Winter Outlook 2024-2025

Summer Review 2024

entsoe

ENTSO-E Mission Statement

Who we are

ENTSO-E, the European Network of Transmission System Operators for Electricity, is the association for the cooperation 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. In addition to its core, historical role in technical cooperation, ENTSO-E is also the common voice of TSOs.

ENTSO-E brings together the unique expertise of TSOs for the benefit of European citizens by keeping the lights on, enabling the energy transition, and promoting the completion and optimal functioning of the internal electricity market, including via the fulfilment of the mandates given to ENTSO-E based on EU legislation.

Our mission

ENTSO-E and its members, as the European TSO community, fulfil a common mission: Ensuring the security of the inter-connected power system in all time frames at pan-European level and the optimal functioning and development of the European interconnected electricity markets, while enabling the integration of electricity generated from renewable energy sources and of emerging technologies.

Our vision

ENTSO-E plays a central role in enabling Europe to become the first climate-neutral continent by 2050 by creating a system that is secure, sustainable and affordable, and that integrates the expected amount of renewable energy, thereby offering an essential contribution to the European Green Deal. This endeavour requires sector integration and close cooperation among all actors.

Europe is moving towards a sustainable, digitalised, integrated and electrified energy system with a combination of centralised and distributed resources. ENTSO-E acts to ensure that this energy system keeps consumers at its centre and is operated and developed with climate objectives and social welfare in mind.

ENTSO-E is committed to use its unique expertise and system-wide view – supported by a responsibility to maintain the system's security – to deliver a comprehensive roadmap of how a climate-neutral Europe looks.

Our values

ENTSO-E acts in solidarity as a community of TSOs united by a shared responsibility.

As the professional association of independent and neutral regulated entities acting under a clear legal mandate, ENTSO-E serves the interests of society by optimising social welfare in its dimensions of safety, economy, environment, and performance.

ENTSO-E is committed to working with the highest technical rigour as well as developing sustainable and innovative responses to prepare for the future and overcoming the challenges of keeping the power system secure in a climate-neutral Europe. In all its activities, ENTSO-E acts with transparency and in a trustworthy dialogue with legislative and regulatory decision makers and stakeholders.

Our contributions

ENTSO-E supports the cooperation among its members at European and regional levels. Over the past decades, TSOs have undertaken initiatives to increase their cooperation in network planning, operation and market integration, thereby successfully contributing to meeting EU climate and energy targets.

To carry out its legally mandated tasks, ENTSO-E's key responsibilities include the following:

› Development and implementation of standards, network codes, platforms and tools to ensure secure system and market operation as well as integration of renewable energy;

› Assessment of the adequacy of the system in different timeframes;

› Coordination of the planning and development of infrastructures at the European level (Ten-Year Network Development Plans, TYNDPs);

› Coordination of research, development and innovation activities of TSOs;

› Development of platforms to enable the transparent sharing of data with market participants.

ENTSO-E supports its members in the implementation and monitoring of the agreed common rules.

Contents

1. Executive summary

ENTSO-E Winter Outlook 2024–2025 highlights the overall favourable adequacy situation in Europe for the coming winter. Some risks of electricity supply might occur in remote areas such as Crete, Cyprus, Ireland, and Malta. On the mainland continent, only Finland and Poland might face some risk in the event of exceptionally adverse operational conditions combined with cold weather and high unplanned outages. Dedicated non-market resources would significantly alleviate such risks in Finland, Ireland, Malta, and Poland.

European power system trends since winter 2023–2024 show further generation fleet expansion (conventional decreases but renewable energy source (RES) considerably increases), and while planned outages are comparable to last winter, demand has slightly declined. Hydro reservoir levels are also higher than average overall, following the high precipitation in different parts of Europe since early spring. These combined factors create favourable conditions for adequacy.

The gas storage level is also remarkably high, reaching 94% on 1 October, thus surpassing the target of 90% by 1 November. This signals a robust European winter preparedness and further increases confidence in the security of supply.

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. European transmission system operators will increase electricity export capacity to Ukraine and Moldova for this winter by 400 MW to boost supply security, reaching 2.1 GW from 1 December 2024.

The Winter Outlook is accompanied by a retrospect of last summer. No adequacy issues were recorded during summer 2023 despite warm temperatures encountered, with heatwaves recorded in some regions. Nonetheless, several countries have faced downward regulation challenges during periods with high renewable generation and low or moderate demand.

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 ahead of 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 they 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 materialise.

Outlook reports are the product of cooperation between 40 European electricity transmission system operators (TSOs). Due to their pan-European scope, the Outlook reports complement the analysis carried out in national and regional assessments, which provide a more detailed picture of adequacy at the local level. They promote cooperation across Europe and between regional and national stakeholders. 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 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 as per Article 8 of the Risk Preparedness Regulation and as approved by the Agency for the Cooperation of Energy Regulators (ACER) on 6 March 2020. Earlier 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 level

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 impacting changes in 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;
- 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;

[1] https://eepublicdownloads.entsoe.eu/clean-documents/sdc-documents/seasonal/Methodology%20for%20Short-term%20and%20Seasonal%2D0Adequacy%20Assessment%20-%20ACER%20Decision%2008-2020%20on%20the%20RPR8%20.pdf

- Communication between ENTSO-E and the European Network of Transmission System Operators for Gas (ENTSOG) to align assumptions and messages between the gas and electric Winter Outlook.

Regional level

- Following the cross-regional STA process, a regional STA process exists in the event of detecting scarcity situations. It is managed by RCCs with the participation of the TSOs concerned to coordinate the proposal of 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 more 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 2024–2025

Generation overview

Generation capacity evolution

Compared to the previous winter, installed renewable capacity in Europe has increased by more than 110 GW (Figure 1). Most of this increase comes from the massive installation of rooftop, industrial, and utility-scale photovoltaic production all over Europe, with total installed capacity increasing by 43% over one year (compared with a 33% increase in the previous year). An evolution of more than 10 GW of installed photovoltaic production over one year has been observed in some countries, such as, Germany the Netherlands, and Spain. Installed wind capacity has also increased by 15 GW, spread over Europe.

Battery energy storage system capacity is rapidly increasing (by 100% compared to the previous winter) but remains very small in scale, with only 11 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 17 GW (-15%). On the other hand, the more flexible gas power plants are slightly expanding with an installed capacity increase of 8 GW compared to the previous winter.

Nuclear capacity has recorded a slight net increase with the commissioning of Flamanville 3 in France.

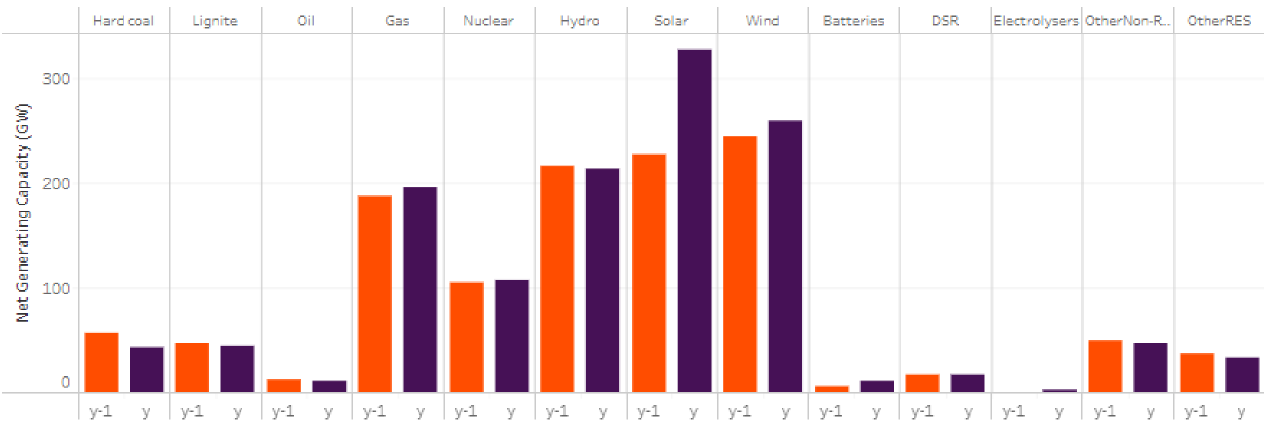

Figure 1. Generation capacity change over one year: Winter Outlook 2024–2025 vs. Winter Outlook 2023–2024

Figure 2 shows that generation capacity in Europe is increasing during winter 2024-2025, mainly due to the expansion in renewables capacity generation. Thermal generation is decreasing due to the decommissioning of hard coal and lignite plants not being balanced 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.

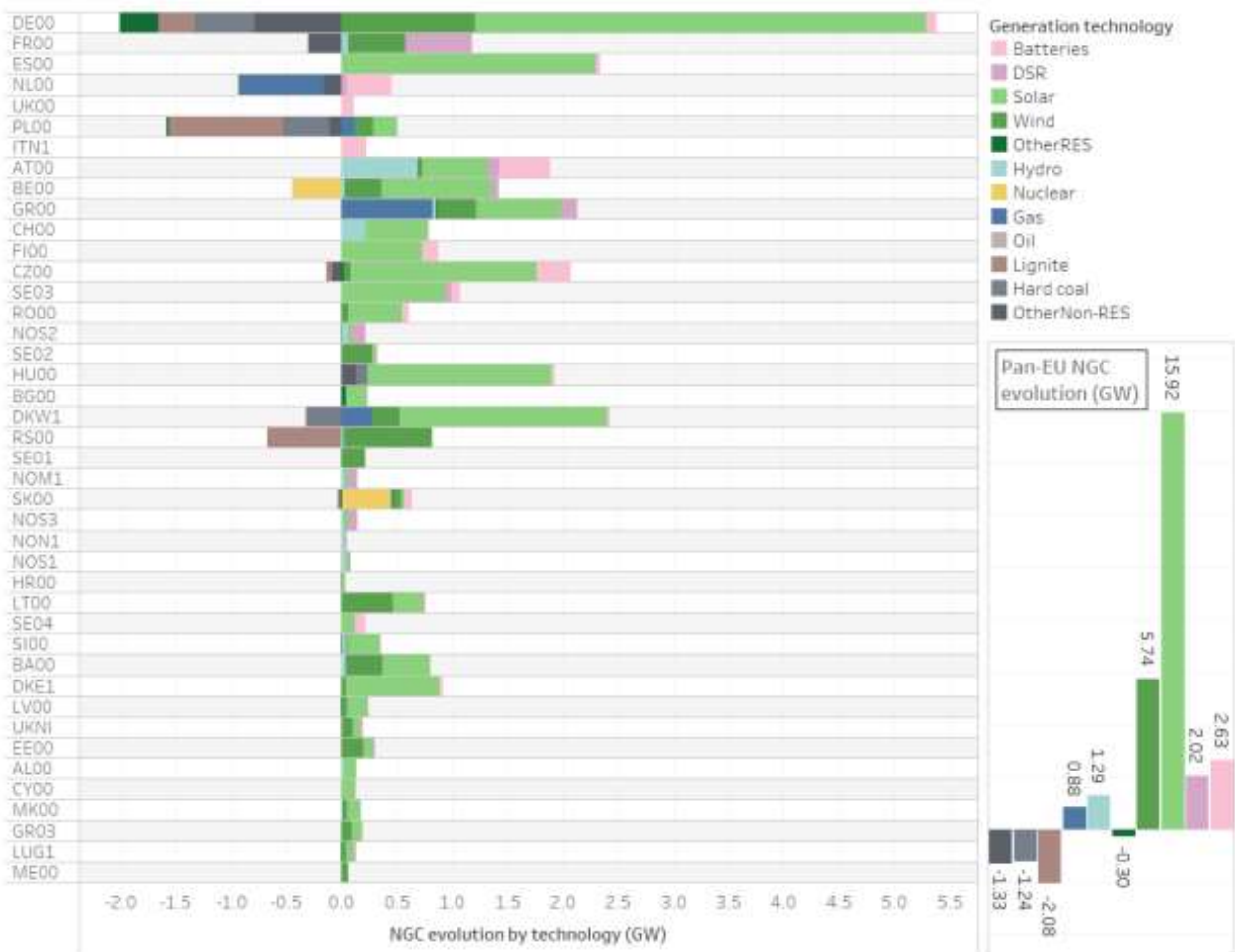

Figure 2. Capacity evolution in winter 2024-2025

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 import. However, considering conventional generation unavailability such as forced outages and planned unavailability, some zones such as Belgium, Denmark, Finland, and Germany might rely on imports in low renewable generation scenarios ("flexible technologies").

