Summer Outlook 2024

Winter Outlook 2023-2024 Review

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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.

Contents

Executive summary

ENTSO-E Summer Outlook 2024: no adequacy risk is identified in Continental Europe. Less interconnected islands (Ireland, Malta, Cyprus) will require close monitoring.

The adequacy risk identified in Ireland at the end of the summer season is driven by two key factors; multiple overlapping planned large dispatchable generator outages, and the lack of new dispatchable generation entering the market to replace old units which have closed and to cover the increase in demand. The actual adequacy situation in Ireland will depend on the operational conditions: on unplanned outages of the ageing generation fleet and especially on wind generation. Compared to last summer 2023, which showed comparable risks, non-market resources (381 MW) are now available and will significantly alleviate the risks.

Some **residual risks** are identified in rather isolated Mediterranean **islands**: Malta and Cyprus. These risks may emerge in the event of high unplanned outages of the generation fleet and unfavourable weather conditions when demand is high and RES generation is low. Malta relies on non-market resources to ensure security of supply.

Compared to previous seasonal outlook editions this study marks a milestone as the first adequacy report to incorporate **two key methodological advancements** aimed at elevating the quality and precision of the analysis. Firstly, this report pioneered the use of **the Pan-European Climatic Database (PECD)** prepared in collaboration with the Copernicus Climate Change Service. Secondly, the **Pan-European Market Modelling Database (PEMMDB)** has undergone significant enhancements, ensuring data integrity and reliability through streamlined processes and robust validation mechanisms.

The Summer Outlook is accompanied by a retrospect of last winter.

In general, no adequacy issues were observed during the past winter of 2023–2024 due to mild temperatures and favourable hydrological conditions, although some countries experienced challenges. Some countries reported higher-than-expected consumption on record. Notably colder-than-average temperatures were recorded in December and January in the Northern part of Europe, while the Southern part experienced above-average temperatures in the same months.

Preparations for next winter 2024–2025 have begun. The TSOs' feedback as well as the gas situation show a much more confident picture than two years ago. No specific concern was identified. Preparedness and tight cooperation with the European Commission, TSOs and Member States will continue in the coming weeks.

Overview of the power system in summer 2024

Generation overview

The generation capacity overview in Figure 1 shows that sufficient generation capacity to supply consumers is available in most countries. However, generation unavailability (planned or unforeseen) and actual renewable generation infeed have an impact, and some countries may rely more strongly on imports. For example, Central Northern Italy (ITCN) is especially dependent on imports when renewable generation is low.

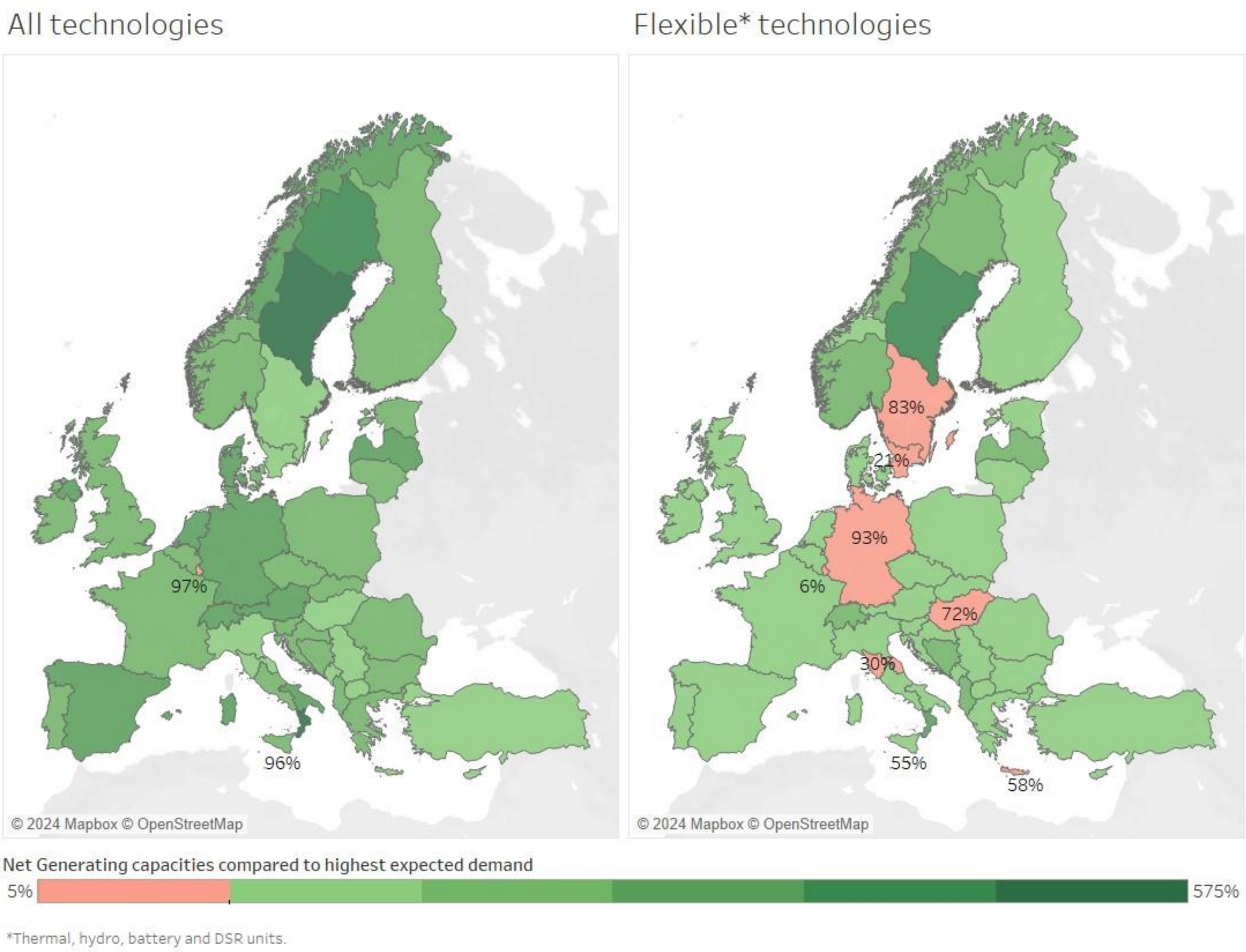

Figure 1: Ratio between the net generating capacity and the highest expected demand

According to Figure 2, thermal net generating capacity (NGC) available on the market accounts for approximately 40% of the total capacity of the European power system at the beginning of summer 2024. This is followed by hydro, wind and solar capacities, which constitute the remainder. In addition, the highest expected demand[1] is depicted with a small black square, and its value is given as a percentage of each study

[1] The highest expected demand is computed by taking the highest value of the hourly demand 95th percentiles. However, the Seasonal Outlook assessment also considers that demand may even exceed the expected highest value as, occasionally, new peak demand records are registered in Europe.

zone's NGC. In most of the study zones, the thermal NGC share is below 60%. This is especially noticeable in study zones with high hydro capacities. Nevertheless, in some study zones (e.g. Western Denmark [DKW1], Germany [DE00] and southern Sweden [SE04]), the thermal NGC share is low despite insignificant hydro capacities. These systems are characterised by a high share of wind and solar generation capacities. Demand Side Response (DSR) resources are gaining volume in Europe. Nevertheless, DSR may be available for a limited period only (e.g. few hours in a day) or at varying capacity. More DSR is likely to be available during peak times, but this is not guaranteed.

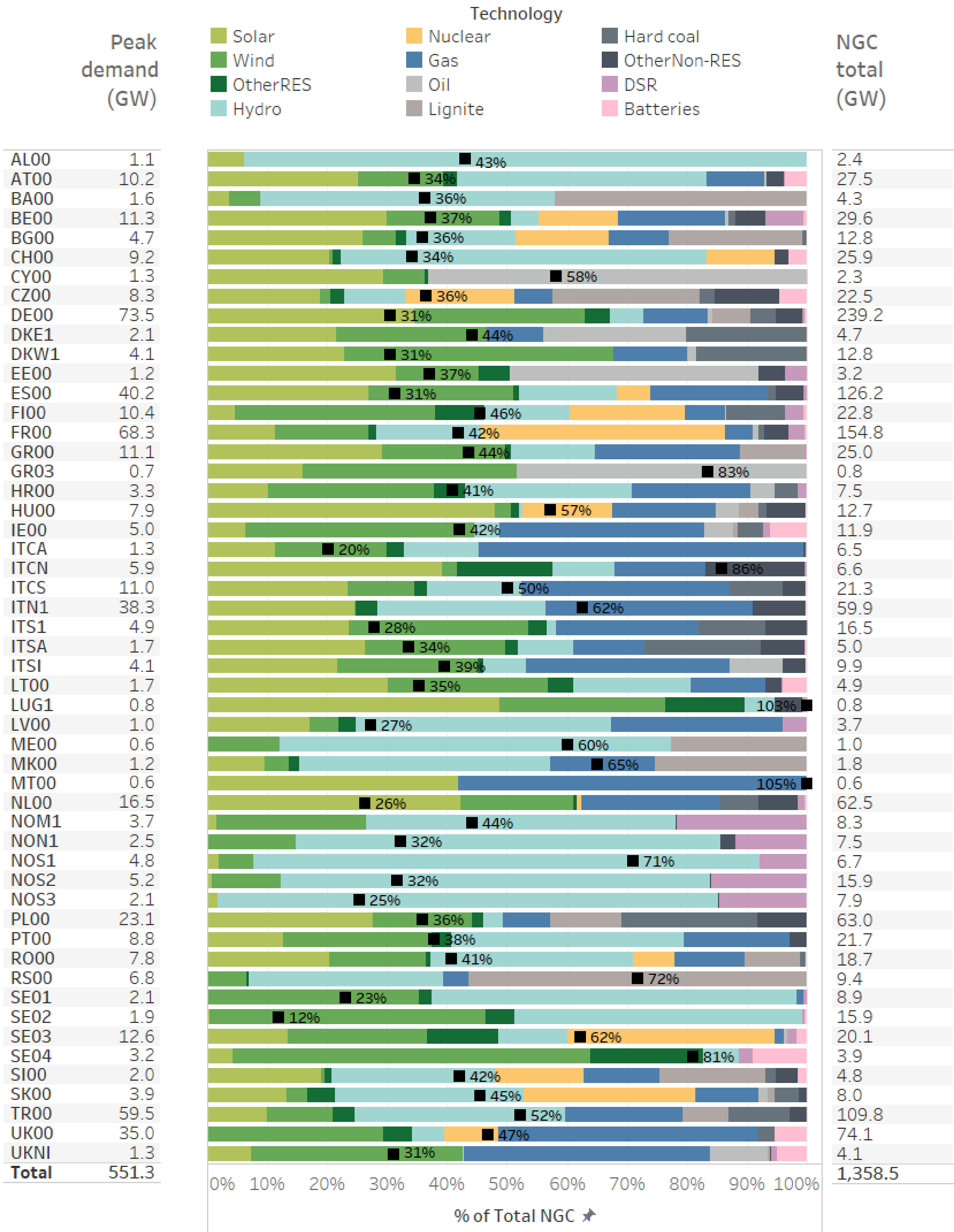

Figure 2: Generation capacity mix at the beginning of summer 2024 per study zones

Figure 3 shows which study zones have non-market resources (NMR) available in addition to the corresponding NGC. In the event of a lack of supply in the market, the activation of dispatchable non-market resources can help address the adequacy challenges. Nine countries utilise non-market resources. From largest to smallest NGC, these are Germany, Poland, Austria, the southern bidding zone of Sweden, Finland, Switzerland, Ireland, Malta and Albania. This report also assesses if these resources are sufficient to address identified adequacy issues (c.f. section 'Adequacy situation in summer 2024').

