Winter Outlook 2021-2022

Summer Review 2021

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ENTSO-E Mission Statement

Who we are

ENTSO-E, the European Network of Transmission System Operators for Electricity, is the **association for the cooperation of the European transmission system operators (TSOs)**. The 42 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

The ENTSO-E Winter Outlook 2021–2022 shows, overall, no risk to electric security of supply this winter.

The current surge of prices on the gas market may have an impact on electricity prices but should not pose additional adequacy risks under reference and severe scenarios (c.f. *ENTSOG Winter Supply Outlook*[1]). Increased gas prices may even support adequacy in the power system as some consumers tend to moderate or postpone use of gas resources and so more gas could be preserved. Furthermore, power plants other than gas (mainly coal-fired) are gaining an economic edge over gas-fired power plants and, consequently, gas consumption for electricity generation over winter may be lower compared to the long-term average. Nevertheless, the situation should be monitored closely in the event of prolonged gas supply route disruptions combined with severe weather conditions.

Risks in specific countries have been identified in the report. In France, risks are observed in January and February in the event of extreme cold weather events. Risks in Ireland are driven by generation planned outages and aging conventional power plants, which presents a higher probability of unplanned outages. The actual adequacy situation in Ireland will depend on the operational conditions and especially on wind generation.

There is an evident need to rely on non-market resources to ensure security of supply in rather isolated Mediterranean systems such as Malta. The Winter Outlook 2021–2022 highlights certain risks in this respect, but non-market resources should be sufficient to cope with operational challenges and supply shortages.

The Winter Outlook is accompanied by a retrospect of last summer. Supply margins were sufficient to ensure adequacy in Summer 2021. Multiple countries reported higher demand levels than those witnessed in 2020 as restrictions related to the COVID-19 pandemic were lifted and economic activity recovered. Croatia, Finland and Norway reported lower than average hydro production due to dry weather conditions; lower-than-average wind generation was also witnessed in Croatia, Denmark and Norway. However, no adequacy concerns were reported.

System Alerts were issued in Ireland and Northern Ireland on multiple occasions during the summer period. Tight supply margins were caused by outages of generation units in combination with lower-than-average wind generation levels. System operators responded with various steps to mitigate the risks associated with these tight margins.

On Saturday, 24 July 2021 at 16:36 CET, the Continental Europe Synchronous Area was separated into two areas due to cascaded trips of several transmission power system elements which initiated in the Southern part of France[2]. In the Iberian Peninsula, the frequency dropped to 48.68 Hz, triggering the disconnection of hydro pumps and the automatic load shedding of 4807 MW in Spain and Portugal. All measures were taken to ensure power system operational continuity and were not related to adequacy. The incident lasted for less than an hour.

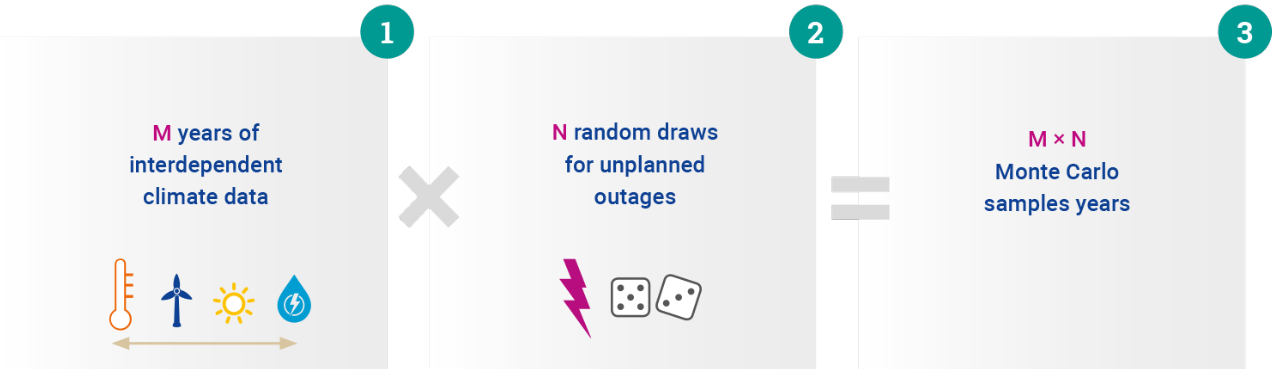
[1] *ENTSOG Winter Supply Outlook 2021/2022*
[2] *Continental Europe Synchronous Area Separation on 24 July 2021 — Technical Report*

Methodological revolution

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[3]. 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)[4]. Although the implementation of this target methodology will still require some extensions in the coming years (for instance to include flow-based modelling), the present Winter Outlook shows major advancements.

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 1 provides a schematic representation of this scenario construction process.



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 moved from a 'shallow' scenario tree, containing only a severe conditions sample and a normal conditions sample, to a 'deep' scenario tree that combines dozens of years of interdependent climate data with random draws of unplanned outages to generate a multitude of alternative scenarios. Furthermore, an improvement in the methodology also enables the consideration of hydro energy availability. Figure 2 illustrates the difference in the number of scenarios between the two modelling approaches.

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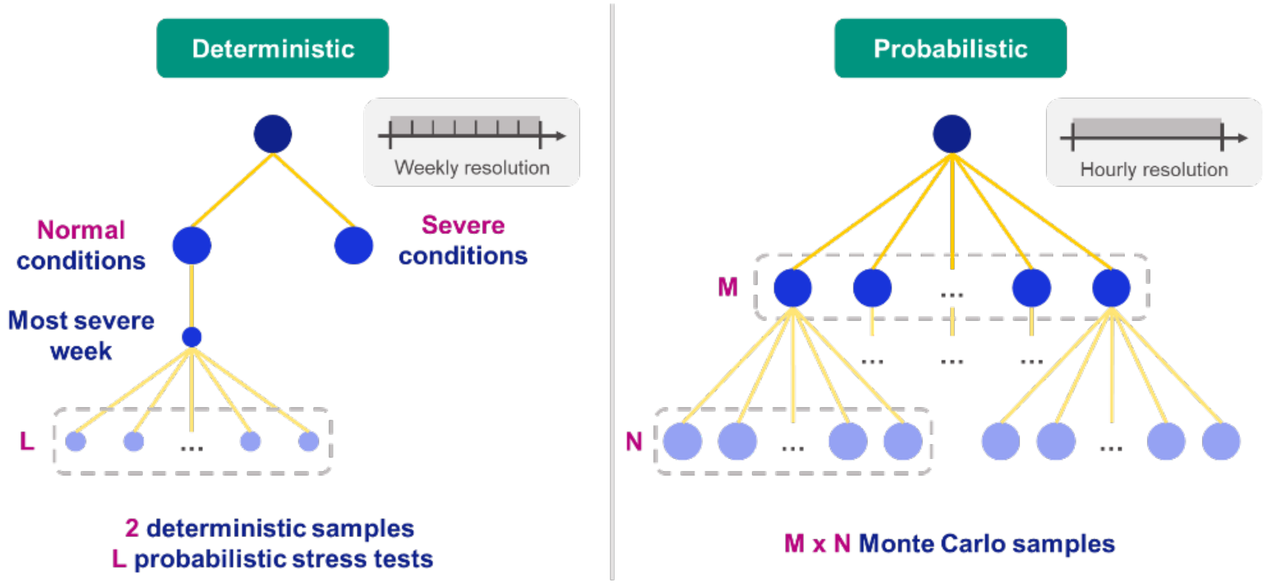
[3] Methodology for Short-term and Seasonal Adequacy assessment
[4] ACER decision (No 08/2020) on the methodology for short-term and seasonal adequacy assessments



For each of the scenarios, an adequacy assessment is performed on the seasonal time horizon, resulting in an overall probabilistic assessment of pan-European resource adequacy that can not only identify whether the adequacy risks exist under various deterministic scenarios but also construct a high number of consistent pan-European scenarios and identify realistic adequacy risk.

After the Winter Outlook 2020–2021, further improvements were made, especially in the modelling of exchanges, where 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).

Overview of the power system in Winter 2021–2022

Information collected for the Winter Outlook 2021–2022 study represents the best available information from August–September 2021. Transmission System Operators (TSOs) continue to cooperate closely and monitor adequacy closer to real-time through the services of the Regional Security Coordinators (RSCs) to address the ever-changing situation in the power system.

Since the Summer Outlook 2020, the study zone configuration has been revised to address recent changes. First, in light of the Italian bidding zone reconfiguration[5], study zones have been updated accordingly. Southern Italy (ITS1) was split into two study zones – Calabria (ITCA) and the remaining southern Italy (ITS1). In addition, the Umbria region in the central Italian bidding zones (study zones ITCN and ITCS) was reassigned from one bidding zone to another. Second, Crete was interconnected with mainland Greece (GR00) in May 2021[6], and hence a study zone has been added (GR03). Any data or result comparison considering previous seasonal outlook editions should take this update into account.

The information about the power system presented in this report considers all the resources available to supply demand in a market-based approach or available resources to supply demand in the event of supply shortage in the market. This means that non-market resources committed to ensuring operational security are not represented. This includes generation, Demand Side Response (DSR) and storage resources, which are dedicated to ensuring grid security and stability, as well as transmission reliability margins (by which transfer capacities are being reduced), which are dedicated to coping with power flow variability. Therefore, the figures presented in the report should not be considered representative of all the physically available resources in the power system.

All figures in this section correspond to resources available in the market. This means that the total capacity overview (Figure 3) and generation capacity mix (Figure 4) disregard non-market resources. Non-market resources that can be used in the event of a supply shortage in the market are presented in a dedicated figure to show the amount of capacity (c.f. Figure 5).

Generation overview

The generation capacity overview in Figure 3 shows that all study zones except south of Sweden (SE04) have sufficient Net Generating Capacities (NGC) available on the market to cover the highest expected demand in Winter 2021–2022. However, in some study zones, imports might be necessary in the event of low renewable generation. When considering only thermal and hydro units, the NGCs in many study zones decrease. In some zones, they even drop below the highest expected demand in Winter 2021–2022. This suggests that in the case of low renewable generation, imports might be necessary to ensure security of supply. Furthermore, this need increases in importance if we consider generation unavailability (e.g. planned and unplanned outages). This demonstrates the importance of the interconnected European power system and the relevance of pan-European adequacy studies.

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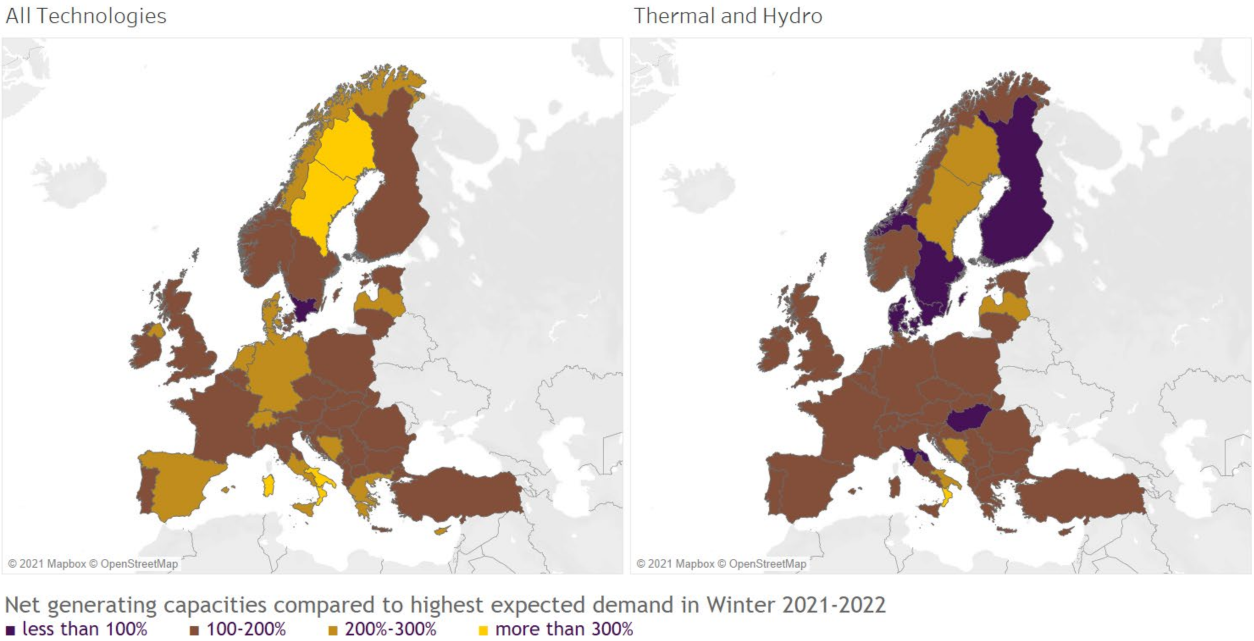
[5] *Effective from 1 January 2021. Deliberation 103/2019/R/eel of the Italian Authority of 19 March 2019*
[6] *Press release: Crete-Peloponnese: The record-breaking interconnection is completed*



According to Figure 4, thermal NGC available on the market accounts for approximately 40% of the total capacity of the European power system at the beginning of Winter 2021–2022. This is followed by hydro, wind and solar capacities, which constitute the remaining half. In addition, the highest expected demand[7] is depicted with a small black square, and its value as a percentage of each node's NGC is given.