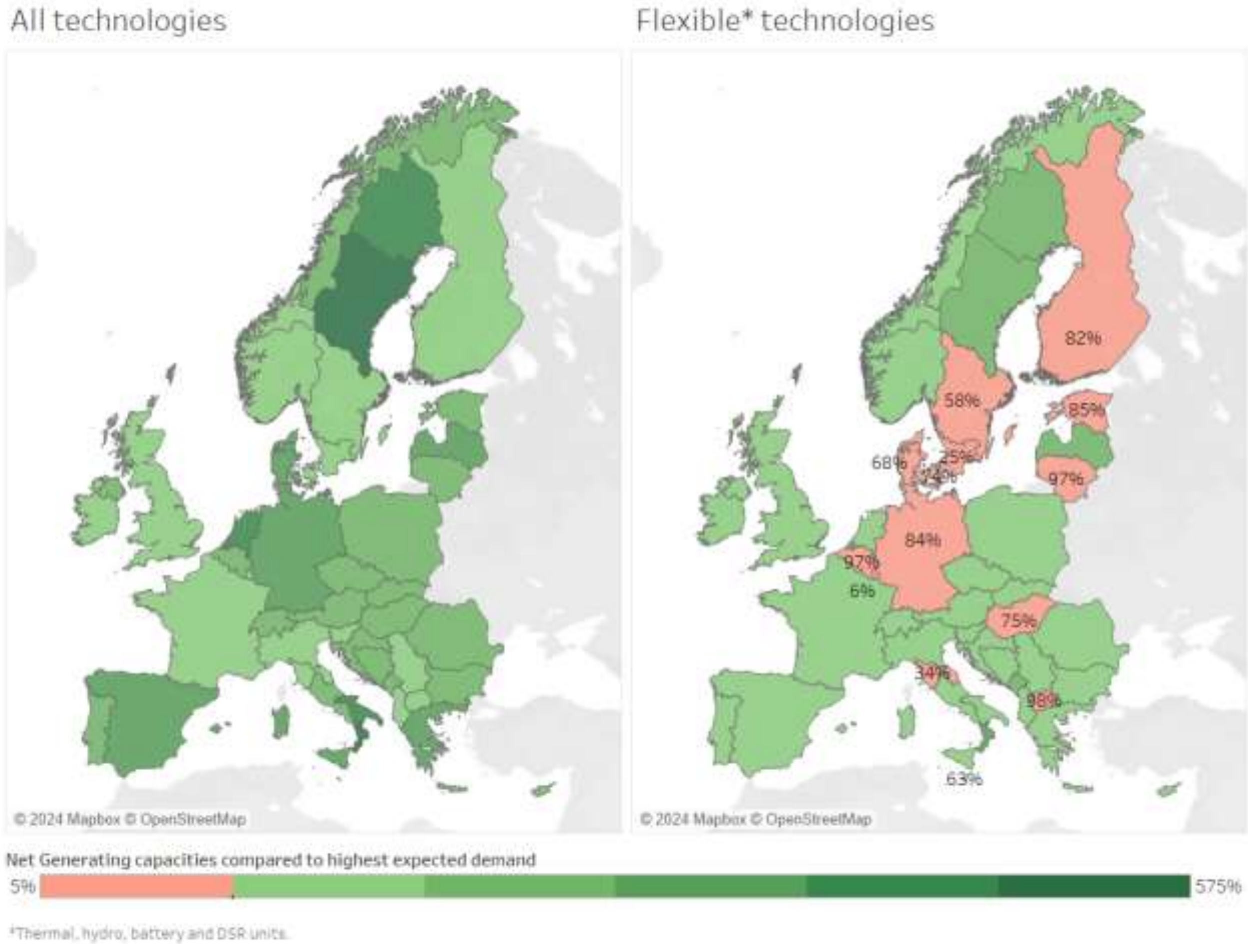

Figure 3. Net generating capacity overview: Comparison with highest expected demand[2]

Figure 4 details the generation capacity mix at the beginning of winter 2024–2025 for each study zone for the reference scenario.

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) excluding demand-side response (DSR). For example, in NOS1, peak demand exceeds NGC by 14% and requires DSR to meet peak demand. All other countries are expected to meet peak demand with their NGC.

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

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

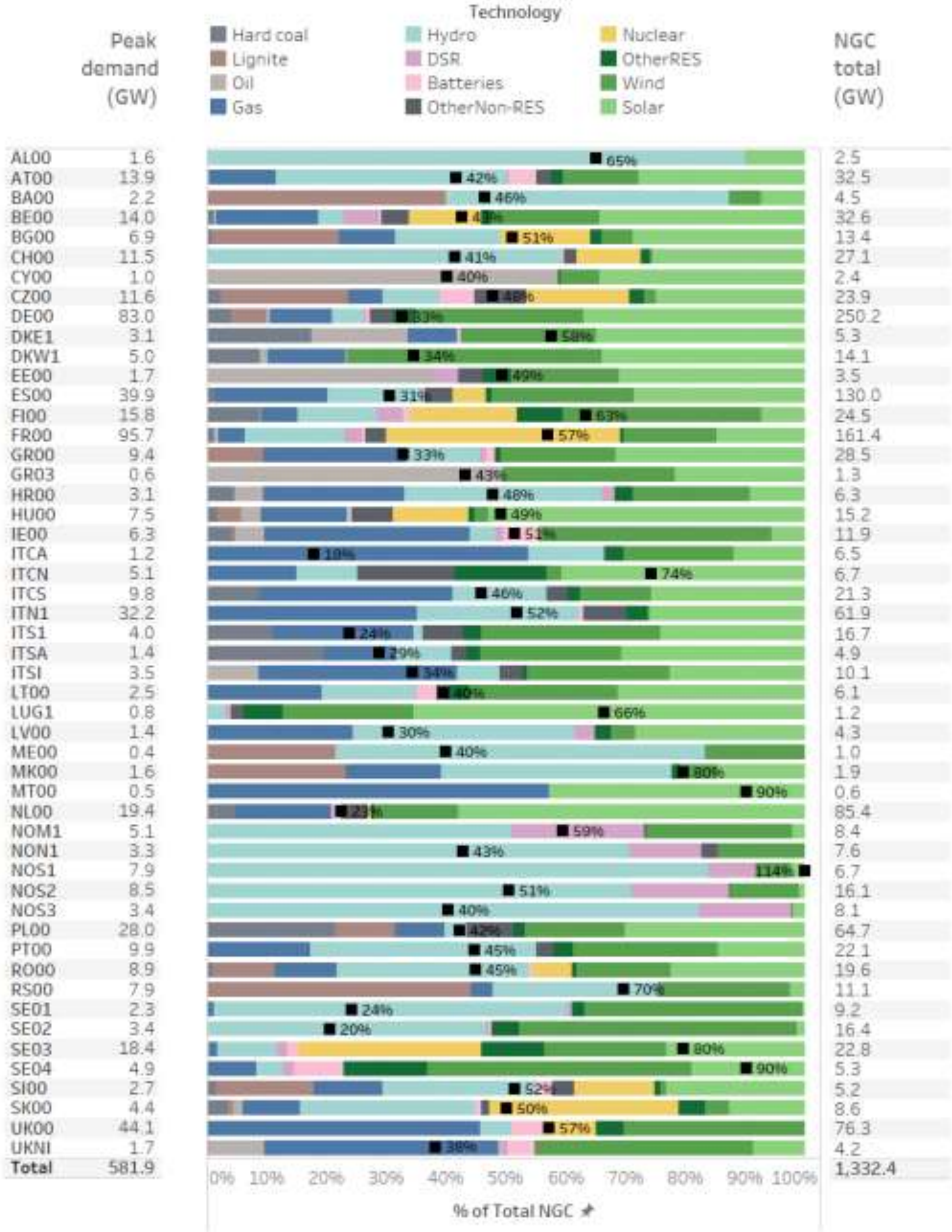

Figure 4. Generation capacity mix at the beginning of winter 2024–2025 for each study zone

Non-market resources are dispatchable units that can be activated in the event of lacking supply. They are available in eight 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.

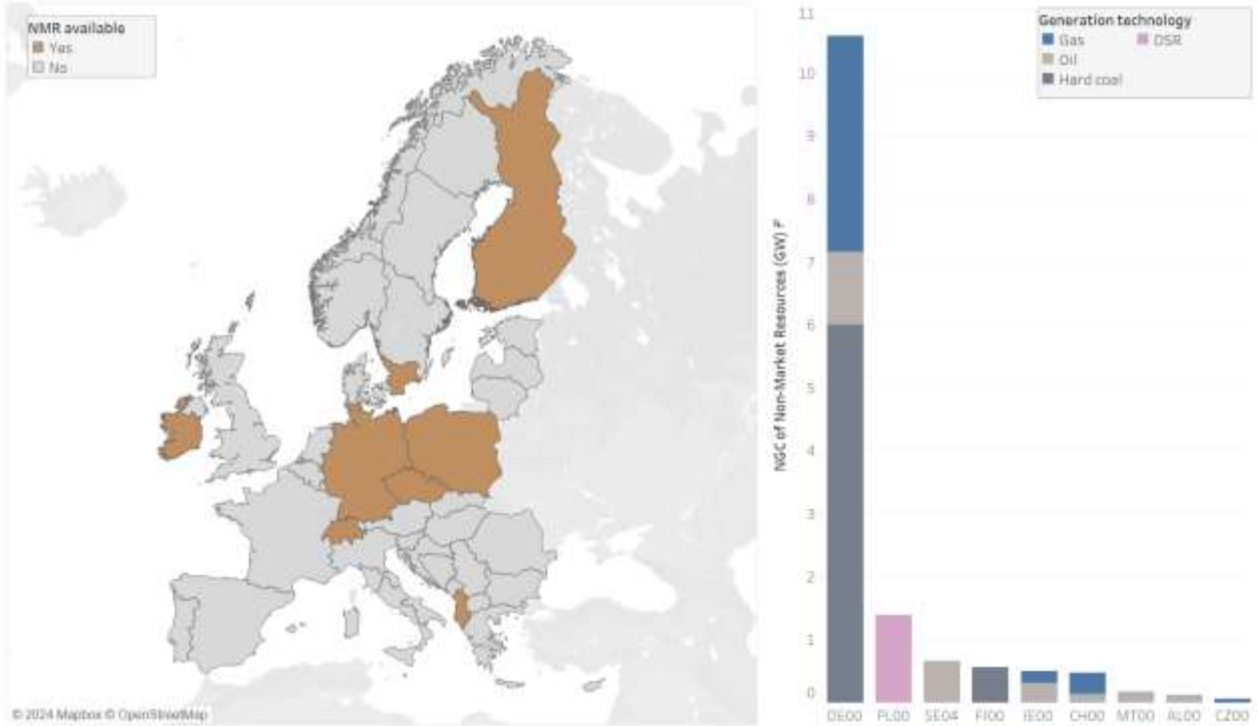

Figure 5. Non-market resources for coping with adequacy challenges in Europe[3]

Planned unavailability of generation

Figure 6 shows the evolution of the planned unavailability of thermal and nuclear generation units throughout winter 2024-2025. The planned unavailability of generation units includes planned outages for maintenance and mothballing. Winter 2024-2025 shows a slightly higher level of planned outages compared to the previous winter, indicating a lower availability of fossil generation capacity. Nonetheless, such planned outages remain much lower than in winter 2022-2023, and nuclear availability is expected to be favourable and in line with the winter 2023-24 levels.

[3] Parts of German non-market resources have a different primary purpose other 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.

