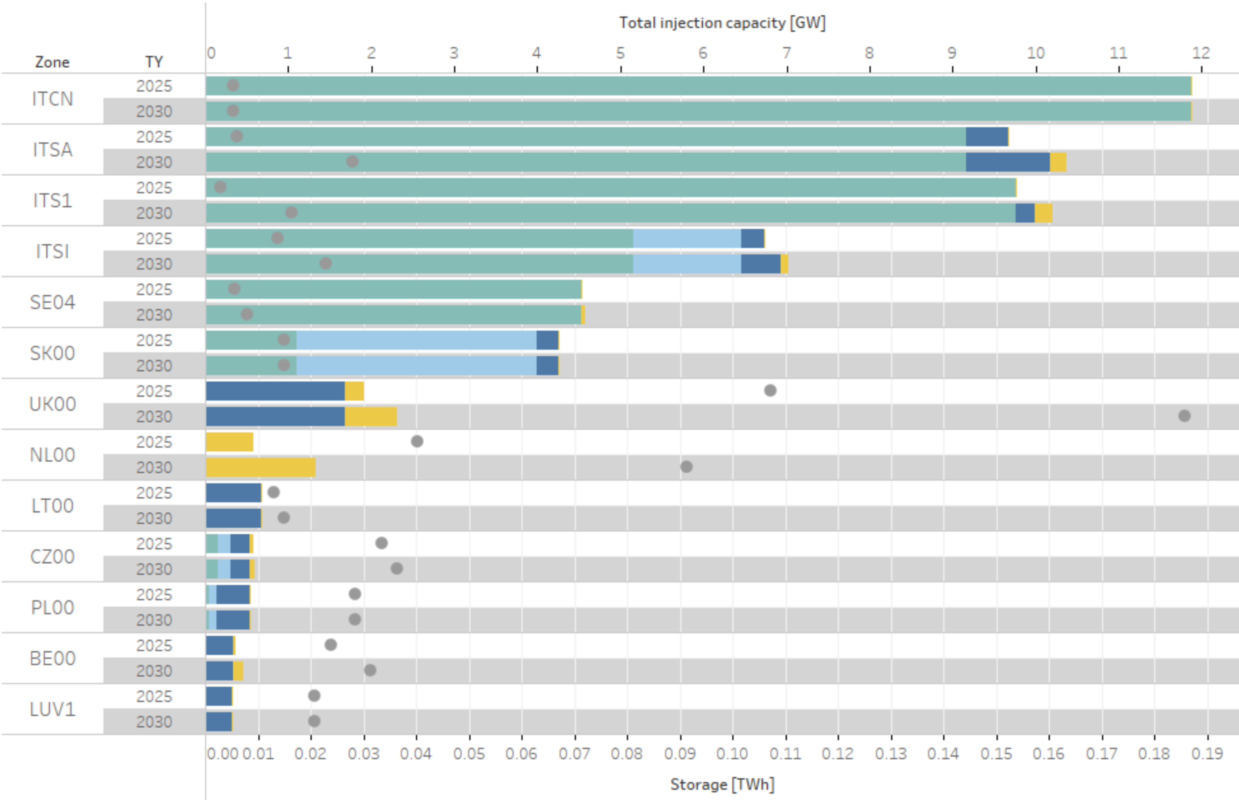
Total injection capacities are also expected to stay stable for most of the countries, whereas Spain, Austria and the UK (UK00) are expected to expand their capacities significantly.

The total injection capacity per country is more or less proportional to the total storage capacity per country; however, some countries display a significantly higher ratio of installed capacity over storage capacity than others. Examples include the UK (UK00), Germany (DE00) and Austria (AT00).


Technology storage capacity (bars)
Trad. Reservoir
Open Loop PSP
Closed Loop PSP
Battery
Total injection capacity (dots)
Total injection capacity [GW]
Zone
TY
TR00
NOS0
NON1
ES00
SE02
SE01
FR00
CH00
NOM1
FI00
GR00
ITN1
RO00
2025
2030
Storage [TWh]



Total injection capacity [GW]
Zone
TY
PT00
SE03
AT00
HR00
BA00
AL00
BG00
DE00
ITCS
RS00
MK00
ITCA
ME00
2025
2030
Storage [TWh]



Total injection capacity [GW]
Zone
TY
ITCN
ITSA
ITS1
ITSI
SE04
SK00
UK00
NL00
LT00
CZ00
PL00
BE00
LUV1
2025
2030
Storage [TWh]

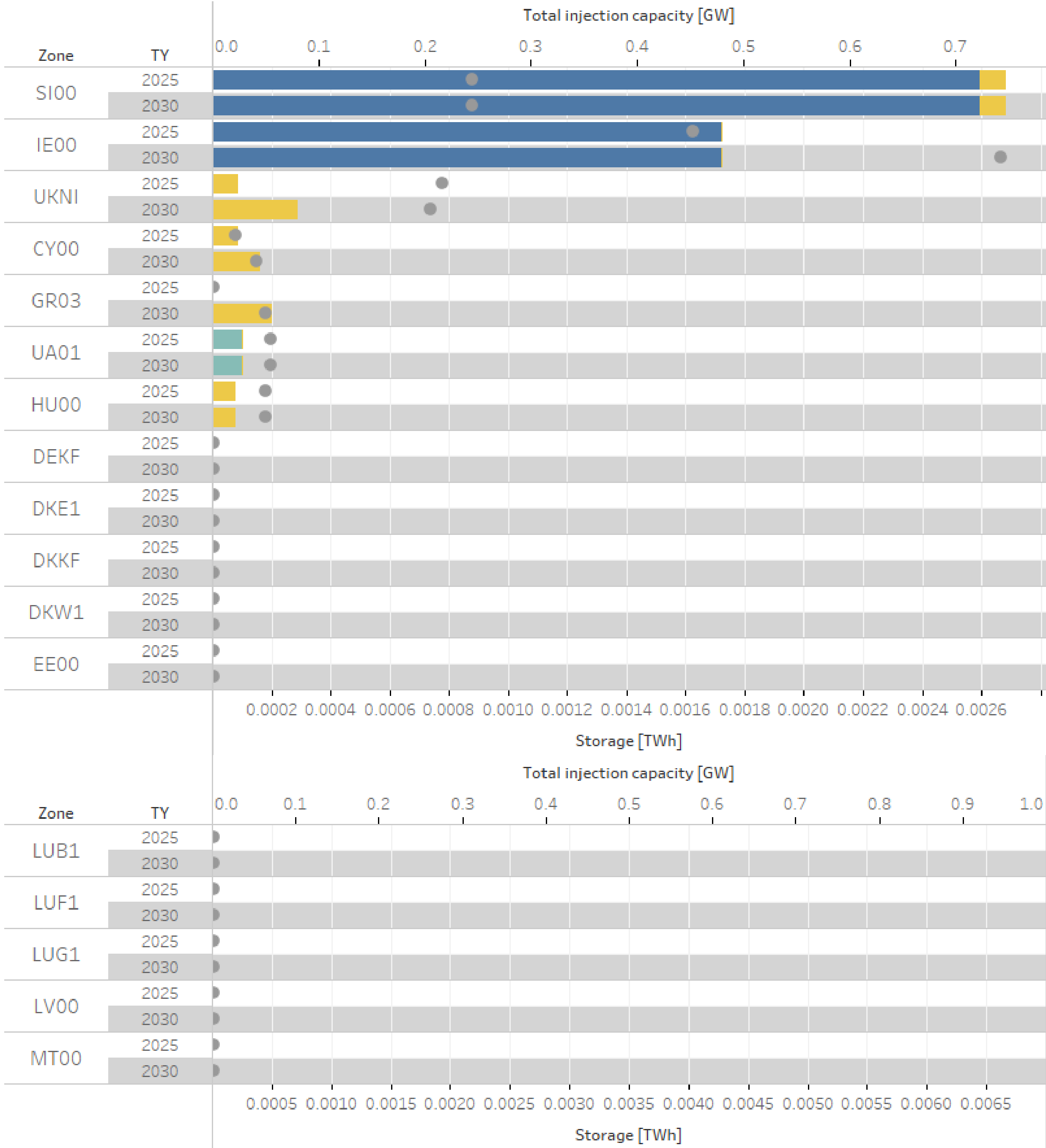
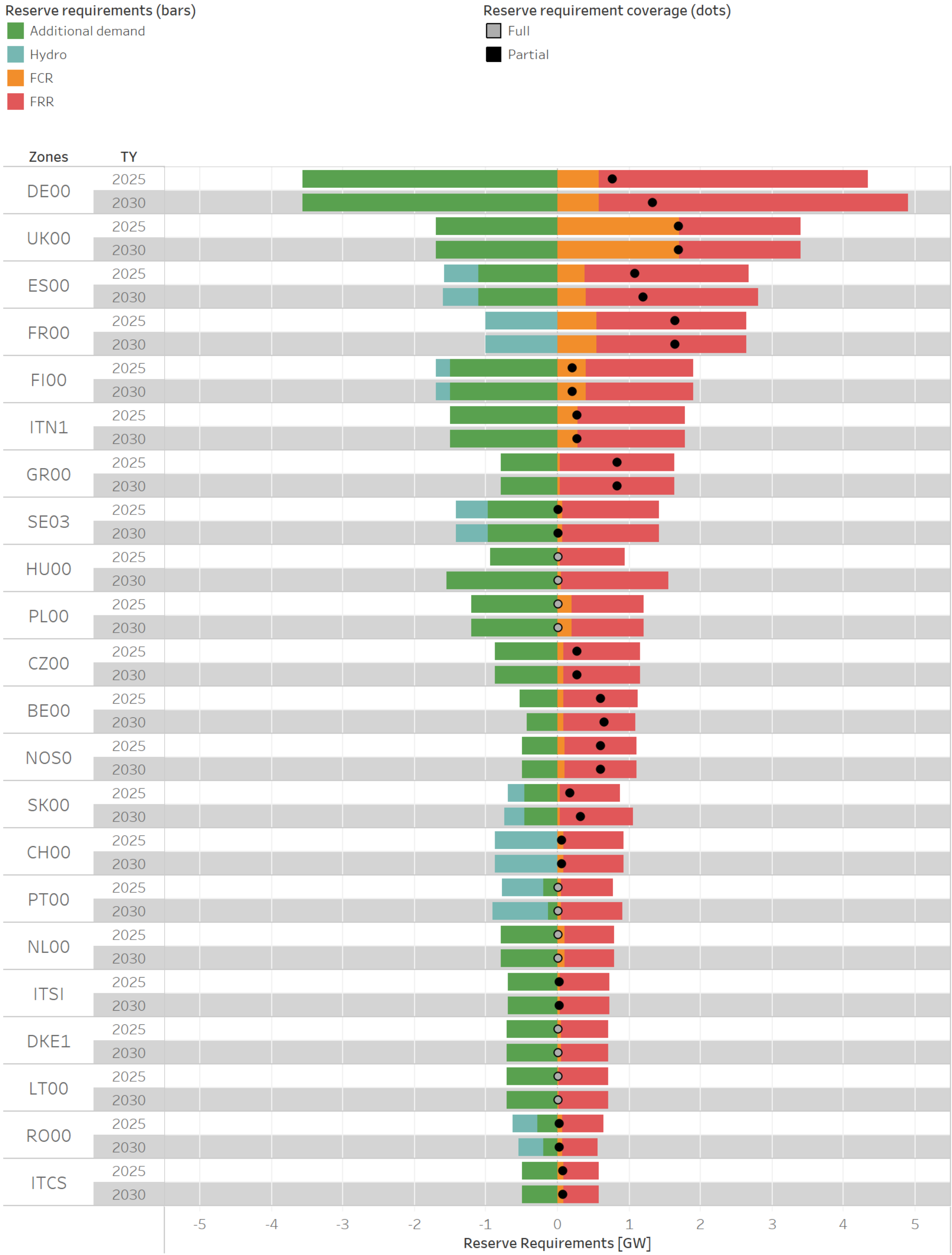


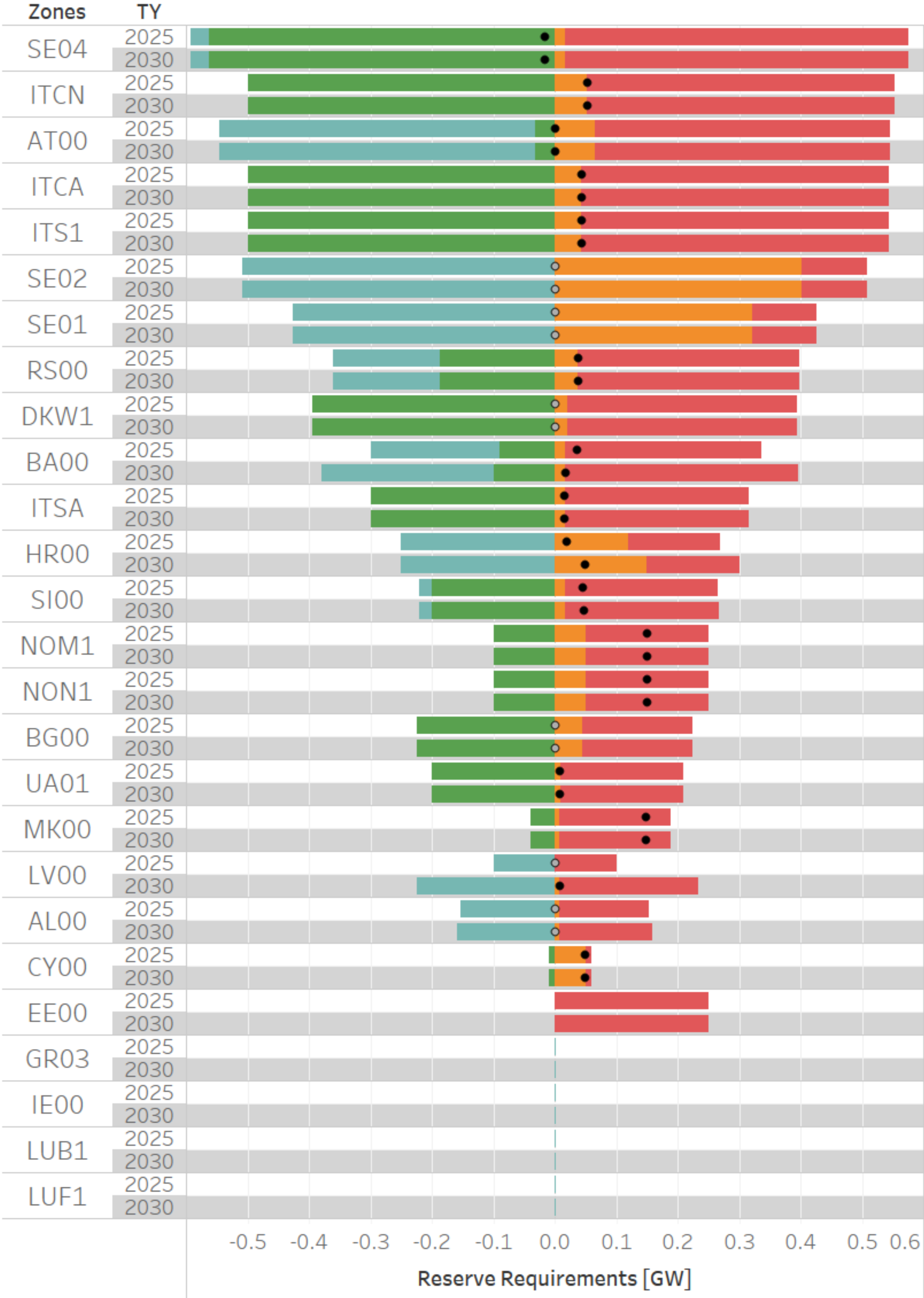
Figure 8: Storage capacity [TWh] per technology and market zone & total injection capacity [GW] per market zone for TYs 2025 and 2030

4.4 Reserve requirements in all scenarios

Although some FCR and FRR contracts to satisfy the respective requirements will be awarded in future auctions, some have already been awarded. Awarded/known capacities are deducted from the reported net generating capacities (NGCs) of generation units and the rest must be accounted for indirectly using two methods: either by increasing demand and/or by decreasing hydro capacity (more information in Annex 3). Figure 9 illustrates the FRR requirements and FCR requirements by country for TYs 2025 and 2030 as well as the amount of the requirement accounted for by one of the two methods. Lastly, the dots indicate the amount of known awarded reserves deducted from the NGCs and of other technologies e.g. DSR units contributing to ancillary services. The grey ones indicate that the entire requirements amount was covered by the two methods (increasing demand or decreasing hydro capacity) i.e “full coverage”.

Most of the zones have identical or similar reserve requirements for both TYs and FRR capacity requirements are much bigger than in-the market FCR requirements for both TYs. The market zones/countries forecasted to have the highest reserve requirements in TYs 2025 and 2030 are Germany (DE00), the United Kingdom (UK00), Spain (ES00) and France (FR00).


