Winter Outlook 2025–2026

Summer Outlook 2025 Review

entsoe

ENTSO-E Mission Statement

ENTSO-E, the European Network of Transmission System Operators for Electricity, **is the association of the European transmission system operators** (TSOs). The **40 member TSOs, representing 36 countries**, are responsible for the secure and coordinated operation of Europe's electricity system, the **largest interconnected electrical grid in the world**.

Before ENTSO-E was established in 2009, there was a long history of cooperation among European transmission operators, dating back to the creation of the electrical synchronous areas and interconnections which were established in the 1950s.

In its present form, ENTSO-E was founded to fulfil the common mission of the European TSO community: to power our society. At its core, European consumers rely upon a secure and efficient electricity system. Our electricity transmission grid, and its secure operation, is the backbone of the power system, thereby supporting the vitality of our society. ENTSO-E was created **to ensure the efficiency and security of the pan-European interconnected power system** across all time frames within the internal energy market and its extension to the interconnected countries.

ENTSO-E is working to secure a carbon-neutral future. The transition is a shared political objective throughout the continent and necessitates a much more electrified economy where sustainable, efficient and secure electricity becomes even more important. **Our Vision: "a power system for a carbon-neutral Europe"*** shows that this is within our reach, but additional work is necessary to make it a reality.

In its Strategic Roadmap presented in 2024, ENTSO-E has organised its activities around two interlinked pillars, reflecting this dual role:

- "Prepare for the future" to organise a power system for a carbon-neutral Europe; and
- "Manage the present" to ensure a secure and efficient power system for Europe.

ENTSO-E is ready to meet the ambitions of Net Zero, the challenges of today and those of the future for the benefit of consumers, by working together with all stakeholders and policymakers.

* https://vision.entsoe.eu/

Contents

1. Executive summary

ENTSO-E Winter Outlook 2025–2026 highlights the overall favourable adequacy situation in Europe for the coming winter. Some electricity supply risks might occur in non-continental areas such as Cyprus, Ireland, and Malta. Dedicated non-market resources significantly alleviate such risks in Ireland and Malta. On the mainland continent, only Finland, Estonia and Lithuania face minor risks in the event of exceptionally adverse operational conditions combined with cold weather and high unplanned outages.

European power system trends since winter 2024–2025 show further generation fleet expansion, with decreases in conventional generation and considerable increases in renewable energy source (RES). Planned outages and demand are comparable to last winter, while hydro reservoir levels are higher than average overall. These combined factors create favourable conditions for adequacy.

Since March 2022, Ukraine and Moldova have been synchronised with the Continental European power system. The situation in Ukraine remains uncertain due to potential attacks on energy infrastructure, according to national experts. Until June 2025, European transmission system operators (TSOs) progressively increased the export capacity to Ukraine and Moldova. Since July 2025, ENTSO-E has transferred the responsibility for determining the import and export capacity to the Eastern Europe capacity calculation region (CCR).

The Winter Outlook is accompanied by a retrospective of last summer. Despite warm temperatures, with heatwaves recorded in some regions, no adequacy issues were recorded for the majority of countries. A few countries (North Macedonia, the Czech Republic and Cyprus) experienced disruptions during summer 2025 due to technical issues.

It is important to note that in winter 2025–2026, the Baltic States (including Estonia, Latvia and Lithuania) will operate in full system operation in synchronous mode with the Continental Europe power system, with a direct connection to Poland, following their desynchronisation from the IPS/UPS since 9 February 2025.

2. Introduction

General purpose of Seasonal Outlook reports

ENTSO-E's Seasonal Outlook reports investigate the security of electricity supply at the pan-European level before each winter and summer period. They are released twice yearly, with a Summer Outlook in June and a Winter Outlook in December. The role of the Outlook is to identify when and where system adequacy — the balance between electricity supply and demand — is at risk. Outlook reports are not forecasts of the future, but rather identify potential resource adequacy risks at a specific point in time for the upcoming season, which can be proactively addressed with preparation or mitigation measures. The risks identified are based on assessing a reference scenario and various sensitivities, considering uncertainties that could arise.

Outlook reports are the result of cooperation between 40 European electricity TSOs, fostering collaboration across Europe and between regional and national stakeholders. Due to their pan-European scope, Outlook reports complement the analysis carried out in national and regional assessments, which provide a more detailed picture of adequacy at the local level. Seasonal Outlook studies model resource adequacy without considering specific operational constraints, such as grid stability or voltage.

Conducting Seasonal Outlook studies (seasonal adequacy assessments) is one of ENTSO-E's legal mandates as specified in the Clean Energy Package and defined in Article 9(2) of the Risk Preparedness Regulation (Regulation (EU) 2019/941). ENTSO-E performs this assessment to inform national authorities, TSOs, and relevant stakeholders of the potential risks related to electricity supply security in the coming season. Seasonal Outlook studies reflect the implementation of the Methodology for Short-Term and Seasonal Adequacy Assessments[1] developed by ENTSO-E under Article 8 of the Risk Preparedness Regulation and as approved by the Agency for the Cooperation of Energy Regulators (ACER) on 6 March 2020. Seasonal Outlook studies published prior to 2020 followed a different methodology (deterministic approach).

The interconnected system is a crucial resource for wider system adequacy. ENTSO-E's Winter Outlook provides results for all ENTSO-E member systems. Data inputs and assumptions from neighbouring interconnected countries are also integrated into the modelling.

Coordination at the national, regional, and European levels

Cross-border cooperation and close coordination at all levels will be essential to ensure that the European power system maintains its balance between supply and demand this winter.

European level

- Exchange on risk preparedness plans via the Electricity Coordination Group and Gas Coordination Group;
- Winter Outlook and updates: updates to ENTSO-E's Winter Outlook are possible if significant changes affecting the European power system occur this winter;
- Following the Winter Outlook, the short-term adequacy (STA) process monitors the coming seven days in a rolling window to detect any adequacy issues at the cross-regional (pan-EU) level;

[1] https://eepublicdownloads.entsoe.eu/clean-documents/sdc-documents/seasonal/Methodology%20for%20Short-term%20and%20Seasonal%20Adequacy%20Assessment%20-%20ACER%20Decision%2008-2020%20on%20the%20RPR8%20.pdf

- ENTSO-E ensures weekly operational coordination between all interconnected TSOs and regional coordination centres (RCCs) to enable swift communication and alignment – when necessary – for operational processes;
- Communication between ENTSO-E and the European Network of Transmission System Operators for Gas (ENTSOG) to align assumptions and messages between the Winter Outlook for gas and electricity.

Regional level

- Following the cross-regional STA process, a regional STA process is implemented if any scarcity situations are detected. This process is managed by RCCs with the participation of the relevant TSOs, to coordinate the proposal for adequacy remedial actions at the regional level;
- TSOs and RCCs will coordinate throughout the winter to maximise cross-border capacities regionally through an established operational planning coordination (OPC) process.

National level

- TSOs conducted national adequacy studies in parallel to the ENTSO-E Winter Outlook, which might use different sensitivities or focus on extreme cases where multiple stress elements coincide. National studies can also consider more detailed constraints, such as internal transmission bottlenecks.
- Each member state has developed a dedicated Risk Preparedness Plan, which includes mitigation measures. The member states set up coordination with governments, national regulatory authorities (NRAs) and key stakeholders to operate these mitigation measures.

3. Overview of the power system in winter 2025–2026

Generation overview

Generation capacity evolution

Compared to the previous winter (see Figure 1), installed renewable capacity in Europe has increased by roughly 60 GW. Most of this increase comes from the rooftop, industrial, and utility-scale photovoltaic panels throughout Europe and installation of wind turbines , with total installed capacity increasing by 15% (solar) and 5% (wind) over one year. Installed photovoltaic production has increased by 50 GW across Europe, whereas wind capacity has increased by 14 GW.

Battery energy storage system capacity is rapidly increasing (by over 150% compared to the previous winter) but remains very small in scale, with 28 GW of installed capacity throughout Europe.

High-carbon-footprint power units such as hard coal, lignite, and oil have seen a combined decrease of installed capacity by nearly 12 GW (- 10%). On the other hand, the more flexible gas power plants are slightly expanding, with an installed capacity increase of 4 GW compared to the previous winter. Nuclear capacity has recorded a slight net decrease of 1 GW.

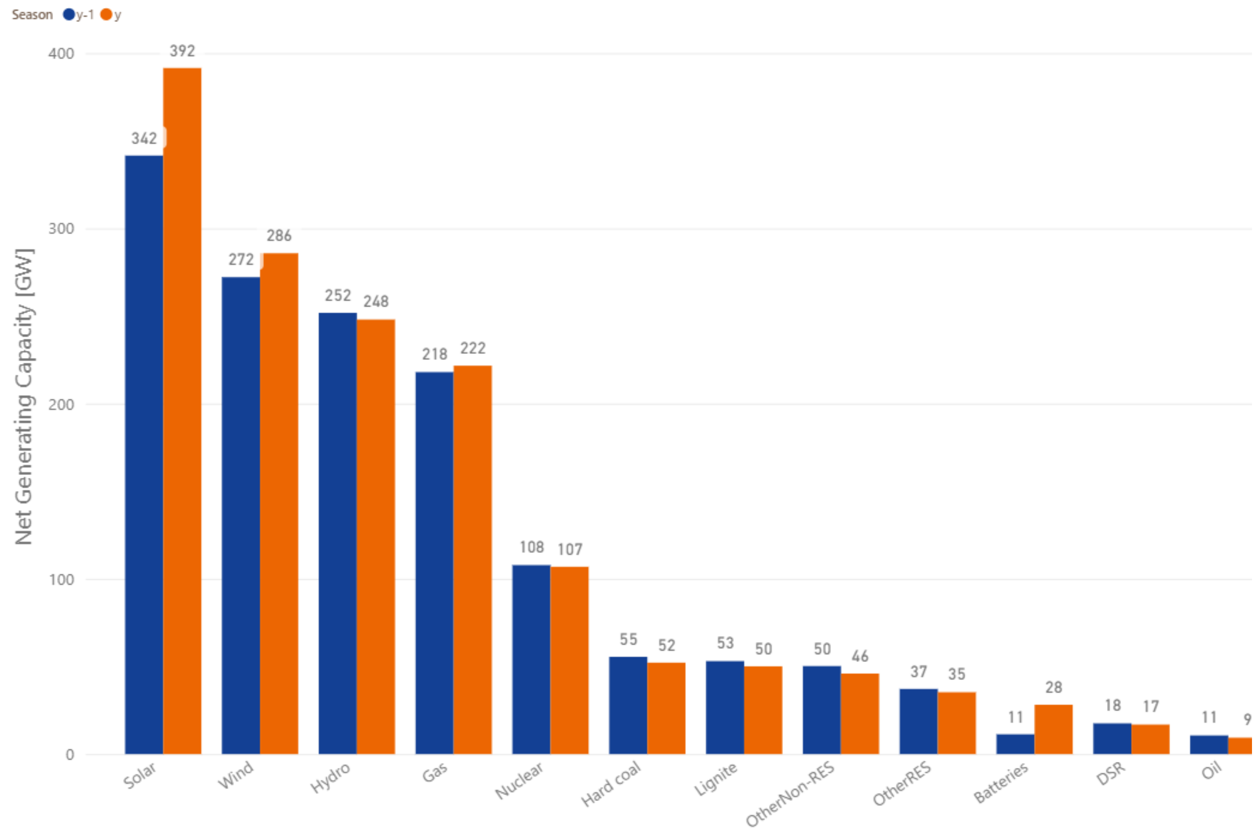


Figure 1. Generation capacity change over one year: Winter Outlook 2025–2026 (orange) vs. Winter Outlook 2024–2025 (blue).[2] [3] [4]

Figure 2 shows that generation capacity in Europe is increasing during winter 2025–2026, mainly due to the expansion in renewables capacity generation. Thermal generation is decreasing due to the decommissioning of hard coal and lignite plants, which is not balanced out by increased gas-fired power plant generation capacity. However, in some exceptional cases, decommissioned units might be contracted as non-market resources to support adequacy or under other non-market schemes to provide system services. Figure 2 presents the study zones with sizeable changes in this winter period.