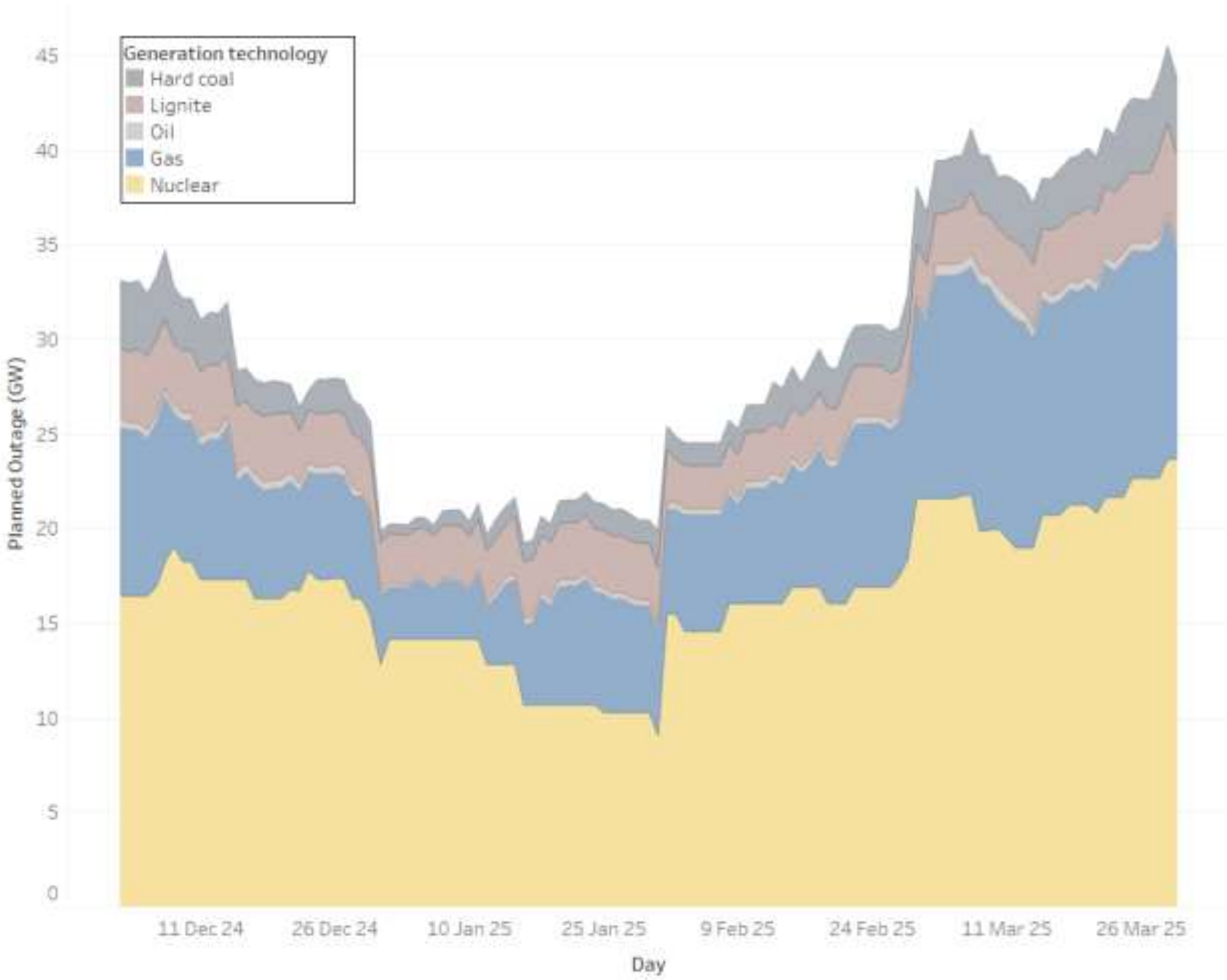

Figure 6. Planned unavailability of thermal generation units

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 the Czech Republic (CZ00), North Macedonia (MK00), and Southern Sweden (SE04).

The high share of planned outages in France is comparable to the previous winter and not uncommon to the large nuclear fleet installed. Planned outages in Cyprus are typically scheduled outside the summer period – when peak demand occurs – and are again comparable to the previous winter.

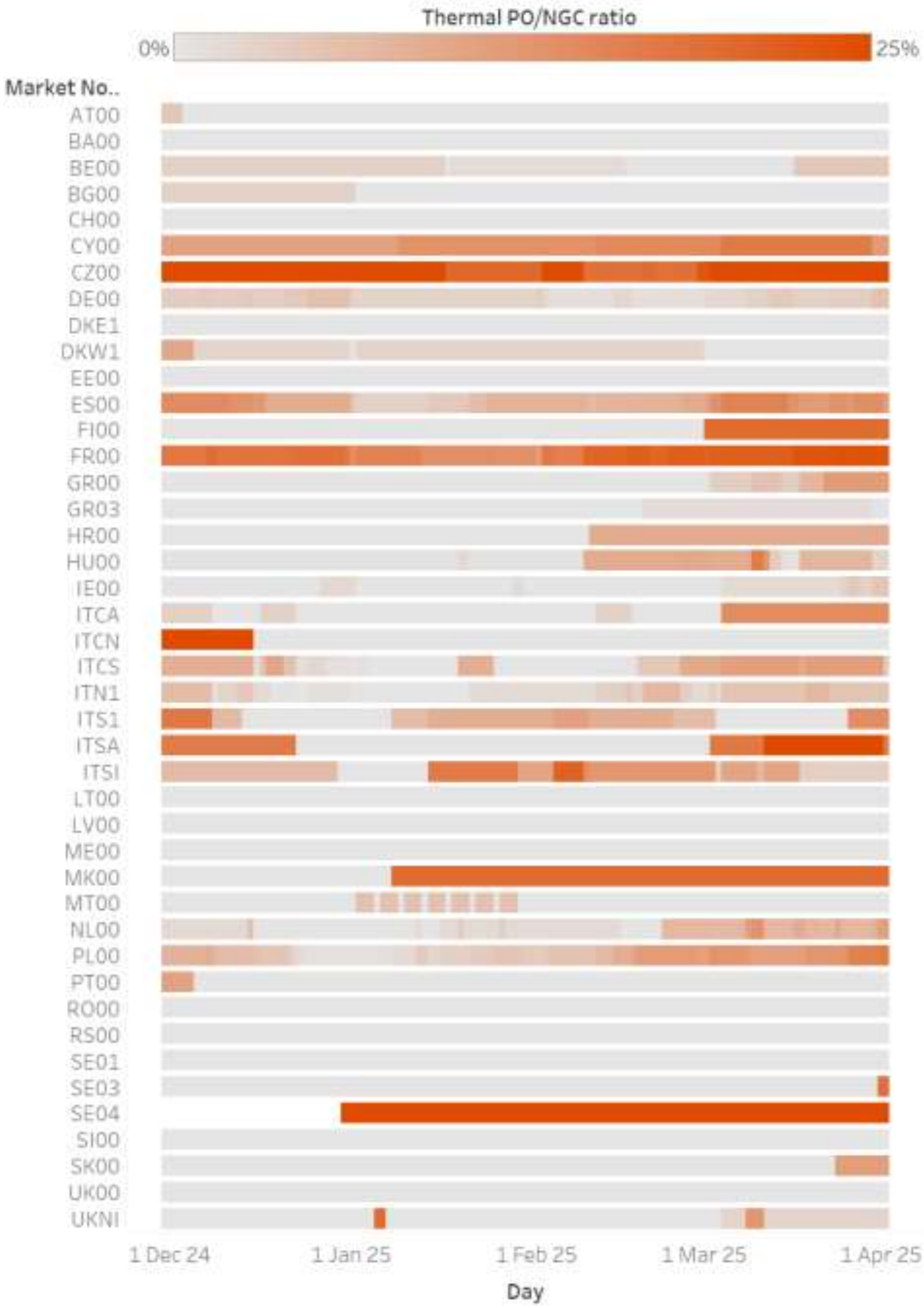

Figure 7. Weekly distribution of thermal planned outage (PO) relative to thermal NGC

Hydro availability

Figure 8 shows hydro storage level expectations compared to previous winters. Total expected hydro storage levels in November 2024 are below 2023 levels and significantly higher than 2022 levels.[4]

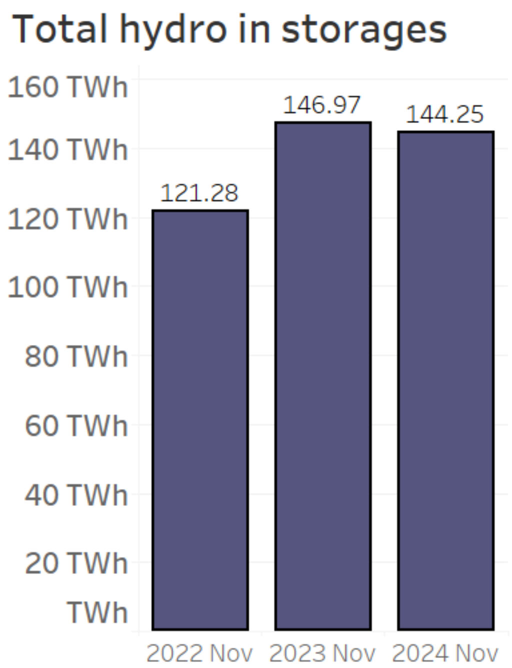

Figure 8. Total hydro storage availability in November in Europe

[4] *While forecasted projections of hydro storage levels modelled in the Winter Outlook already look reasonably high, recent ENTSO-E Transparency Platform data confirms even more favourable hydro levels in several countries, such as France, Norway, Spain, and Switzerland.*

Demand overview

Overall EU electricity demand is expected to be slightly (~2%) lower than the previous year (Figure 9), which should ease the adequacy risk in the coming winter to a moderate extent.

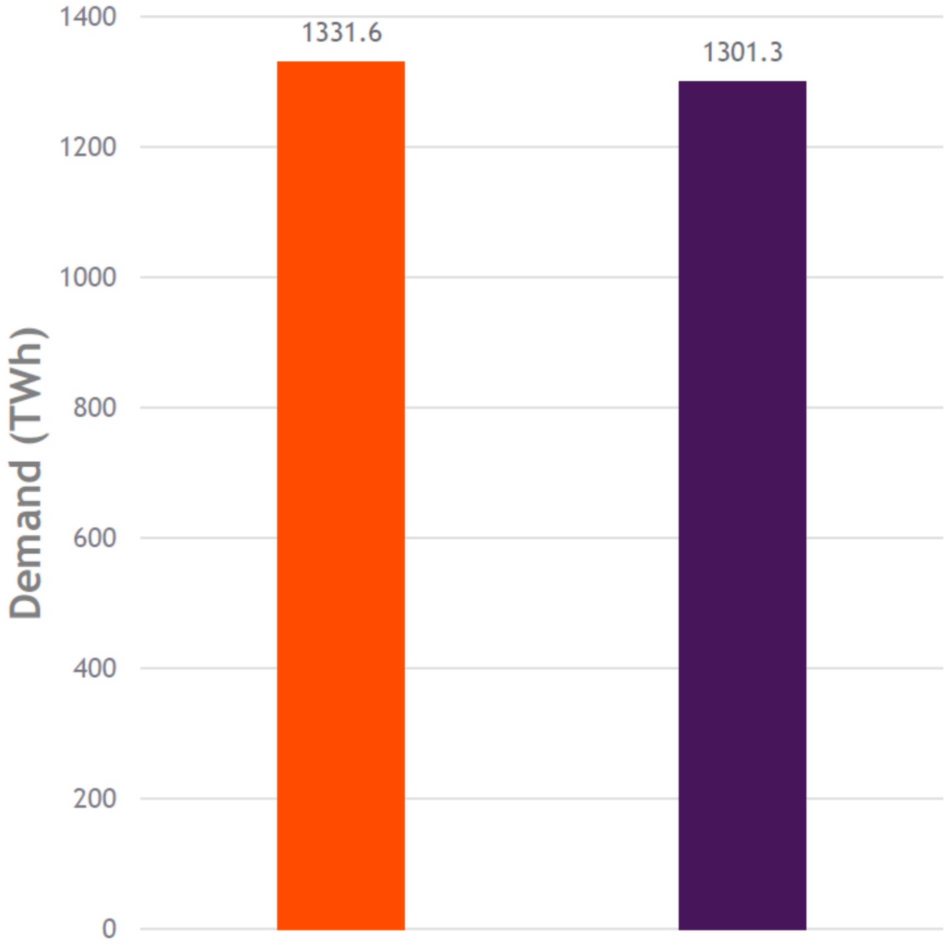

Figure 9. Demand overview: Total demand in winter 2023-2024 (orange) and winter 2024-2025 (purple)

Figure 10 shows a heat map by study zone, comparing the expected consumption in each week with the highest expected weekly consumption in winter 2024–2025. 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 2024–2025. The peak demand in Europe is mostly concentrated during the day.