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, thermal NGC share is low despite low hydro capacities (e.g. Germany [DE00] and southern Sweden [SE04]) or no hydro capacities (Western Denmark [DKW1]). These systems are characterised by a high share of wind and solar generation.

Info box:
Study zone naming convention

Country code ← XX YY

ENTSO-E zone index ←

Map with codes is available in Appendix 1:

DSR services are gaining popularity in Europe. This, in turn, means the greater participation of electricity consumers in the electricity market. Nevertheless, DSR is not continuously available and may only be available for a limited period of time (e.g. 2 hours in a day) or at varying capacity (c.f. Figure 11). More DSR is likely to be available during peak times, but this is not guaranteed.

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[7] *Highest expected demand is computed by taking the highest value of the hourly demand 95^{th} percentiles. Hence, this value is highest expected demand; however the Seasonal Outlook assessment also considers that demand could even exceed expected highest value as, occasionally, new peak demand records are registered in Europe (e.g. in the event of a cold spell).*

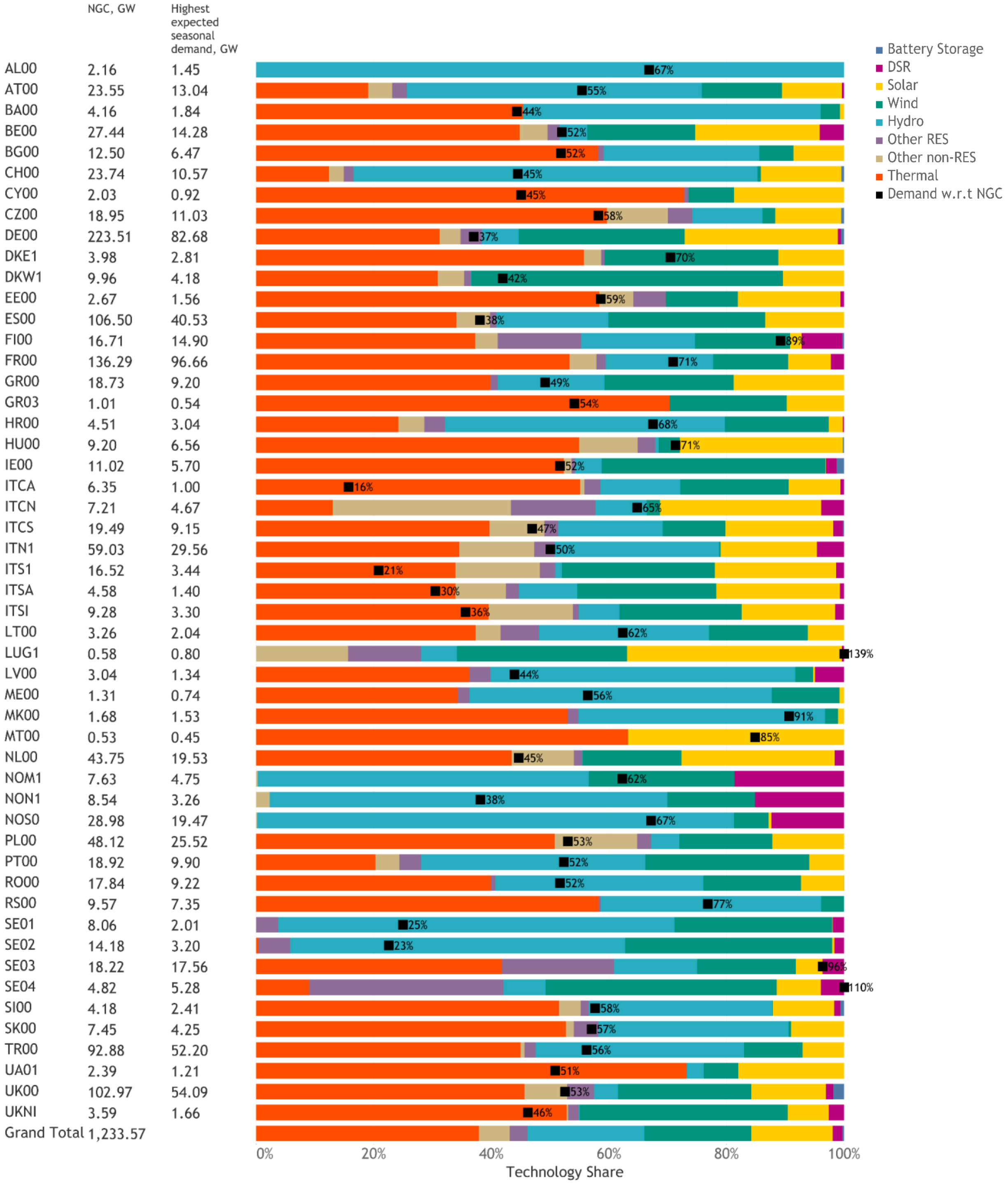
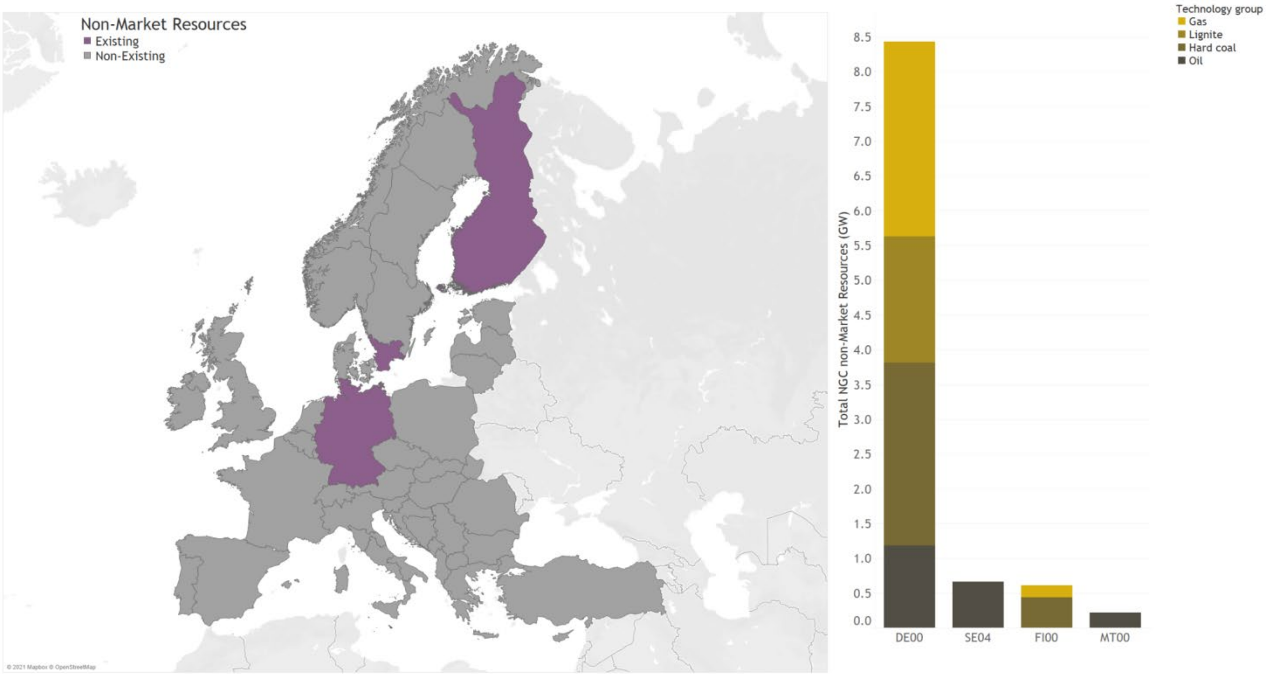


Figure 5 shows which study zones have non-market resources available along with the corresponding NGC. In the event of a lack of supply in the market, the activation of dispatchable non-market resources can help to cope with adequacy challenges. Only four countries make use of non-market resources. From largest to smallest NGC, these are: Germany (8432 MW), Sweden (660 MW), Finland (611 MW) and Malta (215 MW). This report assesses if these resources are sufficient to cope with their adequacy issues and to what extent.



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Capacity evolution

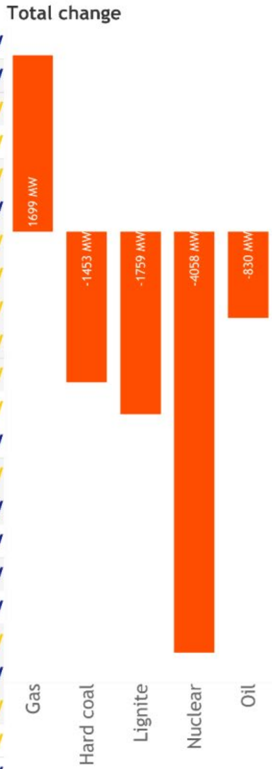
The most relevant capacity evolutions during Winter 2021–2022 are displayed for thermal technologies[9] in Figure 6[10], and for renewable energy technologies[11] in Figure 7.

Thermal evolutions show a net decrease in Europe of approximately 6401 MW. The majority of this decrease comes from the decommissioning of 4058 MW of nuclear capacity in Germany. In addition, the capacity of lignite, hard coal and oil thermal power plants in Europe has decreased; this is partially compensated by the commissioning of gas-fired power plants.

[8] Parts of German non-market resources have primarily a different 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.
[9] Some additional commissioning and decommissioning may occur during the current season
[10] The information collected represents the best available data from August–September 2021; later updates cannot always be accommodated (e.g. the RO00 commissioning date has been postponed to a later date).
[11] Presented as accumulated capacity change over the season.

