Winter Outlook 2023-2024

Summer Review 2023

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 39 member TSOs, representing 35 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 Winter Outlook 2023–2024 highlights the overall favourable adequacy results, with only some risks of electricity supply in remote areas including Ireland, Northern Ireland, Malta and Cyprus. Dedicated non-market resources would help to alleviate those risks in Ireland and Malta. Finland may also face some risk in the event of exceptionally adverse operational conditions combined with cold weather and high unplanned outages. Regional risks are also identified in France, Belgium and Great Britain.

All the risks identified for the next winter season are driven by weather conditions. The challenges in Ireland and Northern Ireland will depend on the availability of aging gas power plants, whereas Malta is more at risk, especially in the event that interconnection with Italy falls under unplanned outage.

Regional risks in France, Belgium and Great Britain are driven by the sensitivity of the demand in France to temperature and are present only under extreme weather conditions combined with high unplanned outages. National studies confirm that Flow-Based Market Coupling would enable more imports, which would address those risks.

Critical Gas Volume (CGV; gas required to ensure European power system adequacy) decreases approximately by 10% compared with winter 2022–2023. CGV would decrease by a further 10% if energy saving measures in line with the European energy saving targets (Council Regulation 2022/1854) of winter 2022–2023 are taken.

European power system trends since winter 2022–2023 are in line with the adequacy and CGV results: generation fleet expands (conventional decreases, but RES increases notably) and planned outages are lower, while demand remains stagnant. These conditions combined create favourable conditions for adequacy and a lower reliance on gas generation.

The EU has filled gas storages to 90% of their capacity, surpassing the 1 November deadline by approximately two and a half months. Storages were almost completely full in early November. This signals a strong European winter preparedness and increases confidence in 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. Ukrenergo carried out an unprecedent restoration and renovation programme to prepare for winter 2023–2024, including the increase of interconnection capacity with neighbours. Furthermore, safety measures against missile strike threats were implemented to mitigate risks. The power supply situation in **Moldova** is adequate but reliant on gas supplies and the availability of one single utility in the Transnistrian region. Furthermore, the Moldovan power system operator faces challenges to balance the system. A number of actions are being taken to mitigate such potential risks.

ENTSO-E, Ukrenergo and Moldelectrica continue to work together for the further integration of these systems on technical and institutional levels after the successful emergency synchronisation in 2022 and continuous increase of interconnection capacities.

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. Alert states were raised in Ireland and Northern Ireland due to tight supply margins, but wind generation and import availabilities were sufficient to supply electricity consumers. Furthermore, Cyprus experienced a lack of replacement reserves, but eventually averted any impact on electricity consumers.

Introduction

General purpose of the seasonal outlooks

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

The Outlooks are the product of cooperation between 39 European electricity Transmission System Operators (TSOs). Because of their pan-European scope, the Outlooks 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. The seasonal outlooks model the resource adequacy, not considering specific operational constraints such as grid stability or voltage.

Performing the Seasonal Outlooks (Seasonal Adequacy Assessments) is one of ENTSO-E's legal mandates as specified in the Clean Energy Package and as 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 the security of electricity supply in the coming season. The Seasonal Outlooks 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 ACER on 6 March 2020. Earlier Seasonal Outlooks (published before 2020) followed a different methodology (deterministic approach).

The interconnected system is a key resource for wider system adequacy. ENTSO-E's Winter Outlook gives results for all ENTSO-E member systems. Data inputs and assumptions from neighbouring interconnected countries are also integrated into the modelling. As in every Outlook, data are collected for Turkey and included in the assessment. The system of Great Britain is strongly interconnected in the North Sea region, and a dedicated collaboration has been set up with National Grid ESO to exchange data. Prospects of adequacy in Ukrainian and Moldovan power systems were shared by the respective TSOs. Furthermore, their system is considered an integral part of the European power system and considered as available for power transits for adequacy. Other neighbouring systems beyond the ENTSO-E perimeter are modelled in a simplified manner by defined hourly exchanges.

Developments since 2022

The situation in the European power system for winter 2023–2024 is far more certain than winter 2022–2023; yet close screening and monitoring is required. This winter, Europe has much greater assurance regarding fuel supply availabilities as supply routes were diversified or alternative supplies were identified by many. Furthermore, nuclear availability and hydro stocks are in much better shape. Nevertheless, an adequacy and Critical Gas Volume (CGV) analysis, just as for winter 2022–2023, is performed to ensure the awareness and preparedness of European power system. All TSOs within ENTSO-E maintain close coordination and contact with the European Commission (EC) and the Electricity Coordination Group (ECG) on the prospects for winter 2023–2024.

[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

Scenarios and assessments

This winter outlook assesses two scenarios: a reference scenario (with and without non-market resources) in addition to an energy saving scenario. This energy saving scenario is mainly covered as a follow-up on demand reduction targets set by the EC for the winter of 2022–2023 following the war in Ukraine and high increases in energy prices. Such demand reduction targets are not set for winter 2023–2024 but insights on an energy saving scenario would be beneficial for member states to assess the impact of such actions on our electricity production, both on adequacy and on gas consumption levels.

In every scenario, both adequacy assessments and CGV assessments are shared in this report.

Ukraine's and Moldova's systems are an integral part of the European Power System

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 power systems since 16 March 2022; whereas the Burshtyn Island (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 to Ukraine in February 2022, but since then collaboration has increased to unprecedented levels.

Ukrainian and Moldovan national perspectives on the situation in winter 2023–2024 are presented in this report. The situation remains uncertain and difficult to predict due to geopolitical threats. Russia's war in Ukraine continues to pose threats to energy infrastructure. Geopolitical tension in Moldova (Transnitria 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. Their power systems are anticipated to be available to support the European power system if necessary. Even if resource availabilities in Ukraine and Moldova remain uncertain, the transmission network should remain available for transit flows between other European power systems.

Coordination at the national, regional and European level

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

On the European level

- Exchange on risk preparedness plans via the Electricity Coordination Group and Gas coordination group;
- Winter outlook and updates: If impacting changes in European power system occur this winter, updates to ENTSO-E's winter outlook are possible;
- Following the winter outlook, the Short Term Adequacy (STA) process monitors the coming seven days in a rolling-window to detect any adequacy issues on the cross-regional (Pan-EU) level;
- ENTSO-E is ensuring weekly Operational Coordination between all interconnected TSOs and Regional Coordination Centres (RCCs) to enable fast communication and alignment, when necessary, for operational processes; and
- Communication between ENTSO-E and ENTSO-G to align assumptions and messages between the gas and electric Winter Outlook.

On the Regional level

- Following the Cross-Regional STA process, in the event of the detection of scarcity situations, a regional STA process exists managed by RCCs with the participation of concerned TSOs to coordinate the proposal of adequacy remedial actions on a regional level; and
- TSOs and RCCs will coordinate during the whole winter to maximise cross-border capacities regionally through an established operational planning coordination (OPC) process.

On the National level

- TSOs conducted national adequacy studies in parallel to the ENTSO-E winter outlook. These national studies may use different sensitivities or focus more on extreme cases, such as the German 'Extraordinary analyses winter 2022/2023', where multiple stress elements coincide. National studies can also consider more detailed constraints, such as internal transmission bottlenecks.
- Each Member State 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.

Overview of the power system in winter 2023–2024

Generation overview

Compared to the previous winter, the generation capacity in Europe follows the same general trend of increasing installed renewable generation and batteries while decommissioning thermal generation as gas. This evolution is beneficial for the carbon footprint of the European electricity power system but should go hand in hand with increased flexibility on the consuming sectors as cold days with low renewables tend to get more problematic as this trend continues.

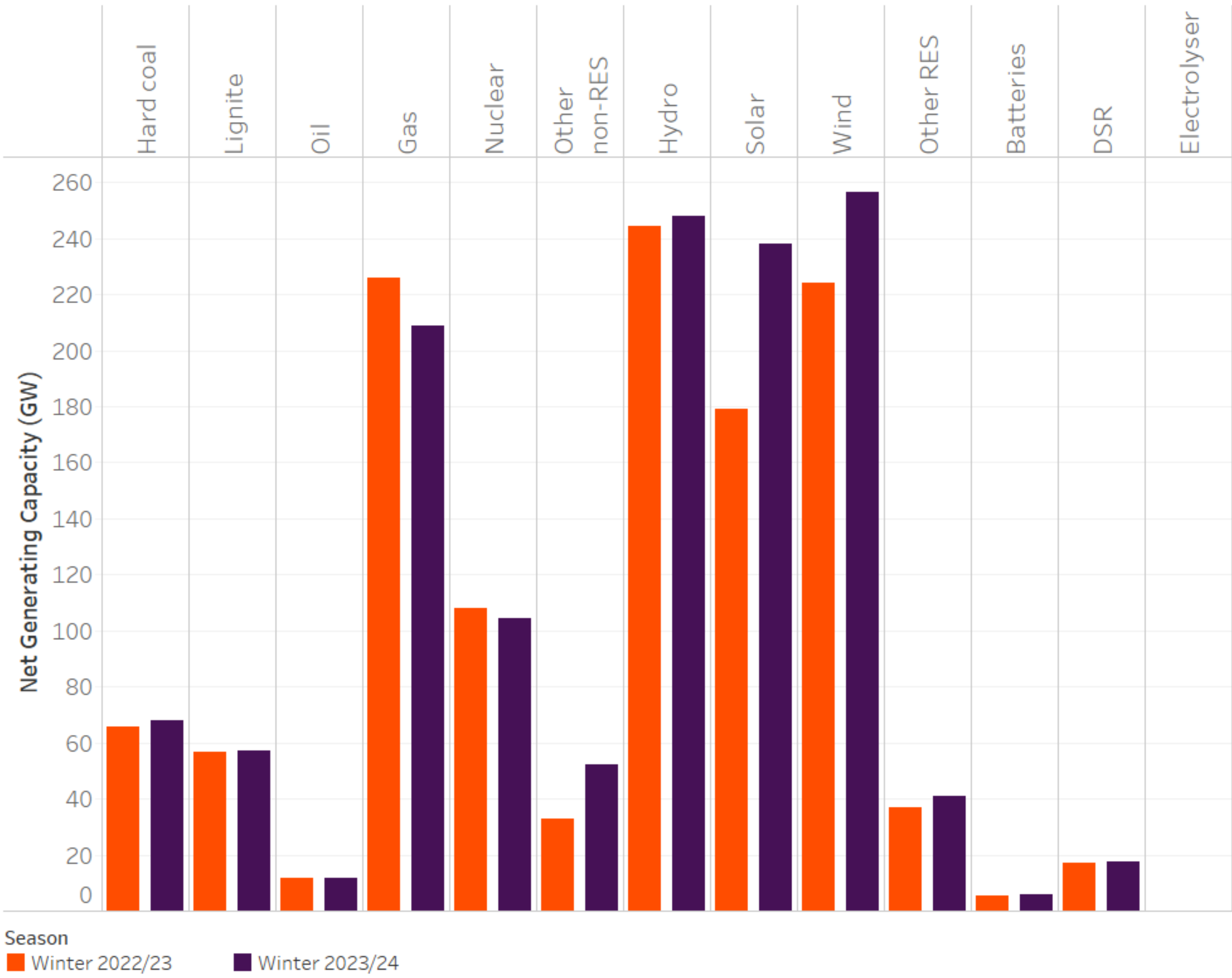

Figure 1 Generation capacity change over year: winter outlook 2023–2024 vs winter outlook 2022–2023

The generation capacity overview in Figure 2 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 dependent on imports when renewable generation is low.

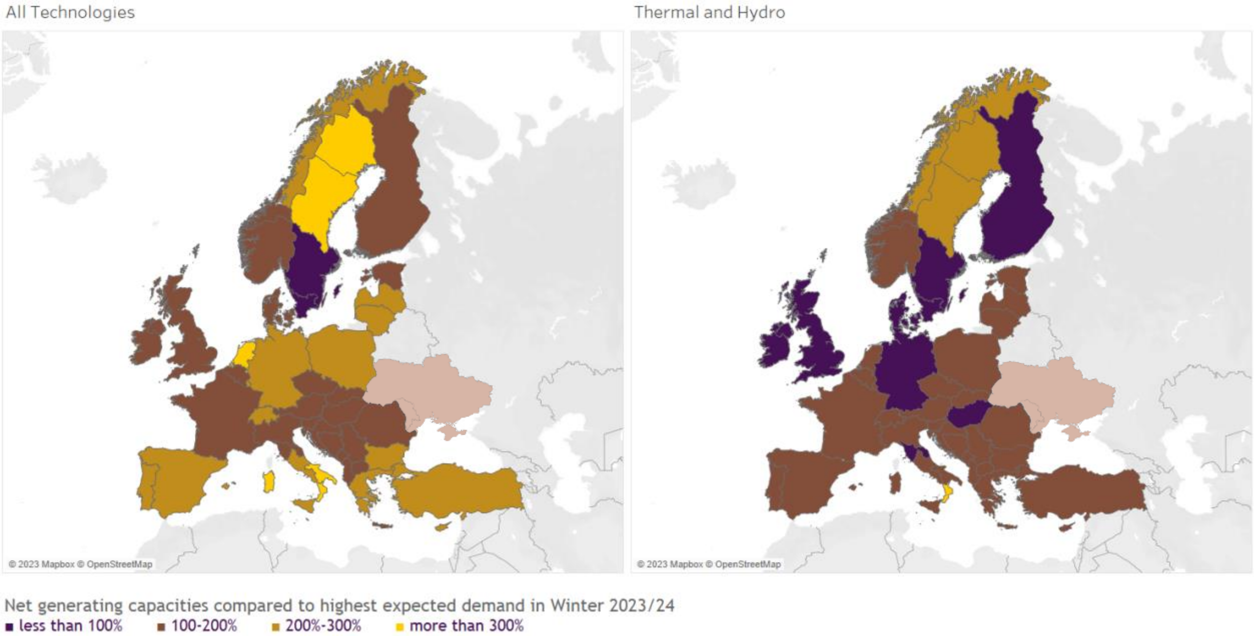

Figure 2: Net generating capacity overview – comparison with highest expected demand

According to Figure 3, thermal net generating capacity (NGC) available on the market accounts for a bit less than 40% of the total capacity of the European power system at the beginning of winter 2023. This is followed by hydro, wind, and solar capacities, which constitute most of the remainder. In addition, the highest expected demand[2] is depicted with a small black square, and its value is given as a percentage of each study 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. Demand Side Response (DSR) resources are gaining volume in Europe. Nevertheless, DSR may be available for a limited period of time 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.

[2] *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.*

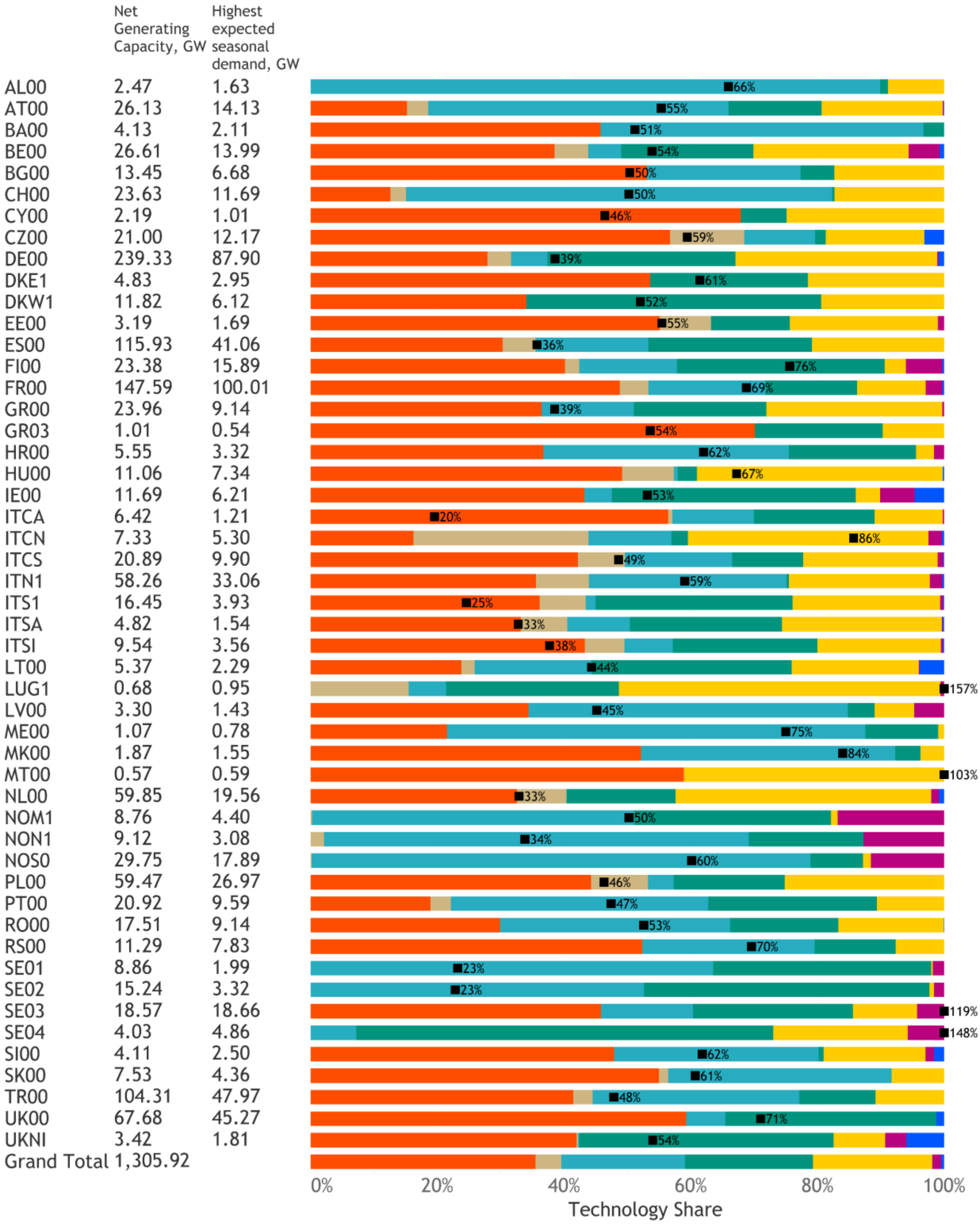

Figure 3: Generation capacity mix at the beginning of winter 2023–2024 per study zones

Figure 4 shows which study zones have non-market resources 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. Only seven countries utilise non-market resources. From largest to smallest NGC, these are: Germany, Poland, the southern bidding zone of Sweden, Austria, Southern Ireland, Switzerland and Malta. This report also assesses if these resources are sufficient to address the identified adequacy issues (c.f. section 'Adequacy situation and gas needs during winter 2023–2024').

