Summer Outlook 2023

Winter Review 2022-2023

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 Summer Outlook 2023: no adequacy risk is identified except for the close monitoring required in Ireland.

The adequacy risk identified in Ireland at the end of summer season is driven by the notable planned outage of conventional generation in Northern Ireland (expected to exceed 600 MW). The actual adequacy situation in Ireland will depend on the operational conditions: on unplanned outages of the aging generation fleet in Ireland and especially on wind generation.

Some residual risks are identified in rather isolated Mediterranean Islands: Malta, Cyprus and Creta. These risks may emerge in the event of high unplanned outages of 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.

The Summer Outlook is accompanied by a retrospect of last winter. Notable preparations were taken by TSOs and Member States before winter 2022–2023 in light of the war in Ukraine.

The weather conditions were favourable during most of the winter, and hydro stock also improved immediately prior to winter, alleviating adequacy concerns for winter 2022–2023. Notably colder than average temperatures were recorded only in December in the Northern part of Europe, but this also coincided with periods when consumers typically consume less electricity due to approaching holiday periods.

Furthermore, a decrease in demand was recorded as a result of EU measures taken to save energy (EU emergency intervention) and also as a response to the high electricity prices faced by European consumers.

In Ukraine, a good balance and the stability of the power system was maintained despite the regular attacks on Ukrainian electricity infrastructure during the winter. Continental Europe TSOs—and especially neighbouring TSOs—have supported the Ukrainian system since 30 June 2022, when the commercial electricity exchanges were resumed.

Preparations for next winter 2023–2024 have begun. The TSOs' feedback as well as the gas situation show a much more confident picture than one year ago. No specific concern was identified. Preparedness and tight cooperation with the European Commission, TSOs and Members States will continue in the coming weeks.

Overview of the power system in summer 2023

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 dependent on imports when renewable generation is low.

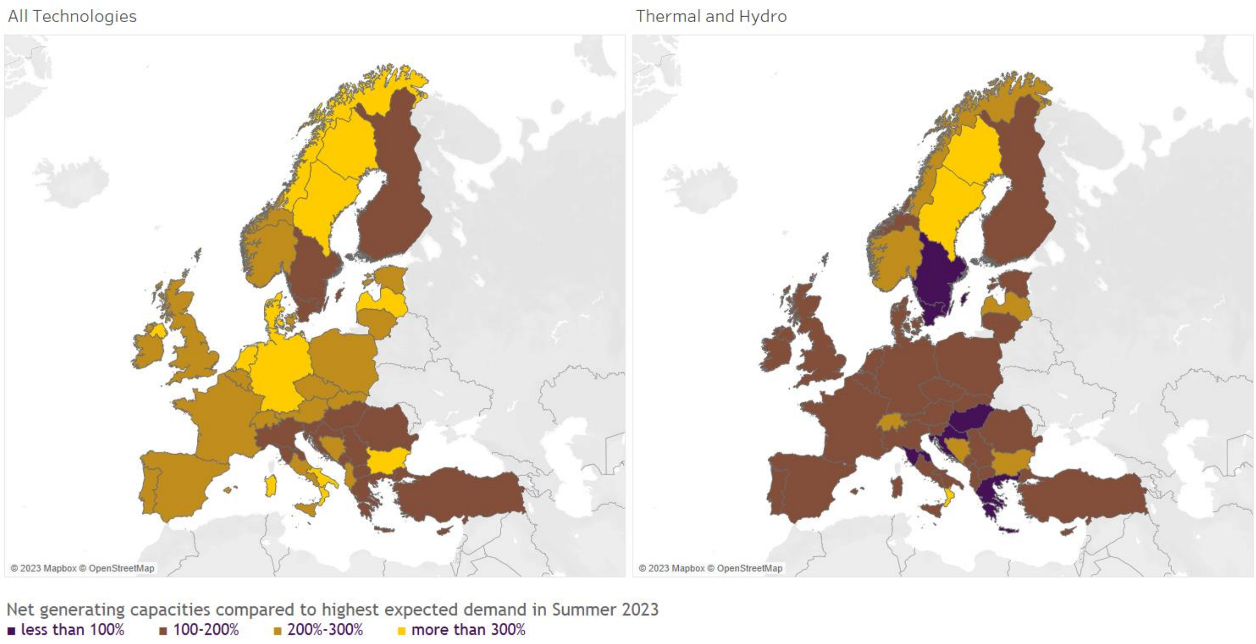


Figure 1: Net generating capacity overview—comparison with highest expected demand

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 2023. 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 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.

[1] *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.*

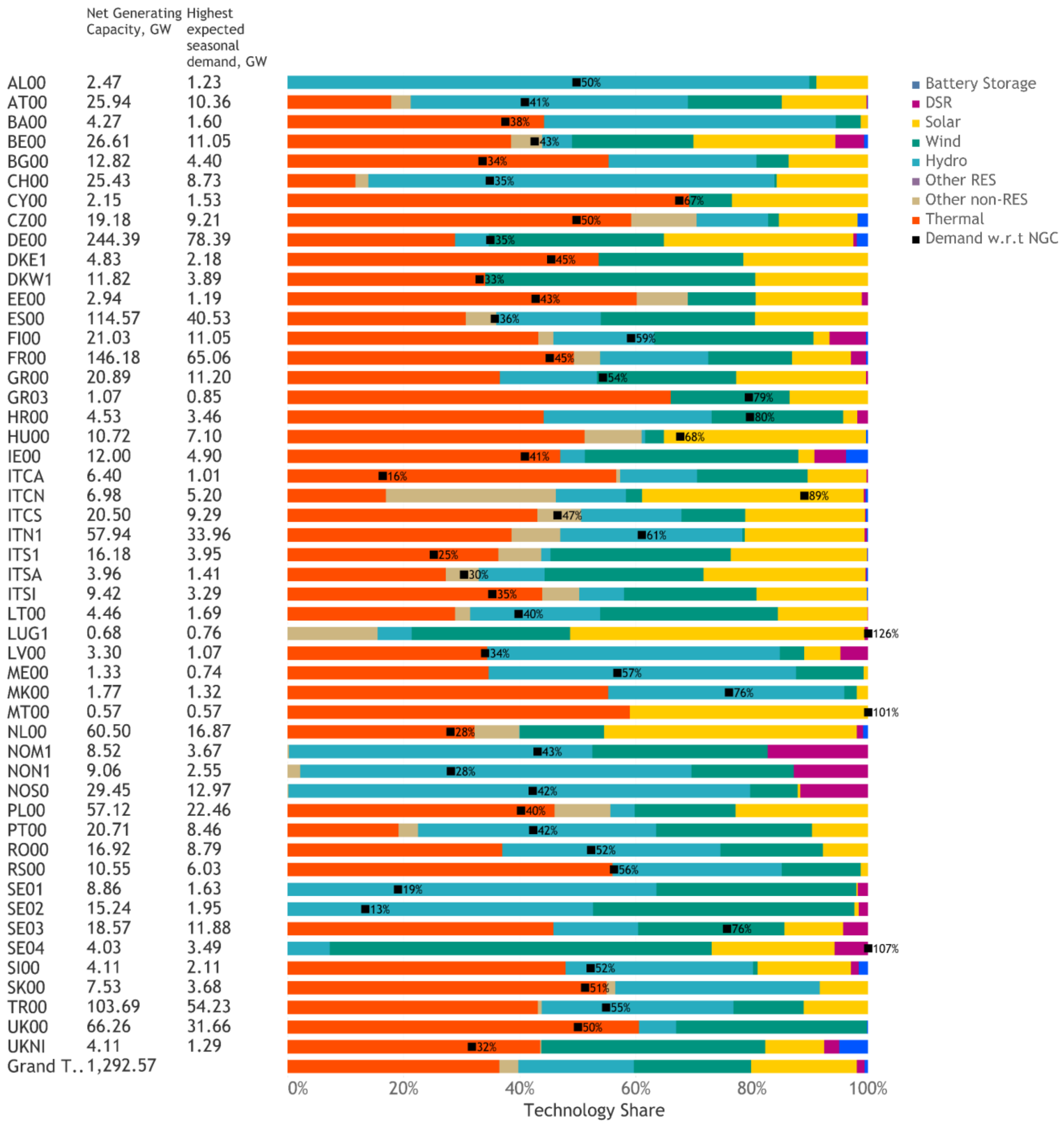


Figure 2: Generation capacity mix at the beginning of summer 2023 per study zones

Figure 3 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 four countries utilise non-market resources. From largest to smallest NGC, these are: Germany, Slovenia, the southern bidding zone of Sweden and Malta. This report also assesses if these resources are sufficient to address identified adequacy issues (c.f. section 'Adequacy situation in summer 2023').

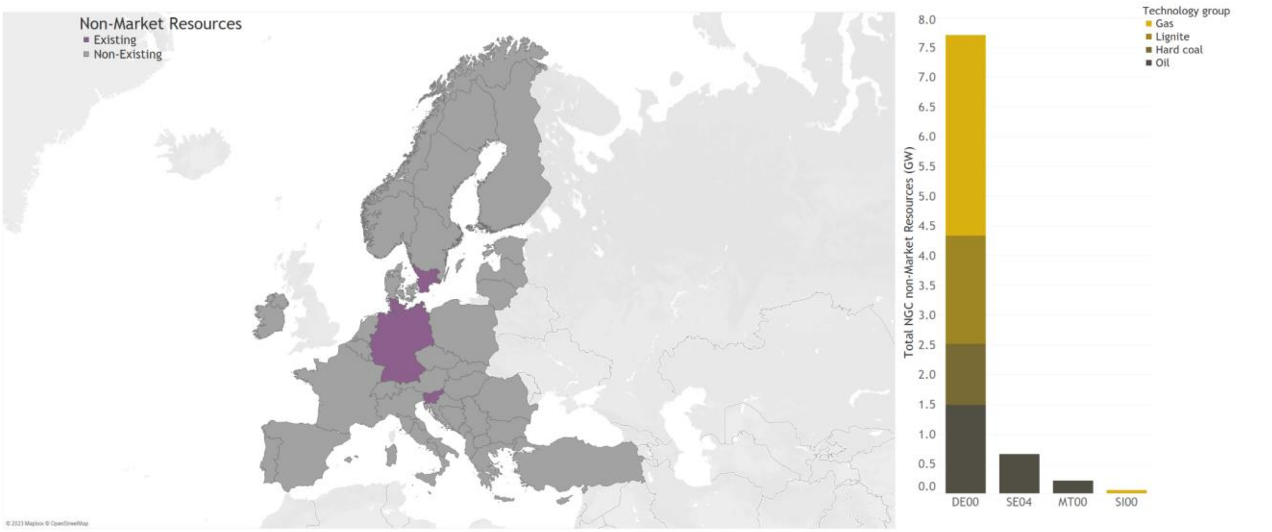


Figure 3: Non-market resources for coping with adequacy challenges in Europe[2]

Capacity evolution

Figure 4 shows that generation capacity in Europe grows during summer 2023[3], with a net increase of approximately 3000 MW, due to the expansion of renewable generation capacity. Overall, thermal generation remains the same; the decommissioning of fossil power plants is balanced by the increase of gas-fired power plant generation capacity.

