ACER

European Union Agency for the Cooperation of Energy Regulators

Security of EU electricity supply

October 2023

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Security of EU electricity supply

October 2023

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Executive Summary

1 In the aftermath of last year's energy crisis, and in view of another challenging winter, ACER publishes its second dedicated annual report in the field of security of electricity supply in Europe, focusing primarily on developments during 2022. The aim of the report is threefold. Firstly, it seeks to draw lessons from Member States' measures to tackle the energy crisis during the winter 2022/2023. It does so, focusing on security of supply, while acknowledging that these measures also aimed at preserving other key objectives such affordability[1]. Secondly, it monitors the progress of the implementation of the European regulatory framework on adequacy at national level. Thirdly, the report looks into currently implemented measures to enhance security of supply, such as capacity mechanisms, interruptibility schemes and other mechanisms. It zooms on two important elements for the design of capacity mechanisms: cross-border participation and the penalty regimes.

The common European framework and the integrated energy market sheltered Member States from the risks of the energy crisis

2 In 2022, the European Union faced an unprecedented energy crisis caused primarily by the steep reduction of Russian gas supplies. Simultaneously, the availability of nuclear power, particularly in France, and hydro resources were well below historical levels putting further pressure on the European power system. In the face of this exceptional, double supply shock, European Member States resorted to emergency measures to mitigate the consequences of high energy prices for European citizens and businesses and reduce the risks of supply disruptions. With respect to the latter, the response included various measures on both the demand and supply side, from energy savings campaigns towards citizens to bringing retired capacities back to the market, while also running very expensive gas generation. Ultimately, European citizens did not face any supply interruptions for a variety of reasons.

3 Looking back on how the energy crisis evolved, a key conclusion is that the integrated and highly interconnected European energy market was paramount to ensure security of energy supply. Russian gas supplies were quickly replaced thanks to the increased utilisation, adaptation and sharing of gas infrastructure across the Union. Similarly, in the electricity sector interconnectivity was key in overcoming the challenges stemming from uncertain gas supplies and the increased unavailability of nuclear and hydropower electricity generation in several Member States.

4 In addition, the common European framework that sets up the cooperation among institutions and stakeholders to ensure security of supply across the EU, was a crucial enabling factor for dealing with the crisis in an effective manner. Overall, the crisis confirmed that multi-level coordination and solid EU energy markets integration are essential for a secure electricity supply.

5 **To increase the security of supply level, ACER encourages Member States to accelerate and strengthen the integration of the European electricity market.** ACER also highlights the need **to further reinforce the inter-institutional and cross-border cooperation in the area of security of supply, e.g., by enhancing preparedness at regional level and by designing and activating emergency measures in a coordinated manner, where possible.**

Learning from the recent energy crisis: targeted, more balanced and coordinated measures should already be thought of for future similar situations.

6 The introduction of emergency measures by Member States to cushion the impact of high energy prices on consumers and to ensure security of supply was essential.

7 Any emergency necessarily calls for trade-offs and compromises. Nevertheless, some approaches outperform others. For example, measures intended to ensure affordability can distort market signals, and hinder the incentive of consumers to reduce or shift their consumption. Targeting such measures to the most vulnerable consumer categories might reduce this adverse effect.

1 Broader aspects of the energy crisis such as those related to retail markets and consumer protection, efficiency and demand response, energy transition and investment signals are analysed in ACER's assessment of emergency measures in electricity markets.

By contrast, some no-regret measures, such as incentivising energy efficiency measures and conservation, risk preparedness and the uptake of renewable energy sources, are more consistent with long-term policy targets and should be prioritised[2].

8 **Based on the experience from the crisis, a well-balanced and coordinated set of emergency measures should be formulated sufficiently in advance to be better prepared for future risks. National authorities should prioritise policies and measures that simultaneously contribute to the various policy objectives.**

The level of implementation of the adequacy framework varies across the EU and some Member States are lagging behind.

9 Setting a reliability standard is a necessary step for any robust decision-making regarding adequacy. It enables a Member State to decide whether measures are needed to ensure that resource adequacy risks remain within acceptable levels. For this reason, setting the reliability standard is mandatory for Member States implementing or intending to implement a capacity mechanism. So far, only eight Member States have reportedly calculated the reliability standard according to the framework. Two Member States that already have capacity mechanisms in place, i.e., Ireland and Poland, have not yet set a reliability standard based on the pan-European methodology[3].

10 Robust and consistent adequacy assessments, performed both at national and European level, are fundamental to evaluate security of supply risks and act, if necessary. Yet the implementation of the common European resource adequacy assessment (ERAA) methodology varies significantly across Member States. Some Member States undergo high-quality and comprehensive adequacy assessments, while some others apply oversimplified approaches that diverge substantially from the EU-wide ERAA methodology. Such uneven implementation at national level risks to trigger undesirable spillover effects. For example, overestimation of the missing capacity could lead to undue support of domestic resources, leaving resources in other Member states in an unfair disadvantage. On the other hand, underestimation could result in "freeriding" on other Member States that correctly calibrated their own adequacy needs.

11 **Member States should fully implement the adequacy framework as prescribed in the Electricity Regulation.** In particular, Member States relying on national resource adequacy assessments[4] as the basis to set up a capacity mechanism should ensure that such assessments abide by the Electricity Regulation and are based on the EU-wide methodology. Moreover, Member States should follow the EU-wide methodologies to estimate the reliability metrics; in particular, **Ireland and Poland, currently applying capacity mechanisms[5], should appropriately set the reliability standard, by following the relevant EU-wide methodology, as soon as possible.**

European-wide adequacy assessments are a key tool for decision-makers to assess security of electricity supply risks. More efforts to bring the ERAA up to standard are needed.

12 ENTSO-E prepares annually two types of assessments: the ERAA covering the next ten years, and separate European seasonal outlooks dedicated to the upcoming winter and summer periods. These assessments consider the whole European market in an integrated manner. Given the depth of interconnectivity within the EU, these assessments are essential to capture the interdependencies between Member States and the benefits of sharing resources between them. ACER's monitoring of the cross-zonal capacities made available to the market demonstrates there is still significant scope to increase these across the EU. Increasing cross-zonal capacities would have material benefits for security of supply across the Member States.

13 In particular, the ERAA aims at providing an objective basis for identifying electricity adequacy concerns in the medium and long-term and assess the need for any additional national measures to secure supplies, such as temporary capacity mechanisms. Therefore, a robust ERAA is particularly important.

2 For more on this topic see also ACER's assessment on the emergency measures in electricity markets.

3 I.e. the Methodology for calculating the reliability standard, as approved by ACER. To assess the progress with the implementation of this methodology, ACER has recently commissioned a study; the study will identify good practices and provide recommendations to support robust and unbiased setting of reliability standards.

4 Currently, in the absence of an approved ERAA, this is the only option available for Member States.

5 At the time of finalising this report, both countries were in the process of setting the reliability standard.

For the second year in a row, ACER decided not to approve the ERAA, i.e., ERAA 2022[6]. While ENTSO-E made several improvements following ACER's recommendations[7], ACER still identified considerable gaps regarding the consistency and robustness of the assessment.

14 Based on the implementation experience of the past two years, ACER and ENTSO-E continues to work closely together to achieve a robust European adequacy assessment in 2023. The focus this year is to ensure that the assessment properly considers the Member States' national energy and climate plans (NECP) and that implementation choices are followed through consistently in the different modules of the ERAA model. The aim is that the assessment delivers robust results without further increasing its complexity.

15 Concerning the seasonal outlooks, ACER acknowledges the improvements introduced by ENTSO-E by expanding the scope of the analysis and taking a more agile approach when conducting the assessment, in response to the uncertainties posed by Russia's invasion of Ukraine[8]. To further improve the assessment, ENTSO-E should ensure that the contribution of interconnection capacity to security of supply is properly assessed.

16 ACER finds that the enhanced cooperation among European stakeholders contributed to increase the quality and relevance of last year's seasonal outlooks. For example, the regular exchange of information among Member States at the Electricity Coordination Group helped to shape meaningful scenarios for decision-making. ACER finds that an increased level of engagement and exchange of information among Member States could further improve coordination when designing security of supply measures. Similarly, given the interaction between electricity and gas security of supply, the close coordination between ENTSO-E and the European Network of Transmission System Operators for Gas (ENTSOG) has become essential to the process. The two organisations should seek ways to enhance the synergies of their security of supply work-streams.

17 **ENTSO-E should improve the ERAA by addressing the implementation gaps identified by ACER. ENTSO-E should also improve the seasonal outlooks by accounting for cross-zonal capacities in a consistent manner across the EU and by applying flow-based modelling, where relevant.**

The costs of capacity mechanisms keep rising and most of the underlying capacity contracts are still allocated to fossil-fuel power plants.

18 To cope with adequacy concerns, Member States may implement capacity mechanisms. Such mechanisms, mainly market-wide capacity mechanisms and strategic reserves, continued to operate in eight Member States. The cost of existing capacity mechanisms in the EU has doubled since 2020 reaching 5.2 billion euros in 2022. It is forecast to increase by another 40% year-on-year in 2023 to 7.4 billion euros. In 2022, the cost of strategic reserves was several orders of magnitude lower than that of market-wide capacity mechanisms, on average.