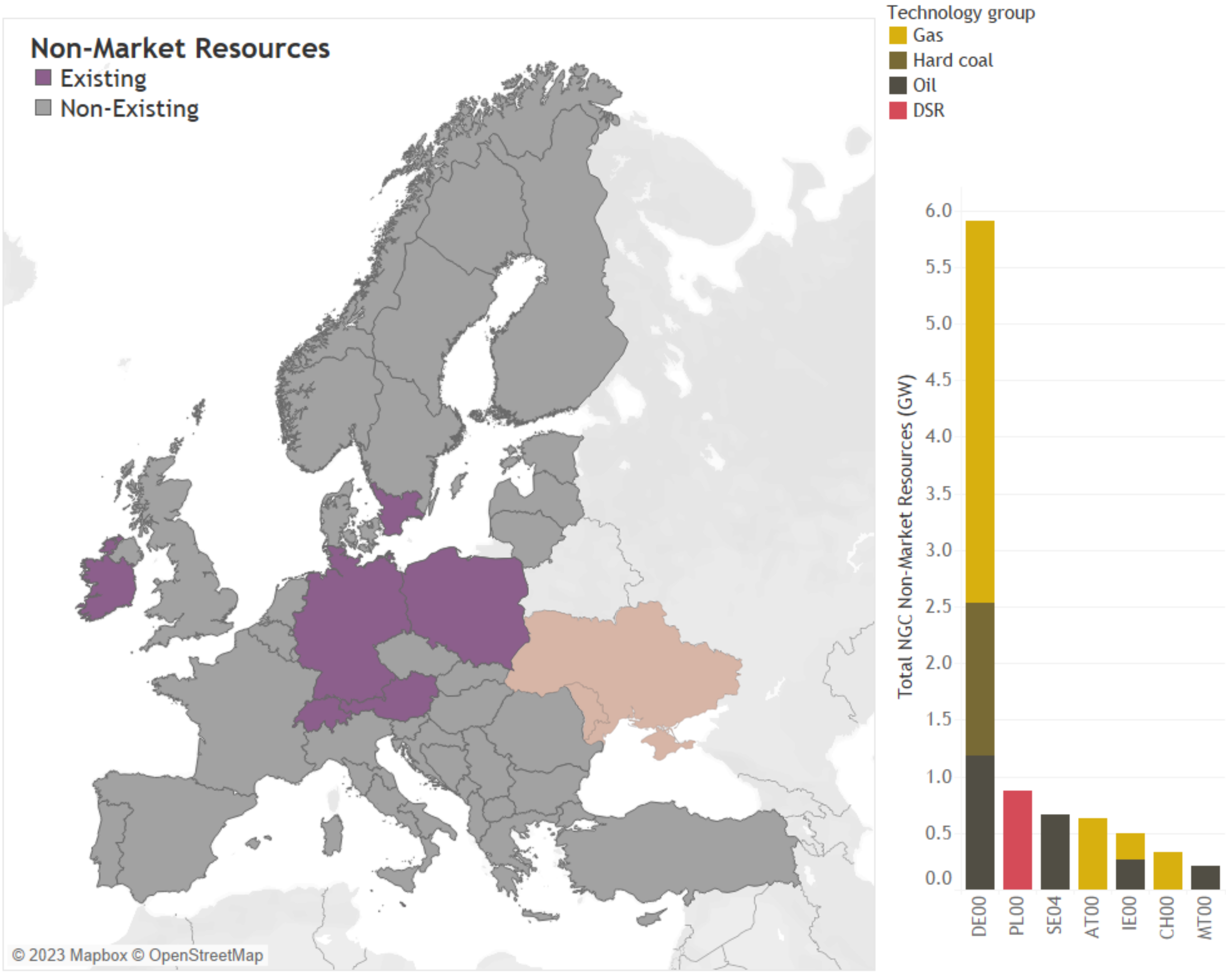

Figure 4: non-market resources for coping with adequacy challenges in Europe[3]

Capacity evolution

Figure 5 shows that generation capacity in Europe grows during winter 2023–2024[4], with a net increase of approximately 32 GW, due mainly to the expansion of renewable generation capacity. Thermal generation is decreasing due to the decommissioning of hard coal and lignite plants not being balanced by the increase of 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.

[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.*
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 reported here for informational purposes.
[4] *30 Oct 2023 – 31 March 2024*

Commissionigs and Decommissionings

BA00	Lignite	1 January 2024	Decrease or decommissioning (MW) 90
BG00	Gas	1 January 2024	Increase or commissioning (MW) 53
DE00	Gas	1 January 2024	Increase or commissioning (MW) 513
		31 March 2024	Decrease or decommissioning (MW) 25
	Hard coal	31 December 2023	Decrease or decommissioning (MW) 76
		31 March 2024	Decrease or decommissioning (MW) 5,259
	Lignite	31 December 2023	Decrease or decommissioning (MW) 57
		31 March 2024	Decrease or decommissioning (MW) 3,027
	Oil	31 December 2023	Decrease or decommissioning (MW) 415
DKE1	Gas	31 December 2023	Decrease or decommissioning (MW) 9
	Hard coal	31 December 2023	Decrease or decommissioning (MW) 9
DKW1	Gas	31 December 2023	Decrease or decommissioning (MW) 109
	Hard coal	31 December 2023	Decrease or decommissioning (MW) 7
	Oil	31 December 2023	Decrease or decommissioning (MW) 10
EE00	Gas	31 December 2023	Decrease or decommissioning (MW) 94
	Oil	31 December 2023	Decrease or decommissioning (MW) 672
FI00	Hard coal	31 March 2024	Decrease or decommissioning (MW) 535
IE00	Gas	13 February 2024	Increase or commissioning (MW) 64
		25 February 2024	Increase or commissioning (MW) 64
ITCS	Gas	26 February 2024	Increase or commissioning (MW) 300
ITN1	Gas	30 November 2023	Increase or commissioning (MW) 112
ITSI	Gas	1 March 2024	Increase or commissioning (MW) 150
NL00	Gas	31 December 2023	Decrease or decommissioning (MW) 266
PL00	Gas	9 December 2023	Increase or commissioning (MW) 110
		1 January 2024	Increase or commissioning (MW) 22
	Hard coal	31 December 2023	Decrease or decommissioning (MW) 629
	Lignite	31 December 2023	Decrease or decommissioning (MW) 184
RO00	Lignite	31 December 2023	Decrease or decommissioning (MW) 90
RS00	Lignite	31 December 2023	Decrease or decommissioning (MW) 800
SK00	Lignite	31 December 2023	Decrease or decommissioning (MW) 240

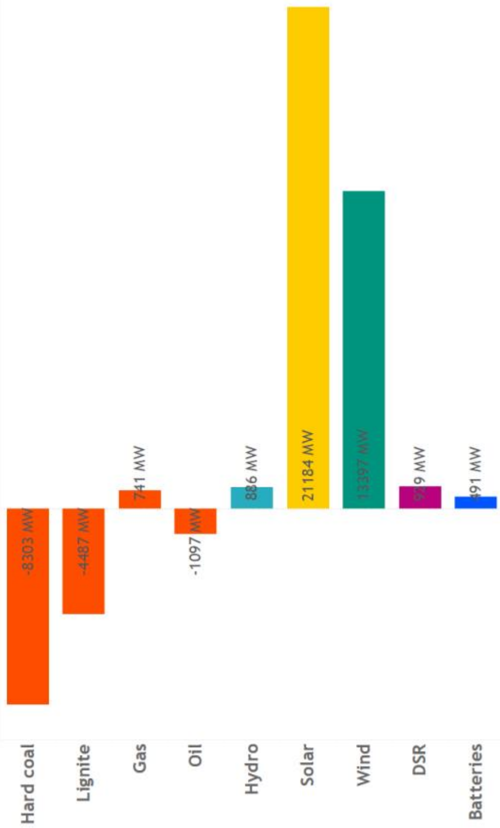

Figure 5: Capacity evolution in winter 2023–2024

Planned unavailability of generation

Compared to last winter, the overall planned outage schedule is more favourable. Several effects can explain this:

- A better situation regarding nuclear availability everywhere in Europe and especially in France
- A better situation regarding gas availability in IT, NL and UK
- Overall the same situation with hard coal, lignite and oil

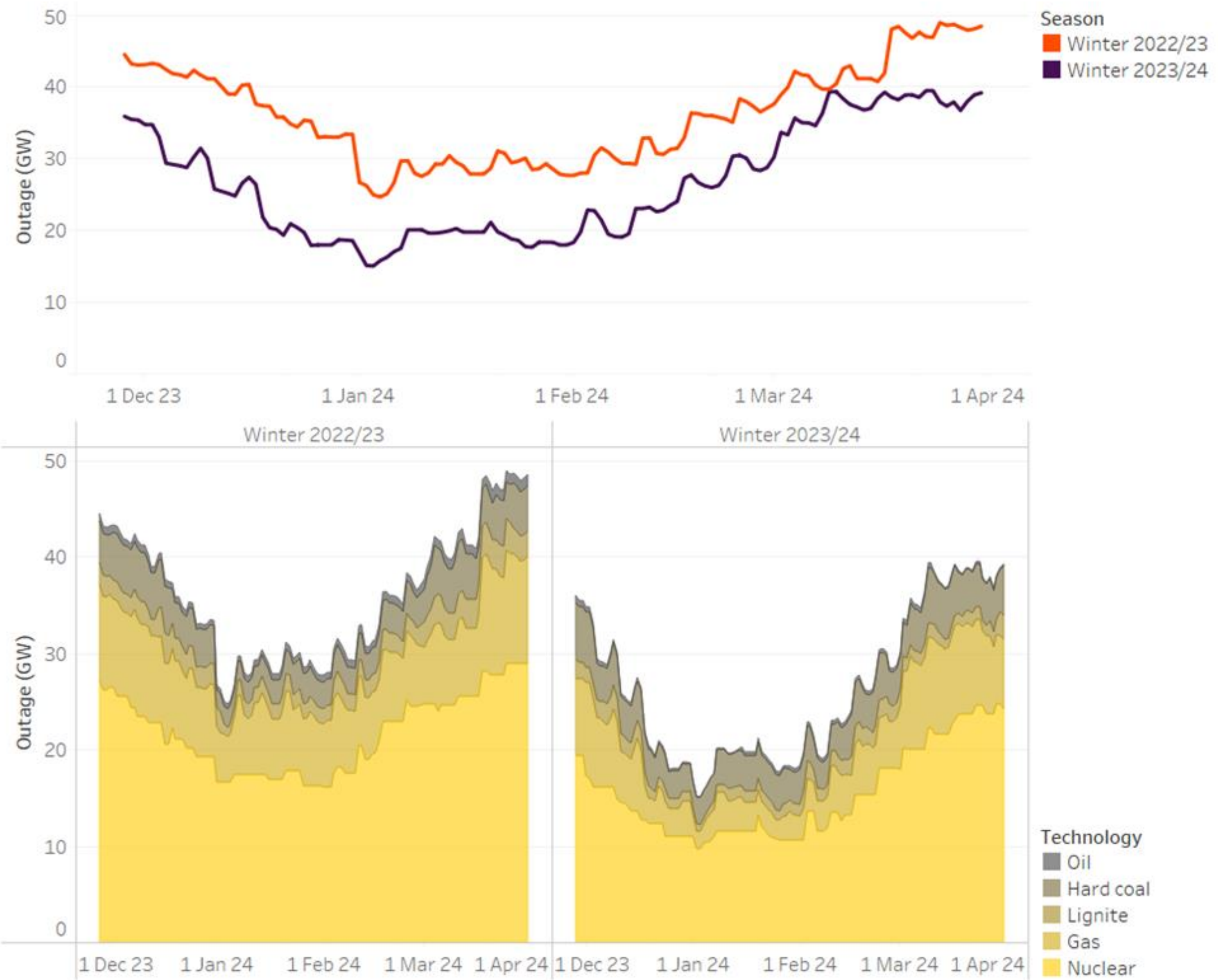

Figure 6: expected planned outages: for winter 2023–2024 vs winter 2022–2023

The planned unavailability of units considered in the assessment is presented in Figure 7. The planned unavailability of generation units includes planned outages for maintenance purposes and mothballing. The total planned unavailability in Europe decreases at the start of winter and arrives at its lowest value during the month of January. Nuclear units show the highest level of unavailability among thermal technologies with gas ranking second, followed by hard coal, lignite and oil.

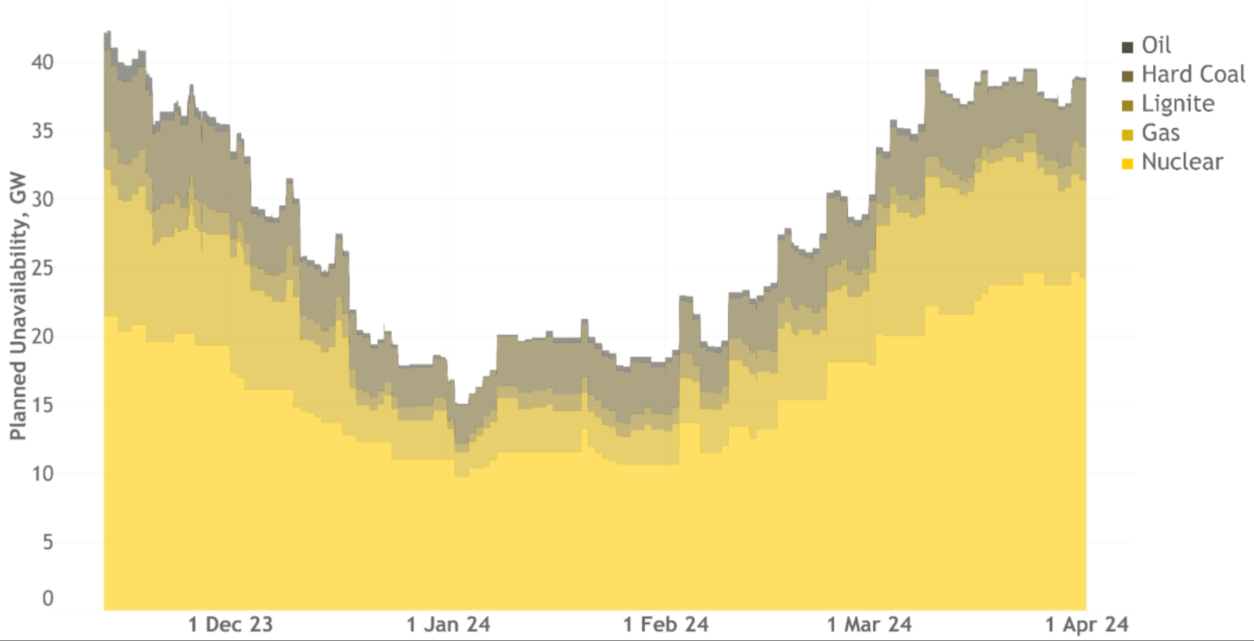

Figure 7: Planned unavailability of thermal units

Planned unavailability in northern countries tends to decrease during the coldest months when highest demand is expected (i.e. in January and February). This can be observed in the cases of Italy or France, as shown in Figure 8. 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. In some countries, very low amounts of planned unavailability are foreseen for the whole winter period.