[2] *TR and MD are included in the data for this visual. UA is excluded.*

[3] *While UK solar is missing in the data used for the figure, solar production is considered in the simulation by lowering the load by the hourly value of solar production.*

[4] *In past editions, the "Electrolysers" technology label comprised both "Power to heat" and "Electrolyser". Therefore, the graph only shows this year's values (orange) for "Power to heat" and "Electrolyser", and last year's values (blue) for "Electrolysers".*

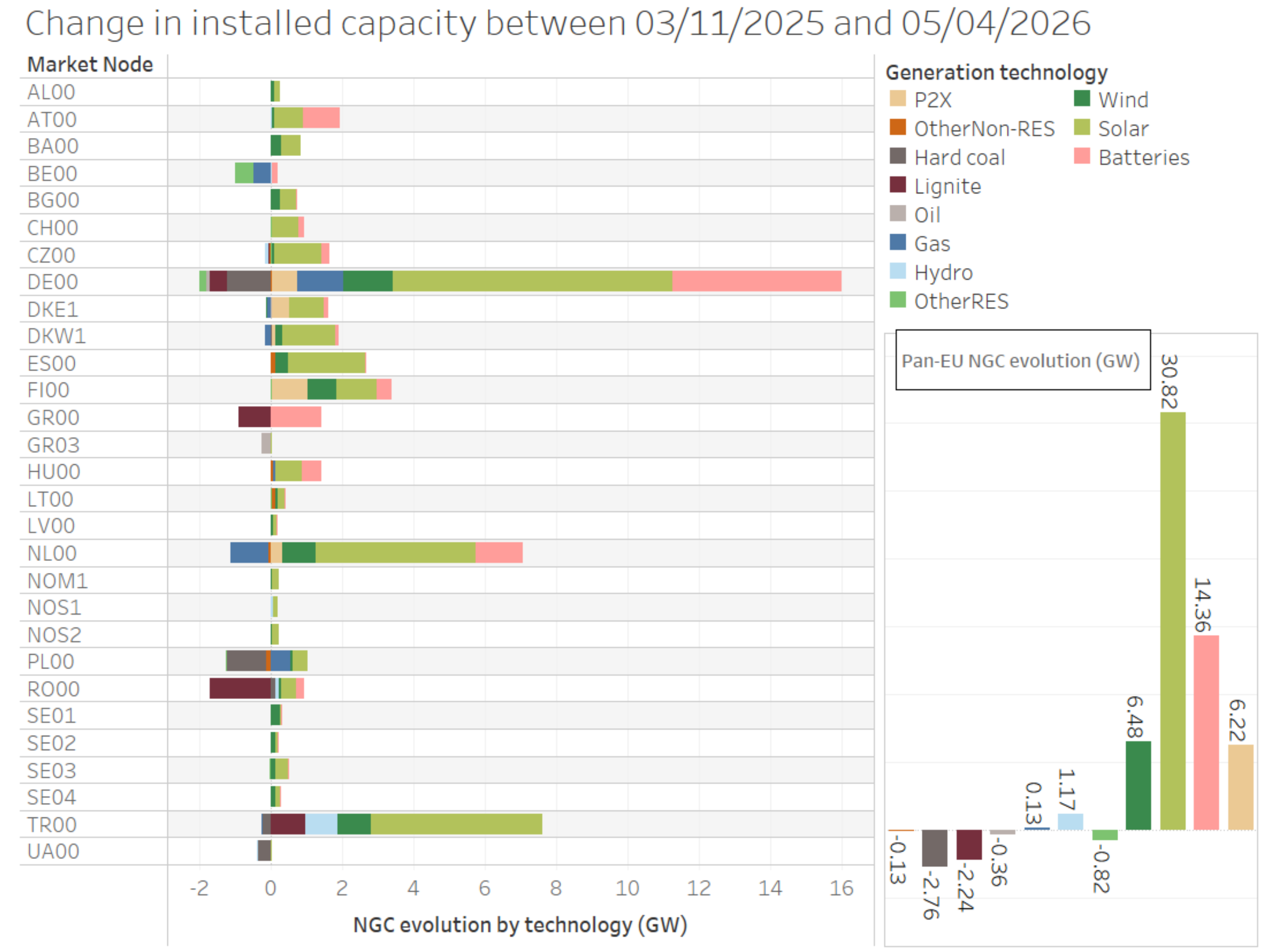


Figure 2. Sizeable capacity evolution in winter 2025–2026. P2X includes both the production of heat (boilers/heat pumps) and H_2 (electrolysers).

Figure 3 shows the net generating capacity compared to the highest expected demand for every European study zone. It shows that in high-renewable-generation scenarios ("all technologies"), all EU countries can cover their peak demand without imports. However, considering conventional generation unavailability, such as forced outages and planned unavailability, some zones, such as Belgium, Denmark, Ireland, Finland, and Germany, might rely on imports in low renewable generation scenarios ("flexible technologies").

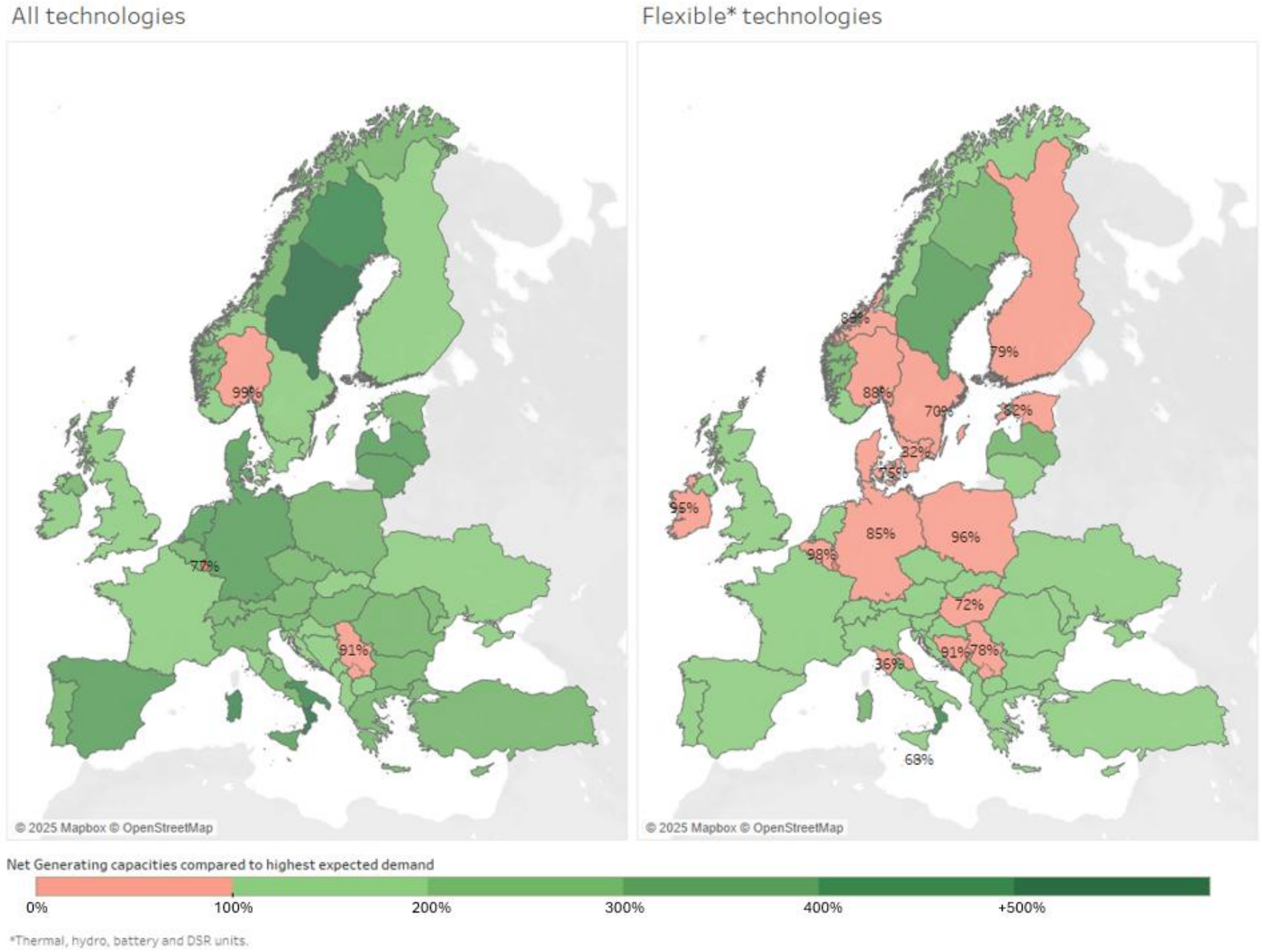


Figure 3. Net generating capacity overview: Comparison with the highest expected demand.[5]

Figure 4 details the generation capacity mix at the beginning of winter 2025–2026 for each study zone for the reference scenario. The date considered in Figure 4 is 3 November 2025, meaning that any unit commissioned beyond that date is not included in the visual (but is still included in the simulation). Similarly, a unit decommissioned after that date is included in the visual.

For each study zone, the small black square indicates the highest expected demand, stated as a percentage of each zone's net generating capacity (NGC). For example, in NOS1, peak demand exceeds NGC by 1% and requires interconnections to meet peak demand. While most countries are expected to meet peak demand with their NGC, LUG1, and RS00 are also expected to see peak demand exceeding NGC.

Some countries or study zones have a high RES NGC combined with a relatively low thermal NGC (e.g. Luxembourg, Central Italy, Denmark, Southern Sweden, and Germany). In periods of low RES production, these countries will rely on imports to cover their peak loads.

---

[5] *The highest expected demand is calculated as the highest 95th percentile based on hourly demand data.*

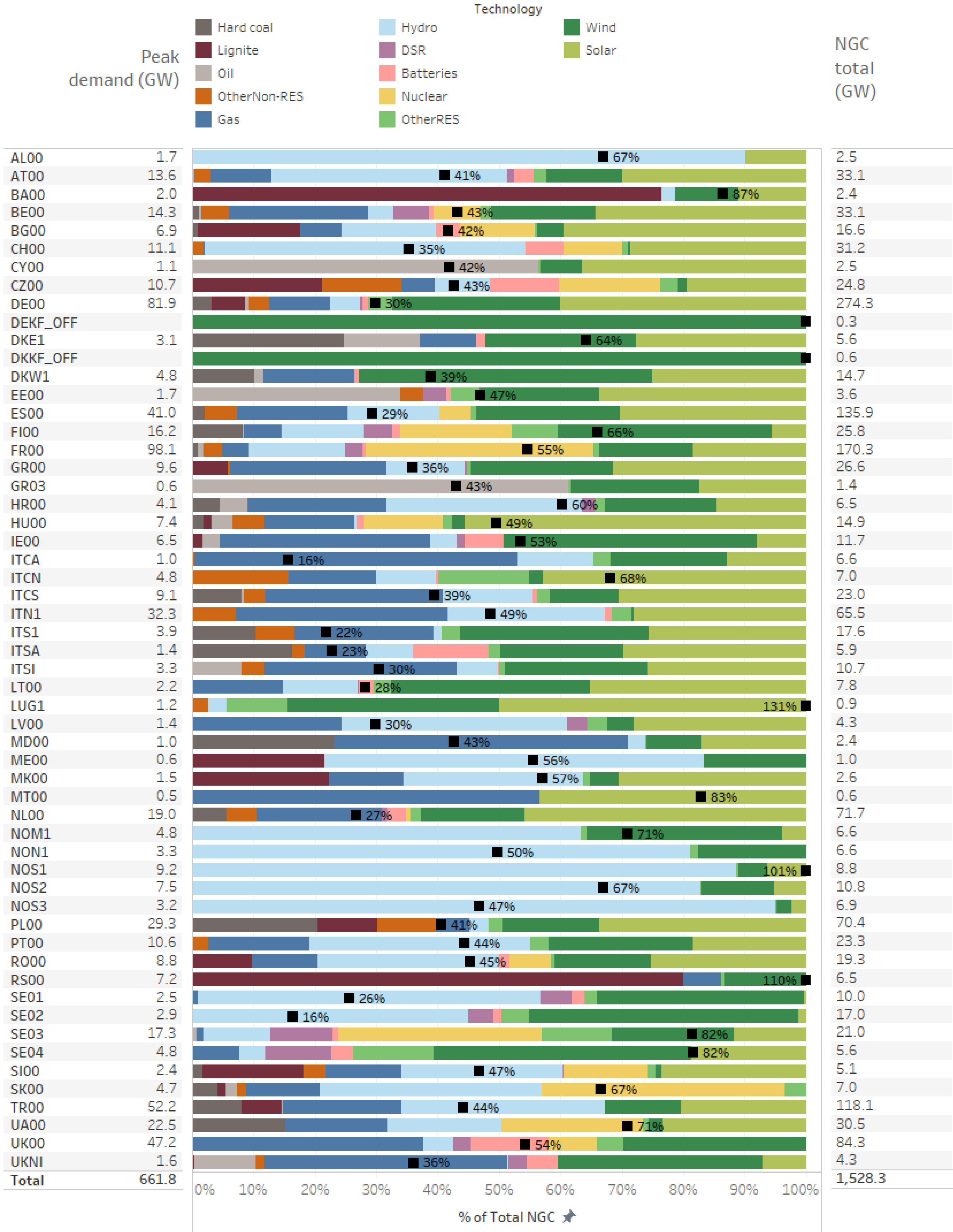


Figure 4. Generation capacity mix at the beginning of winter 2025–2026 for each study zone.

Non-market resources are dispatchable units that can be activated in the event of a lack of supply. They are available in nine study zones in the EU (Figure 5). Non-market resources can play a critical role in addressing adequacy challenges, especially in zones with low interconnection capacity, such as Ireland and Malta. Germany has by far the highest share of non-market resource capacity.

This report assesses whether these non-market resources can address identified adequacy issues for the coming winter.

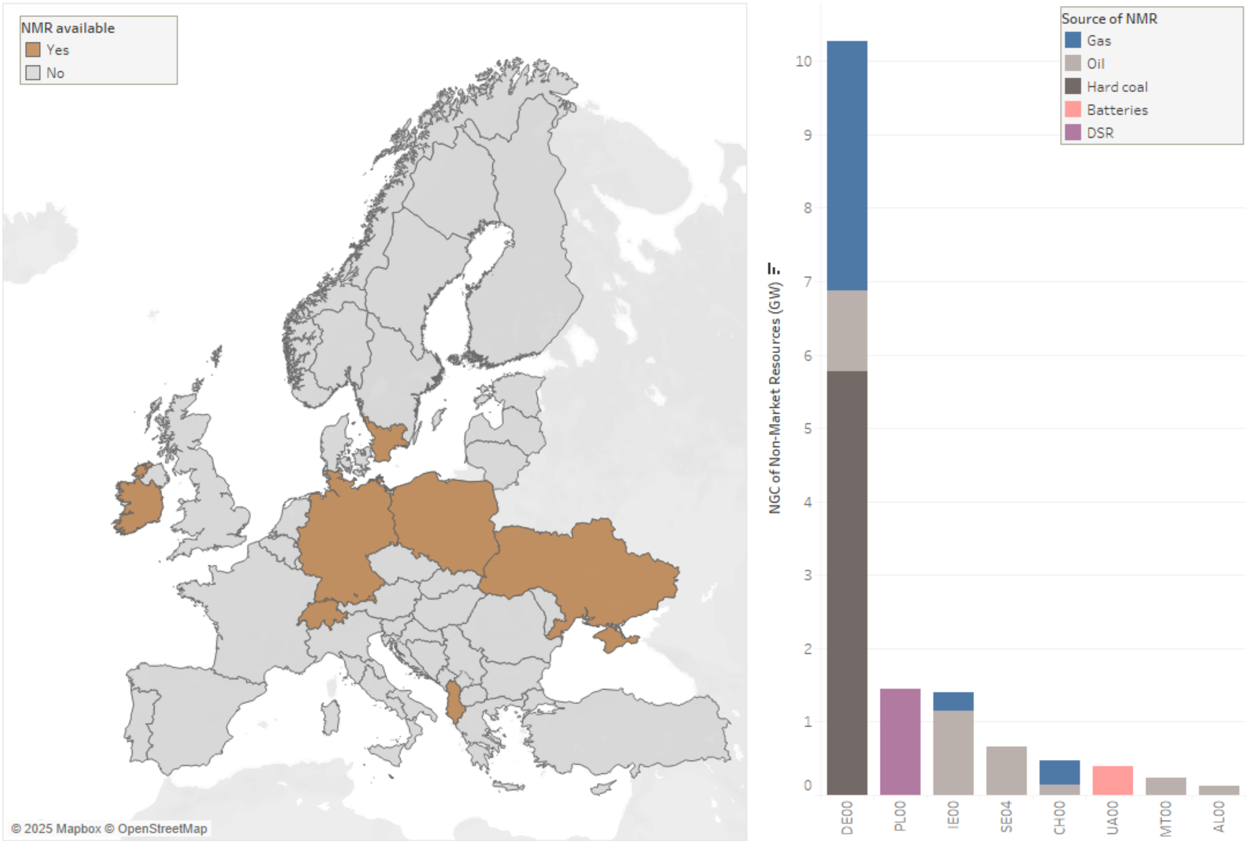


Figure 5. Non-market resources for coping with adequacy challenges in Europe.[6]

[6] *Parts of German non-market resources have a different primary purpose than coping with resource adequacy risks, such as grid stabilisation. In the event of adequacy issues in Germany, these may already be partly exhausted for their primary purpose.*

Planned unavailability of generation

Figure 6 shows the evolution of the planned unavailability of thermal and nuclear generation units throughout winter 2025–2026. The planned unavailability of generation units includes planned outages for maintenance and mothballing. Winter 2025–2026 shows a similar level of planned outages compared to the previous winter.