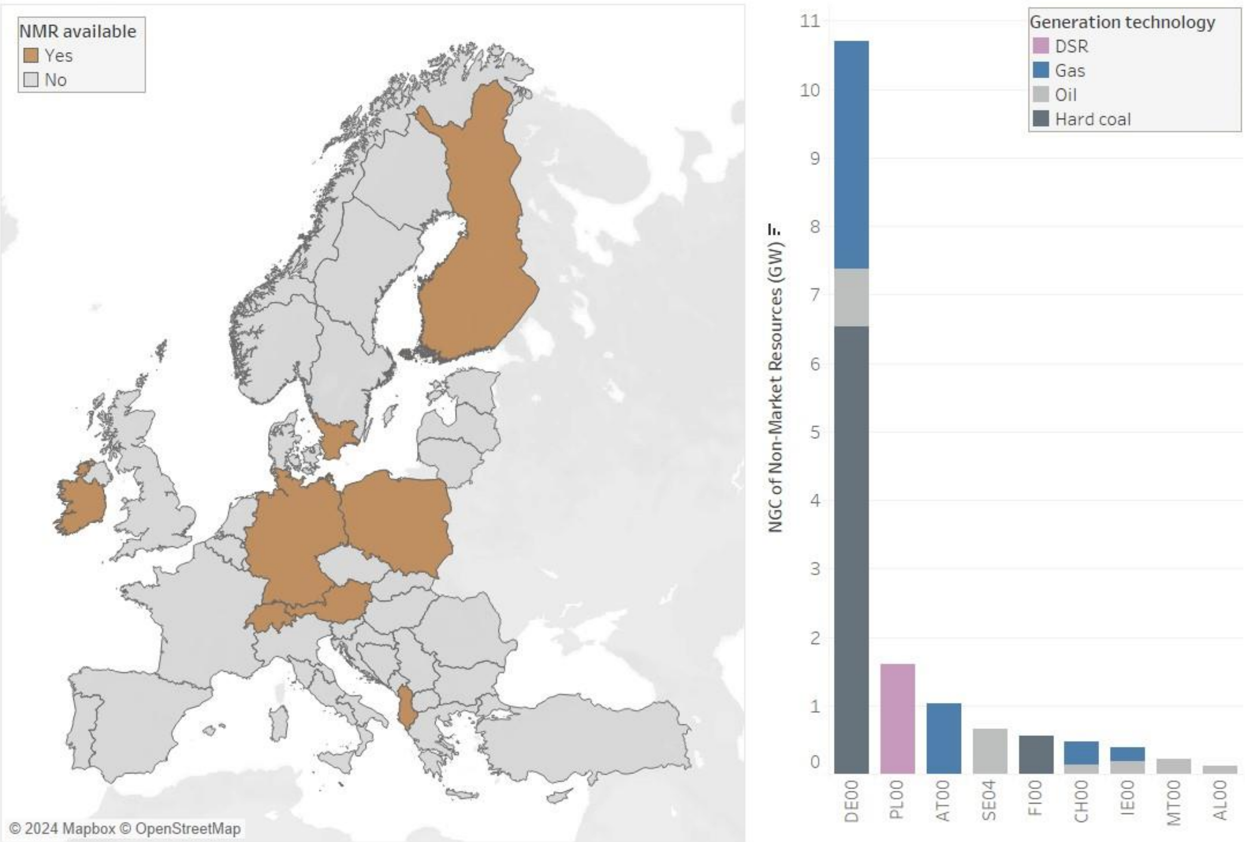

Figure 3: Non-market resources for coping with adequacy challenges in Europe [2]

Net Generating Capacity Evolution

Figure 4 shows that generation capacity in Europe grows during summer 2024[3], with a net increase of approximately 9 GW, due to the expansion of renewable generation capacity. Overall, the thermal generation decreases with around 2 GW decommissioning of hard coal and other fossil fuel power units.

[2] *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.*
Poland has been contracting non-market DSR through their capacity markets. These resources can be activated only under very specific conditions and not in a selective manner (i.e., all resources with a capacity market contract must react during the stress events, i.e., both the generation and demand side). Hence, this non-market DSR is not represented in seasonal outlook models but is reported here for informational purposes.
[3] *27 May 2024 – 6 October 2024*

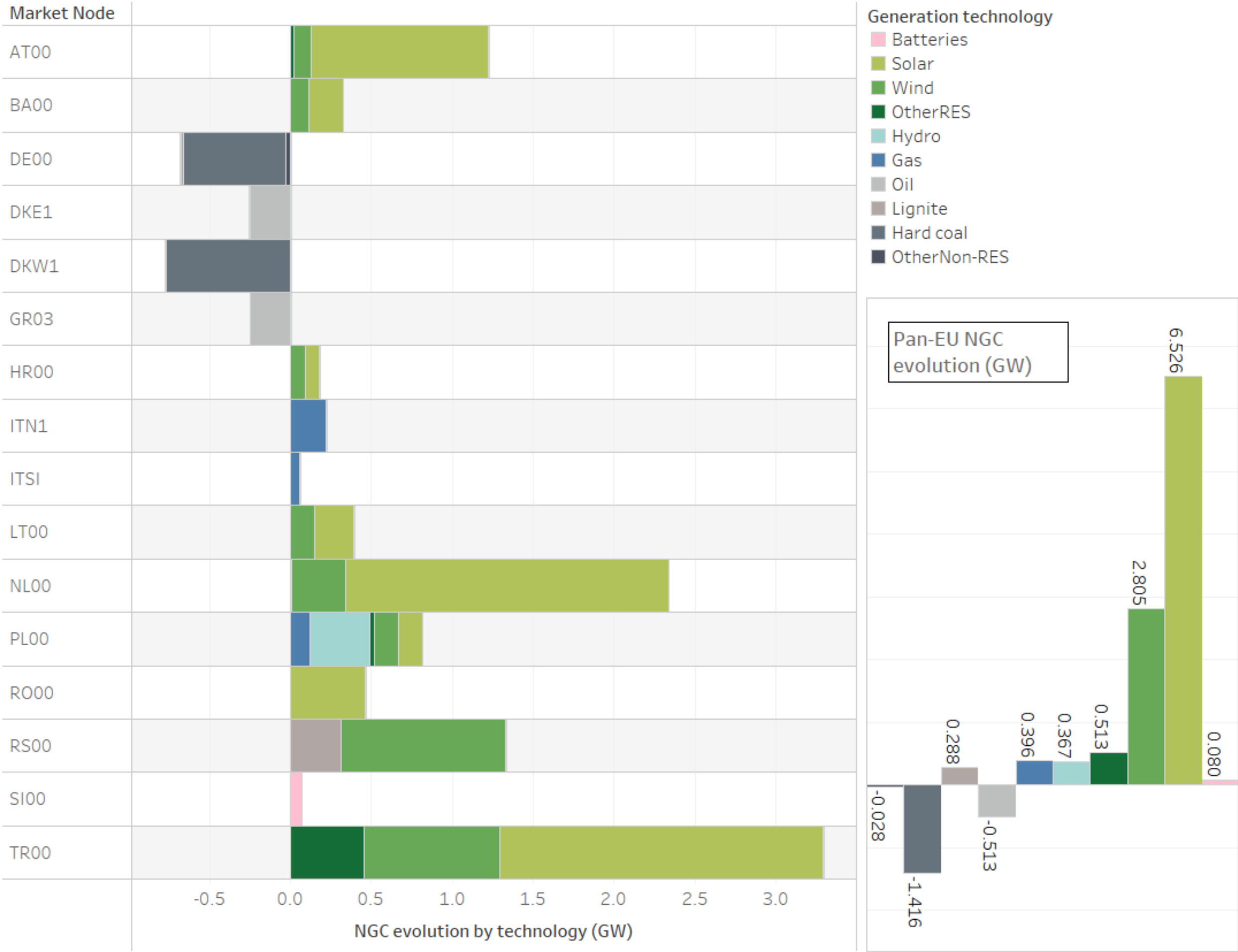

Figure 4: Capacity evolution in summer 2024

Planned unavailability

The planned unavailability of units considered in the assessment is presented in Figure 5. The planned unavailability of generation units includes planned outages for maintenance purposes and mothballing. Total planned unavailability in Europe decreases towards mid-summer and is followed by a minor increase towards the end of summer. Nuclear units show the highest level of unavailability among thermal technologies at the beginning of summer 2024, with gas ranking second, followed by hard coal, lignite, and oil.

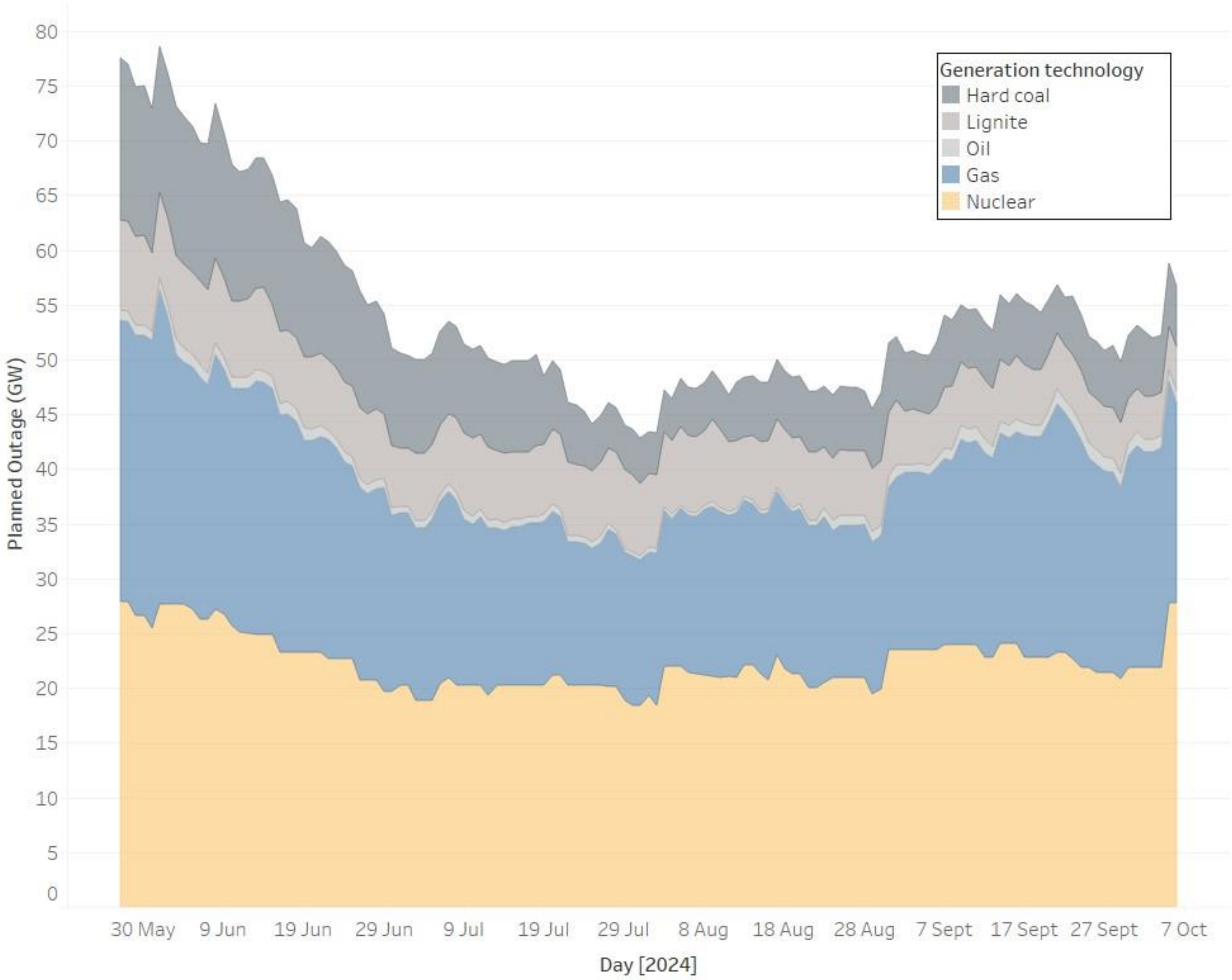

Figure 5: Planned unavailability of thermal units

Planned unavailability in southern countries tends to decrease during the warmest months when the highest demand is expected (i.e., in July and August). This can be observed in the cases of Italy or Greece (GR00) as shown in Figure 6. The figure depicts the weekly ratio of thermal planned unavailability within each study zone with respect to the total thermal NGC of the respective study zone.