Commissionings and Decommissionings

BE00	Hard coal	1 January 2022	Commissioning 22MW
CY00	Gas	1 January 2022	Commissioning 990MW
	Oil	31 December 2021	Decommissioning 830MW
CZ00	Lignite	31 December 2021	Decommissioning 250MW
DE00	Gas	31 December 2021	Decommissioning 268MW
		1 January 2022	Commissioning 1141MW
	Hard coal	8 December 2021	Decommissioning 1447MW
		31 December 2021	Decommissioning 123MW
	Lignite	31 December 2021	Decommissioning 910MW
		1 April 2022	Decommissioning 294MW
	Nuclear	31 December 2021	Decommissioning 4058MW
DKE1	Gas	31 December 2021	Decommissioning 7MW
		1 January 2022	Commissioning 5MW
DKW1	Gas	31 December 2021	Decommissioning 23MW
		1 January 2022	Commissioning 4MW
HR00	Gas	1 January 2022	Commissioning 10MW
NL00	Gas	1 January 2022	Commissioning 10MW
RO00	Gas	1 January 2022	Commissioning 189MW
SI00	Gas	31 December 2021	Decommissioning 23MW
		1 January 2022	Commissioning 114MW
	Lignite	31 December 2021	Decommissioning 305MW
TR00	Gas	31 December 2021	Decommissioning 442MW
	Hard coal	31 December 2021	Commissioning 95MW



For renewable energy sources evolution over the course of Winter 2021–2022, there is a net increase in Europe of 14808 MW (8355 MW in wind technology and 6461 MW in solar technology) over the Winter Outlook 2021–2022 timeline. An increase of renewables can be seen in all study zones, with Germany experiencing the largest evolution of solar capacity in Europe, with a magnitude of 2708 MW from the Winter Outlook. On the other hand, Sweden undergoes the largest evolution of wind capacity, with a total increase of 2023 MW (SE02 experiencing the largest growth of the study zones in Sweden). The study zones of Spain (ES00) and the Netherlands (NL00) also see large growth in their wind capacity, with an increase of 1169 MW and 1050 MW respectively.

Seasonal Evolution of Renewable Energy Sources

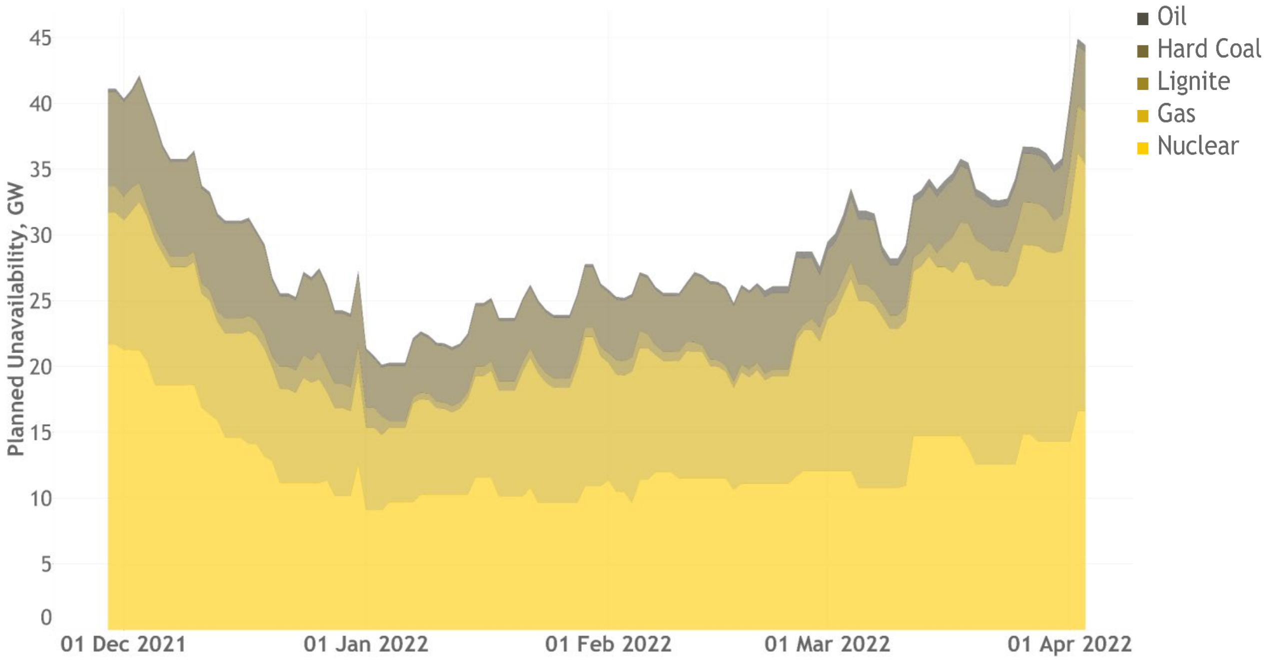
AT00	Solar	Commissioning	142MW
	Wind	Commissioning	85MW
CH00	Hydro	Commissioning	42MW
	Solar	Commissioning	455MW
	Wind	Commissioning	15MW
DE00	Hydro	Decommissioning	43MW
	Solar	Commissioning	2708MW
	Wind	Commissioning	612MW
DKE1	Solar	Commissioning	273MW
	Wind	Commissioning	1MW
DKW1	Solar	Commissioning	637MW
	Wind	Commissioning	223MW
ES00	Solar	Commissioning	677MW
	Wind	Commissioning	1169MW
FI00	Solar	Commissioning	40MW
	Wind	Commissioning	900MW
GR00	Hydro	Commissioning	1MW
	Solar	Commissioning	30MW
	Wind	Commissioning	50MW
GR03	Solar	Commissioning	2MW
HU00	Solar	Commissioning	150MW
LT00	Solar	Commissioning	50MW
	Wind	Commissioning	70MW
MK00	Hydro	Commissioning	7MW
MT00	Solar	Commissioning	1MW
NL00	Solar	Commissioning	420MW
	Wind	Commissioning	1050MW
NOM1	Wind	Commissioning	440MW
NON1	Wind	Commissioning	200MW
NOS0	Wind	Commissioning	740MW
PL00	Hydro	Commissioning	5MW
	Solar	Commissioning	805MW
	Wind	Commissioning	747MW
PT00	Solar	Commissioning	10MW
	Wind	Commissioning	30MW
SE01	Solar	Commissioning	4MW
	Wind	Commissioning	506MW
SE02	Solar	Commissioning	24MW
	Wind	Commissioning	1057MW
SE03	Solar	Commissioning	347MW
	Wind	Commissioning	315MW
SE04	Solar	Commissioning	151MW
	Wind	Commissioning	145MW

Planned unavailability

The planned unavailability of units considered in the assessment is presented in Figure 8. The planned unavailability of generation units includes planned outages for maintenance purposes and mothballing.

Total planned unavailability decreases towards the end of 2021 and reaches the lowest level in January, when supply margins are tight in Europe (especially in central Europe). A sharp drop at the end of December indicates that many planned outages are scheduled to be finished by end of year; therefore, any delays should be carefully monitored. Planned outages start ramping up at the end of January and follow this trend until the end of winter.

Planned outages of each technology decrease towards January in different magnitudes. Lignite planned outages are lowest in January and start increasing very late, whereas hard coal planned outages vary considerably throughout the winter. Nuclear and gas power plant planned outages decrease substantially in January; however, they remain notable.


Oil
Hard Coal
Lignite
Gas
Nuclear
Planned Unavailability, GW
45
40
35
30
25
20
15
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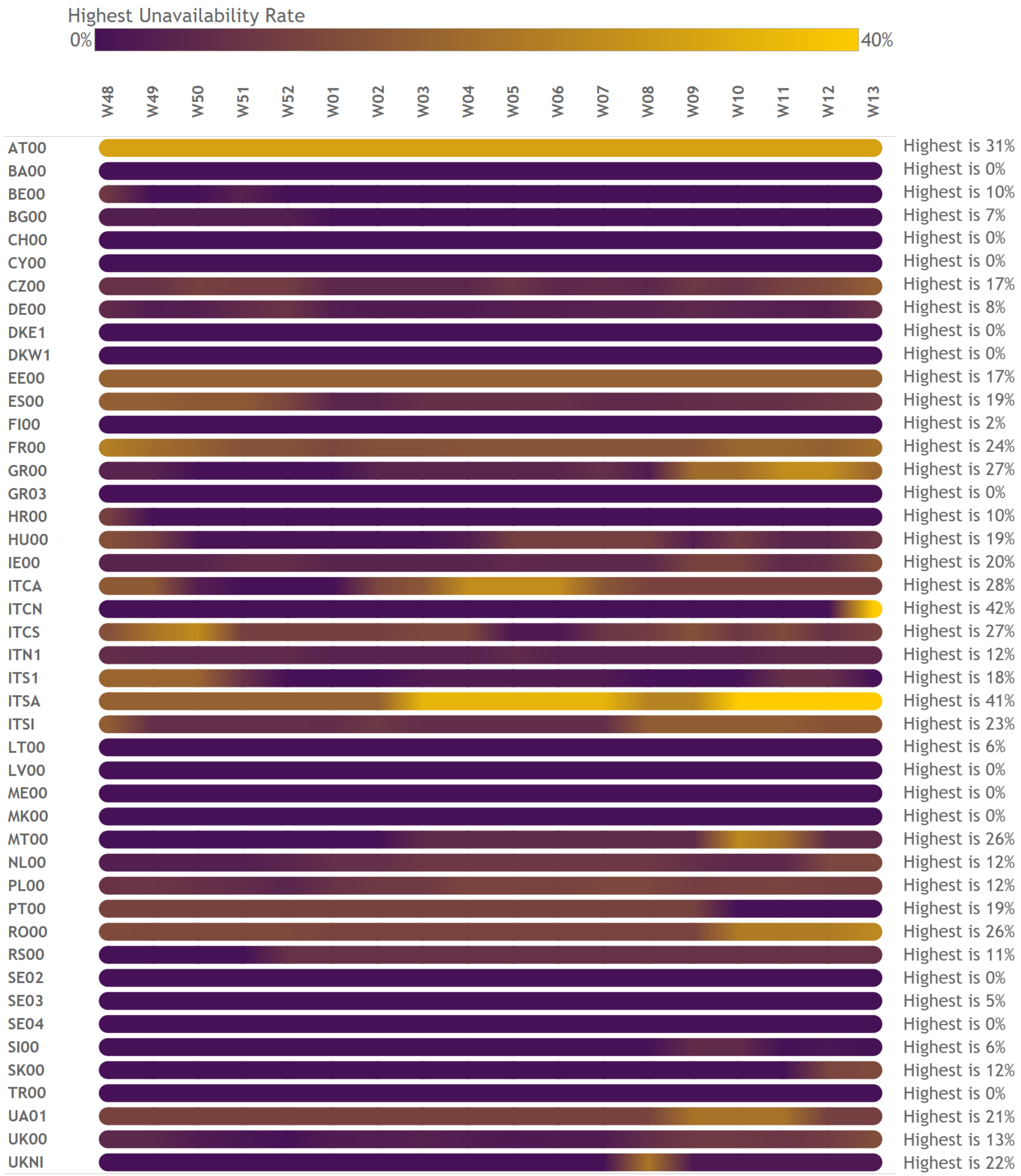
5
0
01 Dec 2021
01 Jan 2022
01 Feb 2022
01 Mar 2022
01 Apr 2022



Further availability limitations

The overview of availability reduction is presented in Figure 10, which shows that resources are further limited by approximately 37 GW in Winter 2021–2022. No clear seasonal pattern is recorded; however, pronounced daily changes are observed for DSR.

Generation and DSR availability can be limited by factors other than planned and unplanned outages, and hence these resources might not be available at full capacity. The generation could be impacted by seasonal factors (e.g. in winter, CHP availability for electricity production might depend on heat needs, whereas in summer, cooling water temperature might have an impact), whereas DSR availability might depend on demand levels in particular hours of the day. The availability of some other technologies might depend on external factors (e.g. CHP availability for electricity production depends on heat needs). Other availabilities might be strongly dependent on climate; they are not represented here but are available in the published dataset.