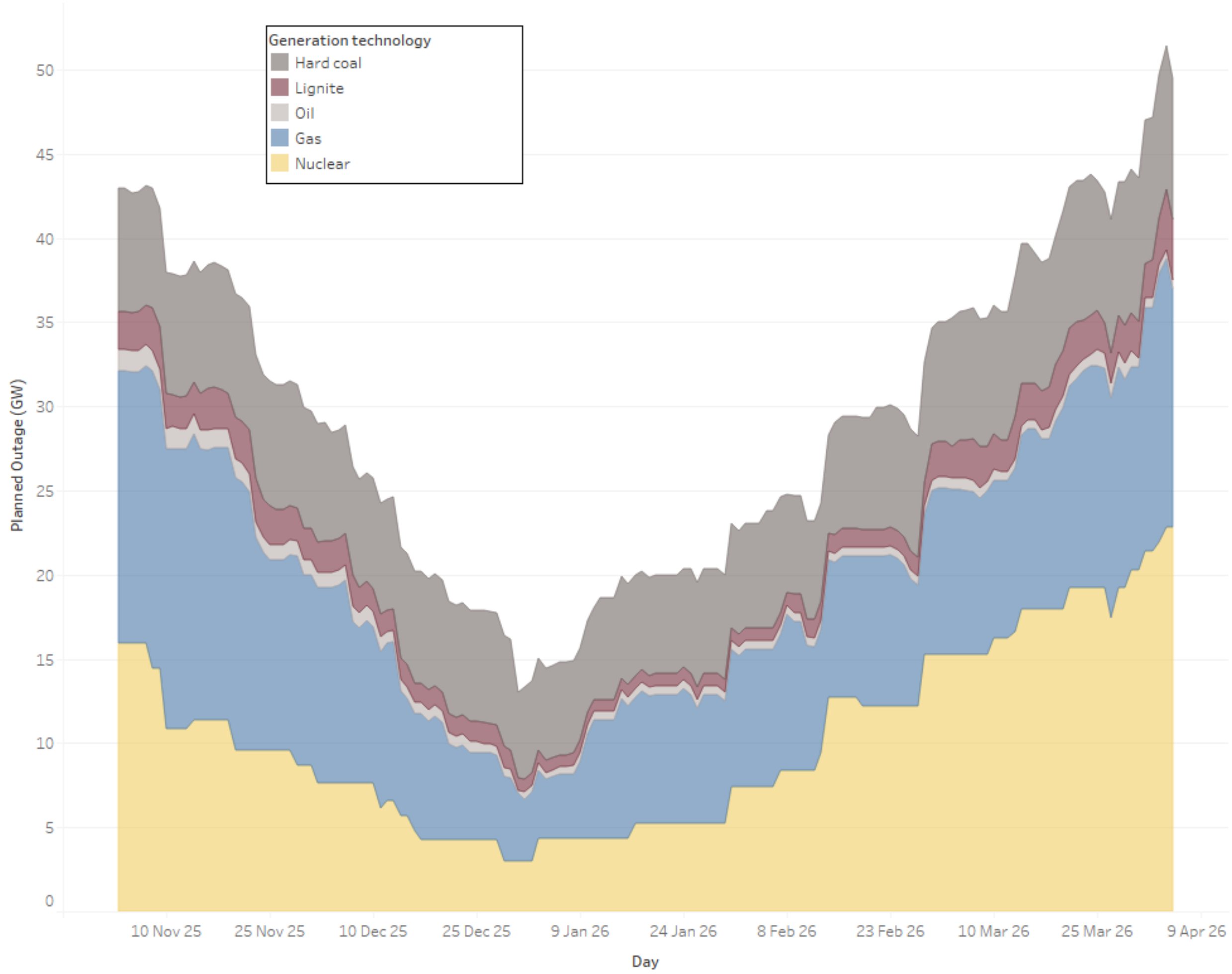


Figure 6. Planned unavailability of thermal generation units.

Figure 7 depicts the weekly share of thermal NGC in planned outages within each study zone. As usual, most countries have minimal maintenance outages planned during the coldest winter period (January and February). However, some countries show higher-than-usual maintenance outage planning, such as Lithuania (LT00), Malta (MT00), Switzerland (CH00) and certain study zones in Italy (e.g. ITCN, ITCS, and ITSI).

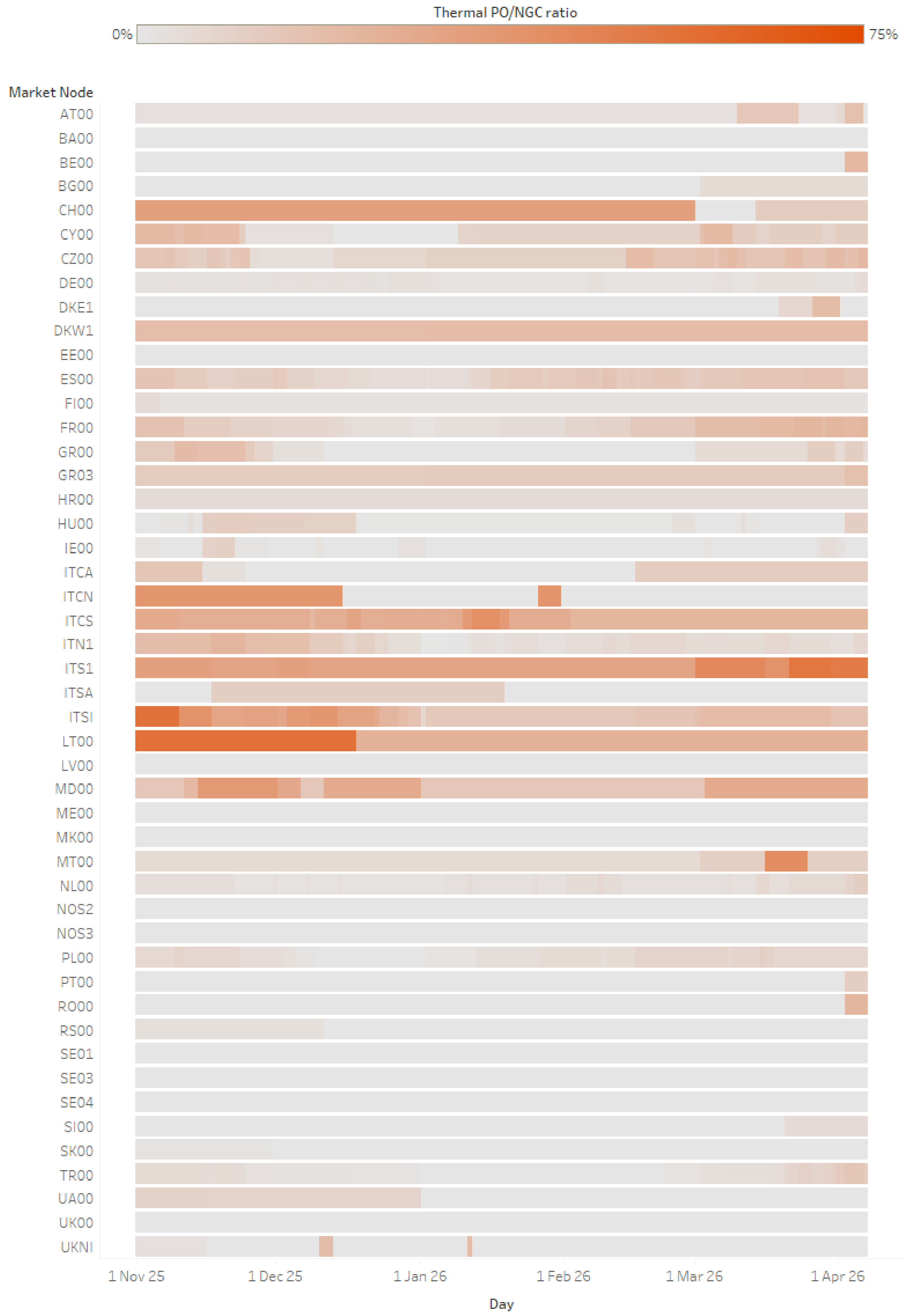


Figure 7. Weekly distribution of thermal planned outage (PO) relative to thermal NGC.

Hydro availability

Figure 8 shows hydro storage level expectations compared to previous winters. Total expected hydro storage levels in November 2025 are well above past levels (2022–2024).

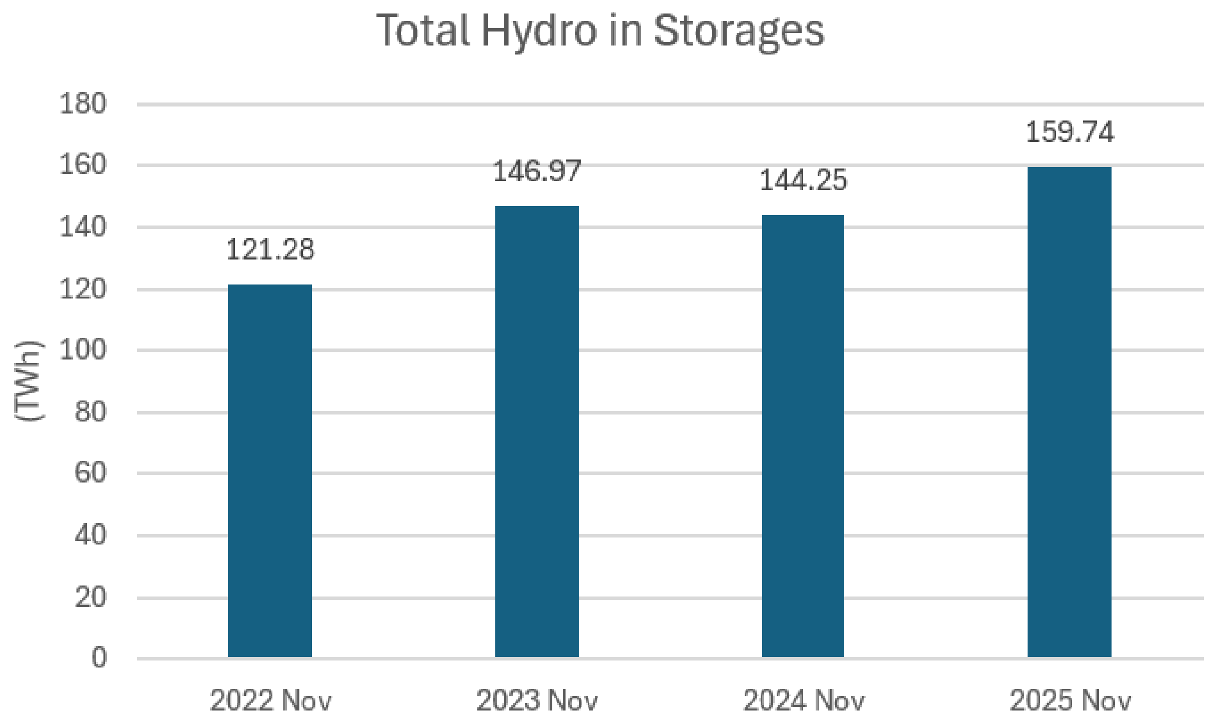


Figure 8. Total hydro storage availability in November in Europe (including UK and excluding UA, TR and MD).

Demand overview

Overall EU electricity demand is expected to be slightly higher (2.9%) than the previous year (Figure 9), but comparable with that of 2023–2024.

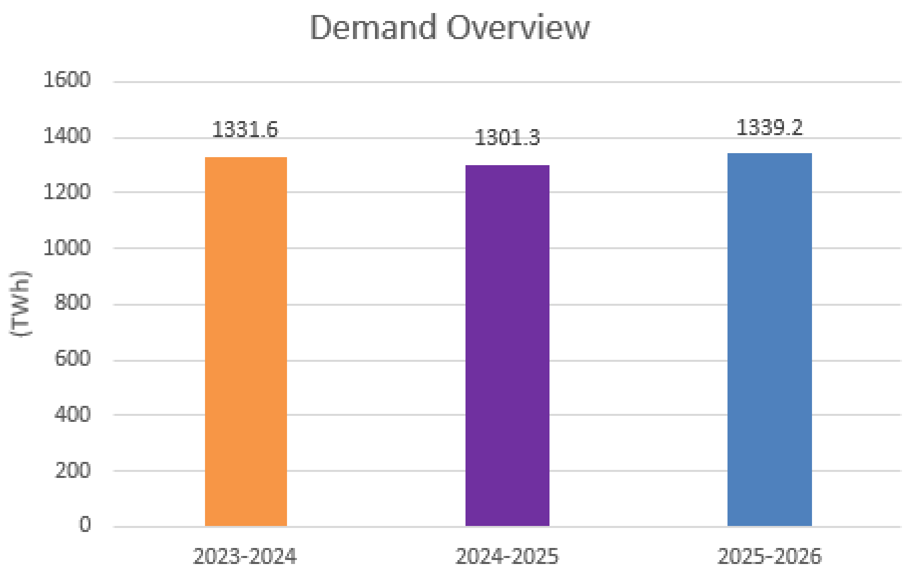


Figure 9. Demand overview: Total demand in winter 2023–2024 (orange), winter 2024–2025 (purple) and winter 2025–2026 (blue). Demand scope includes all of Europe (including the UK and excluding UA, MD, and TR).