---

[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.*

[3] *29 May 2023 – 1 October 2023*

Commissionings and Decommissionings

FI00	Other RES	20 July 2023	Commissioning 250MW
HR00	Gas	1 June 2023	Commissioning 150MW
	Solar	1 June 2023	Commissioning 12MW
ITCS	Gas	1 July 2023	Commissioning 300MW
ITN1	Gas	30 June 2023	Decommissioning 806MW
		1 July 2023	Commissioning 996MW
		1 October 2023	Decommissioning 123MW
ITS1	Gas	1 July 2023	Commissioning 72MW
ITSI	Gas	30 June 2023	Decommissioning 236MW
		1 July 2023	Commissioning 358MW
LT00	Batteries	1 June 2023	Commissioning 200MW
	Wind	3 June 2023	Commissioning 60MW
		25 August 2023	Commissioning 60MW
MK00	Hydro	1 July 2023	Commissioning 32MW
	Solar	1 July 2023	Commissioning 30MW
	Wind	1 July 2023	Commissioning 36MW
NL00	Wind	1 July 2023	Commissioning 760MW
NOM1	Solar	1 July 2023	Commissioning 90MW
	Wind	1 July 2023	Commissioning 152MW
NON1	Wind	1 July 2023	Commissioning 55MW
NOS0	Solar	1 July 2023	Commissioning 243MW
	Wind	1 July 2023	Commissioning 50MW
PL00	Solar	1 September 2023	Commissioning 423MW
	Wind	1 September 2023	Commissioning 300MW
RO00	Lignite	1 October 2023	Decommissioning 588MW
RS00	Other RES	1 June 2023	Commissioning 32MW
UKNI	Hard coal	30 September 2023	Decommissioning 350MW

Total change

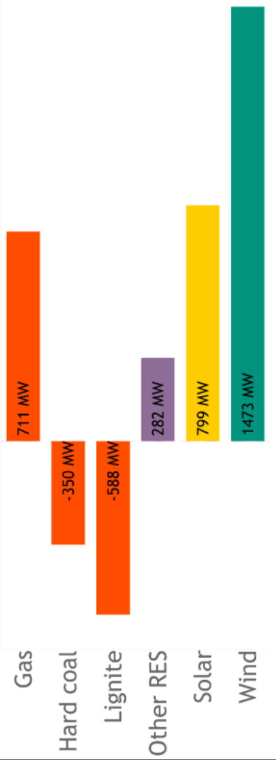


Figure 4: Capacity evolution in summer 2023

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 2023, with gas ranking second, followed by hard coal, lignite and oil.

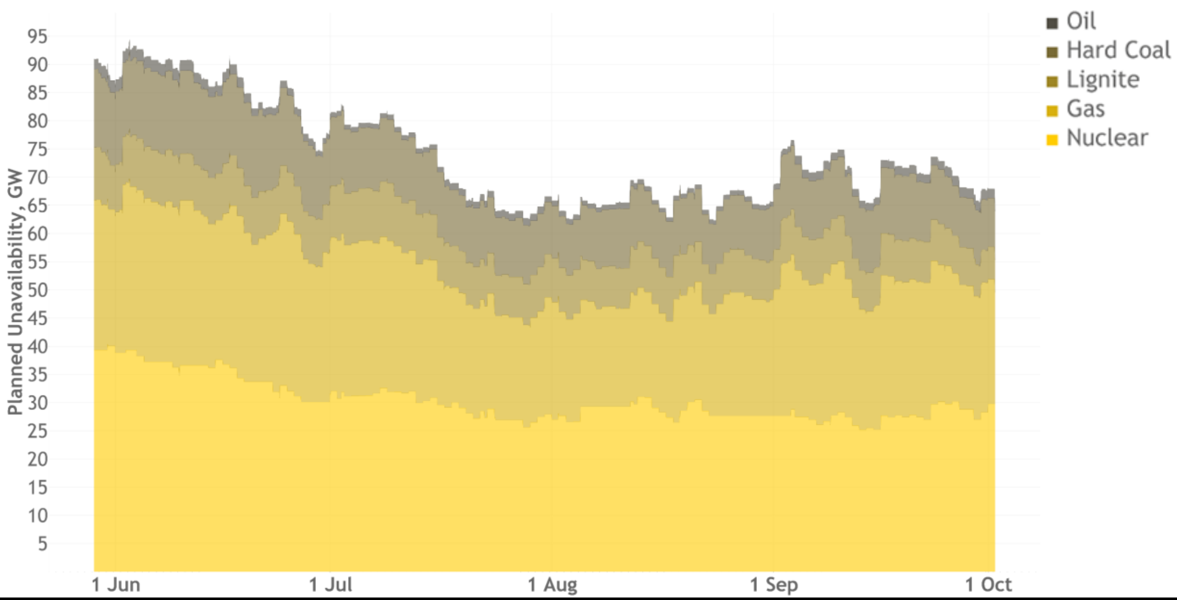


Figure 5: Planned unavailability of thermal units

Planned unavailability in southern countries tends to decrease during the warmest months when 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. In some countries, the planned unavailability varies little throughout the summer or even displays an inverse trend (planned unavailability increases towards the mid-summer). This inverse trend can be observed in North Macedonia (MK00) among others.

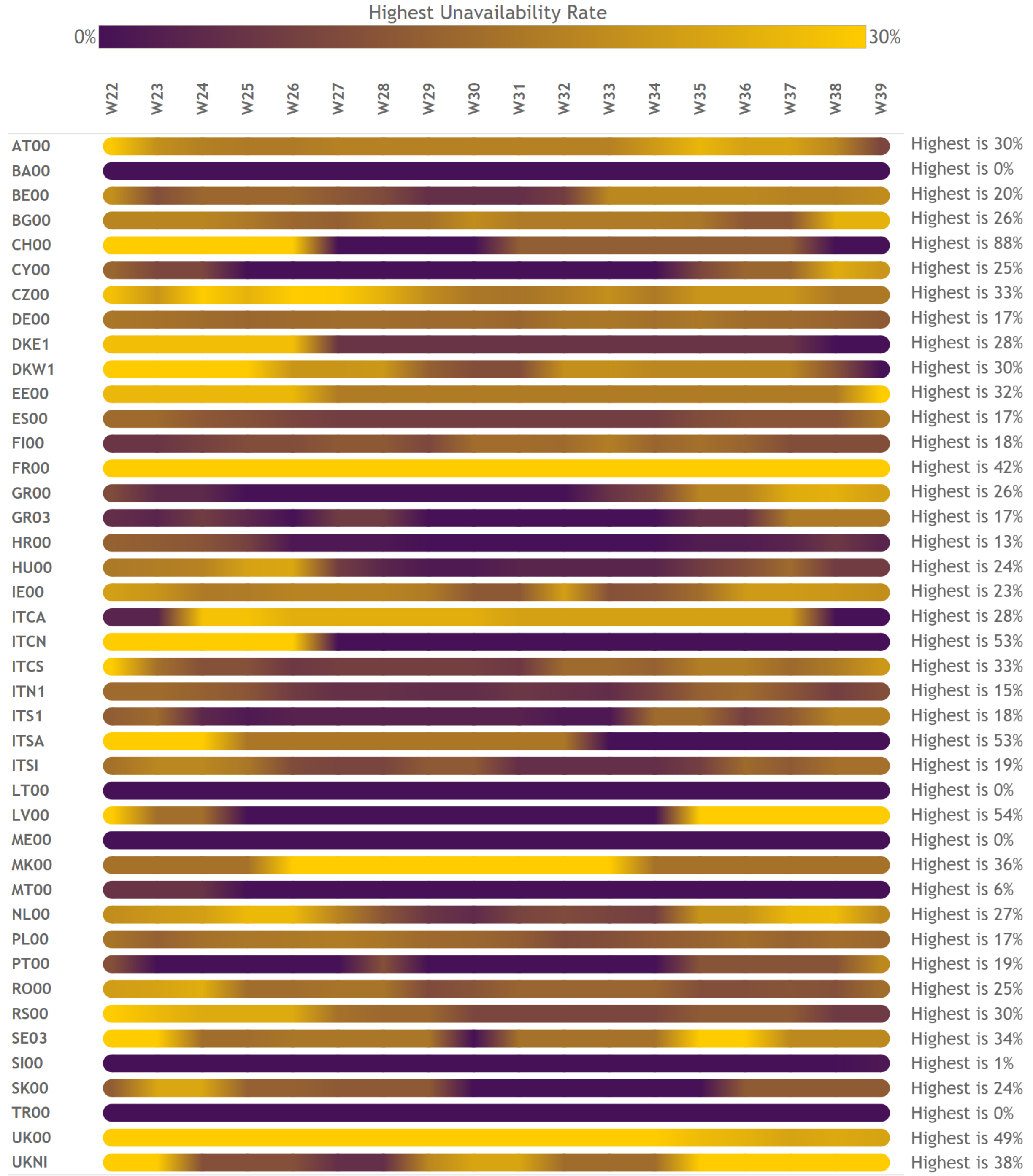


Figure 6: Weekly distribution of thermal planned unavailability relative to thermal NGC

Demand overview

Figure 7, a heat map by study zone, compares the expected consumption in each week with the highest expected weekly consumption in summer 2023. The darker shades indicate low expected consumption compared to highest expected consumption. As evident, demand in continental western Europe (e.g. Austria, Germany, Netherlands) is relatively stable across the summer period. In France and Hungary, demand decreases for a few weeks due to the holiday 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.