19 The largest share of capacity providers receiving support from capacity mechanisms continued to be fossil-fuel power plants. In particular, long-term capacity contracts support mainly coal- and natural gas-fuelled generation capacity, at times, for 15 years or more in the future.

20 **ACER reiterates that Member States should analyse the impacts of long-term capacity contracts, including whether they risk locking-in dependence on high-carbon technologies, potentially hindering the transition to a low-carbon economy.**

21 Moreover, as the energy transition continues to drive the deployment of variable renewables, the need for flexible resources is expected to heavily increase this decade[9]. Currently, climate friendly flexibility resources - like storage and demand response - receive significantly lower, to marginal, support in existing capacity mechanisms that rather tend to remunerate legacy fossil resources. However, the latter are becoming less and less compatible with the long-term EU's climate goals.

6 See ACER Decision 04/2023 on ERAA 2022.

7 See ACER Decision 02/2022 on ERAA 2021.

8 See ACER Opinion 01/2023.

9 See for example, the Joint Research Centre's report on the flexibility requirements and the role of storage in future European power systems.

22 Furthermore, interconnectors are key to share flexible resources across borders and therefore to cover a relevant share of the needs for flexibility at national level; it is thus appropriate to assess the needs for flexibility and explore synergies at European level.

Non-domestic resources from other Member States are still unable to compete on equal footing with domestic capacity providers in capacity mechanisms.

23 In the same spirit, interconnectors allow to address resource adequacy in a more regional as opposed to a strictly national manner. The integrated electricity market, where needs and the means to serve them are approached in a broader geographical context, can bring substantial benefits to Europe. As demonstrated during last year's energy crisis, the integrated market was essential to strengthen security of supply across Member States and mitigate risks in a cost-efficient way.

24 To ensure a level playing field between resources based in different Member States, the Electricity Regulation introduced common rules to enable and govern the direct participation of foreign capacity providers located in other EU Member States in national capacity mechanisms. Member States had until December 2022 to implement this harmonised framework within their capacity mechanisms.

25 Up until the end of 2022, the implementation of these rules varied substantially across Member States' capacity mechanisms and is generally far from being finalised. Except for the Polish capacity mechanism, implementation of the framework for direct cross-border participation is either pending (Belgium, France and Ireland) or simplified (Italy) in the rest of the market-wide capacity mechanisms. Furthermore, there is scope to improve particular aspects of the implementation so far. For example, in Italy, the method to estimate the contribution of resources from other Member States to the national security of supply, diverges materially from the prescribed European methodology[10]. The implementation of the framework in Poland raises some concerns about the establishment of a level playing field between domestic and non-domestic resources.

26 **The responsible national authorities should implement direct cross-border participation in line with the EU-wide technical specifications as soon as possible. They should ensure that domestic capacity providers compete on an equal footing in capacity mechanisms with providers from other Member States and that the detailed rules, for example on obligations and remuneration, do not disadvantage one over the other. ACER also recommends that relevant national authorities monitor closely cross-border participation in capacity mechanisms, particularly in the early years of implementation, to identify whether the rules work as intended or any adjustments might be necessary.**

Existing penalty regimes in capacity mechanisms do not always provide appropriate incentives to guarantee delivery of the contracted service.

27 The key goal of capacity mechanisms is to ensure security of supply by rewarding resources to be available when the system is stressed. To achieve this, beneficiaries of capacity mechanisms failing to provide the service they have been contracted for, incur financial penalties. This incentivises beneficiaries to be available when needed, and to fulfil their obligations.

28 Capacity mechanisms in the EU apply heterogeneous penalties to incentivise capacity providers to deliver on their commitments. Often, the penalties applied to capacity providers do not accurately reflect the costs incurred by the system, and by extension consumers, when a beneficiary fails to comply with its obligation. This inconsistency applies both to the obligation of building new capacity (non-delivery penalties) and to the requirement for capacity providers to be available during system stress (non-performance penalties). Recent developments in Ireland, where new capacity failed to be commissioned on time and was ultimately cancelled, provide a case in point. This led to the deterioration of the security of supply outlook in the short- and medium-term, and the implementation of emergency actions that came with a significant cost tag for consumers. The costs are expected to be a multiple of the original capacity payments, and of the penalties faced by the non-commissioned assets. Notably, existing frameworks also include good practices, for example in relation to monitoring the availability of beneficiaries and commissioning of new resources. This proactive approach bolsters accountability of beneficiaries and can enable authorities to take timely mitigating actions (e.g., procure replacement capacity), if needed.

10 As described in the technical specifications for cross-border participation in capacity mechanisms.

29 **The national authorities responsible for the design of capacity mechanisms should ensure that the penalties applied in capacity mechanisms properly incentivise capacity providers to commission the contracted capacity in a timely manner.** Failure to do so can have significant negative implications for security of supply and the costs to consumers, extending beyond national borders. **National authorities should also ensure that the penalties properly incentivise capacity providers to be available at times of system stress and closely reflect the value placed by consumers on an uninterrupted service.** In other words, they should contribute significantly to recovering the costs incurred by the system. As it stands, beneficiaries do not always receive adequately strong signals to be available when the system needs them.

To cope with various security of supply risks, Member States are increasingly implementing a variety of measures that lie outside the adequacy framework. Such uncoordinated measures risk fragmenting the internal electricity market.

30 ACER's monitoring shows that Member States are increasingly introducing different measures to address security of supply risks, from operational security to adequacy and congestion related risks. These measures often target multiple purposes and include interruptibility schemes, and various types of reserves and ancillary services, among others. Unlike capacity mechanisms, however, and despite sometimes seeking to target resource adequacy, such measures according to ACER's understanding are not subject to a similar scrutiny process. This is particularly true for measures designed in such a way that they are not deemed State aid. As such, this may hamper the identification of adverse effects on neighbouring Member States and may undermine the internal electricity market.

31 By way of illustration, a variety of capacity reserves co-exist in Germany. These reserves serve different purposes but can also provide adequacy-related support, if necessary. Another example is Ireland that has recently procured emergency generation capacity, on top of the capacity procured through its capacity mechanism, to address resource adequacy concerns, alongside enhancing the system's stability and resilience. Also, Portugal and Spain have introduced new demand response measures for the provision of system services, including for addressing potential adequacy risks.

32 All in all, there seems to be a growing patchwork of costly interventions, often outside the adequacy framework, yet contributing, or being suitable, to safeguard adequacy. In ACER's view, this trend brings about considerable risks. Firstly, it may introduce the perception of an uneven playing field, since some mechanisms are subject to clear obligations and scrutiny, while others may come with fewer requirements. Secondly, it risks fragmenting the European internal market for electricity, e.g., if these mechanisms prevent the market from accessing competitive resources. Finally, it may lead to over procurement, due to the lack of a coordinated and transparent approach, to the detriment of end-consumers' bills and the functioning of the electricity market.

33 **ACER therefore sees the need to take action to address the aforementioned risks.** In ACER's understanding, one of the reasons that these heterogeneous measures proliferate is because Member States perceive the State Aid process (and underlying requirements from European legislation) for capacity mechanisms as lengthy and cumbersome. To address this concern, **a first, straightforward measure would be streamlining the process for the approval of capacity mechanisms under the adequacy framework and state aid rules.** This action does not require legislative changes, and only calls for further guidance by the relevant institutions. For example, the European Commission has consulted Member States on the possibility of an accelerated approval procedure for capacity mechanisms provided that certain conditions are met[11]. Similarly, ACER has consulted Member States on the possibility of streamlining the European resource adequacy assessment methodology, while ensuring its robustness is maintained[12]. ACER believes that these proposals are appropriate provided they aim at fast-tracking the administrative process without affecting the quality of the underlying assessments.

34 **A second measure would be the provision of guidance to facilitate the coherent and coordinated introduction of measures targeting adequacy by Member States. Such guidance would aim at providing more clarity on the type of measures that could be introduced to enhance resource adequacy and which ones should not.** For example, ACER is of the view that national authorities

11 See also European Commission's relevant presentation in the 38th European Electricity Regulatory Forum.

12 See also ACER's relevant presentation in the 38th European Electricity Regulatory Forum.

should not introduce additional ancillary services, if the main objective of such services is addressing resource adequacy concerns. Similarly, ancillary services should not be dimensioned based on resource adequacy needs. At the same time, ACER considers that multi-purpose tools could bring benefits by exploring synergies and thus lowering the costs to consumers (e.g., by utilising the same resources to meet different system needs, including adequacy). ACER sees a benefit in clarifying whether such multi-purpose tools fall under a certain EU regulatory framework[13]. Moreover, ACER reiterates that there would be benefits in coordinating the procurement of ancillary services where possible (e.g., for fast response frequency support). Such a coordination ensures a level playing field and reduces procurement costs.

35 Finally, an area for further attention are measures which pursue risk preparedness objectives (under the Risk Preparedness Regulation); objectives which are often linked to, but not identical to, the objectives pursued under the resource adequacy framework (under the Electricity Regulation). ACER recommends exploring the synergies between the two frameworks, i.e., the Electricity Regulation and the Risk Preparedness Regulation, informed inter alia by early lessons drawn from the energy crisis. Such synergies may in turn illustrate the utility or otherwise of further guidance on the types of measures that could be introduced under the latter framework.