Reserve requirements (bars)
Additional demand
Hydro
FCR
FRR
Reserve requirement coverage (dots)
Full
Partial
Zones
TY
DE00
UK00
ES00
FR00
FI00
ITN1
GR00
SE03
HU00
PL00
CZ00
BE00
NOS0
SK00
CH00
PT00
NL00
ITSI
DKE1
LT00
RO00
ITCS
2025
2030
-5
-4
-3
-2
-1
0
1
2
3
4
5
Reserve Requirements [GW]


Zones
TY
SE04
ITCN
AT00
ITCA
ITS1
SE02
SE01
RS00
DKW1
BA00
ITSA
HR00
SI00
NOM1
NON1
BG00
UA01
MK00
LV00
AL00
CY00
EE00
GR03
IE00
LUB1
LUF1
2025
2030
-0.5
-0.4
-0.3
-0.2
-0.1
0.0
0.1
0.2
0.3
0.4
0.5
0.6
Reserve Requirements [GW]

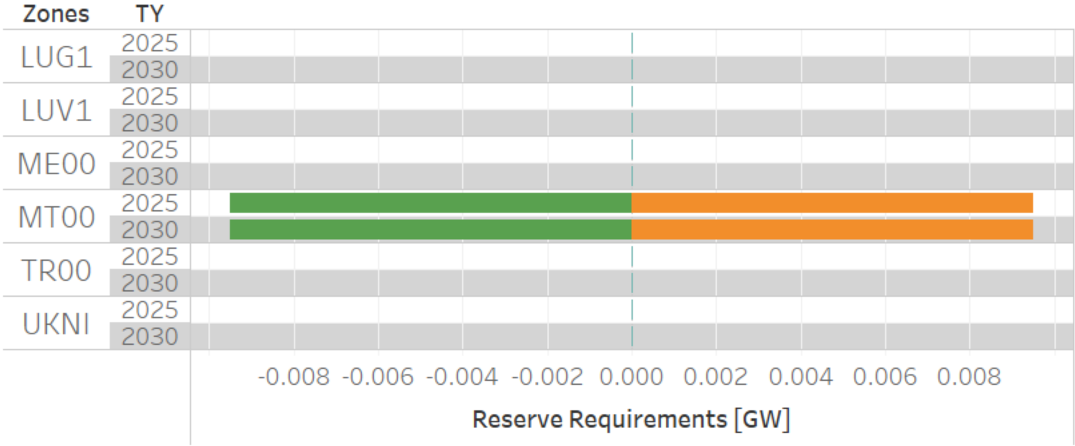


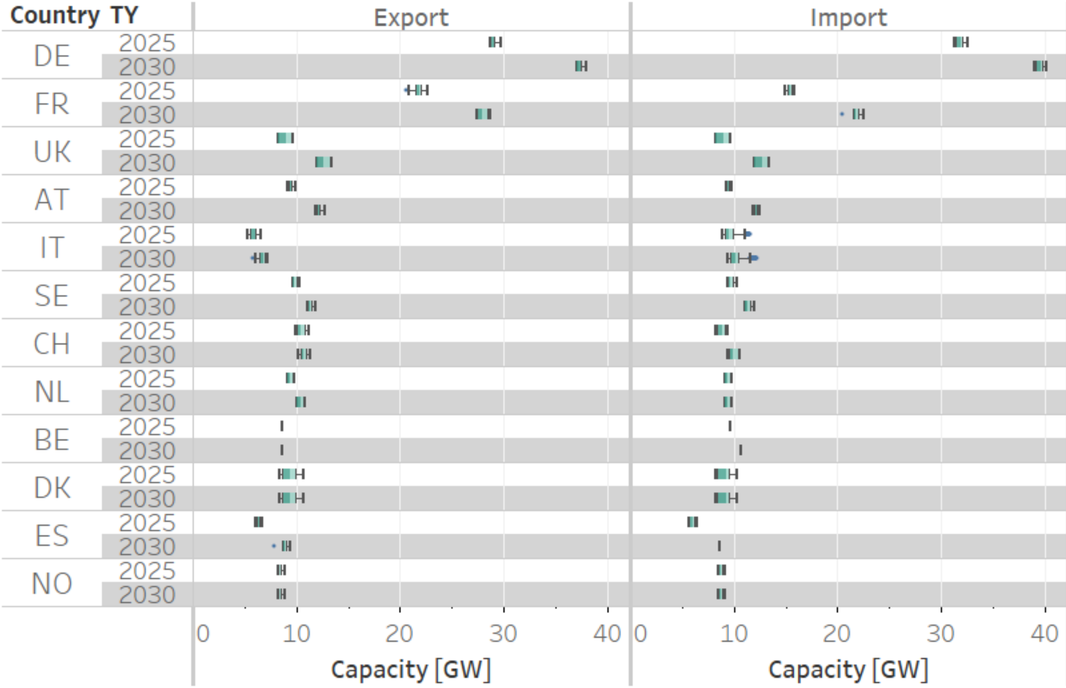
Figure 9: Reserve requirements [MW] for TY 2025 and 2030

5 Net Import/Export Capacities

NTC values represent the theoretical maximum commercial flows in one direction between two countries under specific conditions. Figure 10 shows the NTCs at the import and export sides per country and target year. The boxplots represent the distribution of the maximum hourly NTC capacities for a given country, TY and export/import direction across all the CYs. The green ranges represent the 1st quartile value, the median and the 3rd quartile value respectively, the lower and upper hinges represent the lowest and highest values within 1.5 times the interquartile range from the 1st quartile and the 3rd quartile value respectively. The values not comprised between the hinges are considered as outliers and plotted with dots.

Most of the countries have similar export and import capacities for any given TY, and no country has a decreasing capacity from TY 2025 to TY 2030 at the export or the import side. In addition, capacity variability over the year is often around 5 to 10 %.

Countries with the highest capacities are Germany, France, the United Kingdom, Austria and Sweden.


Country TY
Export
Import
DE 2025 2030
FR 2025 2030
UK 2025 2030
AT 2025 2030
IT 2025 2030
SE 2025 2030
CH 2025 2030
NL 2025 2030
BE 2025 2030
DK 2025 2030
ES 2025 2030
NO 2025 2030
0 10 20 30 40
Capacity [GW]
Capacity [GW]

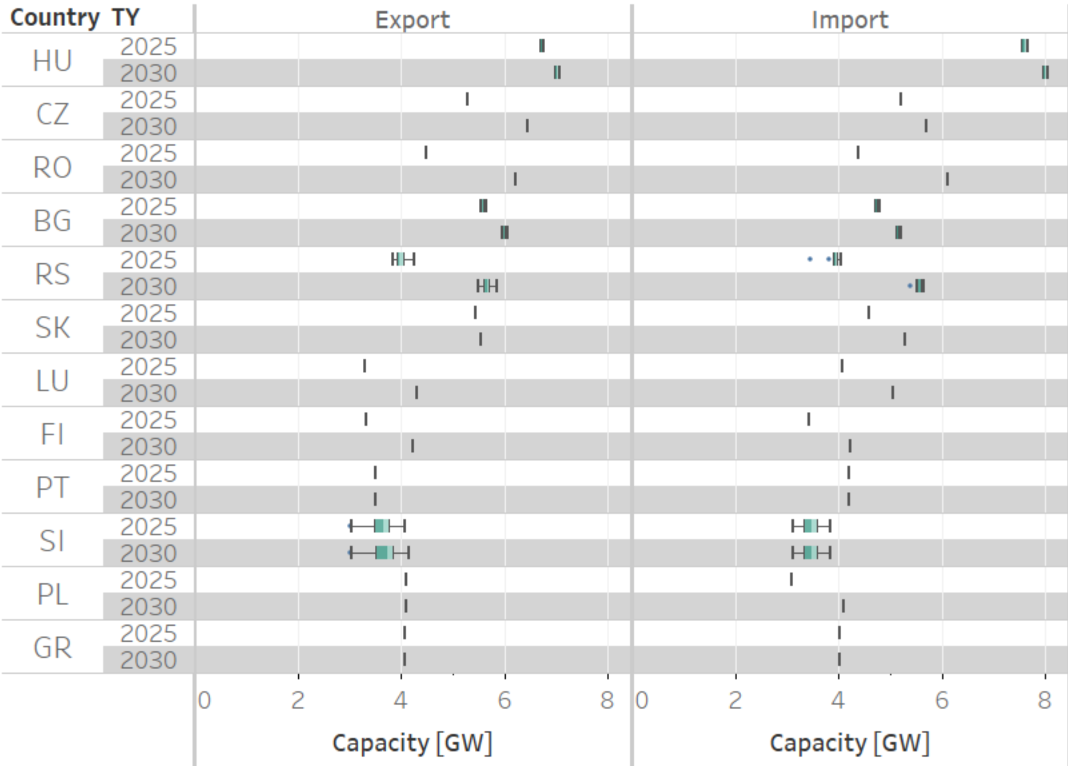

Country TY
Export
Import
HU 2025 2030
CZ 2025 2030
RO 2025 2030
BG 2025 2030
RS 2025 2030
SK 2025 2030
LU 2025 2030
FI 2025 2030
PT 2025 2030
SI 2025 2030
PL 2025 2030
GR 2025 2030
0 2 4 6 8
Capacity [GW]
Capacity [GW]

Figure 10: Net import and export capacity [GW] by country for TYs 2025 and 2030

Additional analysis performed for Bidding Zones in the Core Capacity Calculation Region (Core CCR) shows that TSO-submitted NTCs are less restrictive than NTCs derived from an FB domain set , which were used in Proof-of-Concept analysis[1]. This can be seen in Figure 11, which compares import and export capacities (considering only Core CCR borders) between data submitted by TSOs and NTC data derived from FB domain Set B[2]. It indicates that NTCs submitted by TSOs tend to respect a 70% allocation for cross-border trade requirements as FB domains were computed respecting that requirement; thus, NTCs collected by TSOs are not to be considered as overly conservative[3].

[1] For more details, c.f. ERAA 2021 Annex 4 – Flow Based coupling Proof-of-Concept: FB domain set B.
[2] The methodology is the same as the one used in the operational timeframe to compute 'shadow' NTC values within the Capacity calculation step.
[3] Full compliance with 70% rule in Poland is planned to be reached since 2026. There is agreed trajectory (to reach this level) for the period 2020-2025, specified in Polish Action Plan.

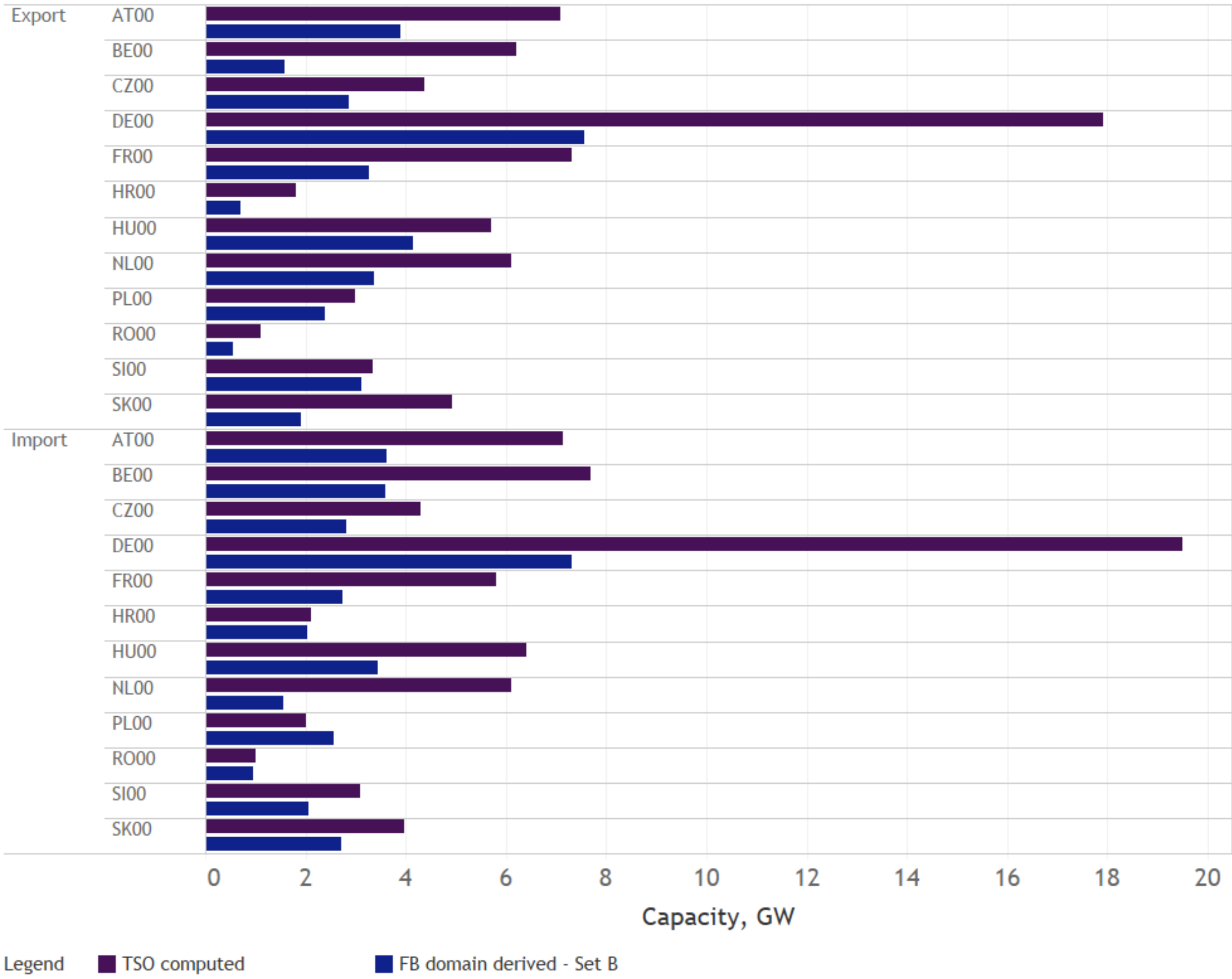


Figure 11: Import and export capacities: derived from TSOs submitted NTCs vs. NTCs derived from the FB domains (c.f. Annex 4) (considering only Core CCR borders)

6 Economic viability assessment parameters

As described in Annex 3, the EVA's objective is to identify and decommission non-economically viable units from the system, add additional economically viable capacities to the system, as well as adding sufficient additional capacity to achieve the reliability standards (in a scenario 'with CM').

Figure 12 illustrates the installed capacity subject to the EVA assessment as well as the capacity excluded from it. As described in Annex 3, the units with a CM contract in place are included in the assessment, whereas units subject to a must-run commitment or policy units are not. Overall, 125 GW of gas fired units (60% of the total gas capacity) are assessed during the EVA, 30 GW of hard coal units (53% of the total hard coal capacity), 30 GW of lignite units (60% of the total lignite capacity) and 6 GW of oil units (90% of the total oil capacity), whereas no nuclear capacity is subject to the EVA.

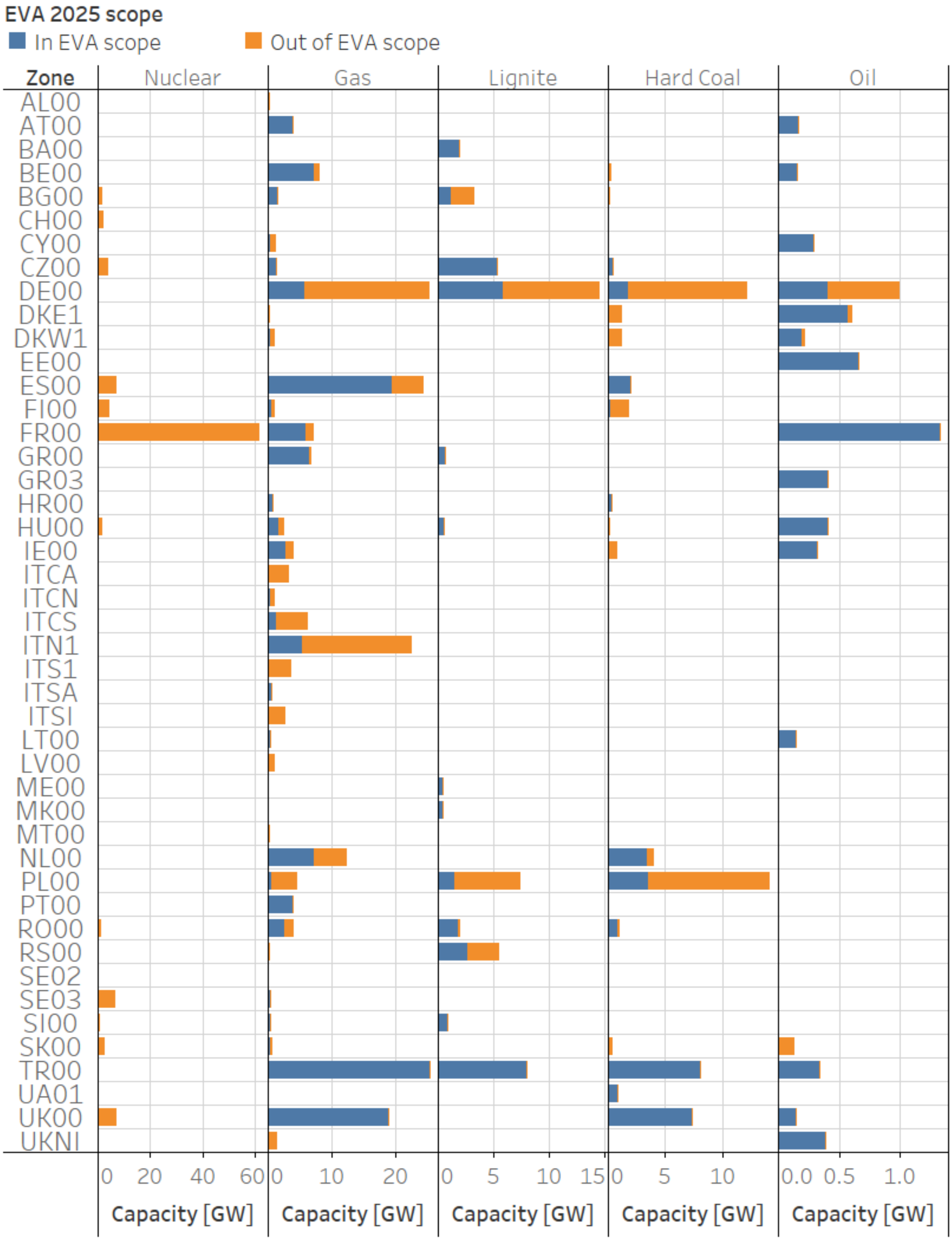


Figure 12: Capacity subject to EVA

Table 2 shows the techno-economic parameters of commissioned and planned units assessed by the EVA for economic decommissioning, whereas Table 3 and Table 4 show the techno-economic parameters given to units to be commissioned as a result of the EVA if such a technology is viable. The value ranges in the tables are the lowest and highest values of the category. The marginal cost depends on the other techno-economic parameters as well as the fuel price, given Table 5, and the CO_2 price, given Table 6. These two last prices are changing between 2025 and 2030, which is why the marginal price depends on the TY. The marginal cost gives insight about the merit order.