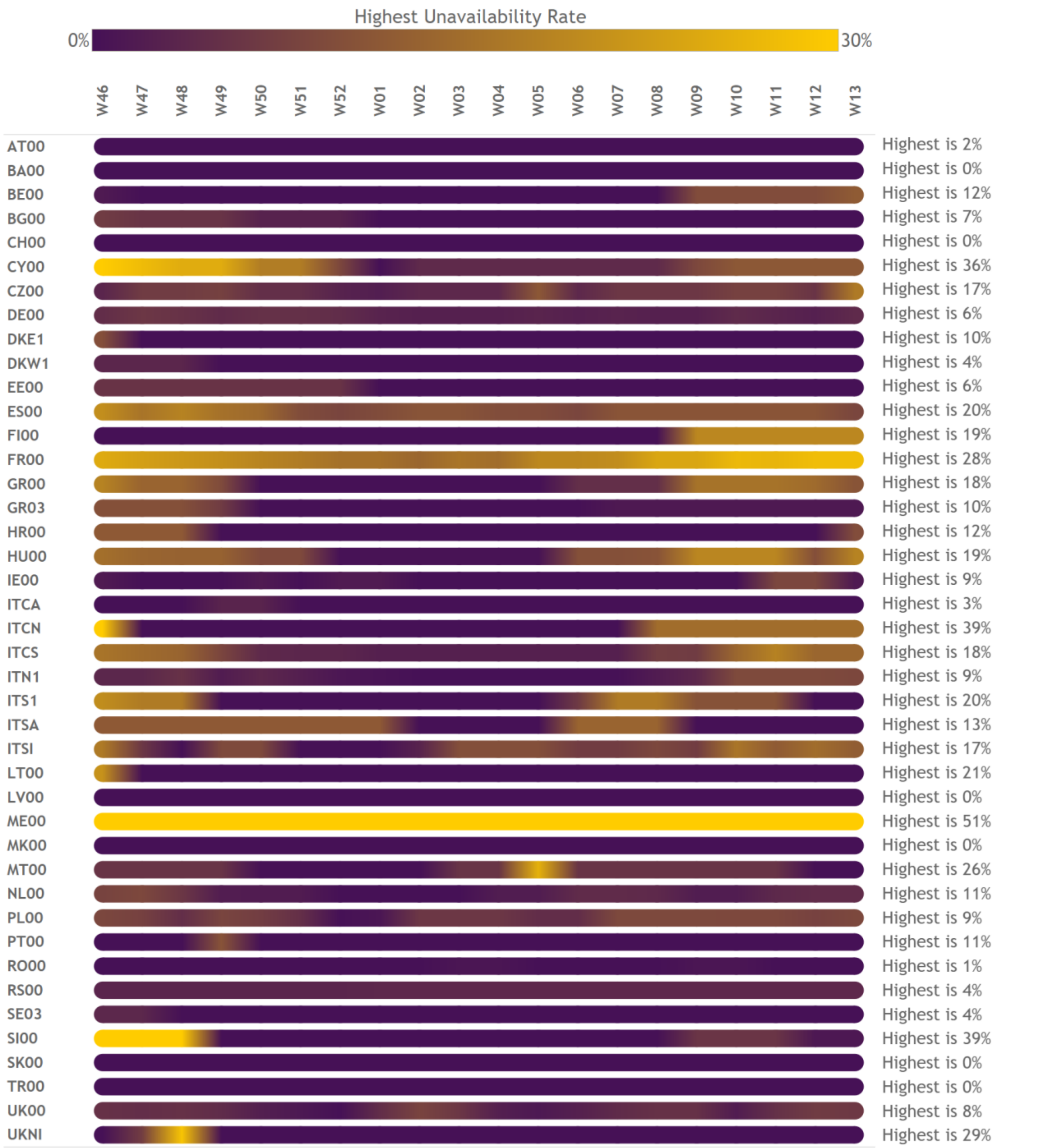

Figure 8: Weekly distribution of thermal planned unavailability relative to thermal NGC

Hydro availability

Concerning hydro storage levels at the beginning of winter, the projections are more favourable all over Europe for winter 2023–2024. Figure 9 shows the hydro storage start levels. Please keep in mind that the comparison is done between the input values of previous and actual winter outlooks and not between the measured values of the previous winter compared to the inputs of this winter outlook.

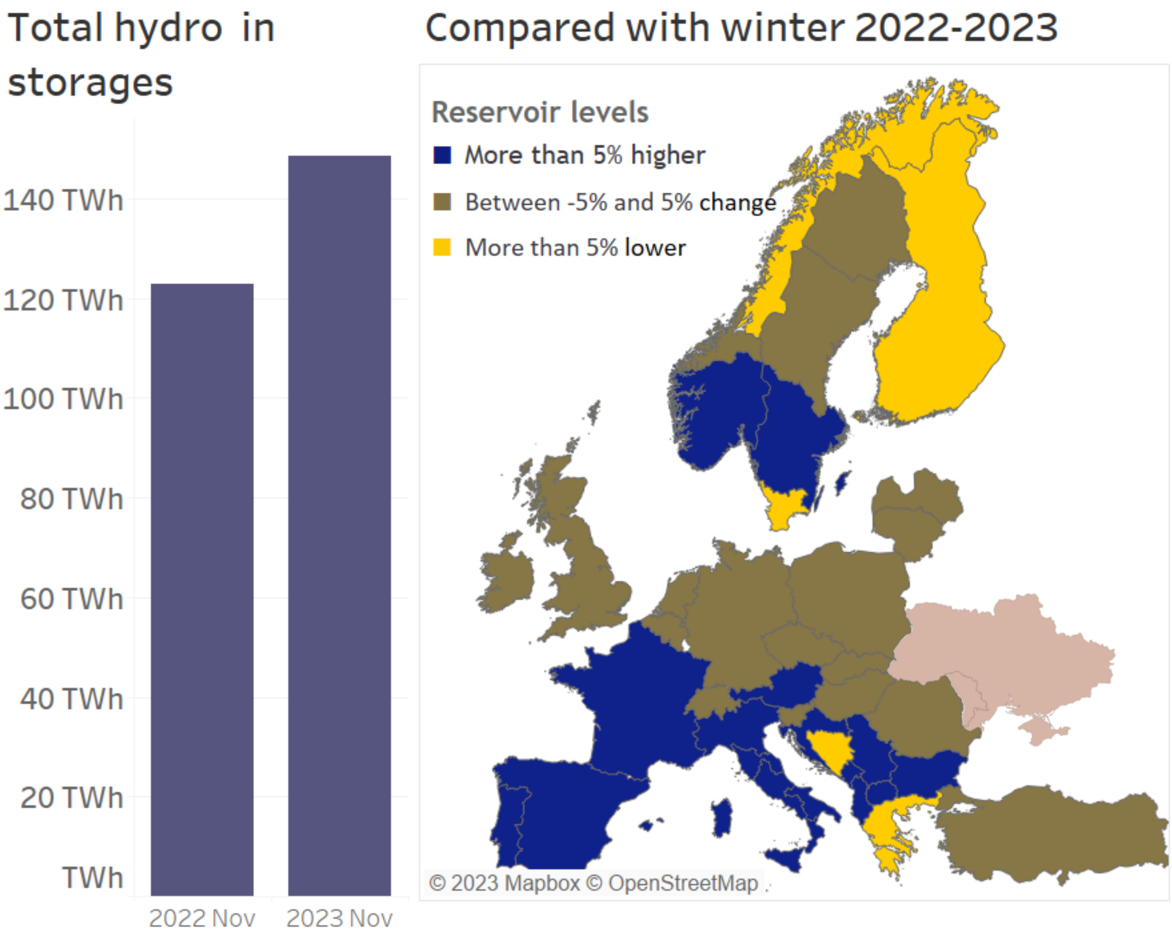

Figure 9: hydro storage level expectations: start of winter 2023–2024 vs winter 2022–2023

Demand overview

Over the past three years, both the COVID situation and the energy price crisis had a significant impact on demand all over Europe. With both crises mitigated, it was important to rely on TSOs to provide qualitative expectations for the next winter. A questionnaire conducted in July 2023 showed that electricity demand is varying across Europe. Figure 10 shows that most of Europe expects similar demand regarding the previous 5 years' statistics, showing a rebound after both crises, while other TSOs, such as France, expect a lower demand following the demand reduction efforts of the previous winter.

An energy saving sensitivity, covering possible new demand reduction requirements in Europe or the over-estimation of demand, is covered in the results section.

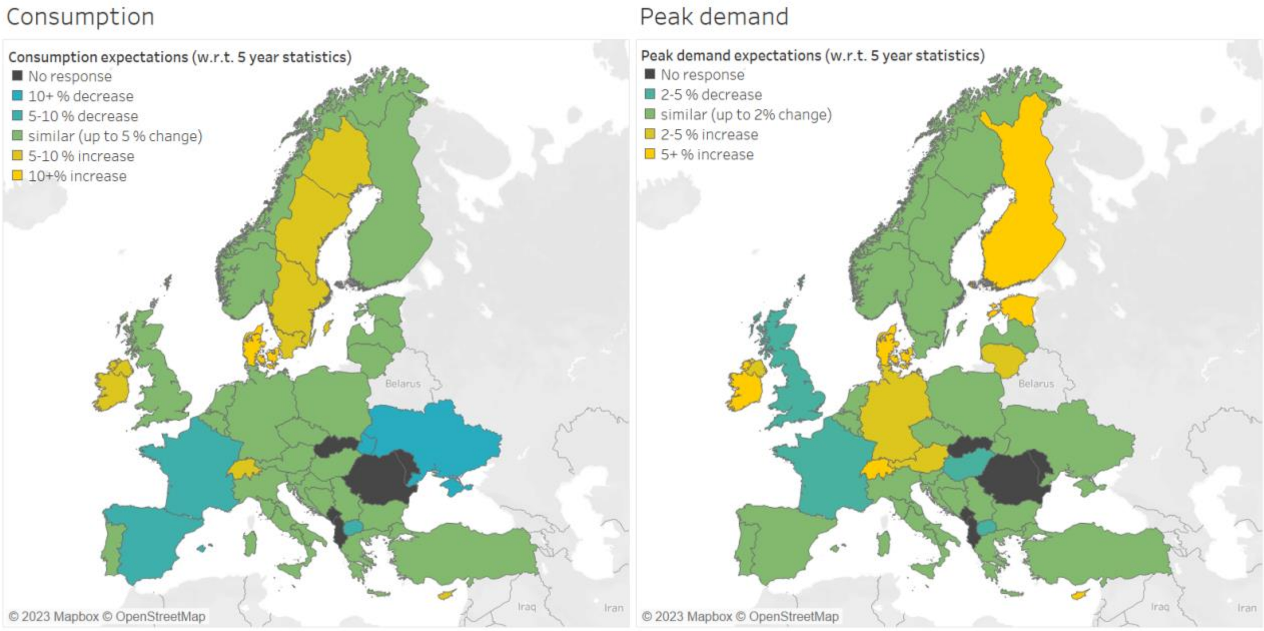

Figure 10: European TSOs' expectation on electricity consumption and demand peaks against last 5 years' statistics

The highest European demand is expected mid-January to mid-February, while actual weather conditions will have a large impact.

Figure 11 shows a heat map by study zone, comparing the expected consumption in each week with the highest expected weekly consumption in winter 2023–2024. The darker shades indicate low expected consumption compared to highest expected consumption. Typically, the period at the start of the winter and between 25 December and 1 January shows low weekly consumption while January and February show the highest weekly consumption.

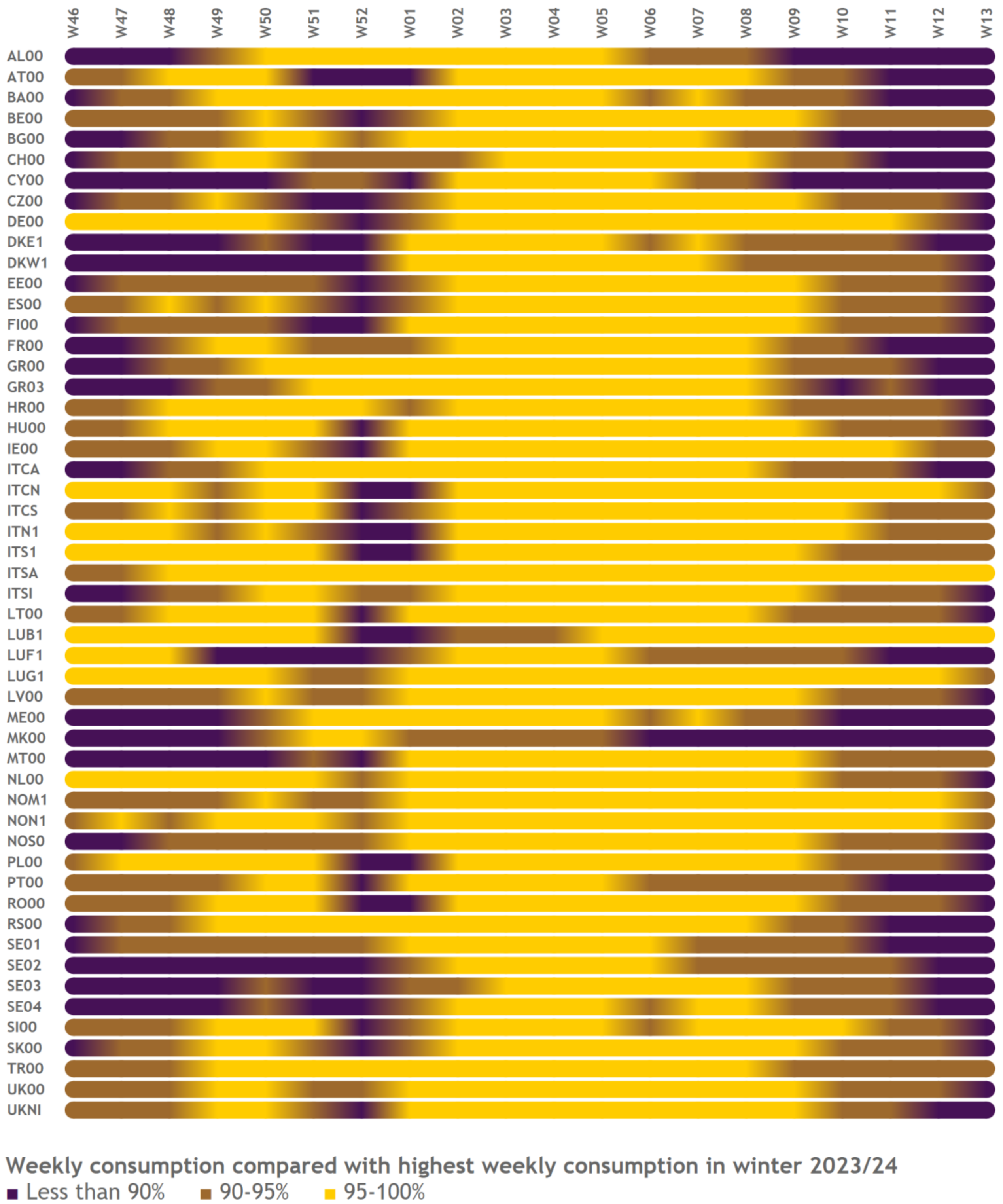

Figure 11: Demand overview – evolution over winter 2023–24

Figure 12 shows workday consumption patterns per study zone by plotting the average demand relative to the highest average demand in winter 2023–2024. The peak demand in Europe is mostly concentrated in the morning and evening. In some study zones (e.g. Netherlands, Poland or Germany), no significant reduction can be seen between these two peaks in the demand.