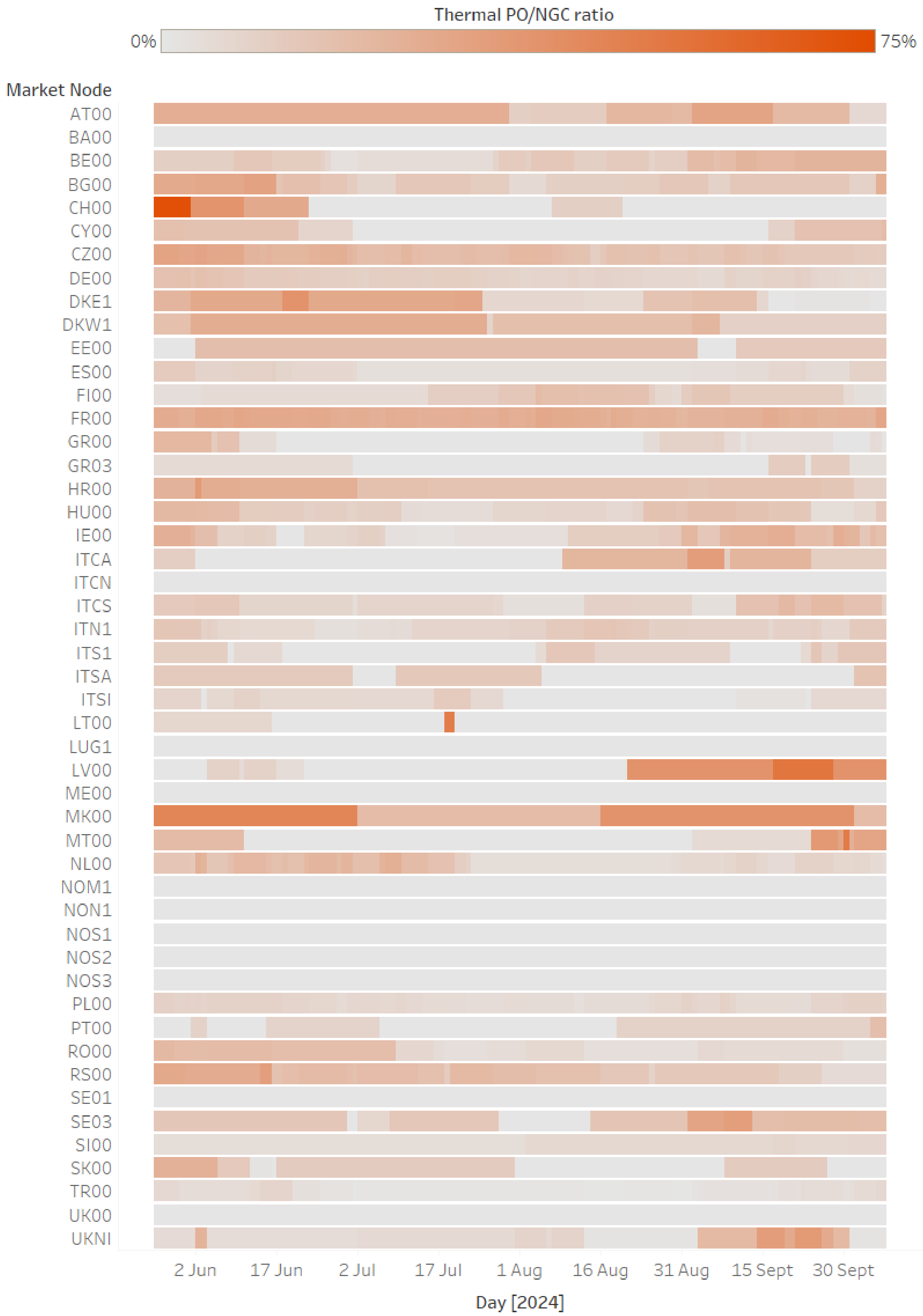

Figure 6: Weekly distribution of thermal planned unavailability relative to thermal NGC

Demand overview

In Figure 7, a heat map by study zone compares the expected consumption in each week with the highest expected weekly consumption in summer 2024. The darker shades indicate high expected consumption compared to the highest expected consumption. Demand in continental western Europe (e.g. Austria, Germany, Netherlands) is relatively stable across the summer period. In southern European countries (e.g. Italy, Greece, Spain), there is a trend towards higher demand in the middle of summer linked to air-conditioning and tourism, when the temperatures reach yearly peak values.

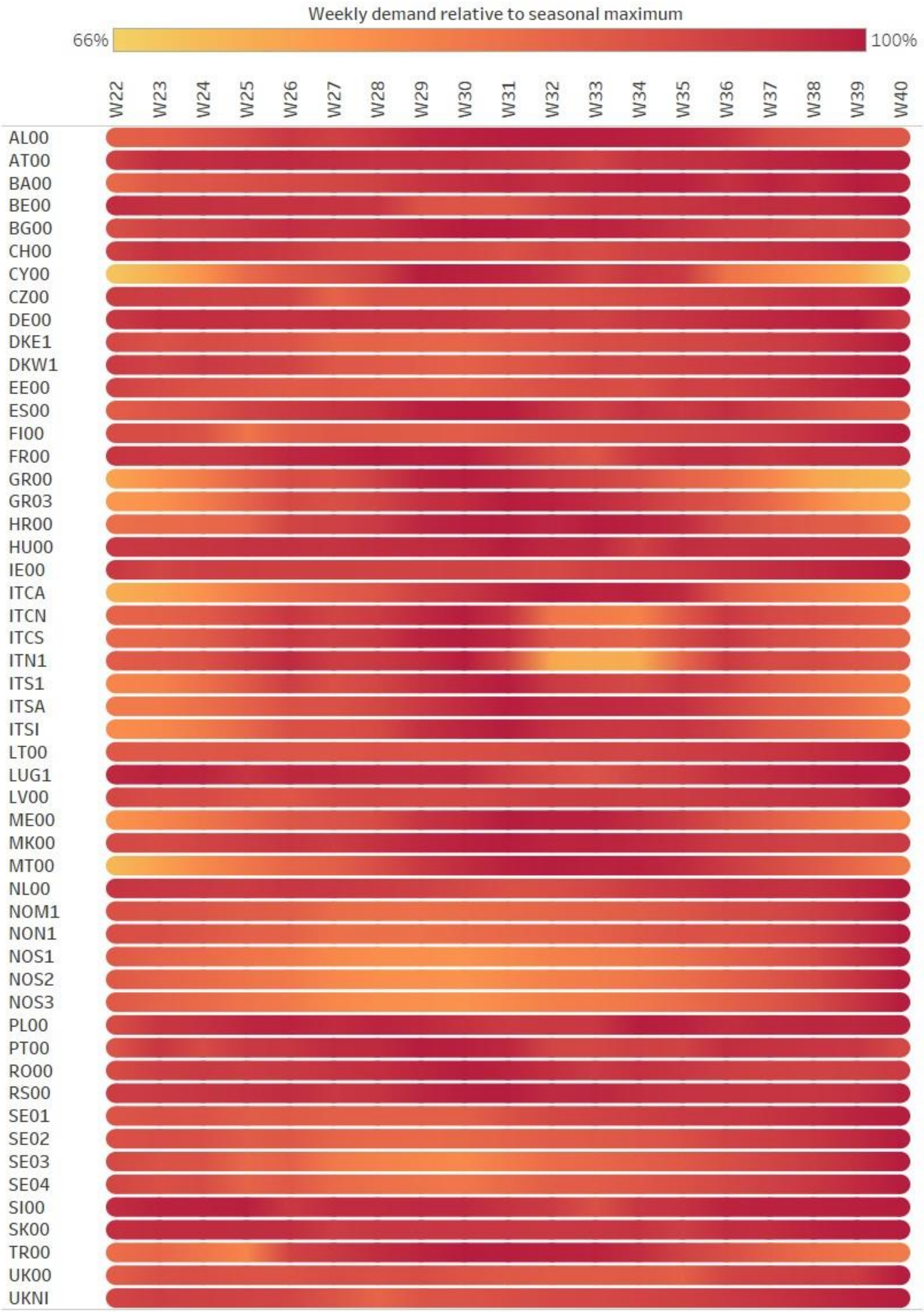

Figure 7: Demand overview—evolution over summer 2024

Figure 8 shows the workday consumption patterns per study zone by plotting the average demand relative to the highest average demand in summer 2024. The peak demand in Europe is mainly concentrated around noon. Some areas (e.g. Finland, Norway, Northern Sweden) face a relatively stable mean demand during the whole day.

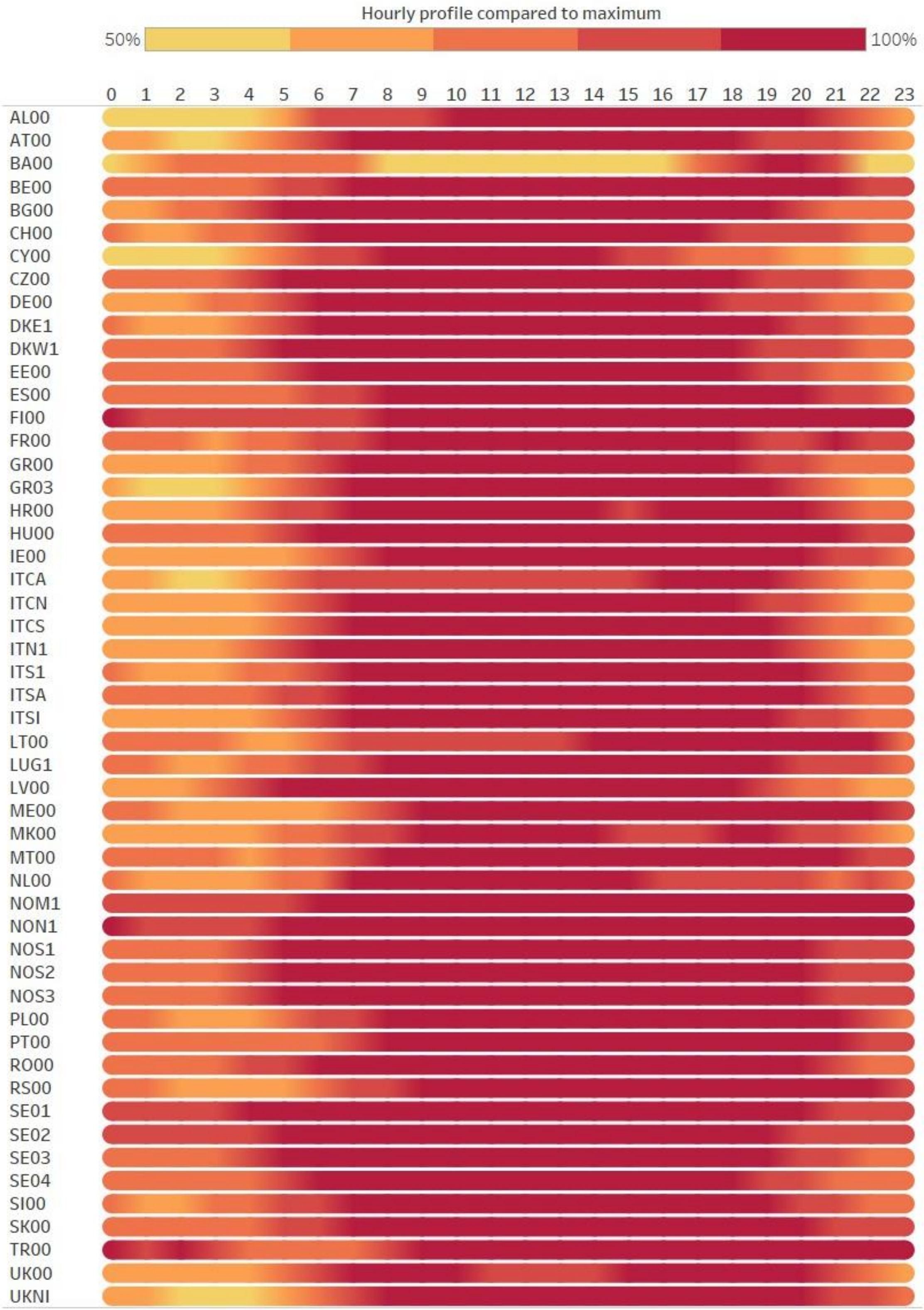

Figure 8: Demand profile overview during Mondays–Fridays in summer 2024[4]

[4] *UTC time convention was used.*

Network overview

Figure 9 shows the ratio of the lowest import capacity to the highest expected demand during the summer. It indicates the extent to which systems may be capable of relying on imports from abroad during supply scarcity moments (if generation abroad is available).