In 2025, hard coal, lignite, gas Combined Cycle Gas Turbine (CCGT) and oil shale have a marginal cost from 50 to 70 €/MWh depending on the technology of the unit. Among the decommissioning candidates, these units will be first to generate electricity in the merit order. The gas Open Cycle Gas Turbine (OCGT) and gas conventional, with a marginal cost around 75 €/MWh, follow these categories in the merit order. Light and heavy oil are the last to commit in the system. Gas OCGT and gas conventional have a fixed cost of 20 €/kW/year, which is the lowest amongst the candidates. Gas CCGT has a fixed cost of 30 €/MWh. Lignite and coal units have the highest range of fixed costs, between 50 and 90 €/MWh.
From 2025 to 2030, the marginal cost of all units increases although the merit order remains almost identical. This increase is driven by the increase of fuel price and CO_2 price.

Table 2: Techno-economic parameters for thermal economic decommissioning candidates in the EVA

Generation Unit Category	Fixed Cost[8,1] [€/kW/y]	Hurdle Rate[7] [%]	Non-fuel Variable O&M[2] [€/MWh]	NCV Efficiency[3] [%]	CO2 Emission Factor[9] [kg/Net GJ]	Marginal Cost in 2025 [€/MWh]	Marginal Cost in 2030 [€/MWh]
Hard Coal	51 – 77	7	2.4 – 3.57	35 – 46	94	51 – 65	74 – 96
Lignite	65 – 89	7	3 – 4.1	35 – 46	101	47 – 77	70 – 108
Gas CCGT	30	7	1.9 – 2.3	40 – 60	57	49 – 73	79 – 118
Gas OCGT	20	8	3.5	35 – 42	57	71 – 84	114 – 136
Gas Conventional	20	8	3.5	36 – 41	57	72 – 82	116 – 132
Light Oil	41	8	2.8	35	78	167	201
Heavy Oil	41	8	2.76	35 – 40	78	126 – 143	154 – 175
Oil Shale	41	8	2.8	29 – 39	100	54 – 72	85 – 113

As shown in Table 3 and Table 4, in ERAA 2021, the commissioning candidates are gas-fuelled generation technologies and DSR. The new gas units' hurdle rate is almost twice the rate of commissioned or planned gas units because of the greater risk involved. Compared to an OCGT, a CCGT has higher CAPEX and fixed costs but lower variable costs. Whereas CAPEX is a main component in the assessment of the commissioning of a new thermal unit, it is neglected for the DSR, where all fixed costs are included in the Fixed Operations and Maintenance (O&M) property. The value of the maximum daily activation duration for DSR is an internal assumption. The plurality of activation prices reflects the diversity in the DSR sources. The lowest DSR activation price of 250 €/MWh is high compared to the variable cost of the commissioning candidates. However, with no CAPEX, the annuity is the lowest of all the candidate technologies.

[1]https://www.elia.be/-/media/project/elia/shared/documents/elia-group/publications/studies-and-reports/20210701_adequacy-flexibility-study-2021_en_v2.pdf
[2] https://ec.europa.eu/energy/sites/ener/files/documents/2018_06_27_technology_pathways_-_finalreportmain2.pdf
[3] Internal ENTSO-E data

Table 3: Techno-economic parameters for thermal commissioning candidates in the EVA

Generation Category	CAPEX [€/kW][1]	Fixed O&M[10] [€/kW/year]	Hurdle Rate [%][10]	Economic Lifetime [years][10]	Non-fuel Variable O&M[2] [€/MWh]	Efficiency in NCV[2] Terms [%]	CO2 Emission Factor [kg/Net GJ][11]	Marginal Cost in 2025 [€/MWh]	Marginal Cost in 2030 [€/MWh]
Gas CCGT	850	30	12	20	1.9	60	57	49	79
Gas OCGT	500	20	14	20	3.5	42	57	71	114

Table 4: Techno-economic parameters for DSR expansion candidates in the EVA

DSR Activation Price [€/MWh]	CAPEX[3] [€/kW]	Maximum Daily Activation Duration[12] [hours]	Fixed O&M[4] [€/kW/year]	Hurdle Rate [%][5]
DSR 250	0	6	30	14
DSR 500	0	6	50	14.2
DSR 900	0	6	60	14.5
DSR 1500	0	6	95	15
DSR 3500	0	6	75	16.5
DSR 4800	0	6	100	17.6

7 Fuel and CO_2 Prices

ENTSO-E regularly updates the fuel and CO2 price forecasts within the TYNDP process based on recent forecasts[6]. Table 5 and Table 6 summarise the price assumptions used in the ERAA 2021.

Table 5: Fuel cost [€/net GJ] per TY

Fuel Type	TY 2025	TY2030
Nuclear	0.5	0.5
Lignite	1.4 – 3.1	1.4 – 3.1
Hard Coal	2.3	2.5
Natural Gas	5.6	8.9
Light Oil	12.9	13.8

[1] https://www.elia.be/-/media/project/elia/shared/documents/elia-group/publications/studies-and-reports/20210701_adequacy-flexibility-study-2021_en_v2.pdf
[2] Internal ENTSO-E data and assumptions
[3] Internal ENTSO-E data and assumptions
[4] https://librairie.ademe.fr/energies-renouvelables-reseaux-et-stockage/1772-effacement-de-consommation-electrique-en-france.html
[5] Derived from the methodology developed by professor K. Boudt: https://www.elia.be/-/media/project/elia/elia-site/public-consultations/2020/20201030_200_report_professorboudt.pdf
[6] https://2022.entsos-tyndp-scenarios.eu/wp-content/uploads/2021/09/2021-10-TYNDP_2022_Scenario_Building_Guidelines.pdf

Heavy Oil	10.6	11.3
Oil Shale	1.6	1.9

Table 6: CO_2 price [€/ton] per TY

Target Year	CO_2 Price
2025	40
2030	70

8 Wholesale market price cap

In the ERAA 2021, a single wholesale market price cap, i.e. the highest price bid/offer price market players can submit, is used across all bidding zones and is set to a single constant value. The price cap is modelled as equal to a proxy for the Value of lost load (VoLL), i.e. the system cost incurred if supply does not meet demand, and is set at 15 k€/MWh. The maximum price cap (referred also as maximum technical bidding limit) for the wholesale Single Day-Ahead Coupling (SDAC) market is currently equal to 3 k€/MWh[1], thus a sensitivity analysis was also carried out with the latter lower price cap. For more on these sensitivity results, c.f. Annex 2.

[1]https://ec.europa.eu/energy/sites/ener/files/documents/swd_2016_385_f1_other_staff_working_paper_en_v3_p1_870001.pdf

Appendix 1: TSO survey on Scenario Assumptions

Minimum 70% Cross-zonal Capacity

TSOs' response on whether the NTC and FB models in ERAA 2021 comply with the 70% minimum interconnection capacity requirement, also referred to as the minimum remaining available margin (minRAM) requirement.

Table 7: TSOs' response on whether or not the NTC and FB models in ERAA 2021 comply with the 70% minimum interconnection capacity requirement

Country	Zone	Compliance of input data with the 70% minimum interconnection capacity requirement
		Provide your comments on and/or confirmation of the compliance of the input data with the 70% minRAM requirement
Albania	AL00	Not applicable – not an EU member.
Austria	AT00	Compliant. APG (Austrian TSO) works on fulfilling the 70% minRAM requirement in the future. Future NTC values are very difficult to determine, since many input variables, including other non-Austrian borders, have to be considered. It should also be pointed out that the time horizons to be determined in ERAA 2021 (TYs 2025 and 2030) is already after the go-live of the Core FB capacity calculation region.
Belgium	BE00	The 70% minRAM requirement is duly considered for all Belgian borders and actually for all borders modelled within the flow-based modelling (c.f. Annex 4). NTC values provided for the Belgian borders do not consider the 70% minRAM criteria explicitly since no clear methodology exists to calculate 70% minRAM compliant NTC values.

Bosnia and Herzegovina	BA00	Not applicable – not an EU member.
Bulgaria	BG00	In 2020 and 2021, EAD (Bulgarian TSO) was exempted from the requirement to ensure a minimum value of 70% of transmission capacity for the borders with EU countries (BG-RO and BG-GR) in accordance with Article 16 (8) of Regulation (EU) 2019/943 due to a derogation, approved by the Bulgarian NRA. In recent years there were major reinforcements performed in the Bulgarian transmission network, which significantly increased the grid transfer capacity in the North-South direction. Transmission capacity for cross zonal electricity trading will be gradually increased to the minimum value of 70% and this value is expected to be reached by 31 December 2021. Regarding the borders with third countries, we are still expecting a confirmation from EMS, MEPSO and TEIAS of their intention to apply the requirement to ensure a minimum value of 70% of transmission capacity in accordance with Article 16 (8) of Regulation (EU) 2019/943 for their borders with EAD. As a consequence, our borders with EMS, MEPSO and TEIAS for TYs 2025 and 2030 are marked as N/A.
Croatia	HR00	In 2020 and 2021, HOPS (Croatian TSO) was exempted from the requirement to ensure a minimum value of 70% of transmission capacity in accordance with Article 16 (8) of Regulation (EU) 2019/943 for the borders between Croatia and Slovenia and Croatia and Hungary in accordance with Article 16 (9) of Regulation (EU) 2019/943, approved by the Croatian NRA. Transmission capacity for trans-zonal electricity trading must be gradually increased to the minimum value of 70% and this value must be reached by 31 December 2025 at the latest.
Cyprus	CY00	Cyprus' electricity system is currently an isolated system. As soon as the expected international interconnection projects are implemented, TSOs will proceed to the adoption of relevant Network Codes and minimum interconnection capacity requirements while considering the island's system stability.
Czech Republic	CZ00	All provided NTC values are meant to be compliant with the minimum 70% interconnection capacity requirement. However, due to the monitoring methodology setup it is difficult to estimate whether a certain value will or will not be compliant. It should also be emphasised that the given time periods occur after the go-live of the Core flow-based capacity calculation and that the Clean Energy Package itself is designed to make all TSOs compliant with the 70% minRAM requirement by the end of 2025.
Denmark	DKE1, DKW1	All Danish interconnectors are in compliance with the 70% minRAM requirement in the data provided for ERAA 2021. The approach to perform the check is based on finding the average available capacity ratio of each Danish interconnector using the time-series values and the maximum market capacity of each interconnector for the provided data. The compliance holds for both target years (2025 and 2030).
Estonia	EE00	The data submitted for the ERAA is compliant with the 70% minimum interconnection capacity requirement. Furthermore the High Voltage Direct Current (HVDC) lines between EE00 and FI00 have no restrictions of NTC.

		Regarding the EE00-LV00 line, the Baltic States are in the middle of desynchronising from the IPS/UPS system. During these significant changes and grid reconstructions, NTCs might differ from current estimates. Regardless, the 70% requirement will be calculated and respected to the best of our knowledge.
Finland	FI00	Fingrid confirms compliance with the 70% minRAM requirement.
France	FR00	RTE is currently working on implementing the 70% minRAM criteria for NTC borders (FR–ES, FR–IT), and in particular for the Spanish–French border. RTE (French TSO) does not yet have any shared results with REE (Spanish TSO) to provide for ERAA 2021. Within the flow-based area (F–BE and FR–DE) : • Domains calculated by RTE are compliant with the 70% minRAM criteria • RTE cannot provide a 70%-compliant analysis with an NTC approach on these borders.
Germany	DE00	It is not guaranteed that the NTC values provided by the German TSOs for the ERAA are compliant with the Clean Energy Package as we do not have a consistent method to determine the NTC values which considers the 70% minRAM requirements. For FB, the calculated domains are compliant with the 70% minRAM requirements.
Greece	GR00, GR03	Greece has asked for a derogation from the 70% minRAM requirement on the GR–BG border for the years 2020 and 2021 due to the absence of consideration of flows of 3rd countries in the capacity calculation and the margin available for cross-zonal trade, and the insufficient potential for remedial actions to guarantee the 70% minRAM criterion. The second 400 kV line on the BG–GR border will partially improve the fulfilment towards the 70% minRAM requirement, but will not resolve the problem. It is expected that the issue should be resolved by the year 2025 and therefore NTCs for the years 2025 and 2030 provided for ERAA are compliant with the 70% minRAM requirements.
Hungary	HU00	For NTCs, our view is that there is currently no methodology to properly assess and ensure the compliance to the 70% minRAM requirement. Hungarian borders in the Core region will reach the 70% minRAM requirement for the FB methodology by 31 December 2025, as a result of our approved derogation. Our action plan containing the necessary measures is under finalisation.
Ireland	IE00	EWIC (East–West interconnector between IE00 and UK00) would generally be compliant as full capacity is available to the market.
Italy	ITCA, ITCN, ITCS, ITN1, ITS1, ITSA, ITSI	The NTC values sent by Terna to ENTSO-E during the data collection are compliant with the 70% minRAM requirement. Variations of these values are allowed by the ERAA methodology (e.g. adopting a conservative approach in case a neighbouring TSO communicates lower NTC values). In the future, Italian NTC values could be further upgraded in the light of the upcoming energy scenarios.

Latvia	LV00	AST (Latvian TSO) confirms compliance the with 70% minRAM requirement.
Lithuania	LT00	The 70% minRAM requirement is fulfilled on all borders.
Luxembourg	LU00	The 70% minRAM requirement from Regulation 2019/943 does not apply to Luxembourg as the Luxemburgish grid does not limit volume of interconnection capacity. No cross-border capacity (LT, DA ID) is currently commercialised at any LU border. No cross-zonal critical network elements or internal congestions, limiting commercial exchanges between the DE and LU bidding zones, were identified.
North Macedonia	MK00	An NTC calculation is applied on all MK borders. Currently, there is still no possibility to apply the 70% minRAM requirement.
Malta	MT00	We confirm compliance of NTC values with the 70% minRAM requirement.
Montenegro	ME00	
Netherlands	NL00	The NTC values provided for the HVAC borders do not consider explicitly the 70% minRAM criteria, as an FB approach has been implemented in the region since 2015. The NTC values are hence an expert best estimate. HVDC interconnectors do comply with the NTC 70% minRAM requirement (c.f. UK00–NL00). For FB calculations the 70% minRAM requirement has been met in the domains used.
Norway	NOM1, NON1,NOS0	We confirm compliance of NTC values with the 70% minRAM requirement.
Poland	PL00	There is an agreed trajectory for the period 2020-2025, specified in Polish Action Plan (link) to meet the 70% minRAM criteria from 2026. The level of transmission capacities in 2025 resulting from the CNEC list provided for FB purpose in ERAA 2021 is consistent with Polish Action Plan. NTC values do not consider the 70% minRAM criteria, due to inclusion an unscheduled through Poland in the calculation, which limits the NTC level.
Portugal	PT00	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.
Romania	RO00	NTC values provided for our EU borders are included in the action plan developed in accordance with the provisions of Regulation (UE) 2019/943 for the 2021–2025 period, and are compliant with the 70% minRAM requirement starting from 2026. For non-EU borders, an NTC calculation is applied.
Serbia	RS00	The 70% minRAM requirement is not applicable on RS00 borders because Serbia is not an EU member. An NTC calculation is applied on all RS00 borders.
Slovakia	SK00	We confirm compliance of NTC values with the 70% minRAM requirement.

Slovenia	SI00	We confirm compliance of NTC values with the 70% minRAM requirement.
Spain	ES00	REE (Spanish TSO) is currently working on a new methodology for implementing the 70% minRAM requirement for NTC borders (FR–ES, PT–ES) along with RTE (French TSO) and REN (Portuguese TSO) to significantly increase compliance from the year 2022 onwards.
Sweden	SE01, SE02, SE03, SE04	The borders within the Nordics are modelled as NTCs and the HVDC borders from Sweden to countries outside the Nordics use 'Advanced Hybrid Coupling – FB border'. Regarding compliance with the 70% minRAM requirement, all borders (internal and from the Nordics to continental Europe) are compliant.
Switzerland	CH00	The 70% minRAM requirement is not applicable to Swissgrid. A capacity reduction on Swiss borders due to compliance with the 70% minRAM requirement of other TSOs is under discussion. Such a capacity reduction will have a negative impact on the Swiss resource adequacy margin in winter, with negative effects on regional security of supply as well.
Northern Ireland	UKNI	The Moyle interconnector (between UKNI and UK00) would generally be compliant since full capacity is available to the market. However, network constraints limit export at times - network upgrade works are planned to alleviate this.