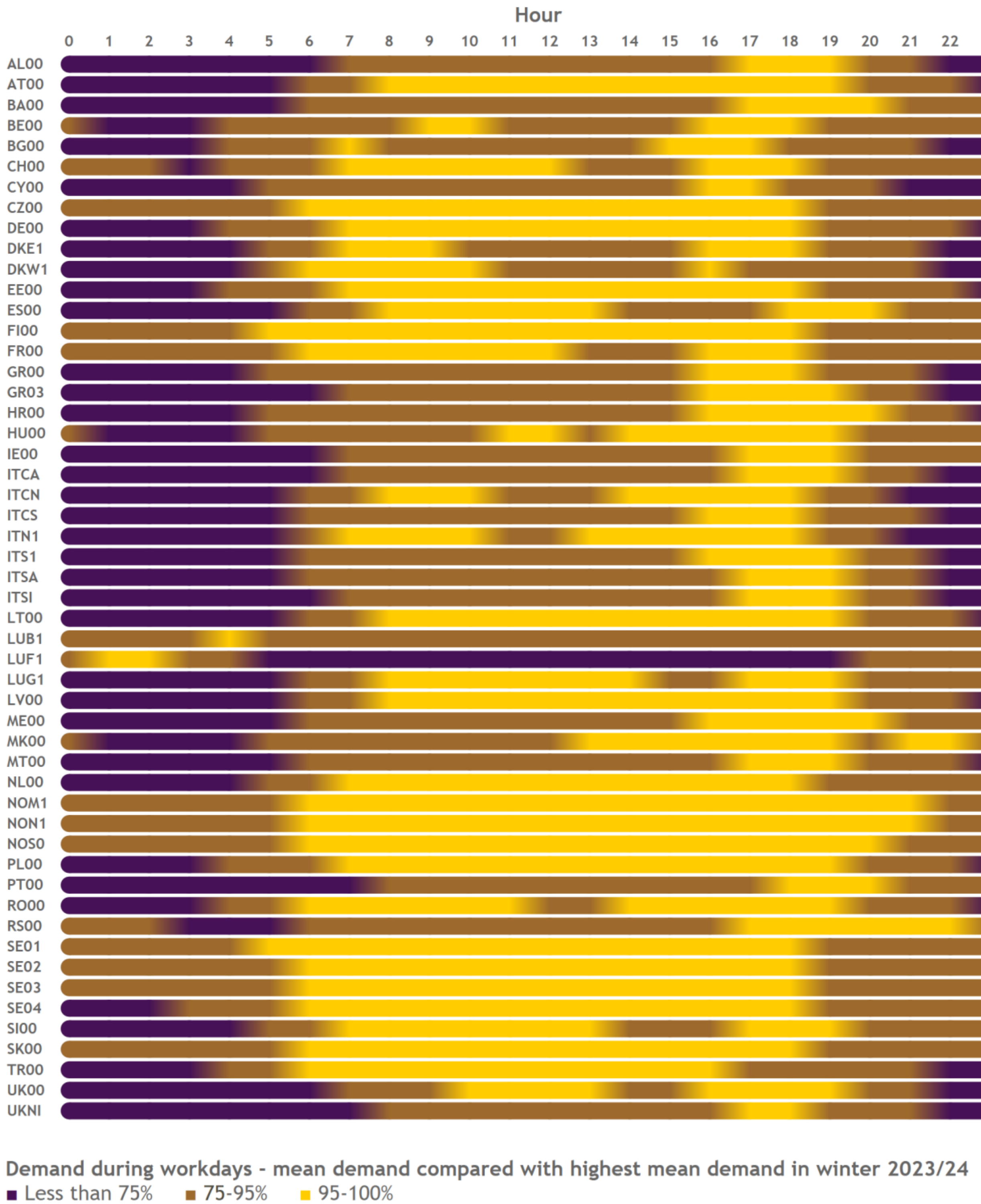

Figure 12: Demand profile overview during Mondays–Fridays in summer 2023[5]

Network overview

Compared to previous winter, only minor changes have been noticed in the maximum NTC in most of Europe, in import and export. However, some infrastructure evolutions of the European network[6] contribute to a noticeable increase in import capacity for zones such as the Northern part of Italy, Slovenia and Hungary.

[5] *The UTC time convention was used.*
[6] *Infrastructure projects in one country may have a positive and notable impact in the other countries.*

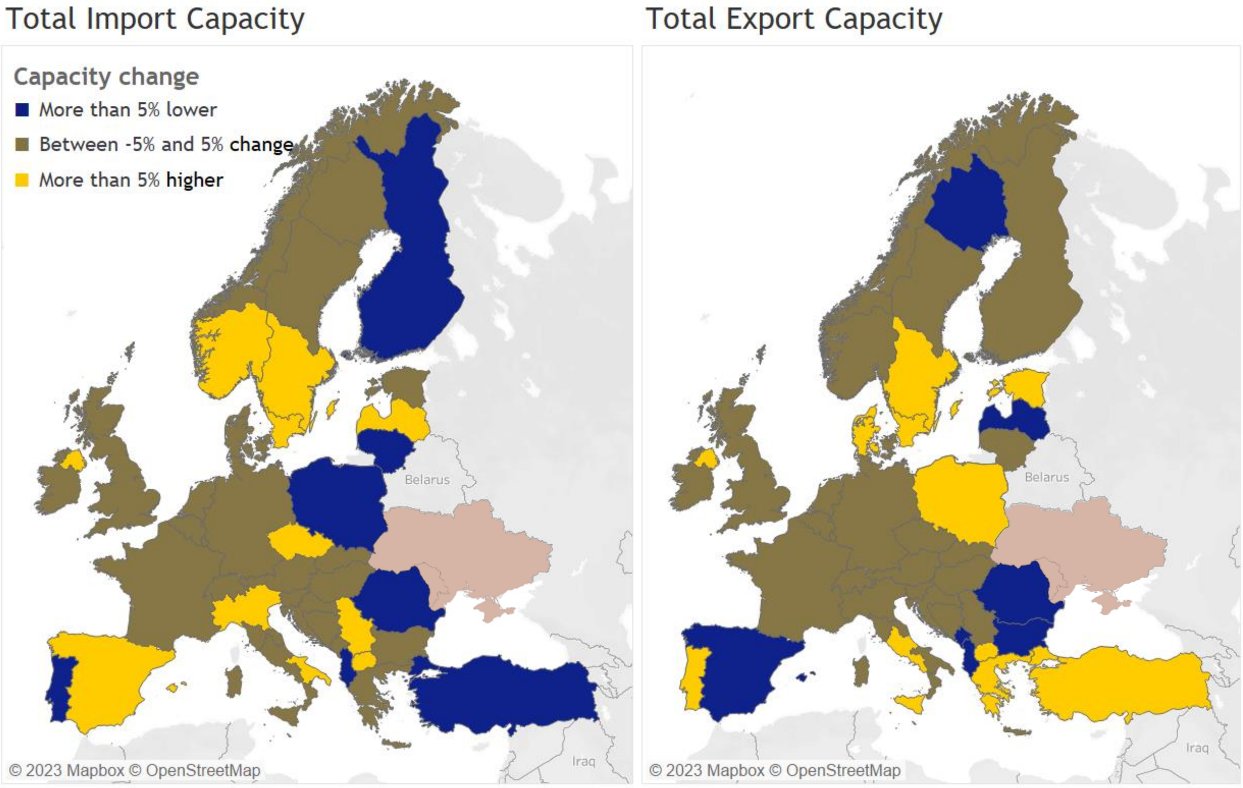

Figure 13 Import and Export capacity trends: winter 2023–2024 vs winter 2022–2023

For coming winter, Figure 14 shows the ratio of lowest import capacity to highest expected demand. It indicates the extent to which systems may be capable of relying on the imports from abroad during supply scarcity moments (if generation abroad is available).

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 2). 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 – for example Northern Italy (ITN1) 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 is 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[7].

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[7] *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 not collected.*

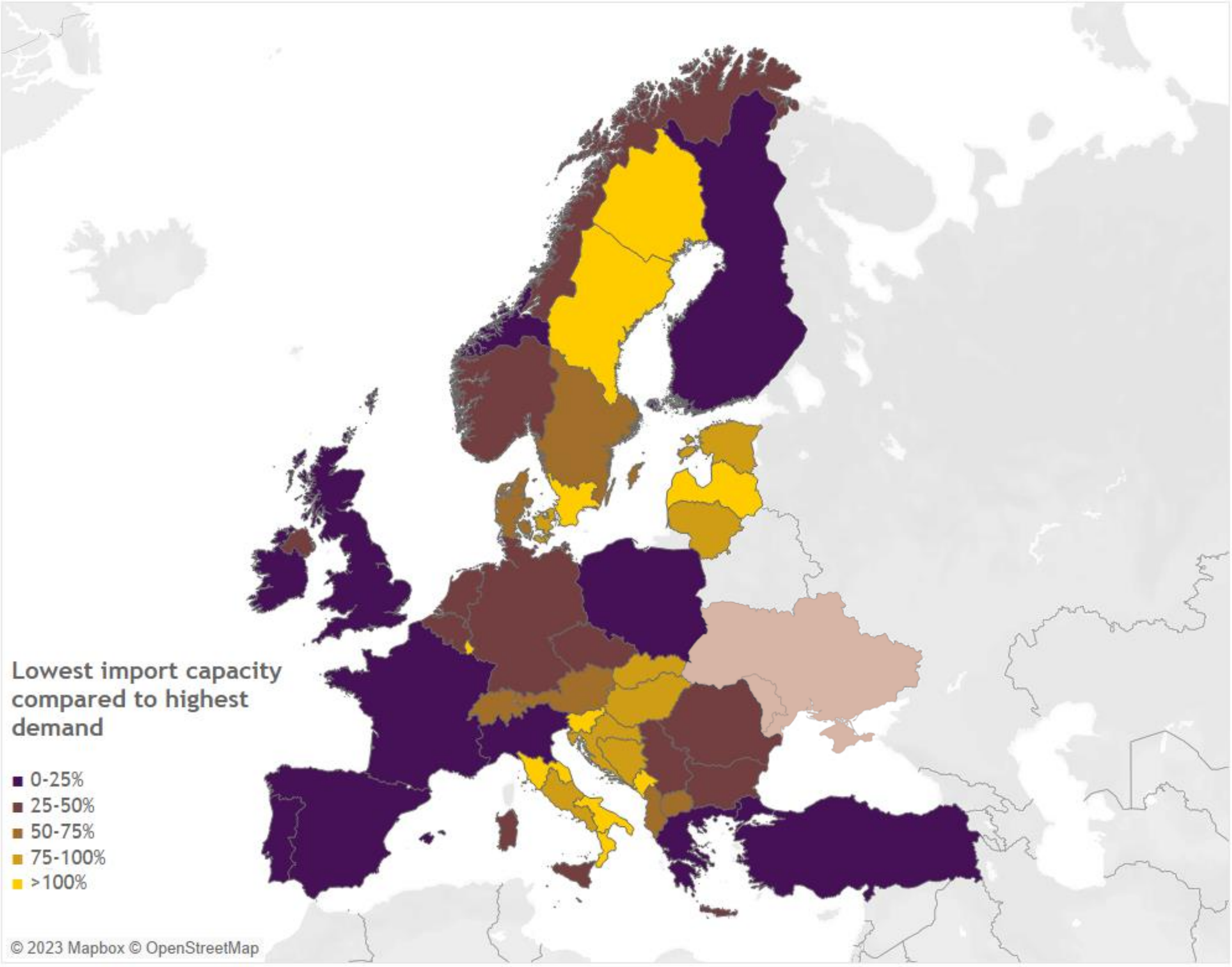


Figure 14: Import capacities per study zone: ratio between lowest import capacity and highest expected demand. C.f. Figure 29 for details

Adequacy situation and gas need during winter 2023–2024

ENTSO-E assesses the adequacy situation with two scenarios: the Reference scenario and Energy saving scenario. In both scenarios, the CGV projections are calculated. The energy-saving scenario serves to indicate the impact of potential demand reductions to achieve adequacy issues as well as on gas fuel reliance.

The adequacy situation in winter 2023–2024 (Figure 15) highlights certain adequacy risks – i.e. the risk of having to rely on non-market measures – in Ireland, Cyprus and Malta. A small regional risk is identified in and around France, with the highest risk affecting Belgium and the UK. Traces of risks are also identified in Finland. Results with energy saving measures suggest that risks could be significantly mitigated by these measures. Only a small regional risk in and around France does not change drastically as demand expectations for winter 2023–2024 in the reference scenario are already low.

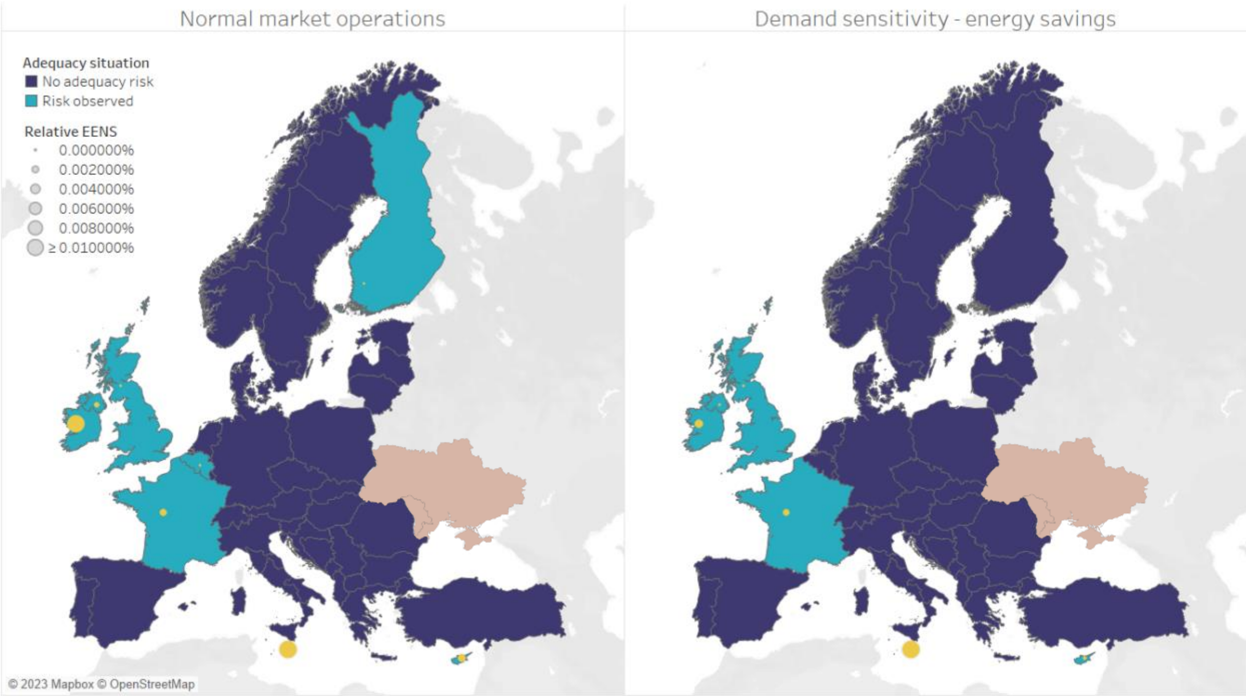


Figure 15: Adequacy overview

The state of the power system is continuously changing and is different since the data collection (performed in August 2023). For this reason, risks are continuously being monitored by TSOs and Regional Coordination Centres (RCCs).

Reference scenario

The adequacy situation 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 whether these would be sufficient to solve the risks identified in the previous step. The non-market resources can be activated to cope with structural supply shortages in the market.

There are some risks of electricity supply in remote areas including Ireland, Northern Ireland, Malta and Cyprus. Dedicated non-market resources would help to alleviate those risks in in Ireland and in Malta. Finland may also encounter some risk in the case of exceptionally adverse operational conditions combined with cold weather and high unplanned outages.

Small regional adequacy risk is identified in and around France (FR00), with the highest probability of affecting Belgium and Great Britain. Efficiencies of Flow-Based Market Coupling, which are considered in French[8] and Belgian[9] national adequacy assessments, suggest that these risks could be averted.