A high import capacity to demand ratio cannot predict whether a study zone is dependent on imports for adequacy. For example, ITCN shows a high import capacity to demand ratio in addition to a low generation capacity to demand ratio (c.f. Figure 1). This indicates that this region is dependent on imports. In contrast, a low import capacity to demand ratio does not guarantee that the system is capable of supplying consumers with domestic generation. Northern Italy (ITN1) for example has a low import capacity to demand ratio but also a rather low generation capacity to demand ratio. Hence, imports to Northern Italy are important for its adequacy as confirmed by the simulations.

The evaluation of import capacities considers the planned unavailability of grid elements. However, additional unplanned outages may constrain import capacities even further. Furthermore, import capacities with non-explicitly modelled systems are not considered in the figure, but their contribution is assessed in adequacy simulations[5].

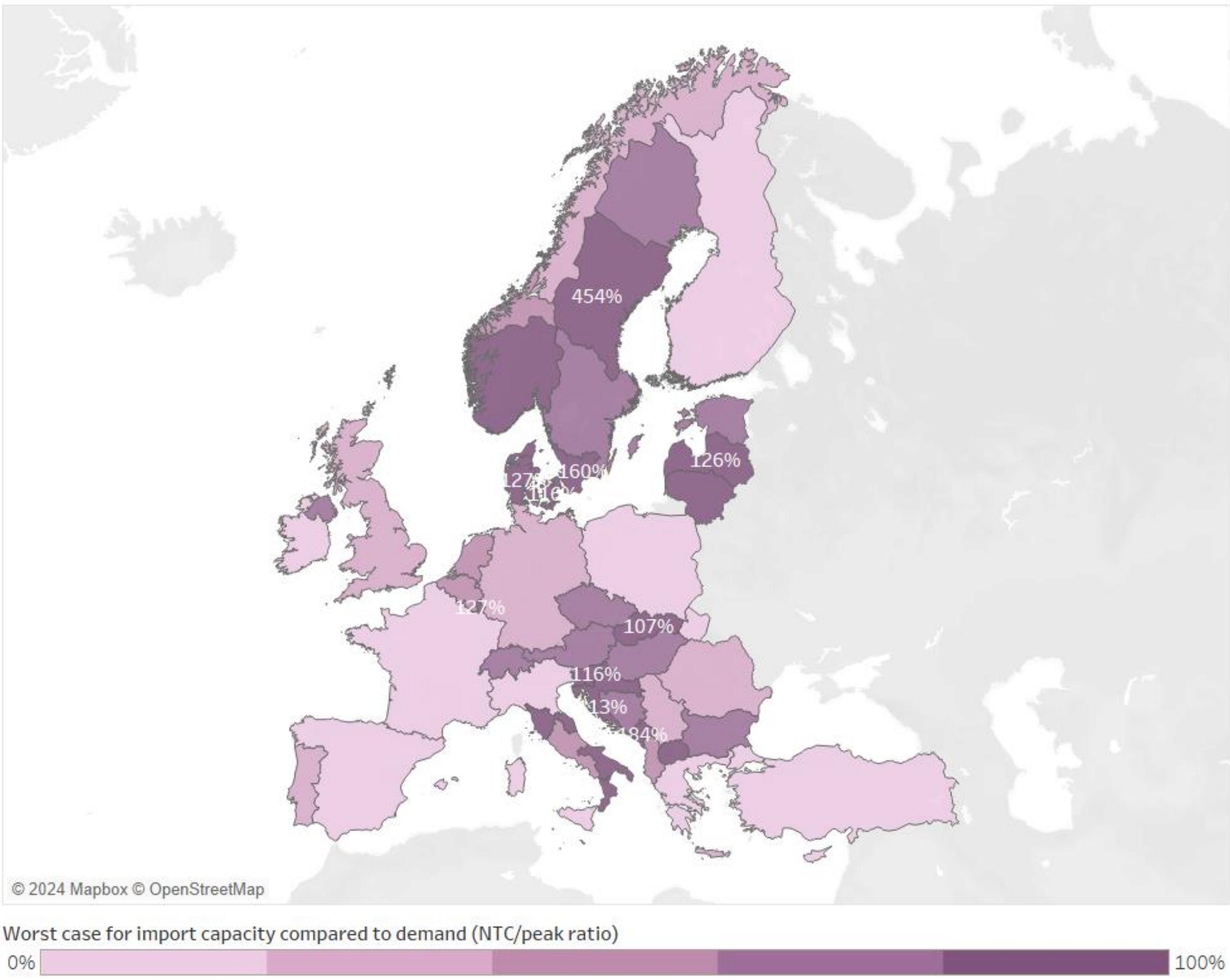

Figure 9: Import capacities per study zone: ratio between lowest import capacity and highest expected demand. C.f. Figure 21 for details

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[5] These systems are modelled in a simplified manner by estimating the potential contributions of those systems to the European power system or potentially needed imports from the European power system. Hence, information concerning interconnection capacity and national assets is not used in the adequacy models and is not collected.

Ukraine and Moldova’s power systems

Ukrenergo and Moldelectrica (the TSOs in Ukraine and Moldova respectively) are part of the European power system and continue working further for the integration of these systems on various technical and institutional levels. They have operated synchronously with the rest of continental Europe’s power systems since 16 March 2022, whereas the Burshtyn Island (located in the western part of Ukraine) has been operating synchronously with continental Europe since 2003. Exchange capacities have continuously increased since then. Furthermore, Ukrenergo and Moldelectrica enhance their contributions to various pan-European studies – close contact was maintained even prior to the Russian invasion of Ukraine in February 2022, but since then collaboration has increased to unprecedented levels.

The Ukrainian and Moldovan situations remain uncertain and difficult to predict due to geopolitical threats. For this reason, the model does not explicitly include demand and supply from the two countries. However, national perspectives on the situation in summer 2024 are presented in this report. Russia’s war in Ukraine continues to pose significant threats to energy infrastructure. Geopolitical tension in Moldova (Transnistria and Gagauzia), in addition to the uncertainty of gas supplies in Moldova, creates additional uncertainty. These systems rely on potential support from other European countries who are continuously investigating available measures to increase support for these systems – especially during the most critical moments.

Ukrenergo and Moldelectrica collaborate with other European TSOs. Even if resource availabilities in Ukraine and Moldova remain uncertain, the transmission network should remain available for transit flows between other European power systems.

Adequacy situation in summer 2024

ENTSO-E assesses the adequacy situation 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 for solving the risks identified in the previous step. The non-market resources can be activated to cope with structural supply shortages in the market.

The adequacy situation in the summer of 2024 (Figure 10) highlights certain adequacy risks—i.e., the risk of having to rely on non-market measures—in Cyprus, Ireland, and Malta. Non-market resources significantly mitigate risks in Malta and Ireland, where they are available. However, risks remain largely unchanged in Cyprus as these resources do not exist and the system is not interconnected with the rest of Europe.

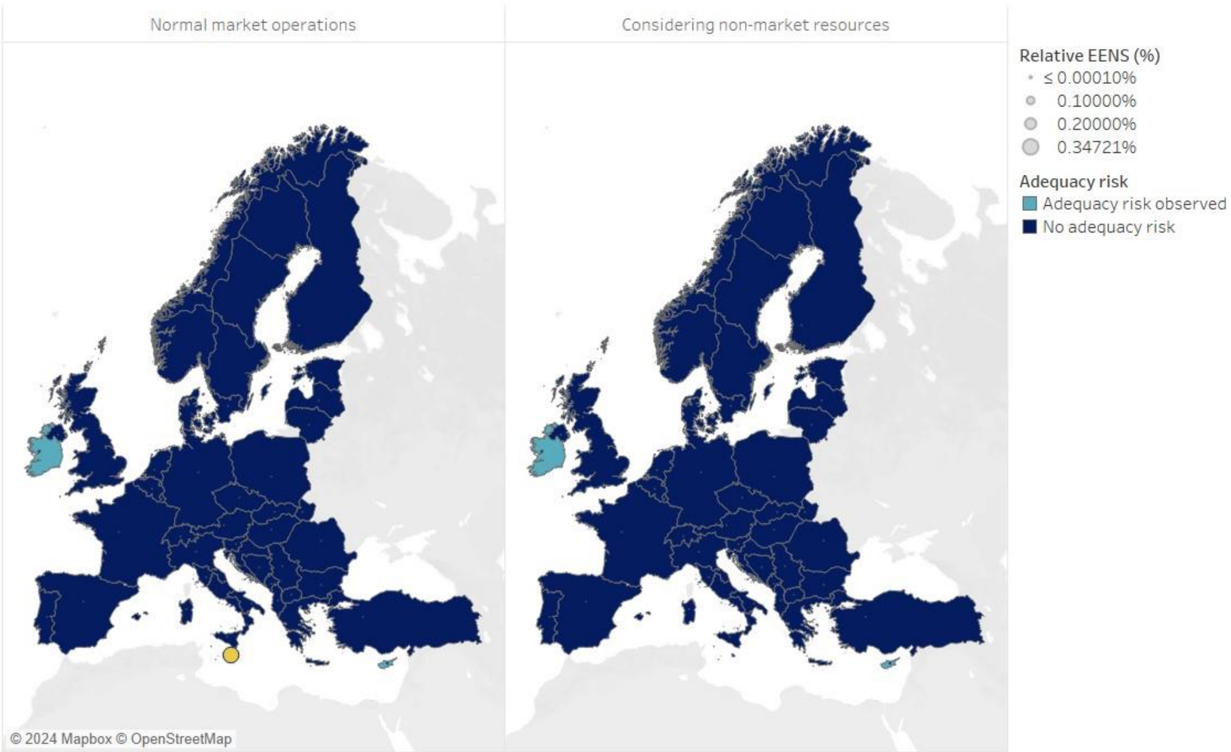

Figure 10: Adequacy overview

The state of the power system is continuously changing and has changed since the data collection (performed in March 2024). For this reason, risks are continuously being monitored by TSOs and Regional Coordination Centres (RCCs).

Focus on adequacy under normal market conditions

Figure 11 presents the adequacy situation under normal market operations. For most countries, no adequacy risks are identified, except for Ireland (IE00), Cyprus (CY00), and Malta (MT00) which have limited or no interconnection to the European continental network. These risks suggest that systems may need to rely on non-market resources or operational measures to cope with supply challenges to prevent load shedding.