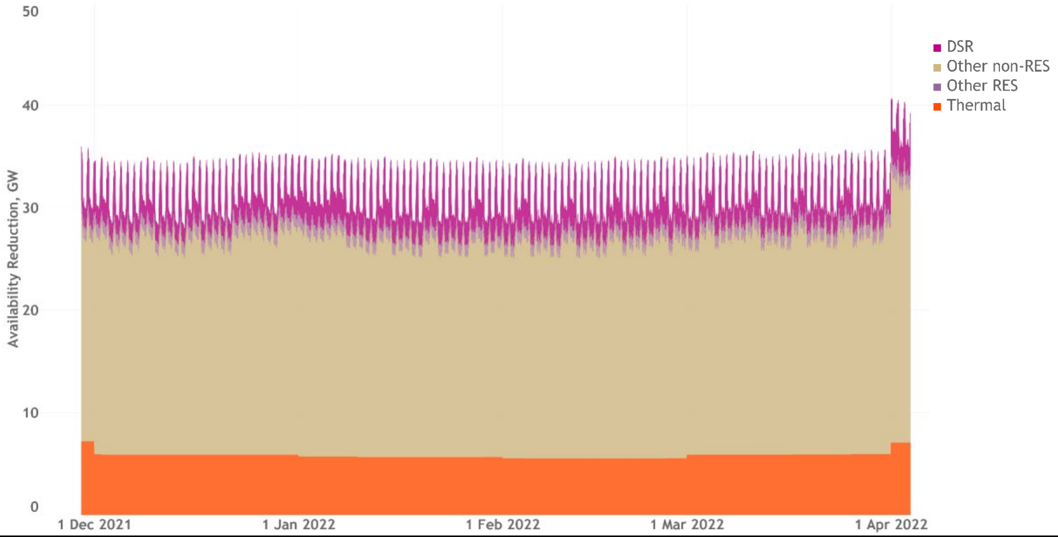


Figure 10: Availability reduction of generation and demand side response

Although the absolute availability decrease appears marginal (37 GW) in Europe, the ratio of capacity that may be unavailable due to limitations is rather notable, as shown in Figure 11. Other non-RES availability may be limited by approximately 33%, whereas DSR varies around 20% depending on the time of the day. This information is especially relevant for study zones with relatively high capacities for these technologies (such as Northern–Centre Italy [ITCN] and Finland [FI00]).

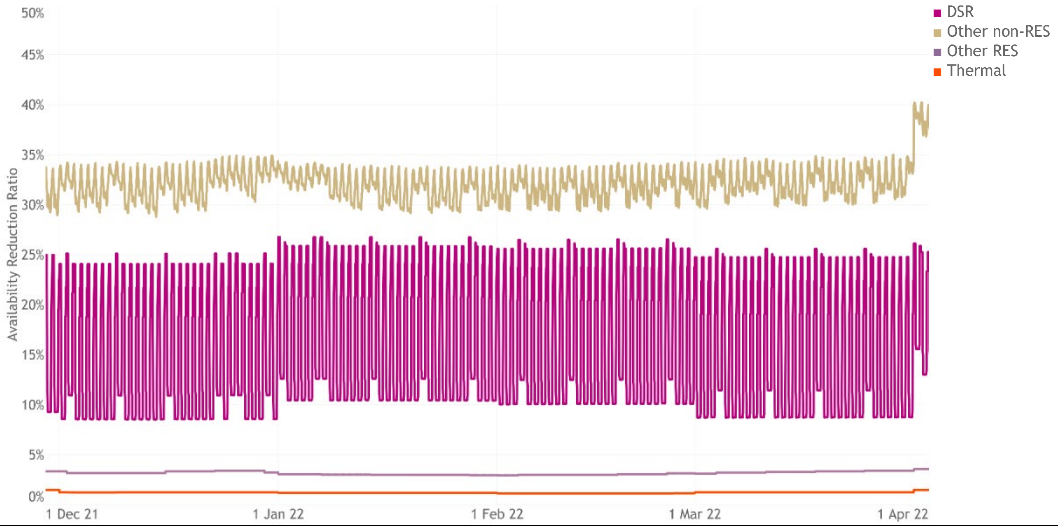


Figure 11: Relative availability reduction – not outage dependent

The overview of availability reduction profile (Figure 12) shows that DSR drops less during daytime, whereas other technologies do not show strong variability throughout the day. However, Figure 11 presents a pan-European overview, and noticeable patterns present in individual countries may not be detectable when examining data aggregated at a pan-European level.

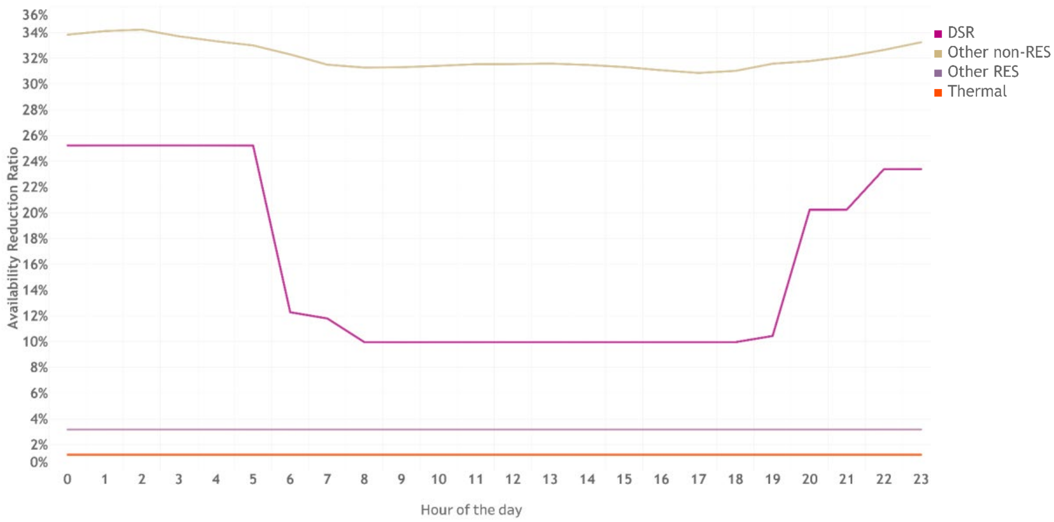


Figure 12: Average daily availability reduction profile overview

Adequacy and gas supply context

The current surge of prices on the gas market may have an impact on electricity prices in Europe but should pose no adequacy risks under normal and severe weather conditions (c.f. *ENTSOG Winter Supply Outlook*[12]). Increased gas prices may even support adequacy in the power system as some gas consumers may decide not to use gas resources and so more gas could be preserved. Furthermore, power plants other than gas (mainly coal-fired) are gaining an economic edge over gas-fired power plants, and gas consumption over the winter may be lower compared to long-term averages. Nevertheless, the situation should be monitored closely in the event of prolonged gas supply route disruptions combined with severe weather conditions.

Considering ENTSOG assessment results, ENTSO-E does not consider a risk of gas availability for the coming winter. It is expected that price signals in electricity and gas markets will support optimal resource distribution — ensuring sufficient supply to gas-fired power plants to meet electricity demand and, in a second step, gas allocation to other sectors when the emergency situation steps in. In addition, gas supply to power plants that guarantees power system operational stability could be ensured by TSOs in accordance with Article 11(7) of REGULATION concerning measures to safeguard the security of gas supply[13].

Demand overview

The overview of demand (Figure 13) compares expected consumption in each week with the highest expected weekly consumption in Winter 2021–2022. The darker shades indicate low expected consumption compared to highest expected consumption. This helps to identify holiday periods and other consumption patterns.

The level of consumption ramps up to reach its highest value in December in most study zones, and typically continues at the same level until February–March. However, a noticeable demand drop is witnessed at the end of the year 2021 (week 52), during the holiday period, for many study zones, e.g. CZ00, IE00, PL00. A pronounced consumption change in the season is typically present in countries that use electricity for heating (e.g. France in winter) or cooling (e.g. Italy in summer), as this makes electricity consumption very sensitive to outdoor temperatures.

[12] *ENTSOG Winter Supply Outlook 2021/2022*
[13] *Regulation (EU) 2017/1938*

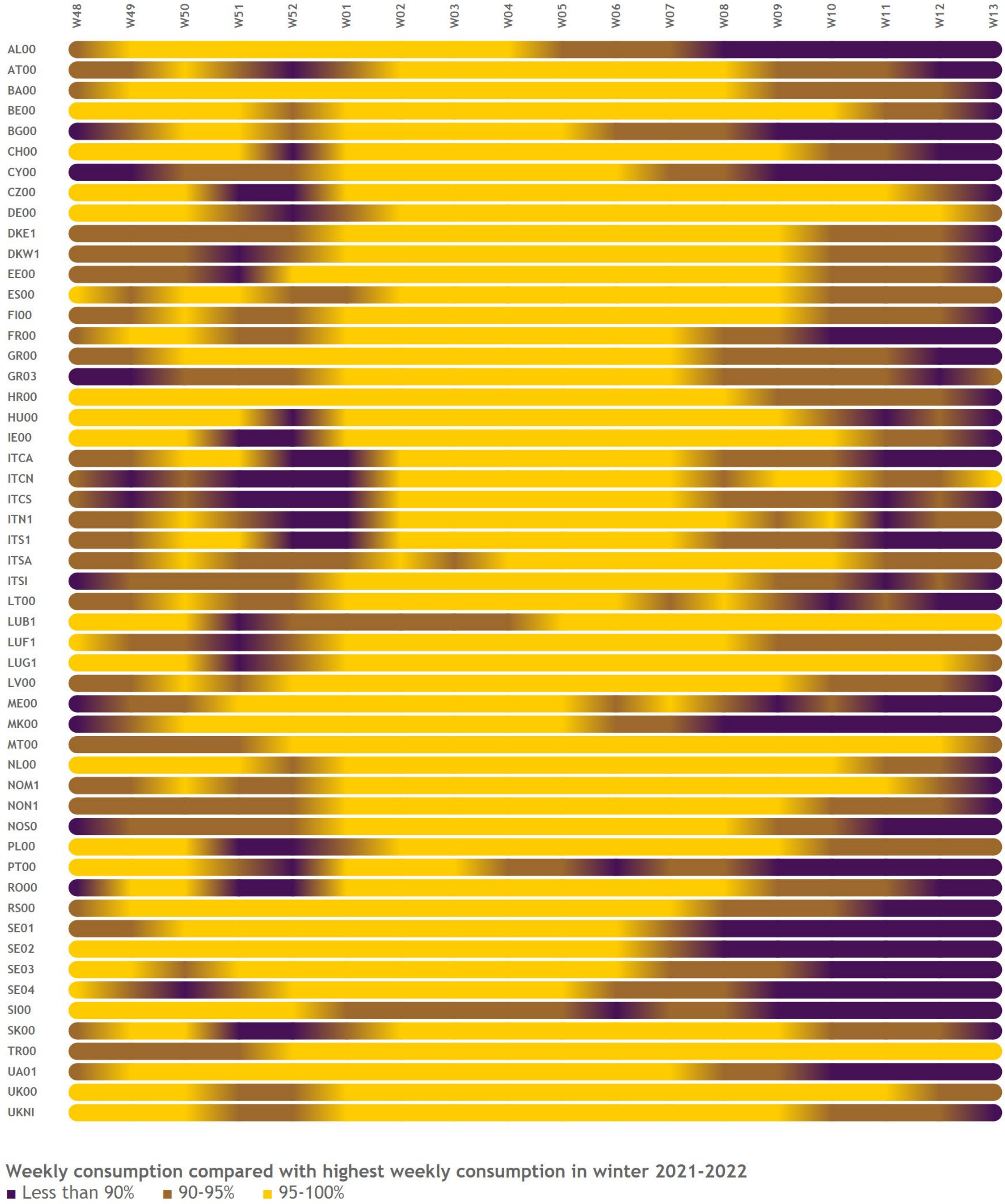


Figure 13: Demand overview – evolution over Winter 2021–2022

Figure 14 shows workday consumption patterns per study zone by plotting mean demand compared to the highest mean demand in winter 2021–2022. Almost all European countries show a clear evening peak. Some countries (e.g. AT00, BE00, CH00, ES00, FR00) typically have distinct morning and evening peaks, with a reduction in demand occurring in the early afternoon. Meanwhile, several Northern and Central European study zones (e.g. CZ00, DE00, EE00, FI00, LT00) display no notable demand variability during daytime.