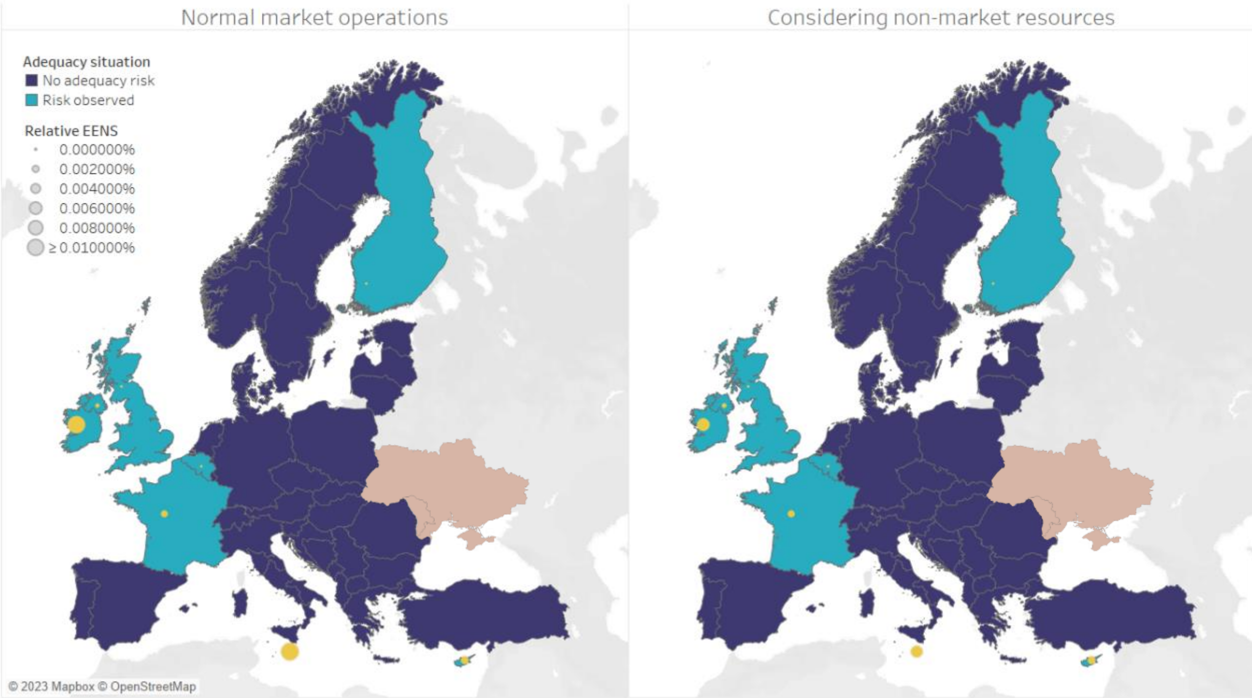


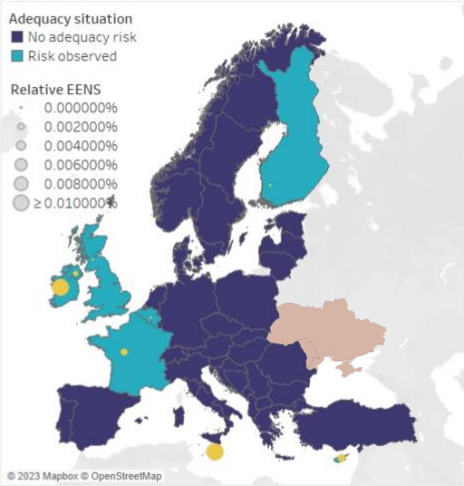
Figure 16: Adequacy overview

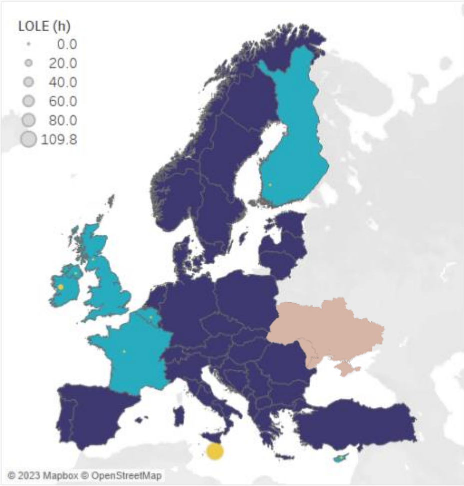
Focus on adequacy under normal market conditions

Figure 17 presents detailed adequacy risks under normal market operations. For most countries, the adequacy risk is not identified. Risks are present in Ireland (IE00), Northern Ireland (UKNI), 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.

A small regional adequacy risk is identified in and around France (FR00), with the highest probability of affecting Belgium and Great Britain in the event of an extreme cold spell. However, the efficiencies of Flow-Based Market Coupling, which are considered in French[10] and Belgian[11] national adequacy assessments, suggest that these risks could be averted. Nevertheless, TSOs will remain vigilant and, if necessary, will adopt regional coordination measures to ensure optimal network operational planning measures being implemented to address such risks. This supports the seasonal outlook methodology development discussions in the TSO community, supporting the idea to implement Flow-Based Market Coupling representation in the foreseeable future.

[8] French national adequacy study
[9] Belgian national adequacy study
[10] French national adequacy study
[11] Belgian national adequacy study





BE00	**EENS:** 0.0014 GWh (**0.00000%** compared to Seasonal Consumption) **99th percentile ENS:** 0.0000 GWh (**0.0000%** compared to Seasonal Consumption) **LOLE:** 0.019 h
CY00	**EENS:** 0.0366 GWh (**0.00178%** compared to Seasonal Consumption) **99th percentile ENS:** 0.5355 GWh (**0.0261%** compared to Seasonal Consumption) **LOLE:** 0.837 h
FI00	**EENS:** 0.0046 GWh (**0.00001%** compared to Seasonal Consumption) **99th percentile ENS:** 0.0000 GWh (**0.0000%** compared to Seasonal Consumption) **LOLE:** 0.013 h
FR00	**EENS:** 3.1724 GWh (**0.00142%** compared to Seasonal Consumption) **99th percentile ENS:** 113.8950 GWh (**0.0511%** compared to Seasonal Consumption) **LOLE:** 0.757 h
IE00	**EENS:** 2.4190 GWh (**0.01523%** compared to Seasonal Consumption) **99th percentile ENS:** 15.5457 GWh (**0.0979%** compared to Seasonal Consumption) **LOLE:** 9.438 h
MT00	**EENS:** 3.8101 GWh (**0.28070%** compared to Seasonal Consumption) **99th percentile ENS:** 6.6489 GWh (**0.4898%** compared to Seasonal Consumption) **LOLE:** 109.807 h
UK00	**EENS:** 0.0088 GWh (**0.00001%** compared to Seasonal Consumption) **99th percentile ENS:** 0.0000 GWh (**0.0000%** compared to Seasonal Consumption) **LOLE:** 0.012 h
UKNI	**EENS:** 0.0301 GWh (**0.00075%** compared to Seasonal Consumption) **99th percentile ENS:** 0.9280 GWh (**0.0232%** compared to Seasonal Consumption) **LOLE:** 0.194 h

Figure 17: Adequacy risk overview

The distribution of risks within the season is presented via visualisation of Loss Of Load Probability. 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. The only common pattern is identified around France (France, Belgium, United Kingdom), where a small regional risk was identified.

Cyprus (CY00) may face risks in the event of adverse weather conditions and combined with unplanned outages. The Cyprus system has no interconnection to the other power systems and must therefore rely on domestic supply. Higher risks are identified in the period until January 2024, though those risks are mitigated to some extent due to planned outage rescheduling performed until the publication of this report. If weather conditions are favourable or at least not combined with high unplanned outages, no adequacy issues should be recorded over winter 2023–2024 in Cyprus.

Ireland (IE00) is marked with adequacy risks throughout winter 2023–2024. These risks are driven by the unplanned outages of aging powerplants and will depend on wind generation if such outages will occur. The decommissioning of a 350 MW gas power plant in Northern Ireland before winter puts additional stress onto the Irish system. This generation is supposed to be replaced by 700 MW gas power plants, which should mitigate risks to a certain extent. However, this will happen only after winter 2023–2024. Meanwhile, Ireland may rely on non-market resources (~500 MW), whose contribution is assessed further in the report.

The adequacy situation in Malta (MT00) should be monitored throughout the winter and especially if significant unplanned outages of generation or interconnection with Italy are recorded. Adequacy in Malta is typically carefully monitored every winter, 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.

The risks faced by Northern Ireland (UKNI) concentrate in late December and January but remain rather low compared to the risks in Ireland. However, the situation should be closely monitored if weather conditions are unfavourable in Northern Ireland or neighbouring systems.

A small regional adequacy risk is identified in and around France (FR00), with the highest probability of affecting Belgium and Great Britain. These risks are identified in January in the event of an extreme cold spell.

Finland (FI00) risks are minute 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 and high unplanned generation or interconnection outages.

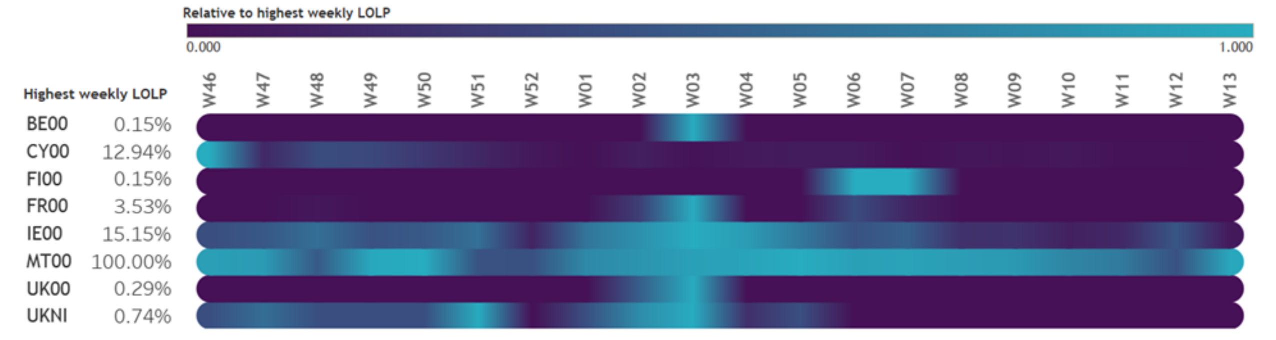


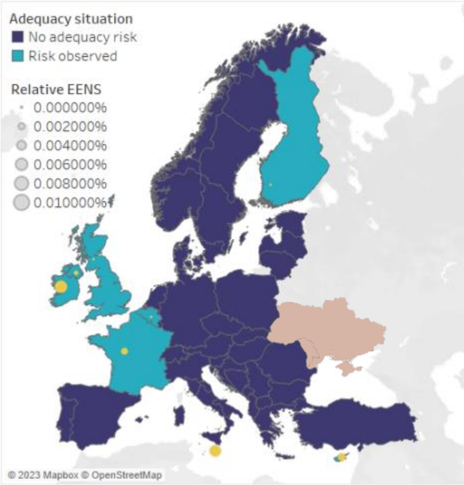
Figure 18: Adequacy weekly insights

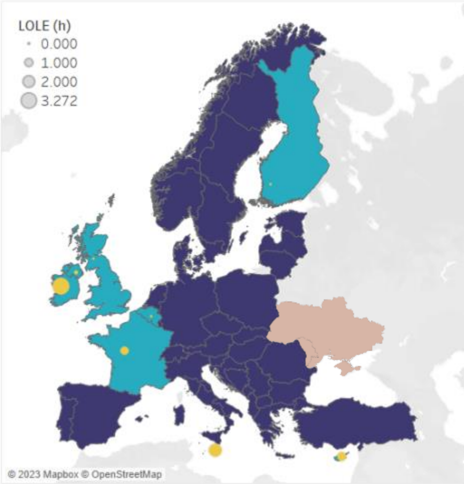
Focus on non-market resources

Dispatching non-market resources reduces the magnitude of the risks (EENS), notably in Malta and Ireland. In Malta it is significantly reduced when compared to the normal market operation and only traces of risks remain as Malta relies on dedicated non-market resources (c.f. Figure 4).

The activation of these resources may depend on the existing legal frameworks[12]. Figure 19 presents the adequacy conditions with non-market resources while the Polish non-market DSR is excluded due to specific conditions of activation.

[12] 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 may depend on the existing legal framework.





BE00	**EENS:** 0.0004 GWh (**0.00000%** compared to Seasonal Consumption) **99th percentile ENS:** 0.0000 GWh (**0.0000%** compared to Seasonal Consumption) **LOLE:** 0.018 h
CY00	**EENS:** 0.0366 GWh (**0.00178%** compared to Seasonal Consumption) **99th percentile ENS:** 0.5355 GWh (**0.0261%** compared to Seasonal Consumption) **LOLE:** 0.837 h
FI00	**EENS:** 0.0046 GWh (**0.00001%** compared to Seasonal Consumption) **99th percentile ENS:** 0.0000 GWh (**0.0000%** compared to Seasonal Consumption) **LOLE:** 0.013 h
FR00	**EENS:** 3.1141 GWh (**0.00140%** compared to Seasonal Consumption) **99th percentile ENS:** 111.5898 GWh (**0.0501%** compared to Seasonal Consumption) **LOLE:** 0.749 h
IE00	**EENS:** 0.8232 GWh (**0.00518%** compared to Seasonal Consumption) **99th percentile ENS:** 9.7176 GWh (**0.0612%** compared to Seasonal Consumption) **LOLE:** 3.272 h
MT00	**EENS:** 0.0561 GWh (**0.00414%** compared to Seasonal Consumption) **99th percentile ENS:** 0.5402 GWh (**0.0398%** compared to Seasonal Consumption) **LOLE:** 1.872 h
UK00	**EENS:** 0.0070 GWh (**0.00001%** compared to Seasonal Consumption) **99th percentile ENS:** 0.0000 GWh (**0.0000%** compared to Seasonal Consumption) **LOLE:** 0.009 h
UKNI	**EENS:** 0.0228 GWh (**0.00057%** compared to Seasonal Consumption) **99th percentile ENS:** 0.6606 GWh (**0.0165%** compared to Seasonal Consumption) **LOLE:** 0.141 h

Figure 19: Adequacy risk overview – considering non-market resources

The distribution of risks in Figure 19 suggests that risks in Malta could not be addressed completely in December (week 50). In addition, Malta should remain vigilant in January–February as residual risks prevail. Risks in Ireland are completely addressed towards the end of the season, while risks in the rest of the winter still remain. Risks in other zones remain unaffected.

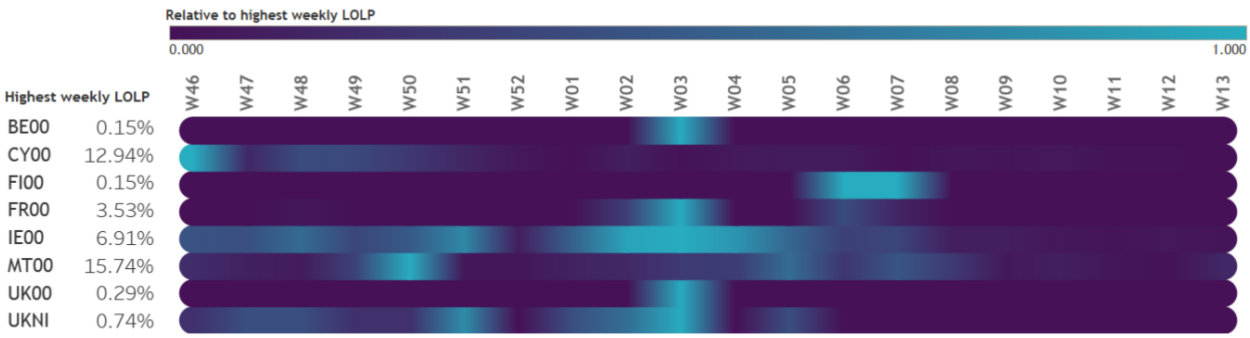


Figure 20: Adequacy weekly insights—considering non-market resources

Figure 21 represents the impact of non-market resources. As already discussed, adequacy risks are significantly mitigated in Malta and Ireland. However, the Figure 21 results also suggest that risks could also be mitigated in areas where such measures do not exist but are accessible through interconnectors. Results in Northern Ireland suggest that Irish non-market resources could contribute to addressing the risks; however, this might be not possible due to legal restrictions on sharing these resources. Indeed, the activation of these resources may depend on the existing legal frameworks[13]. Figure 21 presents the adequacy conditions with non-market resources while the Polish non-market DSR is excluded due to specific conditions of activation.