Out-of-market measures at the disposal of TSOs

TSOs response on which measures were characterised as 'out-of-market' in their system, providing a quantification and a qualitative impact assessment wherever feasible.

Table 8: Out-of-market measures at the disposal of TSOs

Country	**Zone**	**Out-of-market measures at the disposal of TSOs**		
		Which measures are considered/characterised as out-of-market?	Provide a quantification (MW or % peak demand) of the out-of-market measures that could address adequacy crises (e.g. reduction of demand through voltage reduction)	Do these measures contribute to national adequacy?
Albania	AL00	n/a	n/a	n/a

Austria	AT00	The Thermal power plants provided in the PEMMDB are all considered as available on the market for TYs 2025 and 2030. Right now, there is no out-of-market measure dedicated solely to adequacy issues.	n/a	n/a
Belgium	BE00	As relevant 'out-of-the-market capacity' for Belgium, Elia (Belgian TSO) considers any contracted capacity of Strategic Reserves (SR).	SR volumes are equal to zero for the period 2025 and 2030 covered by the study, given that no approved SR mechanism is in place for these time horizons.	
Bosnia and Herzegovina	BA00	n/a	n/a	n/a
Bulgaria	BG00	Voltage reduction, optimising the number of transformers in operation, and emergency assistance from non-EU members.	Reduction of demand through voltage reduction – 200-250 MW. Reduction of demand through optimisation of transformers in operation – 20 MW. Emergency assistance from non-EU countries – 100-200 MW;	Yes, all of them were applied during the 2017 cold spell. As a last resort, load shedding is available as well.
Croatia	HR00	n/a	n/a	n/a
Cyprus	CY00	Contingency reserve auctions on mothballed units. Under study to include dispatchable loads, RES, etc. as EU directions.	Not yet quantified since approved. Market Rules are not fully applied.	Yes.
Czech Republic	CZ00	The Czech Republic does not have out-of-market resources at the TSO's disposal. Nevertheless, the application of out-of-market measures is currently being discussed in the Czech Republic in relation to the expected coal power plant phase-out according to new EU targets. On the other hand, we have to consider	n/a	n/a

		'taxonomy issues' connected to the technology constraints (i.e., carbon intensity).		
Denmark	DKE1, DKW1	Denmark has not reported any out-of-market measures as part of the ERAA dataset since capacity mechanisms / capacity markets / strategic reserves are not used in the country. Reserve / ancillary service capacity is normally considered out-of-market (day-ahead market). However, as reserve requirements in Denmark in the ERAA are modelled as increased load, power plants conventionally delivering reserves are made part of the dataset and available on the market.	Total reserve requirements modelled as increased load in the ERAA amount to 692 MW for DKE1 in 2021 and 712 MW from 2022 and onwards. For DKW1, the requirement is 394 MW for the entire period from 2021 to 2031.	Yes. Reserves will be able to contribute to avoiding loss of load after the day-ahead market.
Estonia	EE00	n/a	n/a	n/a
Finland	FI00	There are a few measures considered as out-of-market, which are at the disposal of Fingrid (Finnish TSO) before activating load shedding: • SR used for adequacy issues • Emergency power contracts with other TSOs Temporary use of disturbance reserve for adequacy issues	The SR includes three power plants with a total capacity of 611 MW. However, the SR is contracted only until 30 June 2022 and is therefore not considered in TYs 2025 and 2030 in the ERAA modelling. Emergency contracts can provide additional imports to Finland in case of unused transmission capacity between Finland and Russia in an adequacy situation. The contracts have historically provided around 100–200 MW of imports during adequacy situations. It should be noted that	Yes. All these measures are supposed to be activated before load shedding given there is enough time to activate them. It should be noted that the procurement of SR is decided by the National Regulatory Authority based on the Finnish reliability standard. Also, disturbance reserves are considered in the ERAA modelling to fulfil the reserve requirements.

			flows from Russia have been considered in the ERAA modelling and thus the emergency contracts are not expected to significantly improve adequacy compared to the ERAA results. Disturbance reserves consist of a capacity equal to around 1250 MW, of which some part can be used temporarily for adequacy issues. The disturbance reserve is considered in the data provided for ERAA modelling.	
France	FR00	Some out-of-market measures have a good reliability for forecasting studies: • Voltage reduction • Interruptible load contracts with large industrial consumers Other measures have a far more uncertain effect, such as: • Eco-gestures (consumers voluntary dropping their consumption during peak hours based on communication by TSOs, helping reducing needs for high CO_2-emitting peak units) • Use of operating reserves for adequacy issues instead of setting them aside for unknown events	C.f. column to the right.	Yes, all these measures are supposed to be activated as a last resort before load shedding. The French NECP highlights a 'double' criterium for the French reliability standard: • 3h of LOLE, with the definition that LOLE = load shedding + the activation of all of these measures; • 2h of load shedding. RTE (French TSO) indicated a few years ago that both criteria are equivalent with the current out-of-market measures. The quantitative effect of these measures is thus the difference between these 2 criteria.

		• Emergency contracts with other TSOs		
Germany	DE00	The out-of-market resources for Germany contain: • Capacity reserve: reserve for unforeseeable events, which are activated in case of a lack of market clearance (day ahead and intraday). They can also be used to resolve grid congestions. • Grid reserve: used to resolve congestions and contains different types of power plants located in Germany. In emergency situations, it can be used for adequacy in grid operation, if not required for solving grid congestion. However, in terms of system forecasting, its reliable availability cannot be counted on for national scarcity situations. Therefore, it is excluded here. • Out-of-the-market Demand Side Response: with the Ordinance on Interruptible Load Agreements (AbLaV), interruptible demand can be obliged to take measures to maintain grid and system	• Capacity reserve: since 1 October 2020 and until 30 September 2022, a total capacity of 1056 MW of gas-fired power plants outside the market is available. These power plants must be available within max. 12 hours. 2025 and 2030: Dimensioning of capacity reserve is not done yet. Best guess of TSO: Same level as today. • Out-of-the-market Demand Side Response (‘AbLaV’): for 2025, 1250 MW of interruptible load is considered, and for 2030, 1758.9 MW of interruptible load is considered. All other out-of-market resources should not be considered for adequacy studies in 2025 and 2030.	The Capacity reserve contributes with 1056 MW to national adequacy. Activation trigger: • Day-ahead price = 3000 €/MWh • Intraday price bid side over one hour = 9999.99 €/MWh All other reserves should not be considered for adequacy studies.

		security. For the purpose of AbLaV, interruptible demand is defined as consumption units, which can reliably reduce their demand for a fixed capacity upon request by the German TSO (If prices above 200€/MWh are reached, this reserve can bid in the market. Therefore, this reserve is on the one hand a TSO out-of-market measure and on the other hand part of the ERAA simulation runs if prices above 200 €/MWh are reached.). • Lignite units in stand–by ('Sicherheitsbereitschaft'). • Frequency Restoration Reserves. • Special Network Equipment: is only used for redispatch.	For information: Development of further reserves which do not directly contribute to national adequacy. • Lignite units in stand–by ('Sicherheitsbereitschaft'): lignite-fired power plant blocks with a total capacity of 2.4 GW are currently in backup mode until 2023. The lead time in which the power plants are completely available is 240 hours. In addition, the TSOs may only dispatch them if the German government determines an energy crisis. The plants will finally be shut down gradually. After 30 September 2023 this reserve is completely dissolved. • Grid reserve: currently comprises a total capacity of 5.6 GW. • Special Network Equipment: a total of 1200 MW is currently under	

			construction and will be available for curative redispatch after October 1, 2022.	
Greece	GR00, GR03	Up to September 2021, there has been an Interruptibility Scheme. A Strategic Reserves and a Capacity Remuneration Market are planned. It is envisaged that the Strategic Reserves Mechanism will be in place during the period 2022-2023, while the CRM will be in place from 2024 and on, however neither of these mechanisms have been officially notified yet.	< not provided >	Yes
Hungary	HU00	Out-of-market measures (such as strategic reserves) are not in place in Hungary. Operating reserves are considered as balancing market measures for real time operation (including adequacy). A short- and long-term flexibility analysis is done regularly on top of adequacy analyses.	n/a	n/a
Ireland	IE00	Voltage reduction and controlled load shedding are available.	< not provided >	< not provided >
Italy	ITCA, ITCN, ITCS, ITN1, ITS1, ITSA, ITSI	At the present time in Italy there is no strategic reserve.	n/a	n/a
Latvia	LV00	In the Baltic States there are some concerns about the FCR and FRR service for the coming ten-year time horizon. AST (Latvian TSO) has received a positive feedback from the NRA and the Cabinet of Ministers about the installation of	< not provided >	< not provided >

		Battery Energy Storage Systems to solve the reserve issue. The FCR and automatic FRR resources have been characterised as out-of-market. This was proven by a market test performed together with the Baltic States' TSOs.		
Lithuania	LT00	Litgrid (Lithuanian TSO) considers the capacity of mothballed power plants, whose resumption of operation before the planned decommissioning is not possible (too high investments required), and capacity with high limited operation resource, as 'out-of-the-market' capacity.	< not provided >	Yes
Luxembourg	LU00	n/a	n/a	n/a
North Macedonia	MK00	Reduction of demand through voltage reduction	30-50 MW	Yes
Malta	MT00	Malta has three emergency backup generation plants which are considered as out-of-market / SR. These consist of gasoil fired combined cycle gas turbines and open cycle gas turbines.	Total capacity of 215MW.	Yes
Montenegro	ME00	< not provided >	< not provided >	< not provided >
Netherlands	NL00	Not applicable for the Netherlands.	n/a	n/a
Norway	NOM1, NON1,NOS0	SR from demand (manual FRR demand) are not considered as out-of-market measures, while other reserves (FFR, FCR, automatic FRR and manual FRR prod) are considered as out-of-market measures.	Total national reserve requirements from production equal to 900 MW are out-of-market. These are roughly distributed on market nodes for modelling purposes only.	No, the capacity margin in Norway is good and subtracting reserves will not affect this margin much.
Poland	PL00	1. Interventional offer of power reduction by consumers - DSR contracted for the period 2021-2025	1. Average values: • 2021: 551–591 MW [a), b)] • 2022: 935–977 MW [a), b), c)]	1-4. Not contributed.

		as a part of already concluded Capacity Market auctions. 2. Voluntary DSR contracted with consumers for the period April 2021 – March 2022. 3. Additional must-run understood as the increase of the contracted infeed of CHPs. 4. Administrative load curtailment according to the national legislation: *'Regulation of the Council of Ministers of 23 July 2007 on the Detailed Principles and procedures of Introducing Limitations on Sale of Solid Fuels and Supply and Consumption of Electricity or Heat (Journal of Laws of 2007, No. 133, item 924)'.)".* 5. The description of this measure is also described in the draft of Risk-preparedness plan here (draft is not publicly available).	• 2023: 801 MM [c)] • 2024: 1039 MW [c)] • 2025: 959 MW [c)] a) level dependent on season; b) values from main and additional CM auctions; c) reduction tests did not proceed yet, effective level may be lower; 2. Up to 100 MW (based on a recent PSE (Polish TSO) survey). Availability not guaranteed and depends on voluntary counterparty offers. 3. About 200 MW. Availability depends on weather conditions (heat demand). Administrative load curtailment refers to electricity consumers throughout the year, for which the contracted power is set above 300 kW. There are many exceptions for the above-mentioned consumers, for which load curtailment cannot be used.	
Portugal	PT00	For ERAA 2021 purposes (TYs 2025 and 2030), REN (Portuguese TSO) did not indicate out-of-market measures, in line with Portugal's national adequacy assessment report.	n/a	n/a
Romania	RO00	n/a	n/a	n/a

Serbia	RS00	According to the national network code, voltage reduction could be considered/characterised as an out-of-market measure. Voltage reductions are performed on transformers of TSOs and DSOs, applying a voltage reduction ratio of 220 /x kV/kV and 110/x kV/kV (x < 110kV). The voltage is reduced by 5% of the nominal secondary voltage. The voltage is maintained at 95% of the rated mains voltage on the low voltage side of the transformer.	The effect of reducing peak demand is about 3%.	Yes
Slovakia	SK00	Measures considered as out-of-market are defined in the PEMMDB like electricity sources. These electricity sources are currently contracted to only provide ancillary services.	263.6 MW	No
Slovenia	SI00	There are few measures considered in critical situations, such as: • Voltage reduction • Emergency contracts (NTC adaptions) with other TSOs Nevertheless, any other out-of-market measures as part of the PEMMDB dataset are not in place in the country. At this point it has to be mentioned that one of the lignite power plants (305 MW) which is marked as available on market in the PEMMDB dataset, will be added to the cold reserve and can be put back to the grid within a one month period.	< not provided >	< not provided >

Spain	ES00	No out-of-market measures are applied or available.	n/a	n/a
Sweden	SE01, SE02, SE03, SE04	In Sweden the SR is kept out of the market between 16 November and 15 March and is available to the market for the remaining time of the year. (Note: it is currently modelled as always being out of the market). The SR is regulated by national law. The disturbance reserve (approximately 2000 MW) is considered out of the market.	The SR with a capacity of 562 MW in price area SE04 is contracted until March 2025 and could address adequacy problems within this period. A portion of the disturbance reserve might be able to help resolve adequacy problems temporarily, but this is not its intended purpose.	Yes, c.f. details in the column to the left.
Switzerland	CH00	Out-of-market measures are currently being reassessed due to the latest developments in the CH–EU relationship and their adequacy implications for Swissgrid (Swiss TSO) and the region.	n/a	n/a
United Kingdom	UK00, UKNI	< not provided >	< not provided >	< not provided >

Market reforms

The below table describes detailed TSOs' responses on whether their country is concerned by national market reforms (e.g. price cap rules, scarcity pricing), and how these were considered when TSOs submit their input dataset for ERAA 2021.

Table 9: Market Reforms

Country	**Market reforms**

	Market reforms (Article 23(5)(e) and Article 20(3) of the Electricity Regulation) shall be considered in the ERAA scenarios. Please provide your feedback on whether or not your country is concerned by national market reforms (e.g. price cap rules, scarcity pricing) and how they were considered when providing the ERAA input data. Which reforms are relevant to your scenarios and how did you consider them?	
Albania	AL00	n/a
Austria	AT00	Currently there are no market reforms regarding price caps or scarcity pricing planned in Austria.
Belgium	BE00	Related to 'measures related to interconnection capacity', and the 70% minRAM requirement (minRAM requirement): • This is duly considered within the flow-based simulations performed in ERAA (c.f. below). Regarding 'measures which relate to balancing energy and procurement of balancing and ancillary services': • These aspects are considered in the assumptions made in the ERAA regarding the volumes on ancillary services and its consideration in the ED modelling. Related to 'price caps' • We refer to the comments provided within the ERAA 2021 report and to Belgium country comments. Finally and following Article 20(3) of the Electricity Regulation, the implementation plan of Belgium was published in 2020[17].
Bosnia and Herzegovina	BA00	n/a
Bulgaria	BG00	No specific market reforms were considered when providing the input data. Bulgaria is expected to carry out a lot of market reforms in the coming years and it is very difficult to assess which measures would be applied and to what extent, and how exactly their execution will affect the market situation.
Croatia	HR00	ERAA input data consider the NECP – chapter 'Internal energy market'. National targets are related to the non-discriminatory participation of renewable energy sources, demand side management and storage, inter alia through aggregation, in all energy markets, including the timeframe for achieving the targets. There are national targets for ensuring that consumers participate in the energy system and benefit from their own production and new technologies, including smart meters. Eliminating energy poverty is also one of the goals.
Cyprus	CY00	Currently there are no market reforms regarding price caps or scarcity pricing planned in Cyprus.
Czech Republic	CZ00	At the moment of providing the ERAA input data, no national market reforms (according to the Article 20(3) of the Electricity Regulation) were considered in the Czech Republic. ERAA input data take the NECP into account.