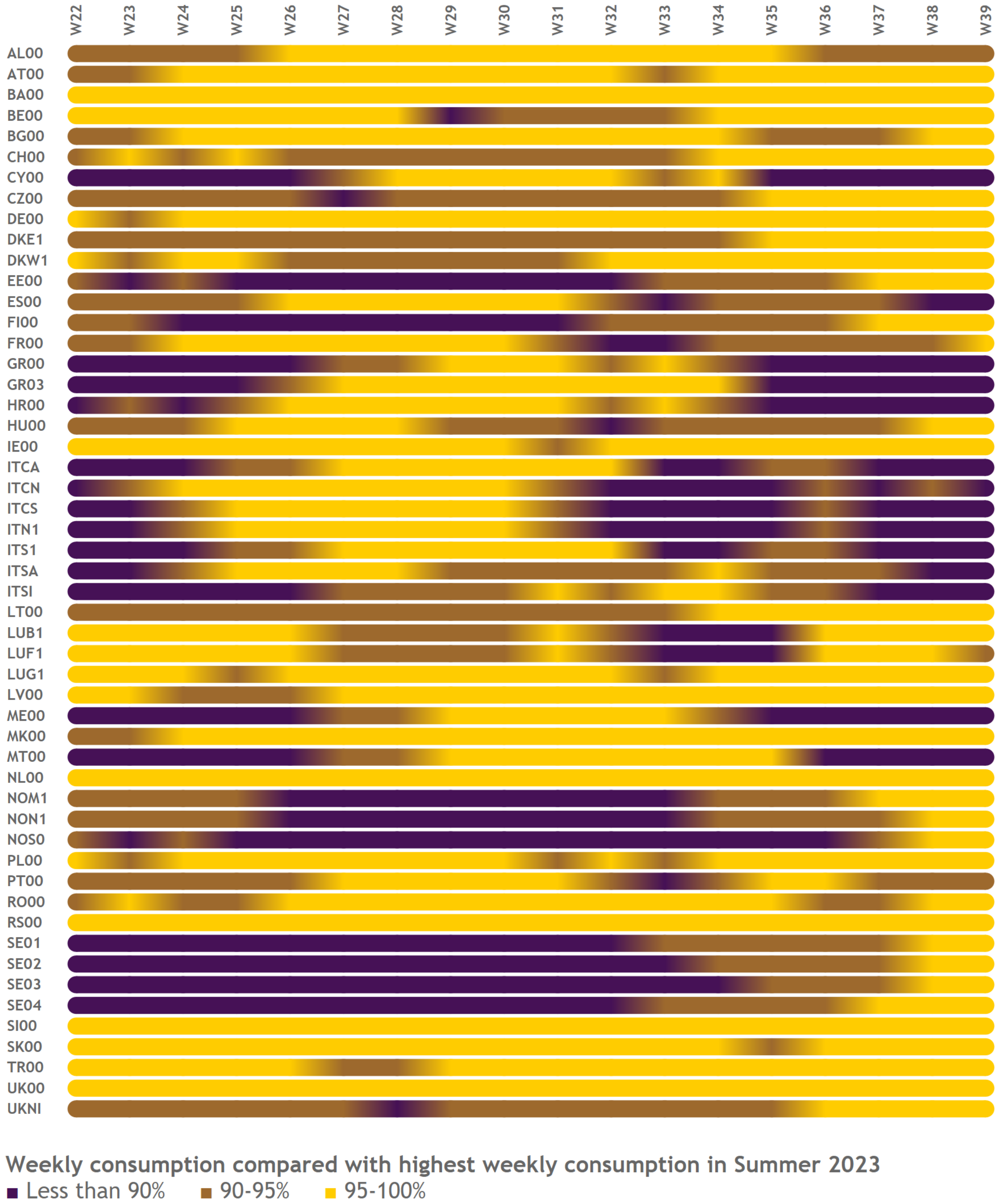


Figure 7: Demand overview—evolution over summer 2023

Figure 8 shows workday consumption patterns per study zone by plotting the average demand relative to the highest average demand in summer 2023. The peak demand in Europe is mostly concentrated around noon. In some study zones (e.g. Albania, Bosnia and Herzegovina), an evening peak similar to the noon demand peak is also observed. In other areas (e.g. some Italian bidding zones, Montenegro) a demand peak is observed in the evening. In addition, other areas (e.g. Finland, Norway, Sweden) face a relatively stable mean demand during the day.

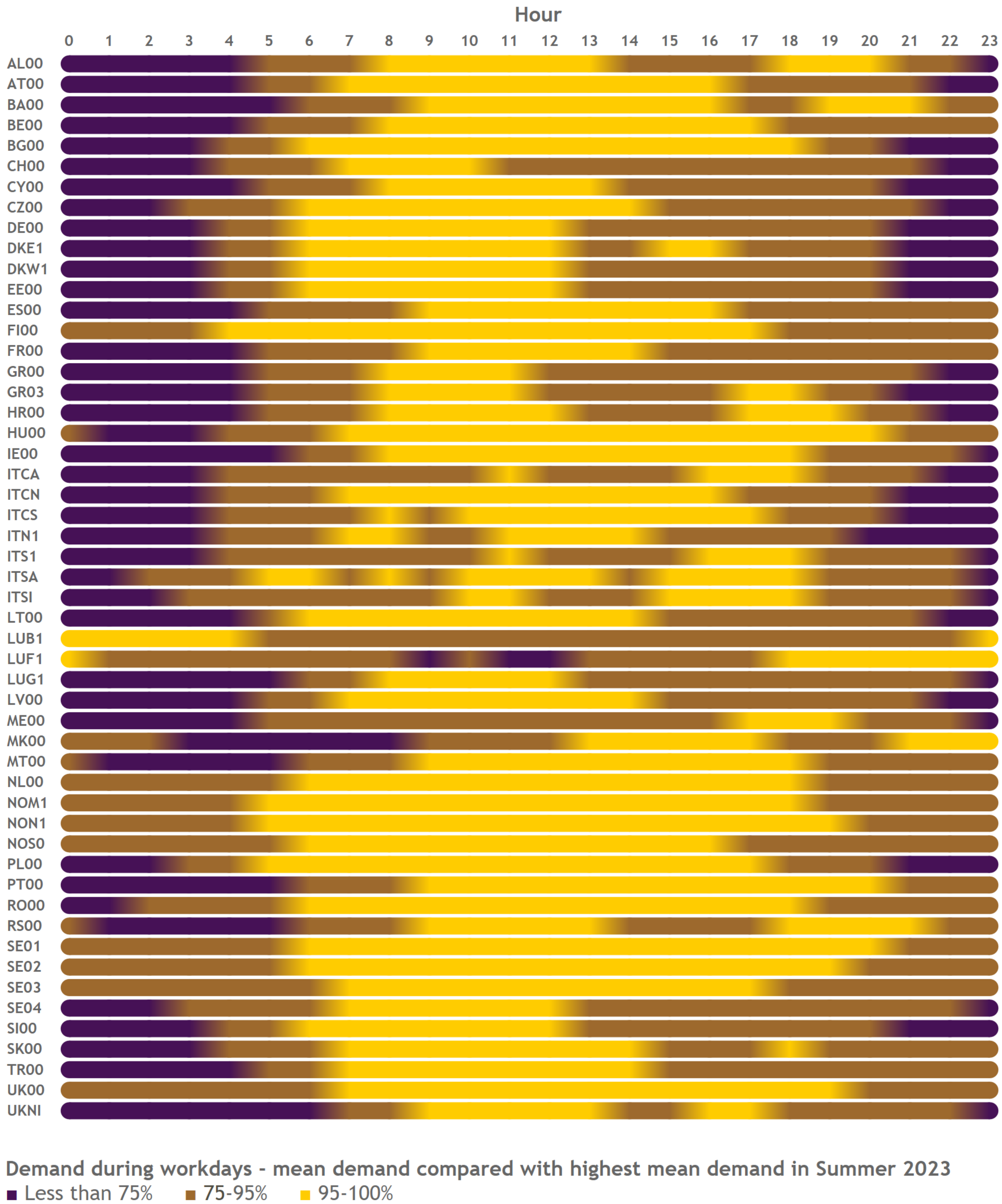


Figure 8: Demand profile overview during Mondays–Fridays in summer 2023[4]

Network overview

Figure 9 shows the ratio of lowest import capacity to highest expected demand during the summer. 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

[4] *UTC time convention was used.*

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—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 it 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[5].

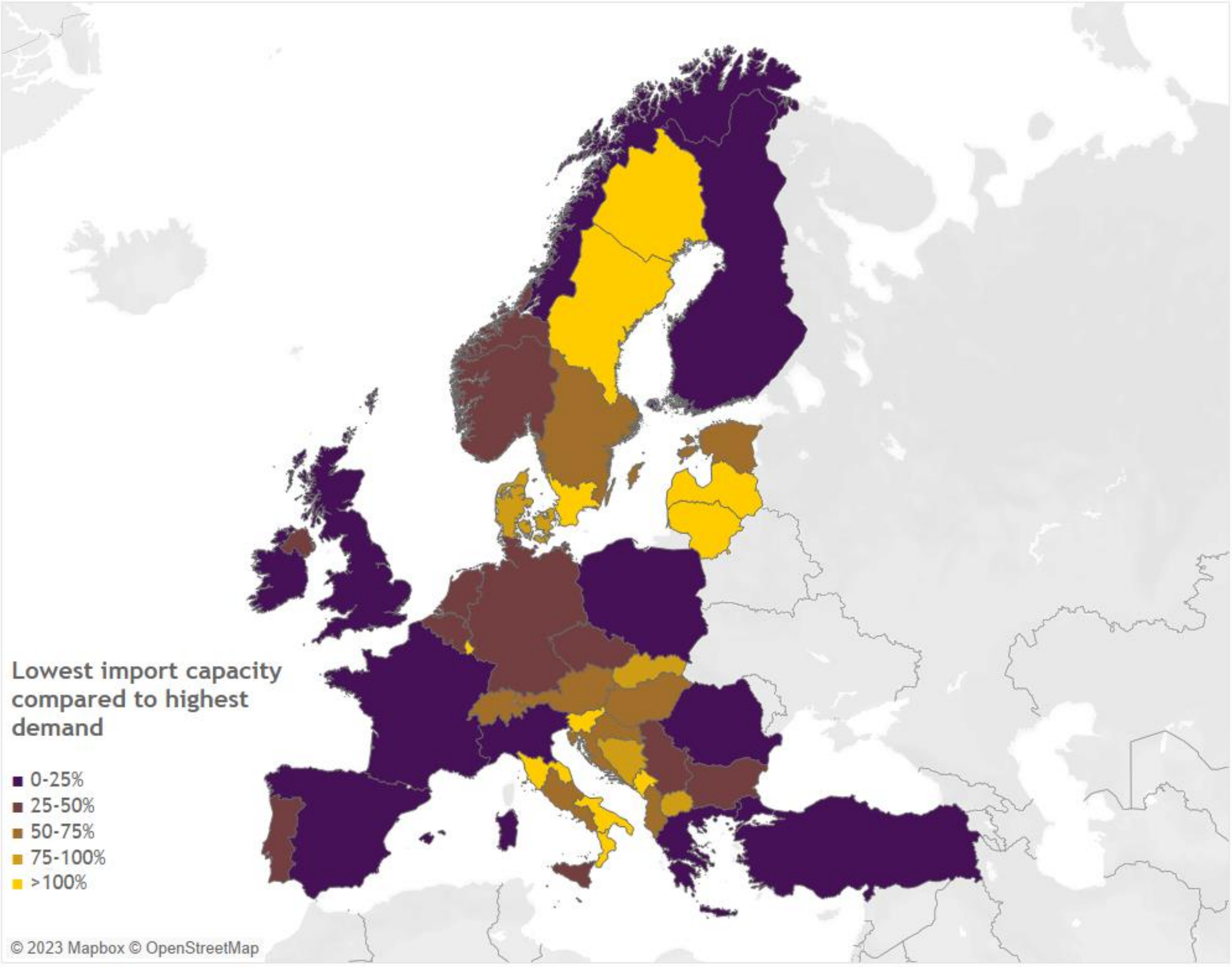


Figure 9: Import capacities per study zone: ratio between lowest import capacity and highest expected demand. C.f. Figure 22 for details

[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 not collected.