Figure 10 shows a heat map by study zone, comparing the expected consumption in each week with the highest expected weekly consumption in winter 2025–2026. The darker shades indicate high expected consumption compared to the highest expected consumption. Typically, January and February show the highest weekly consumption. The workday consumption patterns per study zone are illustrated in Figure 11, where the average demand is plotted relative to the highest average demand in winter 2025–2026. The peak demand in Europe is mostly concentrated during the day.

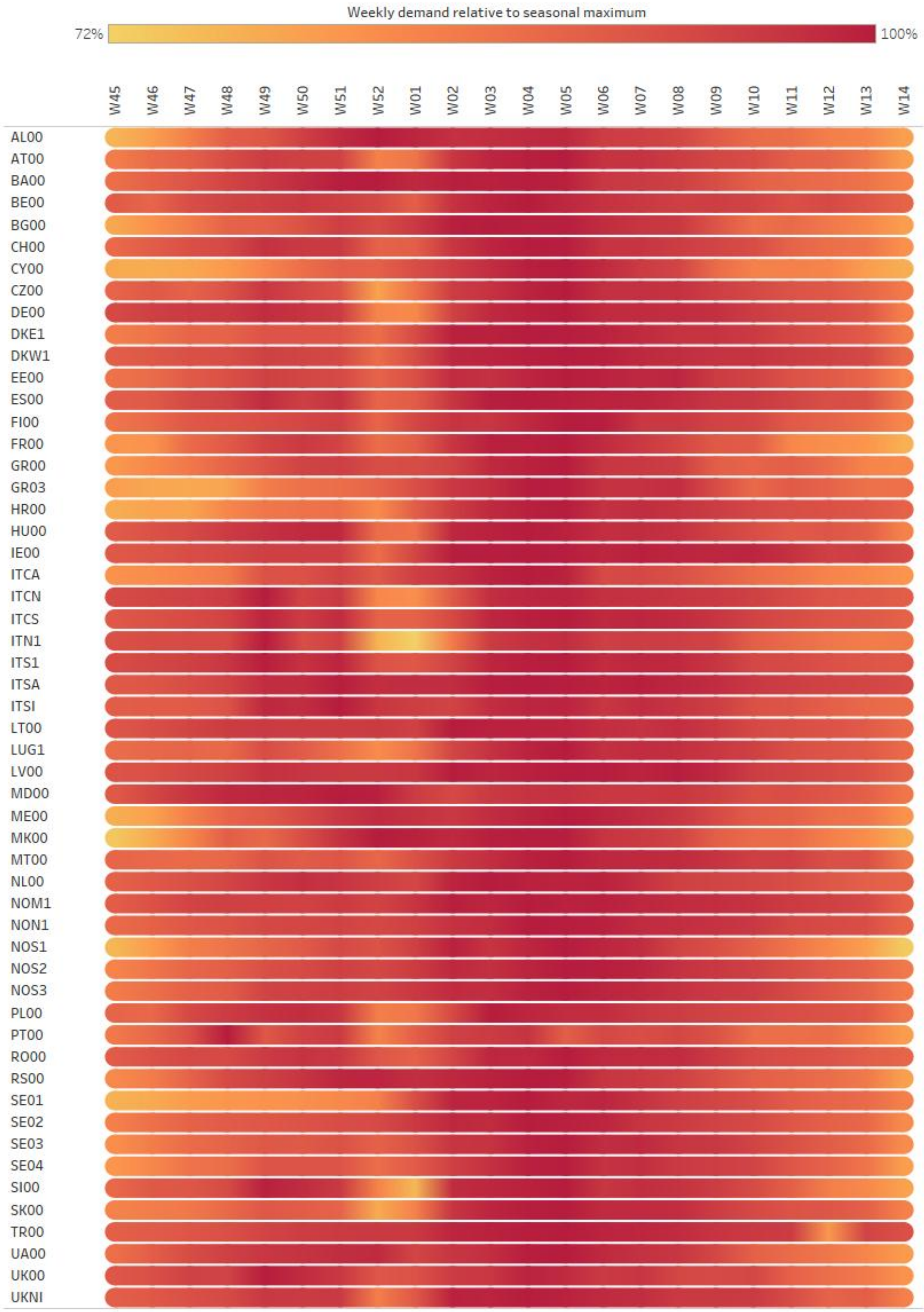


Figure 10. Demand overview: Evolution over winter 2025–2026.

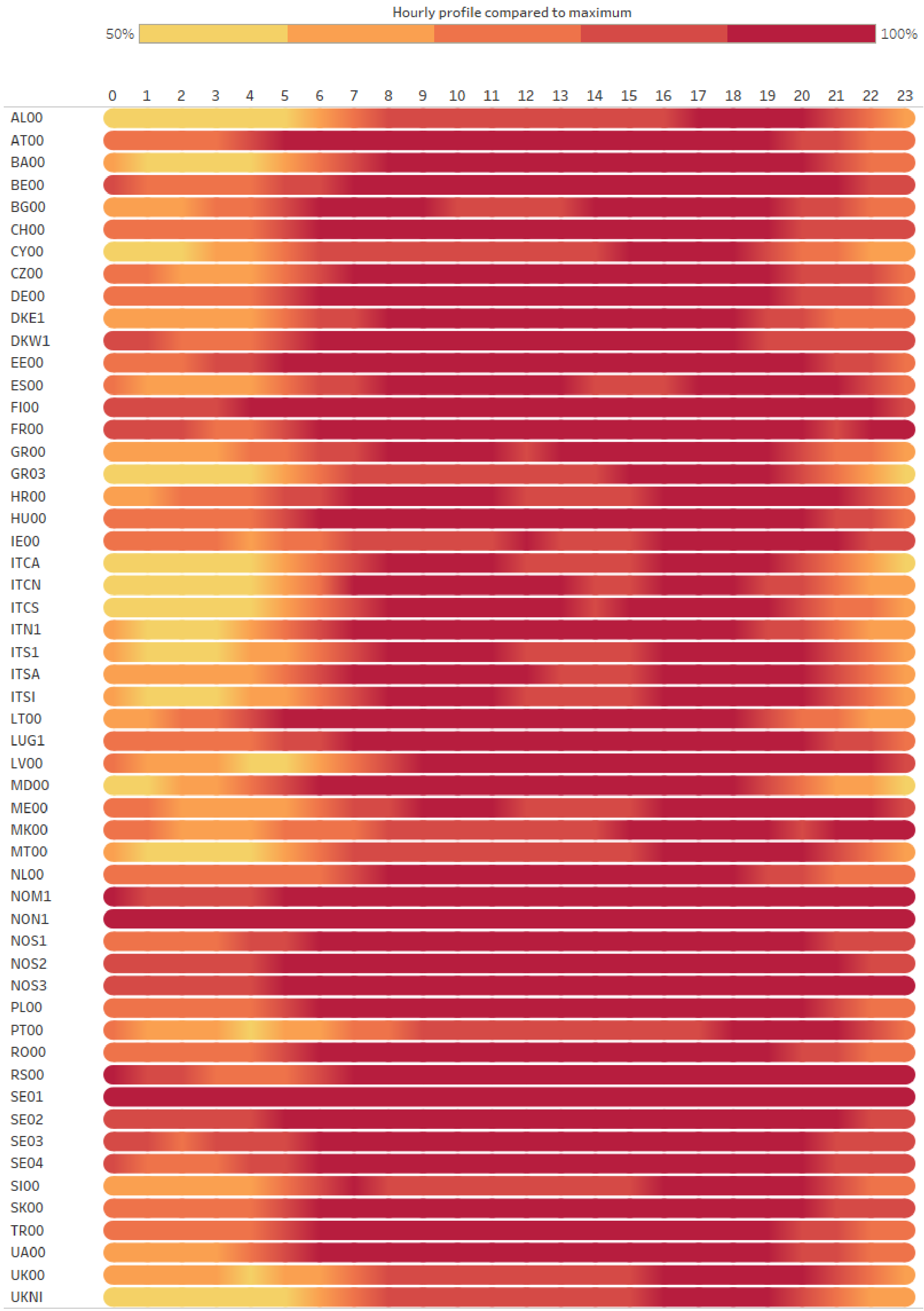


Figure 11. Demand profile overview during Mondays–Fridays in winter 2025–2026.[7]

---

[7] *The Coordinated Universal Time (UTC) convention was used.*

Network overview

Figure 12 shows the ratio of the lowest import capacity (of the studied period) to the highest expected demand (95th percentile) for the coming winter. It indicates the extent to which systems might be capable of relying on imports from abroad during supply scarcity moments (if generation abroad is available). The lighter the shade of purple, the more interconnection capacity of the market node compared to its own load.

The evaluation of import capacities considers the planned unavailability of grid elements, although additional unplanned outages might further constrain import capacities. Furthermore, import capacities with non-explicitly modelled systems are not considered in the figure, but their contribution is assessed in adequacy simulations.

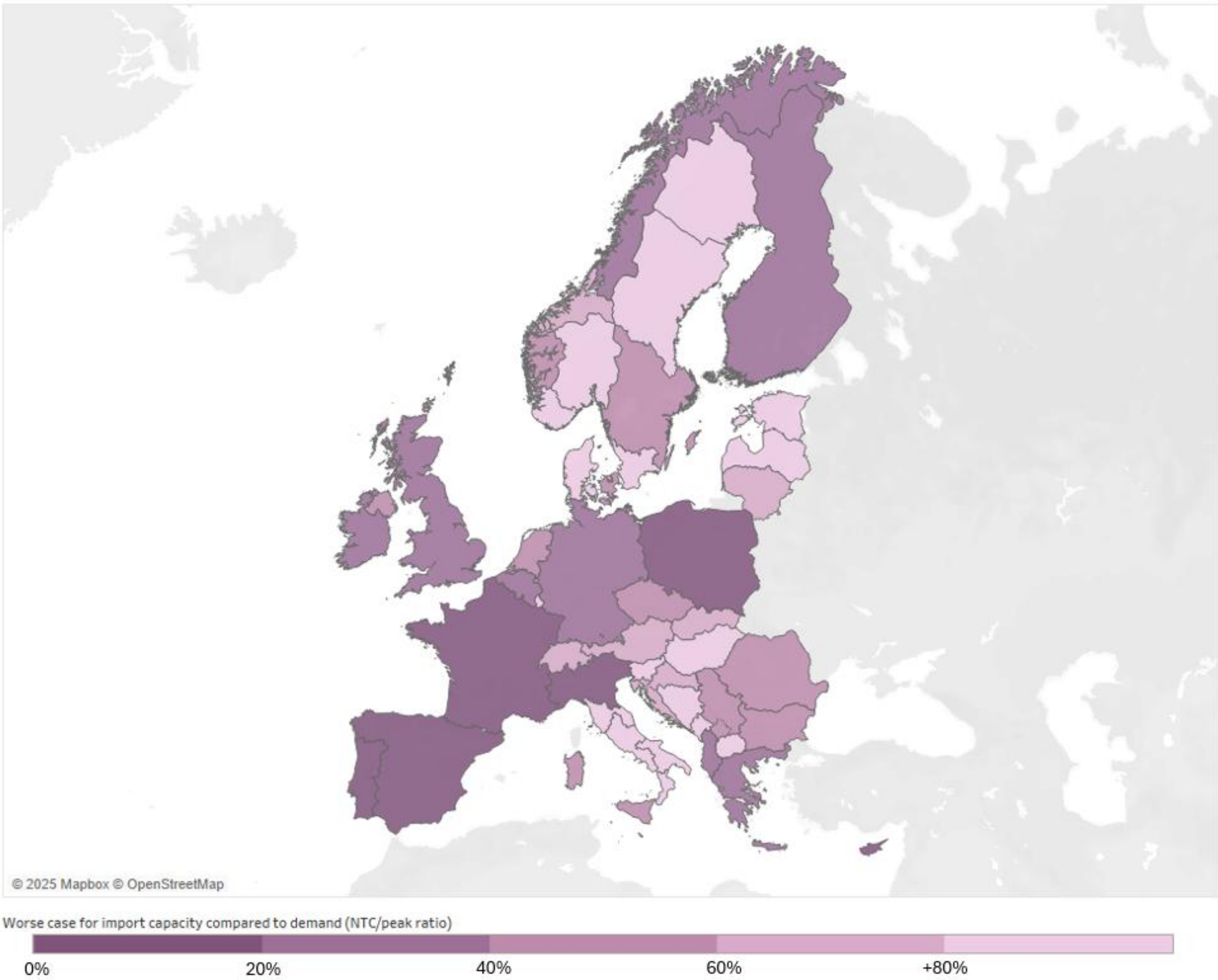


Figure 12. Import capacities per study zone: Ratio between lowest import capacity and highest expected demand.[8]

[8] *Ratios above 100% are also represented in the lightest shade of the scale.*

4. Adequacy situation and gas need during winter 2025–2026

Reference scenario

The adequacy situation during winter 2025–2026 is assessed using a two-step approach. In the first step, adequacy under normal market operation conditions is evaluated. In the second step, non-market resources – such as strategic reserves – are included to assess their sufficiency to solve the risks identified in the previous step. Non-market resources can be activated to address structural supply shortages in the market.

Figure 13 provides an overview of the expected energy not served (EENS) and the presence of adequacy risk for each country for both steps.