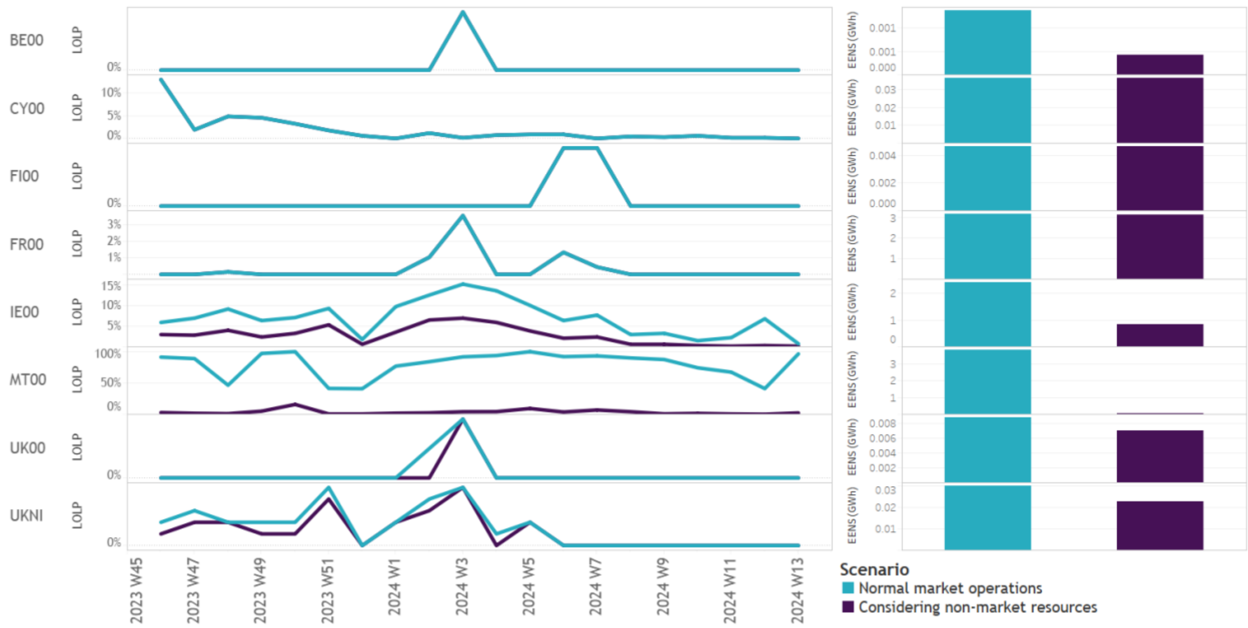


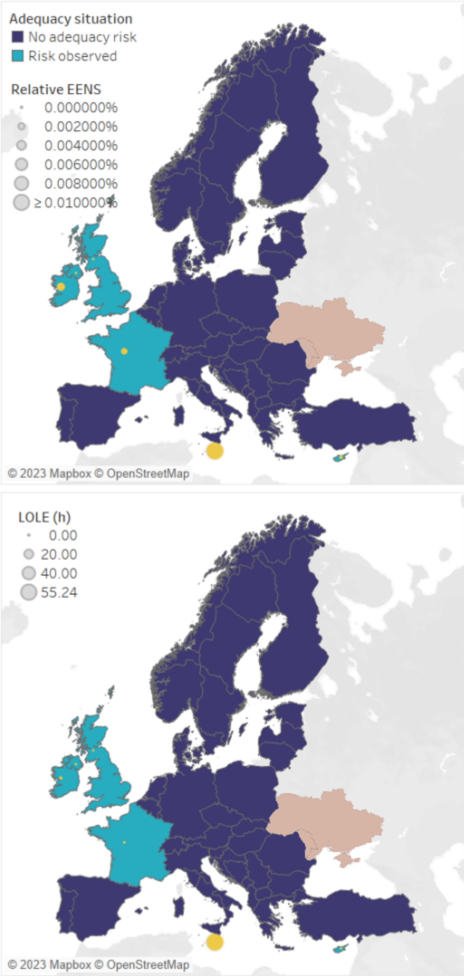
Figure 21: Detailed adequacy overview – weekly LOLP and ENS[14]

Energy savings scenario

Energy saving measures if implemented to achieve European energy saving targets (Council Regulation 2022/1854), as in winter 2022–2023, would contribute to adequacy risk mitigation. Traces of risk would disappear in Finland. Risks elsewhere would still remain, but would decrease substantially (risk disappearance in Belgium suggests that the magnitude of small regional risk in and around France would decrease). These energy saving measures could reduce the necessity to activate non-market resources, but those would remain necessary in Ireland and Malta.

[13] 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 may depend on the existing legal framework.

[14] Results in Northern Ireland suggest that Irish non-market resources could contribute to addressing risks; however, this might be not possible due to legal restrictions on sharing these resources.



CY00	**EENS:** 0.0070 GWh (**0.00034%** compared to Seasonal Consumption) **99th percentile ENS:** 0.1598 GWh (**0.0078%** compared to Seasonal Consumption) **LOLE:** 0.162 h
FR00	**EENS:** 2.8305 GWh (**0.00127%** compared to Seasonal Consumption) **99th percentile ENS:** 99.2804 GWh (**0.0446%** compared to Seasonal Consumption) **LOLE:** 0.724 h
IE00	**EENS:** 0.3313 GWh (**0.00209%** compared to Seasonal Consumption) **99th percentile ENS:** 5.5965 GWh (**0.0352%** compared to Seasonal Consumption) **LOLE:** 1.437 h
MT00	**EENS:** 1.7288 GWh (**0.12736%** compared to Seasonal Consumption) **99th percentile ENS:** 3.4618 GWh (**0.2550%** compared to Seasonal Consumption) **LOLE:** 55.235 h
UK00	**EENS:** 0.0010 GWh (**0.00000%** compared to Seasonal Consumption) **99th percentile ENS:** 0.0000 GWh (**0.0000%** compared to Seasonal Consumption) **LOLE:** 0.004 h
UKNI	**EENS:** 0.0033 GWh (**0.00008%** compared to Seasonal Consumption) **99th percentile ENS:** 0.0000 GWh (**0.0000%** compared to Seasonal Consumption) **LOLE:** 0.025 h

Figure 22: Adequacy risk overview – Energy savings scenario

The distribution of risks in Figure 23 suggests a similar pattern as in the reference scenario, though the risks themselves decrease.

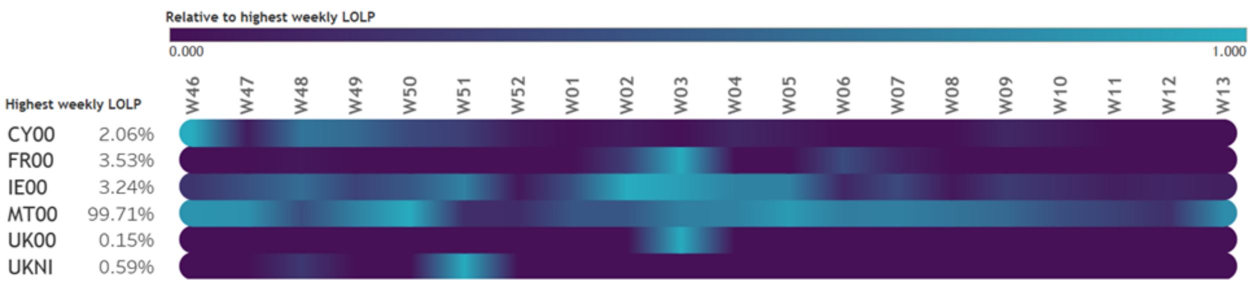


Figure 23: Adequacy weekly insights – Energy savings scenario

Critical Gas Volume for Winter 2023–2024

The Critical Gas Volume (CGV) decreases approximately by 10% compared with winter 2022–2023. Factors such as the higher nuclear availability in Europe, the expansion of renewable production capacity and higher hydro availability, in addition to stagnant demand, all indicate having to rely less on conventional gas power-plant production to cover the demand peaks.

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 unavailabilities and real market behaviour, with some gas units not being last in the merit order. CGV could decrease by 10% if energy saving measures to reduce consumption and peak demand comply with similar targets as approved by Council for winter 2022–2023 (Council regulation 2022/1854). More information is given in in appendix 4.

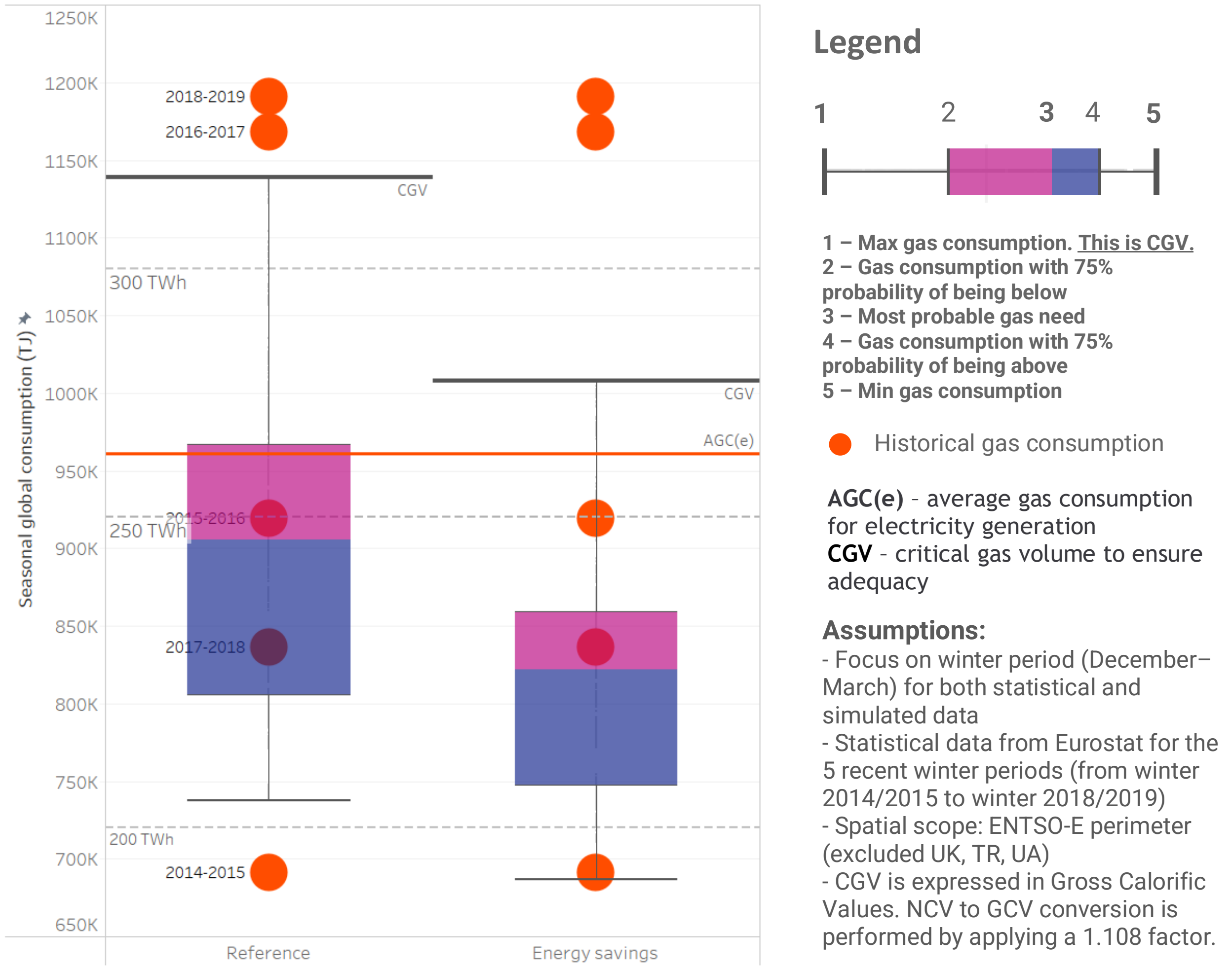
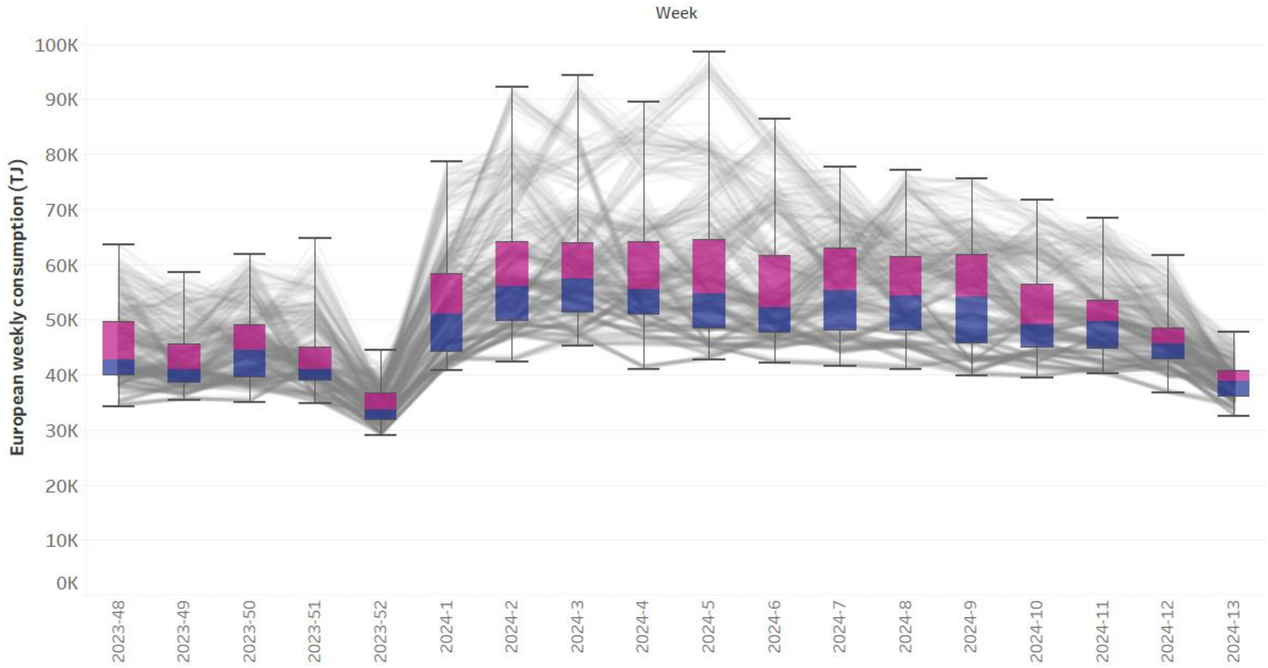


Figure 24: CGV analysis overview

How to interpret the CGV chart

- Each orange 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 the 5 statistical years (orange dots).
- The maximum gas consumption corresponds to the gas volume necessary 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 34 climate condition scenarios). There is a 50% probability of a given year being in this range.

The results also suggest that reliance on gas availabilities is particularly high in January and February if weather conditions are not favourable.



Expectations for Ukraine and Moldova power systems

Russia's military aggression against Ukraine, starting in February 2022, continues during 2023 and causes increased levels of risk and uncertainty 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 may determine the actual situation in Ukraine's power system. Uncertainty over gas supplies and electricity import availabilities are key concerns in Moldova.

Ukraine's national analysis for the upcoming winter season demonstrates an acceptable level of adequacy in the Ukrainian Integrated Power System, especially under conditions similar to the current situation. However, it is important to note that achieving this adequacy level will necessitate higher than usual volumes of natural gas consumption for electricity generation and some minimal required electricity imports throughout the entire winter season. In the most precarious scenarios, which involve significant and hardly predictable damage to generation equipment and grid infrastructure, there is a potential for increased electricity imports and natural gas consumption. In extreme cases, these factors may even lead to the necessity for demand shedding.

Moldova faces several system adequacy risks for the upcoming winter, including heavy dependence on gas, uncertain imports from Ukraine and Romania, weak interconnections at the Romanian border, high 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 Winter 2023–2034, Moldova is taking proactive measures, including risk discussions with the government, ANRE (National regulator), and key market actors, emergency state decisions for the Electricity Market, nominating 'Energocom' as the sole buyer/seller for regulated utilities, implementing capacity allocation at the MD–RO border, and upgrading infrastructure. These preparations, coupled with demand reduction measures and gas stocking in Ukraine and Romania, aim to reduce the system risk significantly.

Summer 2023 review

In general, no adequacy issues were recorded during summer 2023. Europe experienced hot summer months, with extreme weather events in some regions. Heatwaves were experienced in Southern Europe from Spain to the Balkans in July; from Portugal, France, Spain and Italy in August; and Belgium in September. Southwestern Europe experienced wildfires in August, while Eastern Europe and Scandinavian countries experienced significant flooding events. Scandinavia was also affected by Storm Hans in August.

The EU has successfully filled gas storage facilities to 90% of their capacity, surpassing the 1 November deadline by approximately two and a half months. This effort, driven by the gas storage regulation introduced in June 2022, aims to better prepare the EU for the upcoming winter season. Gas storage is crucial for ensuring a secure gas supply in Europe, covering up to one-third of the EU's winter gas demand.

Temperature overview

During the summer of 2023, Europe witnessed unprecedented temperature anomalies (Figure 25). In June, European temperatures were 0.74°C above the 1991–2020 average, with the highest anomalies observed in northwest Europe. Conversely, the southern Balkans, Greece, Türkiye, and western Russia were colder than average, with mixed conditions across Italy and Spain.

July continued this trend, with Europe experiencing a 0.38°C temperature anomaly, while globally, it was the warmest month ever recorded. Heatwaves stretched from Spain to the Balkans, while much of northern Europe had temperatures close to or below average.