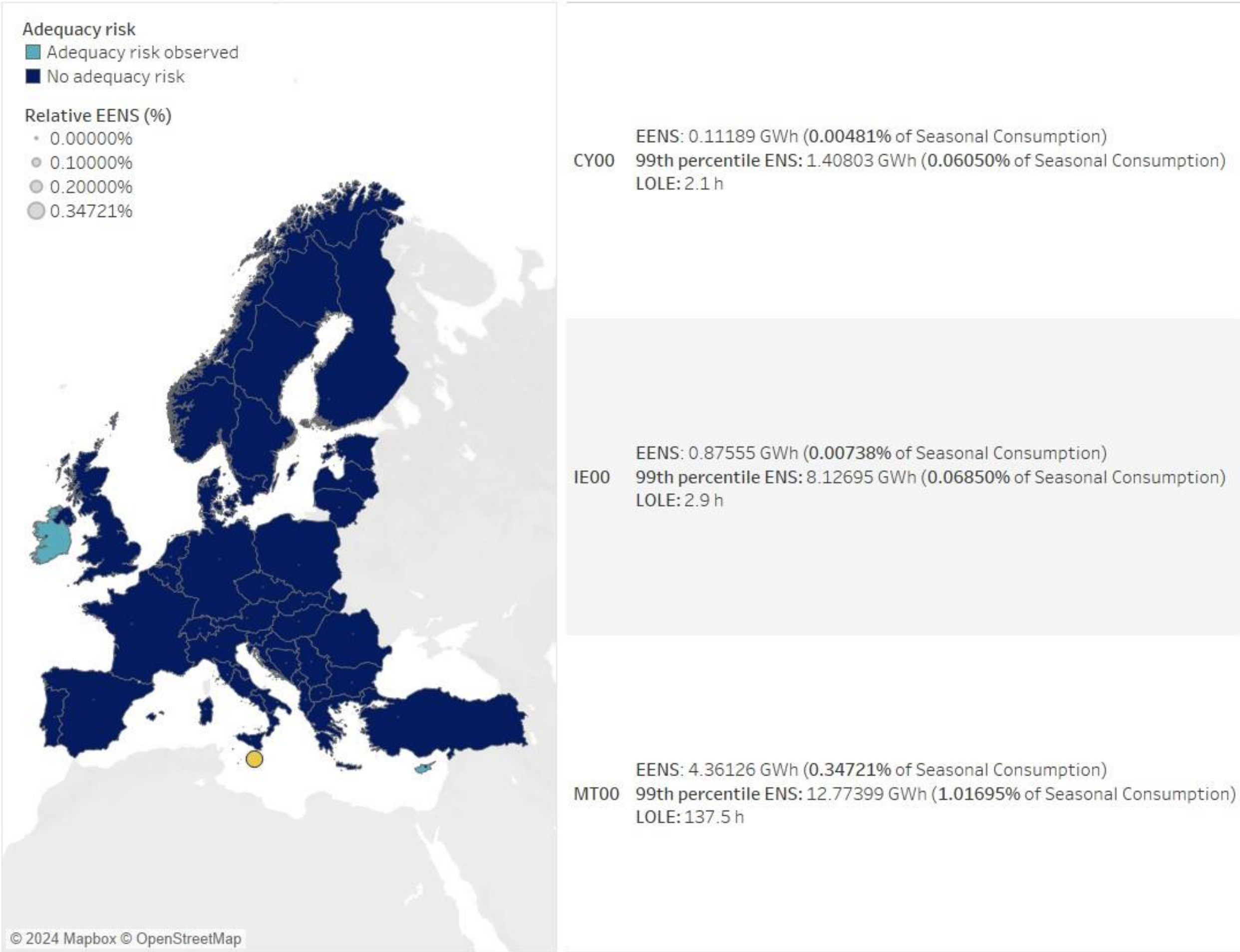

Figure 11: Adequacy risk overview

The distribution of risks within the season is presented in Figure 12 via the visualisation of Loss Of Load Probability (LOLP). No common pattern could be observed as all systems with risks are rather distant from each other, and system-specific conditions may cause local adequacy issues.

Cyprus (CY00) shows a low probability of adequacy issues distributed over the whole summer. This Loss of Load probability arrives in scenarios of high load combined with high unplanned outages of conventional generation. The Cypriot system has no interconnection to the other power systems and, hence, has to rely on domestic supply. If weather conditions are favourable or at least not combined with high unplanned outages, no adequacy issues should be recorded over the summer of 2024 in Cyprus. Ireland (IE00) is marked with adequacy risks in September, where most of the planned outage on conventional generation is foreseen (up to 1.1 GW). These risks are driven by unplanned outages of ageing power plants and will depend on wind generation if such outages occur. The planned outage of conventional generation in Northern Ireland (expected to exceed 700 MW) also limits the capability to rely on imports from the Northern Ireland system. The actual adequacy situation in Ireland will depend on operational conditions such as unplanned outages of the ageing generation fleet in Ireland and especially wind generation.

The adequacy situation in Malta (MT00) should be monitored throughout the summer, with special attention during the middle of the summer. This corresponds very closely to the demand profile in summer 2024 in Malta (c.f. Figure 7). Also, September shows a peak of Loss of Load Probability linked to conventional power plant planned outages. Adequacy in Malta is typically carefully monitored every summer, and for this reason, Malta implemented specifically designed non-market resources, which could be activated in the event of supply scarcity. The impact of these non-market resources is presented in the following section.

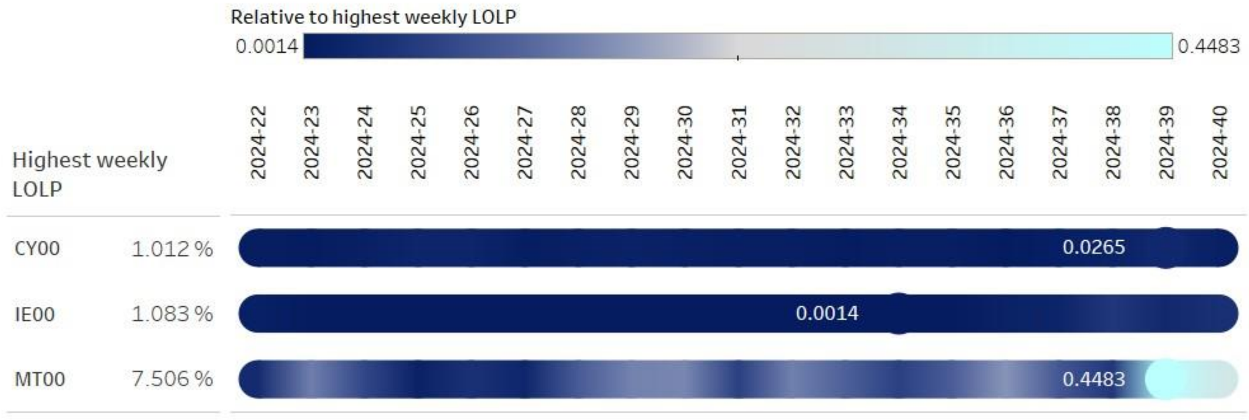

Figure 12: Adequacy weekly insights

Focus on non-market resources

Figure 13 presents the adequacy conditions with non-market resources. The magnitude of the risks (EENS) remains the same, except for Malta and Ireland. It is significantly reduced for the two study zones when compared to the normal market operation as both rely on dedicated non-market resources (c.f. Figure 3).

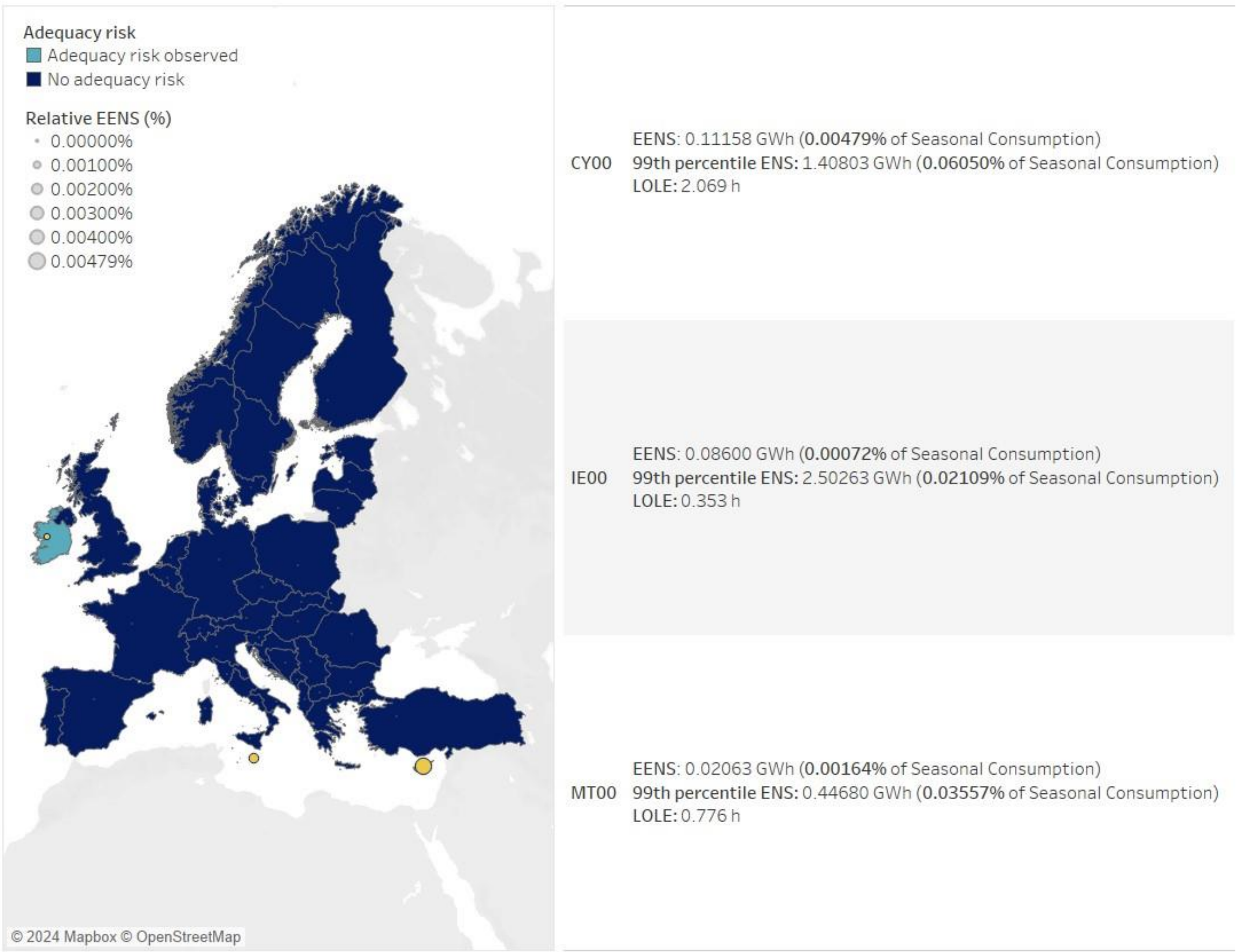

Figure 13: Adequacy risk overview—considering non-market resources

The LOLP in Malta is significantly lower when non-market resources are considered (Figure 14) and shows only occasional risks.

The LOLP in Ireland is significantly reduced over the month of September (Figure 14). This suggests that partial demand shedding might be required only under exceptional operational conditions and only if these conditions occur weeks with an elevated adequacy risk (especially weeks 34 to 40).