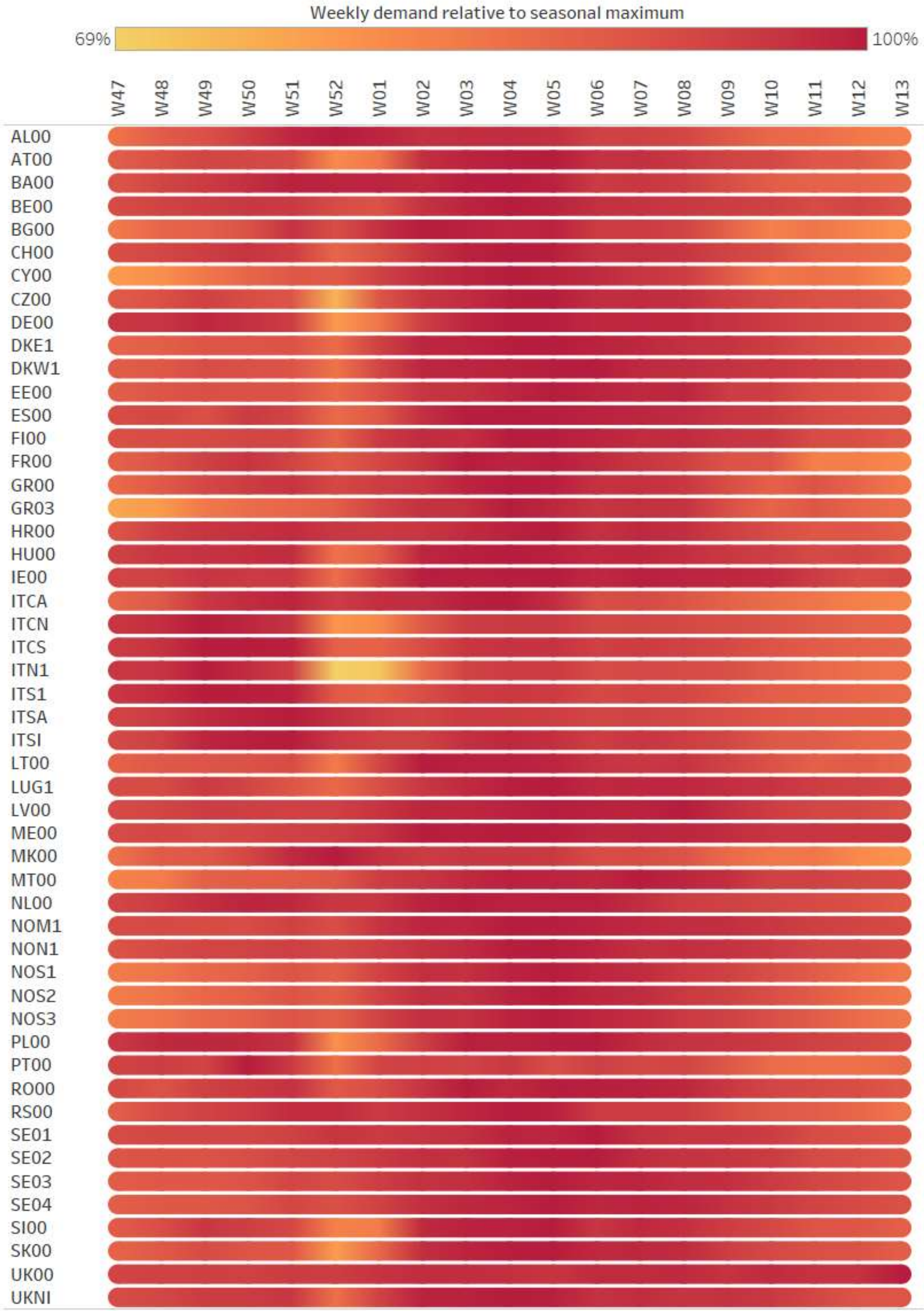

Figure 10. Demand overview: Evolution over winter 2024–2025

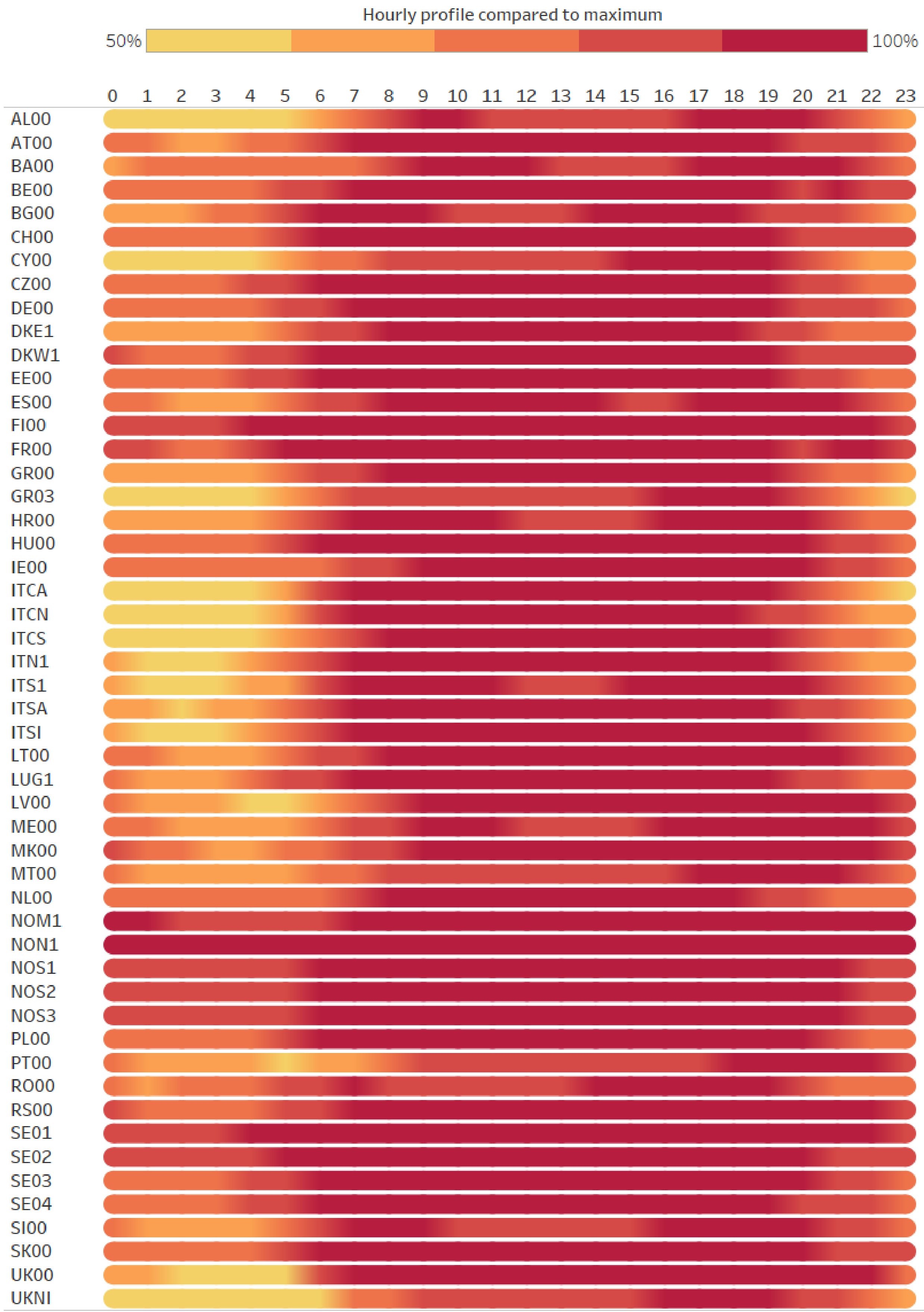

Figure 11. Demand profile overview during Mondays–Fridays in winter 2024–2025[5]

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

Network overview

Figure 12 shows the ratio of the lowest import capacity to the highest expected demand 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 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.

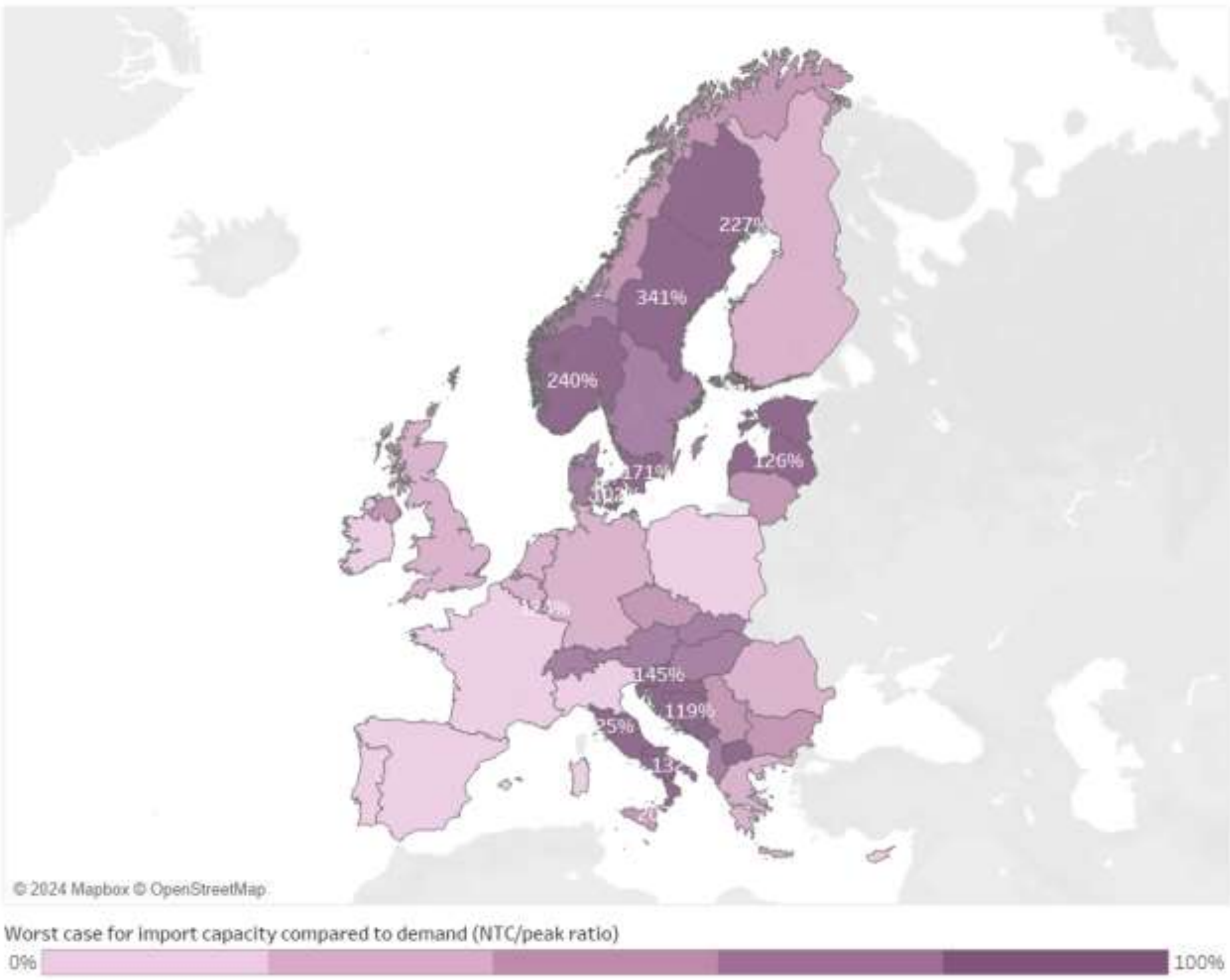

Figure 12. Import capacities per study zone: Ratio between lowest import capacity and highest expected demand (c.f. for details)

4. Adequacy situation and gas need during winter 2024–2025

Reference scenario

The adequacy situation during winter 2024-2025 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 cope with 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.