13 E.g., the adequacy legal framework as far as capacity mechanisms are concerned.

Table 1: Implementation status indication of ACER`s adequacy related methodologies

Legal requirement	Reference	Status regarding applicable ACER methodology	Action/ Recommendation	Reference in the report
Value of Lost Load (VOLL) **Cost of New Entry (CONE)** **Reliability Standard (RS)**	Article 11 (VOLL) and articles 23 and 25 of the Electricity Regulation.	Member States apply the methodology gradually and in various ways. Not all Member States have yet set a reliability standard. Ireland and Poland are the only Member States with a capacity mechanism that have not a reliability standard in place after the adoption of the methodology.	Member States should follow the EU-wide methodologies to estimate the reliability metrics; in particular, Ireland and Poland should appropriately set the value of lost load and the reliability standard as soon as possible.	Chapter 3.1
European Resource Adequacy Assessment (ERAA)	Article 23 of the Electricity Regulation	There are still significant concerns regarding the consistency and robustness of the ERAA, primarily regarding input data reflecting the EU's Fit-for-55 objectives, and consideration of market revenues and cross-zonal capacities.	ENTSO-E should improve the ERAA by addressing the implementation gaps identified by ACER last year and by fully implementing the ERAA methodology by 2024.	Chapter 3.2.1
National resource adequacy assessments	Article 24 of the Electricity Regulation	Implementation of the ERAA methodology to assess adequacy at national level, diverges significantly across Member States.	Member States relying on national adequacy assessments as a basis to set up a capacity mechanism should ensure that such assessments are based on the EU-wide methodology.	Chapter 3.2.2
Seasonal and short-term adequacy assessments	Articles 8 and 9 of the Risk Preparedness Regulation	The outlooks are broadly in line with the methodology, albeit with some remaining implementation gaps, e.g., lack of flow-based modelling.	ENTSO-E should improve the seasonal outlooks by accounting for cross-zonal capacities in a consistent manner across the EU and by applying flow-based modelling.	Chapter 3.3.1
Cross-border participation in capacity mechanisms	Article 26 of the Electricity Regulation	In the absence of an approved ERAA, Regional Coordination Centres do not provide recommendations. Member States use different approaches when calculating the maximum entry capacity.	Member States should implement fully-fledged direct cross-border participation as soon as possible, including the methodologies envisaged in the technical specifications. Member States should ensure that non-domestic and domestic capacity providers compete on equal footing. Relevant national authorities to monitor closely cross-border participation in capacity mechanisms, particularly in the early years of implementation, to identify whether the rules work as intended or any adjustments might be necessary.	Chapter 5.2
Penalties in capacity mechanisms	Article 22(i) of the Electricity Regulation	Not applicable (no common methodology exists for this topic)	Member States should ensure that the penalties applied in capacity mechanisms incentivise providers to commission the underlying physical capacity in a timely manner. Such penalties should relate to the actual costs of replacing the non-delivered capacity. Member States should ensure that penalties incentivise beneficiaries to be available when needed and they should closely reflect the value placed by consumers on an uninterrupted service.	Chapter 5.3

List of acronyms

Acronym	Meaning
ACER	European Agency for the Cooperation of Energy Regulators
ACM	The Netherlands Authority for Consumers and Markets
ARENH	Accès Régulé à l'Electricité Nucléaire Historique (Regulated Access to Incumbent Nuclear Electricity)
BRELL	Belarus, Russia, Estonia, Latvia, and Lithuania
BRP	Balancing responsible party
CCGT	Combined cycle gas turbine
CEEAG	Guidelines on State aid for climate, environmental protection and energy
CEP	Clean energy for all Europeans package
CM	Capacity mechanism
CONE	Cost of new entry
CORP	Cost of renewal and prolongation
DR	Demand response
DSO	Distribution System Operator
EC	European Commission
ENS	Energy not served
ENTSO-E	European network of transmission system operators for electricity
ENTSOG	European network of transmission system operators for gas
ERAA	European resource adequacy assessment
ERSE	Energy Services Regulatory Authority (Portugal)
EU	European Union
EUE	Expected unserved energy
EUR	Euro
FSRU	Floating Storage Regasification Unit
GSE	Gestore dei Servizi Energetici (Italy)
GW	Gigawatt
GWh	Gigawatt hours
Hz	Hertz
ICE	Internal combustion engine
ICJ	International Court of Justice
ICS	Incident classification scale
I-SEM	Irish Single Energy Market
LNG	Liquefied natural gas
LOLE	Loss of load expected
LOLP	Loss of load probability
MMR	Market monitoring report
ms	milliseconds
MW	Megawatt
MWCB	Market wide central buyer
MW-DCO	Market wide de-centralised capacity obligation
MWh	Megawatt hour
NEBEF	The Block Exchange Notification of Demand Response in France

Acronym	Meaning
NRA	National Regulatory Authority
NRAA	National resource adequacy assessment
OCGT	Open cycle gas turbine
OM	Outage minutes
PAC	Pay-as-clear
PSE	Polskie Sieci Elektroenergetyczne (Polish TSO)
RCCs	Regional coordination centre
RES	Renewable energy source
RS	Reliability standard
RTE	French TSO
SAI	System adequacy index
SLR	Series loaded resonant
SME	Small and medium sized enterprises
SMS	Short message service
SNAM	Italian gas transmission company
SR	Strategic reserves
STA	Short-term adequacy assessment
STSAA	Short-term and seasonal adequacy assessments
SVK	Swedish TSO
TAP	Trans Adriatic Pipeline
TERNA	Italian TSO
TSO	Transmission system operator
UK	United Kingdom
UNSCR	United Nations Security Council Resolution
VOLL	Value of lost load
WACC	Weighted average cost of capital
WtA	Willingness to accept
WtP	Willingness to pay

1. Introduction

36 The Clean Energy for All Europeans Package (Clean Energy Package, CEP)[14] enhanced ACER's role in monitoring the electricity market. This includes the topic of security of electricity supply that the CEP explicitly mandates ACER to monitor[15]. In fulfilling this role, ACER publishes its second stand-alone monitoring report on the developments in the field of adequacy and security of electricity supply in Europe[16].

37 The report comes after an unprecedent energy crisis that inflicted radical changes to the sector. The energy price shock experienced last year, primarily due to the steep reduction of Russian gas supplies towards Europe, brought detrimental effects to the European citizens and businesses, forcing the EU Member States and the European Commission to undertake a series of mitigating measures.

38 Evidence from the gas market indicate that the situation regarding gas supply has been normalised this year, with prices gradually returning to early 2021 levels and gas storage facilities in the EU already reaching or even exceeding the 90% filling target[17]. The electricity sector seems also to gradually return to normality. Electricity prices return to pre-crisis levels, allowing Governments to withdraw most of the emergency measures adopted to cope with the impacts of the energy crisis.

39 At the same time, there are still some uncertainties regarding the security of the electricity supply in the following months. These relate mostly to the situation during the coming winter and the way it will affect the ability to fulfil the gas storage obligations in 2024. Apart from the weather-related demand during the winter period, there are increased uncertainties related to the developments regarding the war in Ukraine and any potential further reduction of Russian gas supplies[18], the global gas demand evolution, and the availability of electricity generation units.

40 In view of these risks, this report aims to draw conclusions and lessons learnt from the energy crisis, based on the experience in a number of Member States (Chapter 2). The report also examines the implementation of the adequacy framework. The latter is described in Box 1. The report focuses on the definition of the adequacy metrics[19] and the assessment of adequacy in the mid-, seasonal, and short-term (Chapter 0). Furthermore, the report provides updates on the developments concerning the measures used to cope with security of supply concerns, such as capacity mechanisms, interruptibility schemes and network reserves (Chapter 4). Finally, it investigates in detail two important design features of the existing capacity mechanisms in the EU: the cross-border participation and the penalty regimes (Chapter 5).

14 The Commission's Clean Energy for All Europeans legislative proposal covered energy efficiency, RES generation, the design of the electricity market, security of electricity supply and governance rules for the Energy Union. Relevant material along with the adopted directives and legislation are available here.

15 For example, see Article 18 of Regulation (EU) 2019/941 and Article 15 of Regulation (EU) 2019/942.

16 In this report, EU-27 refers to the 27 Member States after Brexit, i.e., after the UK left the EU on 31 January 2020. As a consequence of Brexit, ACER did not have access to all the UK-related data. Therefore, while UK remained an EU member in 2020, it is excluded from the scope of this MMR for the country-specific figures. EU-wide figures still include 28 Member States, unless specified otherwise. Several aspects of the report cover Norwegian and Swiss markets. For simplicity, the scope of the analysis is referred to as 'the EU' or 'Europe'. Norway enforces most of the EU energy legislation, including legislation on the internal energy market, and is included in the data reported in several sections of this report. Switzerland has been included in some parts of the wholesale sections on the basis of a voluntary commitment of the national regulatory authority (NRA). Consequently, the terms 'countries' and 'Member States' are used interchangeably throughout this report, depending on whether the particular section/graph also covers Norway or Switzerland or not. Several maps included in this report show Kosovo*. In this context the following statement applies: "This designation is without prejudice to positions on status, and is in line with UNSCR 1244 and the ICJ Advisory Opinion on the Kosovo declaration of independence".