August featured above-average temperatures in southern Europe, with Portugal, France, Spain and Italy experiencing a heatwave. Globally, August 2023 was the hottest August on record, with a 0.71°C anomaly above the 1991–2020 average.

September marked the culmination of this remarkable summer, with Europe experiencing a 2.51°C temperature anomaly, making it the hottest September in the European record. Several countries in a band from France to Finland recorded their warmest September on record. Meanwhile Belgium and the United Kingdom reported unprecedented heatwaves in early September. Cooler temperatures were limited to the continent's periphery, including Iceland, Svalbard, and parts of Greece and the Iberian Peninsula.

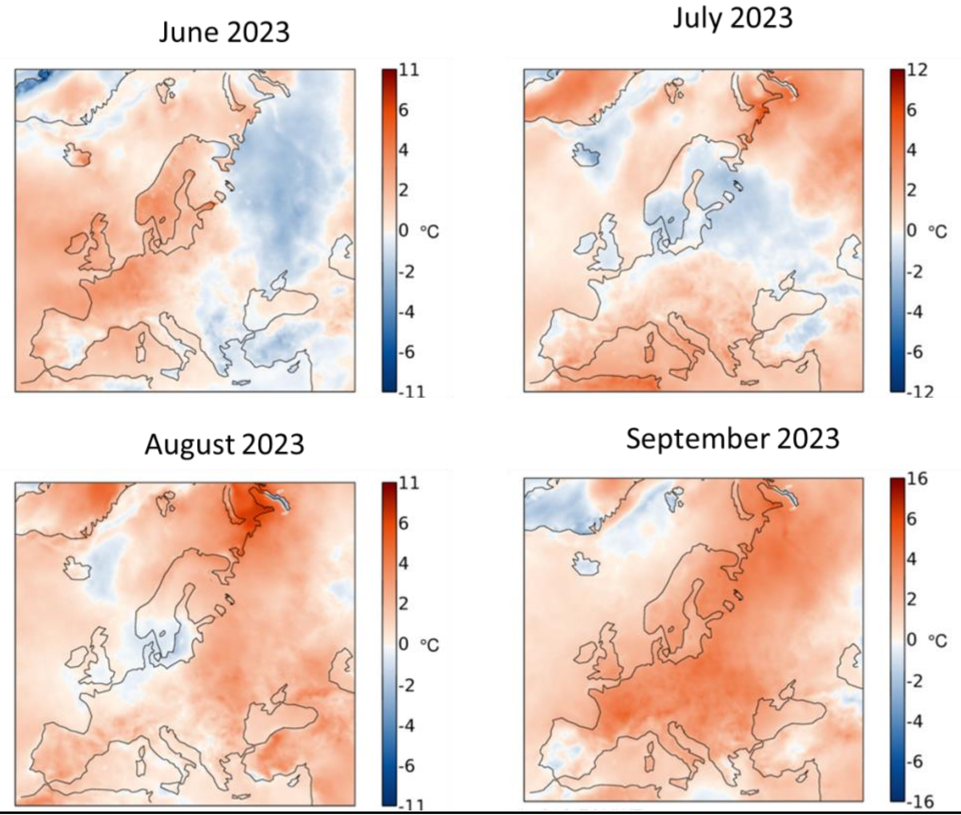


Figure 25: Surface air temperature anomaly in Summer 2023 relative to the average for the periods 1991–2020 (for June, July, August, and September)[15]

Adequacy and other relevant events overview

In general, no adequacy issues were recorded during summer 2023. Some countries faced unusual water levels (low or high), change in electricity demand, and high photovoltaic (PV) output.

Austria experienced record-breaking hydroelectric production due to heavy rainfall, resulting in high exports and reduced imports. The country is rapidly expanding renewable energy sources but faces challenges with unreported PV installations affecting demand. Cyprus had a few hours of reduced reserve availability but managed without significant adequacy issues. Finland had planned outage related capacity drops, but its self-sufficiency in electricity generation is improving, driven by increased wind power.

Reduced gas deliveries from Russia had no impact on electricity generation. Greece saw a slight increase in electricity demand, especially during heatwaves. Fires and severe storms caused localised outages. However, no major adequacy issues were recorded.

Hungary recorded moderate system demand, high PV generation, and consequently a decrease of imports during the summer. The country managed IT and network problems effectively, ensuring a reliable supply. Ireland and Northern Ireland faced tight generation margins during the summer, leading to an alert state on one occasion. Security of supply was maintained through renewable generation and interconnector support.

The Swiss network was highly loaded which required redispatch actions to mitigate bottlenecks. Unplanned power flows and voltage regulation challenges occurred, but overall regulatory stability was maintained.

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

Appendix 1: Methodological insights

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

This new methodology is described in the Methodology for Short-term and Seasonal Adequacy Assessments[16]. 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, and it received formal approval from the Agency for the Cooperation of Energy Regulators (ACER)[17]. Although the implementation of this target methodology 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 analysed timeframe. Figure 26 provides a schematic representation of this scenario construction process.

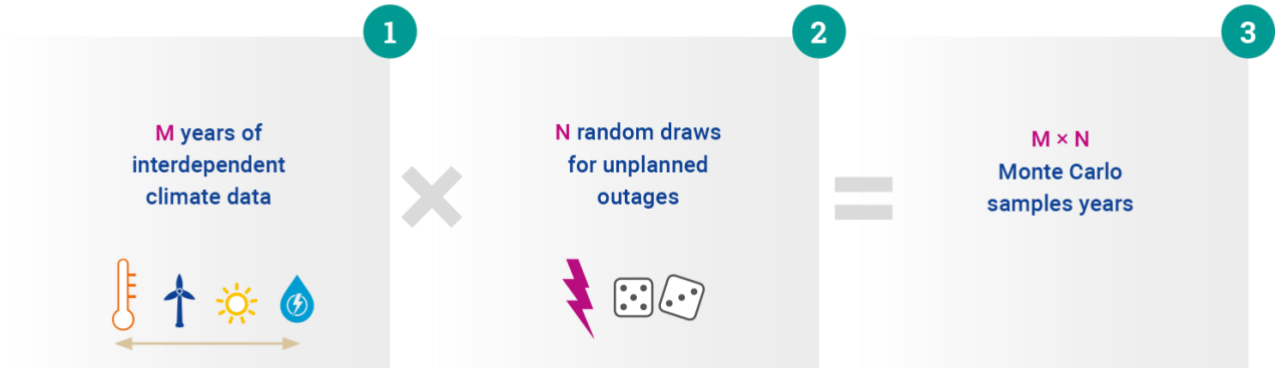


Figure 26: Scenarios assessed in Seasonal Outlooks

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 27 illustrates the difference in the number of scenarios between the two modelling approaches.