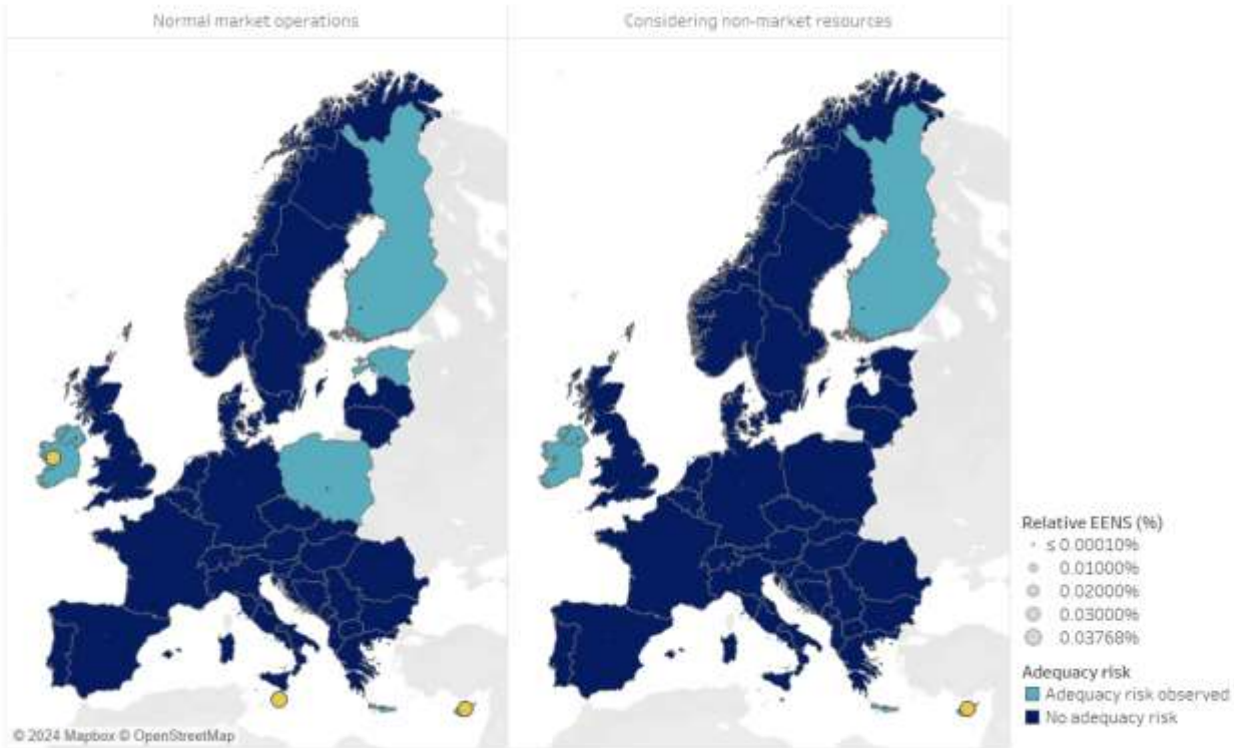

Figure 13. Adequacy overview

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 in Crete (GR03), Estonia (EE00), Finland (FI00), and Poland (PL00). These risks suggest that these systems might need to rely on non-market resources or operational measures to cope with supply challenges and prevent load shedding.

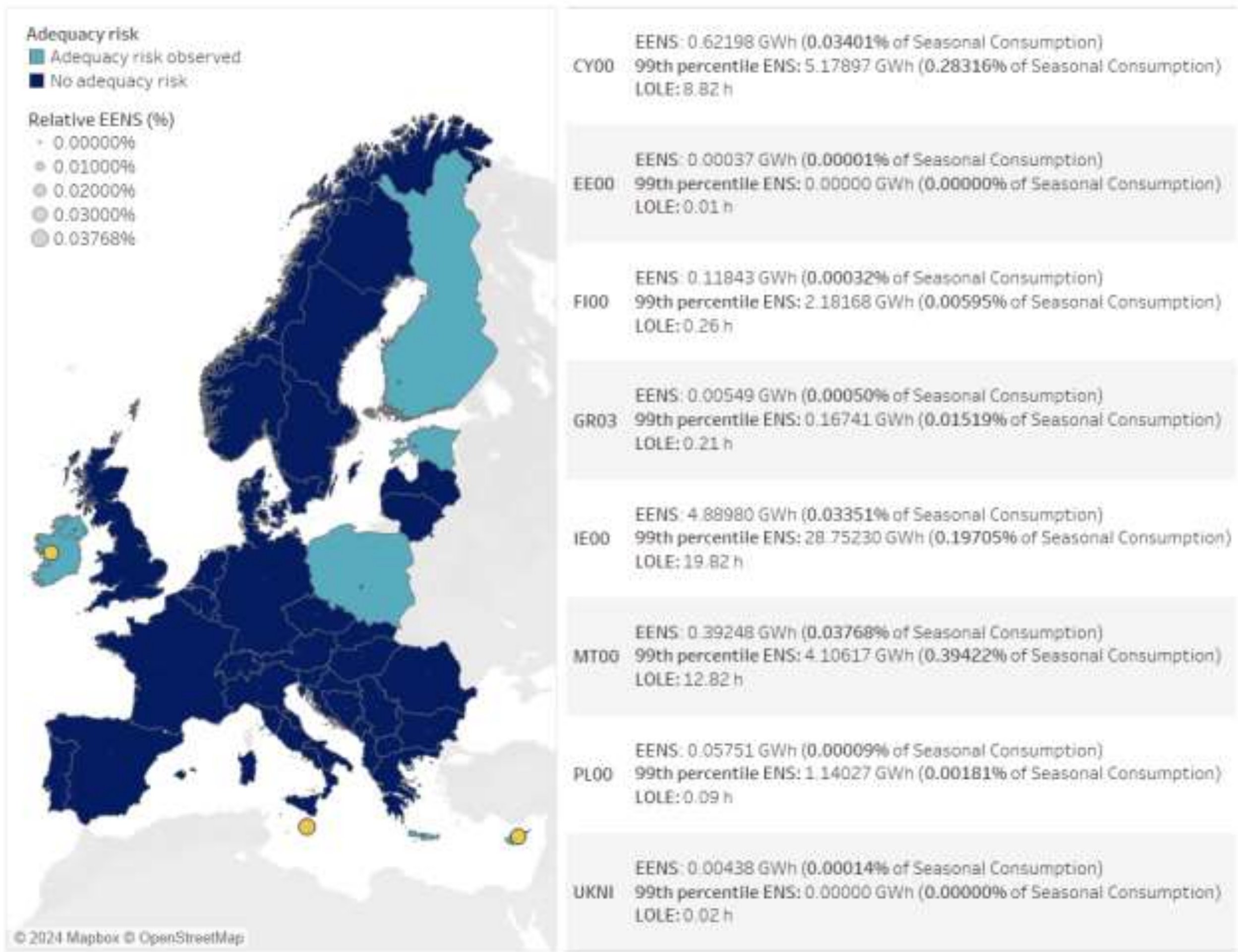

Figure 14. Adequacy risk overview

The loss of load probability (LOLP) for winter 2024-2025 at the weekly level is detailed 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 the other power systems and must therefore rely on domestic supply. Higher risks are identified in the period of January 2025. If unfavourable weather conditions are not combined with high unplanned outages, no adequacy issues should be recorded over winter 2024–2025 in Cyprus.

The Estonian (EE00) system faces minor risks in the winter 2024-2025 as the country is disconnecting its energy infrastructure from the Russian-Belarussian electricity system. Before connecting to the Central European Synchronous Area, the Baltic states (Estonia, Latvia, and Lithuania) will temporarily operate as an "electricity island". Despite the complexity of this switch, no adequacy issues are expected for winter 2024-2025.

Finland's (FI00) risks are minor but suggest 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. The adequacy of electricity increasingly relies on wind power generation, and the reliability of domestic power generation and interconnectors is crucial during cold and calm days.

The Greek island of Crete (GR03) might face minor risks in the upcoming winter 2024-2025. Major infrastructural changes in the power system (DC connection line with the mainland) will be in operation in 2025, implying thermal units being decommissioned once finalised.

Ireland (IE00) is marked with adequacy risks throughout winter 2024-2025, with an expected peak in January 2025. While generation capacity has increased in the past year, the system could enter the alert state at times, most likely during periods of low wind and low interconnector imports.

The Maltese (MT00) system might face risks as of early 2025. Based on careful monitoring of adequacy every winter, Malta has implemented specifically designed non-market resources that could be activated in the event of supply scarcity. The impact of these non-market resources is presented in the following section.

Poland (PL00) faces minor risk in the event of unfavourable weather conditions resulting in a very high demand and low generation from RES technologies. In scarcity periods, a number of remedial measures can be activated to manage shortages.

The risks faced by Northern Ireland (UKNI) remain rather low compared to the risks in Ireland. However, the situation should be closely monitored if weather conditions are unfavourable in Northern Ireland and/or overlapped with forced or unplanned outages of conventional generation.

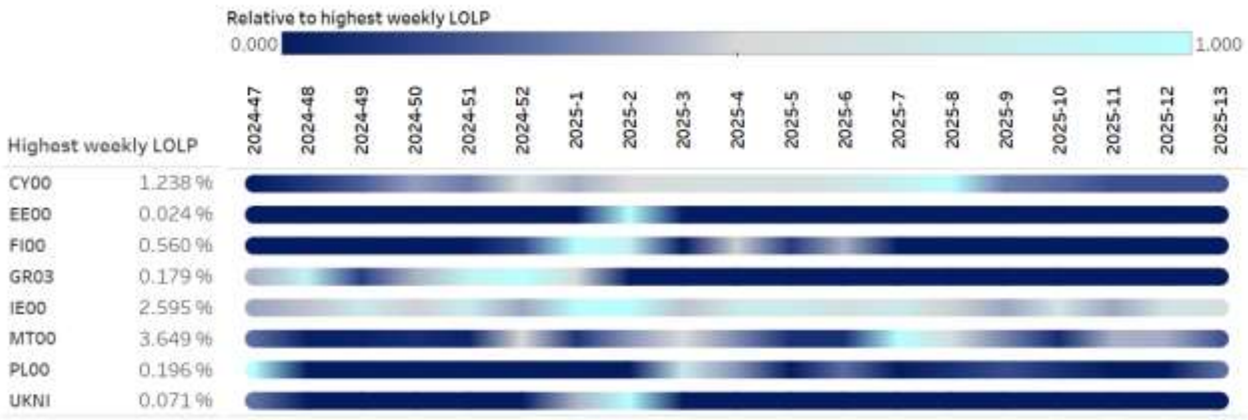

Figure 15. Adequacy weekly insights

Focus on non-market resources

Dispatching non-market resources fully mitigates the risks in Estonia and Poland, while also reducing the magnitude of the risks (EENS), notably in Finland, Ireland, and Malta.