17 Overall, gas storage facilities in the EU were 94% full on 21 September 2023 according to information from the Aggregated Gas Storage Inventory.

18 EU imports of Russian gas dropped from 48% in January 2021 to 8% in March 2023. More information on the developments in the gas wholesale market can be found in ACER's most recent relevant report.

19 As further described in Box 1, the adequacy metrics are the reliability standard, the value of loss load and the cost of new entry.

Box 1: The adequacy framework

The European adequacy framework is described in Chapter V of the Regulation (EU) 2019/943 on the internal market for electricity (Electricity Regulation) and Chapter II of Regulation (EU) 2019/941 on risk-preparedness in the electricity sector (Risk Preparedness Regulation).

The Electricity Regulations prescribes that each individual Member State sets its necessary level of security of electricity supply on the basis of a properly defined reliability standard. The calculation of the reliability standard uses an appropriate estimate of the value consumers place on uninterrupted electricity supply (the value of lost load or VOLL) and of the cost of commissioning additional resources to the system (the cost of new entry or CONE). The calculation of these adequacy metrics is based on a harmonised methodology.

Member States assess whether their market can deliver the required level of security of electricity supply based on a single European Resource Adequacy Assessment (ERAA). The ERAA is performed annually by the European Network of Transmission System Operators for electricity (ENTSO-E). ACER is responsible for approving the inputs, assumptions and results of the ERAA every year. Member States may complement the ERAA with national resource adequacy assessments. Both the ERAA and the national resource adequacy assessments are based on the same methodology.

In case Member States identify adequacy concerns, they first need to identify the root causes leading to these concerns, including any potential regulatory and market distortions. Consequently, Member States have to develop appropriate market reforms to eliminate the identified market root causes. If necessary, they may further introduce temporary and properly designed capacity mechanisms to cope with the remaining adequacy concerns.

The regulatory framework is complemented with a set of methodologies, approved by ACER. These are:

- the methodology for short-term and seasonal adequacy assessments focusing on assessing adequacy risks in the short-run i.e. from week ahead to six months ahead;
- the methodology setting reliability standard for adequacy based on the calculation of the value of lost load and the cost of new entry (VOLL/CONE/RS methodology);
- the methodology for the European resource adequacy assessment, (ERAA methodology) setting the framework to assess potential resource adequacy gaps across Europe for the next ten coming years; and
- the technical specifications for cross-border participation in capacity mechanisms (Technical Specifications) setting a framework allowing for participation of capacity providers in capacity mechanisms of other Member States.

State aid approval

National measures that provide financial support to individual sectors or market entities may be considered State aid, and, as such, they must be assessed and approved by the European Commission. On 18 February 2022, the European Commission published the revised guidelines on State aid for climate, environmental protection and energy (CEEAG), setting the criteria for its assessment. Security of supply measures such as capacity mechanisms, interruptibility schemes and measures to cope with local congestion issues need to abide to the CEEAG rules.

The CEEAG incorporates the relevant provisions of the Electricity Regulation, such as the principle of limiting market distortions inflicted by the measures. In addition, it requires from Member States to demonstrate the necessity of security of supply measures by means of a proper assessment and with reference to a properly defined reliability standard. Pursuant to the Electricity Regulation and the CEEAG, if Member States want to introduce measures targeting adequacy, such as capacity mechanisms, the identification of relevant concerns needs to be consistent with the latest ERAA. Member States may still demonstrate adequacy concerns and the need for measures via complementary national resource adequacy assessments.

2. Lessons learned during the energy crisis

41 In the aftermath of the pandemic, a series of events increased uncertainty, challenging the resilience of the European energy system. Most notable are the Russian invasion of Ukraine and the weaponisation of Russian energy supplies to the EU that followed it, the severe droughts across the continent and the higher-than-expected unavailability of nuclear generation. En route to winter 2022/2023, the drastic shift in the socioeconomic and geopolitical circumstances was experienced differently across Europe. Despite the unfavourable conditions, the targeted and coordinated efforts by the Member States and the European Commission to reduce electricity and gas consumption, combined with the mild weather, contributed to a relatively smooth course of the winter and a general lack of adequacy-related incidents.

42 This section seeks to draw lessons learnt from winter 2022/2023. The first part of the section summarises the measures taken by Member States to mitigate security of supply risks during this period. It builds up on the Inventory and Assessment of such measures published by ACER in March and July 2023, respectively. The latter, deals in more detail with aspects of the energy crisis such as those related to retail markets and consumer protection, efficiency and demand response, energy transition and investment signals[20]. The second part relies on additional information on practical experience provided by NRAs from sixteen Member States[21], which allowed ACER to understand the unique circumstances each of these Member States faced during the winter. The information collected focuses on the main adequacy risks forecast and how they materialised, the most effective measures taken to mitigate these expected risks, and the main lessons drawn. The effective practices implemented by the various Member States exemplifiy the resilience of the European power system and serves as useful knowledge for decision-makers across the continent.

2.1. Overview of security of supply related emergency measures

43 The sharp rise of the natural gas prices at the beginning of the summer of 2021, drifting electricity and oil prices too, prompted Member States to react by adopting a series of measures with the aim of protecting consumers and the economy. The persistence of the emergency status and the prospects for a lasting economic crisis, led the European Commission to issue a toolbox for actions and support measures in October 2021. The toolbox indicated short- and medium-term initiatives that EU countries could implement in line with the then prevailing regulatory framework.

44 After the Russian invasion in Ukraine, what was initially an economic problem, turned into a major security of energy supply crisis threatening the European citizens and economy. In response to the sharp reduction of Russian gas supplies, Member States introduced measures to increase the resilience of their energy system against the emerging risks. As an immediate response to these new challenges, the European Commission outlined (8 March 2022) and consequently detailed (18 May 2022) the REPowerEU plan affirming the intention of the EU Member States to phase out their dependency on Russian fossil fuels through a comprehensive set of actions.

45 Furthermore, additional challenges for the EU's energy supply arose. For example, the unexpectedly low availability of nuclear plants in France[22] and the severe and prolonged droughts across big parts of the continent increased the risks foreseen for the winter. In response, Member States and the European Commission sped up their efforts to tackle the two imminent problems, security of supply and high energy prices. In the months following the Russian invasion, the European Commission produced a number of legislative proposals accompanied by guidelines that steered and coordinated Member States' response to the energy emergency[23]. All Member States reacted to the new challenges by extending and adjusting already adopted measures or designing new support schemes in an effort to

20 Useful insights on the energy crisis can also be found in the recently published Energy Retail and Consumer Protection volume of the 2023 Market Monitoring Report.

21 This includes information provided by the NRAs of Austria, the Czech Republic, Denmark, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Latvia, the Netherlands, Poland, Portugal, Spain and Sweden.

22 In September 2022, 27 GW of nuclear capacity out of the installed 61 GW were available. While some of the reasons for the unavailability were known in advance and linked to planned maintenance and fuel rod replacement, the unexpected corrosion problems detected on several reactors in the end of 2021 pushed availability to an unprecedentedly low level. In September, the deficit in available nuclear capacity compared to a normal year was estimated at 15 GW. See also footnote 26.

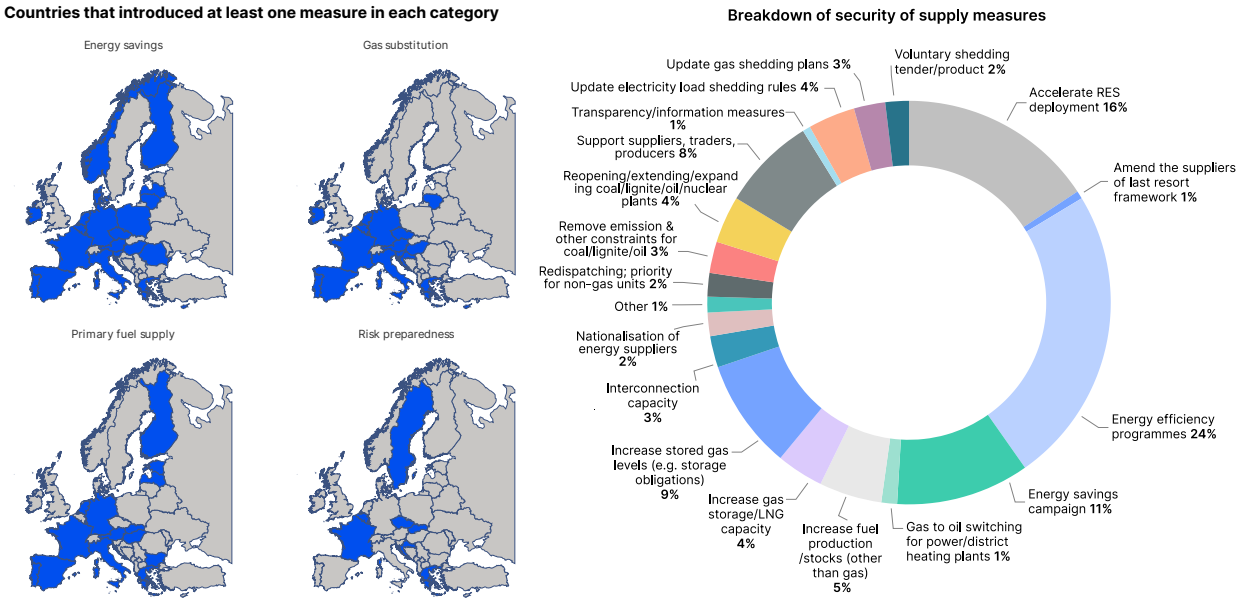
23 An overview of the European Commission's work on tackling the energy crisis can be found here.

ensure security of supply in the short-term and beyond, and to support the economy, often focusing on the most affected sectors and vulnerable citizens.