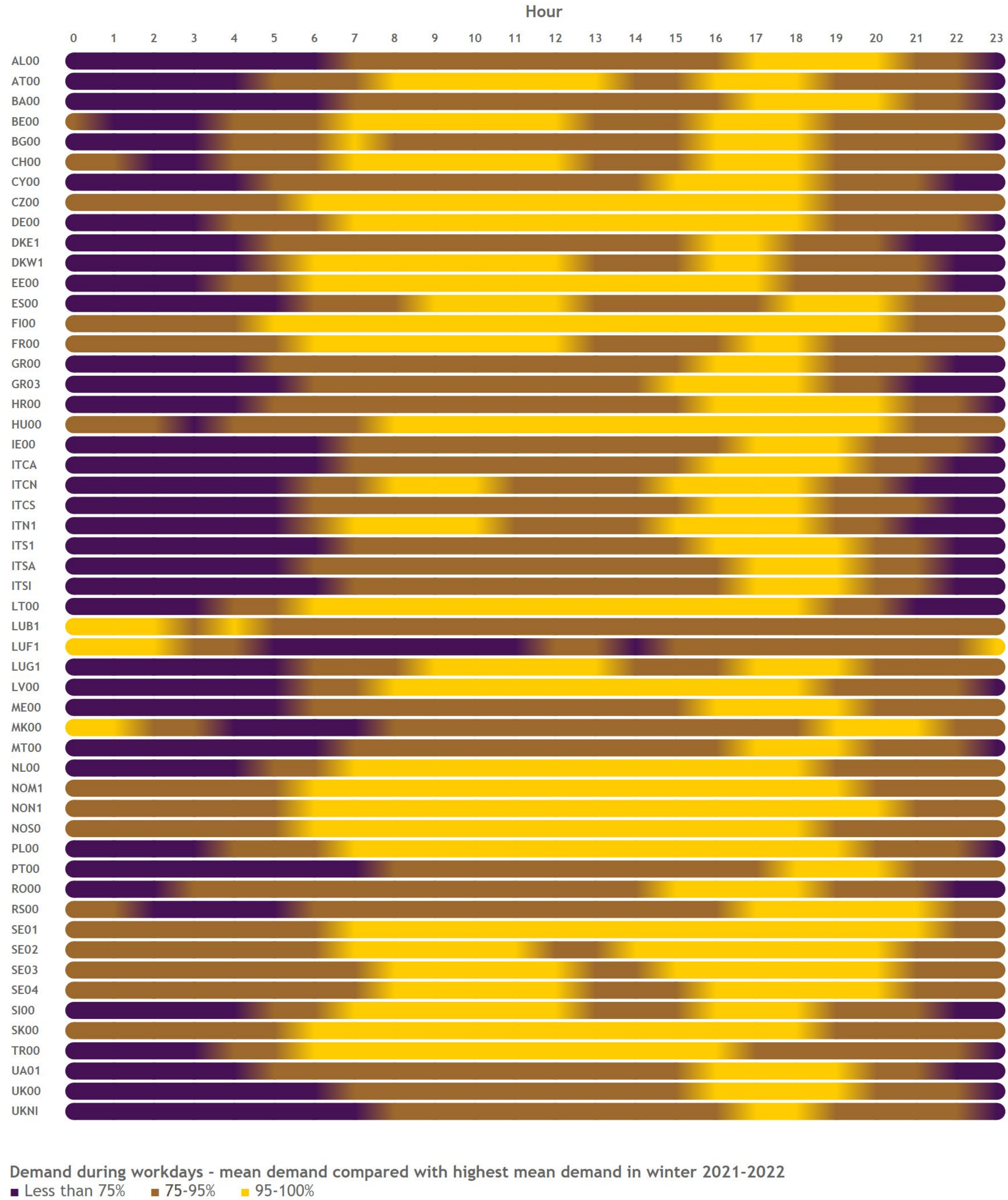


Figure 14: Demand profile overview during Mondays–Fridays in Winter 2021–2022[14]

Network overview

The map in Figure 15 shows the ratio between the lowest import capacity in Winter 2021–2022 and the highest expected demand[7] during the winter. The evaluation of import capacities considers the planned unavailability of grid elements. However, additional unplanned outages may constrain import capacities

[14] *UTC time convention was used.*

even further. Furthermore, import capacities with non-explicitly modelled systems are not considered in the figure, but their contribution is assessed in adequacy simulations[15] .

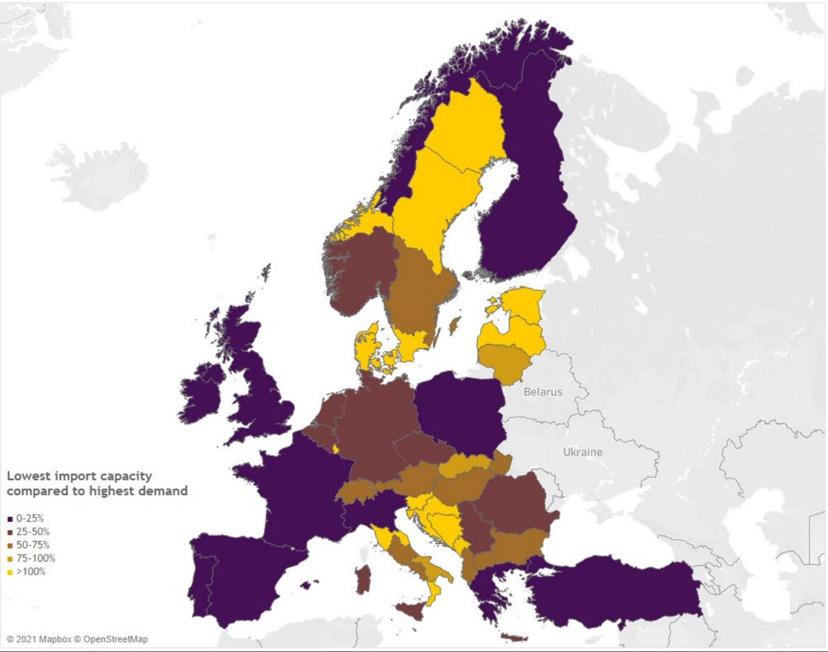


Figure 15: Import capacities per study zone: ratio between lowest import capacity and peak demand. C.f. Figure 24 for details

Sweden, the centre of Norway, the Baltic countries, southern mainland Italy, the south of Central Europe, and the northwest Balkans present the highest ratio (above 50%). Therefore, these countries might be highly reliant on locally available resources during demand peaks. Other regions indicate a lower ratio of available transfer capacities to the highest demand.

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[15] These systems are modelled in a simplified manner by estimating their potential contributions 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.

Adequacy situation

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.

The adequacy situation in Winter 2021–2022 (Figure 16) shows some adequacy risks – i.e. the risk of having to rely on non-market measures – in France, Ireland and Malta. Non-market resources reduce risks substantially in Malta where such resources exist, whereas risks do not decrease notably in France and Ireland as available non-market resources in neighbouring regions cannot be reached due to interconnection limitations[16].

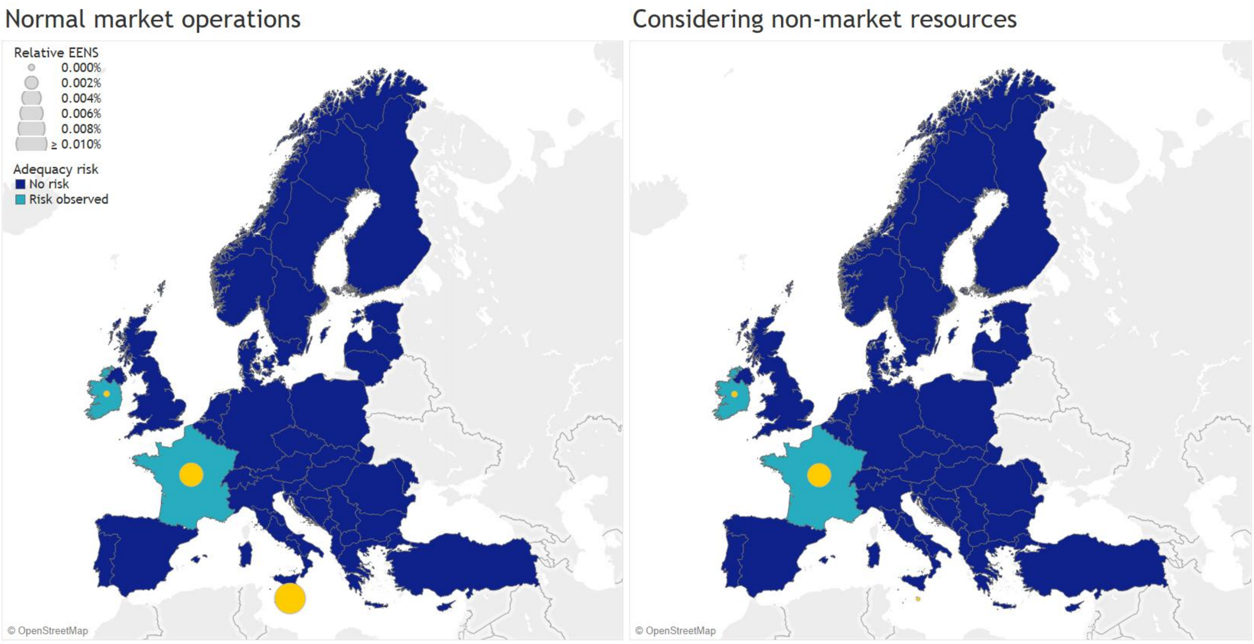

Figure 16: Adequacy overview

The state of the power system is continuously changing and is different since the data collection (performed between late August and early October). For this reason, risks are continuously being monitored by TSOs and RSCs.

Focus on adequacy under normal market conditions

Under normal market operation conditions, risks are identified in France, Ireland and Malta (Figure 17). Risks appear to be marginal in Ireland, whereas risks in France and Malta[17] appear to be higher.

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[16] 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). Actual activation of non-market resources abroad may be dependent on the existing legal framework.
[17] Please note that risks in Malta are capped for visualisation reasons. Please refer to the table on the right of the map for more detailed insights.

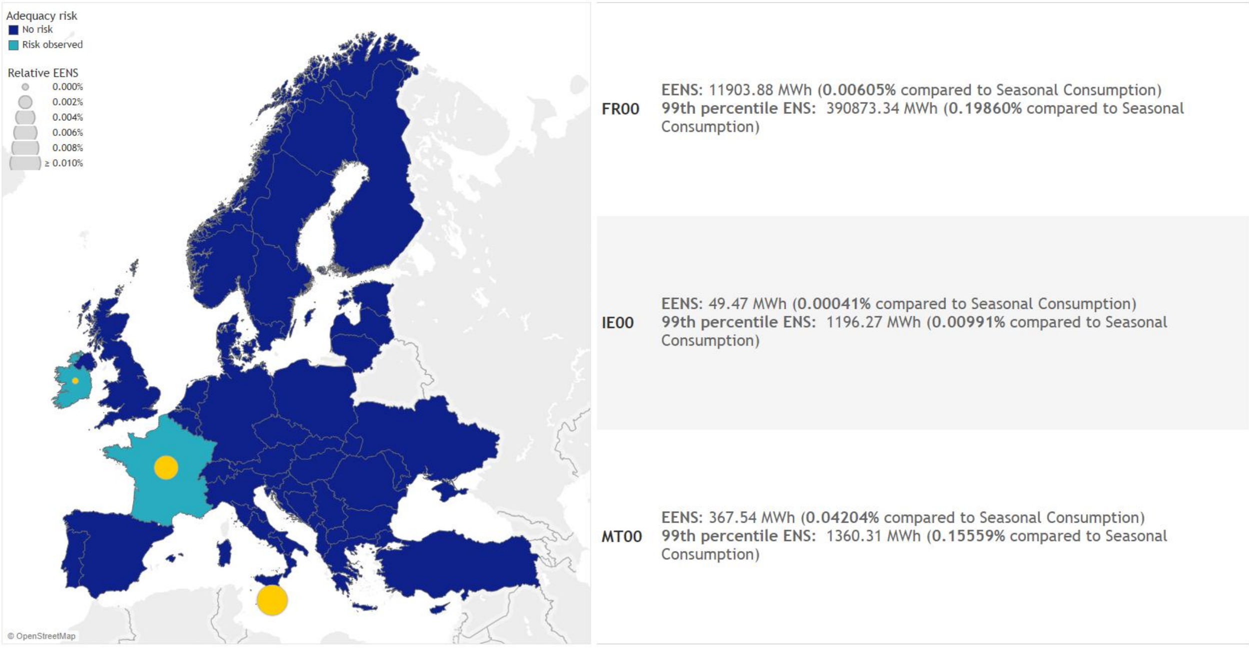

Figure 17 Adequacy risk overview

The distribution of risks within season is presented in Figure 19 by the visualisation of Loss of Load Probability (weekly LOLP[18]). No common pattern could be observed for the three Study Zones. In Malta, the probability of having to activate non-market resources appears to be inevitable. This is a recurring situation, which is why Malta has non-market resources available (c.f. Figure 5).