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

		Currently, we do not apply measures relevant to Article 20(3) of the Electricity Regulation; however, we monitor the impact and the frequency of the price peak appearance and discuss the application of possible measures to deal with the possible unexpected price development.
Denmark	DKE1, DKW1	The Danish scenario reported to the ERAA, called the Analysis Assumptions for Energinet of 2020 provided by the Danish Energy Agency, is the best guess for a likely development pathway for the Danish energy system until 2040. The scenario is constructed around Danish targets such as 70% greenhouse gas emission reductions in 2030 compared to 1990 levels and a climate neutral society by 2050. In addition, the scenario is constructed around assumptions that onshore wind and photovoltaic capacity will enter the market without subsidies / on market terms beyond capacity additions already agreed upon as of now.
Estonia	EE00	After 2025, and after desynchronising from the IPS/UPS system, the Baltics will introduce an ancillary services market which will bring significant opportunities and challenges to the TSOs and market participants. This will affect the resource adequacy as well as constrain the NTCs between EE00–LV00 to some extent.
Finland	FI00	In the upcoming years, significant market reforms to be expected are consequences of an EU-wide harmonised balancing market, imbalance settlement and requirements for the procurement for reactive power. The direct effect on the investments for new capacity cannot be exactly quantified. However, it is expected that the balancing market reforms do support the price signals that incentive DSR development in the balancing timeframe. In addition, the recast for the national regulation on strategic reserve is under preparation, but its effects are not considered to have a significant impact on the provided data.
France	FR00	National market reforms should not have a significant impact on the forecasts provided in the input data of this ERAA, which already consider important developments of new capacities (e.g. DSR). Currently, there is no reason to update these forecasts today due to these reasons. Some of these reforms (e.g. price cap rules) should, however, be modelled within the EVA depending on the simulated market results.
Germany	DE00	For the existing energy-only market design in Germany, only the persistence of the legal basis (EnWG) is of relevance. In addition, numerous laws and regulations have a significant impact on the development of renewable energy and conventional capacities, as well as on flexibility (e.g. KWK-G, KVBG, EEG, ABLaV, EnWG). Depending on the continuing existence or the reform of these directives, changes to the provided scenario data may occur. For many input data values, which are affected by the corresponding legislation, the current legal framework does not yet define the extent to which individual system components are to be dimensioned. Here, a best guess is assumed by the German TSOs, considering the continuation of the directive. From today's perspective, intentions of the regulator to reform pricing, price caps or similar are not predictable.
Greece	GR00, GR03	Greece intends to notify a Strategic Reserves mechanism and a Capacity Renumeration mechanism and therefore the Market Reform Plan is of great importance. A Market Reform Plan was recently compiled and

		submitted to EU for approval. The plan foresees numerous actions that will enhance competition and functionality of the Greek energy market. Among others, the Plan foresees the enabling of DSR participation in the markets, market coupling in the region, participation in European platforms for the exchange of reserves and others. Scarcity pricing in the balancing market is considered and will be examined. The Market Reform Plan was published after the data collection period for the ERAA 2021 study, however most of the planned actions do not affect modelling in the ERAA framework. No data was provided for DSR (implicit or explicit) participation for the ERAA 2021 study, as numerical values were not available, nor data regarding the planned Strategic Reserves and CR mechanisms as they have not been notified yet.
Hungary	HU00	National market reforms should not have a significant impact on the forecasts provided in the input data of this ERAA, as the data is based on the latest National Energy Development Plan and National Energy and Climate Plan, considering government strategy until 2030. Should any update arise, ERAA input data will be updated.
Ireland	IE00	Ireland has indicated in its Market reform plan (https://ec.europa.eu/energy/sites/ener/files/market_reform_plan_ireland.pdf) what market reforms have been undertaken (ASP, capacity mechanism, etc). We anticipate that many further reforms will be required to enable a low carbon energy system that provides system stability and resilience. We have already identified issues that we face in the coming years and have highlighted some areas that will require attention (https://www.eirgridgroup.com/site-files/library/EirGrid/Full-Technical-Report-on-Shaping-Our-Electricity-Future.pdf). For example, the current capacity market needs amendment to ensure delivery of the required capacity as we move to a very-high-RES world, resource adequacy modelling updates for national resource adequacy assessments are required, Brexit and a lack of day-ahead trading leaves us disconnected from internal EU markets so development will be needed in this area and in preparation for reintegration with the EU market via the Celtic interconnector. We already have very high levels of RES on the system (70% instantaneous non-synchronous generation) and this is set to grow alongside increasing demand growth from large energy users, increasing the challenge of meeting our energy demand from low carbon sources.
Italy	ITCA, ITCN, ITCS, ITN1, ITS1, ITSA, ITSI	Some of the National market reforms (e.g. increase of interconnection capacity, enabling self-generation, energy storage and demand side measures and the promotion of European Market Integration) are already considered in the input provided for the ERAA.
Latvia	LV00	n/a
Lithuania	LT00	Due to the nation-wide deployment of smart meters and retail consumer price liberalisation, some consumer behaviour changes towards implicit demand response are expected. However, it should not have any significant impact on the forecasts provided in the input data, which already considers expansion of DSR.

Luxembourg	LU00	No national market reforms according to Article 20(3) of the Electricity Regulation are currently foreseen in Luxembourg.
North Macedonia	MK00	Currently, there are no national market reforms concerning price cap rules, scarcity pricing, etc.
Malta	MT00	There are no market reform plans for Malta for the time being. Malta has specific derogations with respect to third-party access, free choice of supplier and unbundling in the Electricity Market Directive.
Montenegro	ME00	< not provided >
Netherlands	NL00	n/a
Norway	NOM1, NON1,NOS0	No major market reforms are expected in Norway.
Poland	PL00	The data provided for the ERAA 2021 were compliant with the latest official document published by Polish Government: the 1. Energy Policy of Poland until 2040 (link) 2. APPENDIX 2 – Conclusions from forecast analyses for the energy sector (link) Poland is a Member State with identified resource adequacy concerns. In accordance with Article 20 of Regulation (EU) 2019/943, Poland has developed the Implementation Plan (link). This plan includes the identification of regulatory distortions and market failures and the consideration of improvements, and presents a list of market reforms.
Portugal	PT00	The input data provided for ERAA 2021 are in line with the latest national policies and NECP of Portugal, as well as the assumptions used in the national adequacy assessment report.
Romania	RO00	The input data provided for ERAA 2021 are in line with the latest national policies and NECP of Romania. However, further market reforms may have an impact on the forecasts provided during the data collection (i.e. related to energy storage and demand side measures, as no relevant data were available).
Serbia	RS00	< not provided >
Slovakia	SK00	The results of the adequacy calculations at the European level so far (as well as the own calculations at the national level) do not point to problems with the adequacy of resources in Slovakia. For this reason, it was not necessary to apply the principles (market reforms) of Article 20(3) of Regulation (EU) 2019/943 in order to eliminate possible regulatory distortions. We perceive the application of market reforms mainly in connection with INECP (NECP of Slovakia), which corresponds in content to the relevant European regulations and directives, e.g. from the point of view of removing market barriers in the time frames of the daily and intraday market by joining the 4M Market

		Coupling (market coupling between the Czech Republic, Hungary, Romania and Slovakia) and subsequent interconnection with the pan-European MRC, as well as the integration of wholesale electricity markets. A significant contribution in the area of integration of wholesale markets, in terms of reducing price differences between market areas, was the commissioning of new 400 kV lines on the border SK–HU. The commissioning of these new 400 kV cross-border lines results in an increase in cross-border transmission capacity on the SK–HU profile and a positive impact on the release of capacity for the connection of new RES. This was also considered in the provision of data for EERA.
Slovenia	SI00	Input data provided for PEMMDB/ERAA are in line with the current national development plan. Moreover, both are in line with the Slovenian NECP.

Spain	ES00	The provided input data are in line with market arrangements expected from 2022 onwards:
		• Market reforms have taken place in 2021 (July 6th) in which price caps and floors have been modified to +3000 €/MWh and -500 €/MWh and intraday to +/-9999 €/MWh.
		• Interconnection targets as set out in Art. 4 of Regulation (EU) 2018/1999 have not been reached and are not expected to be reached in the 2030 timeframe, although significant progress is expected with the new Bay of Biscay and Transpyrenean projects.
		• There are no identified distortions for the reflection of wholesale prices on the demand side, self-generation, energy storage (both in front of and behind the meter) or the application or energy efficiency measures.
		  ○ Demand-side and storage facilities can participate in balancing services (after the corresponding prequalification process) since January 2020 and will start participating in the redispatch market in 2022 after the entry into force of the required regulatory changes.
		  ○ Participation of Independent aggregators in the markets is also foreseen for 2022.
		• Procurement of balancing services and congestion management are performed in a cost-efficient and market-based manner (also voltage control since March 2022).

Sweden	SE01, SE02, SE03, SE04	Regarding adequacy purposes, it is believed that the transition to a 15-minute imbalance settlement period (launch scheduled in 2024) could have an impact. For scenarios beyond 2024, considerations might be needed for this. Other national market reforms (with respect to Article 20.3 of the Electricity Regulation) relate more to balancing markets and should not have a significant impact on the ERAA input data.
Switzerland	CH00	Article 20(3) is not applicable to Swissgrid.
United Kingdom	UK00, UKNI	< not provided >

Trajectories evolution drivers

TSOs responses on the key capacity and energy mix evolution drivers for the 10-year ahead time horizon. TSOs also justify the data provided at the time of the data collection for the ERAA 2021.

Table 10: Trajectories evolution drivers

Country	Zone	Trajectories evolution drivers Describe the key capacity and energy mix evolution drivers (policy or not) for all 10 TYs, justifying the data provided at the time of the data collection for the ERAA 2021: 1) For example, are the data provided affected by, e.g. coal phase-out, RES deployment targets, DSR deployment, battery deployment etc. Are these assumptions still valid today? 2) How do you expect the impact of your country energy mix evolution on resource adequacy margins (e.g. decreasing margins until 2026, then increasing margins until 2030)? Please organise your response, if possible, in the following categories.			Expected impact on adequacy margins
		Demand	Resource (incl. storage, DSR)	Grid	
Albania	AL00	Total electricity demand values are based on historical data and adjusted with growth rates in line with the current demand trend and future expected growth rates as evidenced in the latest version of the National Development Plan.	• Construction of a new storage hydro power plants in the Drin River cascade (hydro power plant Skavica). • RES development in line with the national strategy regarding the evolution of solar and wind power. • Commissioning of new gas-powered thermal power plants in line with the national strategy regarding the development of the gas transmission grid and storage capabilities, in line	< not provided >	< not provided >

			with the new Trans-Adriatic Pipeline (TAP) project. These assumptions are still valid and were considered for the data collection.		
Austria	AT00	The data provided for the PEMMDB aims to achieve the set goals for fulfilling the climate protection strategy of Austria by 2030. The data is characterised by a continuous increase of electrical consumption due to E-Mobility, heat pumps, data centres, electrolysers …decarbonisation of the industry.	With regard to production, it is assumed that the installed capacity of RES will increase significantly, and that, at the same time, the installed capacity of thermal power plants will sink to a lower level.	< not provided >	< not provided >
Belgium	BE00	The total electricity demand was elaborated by use of growth rates based on the economic projections from the 'Federal Plan Bureau', taking into account the expected effects of the COVID-19 pandemic as well as additional electrification based on the National Energy and Climate Plan (NECP). Energy efficiency assumptions were based	For the 2025 and 2030 time horizons tackled in the ERAA, the assumptions for Belgium are in line with the recent 2021 national study ('Elia study 2021'). RES assumptions are based on the 'National Energy and Climate Plan' submitted by Belgium at the end of December 2018. The 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	The following grid reinforcements have been taken into account for Belgium: Between 2022 – 2025 • Zandvliet-Rilland • PST Zandvliet • Massenhoven – vanEyck • HTLS Mercator - Buggenhout-Bruegel • PST Achêne-Gramme • BRABO III	ERAA 2021 considers NTC simulations as the main simulations for TYs 2025 and 2030, which for Belgium provides compared to FB an 'optimistic' view on the ability of Belgium and its direct neighbours, to receive imports, notably during simultaneous scarcity situations (cf. Annex 4 on FB)

		on 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 and heat pumps, as defined in the final NECP of Belgium published in the end of 2019.	For a detailed overview of the main assumptions taken for Belgium in the ERAA 2021, we refer to the so-called 'CENTRAL' scenario 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'.	After 2025 until 2030 - Ventilus • Boucle de Hainaut • HTLS Gramme-VanEyck All details regarding the evolution of the grid and the interconnection capacity can be found in the Belgium Federal Development Plan https://www.elia.be/en/infrastructure-and-projects/investment-plan/federal-development-plan-2020-2030	
Bosnia and Herzegovina	BA00	The total electricity demand is based on historical values and data from transmission network users. As the NECP is not finalised yet, the Indicative Production Development Plan made by the TSO is used.	Data are based on the Indicative Production Development Plan made by the Independent System Operator in Bosnia and Herzegovina.	< not provided >	It is expected that Bosnia and Herzegovina will stay as an electricity exporter in the next period.
Bulgaria	BG00	The total electricity demand presented in the ERAA 2021 for TYs 2025 and 2030 was adjusted to reflect the projection of the	All the energy mix assumptions for the National Trends Scenario in ERAA 2021 were taken directly from the NECP with a focus on TYs 2025 and 2030. Nevertheless, it should be noted that the NECP is not very detailed in this regard and	All Bulgarian NTC proposals with EU member states (GR, RO) have considered the 70% minimum interconnection capacity	< not provided >

		Bulgarian TYNDP. The demand projection in the Bulgarian TYNDP is produced based on historical trends and minimum growth assumption.	does not provide information on the development of any battery storage and DSR.	requirement for the purposes of the ERAA study. As an agreement with the non-EU states (RS, MK, TR) has not been reached yet, we are not fully compliant there (please c.f. explanation in the chapter 'Minimum 70% Cross-zonal Capacity').	
Croatia	HR00	Demand on the transmission grid will not increase significantly in the coming ten-year period. The energy strategy envisages a maximum consumption of 18.5 TWh for 2030.	Hydropower and wind power plants play a dominant role in the Croatian electricity system. There is only one more coal-fired power plant, and several high-efficiency cogenerations. In the future, renewable energy sources will play a dominant role in the power system. The share of distributed energy sources (photovoltaics mainly) is expected to increase. Storage and DSR are under development.	Every year, the Croatian transmission system operator prepares a ten-year network development plan to meet all the requirements for the connection of generation facilities and demand. Also, the development of an integrated regional and European electricity market is considered.	Croatia is an importer of electricity and has significant interconnection capacities. Over the next ten years, it expects a significant reduction in import dependence due to the construction of large renewable energy capacities.
Cyprus	CY00	Adequacy margins depend on the demand prediction approved by the Regulator.	At the current stage the power plant mix is considered. DSR deployment, battery storage and RES resources will be considered in the future national TYNDP.	On a yearly basis, the TSOC prepares a ten-year network development plan in order to meet all the requirements for the connection of generation facilities and demand. Future international interconnections are considered.	For Cyprus, moving from isolation towards connection with the EU interconnected grid is a change of paradigm, affecting all the adequacy margin issues.
Czech Republic	CZ00	The data reported for the ERAA 2021 for both TYs	The data concerning the side of supply stem from the NECP that predicts a coal phase-out	Due to internal reinforcements on the Czech	It is expected that the Czech Republic shall at

		2025 and 2030 reflect the significant growth in electricity demand that is expected due to electrification, especially in sectors of transportation (incl. electromobility) and heating. At the time of providing data for the ERAA 2021, all relevant factors with a potentially significant impact on the electricity demand, such as the expected development of the national economy in the Czech Republic or the impact of the COVID-19 pandemic, were considered. We are not considering an additional increase in consumption concerning H_2 production.	with gradual decommissioning of all lignite units by the end of 2038 and, consequently, a CHP transition from coal to gas that is expected to happen by the end of 2030. In contrast to the coal decommissioning, new CCGTs are planned to replace the power source. The penetration of RES is expected to increase, which is also in line with NECP and new EU energy climate targets (Fit For 55).	Republic's side connected to Projects of Common Interest (PCI), the trading capacity is increasing, especially on the CZ–DE profile. Exact values can be found in the model dataset. All these assumptions are still valid and were considered for the data collection.	least lower its net export in the mid-term horizon due to phase-outs.
Denmark	DKE1, DKW1	Total Danish demand reported to the ERAA 2021 increases significantly and steadily between 2021 and 2031. In this period, the total Danish electricity demand, excluding the Power-to-X / electrolysers demand not modelled in the ERAA, increases by about 18.7 TWh,	The change in thermal capacities between 2021 and 2031 is characterised by an overall reduction. The reduction is driven by a gradual coal phase-out towards 2029 where all coal-fired power plants are decommissioned in Denmark. Gas capacities increase slightly between 2022 and 2023 – mostly due to refurbishing a large central power plant from being coal- to being gas-fired. From 2023 to 2030, the installed gas capacity decreases slightly whereafter it decreases significantly	For DKE1 the interconnector capacity does not change for the entire period between 2021 and 2031 as the price area has 2890 MW of import capacity and 3285 MW of export capacity in all years – including the import and export capacity of the interconnector between DKW1 and DKE1.	As traditional / thermal technologies are phased out, fluctuating renewables are expanded and demand is increasing, the effect on margins within the 2021–2031 time period is generally negative

		corresponding to about 50.6% relative to 2021. The main drivers for this increase are the electrification of heating (heat pumps and electric boilers) and transport through large increases in the number of electric cars. In addition, large scale datacentres are assumed to contribute to the increase in demand. Classic demand also increases more modestly with 6.3% between 2021 and 2031.	from 2030 to 2031. Oil capacities are relatively constant within the entire period due to most power plants running on oil being regulated and therefore not considered for decommissioning in the scenario. Biomass capacities are relatively constant between 2021 and 2030 whereafter it decreases slightly towards 2031. Overall, the thermal capacity in Denmark is gradually decreasing between 2021 and 2031 with the largest decrease happening between 2030 and 2031. The latter decrease is driven by a gas phase-out and the decommissioning of biomass-fired power plants. The above assumptions and drivers are still valid today. Fluctuating renewables capacity evolution in Denmark in the period from 2021 to 2031 is characterised by a large expansion. Between those years, the installed capacity of onshore wind, offshore wind, rooftop photovoltaics and photovoltaic farms increase by 32%, 218%, 162% and 510%, respectively. The installed capacities for these technologies in 2021 are 4753 MW, 2306 MW, 661 MW and 821 MW, respectively. As mentioned under market reforms, solar and onshore wind is assumed to enter the market without subsidies being necessary after already agreed upon capacity has been build out. In more general terms, the renewable capacities until 2030 are forecasted using pipelines for the technologies and beyond 2030 it is assumed that new demand is covered by renewables. In terms of the overall effect on adequacy margins, as traditional technologies are phased	Interconnector capacity in DKW1 is 5915 MW / 5847 MW in the import / export direction in 2021 and 2022. In 2023 these capacities increase to 6147 MW / 6137 MW and in 2024 further to 8547 MW / 8537 MW due to an assumed reinvestment in an existing interconnector and the commissioning of the Viking Link interconnector, respectively.	until renewables can completely make up for the decrease in thermal capacities. However, the negative effects on margins are to some extent counteracted by the increase in interconnector capacity in the DKW1 area.