46 In March 2023, ACER published an inventory[24] of measures adopted by EU Member States throughout this energy crisis, along with a high-level analysis providing insights about the policies adopted. Following the publication of the inventory, ACER proceeded with an assessment of the measures in electricity markets, publishing its findings in July 2023.

47 The inventory reveals that nearly one third of the 439 recorded measures focus on security of supply, the rest aiming to improve the affordability of energy consumption. Figure 1 shows the breakdown of these measures into specific categories, and their geographical application. Three measures stood out in increasing the readiness of the European system in light of an uncertain winter ahead: gas storage obligations, rules enabling gas substitution, and increased solidarity. Regarding the time horizon of the measures, nearly half of the measures that target security of supply have a long-term impact, despite having been labelled as emergency measures. In particular, measures that target energy efficiency, reducing fossil fuel use, and/or accelerating the deployment of renewables contribute to the transition toward climate neutrality in line with the European Green Deal. Conversely, some temporary measures, necessary to cope with the uncertainties of a prolonged energy crisis, such as the temporary removal or reduction of electricity generation emission limits, the postponement of the phase-out of coal and lignite power plants or the switching of fuel from gas to oil, may have negative environmental and climate effects. In general, several emergency measures that were introduced involve complex trade-offs between different policy objectives. It is therefore important to prioritise emergency measures that contribute to the security of supply but at the same time do not compromise long-term policy goals.

Figure 1: Countries that implemented measures targeting security of supply (left, per category of measures) and breakdown of the entire set of measures (right)



Source: ACER's inventory of emergency measures.

2.2. Lessons Learnt from winter 2022/2023

48 The interruption of Russian gas supply to the EU constituted a common threat for the security of supply of all Member States, regardless of their individual dependency on Russian gas, as spillover effects would have impacts on a wider scale. However, each Member State faced specific challenges depending on the individual characteristics and conditions of its energy system. To draw lessons from the energy crisis, taking into account these specificities, ACER asked NRAs to provide country-specific context on the winter 2022/2023 situation. The NRAs' contribution describes the risks that were initially foreseen for the winter, the level of materialisation of these risks, the main measures that played a role

24 The inventory was updated in July 2023.

to increase preparedness and mitigate those risks, and, lastly, the lessons that can be drawn from this experience. The good practices implemented in various Member States can serve as examples of the resilience of the power system and prove useful to decision-makers in the future. Annex II provides a table summarising the information for each Member State along with the more detailed input from the relevant NRAs.

2.2.1. Expected and realised risks

49 The increased challenges regarding the security of energy supply prompted an uncertain and bleak outlook for most Member States for winter 2022/2023. High natural gas prices and supply shortages were the biggest risks identified by Member States directly impacting tthe ability of the energy sector ability to safeguard the continuous supply of electricity. Around 40% of Europe's gas supplies came from Russia prior to the invasion of Ukraine. Even Member States that were less directly affected by the natural gas supply interruptions, such as Denmark, were alarmed by the possibility of proliferation of a potential supply deficit in neighbouring countries or the spillover effects of potential bankruptcies in the sector.

50 A number of other risks were also recognised some particularly linked to the impacts of climate change[25]. Low precipitation during the spring and summer resulted in severe drought across large parts of the continent. Critically low hydropower availability was reportedly experienced in the Czech Republic, Denmark, France, Germany, Italy, Portugal, Spain, and Sweden, leading to the adoption of precautious measures. In Portugal the severity of the situation forced the Government to implement measures that prevented the use of some reservoirs for electricity generation. Dried-out rivers affected the cooling and operation of thermal power plants e.g. leading to reduced operation of nuclear power plants in France), and caused difficulties and cost increases in the transportation of coal (e.g., in Denmark and Germany), making it necessary to reroute supply chains (for example, by using the railway where possible). The lower contribution of hydro and nuclear power plants resulted in natural gas units operating more often, putting a further strain on the European energy supply at a time when the need to save gas and refill gas storage facilities was critical.

51 In addition to the reduced hydro resources, the unexpected unavailability of thermal electricity generation units across Europe further exacerbated the situation. The unavailability of up to 65% of the French nuclear power fleet due to a combination of factors (including unexpected corrosion issues) was the most prominent and impactful of these incidents[26]. Furthermore, Finland experienced a delay in the commissioning of the Olkiluoto 3 nuclear power unit for several months, at the same time, imports from Russia were cut-off[27]. In neighbouring Sweden the 1,130 MW Ringhals 4 nuclear power plant was also unavailable during the winter period. Similarly, Ireland's winter outlook suggested a high probability of reduced power generation due to the increased rate of forced outages that could have been detrimental in the case of periods of high demand coupled with low wind. Portugal and Spain also experienced severe unavailability of thermal power plants just before the beginning of the winter period[28].

52 When assessing system adequacy for the critical winter months both on the European and national levels, the aforementioned challenges resulted in higher-than-normal expected risks. The level of the risks depended heavily on the underlying conditions (e.g., weather conditions, demand reduction, gas availability). ENTSO-E's winter outlook showed a higher-than-usual probability of adequacy issues for several countries, including Finland, France, and Sweden. National assessments also indicated numerous risks. In Denmark and Sweden, the main concern was low Norwegian hydro reserves. In Finland, France and Spain, a high level of expected thermal plant outages was expected in combination with low hydro reserves. In Greece, the main risk was the possibility of gas supply disruptions. The

25 According to Copernicus Climate Change Services' annual European State of the Climate (ESOTC) report, the key findings show that Europe experienced the second hottest year and the hottest summer in 2022, with the majority of countries experiencing severe droughts due to the low rainfall and warm temperatures.

26 According to the analysis performed by the French TSO, the unavailability was a result of a combination of factors, including planned maintenance works, postponed maintenance works due to the COVID-19 pandemic, unexpected corrosion issues, as well as other reasons. On average in 2022, out of 61.4 GW installed, 27.3 GW were unavailable (corresponding to 44.5%). On 28 August 2022, the unavailability reached a historical high, with 39.7 GW of nuclear capacity unavailable (65%). This unavailability also contributed to the historically high day-ahead electricity prices, which reached its peak in August 2022 (see ACER's dashboard on EU wholesale market trends). For reference, in 2021, French nuclear power plants generated 361 TWh of electricity, representing around 13% of the EU's total electricity generation. In 2022, French nuclear generation was only 279 TWh (-23%).

27 In 2021, the electricity import capacity from Russia (1,400 MW) represented roughly 10% of the typical peak load and covered approximately 10% of electricity consumption in Finland.

28 In Spain, the unavailable capacity during autumn 2022 reached up to 10GW, almost a third of the estimated peak load for the period.

dependency on gas for electricity generation was also a concern in Italy, which was affected by intense droughts too. Droughts were also the main risk identified in Portugal, where autumn assessments for the winter forecast up to 10 weeks in which supply interruptions could be expected.

53 Fortunately, the risks foreseen in the months leading to winter 2022/2023 did not result in any actual involuntary demand disconnections, largely due to the mild course of the winter and the consumers' response to increased electricity prices, which resulted in a lower electricity consumption[29]. For instance, electricity consumption in France during the winter was on average 8-9%[30] below the historical average, while larger reductions were reported in some other Member States[31]. Additionally, higher levels of precipitation during the autumn and early winter months enabled the recovery of hydropower stocks. For example, the Portuguese dams filling level rose from approximately 43% in October 2022 to 90% in January 2023, and the ability to produce electricity rose to 53% more than the average year. Moreover, electricity production from renewable sources reached high levels in some areas, such as the Czech Republic, Finland or Greece, offering valuable support to the electricity system.

54 Evidently, the winter was not without challenges in all Member States. In the Nordics, full operation of the Olkiluoto 3 nuclear power plant was delayed until after the winter, after Russian electricity and gas imports to Finland had already been suspended earlier in the year. However, even during the coldest days of December, Finland's electricity demand was lower than usual, as end consumers actively responded to high prices and awareness campaigns. Similarly, in neighbouring Sweden, the middle of December proved the most challenging with very low temperatures, unavailability of the Ringhals 4 nuclear power plant, low hydro reservoir levels in neighbouring Norway, and the aforementioned situation in Finland. Nevertheless, Sweden overcame the difficulty with a combination of demand response due to public awareness and record-high electricity imports from its neighbours. Public awareness campaigns were also put in place in Ireland, where the winter adequacy assessment showed major risks and that imports of electricity and gas could decrease substantially. Record peak demand was nevertheless experienced during a cold snap in December 2022, but the grid weathered through without system alerts or emergencies.