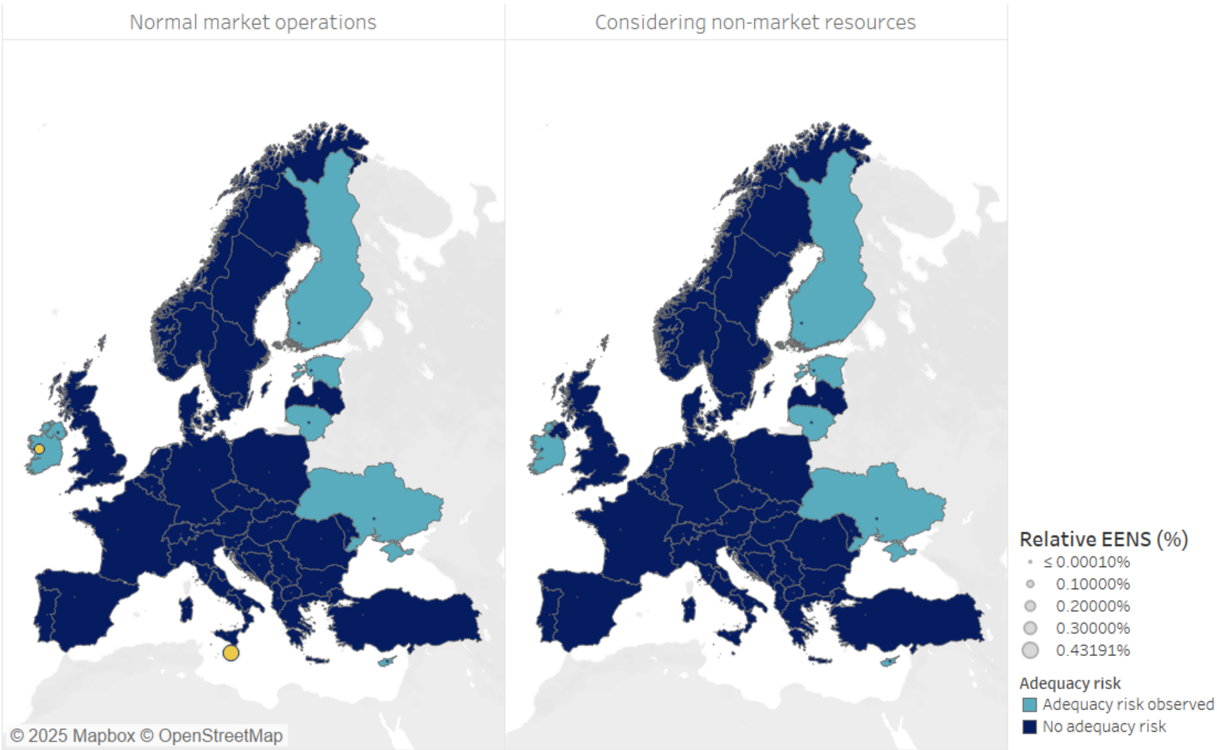
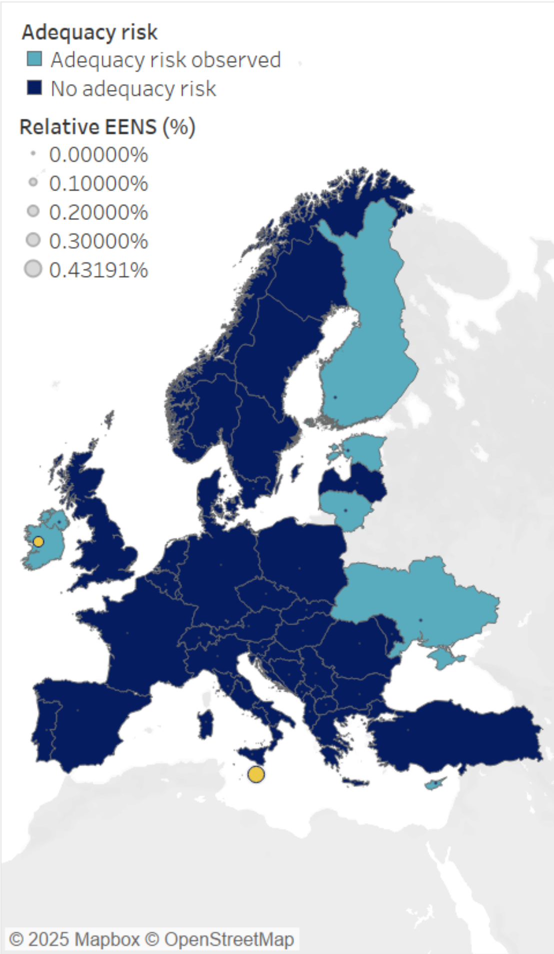


Figure 13. Adequacy overview.

Focus on adequacy under normal market conditions

Under normal market conditions, no adequacy risk is identified for most countries (Figure 14). Risks are present in Cyprus (CY00), Ireland (IE00), and Malta (MT00), which have limited or no interconnection to the European continental network. Traces of EENS and adequacy risk are also visible for Estonia (EE00), Finland (FI00), Lithuania (LT00), Northern Ireland (UKNI) and Ukraine (UA00).



CY00	**EENS**: 0.06831 GWh (**0.00344%** of Seasonal Consumption) **99th percentile ENS:** 0.76395 GWh (**0.03852%** of Seasonal Consumption) **LOLE:** 1.3 h
EE00	**EENS**: 0.01554 GWh (**0.00038%** of Seasonal Consumption) **99th percentile ENS:** 0.05237 GWh (**0.00126%** of Seasonal Consumption) **LOLE:** 0.1 h
FI00	**EENS**: 0.08570 GWh (**0.00020%** of Seasonal Consumption) **99th percentile ENS:** 1.76612 GWh (**0.00418%** of Seasonal Consumption) **LOLE:** 0.2 h
IE00	**EENS**: 29.94459 GWh (**0.17462%** of Seasonal Consumption) **99th percentile ENS:** 109.47228 GWh (**0.63840%** of Seasonal Consumption) **LOLE:** 65.5 h
LT00	**EENS**: 0.03471 GWh (**0.00061%** of Seasonal Consumption) **99th percentile ENS:** 0.26404 GWh (**0.00465%** of Seasonal Consumption) **LOLE:** 0.1 h
MT00	**EENS**: 5.47573 GWh (**0.43191%** of Seasonal Consumption) **99th percentile ENS:** 13.99927 GWh (**1.10422%** of Seasonal Consumption) **LOLE:** 119.1 h
UA00	**EENS**: 0.00686 GWh (**0.00001%** of Seasonal Consumption) **99th percentile ENS:** 0.09982 GWh (**0.00019%** of Seasonal Consumption) **LOLE:** 0.0 h
UKNI	**EENS**: 0.00507 GWh (**0.00015%** of Seasonal Consumption) **99th percentile ENS:** 0.11731 GWh (**0.00338%** of Seasonal Consumption) **LOLE:** 0.1 h

Figure 14. Adequacy risk overview under normal market conditions.

The loss of load probability (LOLP) for winter 2025–2026 at the weekly level is detailed in Figure 15. No common pattern can be observed as all systems with risks are rather distant from each other, and system-specific conditions might cause local adequacy issues.

Cyprus (CY00) might face risks in the event of adverse weather conditions combined with unplanned outages. The Cypriot system has no interconnection to other power systems and must therefore rely on domestic supply.

Ireland (IE00) is marked with adequacy risks throughout winter 2025–2026, with an expected peak in March 2026. While generation capacity has increased in the past year, the system could enter an alert state at times, most likely during periods of low wind and low interconnector imports.

The Maltese (MT00) system might face risks starting in early 2026. Based on careful monitoring of adequacy every winter, Malta has implemented specially designed non-market resources that can be activated in the event of supply scarcity. The impact of these non-market resources is presented in the following section.

The Finnish (FI00), Estonian (EE00), Northern Irish (UKNI) and Lithuanian (LT00) systems face minor risks in winter 2025–2026, suggesting that supply margins in their system are low. This means that electricity consumers might be affected by a combination of extreme weather conditions or interconnection outages.

In Finland, the power system is increasingly dominated by wind power generation, and the reliability of domestic power generation and interconnectors is crucial during cold, calm days.

The forecast for Ukraine (UA00) shows limited adequacy risks this winter. However, it is important to note that this analysis does not cover any disruptive failures of power system elements caused by actions due to the ongoing war. Therefore, the forecasted situation is subject to change at any time.

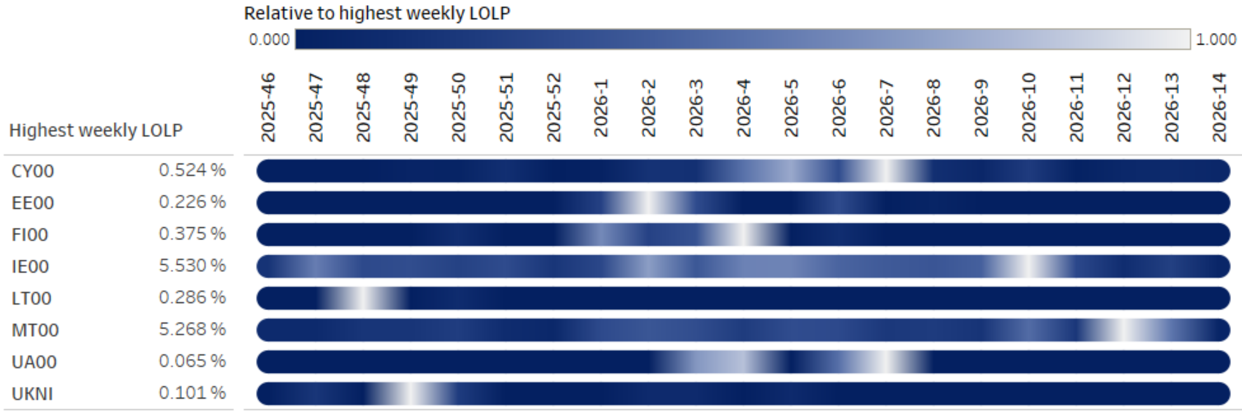
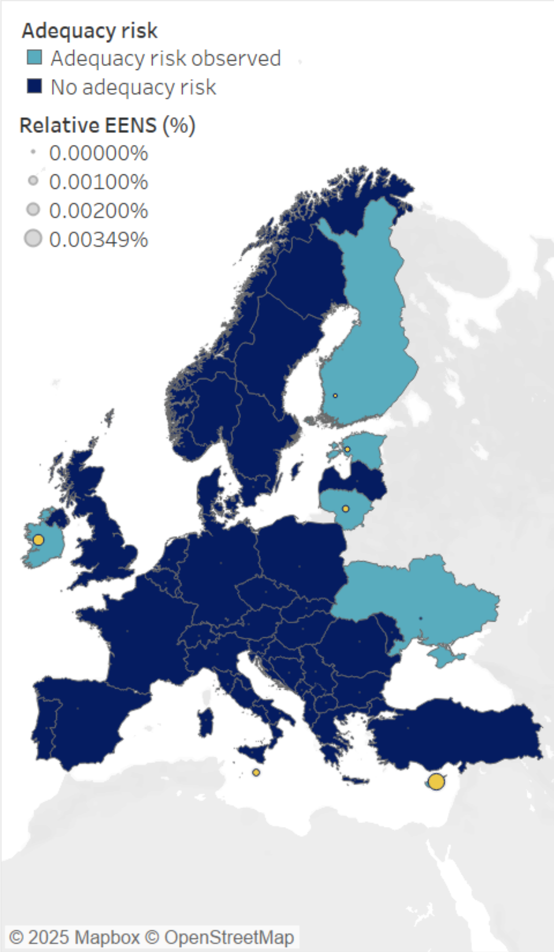


Figure 15. Adequacy weekly insights under normal market conditions.

Focus on non-market resources

Adequacy risks in Malta and Ireland are significantly reduced compared to normal market conditions, with only minimal residual risks remaining due to their reliance on dedicated non-market resources (cf. Figure 5). The activation of these resources can depend on the existing legal frameworks.[9]

Figure 16 presents the adequacy conditions with non-market resources.



CY00	**EENS**: 0.06922 GWh (**0.00349%** of Seasonal Consumption) **99th percentile ENS:** 0.78201 GWh (**0.03943%** of Seasonal Consumption) **LOLE:** 1.374 h
EE00	**EENS**: 0.01554 GWh (**0.00038%** of Seasonal Consumption) **99th percentile ENS:** 0.05237 GWh (**0.00126%** of Seasonal Consumption) **LOLE:** 0.084 h
FI00	**EENS**: 0.08572 GWh (**0.00020%** of Seasonal Consumption) **99th percentile ENS:** 1.76612 GWh (**0.00418%** of Seasonal Consumption) **LOLE:** 0.174 h
IE00	**EENS**: 0.26109 GWh (**0.00152%** of Seasonal Consumption) **99th percentile ENS:** 4.98989 GWh (**0.02910%** of Seasonal Consumption) **LOLE:** 0.868 h
LT00	**EENS**: 0.03366 GWh (**0.00059%** of Seasonal Consumption) **99th percentile ENS:** 0.26404 GWh (**0.00465%** of Seasonal Consumption) **LOLE:** 0.145 h
MT00	**EENS**: 0.00781 GWh (**0.00062%** of Seasonal Consumption) **99th percentile ENS:** 0.10955 GWh (**0.00864%** of Seasonal Consumption) **LOLE:** 0.511 h
UA00	**EENS**: 0.00686 GWh (**0.00001%** of Seasonal Consumption) **99th percentile ENS:** 0.09982 GWh (**0.00019%** of Seasonal Consumption) **LOLE:** 0.029 h

Figure 16. Adequacy risk overview considering non-market resources.

The activation of non-market resources significantly reduces LOLP in Ireland and Malta (Figure 17) For Northern Ireland, EENS is avoided completely. The weekly LOLP remains generally elevated in Cyprus in January and February 2026.