			out and fluctuating renewables are expanded, the effect on margins is generally negative until renewables can completely make up for the decrease in thermal capacities. As is true for thermal technologies, assumptions regarding the expansion of renewables are still valid today.		
Estonia	EE00	The main drivers of demand will be the transportation and electrification of other sectors.	The data provided to the ERAA were mainly based on NECP, among these is the commissioning of the first offshore wind farm in Estonia in 2030. In addition to an increase of renewables, no other changes in resources are expected between the target years. However, it is expected that existing power plants increase their biofuel share considerably compared to what was reported during data collection.	Major grid reconstructions are done between today and 2026, which significantly increases the reliability but only slightly increases the import-export capacity.	The energy mix is transitioning from fossil-fuel-based production to more biofuel- and renewable-based production. The outcome is difficult to say because no major changes in capacity are reported.
Finland	FI00	Electricity demand is expected to grow significantly within the next ten years. The main driver for the demand increase is Finland's target to be climate neutral by 2035. The assumption is that to achieve this goal, a steady electrification of significant sectors (heating, transport, and industry) begins in the next couple of years and then accelerates post-2025.	Main drivers for the generation capacity mix and other resources include: • Olkiluoto 3, a new nuclear power plant of 1600 MW, commissioning is expected during year 2022. • Decrease in the fossil fuel and peat-fired capacity during the 2020s. Main drivers are the Finnish/European climate policies, including a coal-phase set in law in Finland by 2029. • Very significant growth expected in wind power capacity on a merchant basis, which is driven by i.a. increasing demand.	The third AC interconnector (Aurora line) between bidding zones FI and SE1 is expected to be commissioned by the end of 2025. The additional interconnector capacity is assumed to be available from 2026 onwards and is considered in the data provided for the modelled year 2030. In the data, there are also assumed imports from	From an adequacy perspective, Finland is dependent on the imports from the neighbouring countries. Therefore, the energy mix evolution of neighbouring countries also has an important role for the adequacy margins. Commissioning of Olkiluoto 3 nuclear

			• Expected growth also in solar capacity. However, the growth in solar capacity is not expected to have as significant effect on the adequacy situation as it mostly appears during winter in Finland. • Amount of available DSR is assumed to grow significantly as also the rate of electrification increases. Main drivers include assumed increase in price volatility and accurate price signals in the markets.	Russia. Part of the Russian import is provided in data as fixed flow, and part of the import is provided as an equivalent generation capacity with price threshold, which reflects the reality better from the point of adequacy. It is to be noted that there is uncertainty on the future effects of the CBAM to the Russian imports. If the CBAM comes into force as proposed, it likely decreases the imports from Russia.[2] At the time of the data collection, however, there was insufficient information available on CBAM implementation and it has not been quantified on the provided data.	power plant in the near future and the new interconnector between FI and SE1 in the second half of the decade, as well as increasing DSR, are expected to have a positive effect on adequacy margins. The positive effects are to some extent balanced out by the decommissioning of thermal production and expected growth in demand. As a summary, the adequacy margins are expected to slightly improve during the 2020s; however, especially the development of demand and available DSR play a significant role in the future adequacy.
France	FR00	Main drivers for adequacy: • Expansion of electric vehicles	Main drivers for adequacy: • Coal phase-out by 2022 (1 GW of coal may be maintained for a few hours per	Main drivers for adequacy:	According to the last NRAA, adequacy margins will

		• Energy efficiency measures All these assumptions are still valid and were taken into account for the data collection.	year until 2024) and decommissioning of some thermal units • RES and DSR deployment targets • 1 new nuclear unit by 2023 • 4 nuclear units decommissioned between 2025 and 2030, plus 2 others potentially • nuclear availability depends on the TY (more specifically, nuclear availability should be quite low up to 2024) All these assumptions are still valid and were taken into account for the ERAA 2021 data collection	• Import capacity x2 between 2020 and 2030 All these assumptions are still valid and were taken into account for the data collection.	potentially be negative up to 2024 and increase subsequently.
Germany	DE00	Main drivers for adequacy: • Mainly policy driven interpolated as best guesses by national studies (‘NEP21 B2035/B2040’ and ‘Systemanalyse 2021’) • Expansion of electric vehicles and transformation speed of industry towards CO_2-neutral production	Main drivers for adequacy: • Nuclear phase-out by the end of 2022 • Lignite phase-out (power plants > 150 MW) based on § 13g EnWG and Anlage 2 KVBG. 9 GW available to the market until 2030. Complete phase-out by 2038. • Hard coal phase out: Based on the Coal-fired Power Generation Termination Act (Kohleverstromungsbeendigungsgesetz – KVBG). Hard coal power plants and lignite power plants <150 MW phase out step-by-step over the coming years by tendering the capacity to hit the target number of 8 GW (available to the market) by 2030. Considering the tendering process, it is unclear which power plants will phase out by 2030 and which capacity will be	Due to the expansion of interconnector capacity, trading capacity is increasing. Exact values can be found in the model dataset.	Due to decreasing capacities (nuclear and coal phase-out) and simultaneous electrification of fossil fired consumption technologies, the average level and frequency of imports needed to ensure adequacy will increase.

		All these assumptions are valid and will be updated by new political targets.
		
		The data for electricity demand consider consumption-reducing effects due to efficiency improvements (‘Energieeffizienzstrategie 2050’) on the one hand and consumption-increasing effects due to sector coupling on the other hand. The drivers of sector coupling include:
		• E-mobility
		• Heat pumps
		• Large electricity consumers (e.g. data centers, projects for CO_2-free steel production…)
			auctioned for the following years. Therefore, the German TSOs implemented the following assumptions:
			• Disclaimer: presumed assumptions were made in December 2020. New information about the hard coal phase-out based on the second, third and fourth tender are not included
			• Phase-out of all power plants that won in the first tender (4 GW)
			• Additional step-by-step phase-out of 8 GW to hit the target number for 2030
			• Anticipated coal phase-out (oldest plants and power plants with a planned decommissioning date without an official notice)
			• Overview over the years:
			  ○ 2021: 110 MW
			  ○ 2022: 0.3 GW
			  ○ 2023: 1.8 GW
			  ○ 2024: 1.6 GW
			  ○ 2025: 1.5 GW
			  ○ 2026: 1.4 GW
			  ○ 2027: 1.4 GW
			
			A speed-up of the coal phase-out based on changes of the German climate change protection law can be expected.
			
			Assumptions on technical-economic operating life:		

			• Gas (if not CHP) and light oil power plants phase out of the market when they hit an operating life over 45 years Renewables: interpolated as best guesses by national studies (‘NEP21 B2035/B2040’ and ‘Systemanalyse 2021’) All these assumptions are valid and will be updated by new political targets.		
Greece	GR00, GR03	Demand data have been provided based on the approved NECP, taking into account the scheduled timeline of interconnection of groups of islands (West Cyclades, Dodekanisa, North-East Aegean) to the mainland. The NECP foresees significant electrification of various sectors (namely transportation), but at the same time significant energy saving measures the combined result of which is a relatively small increase of electricity demand during the next decade. Data for the first years have been adjusted to account for the impact of the COVID-19 pandemic.	Supply data stems from the approved NECP which foresees the gradual decommissioning of all existing lignite units by the end of 2023 and considerable penetration of RES, as well as storage units. According to the NECP, the gradual retirement of the existing lignite units is planned to be realized in parallel with the entry of two new CCGT units and a new lignite unit. PPC has announced its intention to retire all existing lignite units in 2021, however this has not been realized due to adequacy concerns and the ongoing gas crisis and therefore it is not considered in the framework of the ERAA 2021 study. The entry date of the lignite unit has been pushed back, while the entry date of the second new CCGT is undefined, while the realization of the large pump-storage unit without some support scheme is questionable. Development of Wind and PV in the last couple years has been faster than what was foreseen in the NECP, while for small ROR it has been slower and therefore the capacities up to 2025	Main grid projects during the next decade include the completion of the interconnection of Crete (DC), the interconnection of most Aegean islands to the mainland (West Cyclades, Dodekanisa, NE Aegean), the expansion of the 400 kV grid in Peloponese and the new line on the GR-BG border (in 2022).	Under the assumptions of the approved NECP adequacy levels during the next decade in Greece seem to be satisfactory, with the first period (2021-2024) however being the most stressed. During the first period (2021-2024) the system is highly vulnerable to climatic conditions and extremely dependent on imports. The main factor that would cause serious adequacy concerns during the period 2021-2024 is if the retirement of the

			have been updated to reflect the current situation, however trajectories up to 2030 remain as described in the NECP. Given the Fit for 55 targets, the revised NECP will contain even more ambitious targets regarding RES penetration.		existing lignite units does not follow chronically the entry of the new units that are currently under construction. From 2026 and on, under the assumptions of the approved NECP, adequacy levels are expected to be satisfactory. However, the increasing share of RES generation and the entry of new large CCGT units (with higher efficiencies) could lead to economic viability issues for the older CCGT units, the potential exit of which would raise adequacy concerns during this period.
Hungary	HU00	Electricity demand forecasts and relevant input data (electric vehicles, heat pumps, etc.) are based on government targets (as for electric	Capacity deployment is forecasted based on the last National Energy Development Plan and National Energy and Climate Plan: coal phase out by 2025, significant growth of solar capacities and nuclear capacity, potential CCGT plants driven by the balancing market. Storage	The grid requirements of high RES (photovoltaic) penetration are assessed and ensured through the annual National Development Plan as well as	Over the next 10 years, significant amounts of new capacity (RES, nuclear and CCGT) are assumed to come

		vehicles) and on the TSO–DSO–NRA joint scenario building process of the Hungarian National Grid Development Plan. P2X technologies are slowly growing, with some pilot projects arising.	technologies are slowly growing, with some pilot projects arising.	a revised connection process for generators. Compliance with the 70% minRAM requirement is planned to be ensured by internal reinforcements as part of the action plan. Two new interconnectors are foreseen with Romania (2030) and Serbia (2034).	online, transforming Hungary from a net importer to net exporter and compensating for the growing energy demand. Being a highly interconnected country, any power plant commissioning delays did not give rise to adequacy problems.
Ireland	IE00	< not provided >	Phase-out of coal and peat (lignite) due to the Clean Energy Package. RES-E target of 70% by 2030	< not provided >	The phase-out of fossil-fuel plant will need to be carefully managed in the transition period to maintain adequacy.
Italy	ITCA, ITCN, ITCS, ITN1, ITS1, ITSA, ITSI	Main drivers: • Expansion of Electric Vehicles • Energy efficiency measures • Increasing industrial/residential electrification All these assumptions are still valid and were considered for the data collection.	Main drivers: • Complete coal phase-out by 2025 except for 1 GW in Sardinia (where the coal phase-out will be completed after the Tyrrhenian Link has been commissioned) • Decommissioning of some old thermal units • New thermal plant capacity (according to national Capacity Market auctions 2022/23)	Main drivers: • Tyrrhenian Link considered in the 2030 simulation but not in the 2025 simulation (commissioning will be finalised after 2027) • Import/export capacity set to increase by about	According to our national adequacy assessment, the adequacy margins will not decrease under the following conditions: • The RES and storage targets will be reached. • The development

			• RES deployment targets (Clean Energy Package targets, i.e. 55% RES share) • Storage related to RES deployment All these assumptions are still valid and were considered for the data collection.	27% between 2020 and 2030 All these assumptions are still valid and were considered for the data collection.	of the grid will be realised in accordance with the National Development Plan. • The thermal generation capacity will not decrease further.
Latvia	LV00	< not provided >	The key capacity and energy mix evolution drivers are policy and governmental subsidy schemes. RES deployment is in line with the National Energy and Climate Plan set by the Latvian government.	< not provided >	< not provided >
Lithuania	LT00	Electrification, mainly in the transport (railway transport and electric vehicles) and heating/cooling sectors, will have the greatest impact on the growth of demand.	Main drivers for increasing adequacy margins: • Decommissioning of old fossil fuel generating units before 2025 (~480MW) • Ambitious RES deployment targets after 2025 (onshore & offshore wind, solar) Main drivers for decreasing adequacy margins: • Battery deployment before 2025 • Explicit demand side response deployment All these assumptions are considered in the ERAA 2021 data collection.	An increase in cross-border capacity between Lithuania and Poland is expected between 2025 and 2030. This assumption is already considered in the ERAA 2021 data collection.	Over the next decade, Lithuania expects to significantly reduce its dependence on imports through ambitious RES development.

Luxembourg	LU00	Electricity demand forecasts and relevant drivers (electric vehicles, heat pumps, etc.) are based on the National Energy and Climate Plan and Creos scenario report 2040 considering government targets (as for electric vehicles or heat pumps).	The capacity forecast, especially based on PV and onshore wind, is based on the reference scenario of the National Energy Development Plan and National Energy and Climate Plan. Storage and DSR potentials are currently under assessment.	Luxembourg is an electricity importing country. Due to an increase of electricity demand and despite very ambitious RES development targets, additional 380 kV grid reinforcements are planned towards Germany until 2026.	< not provided >
North Macedonia	MK00	According to the National Energy Strategy, the demand on the transmission grid is not expected to increase significantly in the upcoming years.	Regarding energy resources, Macedonia has chosen to follow the Green Scenario of the National Energy Strategy. This scenario integrates large amounts of wind and solar (both large scale and roof-top) power plants and several new hydro power plants including large pumped storage hydro power plants. In addition, a phase-out of the existing coal power plant is envisaged.	Every year MEPSO (Macedonian TSO) is publishing a ten-year network development plan that incorporates all of the planned reconstructions / upgrades and improvements of the grid as well as requirements for new connections of demand and generation facilities. Currently, a new interconnection with Albania is under construction which will connect the Macedonian grid with all the neighbouring countries. As a result of the increased RES integration in the southeast part of the country, MEPSO is investing in grid strengthening.	From an adequacy perspective, MEPSO expects a scarcity of national reserves if relying only on national resources due to high RES integration, dry hydrology and transition towards the green energy deal (the thermal power plant phase-out is critical and we expect that a strategic reserve mechanism will be required in the near future). Missing energy storages shall ask for the design of a CRM.

Malta	MT00	Electricity demand projections have been developed using Malta's NECP modelling framework, which was updated for the purpose of an electricity supply study with a 2035 timeframe. Electricity demand is driven by growth rates based on macroeconomic projections provided by the Ministry for Finance and policies and measures included in Malta's NECP, as well as the additional electrification of electric vehicles, heat pumps, data centres and shore-to-ship charging.	RES assumptions, including Solar PV potential for the TYs 2025 and 2030, are based primarily on Malta's NECP projections. Power plant capacities reflect the existing set-up and the projections of the NECP.	Further developments to the grid are projected to meet the forecasted increase in demand and to reinforce the grid for additional capacities. A second Interconnector will be commissioned in 2026, with an additional capacity of 200MW, which was not considered in ERAA 2021.	Peak demand and electricity generation demand are projected to continue to increase. An electricity supply study commissioned by the government is expected to present optimal solutions to meet this demand growth, the results of which will be reflected in future ERAA data submissions. This will also have an impact on adequacy margins.
Montenegro	ME00	< not provided >	< not provided >	< not provided >	< not provided >
Netherlands	NL00	Targets are related to the climate agreement for 2030 (electric vehicles, heat pumps, efficiencies/electrification)	Main drivers: • Coal phase-out in 2026 (old units) and in 2030 (all) • Renewables targets for 2030 (wind and solar) • Storage developments are considered for providing flexibility. These targets are still valid today.	An expansion of the grid is foreseen in support of the aforementioned developments	These developments probably reduce the margins for adequacy; this will be further addressed in the national adequacy assessment
Norway	NOM1, NON1,NOS0	Significant growth in demand due to electrification (transport,	Demand growth is assumed to be balanced with more wind power (mainly offshore) and some hydro and solar capacity.	Further development of internal grids. No new	No. We assume sufficient new generating capacity to

		offshore platforms and industry) and new industries such as data centres, battery factories etc.		foreign exchanges in this period.	balance the growth in demand.
Poland	PL00	The data provided for ERAA 2021 were compliant with the latest official document published by the Polish government: Energy Policy of Poland until 2040.	The data provided for ERAA 2021 were compliant with the latest official document published by the Polish Government: Energy Policy of Poland until 2040. Poland has introduced the capacity market, which is a market mechanism aimed to support achieving adequate volumes of stable electricity supply while minimising costs from the perspective of economy. It operates in parallel to the electricity market and does not introduce restrictions on shaping prices in the electricity market. Polish capacity market is valid at least for the period 2021–2030.	Not applicable.	Fulfilment or, in detail, the level of the adequacy margin over the next 10 years will depend on many factors, including the value of fuel and CO2 prices, as well as the implementation of new regulations to achieve a green deal. Nevertheless, the capacity market is a tool that will significantly support the achievement of the desired level of adequacy.
Portugal	PT00	Evolution of demand as foreseen in NECP, with an 1.57% compound annual growth rate between 2019 and 2030, accounting for increasing battery electric vehicle and plug-in hybrid electric vehicle light passenger cars, as well as	Main drivers: • Decommissioning of all existing coal power plants until the end of 2021 (1.7 GW) • New large hydro power plants (1.2 GW, of which 0.9 GW with pumping) until 2023 • Decommissioning of old CCGT (1 GW) in 2029	Increasing NTC with Spain as follows (PT->ES/ES->PT): • 2022: 2600/2300 MW • 2025: 3500/4200 MW • 2030: 3500/4200 MW	Portugal reliability standards are expected not to be met in 2022 (c.f. national comment below) due to the delayed commissioning of the new hydro power plants for 2023

		battery electric vehicle heavy buses	• 12.1 GW of new RES between 2020–2030 (of which new 8 GW are solar)		(initially it was expected for 2022)
Romania	RO00	The relevant data available from national sources and from the NECP were reflected in the trajectory evolution drivers provided for demand and energy mix evolution. That includes a gradual coal phase-out and a RES capacity increase. However, no specific data on the development of battery storage and DSR are available.	It is assumed that some old lignite and hard coal units, totalling 1578 MW, that will be decommissioned by 2026, will be replaced by new CCGT units. Some of these CCGT units will be installed in the same location. However, the speed-up of the coal phase-out or delays in the commissioning of the new CCGT units will have a direct impact on adequacy.	< not provided >	< not provided >
Serbia	RS00	Main driver for adequacy: • Energy efficiency measures This assumption is still valid.	Main drivers for adequacy: • Partial coal phase-out by 2023 (ca. 200 MW of thermal units are expected to be decommissioned by 2023) • RES deployment target (feed-in tariff of 500 MW of wind and 10 MW of solar) These assumptions are still valid and were considered for the data collection.	Main driver: • Import capacity set to increase by about 75% between 2020 and 2030 All these assumptions are still valid and were considered for the data collection	According to the current available data, the mentioned measures and policies will not affect current adequacy parameters (Energy Not Served [ENS] and Loss of Load Duration [LLD]).
Slovakia	SK00	The trajectory of electricity demand until 2050, provided during the data collection for the EERA as well as for the TYNDP, is in line with the National	The resource energy mix evolution in the EERA reflects the national policies translated into the Integrated NECP (INECP). A significant development in increasing production capacity is expected in nuclear technology.	The Slovak Republic meets the target of 10% of the interconnection level of transmission systems of European Union member states by 2020 adopted by	Positive impact on resource adequacy margins.