2.2.2. Main preventive measures

55 Apart from the generally mild weather conditions and the prevailing high electricity prices that led to a reduction of electricity consumption, Member States' efforts to mitigate the risks also contributed to the positive course of the winter. Some of the adopted measures were similar across Member States, while others were specific to each individual Member State.

56 As already illustrated in Section 2.1, all Member States implemented nationwide energy-saving awareness campaigns that instigated a further reaction from the demand side. These campaigns were often complemented by energy saving measures in public buildings and lighting[32]. While the quantification of the impact of the campaigns is difficult, many NRAs indicated that the measure was effective and contributed to the observed reduction of electricity consumption. For example, in Finland the voluntary demand response by households and commercial end-users during the most critical periods of the winter was played a key role in preventing interruptions.

57 The measures taken by Member States to mitigate the impacts of high energy prices, included the provision of, sometimes extensive and mostly not targeted, financial support to consumers. The risk of such measures with regard to security of supply, is that they reduce the incentives for demand reduction and might lead to a vicious circle of overconsumption[33]. At the same time, evidence from some Member States with more mature electricity markets, suggest that consumers reaction to prices was significant and effective. For instance, in Finland some companies shifted their industrial processes

29 See IEA's publication on the drivers of the changes in electricity demand in 2022.

30 The figure is calculated by the French TSO "at normal temperatures" and hence refers to structural demand reduction attributable to factors other than weather conditions. The total (gross) demand reduction, including the impact of milder temperatures, was 11%.

31 See also information in Box 2 about the reduction in total gross electricity consumption in Member States.

32 For instance, the Finnish Government launched an information campaign in October 2022, with the purpose of getting over 95% of Finnish households to save energy and reduce their consumption by 5% during peak hours. The Danish campaign incorporated mandatory public measures such as lowering public building temperatures to 19°C, with exceptions to, e.g., hospitals and retirement homes. Similarly, the Irish distribution system operator, ESB Networks, introduced the 'Beat the Peak' campaign to raise awareness by providing early notification to consumers for upcoming peak demand events via SMS and encouraging them to reduce electricity consumption periods during these stress periods.

33 See also the conclusions of ACER's assessment of emergency measures in electricity markets.

from day to night to benefit from lower electricity prices, while in Denmark there was an observable shift of consumption away from peak hours and at the same time a switch towards dynamic contracts, possibly to take advantage of the short-term price volatility[34].

58 At the same time, specific measures were implemented for enabling and enhancing demand response. For example, Austria introduced a peak shaving scheme, while Portugal and Spain launched similar measures remunerating demand response for being available to provide balancing services35.In Ireland, the NRA collaborated with the transmission and distribution system operators to design and implement enhanced demand control procedures for large energy users that could be deployed in an emergency situation if required.

59 Some Member States put particular emphasis in increasing their preparedness to cope with the potential threats. In a number of Member States, a continuous monitoring of the adequacy situation was put in place. For example, the French TSO expanded the scope of its winter adequacy assessment, with a deeper analysis and complemented it with monthly updates, and weekly reviews of the evolution of French power consumption. Also, preparedness checks, intensified cooperation and exchange of information between relevant authorities and market players, as well as emergency exercises to test and enhance readiness were deployed. For example, Finland conducted test runs with variable power outputs, while in Ireland a large multi-stakeholder emergency test exercise took place. Similarly, the Netherlands focused on the preparedness of stakeholders also by strengthening communication channels, the applicability and appropriateness of procedures and the continuous monitoring of the actual situation.

60 Favourable weather conditions did not only result in lower consumption on the demand side. They also enabled renewable energy generation (including wind, solar but also recovered hydro-reservoirs) to make an important contribution to the supply side. During the energy crisis, there was an increase in self-generation from renewable sources in some Member States, often driven by relevant support schemes. Latvia, for example, recorded a sixfold increase in the number of microgeneration sites: from 2,000 in 2021 to 12,000 in 2022. The Czech Republic started promoting decentralised renewable generation and energy communities in the autumn of 2022.

61 To enhance the resilience of the electricity system, several governments resorted to postponing the phase out of nuclear and coal power. In Germany, almost 8 GW of coal capacity in reserves was brought back to the market and the lifetime of another 1.2 GW was extended. At the same time, the nuclear phase-out was postponed for several months so that the nuclear power plants could support the system throughout winter. Similarly, in Greece the phase out of the lignite power plants was postponed. In a bid to enable increased operation of coal units, France, Greece, and Spain halted or raised the level of emission limitations[36].

62 Additional measures were implemented to tackle Member State-specific risks, some of which were often underestimated in the past. Examples of these measures were the prioritisation of coal transportation by rail in Germany to cope with reduced water levels in main rivers and the development of plans for replenishing secondary fuel supplies to gas generators in Ireland.

2.2.3. Conclusions

63 From a security of supply perspective, the course of the winter was relatively smooth. This was mainly the result of the four following factors: the favourable weather conditions (mainly in terms of temperatures but also in terms of electricity generation from renewable energy sources), the integrated and highly interconnected European energy market, the preparedness measures put in place by Member States (either individually or collectively), and the response of market participants and consumers to price signals and awareness campaigns.

64 Looking back on how the energy crisis evolved, one main conclusion is that the integrated and highly interconnected European energy market was crucial in ensuring the collective security of energy supply. Russian gas supplies were quickly replaced thanks to the increased utilisation and sharing of infrastructure

34 See Figure 22 in Annex II.

35 More details on the Portuguese and Spanish schemes are provided in Box 5.

36 For example, in France, a cap is in place that limits the operation of coal-fired power plants emitting more than 0.55 tCO2e/MWh) at 700 hours/year. For the period between March 2022 to March 2023, the cap was raised to 3,000 hours/year.

across the Union. Whether it was through additional gas supply via alternative pipelines, an increase of LNG imports via the numerous European terminals, or common targets for demand reduction, all Member States managed to face the winter with full gas storages[37] and no further interruptions in the supply chain. The extra gas that reached the continent through the various entry points was smoothly distributed where needed thanks to the available infrastructure.

65 Similarly, the Internal Electricity Market ensured the utilisation of the interconnections in the most efficient way to direct surplus generation where it was most needed. An illustrative example of the importance of interconnections is France – traditionally an exporter of electricity – where the high imports of electricity from neighbours were key in tackling the tight supply situation. Germany accelerated a scheduled 32% increase of the minimum offered capacity for cross-border electricity trade in order to assist the European system during the winter[38]. It was also the increased support from neighbouring systems that enabled Sweden and Finland to prevent power interruptions from occurring during the encountered cold spells and unexpected outages last December[39]. ACER's recently published report on cross zonal capacities highlights the importance of maximising the availability of cross-zonal capacity in ensuring security of electricity supply in the EU. It shows how restrictions of cross-zonal capacity may impact welfare and demonstrates the need to lift the constraints that prevent the full utilisation of the network for cross-zonal exchanges.

66 The European framework with its established multilevel structure for cooperation and coordination among the main institutions and stakeholders provided the necessary basis for an increase in collective preparedness. Exchange of information, frequent coordination meetings of Member State representatives involving NRAs and TSOs, weekly coordination meetings among system operators complemented the enhanced monitoring through European, regional, and national adequacy assessments. This enhanced cooperation at working level largely supported the efforts at the highest administrative level (i.e., national Governments and the European Council, Parliament and Commission) to tackle the crisis in the most effective way.

67 Certain measures, such as awareness and energy saving campaigns, were widely implemented across the EU. At the same time, individual circumstances often asked for tailor-made solutions.

68 Some no-regret measures, like interventions in the public sector to reduce energy demand and measures to increase energy efficiency or increase the uptake of renewable energy sources, are more consistent with long-term energy and environmental policy targets and an enduring security of supply.

69 While the need of Member States to introduce measures to protect consumers from the exposure to high energy prices was legitimate, these measures, if not properly designed, tend to hinder the incentive of consumers to reduce or shift consumption, as they distort market signals. A well-balanced approach is hence necessary, where protection of consumers does not run counter to security of supply.

70 Enhanced monitoring coupled with well-coordinated institutions is key to ensuring a high level of readiness at national level, as reflected, for instance, in the case of Ireland and the Netherlands. Facilitating communication and coordination among actors along with preventive testing and checking of the effectiveness of the procedures and the readiness of the involved actors increases the chances for better decision making and minimises the risk of failures in the event that risk materialise.

71 Going forward, the effects of climate change need to be thoroughly taken into account in the overall preparedness analysis. As extreme weather such as prolonged droughts and heat waves become more frequent and severe, their impacts on the energy system need to be properly considered, mainly in the context of the national Risk Preparedness Plans[40].

37 Cooperation was also crucial to reach the mandatory storage target and increase security of supply levels, for instance through commonly procured floating storage and regasification units as in the case of Finland and Lithuania, or shared storage space as in the case of Greece with Bulgaria and Italy.

38 As per the announcement of the German TSOs in the single allocation platform (JAO), "to strengthen the European cross-border electricity trading in these exceptional times", the minimum remaining available margin for the Core day-ahead capacity calculation increased from 31% to 40.8% already from mid November 2022, while initially scheduled for 1 January 2023.