Adequacy risk in Malta is significantly reduced compared to the normal market operation and only traces of risks remain as Malta relies on dedicated non-market resources (c.f. Figure 5). The activation of these resources might depend on the existing legal frameworks.[6]

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

[6] *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.*

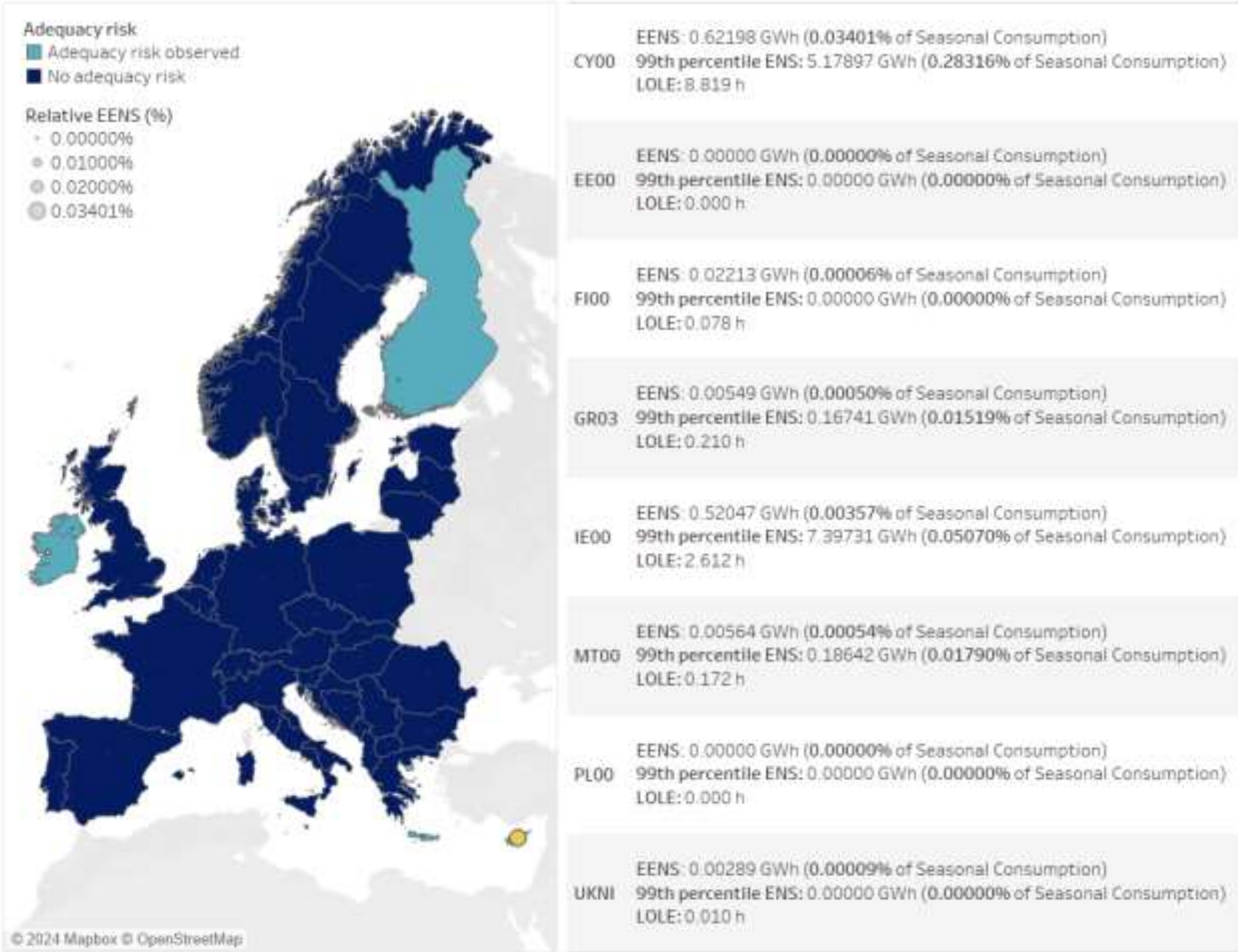

Figure 16. Adequacy risk overview considering non-market resources

The activation of non-market resources significantly reduces LOLP in Ireland, Malta, and – to a lesser extent – Finland (Figure 17). The weekly LOLP remains generally elevated in Cyprus in January and February 2025.

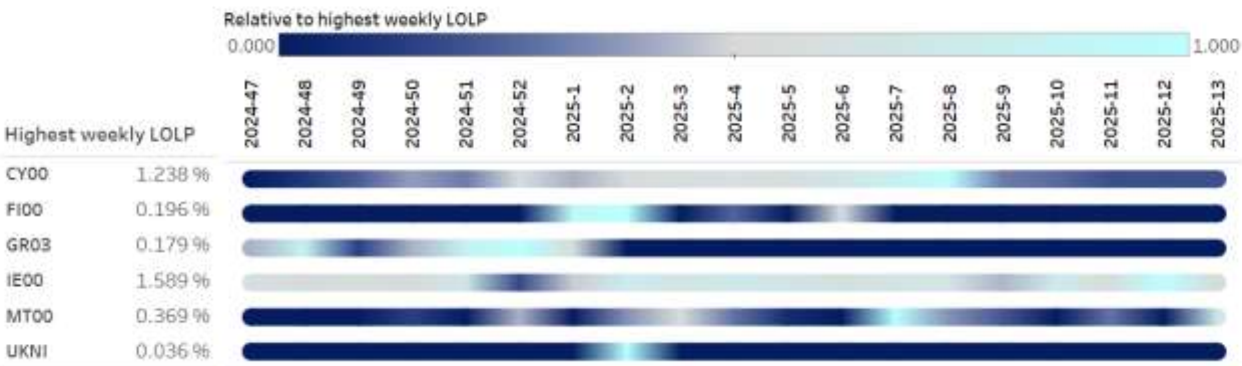

Figure 17. Adequacy weekly insights considering non-market resources

Figure 18 shows the weekly LOLP and EENS, both under normal market operations (light blue) and considering non-market resources (dark blue). Overall, spikes under normal market operations are balanced out (less drastic) when non-market resources are considered. As mentioned above, adequacy risk (LOLP and EENS) is significantly reduced in Finland, Ireland, and Malta when non-market resources are considered.

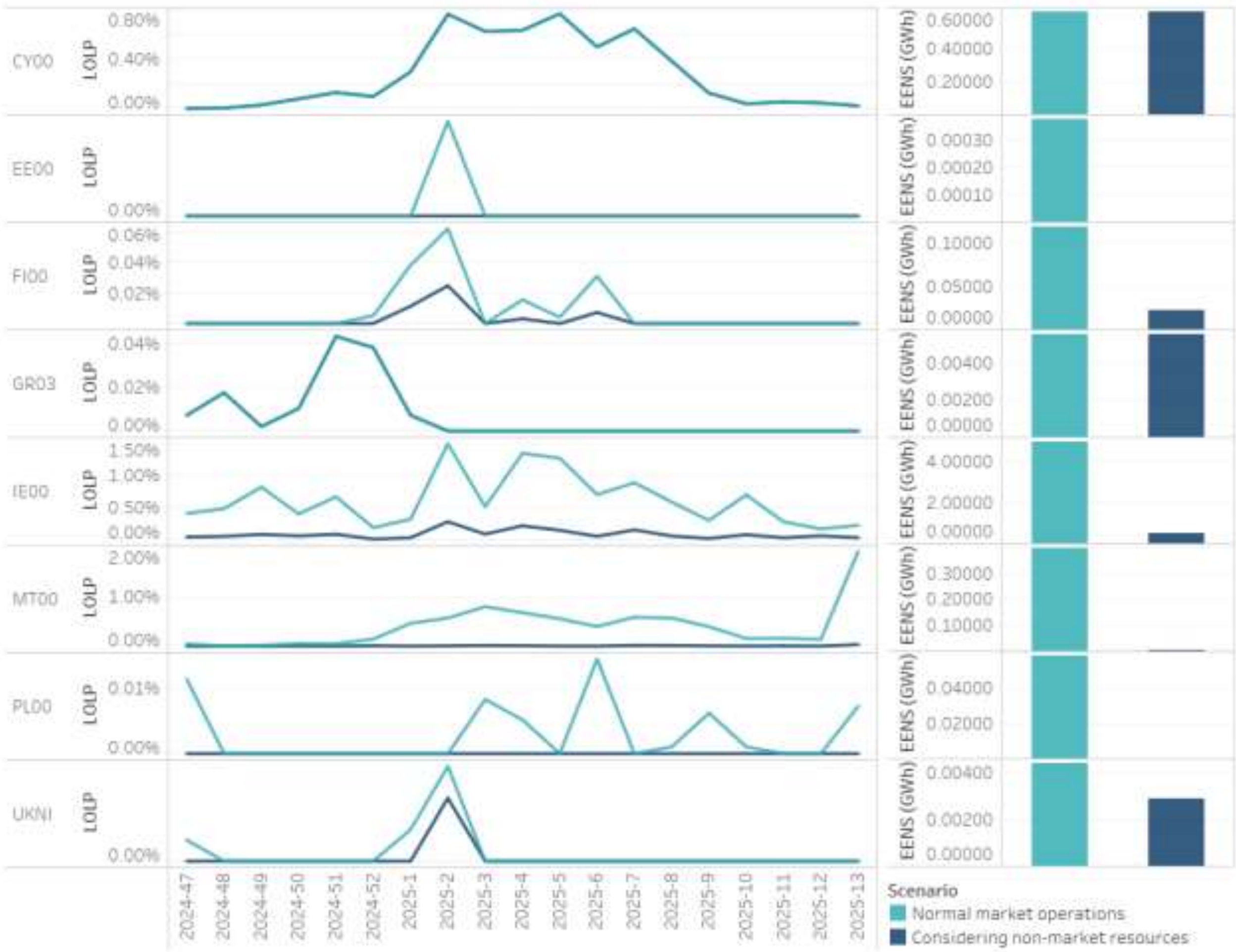

Figure 18. Detailed adequacy overview weekly LOLP and ENS

Critical gas volume for winter 2024–2025

The situation in the European power system is much more certain for winter 2024–2025 than at the same time two years ago in the middle of the European energy crisis. Like the previous winter, Europe has a much greater assurance regarding fuel supply availabilities 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 two years ago. Nevertheless, as for the two previous Winter Outlook assessments, an adequacy and critical gas volume (CGV) analysis has been performed to ensure the awareness of the European power system. CGV projections consider the worst winter scenarios and inform electricity system adequacy. Actual volumes might already be higher, depending on ancillary service demand, additional new unavailabilities, 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.

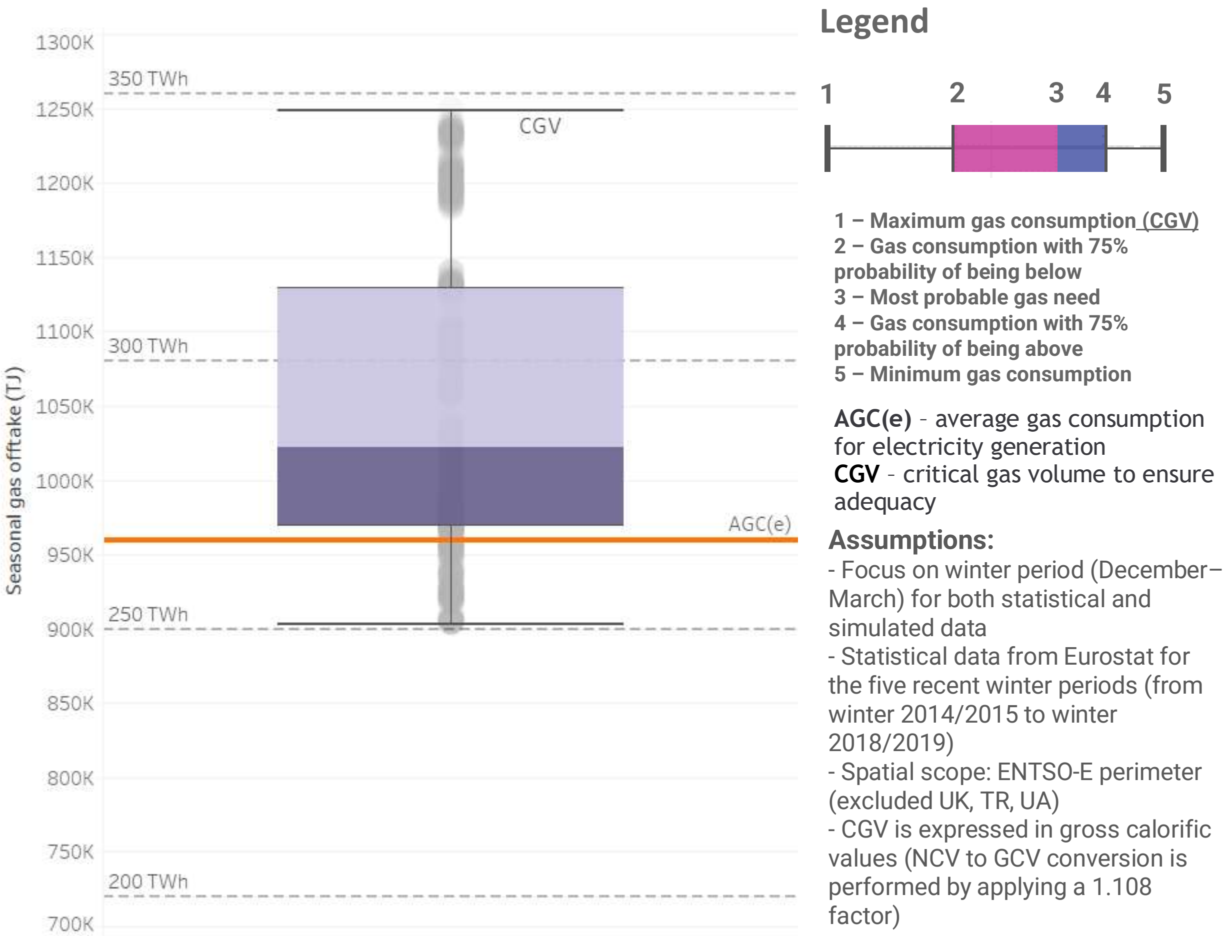

Figure 19. CGV analysis overview

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.