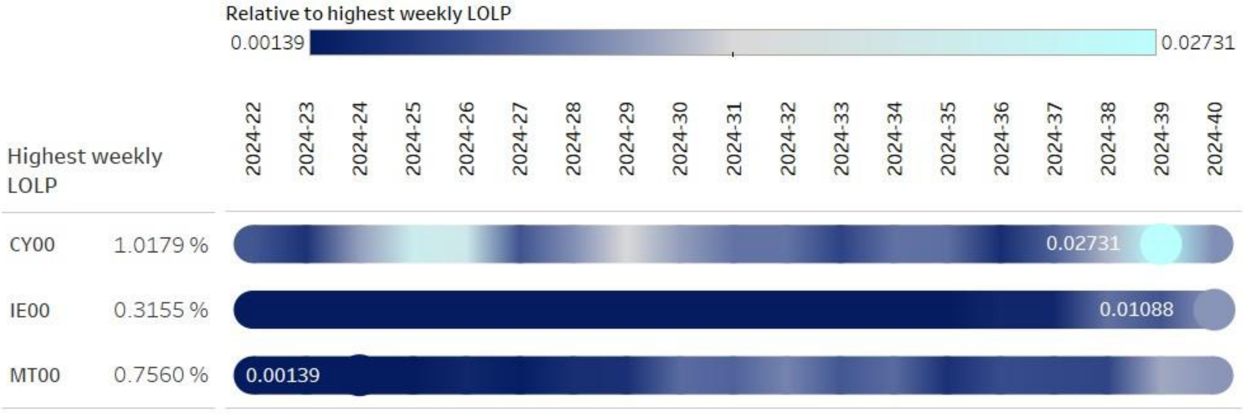

Figure 14: Adequacy weekly insights—considering non-market resources

Figure 15 represents the impact of non-market resources, which demonstrates that non-market resources can, to a large extent, address adequacy concerns in Malta and Ireland.

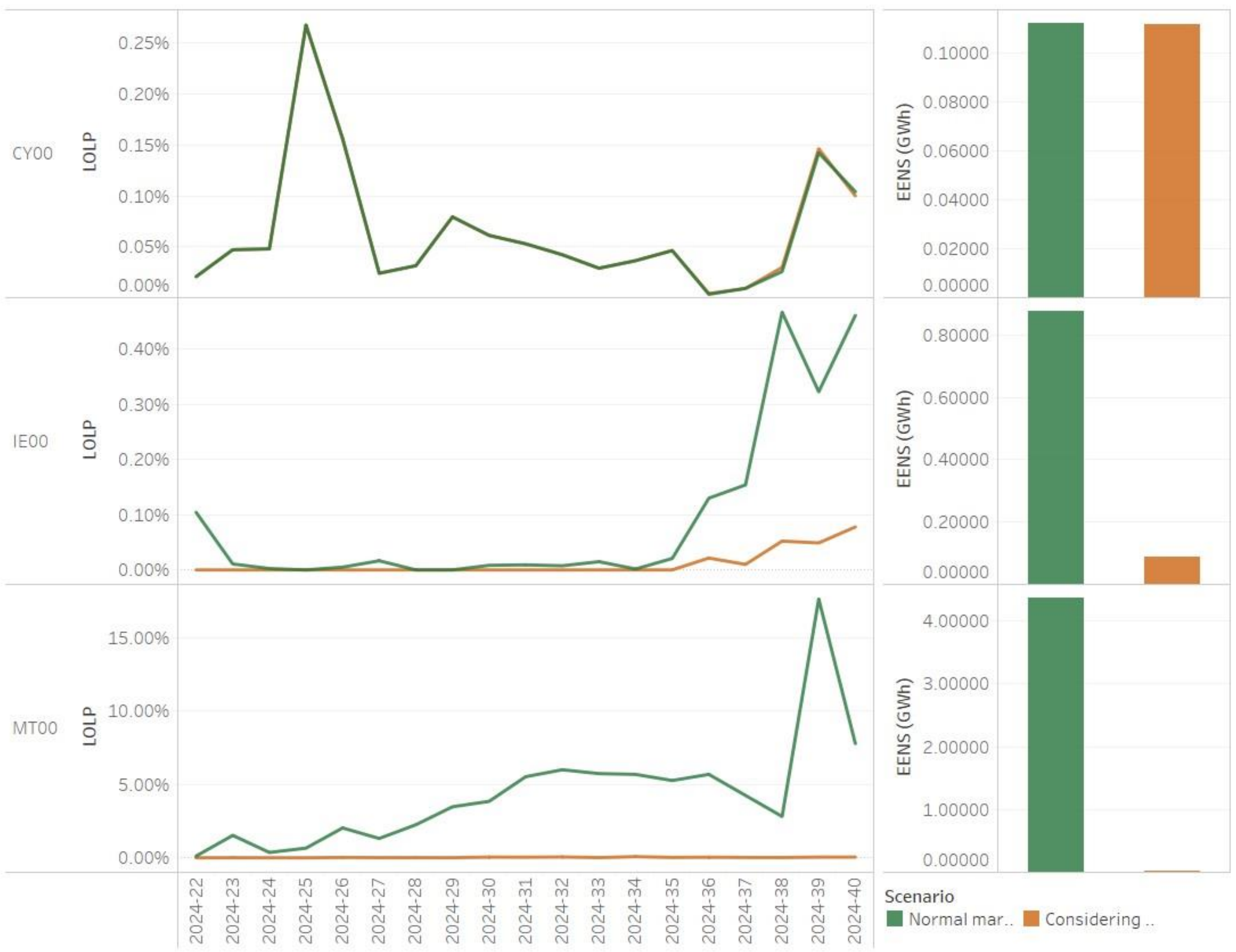

Figure 15: Detailed adequacy overview—weekly LOLP and ENS

Situation for Ukraine's power systems

Ukraine's national analysis for summer 2024 demonstrates significant risks to the energy system. The system faces planned load-shedding activation for both industrial and household consumers daily. Under these circumstances, urgent efforts are carried out to implement small-scale distributed generation connecting to the distribution grid, but also be dispatchable and simultaneously cover local electricity demand. Unpredictable but systematic everyday attacks causing the transportation grid's infrastructure elements' damages require Ukrenergo staff's significant effort to maintain the grid in proper state and operation. The interconnector transfer capacity has reached limits on the Ukrainian side, and options for further increase are being explored.

Winter 2023-2024 review

Background of the energy sector evolution since early 2022

During the year 2022 tensions in the European energy sector have increased significantly as a consequence of the political and economic situation of Europe with the war in Ukraine. In the winter of 2022-2023, a potential gas shortage was identified as one of the most concerning risks for the European power system, together with risks such as coal shortage, low nuclear generation availability and low hydrological reservoir levels. Many remedial actions and policy decisions have been taken, which have considerably consolidated the European robustness to the gas crisis.

Since early 2023 the situation has eased progressively, based on the numerous actions and decisions at the European level (e.g. RePowerEU). ENTSO-E used the experience of 2022-2023 to anticipate and address any risk ahead of and during the winter 2023–2024 period.

Preparations for Winter 2023–2024

To prepare for winter 2023–2024, ENTSO-E kept a broadened scope of the Seasonal Outlook Adequacy assessment beyond the strict legal mandate, as performed already in 2022 to address the crisis. Also, as for the previous winter, an anticipation of the assessment and early release of the report was carried out, in tight coordination with the European Commission, ACER and the Member States.

The preparation of winter 2023-2024 was built on the experience from the previous winter preparation, with enhancement compared to the standard seasonal adequacy assessment:

- Early and continuous monitoring starting from early summer 2023 — surveys and quantitative assessments;

- Assessment of Critical Gas Volume (CGV) to ensure adequacy in Europe.

These assessments ensured sufficient preparation for winter 2023–2024. It supported TSOs and all stakeholders with clear risk identification and enabled them to prepare mitigation actions.

Conditions and events during winter 2023–2024

The weather conditions were favourable throughout most of the winter, and hydro stock also improved in some regions, alleviating adequacy concerns for winter 2023–2024. In some countries, the consumption recorded was higher than expected. Hungary even witnessed a historical maximum peak load of 3143 MW in the second half of March 2024.

Globally, the 2023–2024 winter had above-average temperatures, with February 2024 being the warmest February on record (1.77°C warmer than the historical average). In Europe, a contrast can be observed between the southern and northern parts of the continent: the former experienced higher air temperatures in December and January, whereas the latter was below the long-term climatological values (1991–2020). January 2024 was the warmest January on record globally since 1979, with 0.70°C above the 1991–2020 average. This can be seen in Figure 16, which displays the surface air temperature anomaly observed in winter 2023–2024 (December 2023 to March 2024) from the Copernicus Climate Change Service.

In February 2024, the Balkans and eastern Europe had the most notable warmer-than-average conditions. The same conditions were present in the Alps in the same month. In March 2024, average air temperatures were above those of the 1991–2020 reference period over the entire continent, save for the western part of the Iberian peninsula.

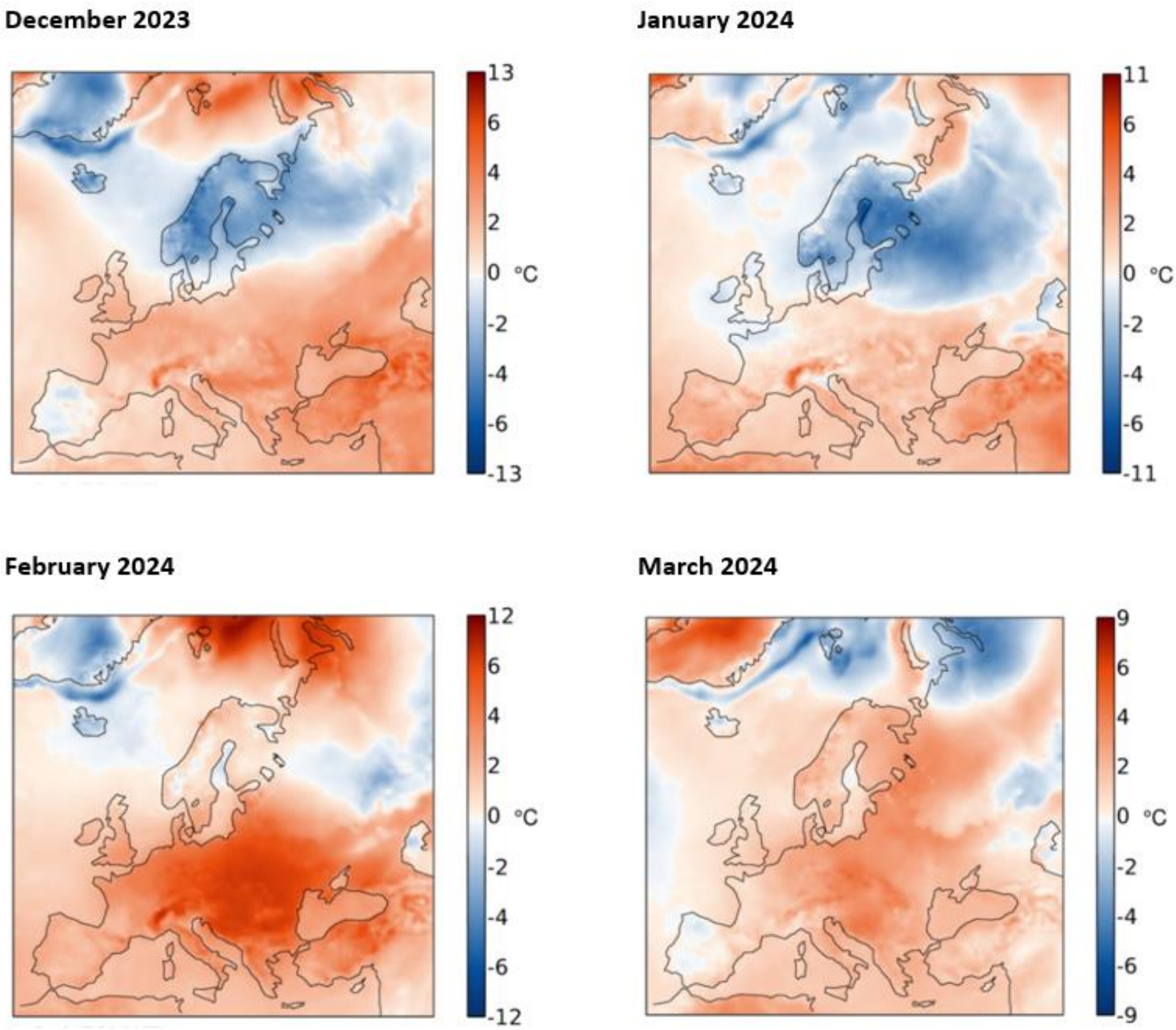

Figure 16: Surface air temperature anomaly in Winter 2023/2024 relative to the average for the periods 1991–2020 (for December, January, February and March)[6]

Specific comments on winter 2023–2024

In general, no adequacy issues were observed during the past winter 2023–2024. Mild temperatures and favourable hydro conditions played a significant role in averting potential shortages.