39 See the relevant country descriptions in Annex II.

40 According to Regulation 2019/941 on the risk preparedness in the electricity sector, every Member State needs to develop risk preparedness plans describing the measures to prevent, prepare for, and mitigate crises in the electricity sector. The public version of these plans can be found here.

2.3. Case studies: The role of demand response during the winter

72 This section provides an overview of how demand response contributed to security of supply during winter 2022/2023 in France and Finland based on input from the relevant NRAs. The case studies are described in more detail in Annex III.

2.3.1. The French case study

73 This section describes how demand response helped to "keep the lights on in winter 2022/2023" in France. It distinguishes between implicit and explicit demand response. Implicit demand response refers to consumers' consumption reaction in response to the end user prices or other rewards, while explicit demand response normally refers to the demand reduction that participates in the wholesale electricity market and gets rewarded for its services.

2.3.1.1. Implicit demand response

74 A significant electricity demand reduction was observed in France during winter 2022/2023. Consumption was on average 8% to 9% lower than the historical average before 2019, excluding the effects of weather[41]. The industrial sector was the frontrunner, with a drop of around 10% to 12% compared to 2021. The services and residential sectors reached a reduction of around 6% to 7% compared to 2021. It is not clear to what extent this decrease was a result of the high electricity prices alone, or whether collective efforts in response to efficiency and awareness campaigns also contributed. Electricity suppliers have to declare implicit demand response for the purpose of the capacity mechanism. The corresponding volume of declared implicit demand response increased for years 2022/2023, compared to previous years, reaching around 700 MW in 2023, while it was constantly declining during the previous period, between 2017 and2022.

2.3.1.2. Explicit demand response

75 In France, the availability of explicit demand response can be remunerated via the capacity mechanism[42] and through the procurement of balancing reserves. In addition, activation of demand response is remunerated via the electricity market in the day-ahead, intraday[43] and balancing timeframes. The participation of demand response to the capacity mechanism was continuously increasing since 2017, reaching 3.1 GW in 2022[44]. Participation in the day-ahead and intraday wholesale market has increased significantly already during winter 2021/2022 driven by the strained state of the French energy system. The increase continued in autumn and early winter of 2022/2023 where activated monthly volumes exceeded 40 GWh, more than four times more compared to years prior to 2021. As the security of supply situation in France improved after January 2023, the activation of demand response returned to pre-crisis levels.

2.3.2. The Finnish case study

76 Typically, in Finland electricity demand peaks occur during the coldest days of winter and are strongly dependent on the duration of the coldest periods. The preliminary analysis suggests that consumers' reaction played an important role in securing supplies in Finland during the winter 2022/2023. During this period, consumption was significantly below its typical levels, even during the coldest days. In particular, electricity demand was approximately 15% or 2 GW lower during the peak load hours compared to demand during the same temperatures in previous years. On a monthly basis, electricity demand was also 5-10% lower than the previous winter. These trends can be attributed to several factors, such as the milder overall winter, consumers' reaction to the energy-saving campaign and shift of consumption

41 See also footnote 30.

42 Under the French capacity mechanism, all resources including demand response receive a capacity payment for their availability in addition to the revenues received on the wholesale market when the electricity is produced or when consumption is reduced. Demand response capacities are procured via specific auctions and via auctions of long-term contracts for new demand response capacities.

43 This is enabled via the so-called NEBEF mechanism.

44 This figure refers to certified capacity and is preliminary since certified capacity for demand response is only known three years after the delivery period in March.

patterns (e.g., shift of demand for heating to off-peak hours).

77 Moreover, a survey[45] conducted by the Finish Energy Authority before the winter 2022/2023, showed that interest in demand response increased in Finland during the fall of 2022. Based on the survey, some 60% of the participants were planning to either increase or initiate demand response participation, indicating an additional potential capacity of nearly 400 MW.

Box 2: Review of measures to reduce electricity demand

Council Regulation (EU) 2022/1854 on an emergency intervention to address high energy prices (the Emergency Regulation) introduced an indicative target aimed at reducing total electricity demand by 10% in comparison to the average consumption of the same months of 2017 and 2018. Moreover, it imposed a mandatory target to reduce demand in peak hours by 5% compared to initial demand forecasts, from 1 December 2022 to 31 March 2023. Member States had the freedom to select which measures were most suitable for their circumstances. Below is an overview of the findings of the European Commission's report reviewing the interventions applied by Member States, with a focus on those targeting demand reduction. The findings of the report are in line the information provided in ACER publications on the topic.

Overall, the majority of Member States implemented awareness campaigns and other energy-saving measures such as setting targets to decrease the heating temperature in public buildings. Nineteen Member States reported administering specific policies to reduce electricity demand at peak hours. Five of them introduced competitive bidding schemes for this purpose. Three Member States have enforced demand reduction measures on specific consumer categories.

The measures that Member States introduced to address high energy prices contributed to mitigating the impact to consumers, albeit with a public finance burden. Since such measures may have an adverse effect on security of supply, by lowering the incentives to reduce demand, the Emergency Regulation requires that any public intervention in the retail market should preserve an incentive to reduce electricity demand. A limited number of Member States introduced specific provisions in the adopted schemes to limit the adverse effect on demand response.

Member States reported a decrease in total electricity consumption ranging between 0.5% and 15% in December 2022. At the same time, all Member States reportedly succeeded in reducing demand during peak hours by at least 5%.

In its electricity market design proposal, the European Commission included demand reduction measures such as the enabling of a peak shaving product and further promoted the use of demand response to cover the system's flexibility needs. In the relevant public consultation stakeholder were largely against the introduction of permanent demand reduction requirements in times of a crisis. In view of these elements and the fact that the new network code on demand response is under development, the European Commission decided against the prolongation of the targets for demand reduction.

45 The survey is available in Finnish here.

3. Implementation of the adequacy framework

78 The European adequacy framework is described in the Electricity Regulation and in the Risk Preparedness Regulation. The Electricity Regulations sets the rules for establishing the cost-efficient level of security of electricity supply and for assessing resource adequacy in the medium-to-long term (up to ten years). It also defines the actions a Member State should follow when it identifies adequacy concerns, including the potential introduction of properly designed capacity mechanisms. The Risk Preparedness Regulation prescribes the assessment of adequacy risks in the short-term, i.e., from day-ahead up to six months ahead, and is, in that respect, more suited to deal with crisis management situations.

79 The regulatory framework is complemented with a set of methodologies, approved by ACER. These set the rules for establishing the reliability standard, including the calculation of the value of lost load (VOLL) and the cost of new entry (CONE)[46], for assessing adequacy in various timeframes and for the participation of foreign capacity providers in capacity mechanisms.

80 This section discusses the implementation of the adequacy framework across the EU. It first presents the progress of Member States in calculating the adequacy metrics (section 3.1) and the developments with regards to the European and national resource adequacy assessments (section 3.2). Finally, it provides an overview of the seasonal and short-term adequacy assessments in 2022 (section 3.3).

3.1. Adequacy metrics

81 There has been little progress since last year's publication of the monitoring report on the security of electricity supply in 2021 (2021 SOS monitoring report) with regard to the calculation of the VOLL, the CONE, and the reliability standard in the Member States. Table 10 in Annex I presents the current status of the adequacy metrics in the Member States.

82 In 2022 the Belgian authorities updated the calculations of the VOLL, the CONE and, consequently, the reliability standard, following commitments set out in the European Commission's Decision approving the new capacity mechanism[47]. The VOLL estimate for Belgium is now 12,832 euros/MWh, down from 17,340 euros/MWh. A further update of the fixed CONE for demand response to 30,000 euros/MW/year (from 45,000 euros/MW/year previously) resulted in the same reliability standard of 3 hours of loss of load expectation (LOLE)[48].

83 In Ireland, the Single Electricity Market (SEM)[49] Committee updated the CONE values to be used both for the calculation of the reliability standard and for the auctions of the capacity mechanism. The CONE value for the purpose of calculating the reliability standard is now 116,000 euros/MW/year (from 96,420 euros/MW/year previously)[50]. The calculation of the VOLL estimate and the reliability standard is ongoing. Similarly, the Polish NRA has published the VOLL (17,700 euros/MWh) and CONE calculations in March 2023[51], while the decision on the reliability standard by the Ministry is still pending. This makes Ireland and Poland the only Member States implementing a capacity mechanism that have not defined a reliability standard after the publication of the relevant methodology, as required by the Electricity Regulation[52].

84 As noted in the 2021 SOS monitoring report, Member States implemented the EU-wide methodology for the calculation of the value of lost load, the cost of new entry and the reliability standard ((the VOLL/CONE/RS methodology) in a non-uniform manner. As certain choices, or a combination of them, could significantly impact the outcome of the calculations, ACER has initiated a study to review the implementation practices of the Member States. The objective of that study is to identify the key implementation components affecting the results of the adequacy metrics and propose ways to facilitate

46 Together, the reliability standard, VOLL and CONE are referred to as adequacy metrics in this report. An explanation of the relationship between the metrics is illustrated in Box 2 of the 2021 SOS monitoring report.