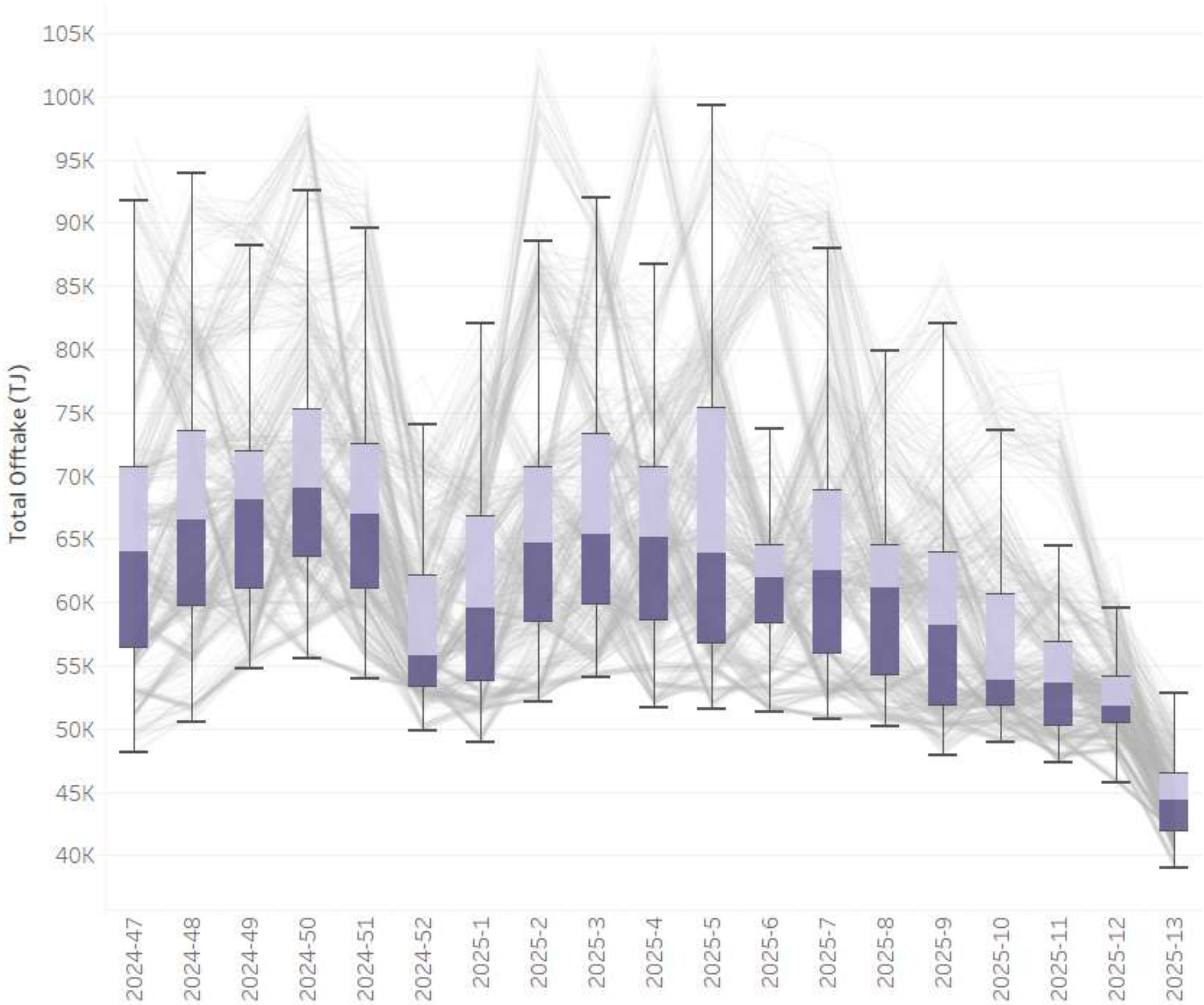

Figure 20. Weekly European gas offtake for the modelled horizon

Expectations for Ukrainian and Moldovan power systems

Russia's military aggression against Ukraine starting in February 2022 has continued during 2023 and 2024, causing increased risk and uncertainty levels in Ukraine's and Moldova's energy systems. Power generation and grid infrastructure availabilities in Ukraine are uncertain due to risks of attacks on these infrastructure objects, which might determine the actual situation in Ukraine's power system.

Since June 2024, following the destruction of numerous power plants in Ukraine and the anticipated large electricity deficit during the winter 2024-25, the TSOs of Continental Europe have evaluated the feasibility to increase the electricity export capacity from the neighbouring EU countries to Ukraine and Moldova, while ensuring power system stability and operational security.

For this purpose, the TSOs have jointly assessed the power system conditions and sought ways to maximise capacity for this winter. The results of the calculations have enabled the TSOs to secure an increase in the export capacity limit to Ukraine and Moldova to 2,100 MW during this winter, representing an increase of 400 MW from the previous value.

This important increase of the electricity export capacity is another sign of the strong support and the solidarity of the European TSO community with the people of Ukraine and Moldova.

The 2,100 MW export capacity limit will apply from 1 December 2024. From March 2025, TSOs will be able to reassess the commercial capacity limit between the EU and Ukraine and Moldova on a monthly basis.

Moldova faces several system adequacy risks for the upcoming winter, including a strong dependence on gas, the unavailability of imports from Ukraine, limited capacity for potential imports from Romania, weak interconnections at the Romanian border, a strong reliance on a single power source, and vulnerability to disturbances in the Ukrainian power system. Other concerns include a lack of flexibility in the power system.

To prepare for winter 2024–25, Moldova has implemented monthly, day-ahead, and intraday capacity allocation at the Moldova-Romania border to maximise the available capacities. Starting from 1 January 2025, Energocom will be nominated as the sole buyer/seller of MGRES electricity, while any other market participant can become a buyer/seller of electricity from any other sources. These preparations – along with infrastructure upgrades, demand reduction measures, and gas stocking in Ukraine and Romania – aim to significantly reduce system risks.

5. Summer 2024 review

Temperature and precipitation overview

Summer 2024 documented record average surface air temperatures in Europe. The average surface air temperature for June-August was the highest on record for Europe and 1.54 °C above the 1991-2020 average. June, July, August and September were each in the range between 1.49 °C (July) and 1.74 °C (September) above the historic average temperatures, thereby breaking or nearly breaking historic monthly average records.

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

Parts of Europe saw substantial heatwaves during the season. Southeastern Europe saw up to 60% more 'warm daytimes' than average. Southeastern Europe experienced 'strong heat stress', where the daily maximum feels-like temperature reached at least 32°C for around two-thirds of the summer period. At 66 days, this is comfortably the largest number of 'strong heat stress' days on record.

Summer 2024 (June-August) was predominantly wetter than average in western and northern Europe. While most of the continent – particularly the southeast – had a below-average number of wet days, other regions – including the Baltic countries, Fennoscandia, and the northern UK – saw up to twenty more wet days than average. Furthermore, September 2024 saw much of Europe experiencing above-average precipitation with Storm Boris leading to heavy rainfall, floods, and associated damage in the middle of the month across Central and Eastern Europe. 35% of European rivers were notably or exceptionally low, especially in the southeast, while much of central Europe saw exceptionally high average river flows for the time of year.

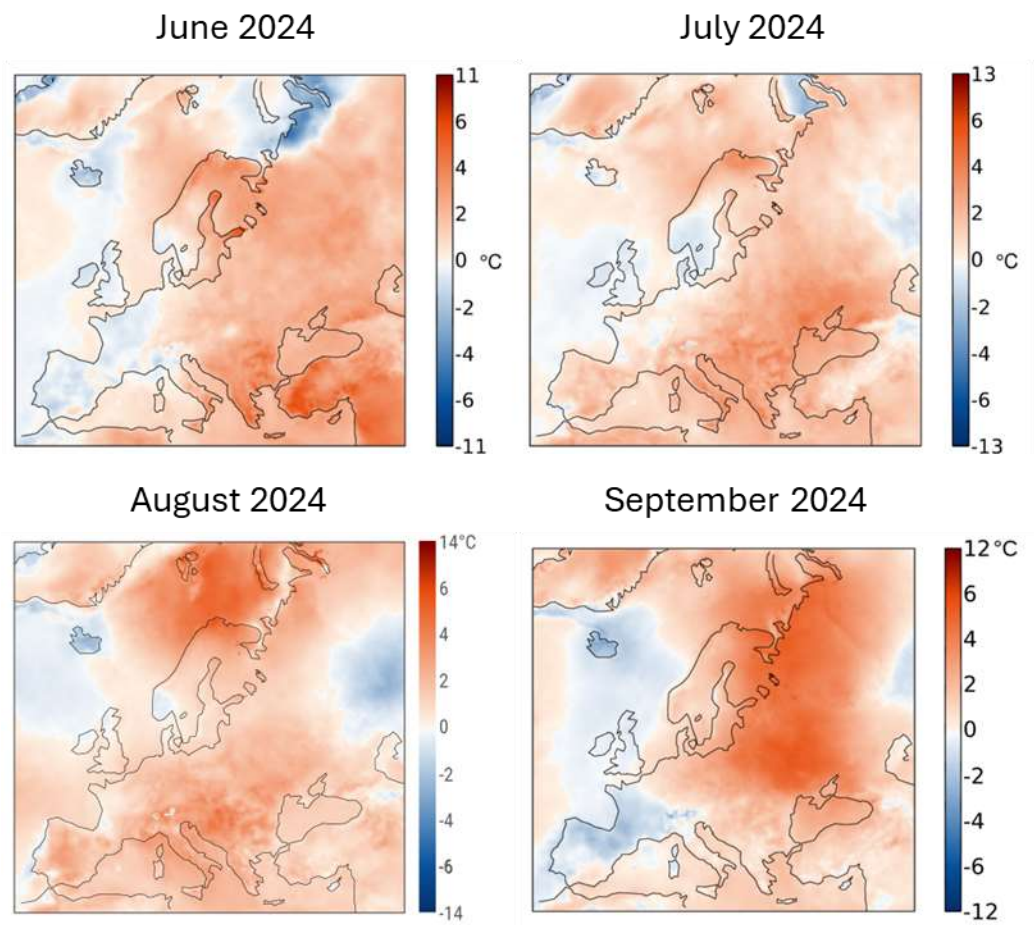

Figure 21. Surface air temperature anomalies in summer 2024 (June-September) relative to the average for 1991–2020[7]

Adequacy and other relevant events overview

In general, no adequacy issues were observed during summer 2024.

On Friday, 21 June 2024, a significant incident occurred in South-East Europe, leading to a major disruption in the Continental Europe power system. The incident resulted in a substantial loss of load and generation, affecting multiple countries including Albania (OST), Bosnia and Herzegovina (NOSBiH), Croatia (HOPS), and Montenegro (CGES). The event was characterised by a series of contingencies in the transmission network, which ultimately led to a (partial) blackout in these four countries.