		Development Plan of the Slovak transmission system. The electricity demand evolution reflects the expected evolution of the national economy in Slovakia. At the time of providing data for the EERA and the TYNDP, all relevant factors known at the time (such as the impact of COVID-19) that could have a significant impact on the electricity demand evolution were considered.	In addition, a significant increase in RES (especially solar and wind) is expected. This is also in line with the INECP. The assumed evolution of the energy mix, affected by an increase in nuclear capacity, indicates an increase of resource adequacy margins.	the EU Council in 2002 and also the target of 15% of the interconnection level by 2030 set by the EU Council in 2014 as a share of net import transmission capacity to total installed capacity electricity generation of a Member State.	
Slovenia	SI00	At the time of providing the data for the PEMMDB, all relevant factors which have an influence on demand were considered. Special attention was paid to the impact of COVID-19.	It must be mentioned that one of the lignite power plants (305 MW), which is marked as available on the market in the PEMMDB, will be put to the cold reserve and can be put back to the grid within a one-month period. Furthermore, there is a high risk of one or more lignite power plants (539 MW) being decommissioned before 2027. The likelihood of new batteries being deployed into the system seems higher than at the time of providing the data for the ERAA and the TYNDP. This would be beneficial for adequacy studies. However, the numbers are hard to estimate due to a high uncertainty. Intense efforts are being made to build a new nuclear power plant in Slovenia. However, it is	< not provided >	Increases in demand may slightly lower adequacy margins, whereas increases in transmission capacity and DSR may increase it.

			not believed that this could be realised within a 10-year period.		
Spain	ES00	The trajectory provided for electricity demand is defined in the NECP approved by the Spanish government. Demand growth affecting system adequacy could arise due to the installation of new data centres, the evolution of electromobility or extreme weather events.	The trajectory provided for the generation facilities is defined in the NECP approved by the Spanish government. A possible coal phase-out before 2025 or closures of CCGTs could affect adequacy. The current evolution of new wind and solar PV installations is in line with the provided scenario. However, solar thermal facilities are not currently evolving at the necessary pace. Adequacy in 2030 is expected to worsen due to an expected nuclear phase-out of 4 GW.	The interconnection values provided are in line with the commissioning dates expected for the different projects as reported in the TYNDP 2020 exercise. Spain is far from reaching interconnection targets and thus REE is promoting several new interconnectors with France and Portugal. The Bay of Biscay project has not been considered in 2025, but will improve adequacy in the following years, although not sufficiently to offset the nuclear phase-out plans.	In any case, a diversion from these trajectories without a significant amount of CCGT closures will not be sufficiently large to compromise adequacy for 2025 or even for 2030.
Sweden	SE01, SE02, SE03, SE04	Main drivers: • Electrification of the transport sector • Increases in electricity-intensive industry • Expansion of hydrogen electrolysers within the steel industry from 2025	Main drivers: • RES targets: 100% renewable electricity production by 2040 (this does not force the closing of nuclear reactors) • Increases in DSR as a result of economic incentives and technological developments • Some increase in market-participating batteries as these become more profitable	Increased transmission capacity between SE02 and SE03 (total capacity equal to 8100 MW from 2024). Increased transmission capacity between SE3 and SE4 (total capacity equal to 6800 MW from 2026) and between SE4 and SE3 (total capacity equal to 3200 MW from 2026).	Increases in demand may lower adequacy margins whereas increases in transmission capacity and DSR may increase it.

		• Emission targets; by 2045 the goal is for Sweden to have zero net emissions of greenhouse gasses.		Increased transmission capacity between SE04 and DE00 (total capacity equal to 1315 MW from 2026). Increased transmission capacity between SE01 and FI00 and between FI00 and SE01 (total capacity equal to 2000 MW in both directions from 2026). Increases in transmission capacity between the Nordics and continental Europe from 2024. This will change power flows and prices in Sweden.	
Switzerland	CH00	Demand is expected to increase, driven by the decarbonisation of society and industry.	In 2020, the Swiss electricity system generated 41 TWh (58%) with hydro power plants, 23 TWh (33%) with nuclear power plants, 5 TWh (7%) with renewable generation facilities (PV, biomass, renewable share of waste incineration and very little wind) and 1 TWh (2%) with traditional thermal generation facilities. Decommissioning of nuclear power stations is decided by the Swiss Federal Nuclear Safety Inspectorate (ENSI, c.f. www.ensi.ch) on the basis of security criteria. The energy perspectives of the Swiss Federal Office of Energy (SFOE, c.f. https://www.bfe.admin.ch/bfe/en/home/policy	< not provided >	Within the timeframe from 2021 to 2030, the Swiss resource adequacy margin will decrease as soon as the nuclear power stations Beznau (730 MW) and Gösgen (1090 MW) are decommissioned. The adequacy situation in Switzerland during winter will increasingly depend on the availability to

			/energy-perspectives-2050-plus.html) assume lifetimes of both 50 and 60 years, depending on the scenario, and it neither assumes the replacement of decommissioned nuclear facilities nor the building of new ones.		import. A capacity reduction on Swiss borders due to compliance with the 70% minRAM requirement of other TSOs will have a negative impact on the Swiss resource adequacy margin in winter, with negative effects on regional security of supply as well.
United Kingdom	UK00, UKNI				

Appendix 2: Compliance of ERAA 2021 with the 70% target for minimum cross-zonal capacity

Detailed tables with the 70% compliance per border for both Target Years 2025 and 2030 are provided in this Appendix. Information on these tables are provided on the following principles:

(i) Compliance is based on TSOs feedback as provided in Appendix 1, Table 7. ENTSO-E performed no central calculations to confirm this input;
(ii) Despite ENTSO-E and TSOs being always engaged to agree on the proposed NTC values for each border, there are still cases where consensus could not be reached. NTC values for a line for which neighbouring TSOs provided different values were selected based on the 'most conservative' principle, i.e. lowest NTC was chosen;
(iii) Flow-Based compliance stems from the methodology used to calculate the FB domains.

Note that a comparison between the NTC values provided by TSOs and the NTC values approximated based on the FB domains, showed that NTC values in ERAA 2021 are generally higher than then FB domains calculated and implemented in the Flow-Based Proof-of-Concept, c.f. Annex 4.

Table 11: Compliance with the 70% target per border for Target Year 2025

Interconnection	NTC - 70% Compliance	FB - 70% Compliance	Line
AL00-GR00	N/A	NTC border	HVAC
GR00-AL00	N/A	NTC border	HVAC
AL00-ME00	N/A	NTC border	HVAC
ME00-AL00	N/A	NTC border	HVAC
AL00-RS00	N/A	NTC border	HVAC
RS00-AL00	N/A	NTC border	HVAC
AL00-MK00	N/A	NTC border	HVAC
MK00-AL00	N/A	NTC border	HVAC
AT00-CH00	Could not be assessed	Advanced Hybrid Coupling - FB border	HVAC
CH00-AT00	Could not be assessed	Advanced Hybrid Coupling - FB border	HVAC
AT00-CZ00	Could not be assessed	Core border - Full Compliance	HVAC
CZ00-AT00	Could not be assessed	Core border - Full Compliance	HVAC
AT00-DE00	Could not be assessed	Core border - Full Compliance	HVAC
DE00-AT00	Could not be assessed	Core border - Full Compliance	HVAC
AT00-HU00	Could not be assessed	Core border - Full Compliance	HVAC
HU00-AT00	Could not be assessed	Core border - Full Compliance	HVAC
AT00-ITN1	Yes	Advanced Hybrid Coupling - FB border	HVAC
ITN1-AT00	Yes	Advanced Hybrid Coupling - FB border	HVAC

Interconnection	NTC - 70% Compliance	FB - 70% Compliance	Line
AT00-SI00	Yes	Core border - Full Compliance	HVAC
SI00-AT00	Yes	Core border - Full Compliance	HVAC
BA00-HR00	Could not be assessed	Advanced Hybrid Coupling - FB border	HVAC
HR00-BA00	Could not be assessed	Advanced Hybrid Coupling - FB border	HVAC
BA00-ME00	N/A	NTC border	HVAC
ME00-BA00	N/A	NTC border	HVAC
BA00-RS00	N/A	NTC border	HVAC
RS00-BA00	N/A	NTC border	HVAC
BE00-FR00	Could not be assessed	Core border - Full Compliance	HVAC
FR00-BE00	Could not be assessed	Core border - Full Compliance	HVAC
BE00-LUB1	Could not be assessed	Core border - Full Compliance	HVAC
BE00-NL00	Could not be assessed	Core border - Full Compliance	HVAC
NL00-BE00	Could not be assessed	Core border - Full Compliance	HVAC
BG00-GR00	Yes	NTC border	HVAC
GR00-BG00	Yes	NTC border	HVAC
BG00-MK00	Yes	NTC border	HVAC
MK00-BG00	Yes	NTC border	HVAC
BG00-RO00	Yes	Advanced Hybrid Coupling - FB border	HVAC
RO00-BG00	Yes	Advanced Hybrid Coupling - FB border	HVAC
BG00-RS00	N/A	NTC border	HVAC
RS00-BG00	N/A	NTC border	HVAC
BG00-TR00	Yes	NTC border	HVAC
TR00-BG00	Yes	NTC border	HVAC
CH00-DE00	Could not be assessed	Advanced Hybrid Coupling - FB border	HVAC
DE00-CH00	Could not be assessed	Advanced Hybrid Coupling - FB border	HVAC
CH00-FR00	Could not be assessed	Advanced Hybrid Coupling - FB border	HVAC
FR00-CH00	Could not be assessed	Advanced Hybrid Coupling - FB border	HVAC
CH00-ITN1	Yes	NTC border	HVAC
ITN1-CH00	Yes	NTC border	HVAC
CZ00-DE00	Could not be assessed	Core border - Full Compliance	HVAC
DE00-CZ00	Could not be assessed	Core border - Full Compliance	HVAC
PLE0-CZ00	Yes	Core border - Full Compliance	HVAC
CZ00-PLI0	Yes	Core border - Full Compliance	HVAC
CZ00-SK00	Yes	Core border - Full Compliance	HVAC
SK00-CZ00	Yes	NTC border	HVAC

Interconnection	NTC - 70% Compliance	FB - 70% Compliance	Line
DE00-DEKF	Could not be assessed	NTC border	HVAC
DEKF-DE00	Could not be assessed	NTC border	HVAC
DE00-DKW1	Yes	Advanced Hybrid Coupling - FB border	HVAC
DKW1-DE00	Yes	Advanced Hybrid Coupling - FB border	HVAC
DE00-FR00	Could not be assessed	Core border - Full Compliance	HVAC
FR00-DE00	Could not be assessed	Core border - Full Compliance	HVAC
DE00-LUG1	Could not be assessed	Core border - Full Compliance	HVAC
LUG1-DE00	Could not be assessed	Core border - Full Compliance	HVAC
DE00-LUV1	Could not be assessed	Core border - Full Compliance	HVAC
LUV1-DE00	Could not be assessed	Core border - Full Compliance	HVAC
DE00-NL00	Could not be assessed	Core border - Full Compliance	HVAC
NL00-DE00	Could not be assessed	Core border - Full Compliance	HVAC
PLE0-DE00	Yes	Core border - Full Compliance	HVAC
DE00-PLI0	Yes	Core border - Full Compliance	HVAC
EE00-LV00	Yes	NTC border	HVAC
LV00-EE00	Yes	NTC border	HVAC
ES00-FR00	Could not be assessed	Advanced Hybrid Coupling - FB border	HVAC
FR00-ES00	Could not be assessed	Advanced Hybrid Coupling - FB border	HVAC
ES00-PT00	Could not be assessed	NTC border	HVAC
PT00-ES00	Could not be assessed	NTC border	HVAC
FI00-SE01	Yes	NTC border	HVAC
SE01-FI00	Yes	NTC border	HVAC
FR00-ITN1	Yes	Advanced Hybrid Coupling - FB border	HVAC
ITN1-FR00	Yes	Advanced Hybrid Coupling - FB border	HVAC
FR00-LUF1	Could not be assessed	Core border - Full Compliance	HVAC
GR00-GR03	Yes	NTC border	HVAC
GR03-GR00	Yes	NTC border	HVAC
GR00-MK00	N/A	NTC border	HVAC
MK00-GR00	N/A	NTC border	HVAC
GR00-TR00	N/A	NTC border	HVAC
TR00-GR00	N/A	NTC border	HVAC
SI00-HR00	Yes	Core border - Full Compliance	HVAC
RS00-HR00	N/A	NTC border	HVAC
HU00-HR00	Could not be assessed	Core border - Full Compliance	HVAC
HR00-SI00	Yes	Core border - Full Compliance	HVAC
HR00-RS00	N/A	NTC border	HVAC
HR00-HU00	Could not be assessed	Core border - Full Compliance	HVAC

Interconnection	NTC - 70% Compliance	FB - 70% Compliance	Line
HU00-RO00	Yes	Core border - Full Compliance	HVAC
RO00-HU00	Yes	Core border - Full Compliance	HVAC
HU00-RS00	N/A	NTC border	HVAC
RS00-HU00	N/A	NTC border	HVAC
HU00-SI00	Yes	Core border - Full Compliance	HVAC
SI00-HU00	Yes	Core border - Full Compliance	HVAC
HU00-SK00	Yes	Core border - Full Compliance	HVAC
SK00-HU00	Yes	Core border - Full Compliance	HVAC
HU00-UA01	Could not be assessed	Advanced Hybrid Coupling - FB border	HVAC
UA01-HU00	Could not be assessed	Advanced Hybrid Coupling - FB border	HVAC
IE00-UKNI	Could not be assessed	NTC border	HVAC
UKNI-IE00	Could not be assessed	NTC border	HVAC
ITCA-ITS1	Yes	NTC border	HVAC
ITS1-ITCA	Yes	NTC border	HVAC
ITCN-ITCS	Yes	NTC border	HVAC
ITCS-ITCN	Yes	NTC border	HVAC
ITCN-ITN1	Yes	NTC border	HVAC
ITN1-ITCN	Yes	NTC border	HVAC
ITCS-ITS1	Yes	NTC border	HVAC
ITS1-ITCS	Yes	NTC border	HVAC
ITN1-SI00	Yes	Advanced Hybrid Coupling - FB border	HVAC
SI00-ITN1	Yes	Advanced Hybrid Coupling - FB border	HVAC
ITSI-MT00	Yes	NTC border	HVAC
MT00-ITSI	Yes	NTC border	HVAC
LV00-LT00	Yes	NTC border	HVAC
LT00-LV00	Yes	NTC border	HVAC
ME00-RS00	N/A	NTC border	HVAC
RS00-ME00	N/A	NTC border	HVAC
MK00-RS00	N/A	NTC border	HVAC
RS00-MK00	N/A	NTC border	HVAC
PLI0-PL00	Yes	Core border - Full Compliance	HVAC
PL00-PLE0	Yes	Core border - Full Compliance	HVAC
RO00-RS00	N/A	NTC border	HVAC
RS00-RO00	N/A	NTC border	HVAC
RO00-UA01	Yes	Advanced Hybrid Coupling - FB border	HVAC
UA01-RO00	Yes	Advanced Hybrid Coupling - FB border	HVAC
PLE0-SK00	Yes	Core border - Full Compliance	HVAC