Nevertheless, some countries faced challenges during the past winter:

[6] *Copernicus Climate Change Service—Surface air temperature maps*

- Finland and Sweden faced severe cold spells in January. These cold spells, combined with several generation outages in Finland led to high market prices, hinting at low remaining capacities available in the region.

- Slovenia had a period where both the biggest power units were out of service (the nuclear power plant of Krško and the coal power plant TEŠ6).

- There were multiple periods with low replacement reserve availability in Cyprus.

- In Ireland, dispatchable generation margins remained tight throughout the winter period. Daily and weekly engagements between EirGrid (Ireland), SONI (Northern Ireland), National Grid (Great Britain) and other TSOs in the region were needed.

However, despite these situations, no adequacy problems were experienced.

Preparations for winter 2024–2025

ENTSO-E does not foresee any extraordinary risks for winter 2024–2025. It remains vigilant and will continue monitoring how the situation in the energy sector will develop. Extra actions will be taken if deemed necessary on an ad hoc basis, whether additional adequacy assessments are needed or mitigating actions are required based on developing circumstances.

The results of the recently released ENTSOG summer outlook[7] reaffirm that the gas system should be well prepared for the coming winter season with gas storage levels at the end of the previous winter in the higher range of the past 5 years combined with high import capacity of LNG throughout summer.

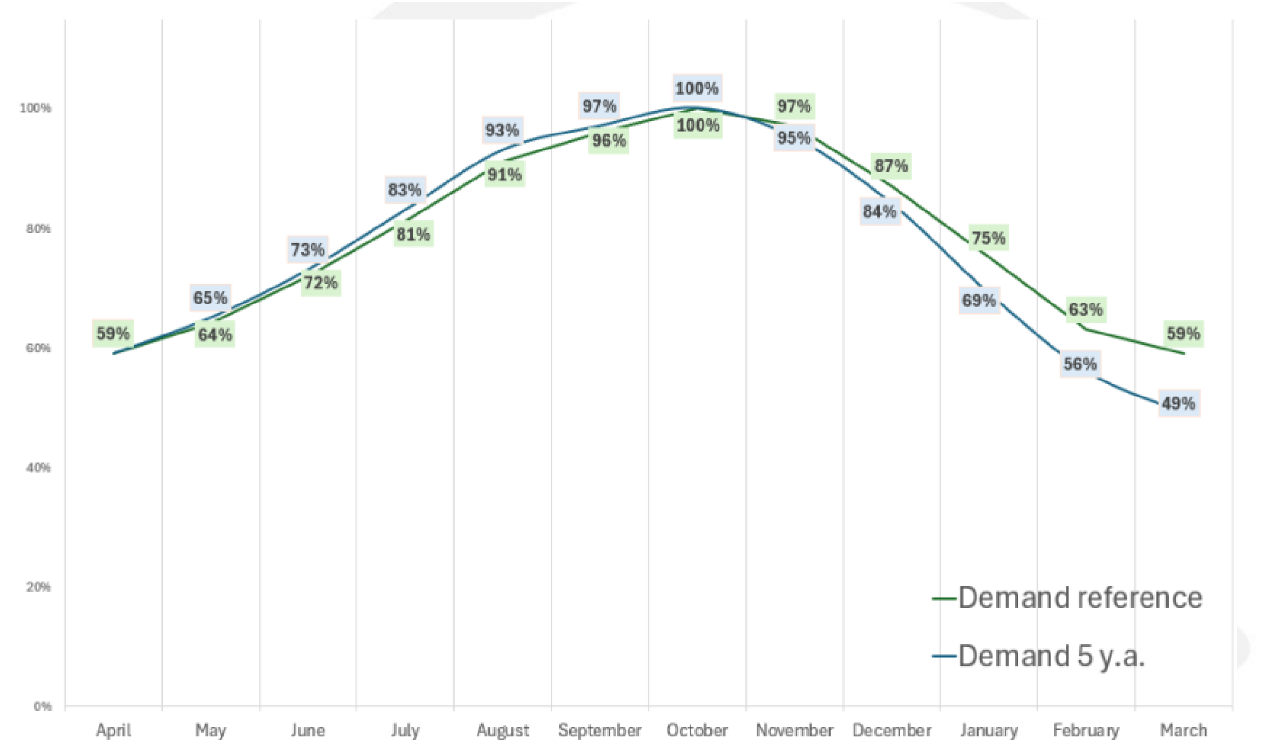

Figure 17: Gas storage developments against ENTSOG summer outlook projections[8]

The adequacy situation in winter 2024–2025 will depend on how the situation in the energy sector evolves. ENTSO-E will also consider closely specific feedback or requests about the future winter outlook from European or National Authorities.

ENTSO-E is striving to release the Winter Outlook 2024–2025 in advance of the legal mandate (mid-November 2024 instead of 1 December). TSOs suggest a single-step approach, with subsequent ad hoc assessments if the situation in the energy sector changes.

[7] OUTLOOKS & REVIEWS | ENTSOG

[8] ENTSOG Seasonal Supply Outlook Monitoring Dashboard]

Appendix 1: Methodological insights

Since the Summer Outlook 2020, ENTSO-E has significantly upgraded its methodology towards a full probabilistic approach for assessing adequacy on the seasonal time horizon.

This 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, approved by the Agency for the Cooperation of Energy Regulators (ACER)[10].

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 analysed timeframe. Figure 18 provides a schematic representation of this scenario construction process.

Figure 18: Scenarios assessed in Seasonal Outlooks

Scenarios are constructed, ensuring that all variables are correlated (interdependent) in time and space. To ensure the highest quality of data in the assessments, they are prepared by experts working within dedicated teams. A Pan-European Climate Database 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 the consideration of hydro energy availability. Figure 19 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

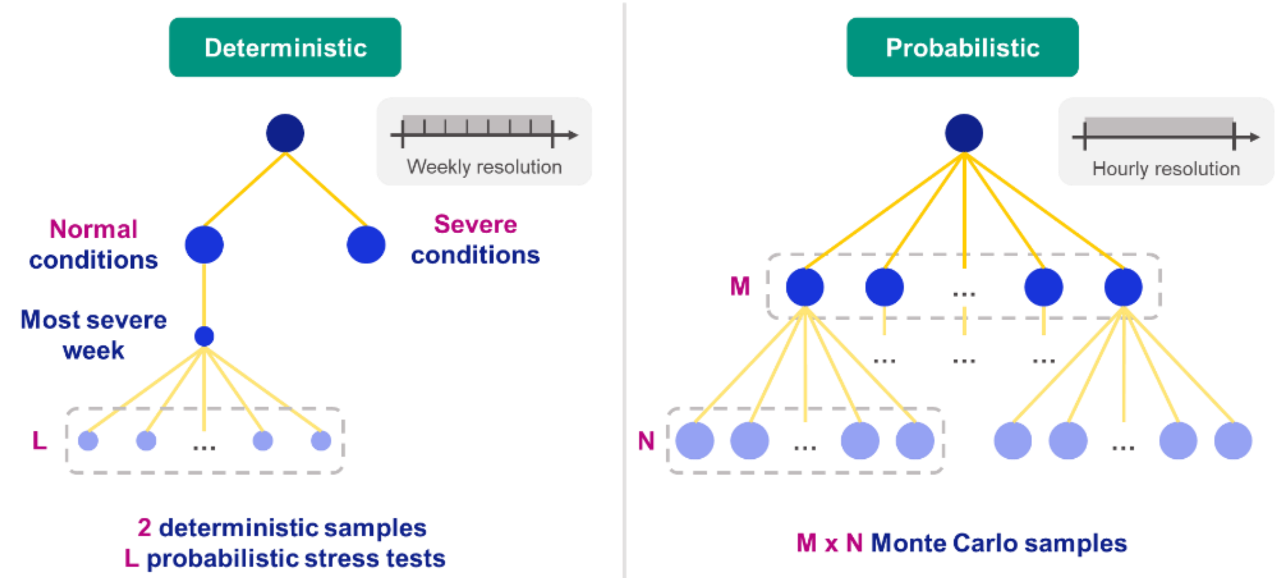

Figure 19: Scenario revolution—from deterministic to probabilistic

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 risks. 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, as were limitations on country position (or net exchange).

Major methodological improvements compared to previous study

Compared to previous editions, two main methodological improvements were introduced in the study. Firstly, the report pioneered the use of the new Pan-European Climatic Database (PECD) version 4, a database that was prepared in cooperation with Copernicus Climate Change Service. Secondly, this year marked a big evolutionary step for the Pan-European Market Modelling Database (PEMMDB).

Climate. The transition from PECD 3 to PECD 4 marks a significant advancement in climate data analysis and its application to energy system modelling. While PECD 3 provided a robust reanalysis of historic climate data from 1982 to 2016, PECD 4 incorporates projections from three distinct climate models, all aligned with a single Shared Socioeconomic Pathway (SSP). Additionally, each model contributes 12 distinct weather scenarios, resulting in a comprehensive set of 36 scenarios. This integration introduces a multidimensional perspective on future climatic conditions, enhancing the robustness and reliability of the analysis. By aligning with an SSP, PECD 4 also contextualizes these projections within a coherent socioeconomic framework, enabling the assessments of how socio-economic developments might interact with climate change to impact energy systems. Moreover, the inclusion of multiple future weather scenarios allows PECD 4 to effectively represent climate change within our assessments, providing critical insights into the potential impacts on resource adequacy. Consequently, PECD 4 offers a more nuanced tool for understanding and preparing for future climate variability and its implications on resource adequacy. This new tool will allow for streamlining the process, reducing the risk of errors through manual data manipulation and facilitating data analysis.

Data. The restructured Pan-European Market Modelling Database (PEMMDB) represents a state-of-the-art solution characterized by a comprehensive suite of features. Its architecture incorporates Extract, Transform, Load (ETL) processes to seamlessly integrate heterogeneous data sources, ensuring consistency and reliability. Implemented business rules enforce data integrity and standardization, mitigating common data errors. Automated data validation routines identify anomalies and discrepancies, guaranteeing the accuracy and completeness of the stored information. At the core of the database lies a Datahouse 2.0 framework, leveraging advanced technologies for efficient data processing, integration, and storage. This innovative solution not only simplifies the workflow for modellers but also enhances the quality and usability of the database, facilitating more informed decision-making and strategic planning in the dynamic landscape of the European energy market.

The methodological advancements detailed in this report aim at significantly enhancing the quality of results and internal processes for modelling energy systems. These improvements mark the first adequacy report on a pan-European scale to incorporate such comprehensive developments, reflecting a pioneering effort in integrating multidimensional climate projections and optimizing data management processes to model the dynamic landscape of the European electricity system more efficiently.