The incident has been classified as a scale three event under the incident classification scale (ICS) methodology, requiring a detailed report by an expert panel. ENTSO-E published an interim (factual) report[8] in October 2024. The final report – expected to be ready by the end of 2024 – will provide additional clarification, inducing a close exploration of the root cause. However, it is already certain that the incident was not related to resource adequacy but rather real-time grid operations.

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[7] *Copernicus Climate Change Service—Surface air temperature maps.*
[8] *Grid incident in South-East Europe on 21 June 2024 (link).*

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 new methodology is described in the Methodology for Short-term and Seasonal Adequacy Assessments.[9] 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.[10] Although this target methodology's implementation will still require certain extensions in the coming year (for instance, to include flow-based modelling), the present Summer Outlook presents a major advancement.

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 timeframe analysed. Figure 22 provides a schematic representation of this scenario construction process.

Figure 22. Scenarios assessed in Seasonal Outlook

Scenarios are constructed, ensuring that all variables are correlated (interdependent) in 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 ENTSO-E 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 multiple weather scenarios. Furthermore, an improvement in the methodology also enables considering hydro energy availability. Figure 22 illustrates the difference in the number of scenarios between the two modelling approaches.

[9] Methodology for Short-term and Seasonal Adequacy assessment.
[10] ACER decision (No 08/2020) on the methodology for short-term and seasonal adequacy assessments.

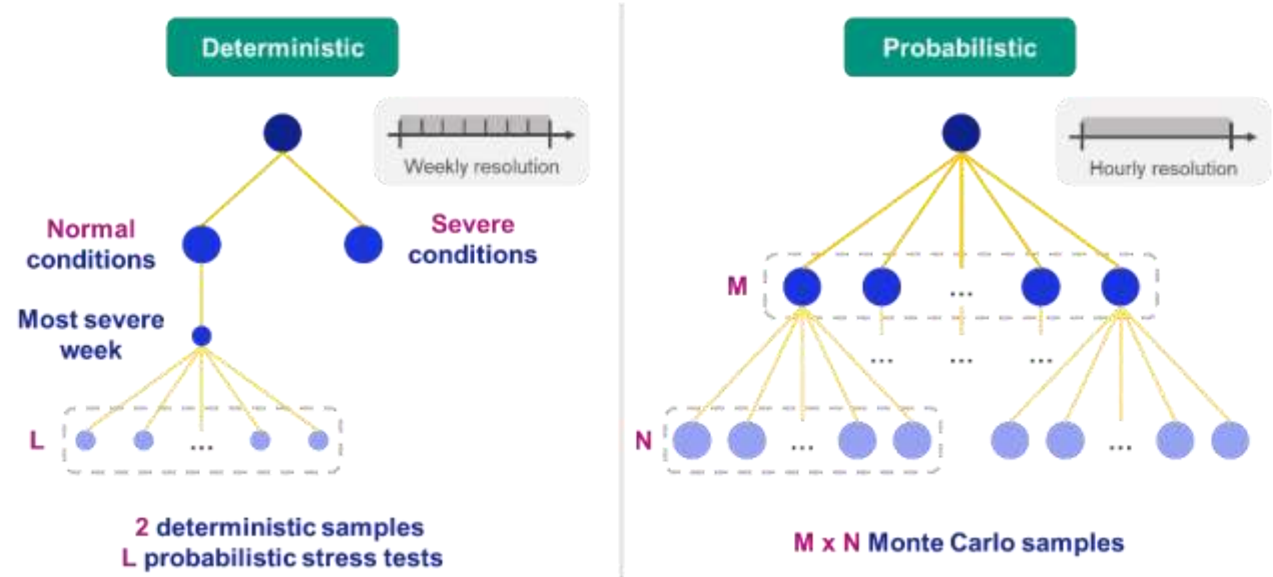

Figure 23. Scenario revolution from deterministic to probabilistic

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. After the Winter Outlook 2020–2021, further improvements were made, especially in the modelling of exchanges, whereby new constraints on total simultaneous exchanges were implemented. In the Summer Outlook 2021, simultaneous import and simultaneous export limitations were considered, likewise limitations on country position (or net exchange).

Appendix 2: Additional information about the study

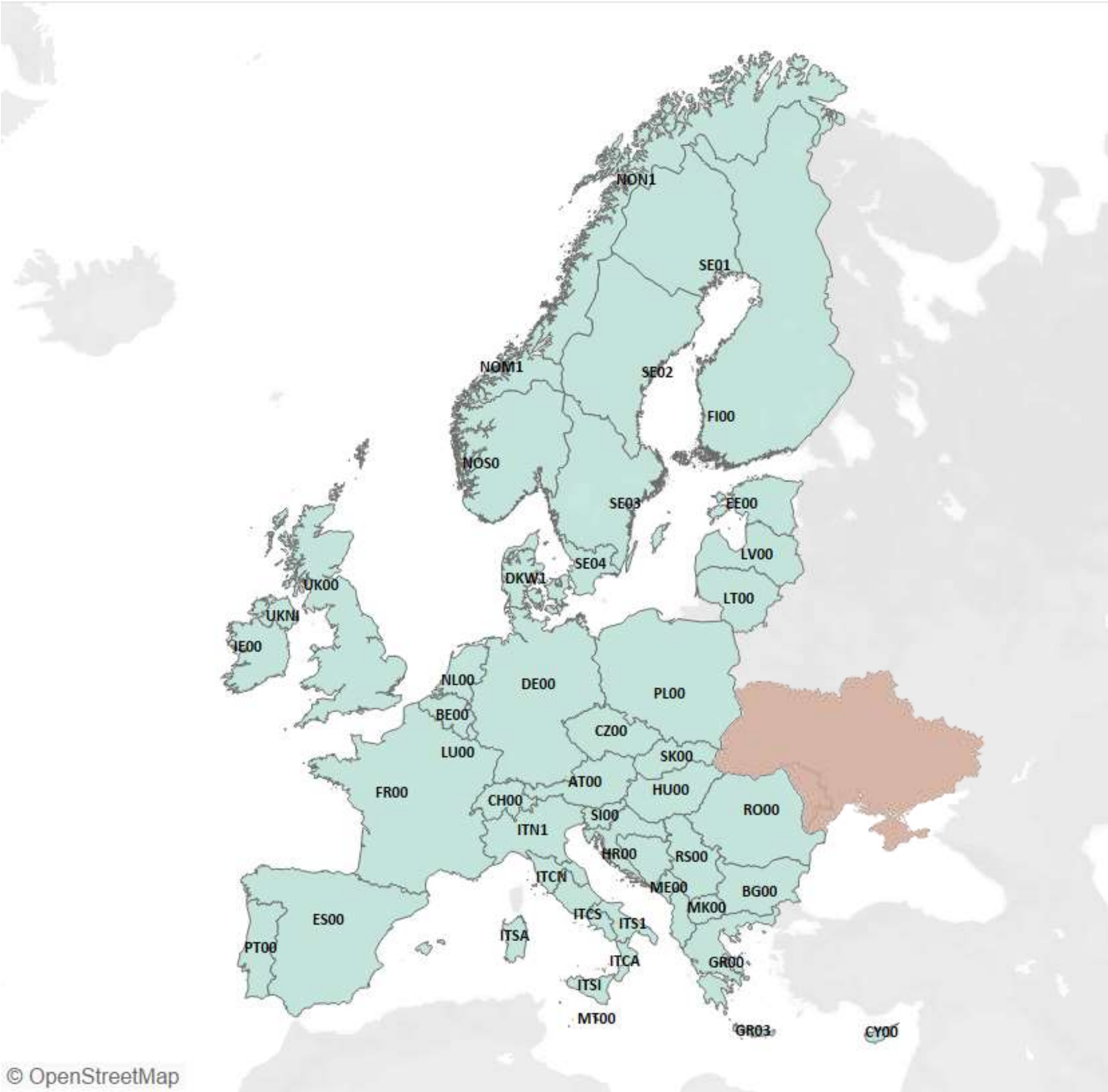

Figure 24. Study zones[11]

[11] *Türkiye could not be modelled in this edition due to data quality issues*

Figure 25. Import capacity overview[12]

[12] *PLI0 represent import on the technical PL00 border with DE00/CZ00/SK00. It limits simultaneous import from respective study zones to Poland until the level of 1,136 MW. The same technical border is used for export purpose (PLE0) and export net transfer capacity (NTC) amounts to 1,650 MW.*

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.[13] However, readers are invited 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 given below, assuming that the annual LOLE reliability standard[14] 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 complies with 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, e.g. 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 comply with the reliability standard. The expected situation in an upcoming season could simply be one of the more constraining from a set of possible season scenarios,[15] e.g. if low water availability in hydro reservoirs and high generation unavailability is expected 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. the establishment of complementary markets such as capacity mechanisms. The latter market decisions are based on a several-year-ahead framework,[16] whereas Seasonal Outlook reports relate to an operational timeframe that relies on the market participants taking short-term corrective actions (e.g. change of planned outage schedules) in addition to the TSOs utilising all available resources in the best manner to reduce the risks to the lowest possible level. Therefore, it is important to understand the purpose of any metric to which Seasonal Outlook results might be compared, and 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).

[13] A comparison with past editions is not yet possible yet because this is the first time that this measure has been reported in a seasonal adequacy assessment.
[14] The conclusions made for annual LOLE are also valid for any other annual metric.
[15] The same applies for a particular historical supply scarcity. If hours when demand was shed exceed the LOLE set by the reliability standard, this does not mean that system design does not comply with the reliability standard. LOLE set by reliability standard simply indicates in how many hours demand shedding is acceptable (due to supply scarcity) over a long time.
[16] Monitored by the European Resource Adequacy Assessment in line with Article 23 of Electricity Regulation 2019/943.

Convergence of the results

In addition to seasonal LOLE results, we also publish the convergence overview, demonstrating the high accuracy of the seasonal assessment.

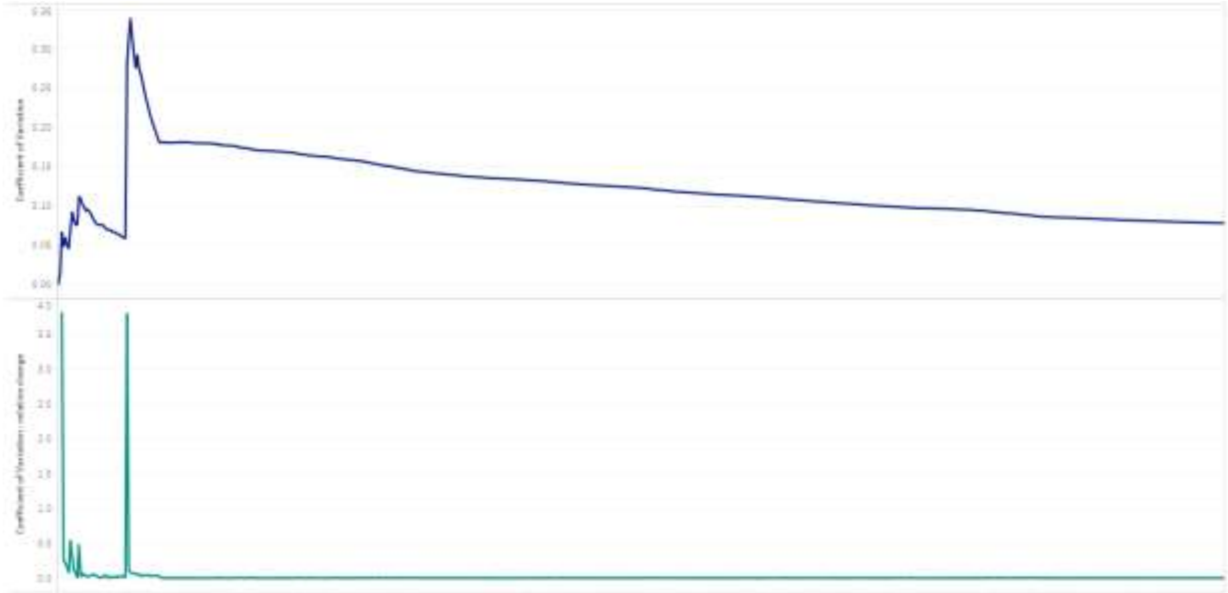

Figure 26. Convergence overview