Situation in the European gas system

ENTSOG Summer Supply Outlook assesses injection levels and the possible evolution of demand, supply, and exports from 1 April to 30 September 2023, in addition to the dependence of the EU on Russian supply to satisfy the gas demand and to inject in the European gas storages. In response to stakeholders' requests, this edition also includes an overview analysis for Winter 2023/24.

The assessment shows that, in the event of minimised Russian gas imports and a full Russian pipeline supply disruption:

- **Reaching 90% storage filling level by end of summer is possible** in both cases, enabled by efficient cooperation between the countries.
- **Russian pipeline supply disruption would require additional measures** to safeguard a 30% target storage level at the end of March 2024.
- Different winter demand situations were assessed. The most stressful case of a **cold** (once in 20 years) **winter with a full Russian pipeline supply disruption would require additional supplies and demand reduction**.
- The gas infrastructure, including **new projects commissioned last year, can efficiently reduce the dependence on Russian supply** due to enhanced cooperation.

The Outlook assessment also shows that **additional LNG supplies, above historically observed import levels, could allow higher targets to be reached for all storage facilities** before the end of September 2023. Enhanced capacities, provided by TSOs, would contribute to the increase of import route capacities from the Caspian Area and Norway, in addition to boosting the possibility of cooperation between Germany and Austria, Belgium, France, Czech Republic, and the Netherlands, resulting in the increase of gas supply flow from West to East.

Gas storages play an essential role in ensuring security of supply, providing the necessary seasonal flexibility during the winter season. Early and significant storage withdrawals will result in low storage levels at the end of the winter season. This might have a negative impact on the flexibility of the gas system. From a security of supply perspective, it would be important to inject gas during the summer season and maintain storages at an adequate level until the end of the winter.

It is important to note that these assessments are not forecasts of expected gas supply—gas supply is influenced by factors external to infrastructure readiness, such as policy and market decisions.

More information and a detailed explanation of assumptions and results can be found in the main document. **The Summer Supply Outlook 2023 and the Summer Supply Review 2022 reports are available on the ENTSOG website[6].**

[6] *https://www.entsog.eu/outlooks-reviews#summer-outlooks-and-reviews*

Adequacy situation in summer 2023

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 summer 2023 (Figure 10) highlights certain adequacy risks—i.e. the risk of having to rely on non-market measures—in Creta[7], Cyprus, Ireland and Malta. Non-market resources significantly mitigate risks in Malta, where they are available. However, risks remain largely unchanged in other areas as interconnection limitations prevent access to non-market resources from neighbouring regions. Risks in Cyprus do not decrease as these resources do not exist and the system is not interconnected with the rest of Europe.

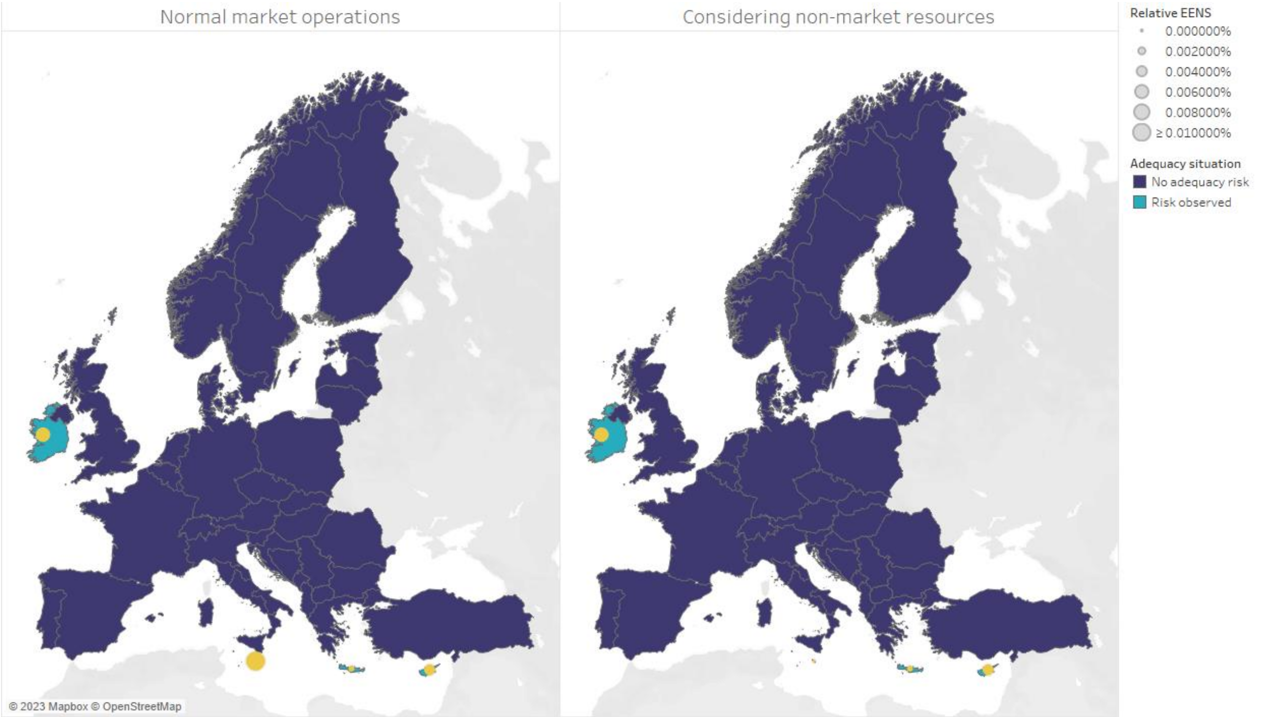


Figure 10: Adequacy overview

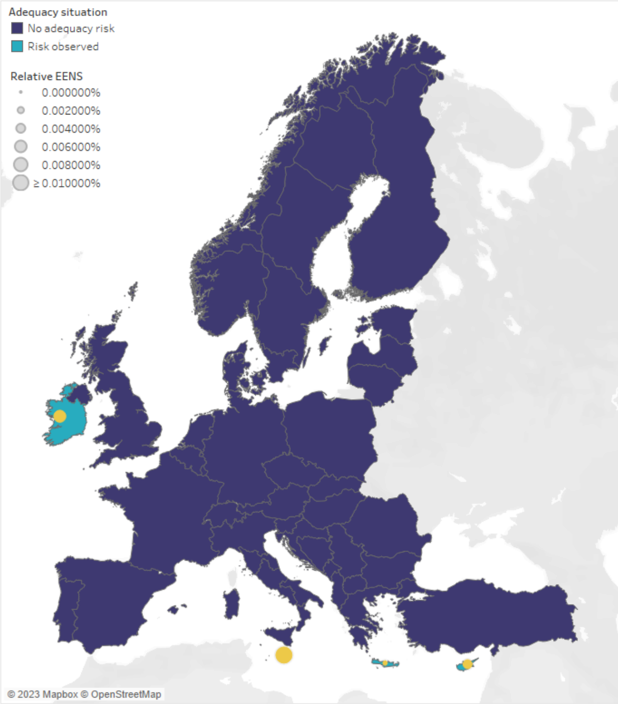
The state of the power system is continuously changing and is different since the data collection (performed in March 2023). For this reason, risks are continuously being monitored by TSOs and Regional Security Coordinators (RSCs).

Focus on adequacy under normal market conditions

Figure 11 presents the adequacy situation under normal market operations. For most countries, the adequacy risk is not identified, except Ireland, Cyprus (CY00), Malta (MT00) and Creta (GR03), 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.

---

[7] IPTO (TSO in Greece) has recently—after data collection for Summer Outlook—rented portable generation (18 MW), which could be made available on the island.



CY00	**EENS:** 0.0723 GWh (**0.00307%** compared to Seasonal Consumption) **99th percentile ENS:** 1.3060 GWh (**0.0555%** compared to Seasonal Consumption) **LOLE:** 1.270 h
GR03	**EENS:** 0.0101 GWh (**0.00076%** compared to Seasonal Consumption) **99th percentile ENS:** 0.2436 GWh (**0.0184%** compared to Seasonal Consumption) **LOLE:** 0.294 h
IE00	**EENS:** 0.6039 GWh (**0.00558%** compared to Seasonal Consumption) **99th percentile ENS:** 7.6258 GWh (**0.0705%** compared to Seasonal Consumption) **LOLE:** 2.091 h
MT00	**EENS:** 0.4837 GWh (**0.04556%** compared to Seasonal Consumption) **99th percentile ENS:** 3.5329 GWh (**0.3328%** compared to Seasonal Consumption) **LOLE:** 18.583 h

Figure 11: Adequacy risk overview

The distribution of risks within season is presented in Figure 12 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.

Cyprus (CY00) may face adequacy issues in mid-summer when demand may reach the highest values (c.f. Figure 7) and if combined with high unplanned outages of conventional generation. The Cyprus system has no interconnection to the other power systems and, hence, it 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 summer 2023 in Cyprus.

Creta (GR03) is marked by the small likelihood of adequacy risks. Probability remains low (below 1%) throughout the summer and only peaks above 1% in week 26 (end of June). These risks can materialise under extreme and low likelihood coinciding with adverse operational conditions—high demand, low renewable generation and loss of interconnection with the continental Greek system. If weather conditions for renewable generation are favourable, adequacy issues should be avoided. In the event these risks emerge, IPTO (TSO in Greece) would rely on a number of operational mitigation measures—including the activation of portable generation[8]. All risks are expected to be mitigated if necessary.

Ireland (IE00) is marked with adequacy risks in September. These risks are driven by unplanned outages of aging powerplants and will depend on wind generation if such outages will occur. The planned outage of conventional generation in Northern Ireland (expected to exceed 600 MW) also limits the capability to rely on imports from the Northern Ireland system. The actual adequacy situation in Ireland will depend on the operational conditions: on unplanned outages of aging generation fleet in Ireland and especially on wind generation.

The adequacy situation in Malta (MT00) should be monitored throughout the summer, with a special focus on the middle of the summer. This corresponds very closely to the demand profile in summer 2023 in Malta (c.f. Figure 7). 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.

[8] *IPTO (TSO in Greece) has recently—after data collection for Summer Outlook—rented portable generation (18 MW) which could be made available on the island.*

Risks in Malta will be alleviated as the exchange capacity between Sicily (ITSI) and Malta (MT00) will reach 200 MW during weeks 27 and 30. The forecasted limitation (120 MW exchange capacity between 6 and 29 July 2023 6:00–16:00) considered in adequacy assessment simulations will not actually take place.