Appendix 2: Additional information about the study

Figure 20: Study zones

DE00	CH00 3,988 MW (3,800 - 4,000) MW	NL00 3,950 MW (3,950 - 3,950) MW	AT00 3,729 MW (3,530 - 4,670) MW	FR00 3,000 MW (3,000 - 3,000) MW	PLE0 3,000 MW (3,000 - 3,000) MW	CZ00 2,800 MW (2,800 - 2,800) MW	DKW1 2,492 MW (300 - 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 585 MW (585 - 585) MW	DEKF 400 MW (400 - 400) MW
DEKF	DE00 400 MW (400 - 400) MW	DKKF 393 MW (0 - 400) MW												
DKE1	SE04 1,249 MW (0 - 1,300) MW	DKKF 1,200 MW (1,200 - 1,200) MW	DE00 600 MW (600 - 600) MW	DKW1 570 MW (0 - 590) MW										
DKKF	DKE1 1,200 MW (1,200 - 1,200) MW	DEKF 393 MW (0 - 400) MW												
DKW1	DE00 2,487 MW (535 - 2,500) MW	NOS2 1,632 MW (1,545 - 1,632) MW	UK00 719 MW (0 - 800) MW	NL00 675 MW (300 - 700) MW	DKE1 600 MW (600 - 600) MW	SE03 447 MW (0 - 715) MW								
EE00	LV00 625 MW (480 - 850) MW	FI00 536 MW (358 - 1,016) MW												
ES00	PT00 2,501 MW (1,800 - 2,900) MW	FR00 1,661 MW (1,300 - 2,500) MW												
FI00	SE03 968 MW (0 - 1,200) MW	SE01 686 MW (200 - 1,200) MW	EE00 536 MW (358 - 1,016) MW											
FR00	UK00 4,000 MW (4,000 - 4,000) MW	DE00 3,000 MW (3,000 - 3,000) MW	ITN1 1,931 MW (460 - 2,160) MW	ES00 1,629 MW (1,300 - 2,300) MW	CH00 1,205 MW (1,200 - 1,300) MW	BE00 650 MW (650 - 650) MW	IE00 0 MW (0 - 0) MW							
GR00	BG00 1,186 MW (800 - 1,200) MW	MK00 493 MW (300 - 500) MW	ITS1 397 MW (0 - 500) MW	AL00 335 MW (0 - 400) MW	GR03 150 MW (150 - 150) MW	TR00 100 MW (100 - 100) MW								
GR03	GR00 150 MW (150 - 150) MW													
HR00	SI00 1,500 MW (1,500 - 1,500) MW	HU00 1,000 MW (1,000 - 1,000) MW	BA00 800 MW (800 - 800) MW	RS00 237 MW (150 - 300) MW										
HU00	SK00 2,600 MW (2,600 - 2,600) MW	HR00 800 MW (800 - 800) MW	RO00 800 MW (800 - 800) MW	SI00 561 MW (0 - 700) MW	RS00 518 MW (0 - 800) MW	AT00 422 MW (250 - 500) MW	UA00 220 MW (220 - 220) MW							
IE00	UK00 500 MW (500 - 500) MW	UKNI 400 MW (400 - 400) MW	FR00 0 MW (0 - 0) MW											
ITCA	ITSI 1,244 MW (100 - 1,300) MW	ITS1 1,096 MW (300 - 1,100) MW												
ITCN	ITN1 3,650 MW (3,100 - 4,200) MW	ITCS 2,598 MW (1,600 - 2,800) MW	ITCO 255 MW (0 - 300) MW											
ITCO	ITCN 255 MW (0 - 300) MW	ITSA 253 MW (0 - 300) MW												
ITCS	ITS1 4,660 MW (2,300 - 5,200) MW	ITCN 2,099 MW (1,200 - 2,900) MW	ITSA 858 MW (0 - 900) MW	ME00 600 MW (600 - 600) MW										
ITN1	FR00 3,388 MW (460 - 4,044) MW	CH00 2,949 MW (413 - 4,122) MW	ITCN 2,507 MW (1,800 - 3,100) MW	AT00 518 MW (68 - 605) MW	SI00 443 MW (0 - 753) MW									
ITS1	ITCS 2,400 MW (2,400 - 2,400) MW	ITCA 2,299 MW (1,500 - 2,350) MW	GR00 397 MW (0 - 500) MW											
ITSA	ITCS 696 MW (0 - 720) MW	ITCO 227 MW (0 - 300) MW												
ITSI	ITCA 1,480 MW (100 - 1,550) MW	MT00 201 MW (0 - 225) MW												
LT00	LV00 914 MW (810 - 1,085) MW	SE04 479 MW (350 - 700) MW	PL00 474 MW (0 - 492) MW											
LUG1	DE00 1,000 MW (1,000 - 1,000) MW													
LUV1	DE00 1,300 MW (1,300 - 1,300) MW													
LV00	LT00 1,018 MW (904 - 1,224) MW	EE00 630 MW (375 - 1,060) MW												
MD00	RO00 255 MW (255 - 255) MW													
ME00	ITCS 600 MW (600 - 600) MW	AL00 300 MW (300 - 300) MW	RS00 264 MW (200 - 300) MW											
MK00	RS00 512 MW (480 - 574) MW	GR00 493 MW (300 - 500) MW	BG00 359 MW (350 - 450) MW											
MT00	ITSI 201 MW (0 - 225) MW													
NL00	DE00 3,950 MW (3,950 - 3,950) MW	BE00 1,400 MW (1,400 - 1,400) MW	UK00 1,000 MW (1,000 - 1,000) MW	DKW1 699 MW (250 - 700) MW	NOS2 640 MW (640 - 640) MW									
NOM1	NON1 1,200 MW (1,200 - 1,200) MW	SE02 859 MW (0 - 1,000) MW	NOS1 500 MW (500 - 500) MW	NOS3 500 MW (500 - 500) MW										
NON1	SE01 477 MW (150 - 600) MW	NOM1 400 MW (400 - 400) MW	SE02 244 MW (200 - 250) MW											
NOS1	NOS3 3,900 MW (3,900 - 3,900) MW	NOS2 3,500 MW (3,500 - 3,500) MW	SE03 1,743 MW (450 - 2,095) MW	NOM1 500 MW (500 - 500) MW										
NOS2	NOS1 2,200 MW (2,200 - 2,200) MW	DKW1 1,631 MW (1,435 - 1,632) MW	DE00 1,400 MW (1,400 - 1,400) MW	UK00 1,400 MW (1,400 - 1,400) MW	NL00 640 MW (640 - 640) 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 1,136 MW (1,136 - 1,136) MW	LT00 337 MW (0 - 350) MW	SE04 303 MW (0 - 600) MW	UA00 83 MW (83 - 83) MW										
PLE0	PL00 1,650 MW (1,650 - 1,650) MW													
PLI0	CZ00 800 MW (800 - 800) MW	DE00 500 MW (500 - 500) MW												
PT00	ES00 3,431 MW (2,500 - 4,000) MW													
RO00	BG00 1,560 MW (1,560 - 1,560) MW	HU00 500 MW (500 - 500) MW	RS00 500 MW (500 - 500) MW	MD00 82 MW (82 - 82) MW	UA00 82 MW (82 - 82) MW									
RS00	MK00 460 MW (308 - 550) MW	RO00 449 MW (358 - 500) MW	BA00 443 MW (300 - 496) MW	HU00 349 MW (0 - 622) MW	BG00 290 MW (0 - 350) MW	HR00 237 MW (150 - 300) MW	ME00 223 MW (200 - 300) MW	AL00 207 MW (188 - 250) MW						
SE01	SE02 2,877 MW (300 - 3,300) MW	FI00 669 MW (0 - 1,100) MW	NON1 473 MW (250 - 650) MW											
SE02	SE03 7,300 MW (7,300 - 7,300) MW	SE01 2,273 MW (1,100 - 3,300) MW	NOM1 586 MW (0 - 600) MW	NON1 173 MW (150 - 178) MW										

Figure 21: Import capacity overview

Appendix 3: Additional information about the results

Loss of Load Expectation and other annual metrics

Information about Loss of Load Expectation (LOLE) in the assessed season is presented in this appendix. LOLE figures can be useful when comparing how adequacy evolved between editions of seasonal adequacy assessments. However, readers are invited to interpret them carefully as LOLE is commonly known as an annual metric, whereas in seasonal adequacy assessment, only a specific season (part of the year) is considered.

LOLE analysis may 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[11] is set and compared with seasonal LOLE:

- Seasonal LOLE can be lower than the Reliability Standard, but 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, but this does not necessarily mean that the system design does not comply with the Reliability Standard. The expected situation in the upcoming season could simply be one of the more constraining from a set of possible season scenarios[12] (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 as an operational system adequacy metric target. To meet the Reliability Target set for power system design purposes, Europe relies initially on market signals (for supply and network investments) and, if those are insufficient, market design corrections can be made (for example the establishment of complementary markets such as Capacity Mechanisms). The latter market decisions are based on a several-year-ahead framework[13], whereas seasonal outlooks relate to an operational timeframe which 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 may be compared, and this is especially important for LOLE.

Considering the background and interpretation limitations, Figure 22 below represents the LOLE results of the Summer Outlook 2024.

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[11] *The conclusions made for annual LOLE are also valid for any other annual metric.*
[12] *The same applies to a particular historical supply scarcity. If hours when demand was shed exceed the LOLE set by the Reliability Standard, it does not mean that the system design does not comply with the Reliability Standard. LOLE set by the Reliability Standard simply indicates in how many hours demand shedding is acceptable (due to supply scarcity) over a long time.*
[13] *Monitored by the European Resource Adequacy Assessment in line with Article 23 of the Electricity Regulation 2019/943*

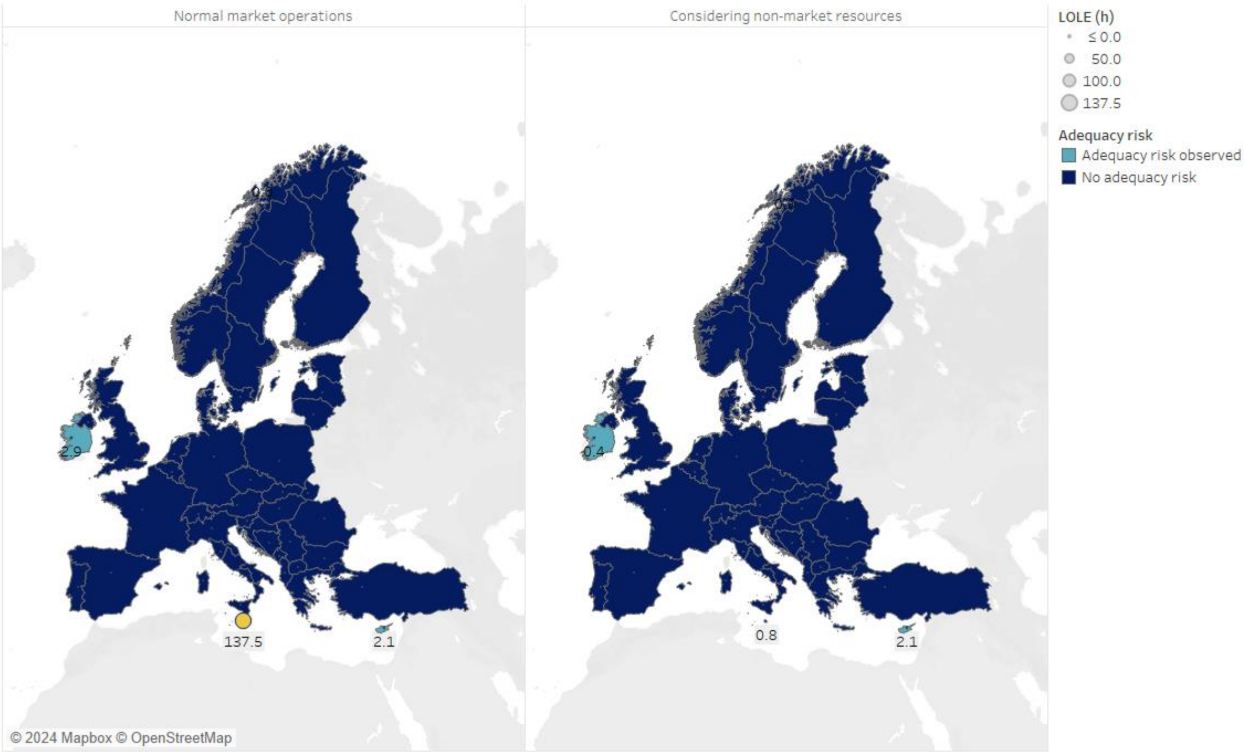

Figure 22: Seasonal LOLE results