---

[9] *The assessment considers pan-European cooperation when activating non-market resources, which means that non-market resources in one country are also considered in another during scarcity (but also considering network limitations). The actual activation of non-market resources abroad might depend on the existing legal framework.*

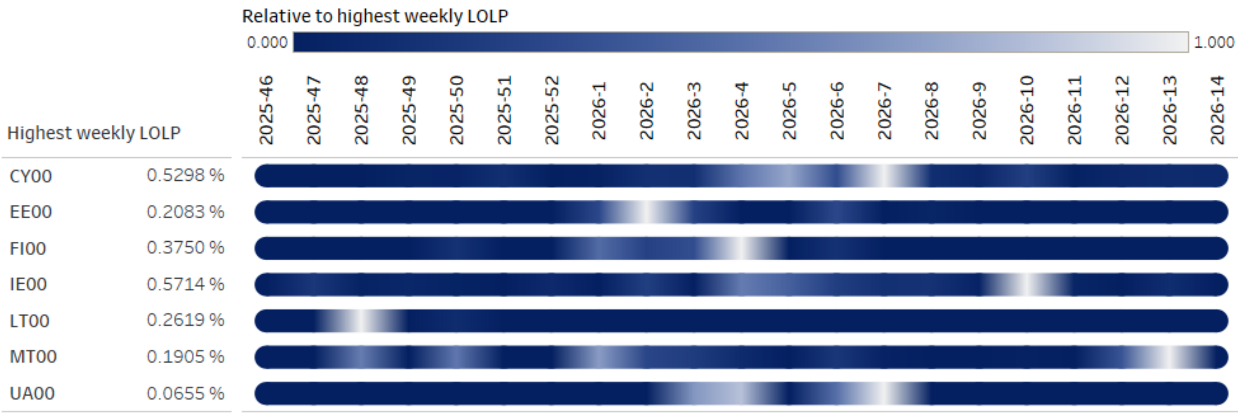


Figure 17. Adequacy weekly insights considering non-market resources.

Figure 18 shows the weekly LOLP and EENS, both under normal market operations (light blue) and considering non-market resources (dark blue). For study zones with higher ENS in normal market operations, spikes are balanced out (less drastic) when non-market resources are considered. As mentioned above, adequacy risks (LOLP and EENS) are significantly reduced in Ireland, Northern Ireland and Malta when non-market resources are considered.

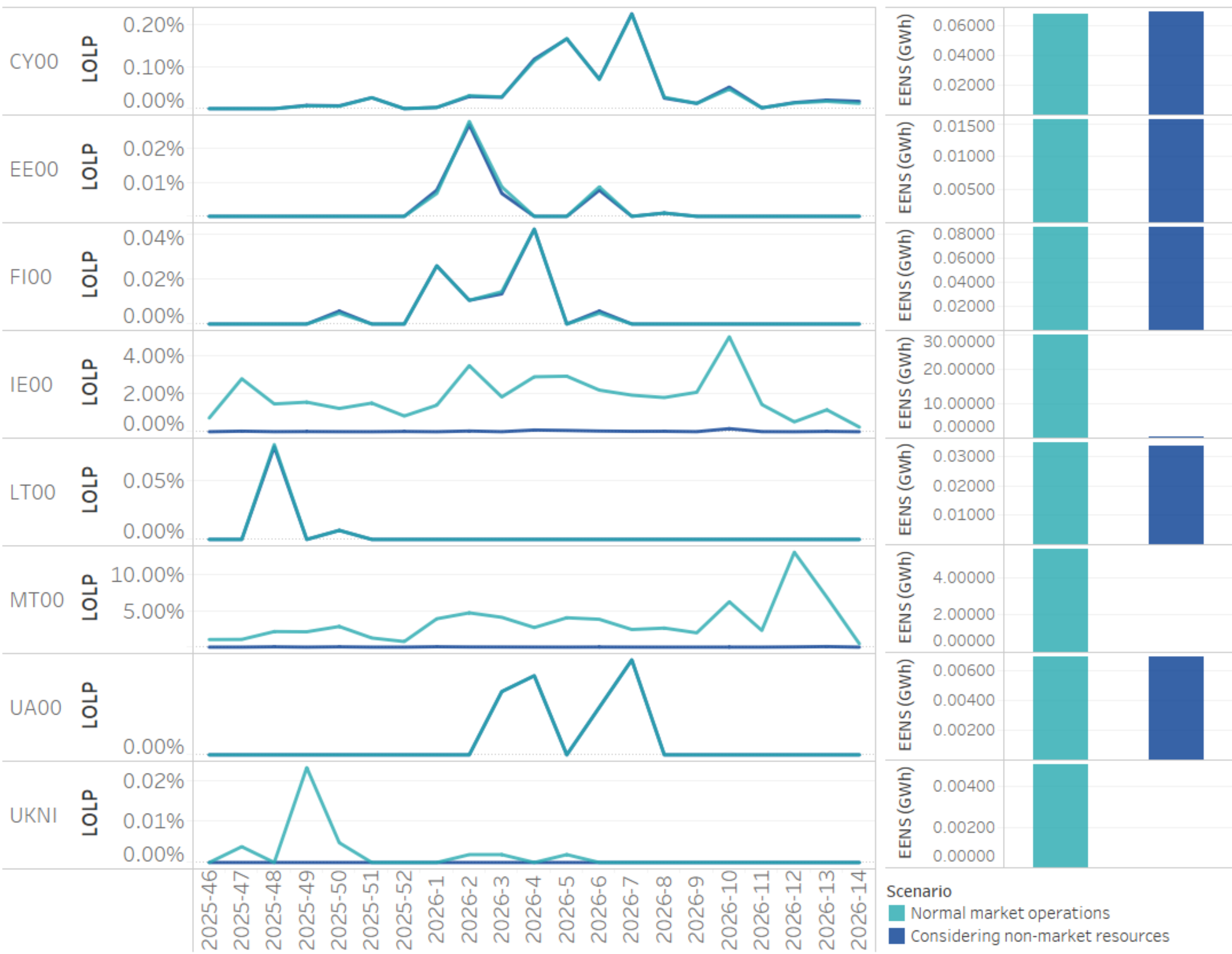


Figure 18. Detailed adequacy overview weekly LOLP and EENS.

Critical gas volume for winter 2025–2026

The situation in the European power system is much more certain for winter 2025–2026 than at the same time three years ago, in the middle of the European energy crisis. As in the previous winter, Europe has much greater assurance regarding fuel supply availability as supply routes have been diversified and alternative supplies identified by many actors. Furthermore, nuclear availability and hydro stocks are in much better shape compared to three years ago. Nevertheless, as in previous Winter Outlook assessments, an adequacy and critical gas volume (CGV) analysis has been performed to ensure awareness of the European power system. CGV projections consider the worst winter scenarios and inform electricity system adequacy. Actual volumes may already be higher, depending on ancillary service demand, additional new unavailability, and real market behaviour, with some gas units not being last in the merit order. Figure 19 and Figure 20 illustrate the CGV analysis conducted for this winter.

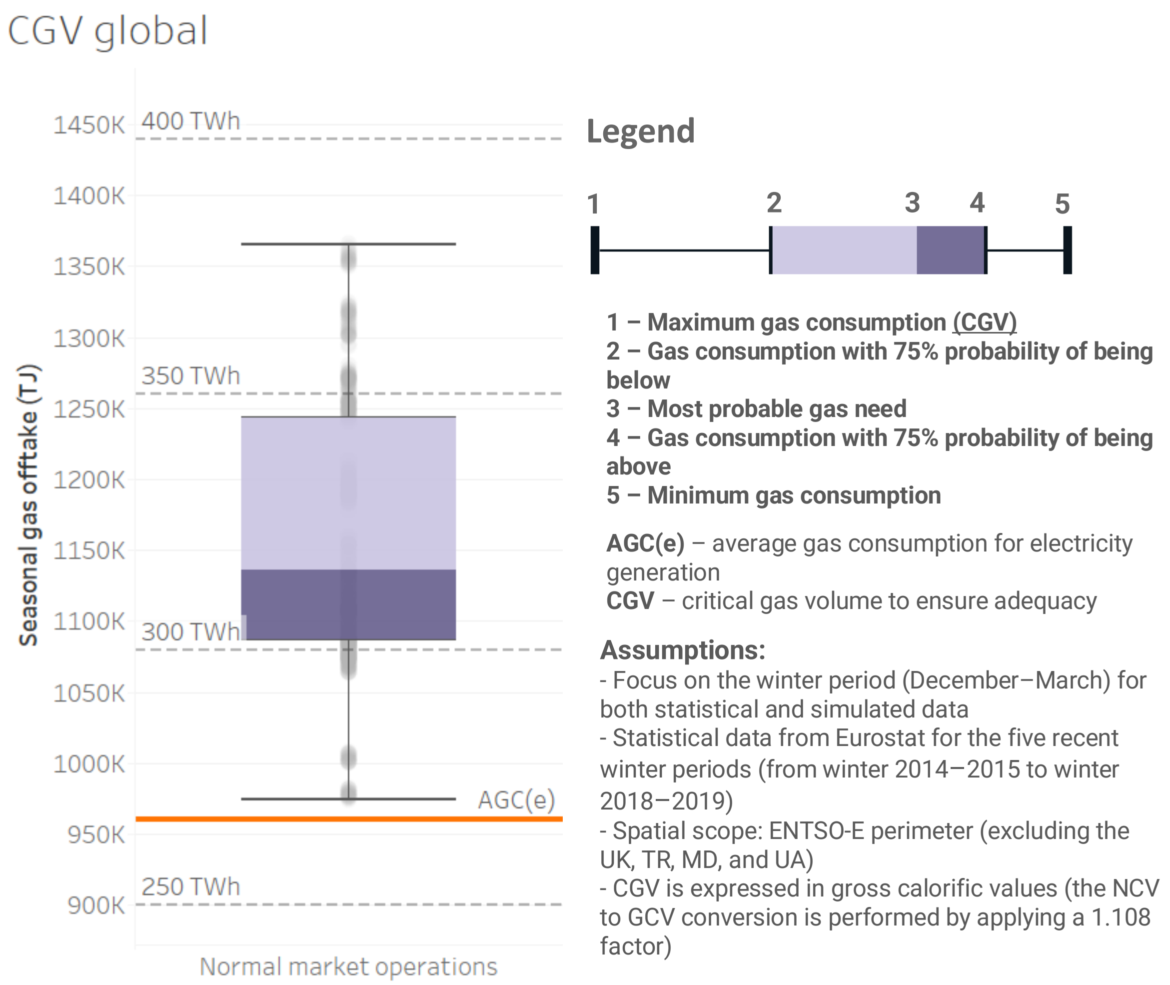


Figure 19. CGV analysis overview.

How to interpret the CGV chart

- Each grey dot represents a historical winter period of gas consumption for electricity generation. The significant differences between periods are primarily related to temperature and climate conditions but can also be influenced by the situation in the electricity market (prices, planned outages, changing generation fleet, etc.).
- The AGC(e) (orange line) represents the average gas consumption for electricity generation for five statistical years (winter 2014–2015 to winter 2018–2019).
- The maximum gas consumption corresponds to the necessary gas volume to ensure adequacy in the worst-case simulated weather condition scenario. This maximum is indicated as the CGV to ensure adequacy.
- The dark and light purple colours represent the range of simulation outcomes of gas volume necessary to ensure adequacy for a given year, depending on the climate conditions (the simulation uses 29 climate condition scenarios). There is a 50% probability of a given year being in this range.

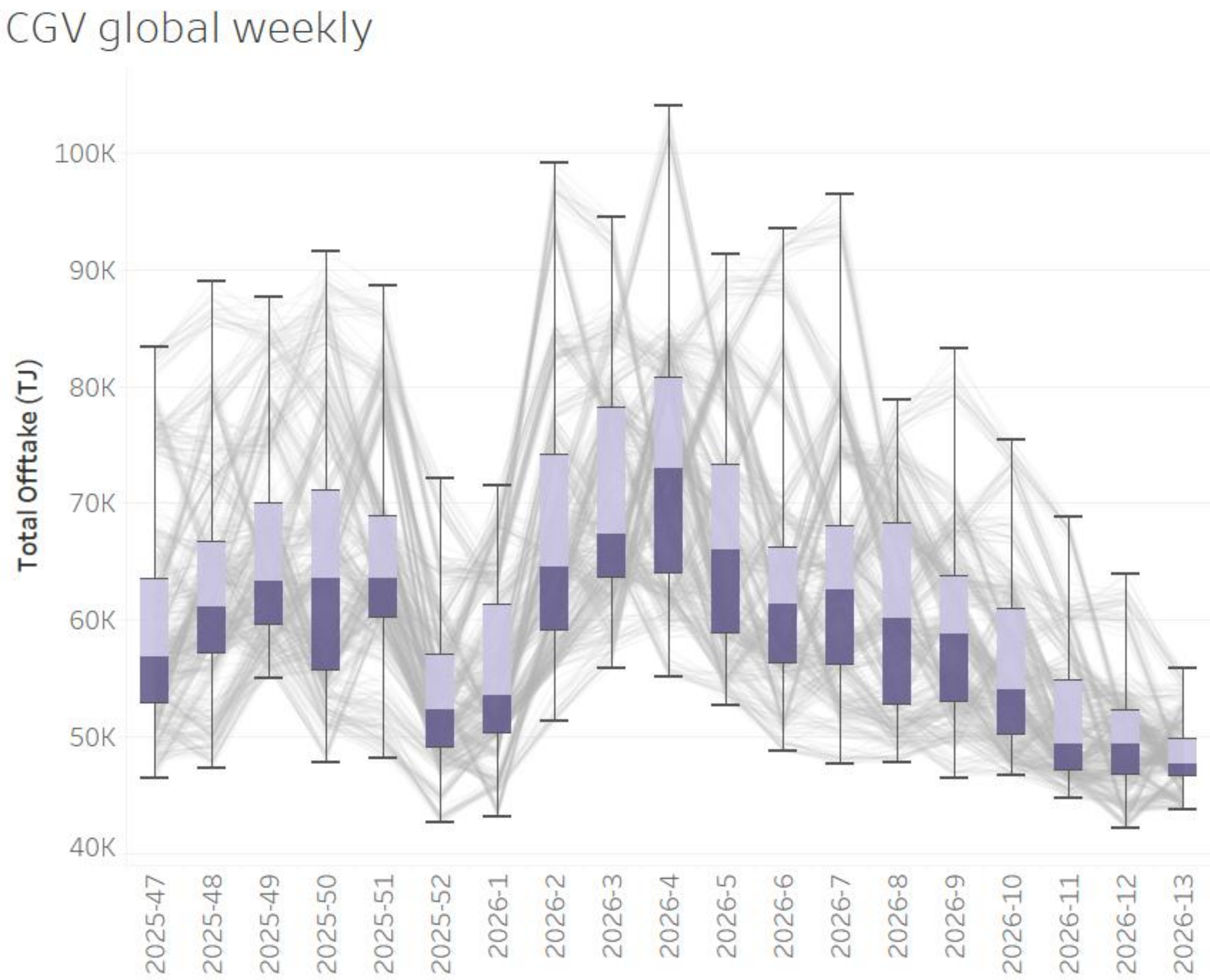


Figure 20. Weekly European gas offtake for the modelled horizon.[10]

[10] *The whiskers of the boxplot indicate the maximum and minimum gas consumption by week.*

Expectations for Ukrainian and Moldovan power systems

The Winter Outlook 2025–2026 includes inputs and outputs for both Moldova and Ukraine. However, these figures are subject to variation and should be considered with the utmost care, considering the high uncertainty related to security of supply evolution. Russia's military aggression against Ukraine, which began in February 2022, continues to create elevated risk and uncertainty in the energy systems of both Ukraine and Moldova. Power generation and grid infrastructure availability in Ukraine are uncertain due to the risk of attacks on infrastructure elements, which may determine the actual situation in Ukraine's power system.