Interconnection	NTC - 70% Compliance	FB - 70% Compliance	Line
SK00-PLI0	Yes	Core border - Full Compliance	HVAC
SK00-UA01	Yes	Advanced Hybrid Coupling - FB border	HVAC
BE00-LUG1	No	Core border - Full Compliance	HVDC
LUG1-BE00	No	Core border - Full Compliance	HVDC
BE00-UK00	No	Advanced Hybrid Coupling - FB border	HVDC
UK00-BE00	No	Advanced Hybrid Coupling - FB border	HVDC
DE00-BE00	No	Core border - Full Compliance	HVDC
BE00-DE00	No	Core border - Full Compliance	HVDC
DE00-DKE1	Yes	Advanced Hybrid Coupling - FB border	HVDC
DKE1-DE00	Yes	Advanced Hybrid Coupling - FB border	HVDC
NON1-SE01	Yes	NTC border	HVAC
SE01-NON1	Yes	NTC border	HVAC
NOS0-SE03	Yes	NTC border	HVAC
SE03-NOS0	Yes	NTC border	HVAC
NON1-SE02	Yes	NTC border	HVAC
SE02-NON1	Yes	NTC border	HVAC
DE00-SE04	Yes	Advanced Hybrid Coupling - FB border	HVDC
SE04-DE00	Yes	Advanced Hybrid Coupling - FB border	HVDC
EE00-FI00	Yes	NTC border	HVDC
FI00-EE00	Yes	NTC border	HVDC
FI00-SE03	Yes	NTC border	HVDC
SE03-FI00	Yes	NTC border	HVDC
FR00-UK00	Could not be assessed	Advanced Hybrid Coupling - FB border	HVDC
UK00-FR00	Could not be assessed	Advanced Hybrid Coupling - FB border	HVDC
GR00-ITS1	Yes	NTC border	HVDC
ITS1-GR00	Yes	NTC border	HVDC
IE00-UK00	Could not be assessed	NTC border	HVDC
UK00-IE00	Could not be assessed	NTC border	HVDC
ITCS-ITSA	Yes	NTC border	HVDC
ITSA-ITCS	Yes	NTC border	HVDC
ITCS-ME00	N/A	NTC border	HVDC
ME00-ITCS	N/A	NTC border	HVDC
PL00-LT00	Yes	Advanced Hybrid Coupling - FB border	HVDC

Interconnection	NTC - 70% Compliance	FB - 70% Compliance	Line
LT00-PL00	Yes	Advanced Hybrid Coupling - FB border	HVDC
NL00-DKW1	Yes	Advanced Hybrid Coupling - FB border	HVDC
DKW1-NL00	Yes	Advanced Hybrid Coupling - FB border	HVDC
NL00-UK00	Could not be assessed	Advanced Hybrid Coupling - FB border	HVDC
UK00-NL00	Could not be assessed	Advanced Hybrid Coupling - FB border	HVDC
PL00-SE04	Yes	Advanced Hybrid Coupling - FB border	HVDC
SE04-PL00	Yes	Advanced Hybrid Coupling - FB border	HVDC
LT00-SE04	Yes	NTC border	HVDC
SE04-LT00	Yes	NTC border	HVDC
UKNI-UK00	N/A	NTC border	HVDC
UK00-UKNI	N/A	NTC border	HVDC
NL00-NOS0	Yes	NTC border	HVDC
NOS0-NL00	Yes	NTC border	HVDC
NOS0-DE00	Yes	NTC border	HVDC
DE00-NOS0	Yes	NTC border	HVDC
DKW1-NOS0	Yes	NTC border	HVDC
NOS0-DKW1	Yes	NTC border	HVDC
NOS0-UK00	Yes	NTC border	HVDC
UK00-NOS0	Yes	NTC border	HVDC

Compliance with the 70% target per border for Target Year 2030

Interconnection	NTC - 70% Compliance	FB - 70% Compliance	Line
AL00-GR00	N/A	N/A in ERAA 2021	HVAC
GR00-AL00	N/A	N/A in ERAA 2021	HVAC
AL00-ME00	N/A	N/A in ERAA 2021	HVAC
ME00-AL00	N/A	N/A in ERAA 2021	HVAC
AL00-RS00	N/A	N/A in ERAA 2021	HVAC
RS00-AL00	N/A	N/A in ERAA 2021	HVAC
AL00-MK00	N/A	N/A in ERAA 2021	HVAC
MK00-AL00	N/A	N/A in ERAA 2021	HVAC
AT00-CH00	Could not be assessed	N/A in ERAA 2021	HVAC
CH00-AT00	Could not be assessed	N/A in ERAA 2021	HVAC
AT00-CZ00	Could not be assessed	N/A in ERAA 2021	HVAC
CZ00-AT00	Could not be assessed	N/A in ERAA 2021	HVAC
AT00-DE00	Could not be assessed	N/A in ERAA 2021	HVAC

Interconnection	NTC - 70% Compliance	FB - 70% Compliance	Line
DE00-AT00	Could not be assessed	N/A in ERAA 2021	HVAC
AT00-HU00	Could not be assessed	N/A in ERAA 2021	HVAC
HU00-AT00	Could not be assessed	N/A in ERAA 2021	HVAC
AT00-ITN1	Yes	N/A in ERAA 2021	HVAC
ITN1-AT00	Yes	N/A in ERAA 2021	HVAC
AT00-SI00	Yes	N/A in ERAA 2021	HVAC
SI00-AT00	Yes	N/A in ERAA 2021	HVAC
BA00-HR00	Could not be assessed	N/A in ERAA 2021	HVAC
HR00-BA00	Could not be assessed	N/A in ERAA 2021	HVAC
BA00-ME00	N/A	N/A in ERAA 2021	HVAC
ME00-BA00	N/A	N/A in ERAA 2021	HVAC
BA00-RS00	N/A	N/A in ERAA 2021	HVAC
RS00-BA00	N/A	N/A in ERAA 2021	HVAC
BE00-FR00	Could not be assessed	N/A in ERAA 2021	HVAC
FR00-BE00	Could not be assessed	N/A in ERAA 2021	HVAC
BE00-LUB1	Could not be assessed	N/A in ERAA 2021	HVAC
BE00-NL00	Could not be assessed	N/A in ERAA 2021	HVAC
NL00-BE00	Could not be assessed	N/A in ERAA 2021	HVAC
BG00-GR00	Yes	N/A in ERAA 2021	HVAC
GR00-BG00	Yes	N/A in ERAA 2021	HVAC
BG00-MK00	Yes	N/A in ERAA 2021	HVAC
MK00-BG00	Yes	N/A in ERAA 2021	HVAC
BG00-RO00	Yes	N/A in ERAA 2021	HVAC
RO00-BG00	Yes	N/A in ERAA 2021	HVAC
BG00-RS00	N/A	N/A in ERAA 2021	HVAC
RS00-BG00	N/A	N/A in ERAA 2021	HVAC
BG00-TR00	Yes	N/A in ERAA 2021	HVAC
TR00-BG00	Yes	N/A in ERAA 2021	HVAC
CH00-DE00	Could not be assessed	N/A in ERAA 2021	HVAC
DE00-CH00	Could not be assessed	N/A in ERAA 2021	HVAC
CH00-FR00	Could not be assessed	N/A in ERAA 2021	HVAC
FR00-CH00	Could not be assessed	N/A in ERAA 2021	HVAC
CH00-ITN1	Yes	N/A in ERAA 2021	HVAC
ITN1-CH00	Yes	N/A in ERAA 2021	HVAC
CZ00-DE00	Could not be assessed	N/A in ERAA 2021	HVAC
DE00-CZ00	Could not be assessed	N/A in ERAA 2021	HVAC
PLE0-CZ00	Yes	N/A in ERAA 2021	HVAC
CZ00-PLI0	Yes	N/A in ERAA 2021	HVAC
CZ00-SK00	Yes	N/A in ERAA 2021	HVAC
SK00-CZ00	Yes	N/A in ERAA 2021	HVAC
DE00-DEKF	Could not be assessed	N/A in ERAA 2021	HVAC

Interconnection	NTC - 70% Compliance	FB - 70% Compliance	Line
DEKF-DE00	Could not be assessed	N/A in ERAA 2021	HVAC
DE00-DKW1	Yes	N/A in ERAA 2021	HVAC
DKW1-DE00	Yes	N/A in ERAA 2021	HVAC
DE00-FR00	Could not be assessed	N/A in ERAA 2021	HVAC
FR00-DE00	Could not be assessed	N/A in ERAA 2021	HVAC
DE00-LUG1	Could not be assessed	N/A in ERAA 2021	HVAC
LUG1-DE00	Could not be assessed	N/A in ERAA 2021	HVAC
DE00-LUV1	Could not be assessed	N/A in ERAA 2021	HVAC
LUV1-DE00	Could not be assessed	N/A in ERAA 2021	HVAC
DE00-NL00	Could not be assessed	N/A in ERAA 2021	HVAC
NL00-DE00	Could not be assessed	N/A in ERAA 2021	HVAC
PLE0-DE00	Yes	N/A in ERAA 2021	HVAC
DE00-PLI0	Yes	N/A in ERAA 2021	HVAC
EE00-LV00	Yes	N/A in ERAA 2021	HVAC
LV00-EE00	Yes	N/A in ERAA 2021	HVAC
ES00-FR00	Could not be assessed	N/A in ERAA 2021	HVAC
FR00-ES00	Could not be assessed	N/A in ERAA 2021	HVAC
ES00-PT00	Could not be assessed	N/A in ERAA 2021	HVAC
PT00-ES00	Could not be assessed	N/A in ERAA 2021	HVAC
FI00-SE01	Yes	N/A in ERAA 2021	HVAC
SE01-FI00	Yes	N/A in ERAA 2021	HVAC
FR00-ITN1	Yes	N/A in ERAA 2021	HVAC
ITN1-FR00	Yes	N/A in ERAA 2021	HVAC
FR00-LUF1	Could not be assessed	N/A in ERAA 2021	HVAC
GR00-GR03	Yes	N/A in ERAA 2021	HVAC
GR03-GR00	Yes	N/A in ERAA 2021	HVAC
GR00-MK00	N/A	N/A in ERAA 2021	HVAC
MK00-GR00	N/A	N/A in ERAA 2021	HVAC
GR00-TR00	N/A	N/A in ERAA 2021	HVAC
TR00-GR00	N/A	N/A in ERAA 2021	HVAC
SI00-HR00	Yes	N/A in ERAA 2021	HVAC
RS00-HR00	N/A	N/A in ERAA 2021	HVAC
HU00-HR00	Could not be assessed	N/A in ERAA 2021	HVAC
HR00-SI00	Yes	N/A in ERAA 2021	HVAC
HR00-RS00	N/A	N/A in ERAA 2021	HVAC
HR00-HU00	Could not be assessed	N/A in ERAA 2021	HVAC
HU00-RO00	Yes	N/A in ERAA 2021	HVAC
RO00-HU00	Yes	N/A in ERAA 2021	HVAC
HU00-RS00	N/A	N/A in ERAA 2021	HVAC
RS00-HU00	N/A	N/A in ERAA 2021	HVAC
HU00-SI00	Yes	N/A in ERAA 2021	HVAC

Interconnection	NTC - 70% Compliance	FB - 70% Compliance	Line
SI00-HU00	Yes	N/A in ERAA 2021	HVAC
HU00-SK00	Yes	N/A in ERAA 2021	HVAC
SK00-HU00	Yes	N/A in ERAA 2021	HVAC
HU00-UA01	Could not be assessed	N/A in ERAA 2021	HVAC
UA01-HU00	Could not be assessed	N/A in ERAA 2021	HVAC
UKNI-IE00	Could not be assessed	N/A in ERAA 2021	HVAC
IE00-UKNI	Could not be assessed	N/A in ERAA 2021	HVAC
LV00-LT00	Yes	N/A in ERAA 2021	HVAC
LT00-LV00	Yes	N/A in ERAA 2021	HVAC
ME00-RS00	N/A	N/A in ERAA 2021	HVAC
RS00-ME00	N/A	N/A in ERAA 2021	HVAC
MK00-RS00	N/A	N/A in ERAA 2021	HVAC
RS00-MK00	N/A	N/A in ERAA 2021	HVAC
MT00-ITSI	Yes	N/A in ERAA 2021	HVAC
ITSI-MT00	Yes	N/A in ERAA 2021	HVAC
PLI0-PL00	Yes	N/A in ERAA 2021	HVAC
PL00-PLE0	Yes	N/A in ERAA 2021	HVAC
RO00-RS00	N/A	N/A in ERAA 2021	HVAC
RS00-RO00	N/A	N/A in ERAA 2021	HVAC
RO00-UA01	Yes	N/A in ERAA 2021	HVAC
UA01-RO00	Yes	N/A in ERAA 2021	HVAC
SI00-ITN1	Yes	N/A in ERAA 2021	HVAC
ITN1-SI00	Yes	N/A in ERAA 2021	HVAC
PLE0-SK00	Yes	N/A in ERAA 2021	HVAC
SK00-PLI0	Yes	N/A in ERAA 2021	HVAC
SK00-UA01	Yes	N/A in ERAA 2021	HVAC
UA01-SK00	Yes	N/A in ERAA 2021	HVAC
NOM1-NON1	Yes	N/A in ERAA 2021	HVAC
NON1-NOM1	Yes	N/A in ERAA 2021	HVAC
NOM1-NOS0	Yes	N/A in ERAA 2021	HVAC
NOS0-NOM1	Yes	N/A in ERAA 2021	HVAC
NOM1-SE02	Yes	N/A in ERAA 2021	HVAC
SE02-NOM1	Yes	N/A in ERAA 2021	HVAC
NON1-SE01	Yes	N/A in ERAA 2021	HVAC
SE01-NON1	Yes	N/A in ERAA 2021	HVAC
NOS0-SE03	Yes	N/A in ERAA 2021	HVAC
SE03-NOS0	Yes	N/A in ERAA 2021	HVAC
NON1-SE02	Yes	N/A in ERAA 2021	HVAC
SE02-NON1	Yes	N/A in ERAA 2021	HVAC
BE00-LUG1	Could not be assessed	N/A in ERAA 2021	HVDC
LUG1-BE00	Could not be assessed	N/A in ERAA 2021	HVDC

Interconnection	NTC - 70% Compliance	FB - 70% Compliance	Line
BE00-UK00	Could not be assessed	N/A in ERAA 2021	HVDC
UK00-BE00	Could not be assessed	N/A in ERAA 2021	HVDC
DE00-BE00	Could not be assessed	N/A in ERAA 2021	HVDC
BE00-DE00	Could not be assessed	N/A in ERAA 2021	HVDC
DE00-DKE1	Yes	N/A in ERAA 2021	HVDC
DKE1-DE00	Yes	N/A in ERAA 2021	HVDC
DE00-UK00	Could not be assessed	N/A in ERAA 2021	HVDC
UK00-DE00	Could not be assessed	N/A in ERAA 2021	HVDC
DE00-NOS0	Could not be assessed	N/A in ERAA 2021	HVDC
NOS0-DE00	Could not be assessed	N/A in ERAA 2021	HVDC
DE00-SE04	Yes	N/A in ERAA 2021	HVDC
SE04-DE00	Yes	N/A in ERAA 2021	HVDC
EE00-FI00	Yes	N/A in ERAA 2021	HVDC
FI00-EE00	Yes	N/A in ERAA 2021	HVDC
FI00-SE03	Yes	N/A in ERAA 2021	HVDC
SE03-FI00	Yes	N/A in ERAA 2021	HVDC
FR00-UK00	Could not be assessed	N/A in ERAA 2021	HVDC
UK00-FR00	Could not be assessed	N/A in ERAA 2021	HVDC
FR00-IE00	Could not be assessed	N/A in ERAA 2021	HVDC
IE00-FR00	Could not be assessed	N/A in ERAA 2021	HVDC
GR00-ITS1	Yes	N/A in ERAA 2021	HVDC
ITS1-GR00	Yes	N/A in ERAA 2021	HVDC
IE00-UK00	Could not be assessed	N/A in ERAA 2021	HVDC
UK00-IE00	Could not be assessed	N/A in ERAA 2021	HVDC
PL00-LT00	Yes	N/A in ERAA 2021	HVDC
LT00-PL00	Yes	N/A in ERAA 2021	HVDC
ME00-ITCS	Yes	N/A in ERAA 2021	HVDC
ITCS-ME00	Yes	N/A in ERAA 2021	HVDC
NL00-DKW1	Yes	N/A in ERAA 2021	HVDC
DKW1-NL00	Yes	N/A in ERAA 2021	HVDC
NL00-UK00	Could not be assessed	N/A in ERAA 2021	HVDC
UK00-NL00	Could not be assessed	N/A in ERAA 2021	HVDC
SE04-PL00	Yes	N/A in ERAA 2021	HVDC
PL00-SE04	Yes	N/A in ERAA 2021	HVDC
LT00-SE04	Yes	N/A in ERAA 2021	HVDC
SE04-LT00	Yes	N/A in ERAA 2021	HVDC
UKNI-UK00	N/A	N/A in ERAA 2021	HVDC
UK00-UKNI	N/A	N/A in ERAA 2021	HVDC
NL00-NOS0	Yes	N/A in ERAA 2021	HVDC
NOS0-NL00	Yes	N/A in ERAA 2021	HVDC
NOS0-DE00	Yes	N/A in ERAA 2021	HVDC

Interconnection	NTC - 70% Compliance	FB - 70% Compliance	Line
DE00-NOS0	Yes	N/A in ERAA 2021	HVDC
DKW1-NOS0	Yes	N/A in ERAA 2021	HVDC
NOS0-DKW1	Yes	N/A in ERAA 2021	HVDC
NOS0-UK00	Yes	N/A in ERAA 2021	HVDC
UK00-NOS0	Yes	N/A in ERAA 2021	HVDC