France (FR00) shows adequacy stress, in particular weeks in January–February 2022, with a highest weekly LOLP of 4.93%. All risks in France are common and could be associated with severely cold weather conditions as demand in France is temperature sensitive. The situation is being continuously monitored for the following months in coordination with other TSOs through RSCs.

Ireland (IE00) indicates some risks uncommon in the region. Risks in March are elevated by planned outages of generation units totalling 627 MW, as well as the poor reliability of certain older units on the system. Nevertheless, as Ireland is characterised by a large share of wind generation (Figure 4), actual risks are expected only if renewable generation is low and if other non-favourable operational conditions occur simultaneously (high demand or unplanned outages of other generation units or interconnectors). However, if these conditions occur simultaneously, partial and controlled demand shedding may be conceivable because no non-market measures, other than information about low supply margins through market messages (System Alerts), are available in Ireland.

The adequacy situation in Malta (MT00) should be monitored throughout winter with a special focus on the early winter and March (week 10). Adequacy in Malta is typically carefully monitored every season, and, for this reason, Malta implemented specifically designed non-market resources, which could be activated in the event of supply scarcity. These resources are dedicated for coping with challenging operational situations and could be used during unplanned and planned outages of interconnection or generation to ensure electricity supply continuity. The risk (showing the risk that non-market resources would need to be activated) in week 49 is associated with the planned outage of interconnection with Sicily (ITSI), whereas risks in week 10 are associated with generation planned outage. The impact of non-market resources is presented in the following section.

[18] *Weekly LOLP represents a probability that lack of supply in a respective scenario could be expected for at least 1 hour and for any amount (even 1 MW). This suggests that weekly LOLP under normal market conditions represents the probability that system operators would need to look for non-market resources, whereas weekly LOLP when considering non-market resources represents the probability that the power system may face a lack of supply and TSOs may need to look for non-market measures and, if none are available, partial and controlled demand shedding for a limited duration will be necessary to restore power balance.*

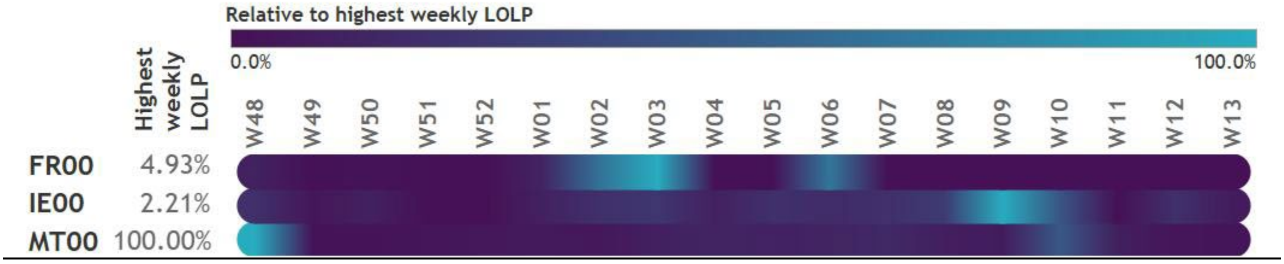

Figure 18 Weekly adequacy insights

Focus on non-market resources

Non-market resources (overview in Figure 5) drastically reduce Expected Energy Not Served (EENS) in Malta (Figure 19). No notable impact in other Study Zones is observed as they do not have dedicated non-market resources available and resources that are available abroad are not accessible due to interconnection limitations. Risk in France appears marginally decreased, whereas the risk in Ireland remains unchanged.

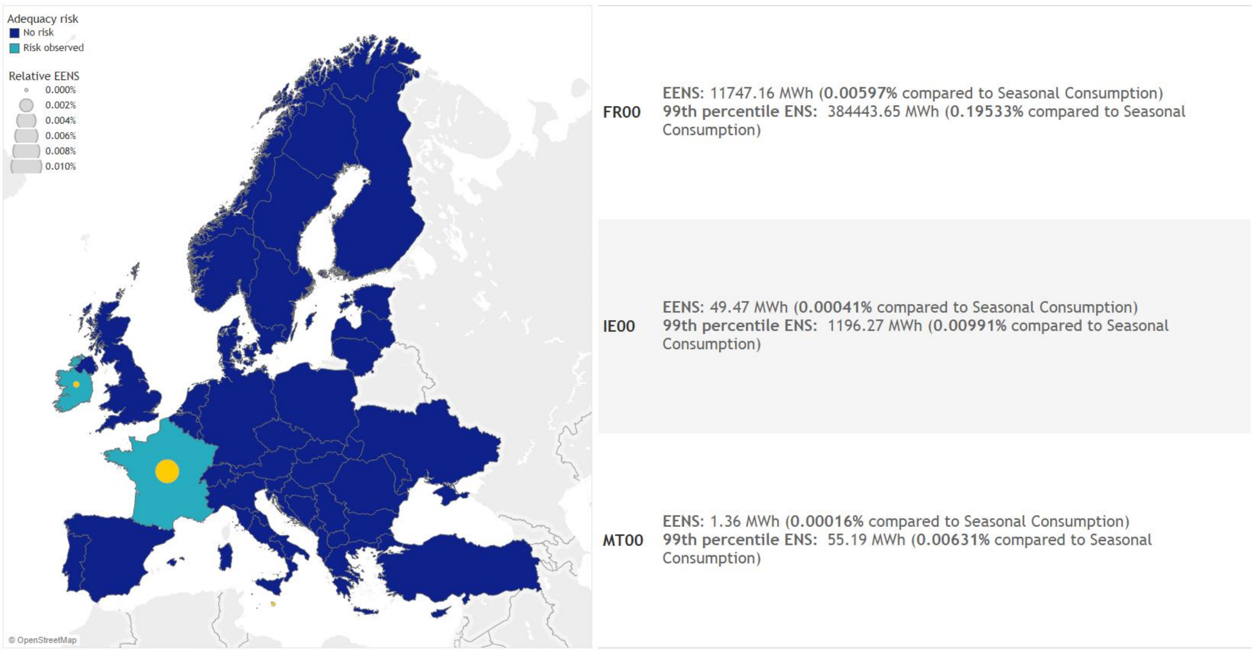

Figure 19: Detailed adequacy overview – weekly LOLP and ENS

LOLP in Malta is significantly lower when non-market resources are considered and shows only occasional risks (Figure 21). This suggests that partial demand shedding might be required only under exceptional operational conditions and only if these conditions occur in particular weeks with elevated adequacy risk (week 48 in November 2021 and weeks 8 to 10 in February and March 2022).

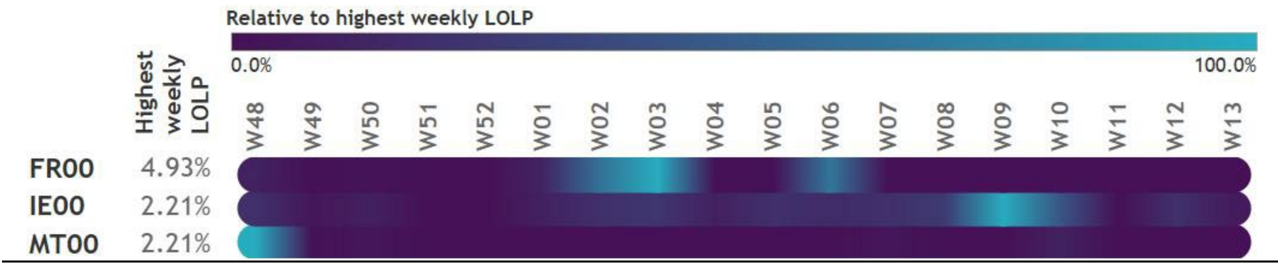

Figure 20: Adequacy weekly insights – considering non-market resources

Figure 21 represents the impact of non-market resources, which demonstrates that non-market resources can, to a large extent, address adequacy concerns in Malta.

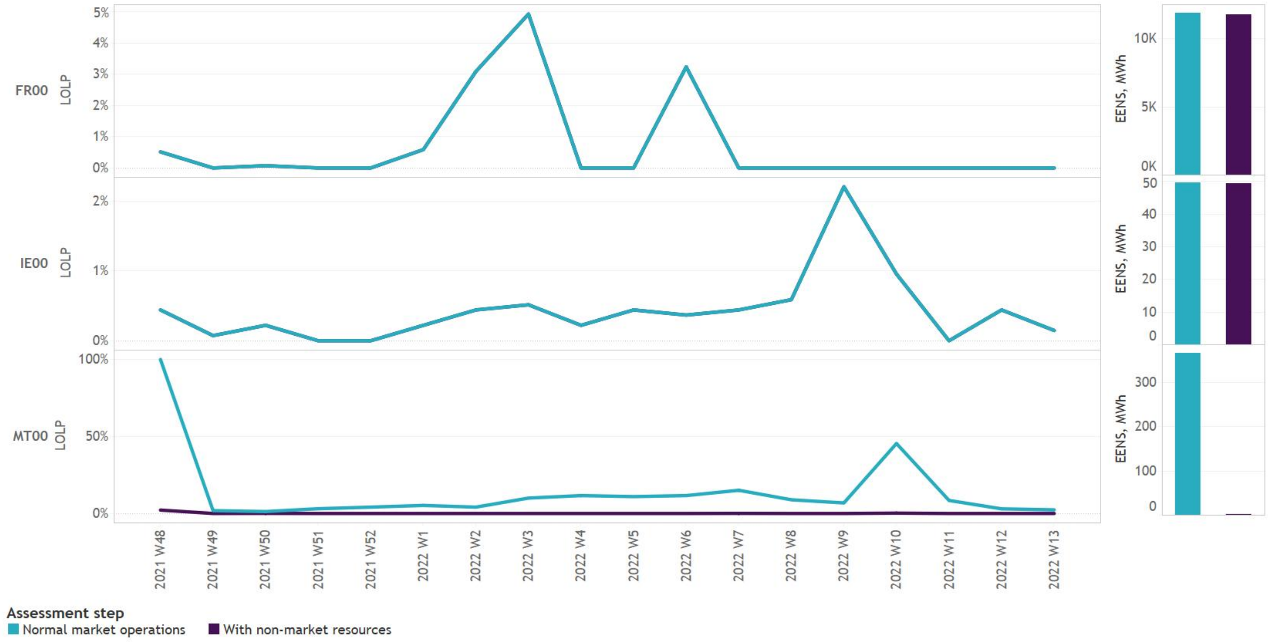

Figure 21: Detailed adequacy overview – weekly LOLP and ENS

Summer 2021 Review

The Summer Review is based on the qualitative information submitted by ENTSO-E TSOs in October 2021 to represent the most important events that occurred during the summer of 2021 and compare them to the study results reported in the previous Seasonal Outlook. Important or unusual events or conditions in the power system and remedial actions taken by the TSOs are also mentioned. A detailed Summer Review by country can be found in the separate Country Comments document.