Since June 2022 and the start of the electricity commercial exchanges between Ukraine-Moldova and their European neighbours, the TSOs have continuously assessed the power system conditions and sought ways to maximise export and import capacity, while ensuring power system stability and operational security. Capacity calculation processes were developed and implemented and allowed European TSOs to progressively and regularly increase the export and import capacity limits to/from Ukraine and Moldova. In July 2025, ENTSO-E transferred the responsibility for determining the import and export capacity to the Eastern Europe CCR.

Moldova faces several system adequacy risks for the upcoming winter, including a strong dependence on imports from Romania, weak interconnections at the Romanian border, a strong reliance on power transmission through the unstable Transnistria region, and vulnerability to disturbances in the Ukrainian power system. These adequacy challenges are caused by the fact that the supply contracts with the large power plant located in Transnistria (MGRES) expired on 31 December 2024. The security of supply in Moldova also depends on the reallocation of unused capacity at the borders between Ukraine and European countries, based on a process agreed upon between all relevant TSOs starting from January 2025. Other concerns include a lack of flexibility in the power system.

5. Summer 2025 review

Temperature and precipitation overview

Record surface air temperatures in Europe were recorded in the summer of 2025. Temperatures in June, July, August and September ranged from 0.30 °C (August) to 1.30 °C (July) above the historic average temperatures, close to historic monthly average records.

Temperatures strongly varied across the continent and over the summer months, with close-to or below-average temperatures in the northwest, while southern Europe and northern Fennoscandia saw their warmest summer (June–August) on record. This pattern was mirrored in September, when temperatures were above average in northern and eastern Europe and below average in most of western Europe.

Parts of Europe saw substantial heatwaves during the season. Southern Europe experienced “strong heat stress”, experiencing its warmest June on record (2.81 °C above the historical average) and was affected by heatwave conditions in August 2025. Meanwhile, southeastern Europe faced heatwaves and wildfire activity, particularly in July 2025.

Summer 2025 (June–August) was mostly drier than average in the western and southern parts of Europe, as well as in the Balkan and Black Sea regions. Northern Italy and northeastern Spain experienced wetter than average days. Northern and eastern Adriatic coasts experienced severe precipitation events, leading to floods. Fennoscandia and the Baltic States also experienced wetter than average conditions.

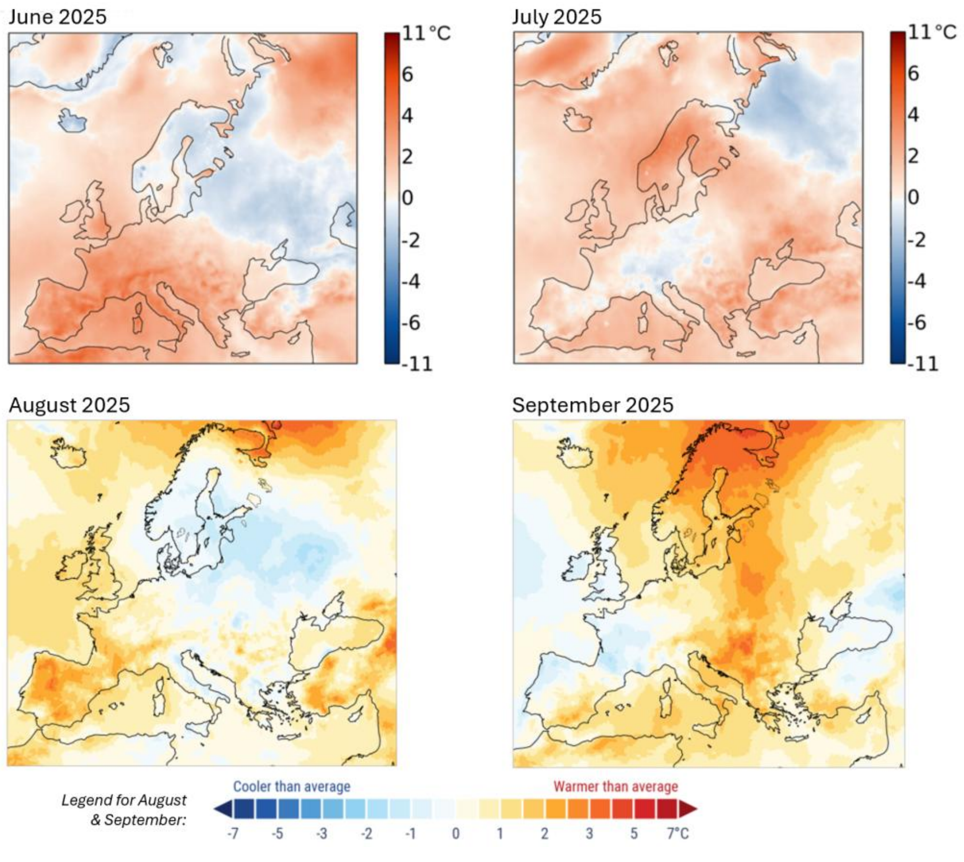


Figure 21. Surface air temperature anomalies in summer 2025 relative to the average for 1991–2020.[11]

[11] *Copernicus Climate Change Service – surface air temperature maps.*

Adequacy and other relevant events overview

In general, no adequacy issues were observed during summer 2025. Yet, Cyprus had to implement cyclic load shedding on two occasions, due to high temperatures combined with unplanned outages.

While not being related to adequacy issues, three relevant power system events have occurred during the past months:

Spain and Portugal incident

On 28 April 2025, at 12:33 CEST, the power systems of Spain and Portugal experienced a blackout. A small area in France near the Spanish border also experienced short-term disruptions. The remainder of the Continental Europe power system did not experience any significant disturbance. Following the incident, each affected TSO – REN (Portugal), RE (Spain), and RTE (France) – immediately activated their respective system restoration plans, as well as any other relevant procedures and protocols for restoring the voltage of the electricity system. The system restoration was completed on 29 April 2025 at 00:22 in Portugal, and at 04:00 in Spain. This blackout was the most serious incident to occur on the European power system in over 20 years, significantly impacting citizens and society in Spain and Portugal. The incident was classified as a Scale 3 event – the highest level in terms of severity – following Article 15(5) of the Commission Regulation (EU) 2017/1485 of 2 August 2017, establishing a guideline on electricity transmission system operation and the Incident Classification Scale (ICS) Methodology. Consequently, pursuant to the same legal framework, an Expert Panel was set up, which investigated the incident and has already delivered a factual report, while the final report is currently being prepared and scheduled to release in Q1 2026.[12]

North Macedonian incident

On 18 May 2025, at 04:59 CEST, the power system of North Macedonia experienced a separation of the 400 kV and 110 kV voltage levels, which led to a loss of stability, supply, and load in the 110 kV transmission network, while the 400 kV transmission network remained operational. Under the applicable EU legislation, this incident is classified as a blackout due to the 100% loss of load in the 110 kV transmission network. On the same day, the Bulgarian control area was in an alert state for eight hours due to the high voltages in the western part of its system. The remainder of the Continental Europe power system did not experience any significant disturbances. The incident was classified as Scale 3 based on the ICS and the Expert panel's investigation is ongoing.

Czech Republic incident

On 4 July 2025, shortly before 12:00 CEST, an incident occurred in the Czech power system which led to significant outages in the eastern and northern part of the Czech Republic, including areas of Prague. The incident was initiated by the fall of a phase conductor of an overhead line. This failure led to the loss of generation and overload of several transmission system elements, leading to the disconnection of several transmission lines. As a result, part of the transmission network went into island operation mode, disconnecting from the larger national system, which in turn rendered it inoperable. Approximately 1,500 MW of production and 2,700 MW of consumption were affected by this sequence of events. ČEPS immediately activated its system restoration procedures. By 14:10 CEST, the transmission system substations were put back into operation. The restoration of electricity supply to all consumers was well coordinated between ČEPS and the distribution network operators. At 17:35 CEST, all distribution companies confirmed that 100% of the lost load had been restored. The incident was classified as Scale 2 based on the ICS and the Expert panel's investigation is ongoing.

---

[12] *ENTSO-E has already published a first (non-final) report: https://www.entsoe.eu/publications/blackout/28-april-2025-iberian-blackout/*

Appendix 1: Methodological insights

ENTSO-E has significantly upgraded its methodology for assessing adequacy on the seasonal time horizon since the Summer Outlook 2020 report.

This methodology is described in the Methodology for Short-term and Seasonal Adequacy Assessments.[13] It was developed by ENTSO-E in line with the Clean Energy for all Europeans package and especially the Regulation on Risk Preparedness in the Electricity Sector (EU) 2019/941, receiving formal approval from ACER.[14]

Most notably, the seasonal adequacy assessment has shifted from a weekly snapshot based on a deterministic approach to the well-proven, state-of-the-art, sequential, hourly Monte Carlo probabilistic approach. In the Monte Carlo approach, a set of possible scenarios for each variable is constructed to assess adequacy risks under various conditions for the time frame analysed. Figure 22 provides a schematic representation of this scenario construction process.

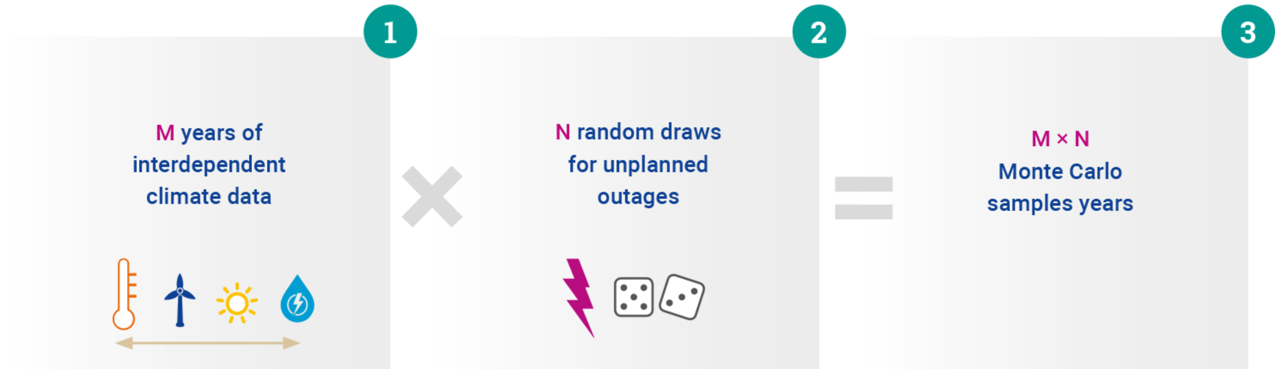


Figure 22. Scenarios assessed in Seasonal Outlook.

Scenarios are constructed so that all variables are correlated (interdependent) across both time and space. To ensure the highest data quality in the assessments, they are prepared by experts working within dedicated teams. A pan-European climate database (PECD) maintained by Copernicus Climate Change Service (C3S) ensures high data quality and consistency across Europe.

Consequently, ENTSO-E has transitioned from a “shallow” scenario tree with limited severe and normal conditions samples to a “deep” scenario tree that incorporates extensive interdependent weather data and random unplanned outages. This generates a wide range of alternative scenarios spanning 31 weather scenarios and 20 forced outage patterns. Furthermore, an improvement in the methodology also enables the consideration of hydro energy availability. Figure 23 illustrates the difference in the number of scenarios between the two modelling approaches.

[13] *Methodology for Short-term and Seasonal Adequacy assessment.*
[14] *https://acer.europa.eu/sites/default/files/documents/Individual%20Decisions/ACER%20Decision%2008-2020%20on%20the%20short-term%20and%20seasonal%20adequacy%20assessments%20methodology_RPR8_1.pdf*

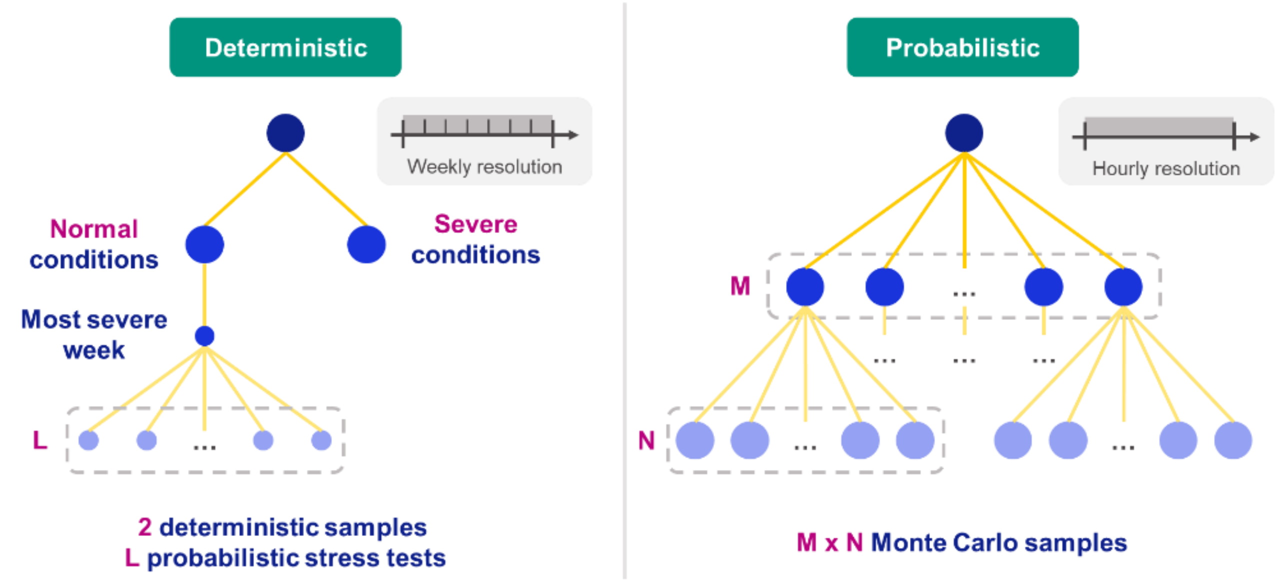


Figure 23. Scenario revolution from deterministic to probabilistic.