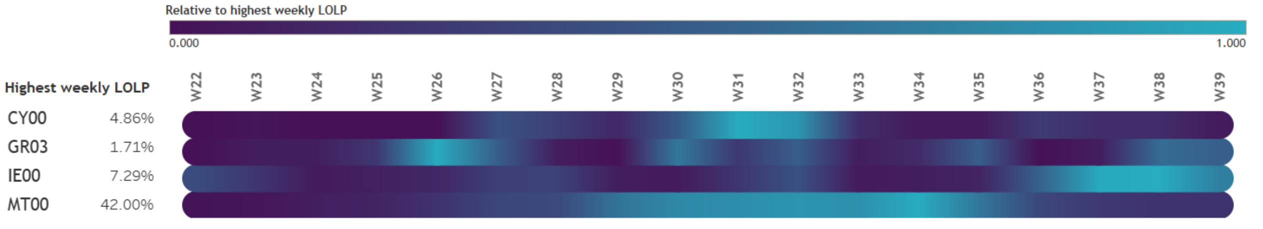
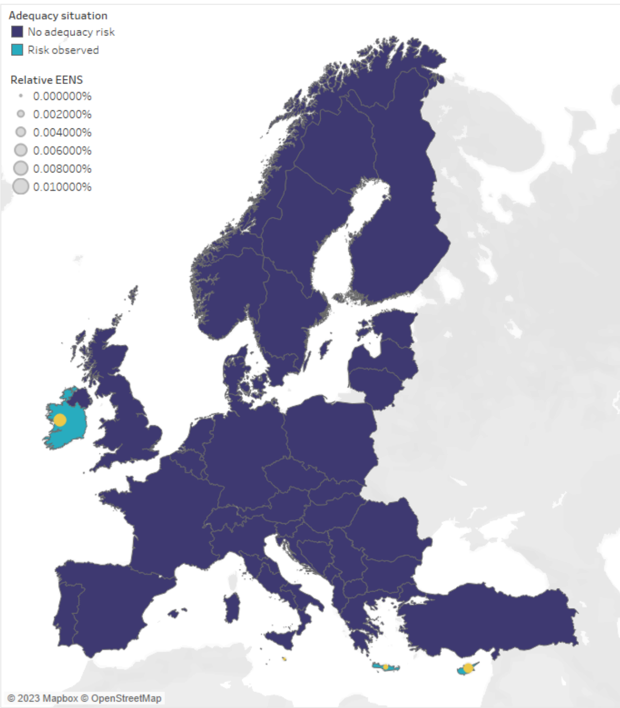


Figure 12: Adequacy weekly insights

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, which is significantly reduced when compared to the normal market operation as Malta relies on dedicated non-market resources (c.f. Figure 3).



CY00	**EENS:** 0.0723 GWh (**0.00307%** compared to Seasonal Consumption) **99th percentile ENS:** 1.3060 GWh (**0.0555%** compared to Seasonal Consumption) **LOLE:** 1.270 h
GR03	**EENS:** 0.0101 GWh (**0.00076%** compared to Seasonal Consumption) **99th percentile ENS:** 0.2436 GWh (**0.0184%** compared to Seasonal Consumption) **LOLE:** 0.294 h
IE00	**EENS:** 0.6039 GWh (**0.00558%** compared to Seasonal Consumption) **99th percentile ENS:** 7.6258 GWh (**0.0705%** compared to Seasonal Consumption) **LOLE:** 2.091 h
MT00	**EENS:** 0.0014 GWh (**0.00013%** compared to Seasonal Consumption) **99th percentile ENS:** 0.0196 GWh (**0.0019%** compared to Seasonal Consumption) **LOLE:** 0.071 h

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

The LOLP in Malta is significantly lower when non-market resources are considered and shows only occasional risks (Figure 14). This suggests that partial demand shedding might be required only under exceptional operational conditions and only if these conditions occur in particular weeks with an elevated adequacy risk (especially week 32 to week 34).

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.

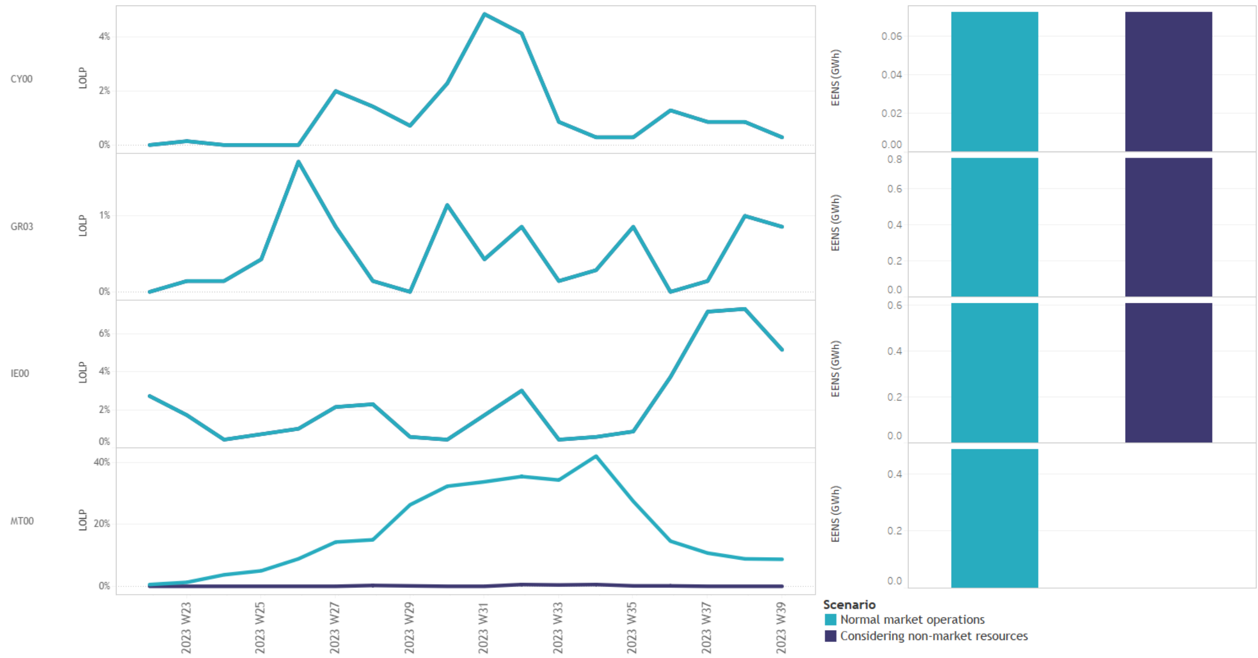


Figure 15: Detailed adequacy overview—weekly LOLP and ENS

Winter 2022–2023 review

Recap: actions taken by the TSOs to prepare for Winter 2022–2023

The tensions in the European energy sector began to increase as a consequence of the political and economic situation of Europe since the start of the war in Ukraine. Potential gas shortage was identified as one of the most concerning risks for the European power system, but not the only one. Other risks included coal shortage, low nuclear generation availability and low hydrological reservoir levels. ENTSO-E took the utmost efforts to address these risks before and during winter 2022–2023.

Preparations for Winter 2022–2023 and coordination during it

ENTSO-E made extra efforts to prepare for winter 2022–2023. First, it broadened the scope of the Seasonal Outlook Adequacy assessment. Furthermore, it established a dedicated Task Force to address topics outside of quantitative adequacy assessment. Activities commenced in early 2022—shortly after the Russian invasion of Ukraine.

Seasonal adequacy assessments

In 2022, most notable additions to the standard seasonal adequacy assessment activities included:

- Early and continuous monitoring (June 2022, October 2022, December 2022) —surveys and quantitative assessments;
- Tailor-made scenarios for adequacy assessment (concerning risks and EU Emergency intervention toolkit impact assessment); and
- New analysis—assessment of Critical Gas Volume (CGV) to ensure adequacy in Europe

All these assessments ensured proper preparation for winter 2022–2023, It supported TSOs and all stakeholders with a clear risk identification and enabled them to prepare mitigation actions.

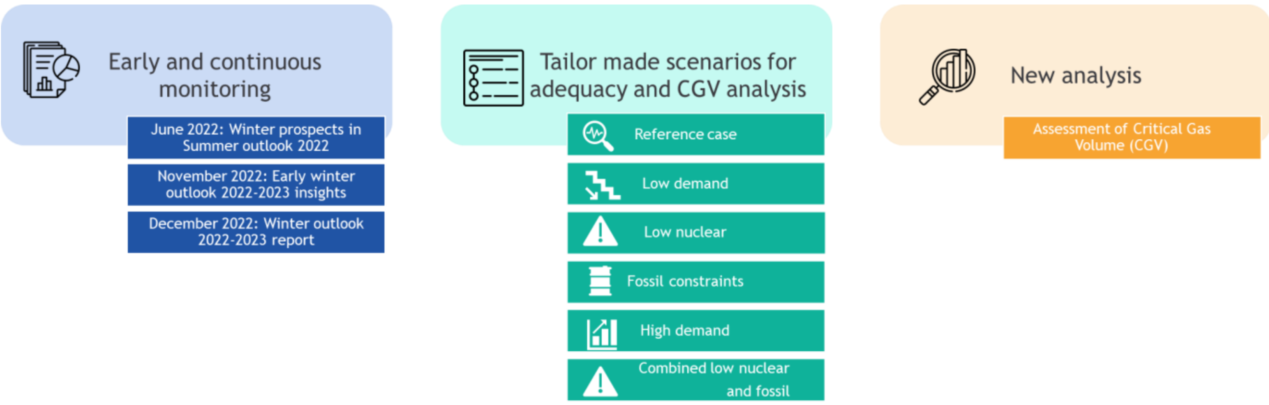


Figure 16: Overview of additional activities taken for winter 2022–2023 preparations

Complementary activities undertaken

ENTSO-E identified that gas is not the only potential source of challenges that European TSOs will face during upcoming winter, and therefore the scope of the activities was broadened to address the general topic of winter preparation by all relevant structures of the Association. ENTSO-E established a dedicated Task

Force to perform additional activities to prepare for winter 2022–2023 to cover topics outside of the typical Seasonal Adequacy Assessments (i.e. Seasonal Outlooks). The Task Force covered the following areas:

- Evaluation of the operational impact on a short-term of the 2022–2023 Winter Outlook findings;
- Verification of existing and development of new countermeasures to mitigate system risks;
- Organisation of training necessary for the control room staff within the TSOs and Regional Coordination Centres (RCCs);
- Implementation of an Operational Group to share system data and align on a weekly basis; and
- Development of a crisis communication procedure between ENTSO-E, TSOs and Regional Coordination Centres (RCCs) for communicating with the external stakeholders.

ENTSO-E managed to increase the alignment and level of cooperation between TSOs and RCCs on different levels and time frames in the context of thise dedicated task force activities. This was achieved by a set of customised processes, e.g. weekly calls, a Critical Grid Situation (CGS) process, D-3, D-2, D-1 and real time. The end goal was to provide a large spectrum of countermeasures for ensuring security of supply, i.e. from week ahead until real time, that could be considered and used by TSOs and / or RCCs when necessary.

Additional deliverables that are now implemented at TSOs and / or RCCs level refer to the performance of training sessions for all operators to (re)explain and validate the operational procedures, but also the setup of the crisis communication process for external stakeholder engagement. ENTSO-E gathered all the interconnected TSOs and all RCCs to meet, discuss and monitor the system status on a weekly basis during winter 2022–2023. Such a setup is now available and can be activated whenever there are emerging concerns in the pan-European system.