Temperature overview[19]

In the past summer (June to September 2021), temperatures in Europe were considerably warmer than the 1991–2020 average in June and July and close to the 1991–2020 average in August and September (see Figure 22).

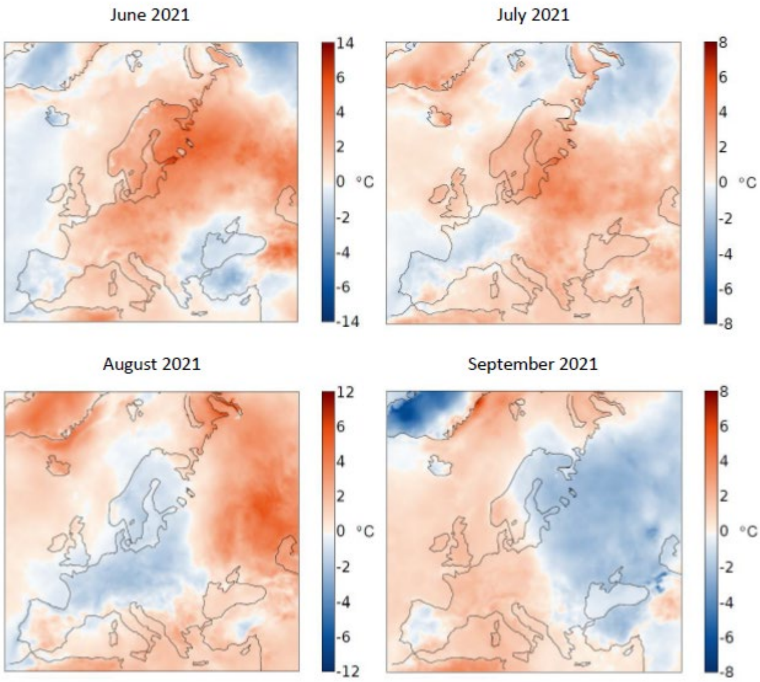

Figure 22: Surface air temperature anomaly in summer 2021 relative to the average of the periods 1991–2020 (for June, July, August, and September)[20]

June 2021 was the second warmest June on record with heatwave conditions in Finland and many other European countries. Temperatures were close to or below average over the south-east of the continent, the Iberian Peninsula and western Ireland. Like June, July 2021 was the second warmest July on record. July was considerably warmer than average over most of northern and eastern Europe, and a little colder than average over a band stretching from Portugal to Germany. August 2021 was near the average with record-breaking maximum temperatures in Mediterranean countries, warmer-than-average temperatures in the east and generally below-average temperatures in the north. September was close to average overall, but much warmer than average over most western regions and cooler than average in the east.

Adequacy overview

In Summer 2021, no adequacy issues were recorded as extreme weather events were generally absent and supply margins were sufficient to cover peak demand. Multiple countries reported higher demand levels than

[19] June, July, August, and September 2021 temperatures are compared with the average June, July, August, and September temperatures of the period 1991–2020.
[20] [Copernicus Climate Change Service—Surface air temperature maps]

those witnessed in 2020 as restrictions related to the COVID-19 pandemic were lifted and economic activity recovered. Lower-than average hydro generation due to dry weather was witnessed in Croatia, Finland and Norway and lower-than-average wind generation was witnessed in Croatia, Denmark, Ireland and Norway. Croatia relied heavily on imports to cover demand, but, as in other countries, adequacy margins were always sufficient. Only in Ireland and Northern Ireland did low wind generation, together with the occurrence of forced outages, lead to the issuing of System Alerts on multiple occasions during summer.

The **Ireland** power system entered the Alert state on 17 May, 6 September and 9 September. Tight generation margins were mainly caused by the long-term forced outage of two large Combined Cycle Gas Turbine (CCGT) generation units with an installed capacity of 844 MW, the poor reliability of some older generation units and lower-than-average wind generation levels. Steps taken by the System Operator to reduce risk associated with tight generation margins included re-scheduling of multiple generator outages, postponing a 7-week East–West Interconnector outage to 2022, countertrading, and Net Transfer Capacities (NTC) reduction on the East–West Interconnector.

Generation margin in **Northern Ireland** was generally low but secure throughout the summer period, with the outage of large generation units planned sequentially insofar as possible. The Northern Ireland power system entered the Alert state on 6 September and on 12 September. Steps taken by the System Operator to reduce risk associated with tight generation margins include countertrading and NTC reduction on the Moyle Interconnector.

In **Spain and Portugal**, a major incident took place on 24 July due to the disconnection of the Iberian Peninsula from **France**. Spain was importing 2.5 GW from France at the time of the incident. In the large North-East area of Continental Europe, the incident led to a frequency increase of 60 mHz without further consequences. In the Iberian Peninsula, frequency dropped down to 48.68 Hz, triggering the disconnection of 2302 MW of hydro pumps and the automatic shedding of approximately 4807 MW of load in Spain and Portugal. The incident started at 16:32 and the reconnection of the Iberian Peninsula occurred at 17:10.

Endnote

The Winter Outlook 2021–2022 represents the Seasonal Adequacy Assessments defined in Article 9 of the Risk Preparedness Regulation (Regulation (EU) 2019/941). ENTSO-E performs this assessment to alert Member States and TSOs of the potential risks related to the security of electricity supply in the coming season.

This assessment aims to reflect the implementation of the methodology[21] approved by ACER on 6 March 2020 (decision No 08/2020).

[21] *Short-term and Seasonal Adequacy Assessment methodology*

Appendix 1: Additional information about the study

Figure 23: Study zones

AL00	From: GR00 Avg. 400 MW (400 - 400) MW	From: ME00 Avg. 300 MW (300 - 300) MW	From: RS00 Avg. 238 MW (150 - 300) MW											
AT00	From: DE00 Avg. 4,900 MW (4,900 - 4,900) MW	From: CH00 Avg. 1,046 MW (186 - 1,200) MW	From: SI00 Avg. 950 MW (950 - 950) MW	From: CZ00 Avg. 777 MW (600 - 800) MW	From: HU00 Avg. 600 MW (600 - 600) MW	From: ITN1 Avg. 100 MW (15 - 145) MW								
BA00	From: HR00 Avg. 1,000 MW (1,000 - 1,000) MW	From: RS00 Avg. 512 MW (400 - 600) MW	From: ME00 Avg. 500 MW (500 - 500) MW											
BE00	From: FR00 Avg. 1,800 MW (1,800 - 1,800) MW	From: NL00 Avg. 950 MW (950 - 950) MW	From: DE00 Avg. 750 MW (750 - 750) MW	From: UK00 Avg. 400 MW (400 - 400) MW										
BG00	From: RO00 Avg. 2,105 MW (1,900 - 2,400) MW	From: GR00 Avg. 750 MW (750 - 750) MW	From: MK00 Avg. 399 MW (250 - 400) MW	From: TR00 Avg. 334 MW (334 - 334) MW	From: RS00 Avg. 271 MW (250 - 300) MW									
CH00	From: FR00 Avg. 3,189 MW (3,000 - 3,200) MW	From: DE00 Avg. 1,944 MW (1,300 - 2,000) MW	From: ITN1 Avg. 1,851 MW (1,810 - 1,910) MW	From: AT00 Avg. 1,043 MW (186 - 1,200) MW										
CZ00	From: DE00 Avg. 2,500 MW (2,500 - 2,500) MW	From: SK00 Avg. 1,200 MW (1,200 - 1,200) MW	From: AT00 Avg. 877 MW (700 - 900) MW	From: PLE0 Avg. 800 MW (800 - 800) MW										
DE00	From: AT00 Avg. 4,900 MW (4,900 - 4,900) MW	From: NL00 Avg. 4,250 MW (4,250 - 4,250) 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. 2,800 MW (2,800 - 2,800) MW	From: DKW1 Avg. 2,500 MW (2,500 - 2,500) MW	From: LUV1 Avg. 1,300 MW (1,300 - 1,300) 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: NOS0 Avg. 507 MW (384 - 628) MW	From: BE00 Avg. 400 MW (400 - 400) 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: DKKF Avg. 600 MW (600 - 600) MW	From: DKW1 Avg. 590 MW (590 - 590) MW										
DKW1	From: DE00 Avg. 2,500 MW (2,500 - 2,500) MW	From: NOS0 Avg. 1,480 MW (1,275 - 1,532) MW	From: NL00 Avg. 700 MW (700 - 700) MW	From: DKE1 Avg. 600 MW (600 - 600) MW	From: SE03 Avg. 574 MW (360 - 715) MW									
EE00	From: LV00 Avg. 1,124 MW (889 - 1,259) MW	From: FI00 Avg. 1,016 MW (1,016 - 1,016) MW												
ES00	From: FR00 Avg. 2,977 MW (2,300 - 3,000) MW	From: PT00 Avg. 2,558 MW (2,250 - 2,700) MW												
FI00	From: SE01 Avg. 1,500 MW (1,500 - 1,500) MW	From: SE03 Avg. 1,200 MW (1,200 - 1,200) MW	From: EE00 Avg. 1,016 MW (1,016 - 1,016) MW											
FR00	From: DE00 Avg. 3,000 MW (3,000 - 3,000) MW	From: ES00 Avg. 2,884 MW (2,550 - 2,900) MW	From: CH00 Avg. 1,200 MW (1,200 - 1,200) MW	From: ITN1 Avg. 1,069 MW (995 - 1,160) MW	From: UK00 Avg. 1,045 MW (1,000 - 2,000) MW	From: BE00 Avg. 600 MW (600 - 600) MW								
GR00	From: BG00 Avg. 750 MW (750 - 750) 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. 100 MW (100 - 100) MW								
GR03	From: GR00 Avg. 150 MW (150 - 150) MW													
HR00	From: SI00 Avg. 1,500 MW (1,500 - 1,500) MW	From: HU00 Avg. 1,200 MW (1,200 - 1,200) MW	From: BA00 Avg. 1,000 MW (1,000 - 1,000) MW	From: RS00 Avg. 576 MW (0 - 600) MW										
HU00	From: SK00 Avg. 1,500 MW (1,500 - 1,500) MW	From: HR00 Avg. 1,000 MW (1,000 - 1,000) MW	From: RO00 Avg. 700 MW (700 - 700) MW	From: RS00 Avg. 699 MW (300 - 700) MW	From: UA01 Avg. 650 MW (650 - 650) MW	From: AT00 Avg. 600 MW (600 - 600) MW								
IE00	From: UK00 Avg. 500 MW (500 - 500) MW	From: UKNI Avg. 400 MW (400 - 400) MW												
ITCA	From: ITSI Avg. 1,186 MW (700 - 1,200) MW	From: ITS1 Avg. 994 MW (300 - 1,100) MW												
ITCN	From: ITN1 Avg. 3,668 MW (2,800 - 4,300) MW	From: ITCS Avg. 2,624 MW (1,900 - 2,800) MW	From: ITCO Avg. 300 MW (300 - 300) MW											
ITCS	From: ITS1 Avg. 4,807 MW (3,800 - 5,000) MW	From: ITCN Avg. 2,433 MW (1,100 - 2,900) MW	From: ITSA Avg. 886 MW (870 - 900) MW	From: ME00 Avg. 600 MW (600 - 600) MW										
ITN1	From: CH00 Avg. 3,559 MW (1,461 - 4,240) MW	From: FR00 Avg. 2,805 MW (1,179 - 3,150) MW	From: ITCN Avg. 2,457 MW (1,900 - 3,100) MW	From: SI00 Avg. 631 MW (106 - 730) MW	From: AT00 Avg. 165 MW (80 - 315) MW									
ITS1	From: ITCA Avg. 2,235 MW (900 - 2,350) MW	From: ITCS Avg. 2,000 MW (2,000 - 2,000) MW	From: GR00 Avg. 500 MW (500 - 500) MW											
ITSA	From: ITCS Avg. 719 MW (690 - 720) MW	From: ITCO Avg. 264 MW (0 - 300) MW												
ITSI	From: ITCA Avg. 1,477 MW (700 - 1,500) MW	From: MT00 Avg. 221 MW (0 - 225) MW												
LT00	From: LV00 Avg. 1,072 MW (802 - 1,199) MW	From: SE04 Avg. 700 MW (700 - 700) MW	From: PL00 Avg. 500 MW (500 - 500) MW											
LUG1	From: DE00 Avg. 1,000 MW (1,000 - 1,000) MW													
LV00	From: EE00 Avg. 1,174 MW (867 - 1,380) MW	From: LT00 Avg. 1,073 MW (960 - 1,184) MW												
ME00	From: RS00 Avg. 626 MW (550 - 700) MW	From: ITCS 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. 536 MW (219 - 600) MW	From: GR00 Avg. 400 MW (399 - 400) MW	From: BG00 Avg. 359 MW (300 - 400) MW											
MT00	From: ITSI Avg. 221 MW (0 - 225) MW													
NL00	From: DE00 Avg. 4,250 MW (4,250 - 4,250) MW	From: UK00 Avg. 1,000 MW (1,000 - 1,000) MW	From: BE00 Avg. 950 MW (950 - 950) MW	From: DKW1 Avg. 700 MW (700 - 700) MW	From: NOS0 Avg. 573 MW (0 - 700) MW									
NOM1	From: NOS0 Avg. 3,570 MW (3,570 - 3,570) MW	From: SE02 Avg. 971 MW (650 - 1,000) MW	From: NON1 Avg. 942 MW (915 - 945) MW											
NON1	From: SE01 Avg. 454 MW (250 - 473) MW	From: SE02 Avg. 260 MW (238 - 263) MW	From: NOM1 Avg. 210 MW (210 - 210) MW											
NOS0	From: NOM1 Avg. 5,700 MW (5,700 - 5,700) MW	From: SE03 Avg. 1,504 MW (750 - 2,095) MW	From: DKW1 Avg. 1,110 MW (1,110 - 1,110) MW	From: DE00 Avg. 1,028 MW (384 - 1,400) MW	From: UK00 Avg. 976 MW (416 - 1,464) MW	From: NL00 Avg. 573 MW (0 - 700) MW								
PL00	From: PLI0 Avg. 800 MW (800 - 800) MW	From: SE04 Avg. 600 MW (600 - 600) MW	From: LT00 Avg. 500 MW (500 - 500) MW											
PT00	From: ES00 Avg. 2,265 MW (2,070 - 2,700) MW													
RO00	From: BG00 Avg. 2,105 MW (1,900 - 2,400) MW	From: RS00 Avg. 766 MW (500 - 800) MW	From: HU00 Avg. 500 MW (500 - 500) MW											
RS00	From: BA00 Avg. 600 MW (600 - 600) MW	From: HR00 Avg. 589 MW (0 - 600) MW	From: ME00 Avg. 534 MW (500 - 700) MW	From: HU00 Avg. 499 MW (300 - 500) MW	From: MK00 Avg. 449 MW (314 - 500) MW	From: RO00 Avg. 440 MW (250 - 600) MW	From: BG00 Avg. 321 MW (300 - 350) MW	From: AL00 Avg. 238 MW (150 - 250) MW						
SE01	From: SE02 Avg. 3,300 MW (3,300 - 3,300) MW	From: FI00 Avg. 1,100 MW (1,100 - 1,100) MW	From: NON1 Avg. 672 MW (483 - 700) MW											
SE02	From: SE03 Avg. 7,300 MW (7,300 - 7,300) MW	From: SE01 Avg. 2,960 MW (2,700 - 3,300) MW	From: NOM1 Avg. 600 MW (600 - 600) MW	From: NON1 Avg. 147 MW (132 - 158) MW										
SE03	From: SE02 Avg. 6,106 MW (5,500 - 7,300) MW	From: NOS0 Avg. 2,017 MW (895 - 2,145) MW	From: SE04 Avg. 1,400 MW (800 - 2,000) MW	From: FI00 Avg. 883 MW (400 - 1,200) MW	From: DKW1 Avg. 715 MW (715 - 715) MW									
SE04	From: SE03 Avg. 2,681 MW (800 - 5,400) 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. 398 MW (0 - 600) MW									
SI00	From: HR00 Avg. 1,500 MW (1,500 - 1,500) MW	From: AT00 Avg. 950 MW (950 - 950) MW	From: ITN1 Avg. 649 MW (244 - 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. 484 MW (0 - 500) MW	From: UA01 Avg. 400 MW (400 - 400) MW										
TR00	From: BG00 Avg. 432 MW (432 - 432) MW	From: GR00 Avg. 216 MW (216 - 216) MW												
UA01	From: HU00 Avg. 450 MW (450 - 450) MW	From: SK00 Avg. 400 MW (400 - 400) MW												
UK00	From: FR00 Avg. 1,045 MW (1,000 - 2,000) MW	From: NL00 Avg. 1,000 MW (1,000 - 1,000) MW	From: NOS0 Avg. 976 MW (416 - 1,464) MW	From: BE00 Avg. 750 MW (750 - 750) MW	From: IE00 Avg. 500 MW (500 - 500) MW	From: UKNI Avg. 497 MW (0 - 500) MW								
UKNI	From: UK00 Avg. 497 MW (0 - 500) MW	From: IE00 Avg. 400 MW (400 - 400) MW												