An adequacy assessment is conducted for each sample case on the seasonal time horizon, yielding a probabilistic pan-European resource assessment. It identifies adequacy risks in each deterministic sample and generates numerous consistent pan-European draws while identifying realistic adequacy risk.

Appendix 2: Additional information about the study

Figure 24. Study zones.

NTC import table

AL00	RS00 400 MW (400 - 400) MW	GR00 300 MW (300 - 300) MW	ME00 300 MW (300 - 300) MW										
AT00	DE00 4,900 MW (4,900 - 4,900) MW	CH00 1,188 MW (936 - 1,200) MW	SI00 950 MW (950 - 950) MW	CZ00 900 MW (900 - 900) MW	HU00 800 MW (800 - 800) MW	ITN1 101 MW (50 - 145) MW							
BA00	HR00 800 MW (800 - 800) MW	RS00 474 MW (474 - 474) MW	ME00 450 MW (450 - 450) MW										
BE00	FR00 2,000 MW (2,000 - 2,000) MW	DE00 1,000 MW (1,000 - 1,000) MW	UK00 1,000 MW (1,000 - 1,000) MW	NL00 950 MW (950 - 950) MW									
BG00	RO00 1,893 MW (1,800 - 1,900) MW	GR00 1,081 MW (600 - 1,100) MW	MK00 400 MW (400 - 400) MW	RS00 400 MW (400 - 400) MW									
CH00	FR00 3,191 MW (3,000 - 3,200) MW	DE00 1,970 MW (1,650 - 2,000) MW	ITN1 1,830 MW (420 - 1,910) MW	AT00 1,184 MW (636 - 1,200) MW									
CZ00	DE00 2,750 MW (2,750 - 2,750) MW	SK00 1,100 MW (1,100 - 1,100) MW	AT00 900 MW (900 - 900) MW	PLE0 800 MW (800 - 800) MW	PLI0 0 MW (0 - 0) MW								
DE00	AT00 4,900 MW (4,900 - 4,900) MW	NL00 4,400 MW (4,400 - 4,400) MW	CH00 4,000 MW (4,000 - 4,000) MW	FR00 3,000 MW (3,000 - 3,000) MW	PL00 3,000 MW (3,000 - 3,000) MW	CZ00 2,900 MW (2,900 - 2,900) MW	DKW1 2,500 MW (2,500 - 2,500) MW	NOS2 1,400 MW (1,400 - 1,400) MW	LUV1 1,300 MW (1,300 - 1,300) MW	BE00 1,000 MW (1,000 - 1,000) MW	LUG1 1,000 MW (1,000 - 1,000) MW	SE04 615 MW (615 - 615) MW	DKE1 294 MW (0 - 585) MW
DKE1	SE04 1,255 MW (250 - 1,300) MW	DKW1 590 MW (590 - 590) MW	DE00 569 MW (0 - 585) MW										
DKW1	DE00 2,500 MW (2,500 - 2,500) MW	NOS2 1,627 MW (0 - 1,632) MW	UK00 1,215 MW (1,100 - 1,400) MW	NL00 700 MW (700 - 700) MW	SE03 688 MW (100 - 715) MW	DKE1 600 MW (600 - 600) MW							
EE00	FI00 1,016 MW (1,016 - 1,016) MW	LV00 950 MW (950 - 950) MW											
ES00	FR00 2,657 MW (2,100 - 2,700) MW	PT00 2,028 MW (1,600 - 2,200) MW											
FI00	SE01 1,694 MW (1,200 - 2,000) MW	SE03 1,200 MW (1,200 - 1,200) MW	EE00 1,016 MW (1,016 - 1,016) MW	NON1 80 MW (80 - 80) MW									
FR00	UK00 4,000 MW (4,000 - 4,000) MW	DE00 3,000 MW (3,000 - 3,000) MW	ES00 2,300 MW (2,300 - 2,300) MW	ITN1 2,020 MW (451 - 2,100) MW	CH00 1,300 MW (1,300 - 1,300) MW	BE00 650 MW (650 - 650) MW							
GR00	BG00 1,177 MW (600 - 1,200) MW	ITS1 500 MW (500 - 500) MW	MK00 482 MW (300 - 500) MW	AL00 450 MW (450 - 450) MW	GR03 150 MW (150 - 150) MW								
GR03	GR00 150 MW (150 - 150) MW												
HR00	SI00 1,500 MW (1,500 - 1,500) MW	BA00 800 MW (800 - 800) MW	HU00 800 MW (800 - 800) MW										
HU00	SK00 2,513 MW (2,513 - 2,513) MW	RO00 1,000 MW (1,000 - 1,000) MW	RS00 1,000 MW (1,000 - 1,000) MW	AT00 800 MW (800 - 800) MW	HR00 800 MW (800 - 800) MW	SI00 700 MW (700 - 700) MW							
IE00	UK00 1,000 MW (1,000 - 1,000) MW	UKNI 400 MW (400 - 400) MW											
ITCA	ITSI 1,300 MW (1,300 - 1,300) MW	ITS1 1,100 MW (1,100 - 1,100) MW											
ITCN	ITN1 3,894 MW (3,400 - 4,550) MW	ITCS 2,947 MW (2,800 - 3,400) MW	ITSA 300 MW (300 - 300) MW										
ITCS	ITS1 4,983 MW (3,600 - 5,200) MW	ITCN 2,688 MW (2,000 - 3,500) MW	ITSA 885 MW (740 - 900) MW	ME00 600 MW (600 - 600) MW									
ITN1	CH00 3,880 MW (420 - 4,572) MW	FR00 3,716 MW (451 - 3,900) MW	ITCN 2,567 MW (1,900 - 3,350) MW	SI00 661 MW (67 - 753) MW	AT00 365 MW (63 - 475) MW								
ITS1	ITCS 2,400 MW (2,400 - 2,400) MW	ITCA 2,265 MW (1,500 - 2,350) MW	GR00 500 MW (500 - 500) MW										
ITSA	ITCS 716 MW (270 - 720) MW	ITCN 300 MW (300 - 300) MW											
ITSI	ITCA 1,550 MW (1,550 - 1,550) MW	MT00 225 MW (225 - 225) MW											
LT00	LV00 783 MW (783 - 783) MW	SE04 700 MW (700 - 700) MW	PL00 156 MW (150 - 160) MW										
LUG1	DE00 1,000 MW (1,000 - 1,000) MW												
LUV1	DE00 1,300 MW (1,300 - 1,300) MW												
LV00	EE00 1,240 MW (1,240 - 1,240) MW	LT00 846 MW (846 - 846) MW											
ME00	ITCS 600 MW (600 - 600) MW	BA00 500 MW (500 - 500) MW	AL00 300 MW (300 - 300) MW	RS00 300 MW (300 - 300) MW									
MK00	RS00 600 MW (600 - 600) MW	GR00 482 MW (300 - 500) MW	BG00 400 MW (400 - 400) MW										
MT00	ITSI 225 MW (225 - 225) MW												
NL00	DE00 4,400 MW (4,400 - 4,400) MW	BE00 1,400 MW (1,400 - 1,400) MW	UK00 1,000 MW (1,000 - 1,000) MW	DKW1 700 MW (700 - 700) MW	NOS2 700 MW (700 - 700) MW								
NOM1	NON1 1,200 MW (1,200 - 1,200) MW	SE02 966 MW (700 - 1,000) MW	NOS1 500 MW (500 - 500) MW	NOS3 500 MW (500 - 500) MW									
NON1	SE01 599 MW (400 - 600) MW	NOM1 400 MW (400 - 400) MW	SE02 300 MW (250 - 300) MW	FI00 80 MW (80 - 80) MW									
NOS1	NOS3 3,900 MW (3,900 - 3,900) MW	NOS2 3,500 MW (3,500 - 3,500) MW	SE03 2,072 MW (1,895 - 2,095) MW	NOM1 500 MW (500 - 500) MW									
NOS2	NOS1 2,200 MW (2,200 - 2,200) MW	DKW1 1,627 MW (0 - 1,632) MW	DE00 1,400 MW (1,400 - 1,400) MW	UK00 1,400 MW (1,400 - 1,400) MW	NL00 700 MW (700 - 700) MW	NOS3 600 MW (600 - 600) MW							
NOS3	NOM1 800 MW (800 - 800) MW	NOS1 600 MW (600 - 600) MW	NOS2 500 MW (500 - 500) MW										
PL00	PLI0 2,300 MW (2,300 - 2,300) MW	DE00 1,300 MW (1,300 - 1,300) MW	SE04 600 MW (600 - 600) MW	LT00 169 MW (150 - 180) MW	PLE0 0 MW (0 - 0) MW								
PLE0	PL00 2,400 MW (2,400 - 2,400) MW	CZ00 0 MW (0 - 0) MW											
PLI0	CZ00 600 MW (600 - 600) MW	PL00 0 MW (0 - 0) MW											
PT00	ES00 3,209 MW (2,000 - 3,600) MW												
RO00	BG00 1,893 MW (1,800 - 1,900) MW	HU00 1,000 MW (1,000 - 1,000) MW	RS00 1,000 MW (1,000 - 1,000) MW										
RS00	HU00 1,000 MW (1,000 - 1,000) MW	RO00 1,000 MW (1,000 - 1,000) MW	MK00 800 MW (800 - 800) MW	AL00 400 MW (400 - 400) MW	BG00 400 MW (400 - 400) MW	BA00 300 MW (300 - 300) MW	ME00 200 MW (200 - 200) MW						
SE01	SE02 3,300 MW (3,300 - 3,300) MW	FI00 1,655 MW (1,100 - 2,000) MW	NON1 700 MW (600 - 700) MW										
SE02	SE03 7,300 MW (7,300 - 7,300) MW	SE01 3,300 MW (3,300 - 3,300) MW	NOM1 598 MW (0 - 600) MW	NON1 250 MW (150 - 250) MW									
SE03	SE02 7,197 MW (5,700 - 7,300) MW	SE04 2,800 MW (2,800 - 2,800) MW	NOS1 2,042 MW (100 - 2,145) MW	FI00 1,200 MW (1,200 - 1,200) MW	DKW1 701 MW (400 - 715) MW								
SE04	SE03 6,039 MW (3,500 - 6,200) MW	DKE1 1,635 MW (350 - 1,700) MW	LT00 700 MW (700 - 700) MW	DE00 615 MW (615 - 615) MW	PL00 600 MW (600 - 600) MW								
SI00	HR00 1,500 MW (1,500 - 1,500) MW	AT00 950 MW (950 - 950) MW	HU00 700 MW (700 - 700) MW	ITN1 644 MW (67 - 680) MW									
SK00	HU00 1,800 MW (1,800 - 1,800) MW	CZ00 1,700 MW (1,700 - 1,700) MW											
UK00	FR00 4,000 MW (4,000 - 4,000) MW	NOS2 1,400 MW (1,400 - 1,400) MW	DKW1 1,153 MW (1,000 - 1,400) MW	BE00 1,000 MW (1,000 - 1,000) MW	IE00 1,000 MW (1,000 - 1,000) MW	NL00 1,000 MW (1,000 - 1,000) MW	UKNI 400 MW (400 - 400) MW						
UKNI	UK00 450 MW (450 - 450) MW	IE00 400 MW (400 - 400) MW											

Node from, average of NTC cross-technology (MW), minimum of NTC cross-technology (MW) and maximum of NTC cross-technology (MW) broken down by Rank of Avg. NTC cross-technology (MW) vs. Node to. The data is filtered on Technology, which keeps multiple members.

Figure 25. Import capacity overview.[15]

Appendix 3: Additional information about the results

Loss of load expectation and other annual metrics

This appendix presents information about loss of load expectation (LOLE) in the assessed season. LOLE figures can be useful when comparing how adequacy has evolved between different seasonal adequacy assessment editors. However, readers are encouraged to interpret them carefully as LOLE is commonly known as an annual metric, whereas only a specific season (part of the year) is considered in seasonal adequacy assessments.

LOLE analysis might lead to misleading conclusions when compared with reliability standards (existing or under development in accordance with Article 26 of Regulation 2019//943). Some examples are provided below, assuming that the annual LOLE reliability standard[16] is set and compared with seasonal LOLE:

- Seasonal LOLE can be lower than the reliability standard, although this does not mean that adequacy within the assessed season meets the reliability standard. For example, even a minor LOLE value can indicate unusual risk in a study zone if the risk is identified in an unusual season, such as risk in summer for a northern country.

- Seasonal LOLE can be higher than the reliability standard, although this does not necessarily mean that the system design does not meet the reliability standard. The expected situation in an upcoming season could simply be a rather constraining one from a set of possible seasonal scenarios. E.g., low water availability in hydro reservoirs could coincide with a high generation unavailability at the beginning of the season.

It is worth considering whether the reliability standard is defined as a system design target or an operational system adequacy metric target. Europe initially relies on market signals (for supply and network investments) to meet the reliability target set for power system design purposes. If they are insufficient, market design corrections can be made, e.g. by establishing complementary markets, such as capacity mechanisms. The latter market decisions are based on a several-year-ahead framework,[17] whereas Seasonal Outlook reports pertain to an operational time frame that relies on market participants taking short-term corrective actions (e.g. changing planned outage schedules) in addition to TSOs utilising all available resources to minimise risks. Therefore, it is important to understand the purpose of any metric to which Seasonal Outlook results might be compared., This is especially important for LOLE.

Considering the aforementioned background and interpretation limitations, LOLE figures can be found in the main report content (Figure 14 and 16).

[16] The conclusions made for annual LOLE are also valid for any other annual metric.

[17] Monitored by the European Resource Adequacy Assessment in line with Article 23 of Electricity Regulation 2019/943.