Conditions and events during winter 2022–2023

The weather conditions were favourable throughout most of the winter, and hydro stock also improved in some regions just before the winter commenced, alleviating adequacy concerns for winter 2022–2023. In some countries, the recorded consumption recorded was lower than expected due to consumers' efforts. Consumer efforts were driven by the policy calls to save energy and, in general, by the high electricity prices. These energy savings were notable and contributed substantially to electrical system operations.

A good balance and the stability of the power system in Ukraine was maintained despite the regular attacks on Ukrainian infrastructure during the winter. Continental Europe TSOs—and especially neighbouring TSOs—have supported the Ukrainian system since 30 June 2022, when the commercial electricity exchanges resumed. Exchange capacity has been continuously increasing since then. The entry into operation of the new line between Poland and Ukraine in May 2023 brings additional commercial exchange capacity between Continental Europe and the Ukraine–Moldova control area.

Globally, the 2022–2023 winter had above-average temperatures, with February 2023 being the fifth warmest (0.29°C) February on record. In Europe, a contrast can be observed between the southern and northern parts of the continent: the first experienced well-above-average air temperatures in December, whereas the second were below the long-term climatological values (1991–2020). January 2023 was the 3rd warmest January on record in Europe since 1979, with 2.20°C above the 1991–2020 average. This can be seen in Figure 17, which displays the surface air temperature anomaly observed in winter 2022–2023 (December 2022 to March 2023) from the Copernicus Climate Change Service.

In January, the Balkans, eastern Europe and Finland, had the most notable warmer-than-average conditions. The same conditions were present in northern Norway and Sweden, across north western Russia in areas surrounding the Kara Sea, and in the Svalbard region in February 2023. In March 2023, average air temperatures were above those of the 1991–2020 reference period over southern and central Europe, and colder than normal over most of northern Europe.

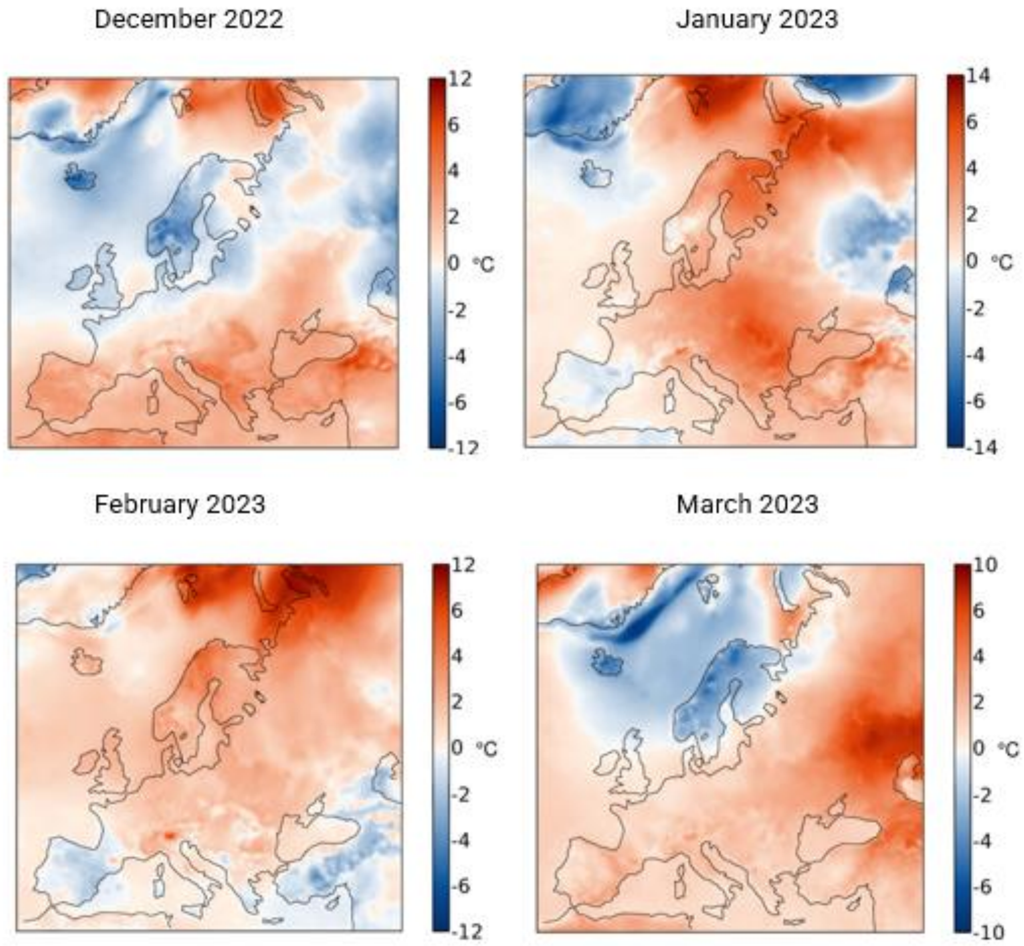


Figure 17: Surface air temperature anomaly in Winter 2022/2023 relative to the average for the periods 1991–2020 (for December, January, February and March)[9]

Specific comments on winter 2022–2023

In general, no adequacy issues were observed during the past winter 2022–2023. Mild temperatures, favourable changed hydro conditions and reduced demand played a significant role in averting potential shortages.

The situation was further helped by proactive measures and preparations for the winter, such as prolonged phase outs, new-built LNG (Liquified Natural Gas) Terminals in Germany and Finland, coordination with neighbouring countries (import capacities), and the availability of French nuclear power plants in line with published scenarios.

Nevertheless, some countries mention facing challenges during the past winter (Bulgaria, Cyprus, Finland, Northern Ireland, Slovenia and Poland): unplanned outages in Bulgaria, a few instances of low replacement reserve in Cyprus, the delay of Olkiluoto 3 and unplanned outage of AC connections between Northern Sweden and Finland, tight generation margins due to several forced outages and reduced capacities in Northern Ireland, and the simultaneous unavailability of the two biggest power plants in Slovenia. Last winter was difficult for the Polish TSO from an operational perspective. Due to the limited amount of coal nationwide, and in particular the low level of mandatory coal stocks in coal-fired power plants, which resulted in the unavailability of many units, PSE often had to manage a tight power balance. However, despite these situations, no adequacy problems were experienced,

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

Preparations for winter 2023–2024

ENTSO-E does not foresee any extraordinary risks for winter 2023–2024. It remains vigilant and will continue monitoring how the situation in energy sector will develop. Extra actions will be taken if deemed necessary on 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[10] reaffirm that the gas system should be well prepared for the coming winter season. However, ENTSO-E plans to assess Critical Gas Volume for winter 2023–2024 as it did for winter 2022–2023 to be aware of the power system needs as gas supply adequacy can depend on actual weather conditions during winter months. Nevertheless, ENTSO-E remains fairly confident that gas supplies should be ensured to satisfy electricity security of supply needs, given the available framework and preparatory work with stakeholders during preparations for winter 2022–2023.

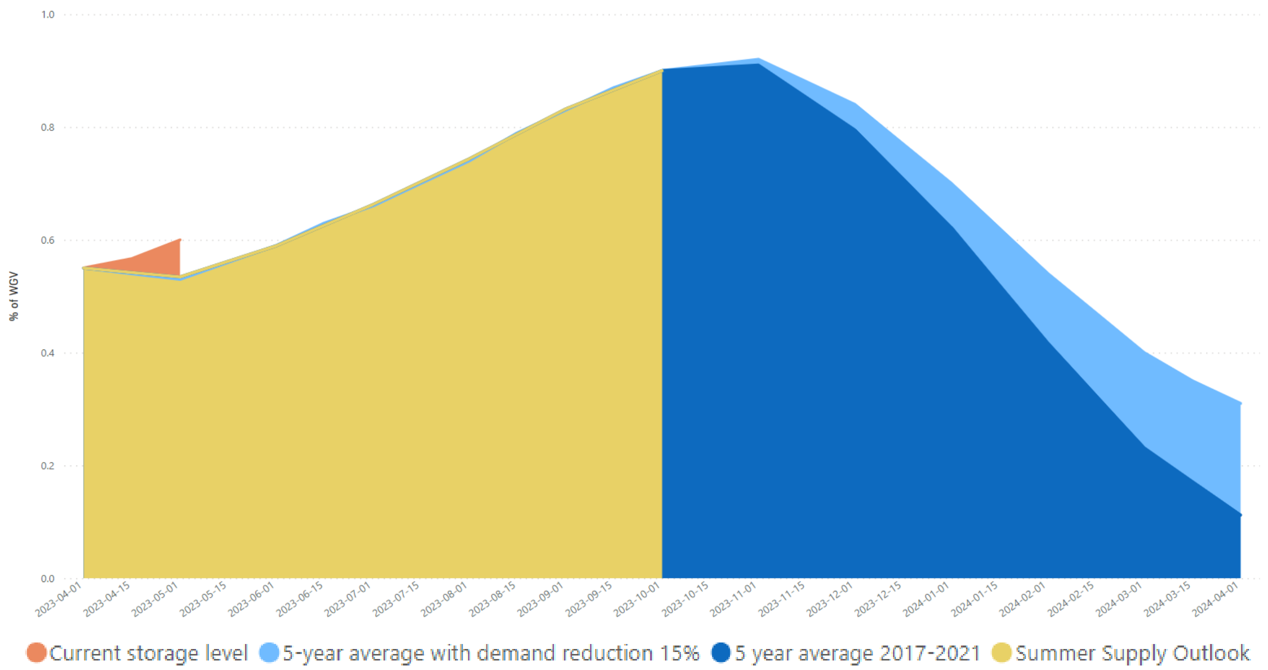


Figure 18: Gas storage developments against ENTSOG summer outlook projections[11]

No specific sensitivity scenario for winter 2023–2024 was identified by ENTSO-E TSOs as yet required. The adequacy situation in winter 2023–2024 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 the European or National Authorities. According to the electricity TSOs, the most prominent factors will be hydro stocks in the reservoirs and nuclear availability in Europe. A demand sensitivity could be relevant in the event of identified risk. In conclusion, complementary sensitivities for winter 2023–2024 adequacy assessment may be defined if new circumstances develop, which could impact the power sector.

ENTSO-E is striving to release the Winter Outlook 2023–2024 in advance of the legal mandate (early November 2023 instead of 1 December). TSOs suggest a single step approach, with subsequent ad hoc assessments if the situation in the energy sector changes.

---

[10] *https://www.entsog.eu/outlooks-reviews#summer-outlooks-and-reviews*

[11] *ENTSOG Seasonal Supply Outlook Monitoring Dashboard [12 May 2023]*

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[12]. 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)[13]. 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 19 provides a schematic representation of this scenario construction process.