Figure 24: Import capacity overview

Appendix 2: Additional information about the results

Loss of Load Expectation and other annual metrics

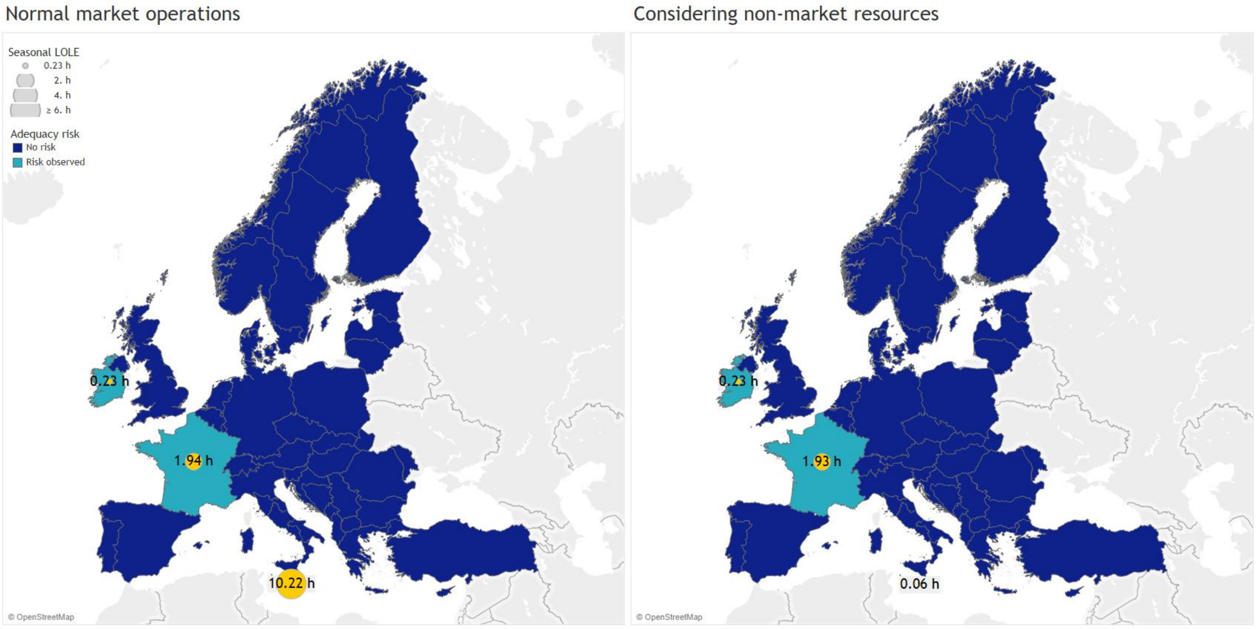

Figure 25: Seasonal LOLE results

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. The number of analysed Monte Carlo samples was 1360.

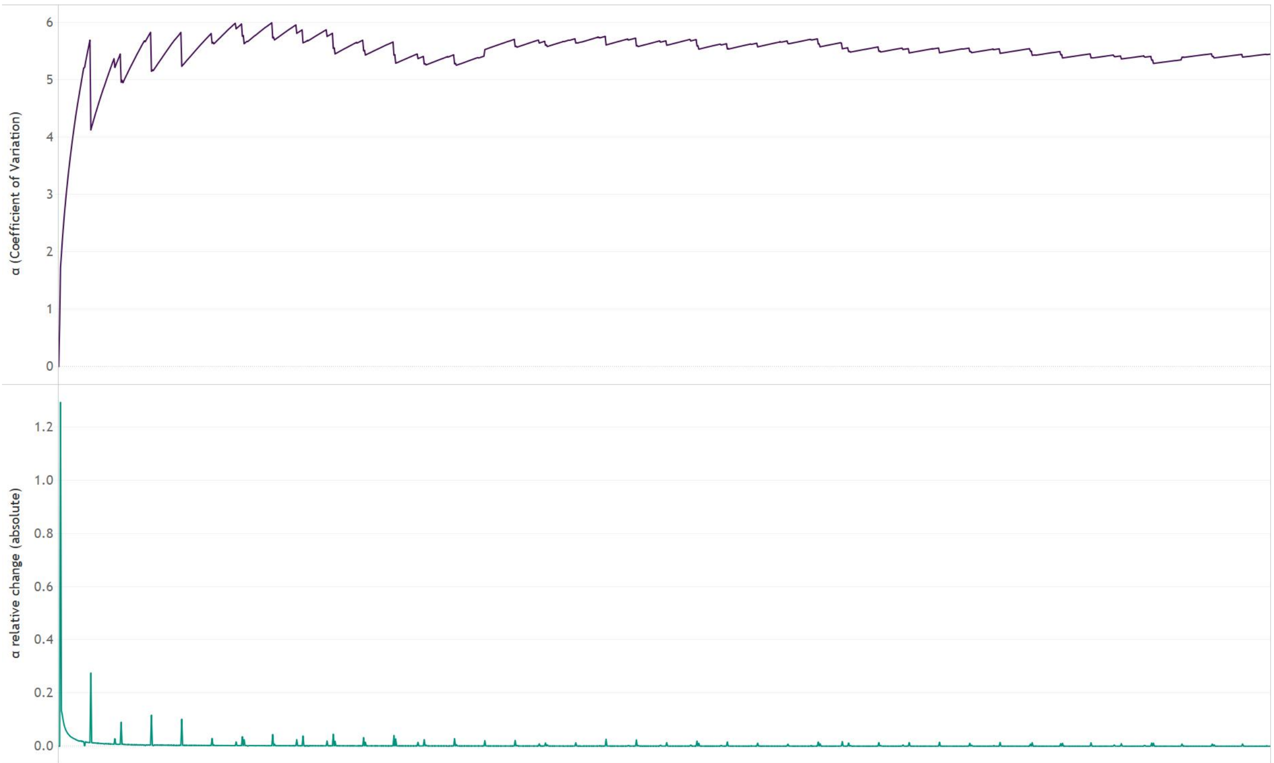

Figure 26: Convergence overview[22]

[22] The convergence overview shows that the seasonal assessment has a high accuracy level. The number of analysed Monte Carlo samples was 1360.