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

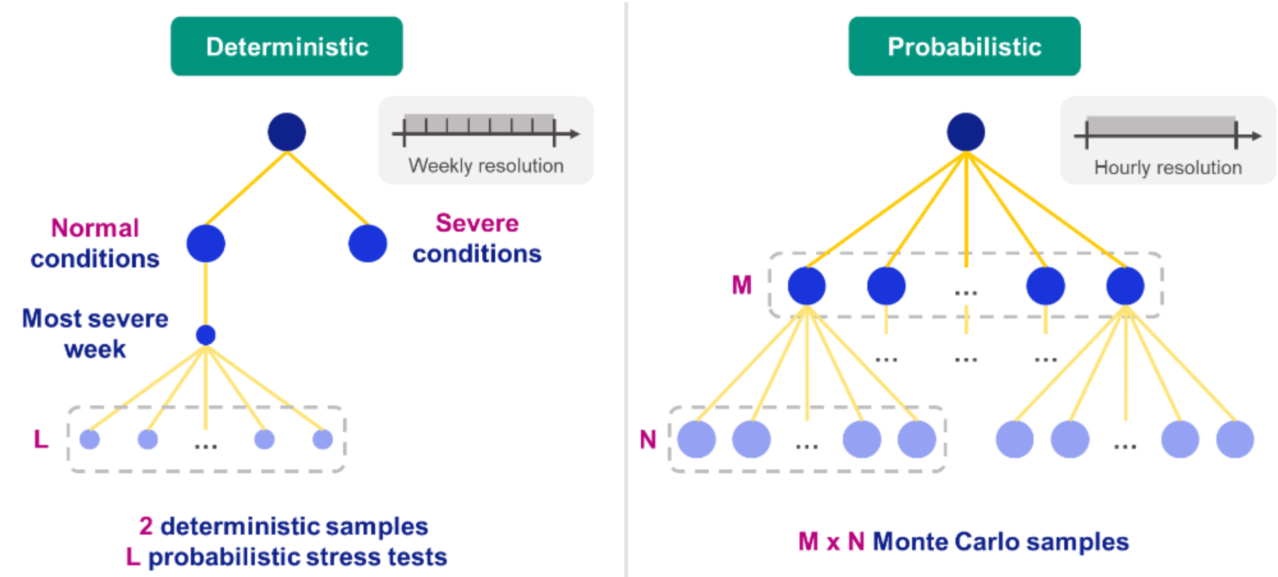


Figure 27: Scenario revolution – from deterministic to probabilistic

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

Appendix 2: Additional information about the study

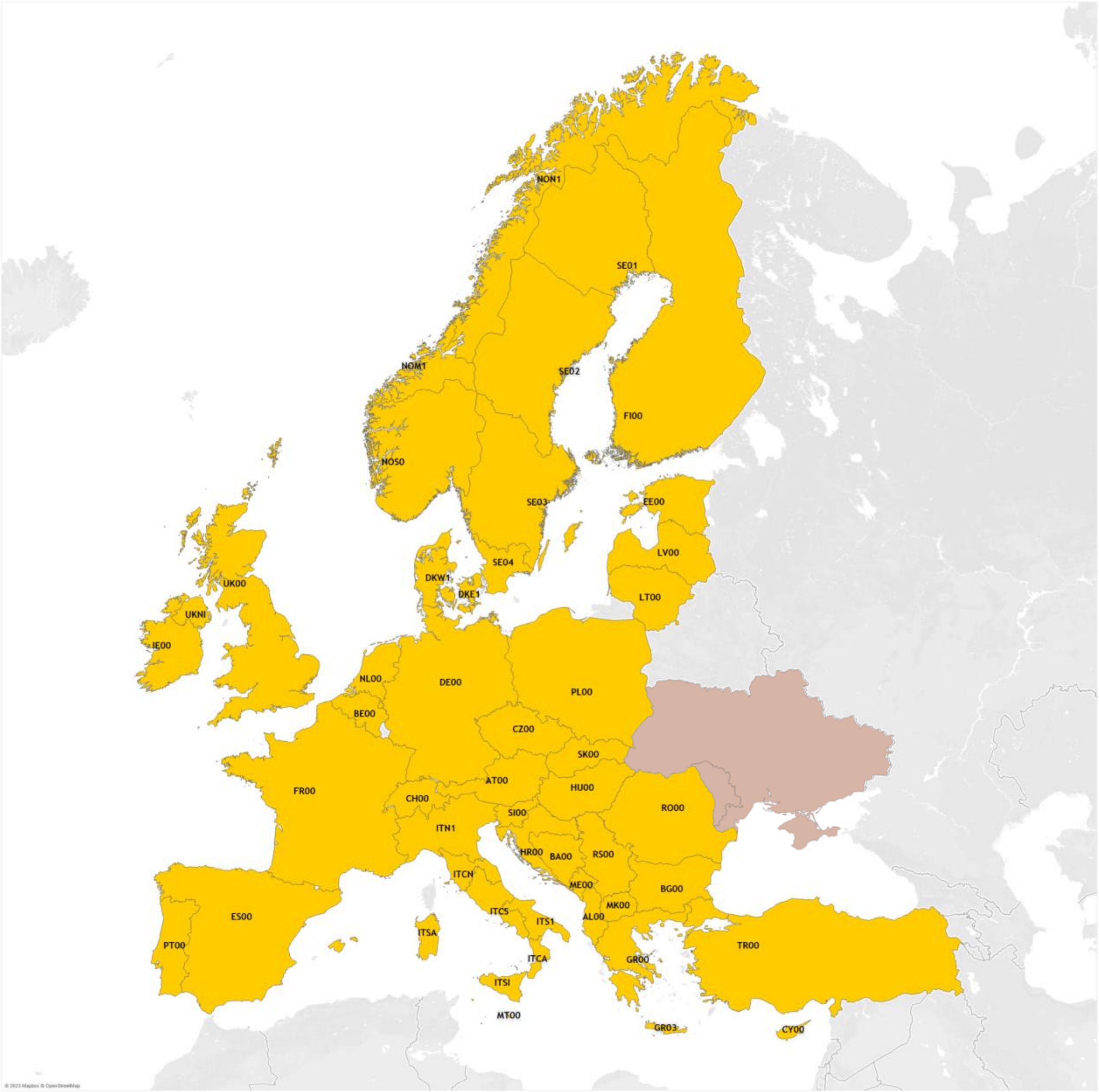


Figure 28: Study zones

AL00	From: GR00 Avg. 400 MW (400 - 400) MW	From: ME00 Avg. 300 MW (300 - 300) MW	From: RS00 Avg. 200 MW (200 - 200) MW												
AT00	From: DE00 Avg. 4,900 MW (4,900 - 4,900) MW	From: CH00 Avg. 1,200 MW (1,200 - 1,200) MW	From: SI00 Avg. 950 MW (950 - 950) MW	From: CZ00 Avg. 800 MW (800 - 800) MW	From: HU00 Avg. 800 MW (800 - 800) MW	From: ITN1 Avg. 108 MW (85 - 145) MW									
BA00	From: HR00 Avg. 800 MW (800 - 800) MW	From: RS00 Avg. 553 MW (450 - 600) MW	From: ME00 Avg. 500 MW (500 - 500) MW												
BE00	From: FR00 Avg. 1,850 MW (1,850 - 1,850) MW	From: DE00 Avg. 1,000 MW (1,000 - 1,000) MW	From: UK00 Avg. 1,000 MW (1,000 - 1,000) MW	From: NL00 Avg. 950 MW (950 - 950) MW											
BG00	From: RO00 Avg. 1,560 MW (1,560 - 1,560) MW	From: GR00 Avg. 700 MW (700 - 700) MW	From: MK00 Avg. 350 MW (250 - 350) MW	From: TR00 Avg. 334 MW (334 - 334) MW	From: RS00 Avg. 291 MW (250 - 350) MW										
CH00	From: FR00 Avg. 3,080 MW (2,500 - 3,200) MW	From: DE00 Avg. 2,158 MW (1,900 - 2,200) MW	From: ITN1 Avg. 1,852 MW (1,810 - 1,910) MW	From: AT00 Avg. 1,174 MW (936 - 1,200) MW											
CZ00	From: DE00 Avg. 2,300 MW (2,300 - 2,300) MW	From: SK00 Avg. 1,200 MW (1,200 - 1,200) MW	From: PLE0 Avg. 1,100 MW (1,100 - 1,100) MW	From: AT00 Avg. 900 MW (900 - 900) MW											
DE00	From: AT00 Avg. 4,900 MW (4,900 - 4,900) MW	From: NL00 Avg. 4,400 MW (4,400 - 4,400) MW	From: CH00 Avg. 4,000 MW (4,000 - 4,000) MW	From: FR00 Avg. 3,000 MW (3,000 - 3,000) MW	From: PLE0 Avg. 3,000 MW (3,000 - 3,000) MW	From: CZ00 Avg. 2,500 MW (2,500 - 2,500) MW	From: DKW1 Avg. 2,403 MW (700 - 2,500) MW	From: NOS0 Avg. 1,400 MW (1,400 - 1,400) MW	From: LUV1 Avg. 1,300 MW (1,300 - 1,300) MW	From: BE00 Avg. 1,000 MW (1,000 - 1,000) MW	From: LUG1 Avg. 1,000 MW (1,000 - 1,000) MW	From: SE04 Avg. 615 MW (615 - 615) MW	From: DKE1 Avg. 585 MW (585 - 585) MW	From: DEKF Avg. 400 MW (400 - 400) MW	
DKE1	From: SE04 Avg. 1,300 MW (1,300 - 1,300) MW	From: DE00 Avg. 600 MW (600 - 600) MW	From: DKW1 Avg. 590 MW (590 - 590) MW	From: DKKF Avg. 400 MW (400 - 400) MW											
DKW1	From: DE00 Avg. 2,378 MW (665 - 2,500) MW	From: NOS0 Avg. 1,623 MW (1,435 - 1,632) MW	From: NL00 Avg. 679 MW (0 - 700) MW	From: SE03 Avg. 636 MW (150 - 680) MW	From: DKE1 Avg. 600 MW (600 - 600) MW										
EE00	From: FI00 Avg. 1,016 MW (1,016 - 1,016) MW	From: LV00 Avg. 929 MW (569 - 970) MW													
ES00	From: PT00 Avg. 2,732 MW (2,400 - 3,200) MW	From: FR00 Avg. 2,276 MW (2,050 - 2,600) MW													
FI00	From: SE01 Avg. 1,200 MW (1,200 - 1,200) MW	From: SE03 Avg. 1,199 MW (800 - 1,200) MW	From: EE00 Avg. 1,016 MW (1,016 - 1,016) MW												
FR00	From: UK00 Avg. 4,000 MW (4,000 - 4,000) MW	From: DE00 Avg. 3,000 MW (3,000 - 3,000) MW	From: ES00 Avg. 1,889 MW (1,250 - 2,400) MW	From: CH00 Avg. 1,200 MW (1,200 - 1,200) MW	From: ITN1 Avg. 957 MW (600 - 1,160) MW	From: BE00 Avg. 600 MW (600 - 600) MW									
GR00	From: BG00 Avg. 700 MW (700 - 700) MW	From: ITS1 Avg. 500 MW (500 - 500) MW	From: AL00 Avg. 400 MW (400 - 400) MW	From: MK00 Avg. 385 MW (212 - 400) MW	From: GR03 Avg. 150 MW (150 - 150) MW	From: TR00 Avg. 50 MW (50 - 50) MW									
GR03	From: GR00 Avg. 150 MW (150 - 150) MW														
HR00	From: HU00 Avg. 1,000 MW (1,000 - 1,000) MW	From: SI00 Avg. 1,000 MW (1,000 - 1,000) MW	From: BA00 Avg. 800 MW (800 - 800) MW	From: RS00 Avg. 400 MW (400 - 400) MW											
HU00	From: SK00 Avg. 1,500 MW (1,500 - 1,500) MW	From: RS00 Avg. 1,000 MW (1,000 - 1,000) MW	From: AT00 Avg. 800 MW (800 - 800) MW	From: HR00 Avg. 800 MW (800 - 800) MW	From: RO00 Avg. 800 MW (800 - 800) MW	From: SI00 Avg. 700 MW (700 - 700) MW									
IE00	From: UK00 Avg. 500 MW (500 - 500) MW	From: UKNI Avg. 400 MW (400 - 400) MW													
ITCA	From: ITSI Avg. 1,300 MW (1,300 - 1,300) MW	From: ITS1 Avg. 1,100 MW (1,100 - 1,100) MW													
ITCN	From: ITN1 Avg. 3,688 MW (2,800 - 4,300) MW	From: ITCS Avg. 2,756 MW (2,200 - 2,800) MW													
ITCS	From: ITS1 Avg. 5,006 MW (3,800 - 5,100) MW	From: ITCN Avg. 2,666 MW (2,400 - 2,900) MW	From: ITSA Avg. 886 MW (870 - 900) MW	From: ME00 Avg. 600 MW (600 - 600) MW											
ITN1	From: CH00 Avg. 4,038 MW (2,314 - 4,572) MW	From: ITCN Avg. 2,494 MW (1,900 - 3,100) MW	From: FR00 Avg. 2,011 MW (600 - 3,150) MW	From: SI00 Avg. 645 MW (0 - 753) MW	From: AT00 Avg. 282 MW (175 - 325) MW										
ITS1	From: ITCS Avg. 2,400 MW (2,400 - 2,400) MW	From: ITCA Avg. 2,350 MW (2,350 - 2,350) MW	From: GR00 Avg. 500 MW (500 - 500) MW												
ITSA	From: ITCS Avg. 720 MW (720 - 720) MW														
ITSI	From: ITCA Avg. 1,500 MW (1,500 - 1,500) MW	From: MT00 Avg. 216 MW (0 - 225) MW													
LT00	From: LV00 Avg. 920 MW (871 - 951) MW	From: SE04 Avg. 700 MW (700 - 700) MW	From: PL00 Avg. 497 MW (492 - 500) MW												
LUB1	From: BE00 Avg. 280 MW (280 - 280) MW														
LUF1	From: FR00 Avg. 380 MW (380 - 380) MW														
LUG1	From: DE00 Avg. 1,000 MW (1,000 - 1,000) MW														
LV00	From: LT00 Avg. 1,049 MW (904 - 1,114) MW	From: EE00 Avg. 1,045 MW (606 - 1,200) MW													
ME00	From: ITCS Avg. 600 MW (600 - 600) MW	From: RS00 Avg. 600 MW (600 - 600) MW	From: BA00 Avg. 500 MW (500 - 500) MW	From: AL00 Avg. 300 MW (300 - 300) MW											
MK00	From: RS00 Avg. 576 MW (219 - 1,020) MW	From: GR00 Avg. 400 MW (399 - 400) MW	From: BG00 Avg. 341 MW (300 - 350) MW												
MT00	From: ITSI Avg. 216 MW (0 - 225) MW														
NL00	From: DE00 Avg. 4,400 MW (4,400 - 4,400) MW	From: UK00 Avg. 1,000 MW (1,000 - 1,000) MW	From: BE00 Avg. 950 MW (950 - 950) MW	From: NOS0 Avg. 700 MW (700 - 700) MW	From: DKW1 Avg. 679 MW (0 - 700) MW										
NOM1	From: NON1 Avg. 1,300 MW (1,300 - 1,300) MW	From: SE02 Avg. 1,000 MW (1,000 - 1,000) MW	From: NOS0 Avg. 589 MW (300 - 600) MW												
NON1	From: SE01 Avg. 600 MW (600 - 600) MW	From: NOM1 Avg. 350 MW (350 - 350) MW	From: SE02 Avg. 300 MW (300 - 300) MW												
NOS0	From: SE03 Avg. 1,950 MW (350 - 2,095) MW	From: DKW1 Avg. 1,628 MW (1,545 - 1,632) MW	From: DE00 Avg. 1,400 MW (1,400 - 1,400) MW	From: UK00 Avg. 1,400 MW (1,400 - 1,400) MW	From: NOM1 Avg. 800 MW (800 - 800) MW	From: NL00 Avg. 700 MW (700 - 700) MW									
PL00	From: PLI0 Avg. 1,136 MW (1,136 - 1,136) MW	From: SE04 Avg. 600 MW (600 - 600) MW	From: LT00 Avg. 350 MW (350 - 350) MW												
PT00	From: ES00 Avg. 2,549 MW (2,200 - 3,400) MW														
RO00	From: BG00 Avg. 1,560 MW (1,560 - 1,560) MW	From: HU00 Avg. 933 MW (500 - 1,000) MW	From: RS00 Avg. 500 MW (500 - 500) MW	From: UA01 Avg. 200 MW (200 - 200) MW											
RS00	From: HU00 Avg. 933 MW (500 - 1,000) MW	From: MK00 Avg. 720 MW (314 - 1,423) MW	From: BA00 Avg. 600 MW (600 - 600) MW	From: RO00 Avg. 465 MW (250 - 500) MW	From: ME00 Avg. 400 MW (400 - 400) MW	From: BG00 Avg. 321 MW (300 - 350) MW	From: HR00 Avg. 300 MW (300 - 300) MW	From: AL00 Avg. 200 MW (200 - 200) MW							
SE01	From: SE02 Avg. 3,300 MW (3,300 - 3,300) MW	From: FI00 Avg. 1,076 MW (750 - 1,100) MW	From: NON1 Avg. 700 MW (700 - 700) MW												
SE02	From: SE03 Avg. 7,300 MW (7,300 - 7,300) MW	From: SE01 Avg. 3,292 MW (3,100 - 3,300) MW	From: NOM1 Avg. 600 MW (600 - 600) MW	From: NON1 Avg. 250 MW (250 - 250) MW											
SE03	From: SE02 Avg. 7,150 MW (5,500 - 7,300) MW	From: SE04 Avg. 2,800 MW (2,800 - 2,800) MW	From: NOS0 Avg. 2,083 MW (1,400 - 2,145) MW	From: DKW1 Avg. 715 MW (715 - 715) MW	From: FI00 Avg. 383 MW (200 - 400) MW										
SE04	From: SE03 Avg. 4,800 MW (3,700 - 4,900) MW	From: DKE1 Avg. 1,700 MW (1,700 - 1,700) MW	From: LT00 Avg. 700 MW (700 - 700) MW	From: DE00 Avg. 615 MW (615 - 615) MW	From: PL00 Avg. 600 MW (600 - 600) MW										
SI00	From: HR00 Avg. 1,100 MW (1,100 - 1,100) MW	From: AT00 Avg. 931 MW (600 - 950) MW	From: HU00 Avg. 700 MW (700 - 700) MW	From: ITN1 Avg. 666 MW (368 - 680) MW											
SK00	From: CZ00 Avg. 1,500 MW (1,500 - 1,500) MW	From: HU00 Avg. 1,500 MW (1,500 - 1,500) MW	From: PLE0 Avg. 600 MW (600 - 600) MW												
TR00	From: BG00 Avg. 432 MW (432 - 432) MW	From: GR00 Avg. 150 MW (150 - 150) MW													
UK00	From: FR00 Avg. 4,000 MW (4,000 - 4,000) MW	From: NOS0 Avg. 1,400 MW (1,400 - 1,400) MW	From: BE00 Avg. 1,000 MW (1,000 - 1,000) MW	From: NL00 Avg. 1,000 MW (1,000 - 1,000) MW	From: IE00 Avg. 500 MW (500 - 500) MW	From: UKNI Avg. 459 MW (400 - 500) MW									
UKNI	From: UK00 Avg. 480 MW (450 - 500) MW	From: IE00 Avg. 400 MW (400 - 400) MW													

Figure 29: Import capacity overview[18]

[18] PLI0 represent import on the technical PL00 border with DE00/CZ00/SK00. It limits simultaneous import from respective Study Zones to Poland. The same technical border is used for export purpose (PLE0) and export NTC amounts to 1650 MW.

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[19]. 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[20] 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); and

- 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 an upcoming season could simply be one of the more constraining from a set of possible season scenarios[21] (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[22], 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 aforementioned background and interpretation limitations, LOLE figures can be found in the main report content (Figure 17, Figure 19, Figure 22).

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[19] A comparison with past editions is not yet possible yet because this is the first time this measure has been reported in a seasonal adequacy assessment.
[20] The conclusions made for annual LOLE are also valid for any other annual metric.
[21] 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.
[22] 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, which shows that the seasonal assessment has a high accuracy level.

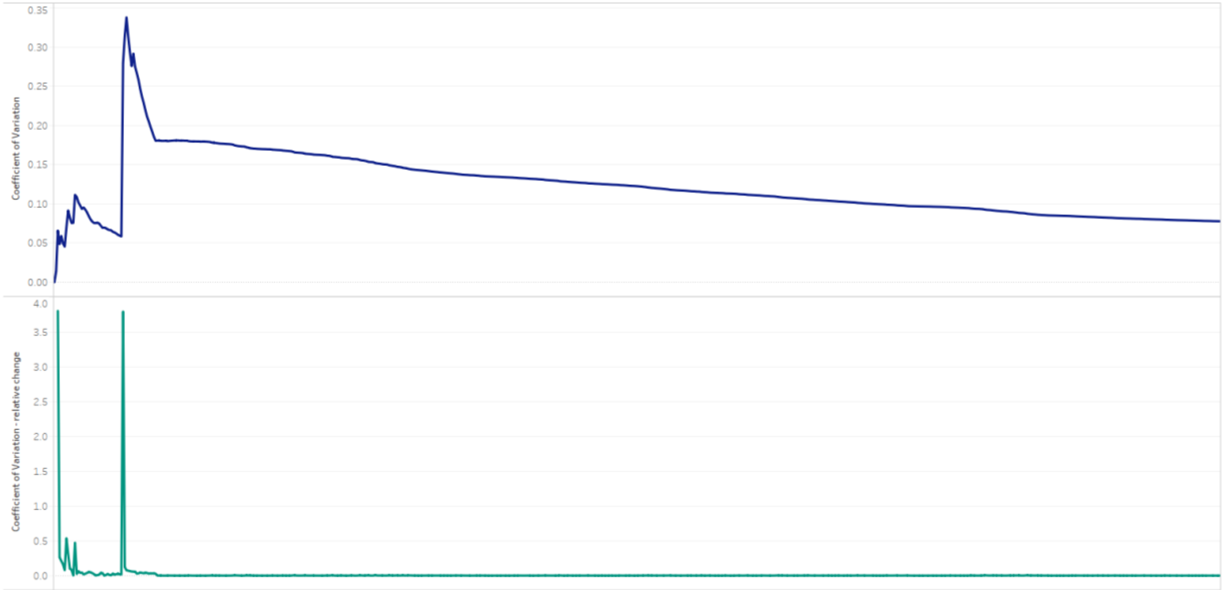

Figure 30: Convergence overview[23]

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[23] *The convergence overview shows that the seasonal assessment has a high accuracy level. The number of analysed Monte Carlo samples was 700, one per scenario.*

Appendix 4: Demand reductions in the energy savings scenario

To account for the different evolutions of demand profiles in Europe next winter (c.f. Overview of the power system in winter 2023/2024 – Demand overview), decreasing the total consumption and peak demand of each TSO in a homogeneous manner across Europe would not be the correct method to achieve similar energy saving targets as adopted by European Council for winter 2022–2023. For the energy savings scenario, ENTSO-E therefore took another approach, validated by TSOs, of reducing the total consumption and peak demand values for each country individually. Adjustment depended on their expectations of consumption and demand peaks (Figure 10) for the coming winter – the higher they were from historical averages, the more it was reduced. Displayed in both figures below are the reduction values applied to each TSO demand data in function of their estimations for next winter.

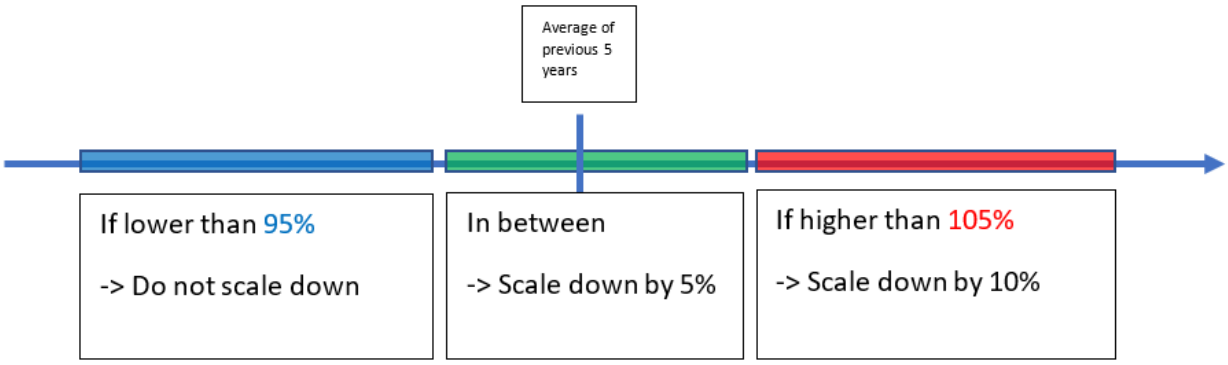

Figure 31: Reductions applied to total consumption data

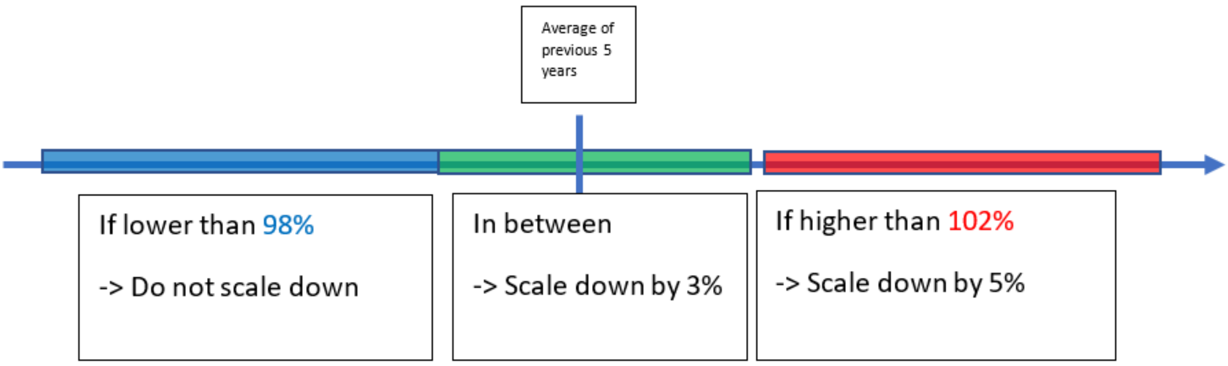

Figure 32: Reductions applied to demand data