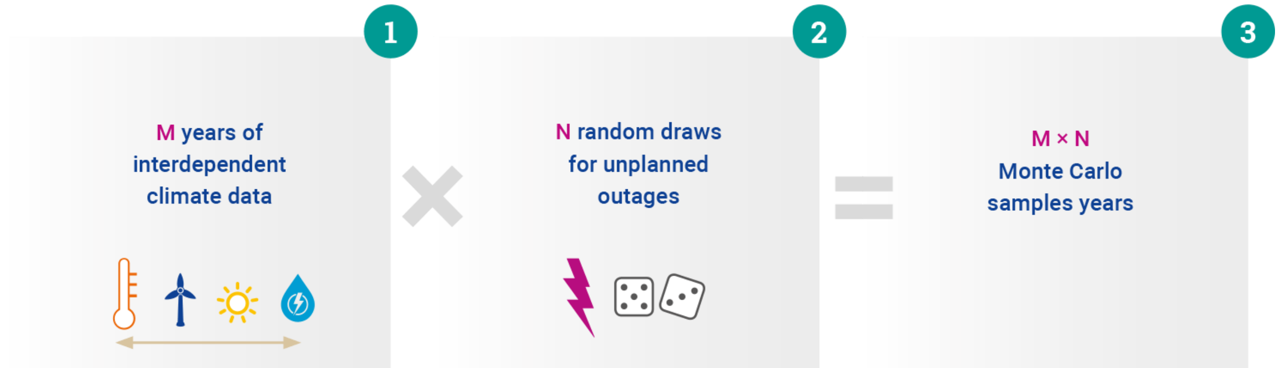


Figure 19: Scenarios assessed in Seasonal Outlooks

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

---

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

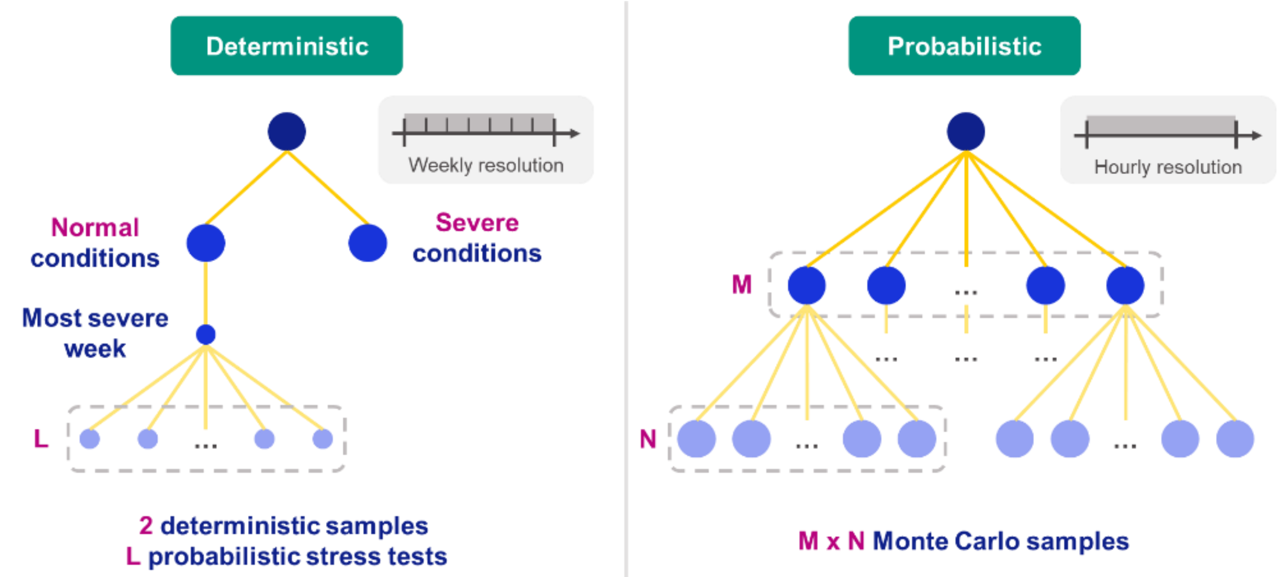


Figure 20: Scenario revolution—from deterministic to probabilistic

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 21: 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. 1,162 MW (486 - 1,200) MW	From: SI00 Avg. 600 MW (600 - 600) MW	From: HU00 Avg. 500 MW (500 - 500) MW	From: CZ00 Avg. 400 MW (400 - 400) MW	From: ITN1 Avg. 78 MW (10 - 100) MW								
BA00	From: HR00 Avg. 800 MW (800 - 800) MW	From: ME00 Avg. 500 MW (500 - 500) MW	From: RS00 Avg. 490 MW (200 - 600) MW											
BE00	From: FR00 Avg. 1,800 MW (1,800 - 1,800) MW	From: DE00 Avg. 1,000 MW (1,000 - 1,000) MW	From: NL00 Avg. 950 MW (950 - 950) MW	From: UK00 Avg. 946 MW (0 - 1,000) MW										
BG00	From: RO00 Avg. 1,667 MW (0 - 2,000) MW	From: GR00 Avg. 750 MW (750 - 750) MW	From: MK00 Avg. 358 MW (350 - 450) MW	From: RS00 Avg. 276 MW (0 - 300) MW	From: TR00 Avg. 100 MW (100 - 100) MW									
CH00	From: FR00 Avg. 2,838 MW (2,300 - 3,500) MW	From: DE00 Avg. 1,998 MW (1,800 - 2,000) MW	From: ITN1 Avg. 1,518 MW (744 - 1,910) MW	From: AT00 Avg. 1,016 MW (436 - 1,200) MW										
CZ00	From: DE00 Avg. 2,521 MW (2,100 - 2,600) MW	From: SK00 Avg. 1,177 MW (1,000 - 1,200) MW	From: PLE0 Avg. 783 MW (650 - 800) MW	From: AT00 Avg. 400 MW (400 - 400) 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. 3,960 MW (3,800 - 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. 2,641 MW (1,800 - 2,800) MW	From: DKW1 Avg. 2,469 MW (1,110 - 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: DKE1 Avg. 585 MW (585 - 585) MW	From: SE04 Avg. 551 MW (0 - 615) MW	From: DEKF Avg. 400 MW (400 - 400) MW
DKE1	From: SE04 Avg. 1,260 MW (500 - 1,300) MW	From: DE00 Avg. 600 MW (600 - 600) MW	From: DKW1 Avg. 569 MW (0 - 590) MW	From: DKKF Avg. 384 MW (0 - 400) MW										
DKW1	From: DE00 Avg. 2,459 MW (665 - 2,500) MW	From: NOS0 Avg. 1,430 MW (802 - 1,632) MW	From: NL00 Avg. 700 MW (700 - 700) MW	From: SE03 Avg. 579 MW (0 - 680) MW	From: DKE1 Avg. 579 MW (0 - 600) MW									
EE00	From: FI00 Avg. 944 MW (358 - 1,016) MW	From: LV00 Avg. 536 MW (529 - 819) MW												
ES00	From: PT00 Avg. 2,286 MW (1,500 - 3,650) MW	From: FR00 Avg. 1,307 MW (900 - 1,900) MW												
FI00	From: SE03 Avg. 1,150 MW (0 - 1,200) MW	From: SE01 Avg. 936 MW (400 - 1,200) MW	From: EE00 Avg. 916 MW (358 - 1,016) MW											
FR00	From: UK00 Avg. 3,598 MW (2,000 - 4,000) MW	From: DE00 Avg. 3,000 MW (3,000 - 3,000) MW	From: CH00 Avg. 1,200 MW (1,200 - 1,200) MW	From: ES00 Avg. 1,173 MW (700 - 2,400) MW	From: ITN1 Avg. 910 MW (555 - 1,370) MW	From: BE00 Avg. 600 MW (600 - 600) MW								
GR00	From: BG00 Avg. 750 MW (750 - 750) MW	From: MK00 Avg. 721 MW (396 - 974) MW	From: ITS1 Avg. 418 MW (0 - 500) MW	From: AL00 Avg. 400 MW (400 - 400) MW	From: GR03 Avg. 150 MW (150 - 150) MW	From: TR00 Avg. 48 MW (0 - 50) MW								
GR03	From: GR00 Avg. 150 MW (150 - 150) MW													
HR00	From: SI00 Avg. 1,000 MW (1,000 - 1,000) MW	From: HU00 Avg. 927 MW (500 - 1,000) MW	From: BA00 Avg. 800 MW (800 - 800) MW	From: RS00 Avg. 388 MW (200 - 400) MW										
HU00	From: SK00 Avg. 1,500 MW (1,500 - 1,500) MW	From: RO00 Avg. 892 MW (500 - 1,000) MW	From: RS00 Avg. 796 MW (0 - 1,000) MW	From: HR00 Avg. 741 MW (400 - 800) MW	From: SI00 Avg. 700 MW (700 - 700) MW	From: AT00 Avg. 500 MW (500 - 500) MW								
IE00	From: UK00 Avg. 500 MW (500 - 500) MW	From: UKNI Avg. 368 MW (100 - 400) MW												
ITCA	From: ITSI Avg. 1,235 MW (700 - 1,300) MW	From: ITS1 Avg. 1,002 MW (300 - 1,100) MW												
ITCN	From: ITN1 Avg. 3,755 MW (2,800 - 4,200) MW	From: ITCS Avg. 2,694 MW (1,800 - 2,800) MW												
ITCS	From: ITS1 Avg. 4,009 MW (2,600 - 5,100) MW	From: ITCN Avg. 2,151 MW (1,700 - 2,900) MW	From: ITSA Avg. 856 MW (0 - 900) MW	From: ME00 Avg. 555 MW (0 - 600) MW										
ITN1	From: CH00 Avg. 2,693 MW (744 - 3,747) MW	From: ITCN Avg. 2,581 MW (2,000 - 3,100) MW	From: FR00 Avg. 1,273 MW (200 - 3,138) MW	From: SI00 Avg. 430 MW (0 - 641) MW	From: AT00 Avg. 234 MW (58 - 280) MW									
ITS1	From: ITCS Avg. 2,400 MW (2,400 - 2,400) MW	From: ITCA Avg. 2,101 MW (1,500 - 2,350) MW	From: GR00 Avg. 418 MW (0 - 500) MW											
ITSA	From: ITCS Avg. 690 MW (0 - 720) MW													
ITSI	From: ITCA Avg. 1,413 MW (700 - 1,500) MW	From: MT00 Avg. 194 MW (120 - 225) MW												
LT00	From: LV00 Avg. 821 MW (821 - 821) MW	From: SE04 Avg. 700 MW (700 - 700) MW	From: PL00 Avg. 492 MW (492 - 492) 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. 1,004 MW (1,004 - 1,004) MW	From: EE00 Avg. 515 MW (506 - 885) MW												
ME00	From: ITCS Avg. 555 MW (0 - 600) MW	From: BA00 Avg. 500 MW (500 - 500) MW	From: RS00 Avg. 480 MW (0 - 700) MW	From: AL00 Avg. 300 MW (300 - 300) MW										
MK00	From: GR00 Avg. 932 MW (655 - 1,148) MW	From: RS00 Avg. 381 MW (150 - 500) MW	From: BG00 Avg. 347 MW (308 - 370) MW											
MT00	From: ITSI Avg. 194 MW (120 - 225) MW													
NL00	From: DE00 Avg. 4,400 MW (4,400 - 4,400) MW	From: UK00 Avg. 966 MW (0 - 1,000) MW	From: BE00 Avg. 950 MW (950 - 950) MW	From: NOS0 Avg. 723 MW (723 - 723) MW	From: DKW1 Avg. 700 MW (700 - 700) MW									
NOM1	From: NON1 Avg. 1,200 MW (1,200 - 1,200) MW	From: SE02 Avg. 767 MW (0 - 1,000) MW	From: NOS0 Avg. 492 MW (200 - 500) MW											
NON1	From: SE01 Avg. 468 MW (150 - 600) MW	From: NOM1 Avg. 400 MW (400 - 400) MW	From: SE02 Avg. 213 MW (0 - 300) MW											
NOS0	From: SE03 Avg. 1,963 MW (645 - 2,000) MW	From: DKW1 Avg. 1,458 MW (802 - 1,632) MW	From: DE00 Avg. 1,400 MW (1,400 - 1,400) MW	From: UK00 Avg. 1,100 MW (1,100 - 1,100) MW	From: NOM1 Avg. 800 MW (800 - 800) MW	From: NL00 Avg. 723 MW (723 - 723) MW								
PL00	From: PLI0 Avg. 1,500 MW (1,500 - 1,500) MW	From: SE04 Avg. 600 MW (600 - 600) MW	From: LT00 Avg. 350 MW (350 - 350) MW											
PT00	From: ES00 Avg. 2,806 MW (2,200 - 4,150) MW													
RO00	From: BG00 Avg. 1,667 MW (0 - 2,000) MW	From: HU00 Avg. 892 MW (500 - 1,000) MW	From: RS00 Avg. 555 MW (300 - 700) MW											
RS00	From: HU00 Avg. 819 MW (0 - 1,000) MW	From: ME00 Avg. 605 MW (0 - 700) MW	From: BA00 Avg. 465 MW (150 - 600) MW	From: MK00 Avg. 455 MW (250 - 500) MW	From: RO00 Avg. 374 MW (300 - 450) MW	From: BG00 Avg. 322 MW (0 - 350) MW	From: HR00 Avg. 289 MW (150 - 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. 837 MW (300 - 1,100) MW	From: NON1 Avg. 459 MW (100 - 700) MW											
SE02	From: SE03 Avg. 7,300 MW (7,300 - 7,300) MW	From: SE01 Avg. 3,011 MW (2,100 - 3,300) MW	From: NOM1 Avg. 577 MW (0 - 600) MW	From: NON1 Avg. 156 MW (0 - 250) MW										
SE03	From: SE02 Avg. 6,081 MW (5,000 - 7,300) MW	From: SE04 Avg. 2,697 MW (2,400 - 2,800) MW	From: NOS0 Avg. 1,710 MW (200 - 2,145) MW	From: DKW1 Avg. 661 MW (0 - 715) MW	From: FI00 Avg. 211 MW (0 - 300) MW									
SE04	From: SE03 Avg. 4,348 MW (3,000 - 5,200) MW	From: DKE1 Avg. 1,572 MW (350 - 1,700) MW	From: LT00 Avg. 668 MW (400 - 700) MW	From: PL00 Avg. 589 MW (500 - 600) MW	From: DE00 Avg. 557 MW (0 - 615) MW									
SI00	From: HR00 Avg. 1,100 MW (1,100 - 1,100) MW	From: HU00 Avg. 700 MW (700 - 700) MW	From: AT00 Avg. 600 MW (600 - 600) MW	From: ITN1 Avg. 543 MW (0 - 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. 388 MW (166 - 432) MW	From: GR00 Avg. 207 MW (0 - 216) MW												
UK00	From: FR00 Avg. 3,598 MW (2,000 - 4,000) MW	From: NOS0 Avg. 1,100 MW (1,100 - 1,100) MW	From: NL00 Avg. 966 MW (0 - 1,000) MW	From: BE00 Avg. 946 MW (0 - 1,000) MW	From: IE00 Avg. 500 MW (500 - 500) MW	From: UKNI Avg. 369 MW (250 - 400) MW								
UKNI	From: UK00 Avg. 409 MW (250 - 450) MW	From: IE00 Avg. 368 MW (100 - 400) MW												

Figure 22: 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[14]. 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[15] 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 upcoming season could simply be one of the more constraining from a set of possible season scenarios[16] (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[17], 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.

---

[14] A comparison with past editions is not possible yet because this is the first time this measure has been reported in a seasonal adequacy assessment.
[15] The conclusions made for annual LOLE are also valid for any other annual metric.
[16] The same applies for a particular historical supply scarcity. If hours when demand was shed exceed the LOLE set by the Reliability Standard, it 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.
[17] Monitored by the European Resource Adequacy Assessment in line with Article 23 of the Electricity Regulation 2019/943

Considering the aforementioned background and interpretation limitations, Figure 23 below represents the LOLE results of the Summer Outlook 2022.

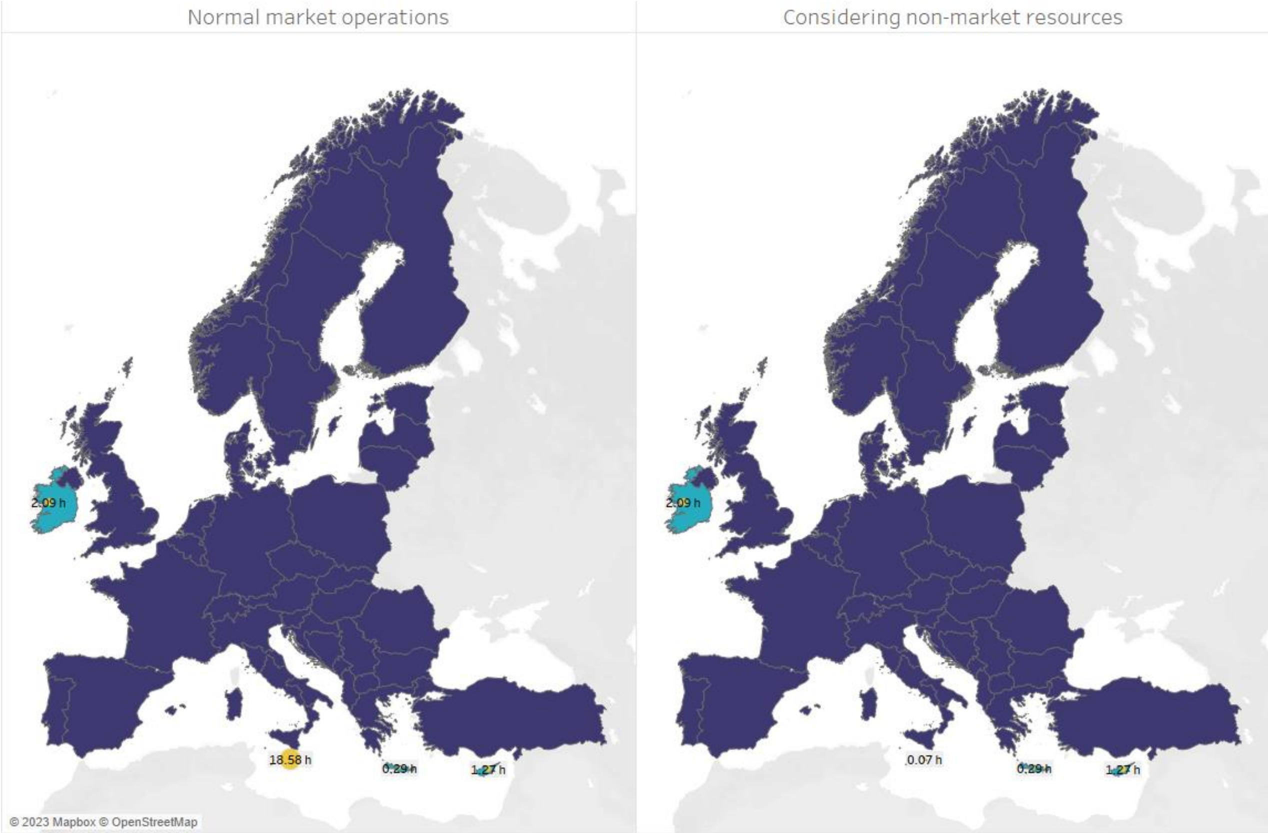


Figure 23: Seasonal LOLE results

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.

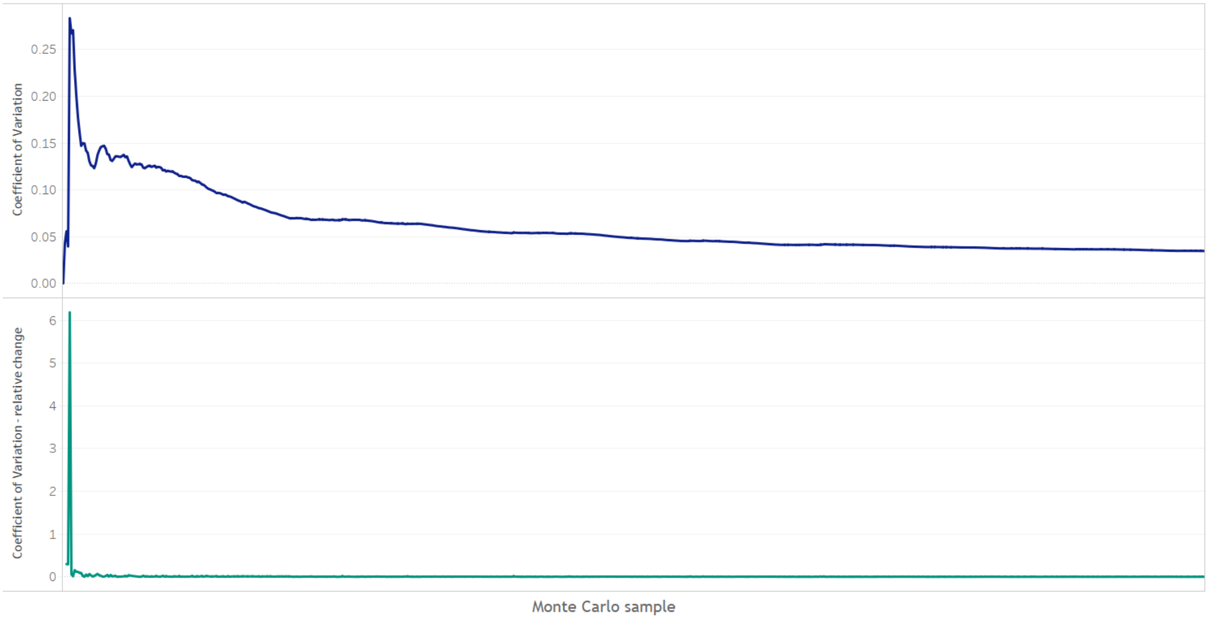


Figure 24: Convergence overview[18]

[18] *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.*