47 See recital 28 of Commission Decision C(2021) 6431 final.

48 The decision on the new VOLL can be found here, on the new CONE here and on the reliability standard here.

49 SEM is the wholesale electricity market for the island of Ireland, i.e. Ireland and Northern Ireland.

50 Both values refer to the derated capacity of open cycle gas turbines in Ireland.

51 For more information on VOLL see public announcements here. Data on CONE can be found here.

52 Articles 11 and 25 of the Electricity Regulation.

the implementation of the VOLL/CONE/RS methodology in a way that reduces biases and improves the quality of the results. ACER aims to publish the results of the study in the second quarter of 2024.

3.2. Resource adequacy assessments

85 The European regulatory framework prescribes that assessments of adequacy should be performed for different time horizons. The Electricity Regulation establishes the European resource adequacy assessment (ERAA) looking ten years ahead and sets the rules for similar national assessments. The purpose of the resource adequacy assessments is to identify potential resource adequacy concerns and provide an objective basis for assessing the need for additional national measures. This section looks into the implementation of the European and national resource adequacy assessments in 2022 (sub-sections 3.2.1 and 3.2.2 respectively).

3.2.1. European resource adequacy assessment

86 According to the Electricity Regulation, ENTSO-E has to perform the ERAA annually , following the ERAA methodology. ACER is responsible for approving or amending the input assumptions (including scenarios and sensitivities) and ultimately the results of the ERAA[53].

87 For the second time in a row, ACER decided not to approve the ERAA[54]. While ENTSO-E has made a number of significant improvements, following ACER's initial recommendations reflected in the Decision for ERAA 2021, ACER found there were still significant concerns regarding the robustness and consistency of the assessment.

88 ACER's decision provided further recommendations intended as guidance for ENTSO-E to ensure a successful implementation. These concern primarily the use of reliable and transparent input data (in particular scenario assumptions reflecting the EU's Fit-for-55 objectives) and the consistent and effective implementation of the methodological framework (in particular the robust consideration of market revenues and cross-zonal capacities).

3.2.2. National resource adequacy assessments

89 While ERAA is the main tool for assessing mid- to long-term resource adequacy, Member States may complement the ERAA by performing national resource adequacy assessments that are based on the ERAA methodology. As shown in Table 11 in Annex I, twenty-two out of twenty-three Member States, for which information was available, perform a national resourse adequacy assessment with varying frequency[55]. However, not all of these assessments qualify as national resource adequacy assessments as per the Electricity Regulation[56].

90 In 2022, eleven Member States concluded the resourse adequacy assessment of their system, while another two assessments were still ongoing at the time information was being collected for this report. In six out of the eleven cases, the assessments indicated potential adequacy concerns, as the resulted risks of loss of load were higher than the established reliability standards[57]. Figure 2 shows whether the most recent adequacy assessments (i.e., conducted either in 2022 or in 2021 in the absence of the former) indicate potential adequacy concerns in any of the next ten years.

53 Article 23(7) of the Electricity Regulation.

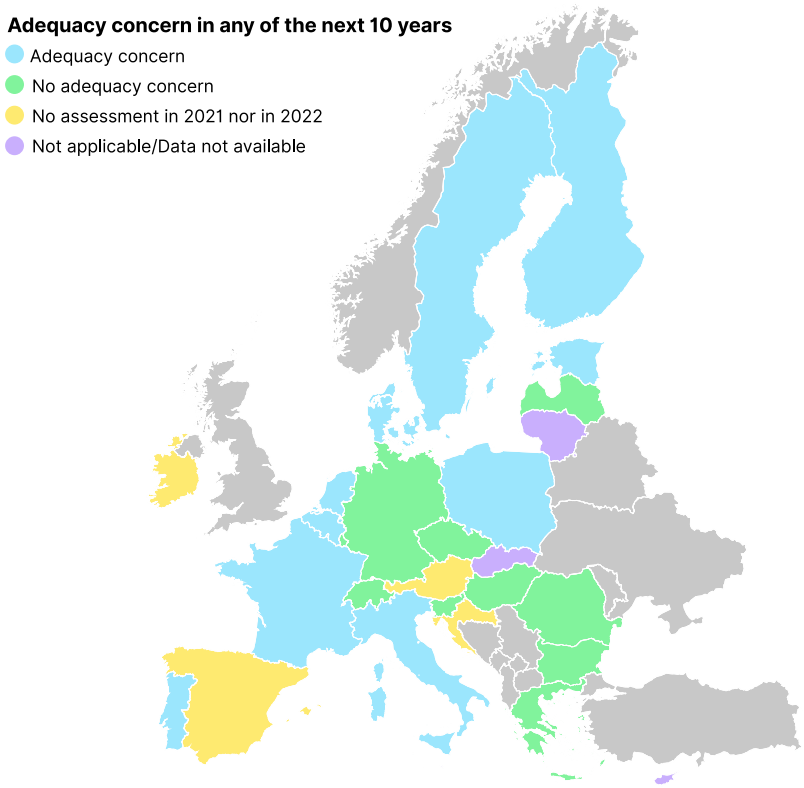
54 ACER Decision 4/2023.

55 Information collected from 25 NRAs shows that only in Austria, a national resource adequacy assessment is not performed regularly. An enhanced national legal basis for a national assessment is currently under consideration by the Austrian government. Some Member States combine these assessments with the ten-year network development plans or rely largely on ERAA results.

56 The Electricity Regulation prescribes that Member States shall monitor the resource adequacy based on results of the ERAA, and may complement the ERAA with national assessments that shall apply the same methodological requirements (Articles 20(1) and 24(1)). Member States may use the national assessments to justify adequacy concerns that would allow the conclusions of contracts in existing capacity mechanisms or the introduction of a new capacity mechanism. ACER understands that it is in these cases only that national assessment shall apply the ERAA methodology. In all other cases, and since there is no obligation for the national assessments, the national assessment does not have to comply with the requirement to apply the ERAA methodology, although the later would ensure a high level of accuracy and robustness.

57 According to the ERAA methodology, an adequacy concern is identified – for a given target year and modelled zone – if the estimated loss of load expectation (LOLE) by the resource adequacy assessment is higher than the target set by the reliability standard, calculated as per the VOLL/CONE/RS methodology.

Figure 2: Adequacy concern in Member States in any of the next ten years indicated by the national resource adequacy assessment performed in 2021 or 2022



Source: ACER based on information from NRAs

Note: The figure shows information stemming from mid-/long-term national adequacy assessments, even if they are not performed for the purposes laid out in the Electricity Regulation (i.e., complementing the ERAA and justifying a capacity mechanism). Information on Belgium, Hungary, and Poland refer to the results of 2021 assessments. In Croatia, the Government is entitled to issue an annual report on security of supply for previous calendar year with projection for next 10 years based on annual reports issued by TSO and DSO on which NRA gives its opinion. Cyprus is exempted from adequacy-related provisions pursuant to Article 64(2) of the Electricity Regulation. Estonia relies on the ERAA for its adequacy assessment. In Hungary the TSO is obliged by law to include a study on the mid- and long-term adequacy in the annual network development plan, approved by the NRA. In Ireland the TSOs are currently producing an "All-Island Generation Capacity Statement" that indicated extensive deficit of generation capacity in the mid-term, yet they are also preparing for a national resource adequacy assessment from 2024 onward. Latvia uses primarily the ERAA for assessing the national resource adequacy (see annual statement for 2021 here). Similarly, in Lithuania the bi-annual ten-year network development plan (TYNDP) report includes an adequacy analysis based on the ERAA results and a national resource adequacy assessment may be performed only if there is a need to analyse additional scenarios. There is no consensus among Lithuanian authorities on whether the adequacy assessment can be considered as a national resource adequacy assessment in line with the Electricity Regulation. There is also no approved reliability standard in Lithuania since 1 January 2022. In Luxemburg the Government issues an adequacy and security of supply report that is not based on primary calculations and simulations but instead analyses information from other assessments (e.g. the 2022 report used, inter alia, information from the ERAA, the Pentalateral resource adequacy assessment and the 2021 German resource adequacy assessment). In Slovenia, the TSO published an adequacy assessment in the ten-year network development plan report, using primarily ERAA results, and including a simple assessment of capacity development for different scenarios, that resulted in no concerns. In Spain, no national resource adequacy assessment has been published so far.

91 According to the Electricity Regulation[58] the national resource adequacy assessments shall be based on the ERAA methodology. ACER collected high level information on the main aspects of the ERAA methodology as described in the Electricity Regulation[59]. Table 12 summarises this information. Important features, like the probabilistic calculations and the regional scope of the assessment, seem to be largely deployed. At the same time, other characteristics, such as the inclusion of an economic evaluation of market entries and exits of resources and flow-based market coupling, are still not implemented in a number of assessments. In all seventeen reported cases the assessments include alternative scenarios and/or sensitivities.

92 The methodological requirements for the national resource adequacy assessments are particularly

58 Article 24(1) of the Electricity Regulation.

59 Article 23(5) of the Electricity Regulation.

important for Member States that have in place or intend to introduce a capacity mechanism. In this cases, the national assessments may complement ERAA to justify new capacity contracts[60] or the need of the capacity mechanism in the first place[61]. As depicted in Table 12, six out of the eight Member States implementing a capacity mechanism[62] perform a national assessment regularly, reportedly incorporating most of the main methodological features[63]. Ireland and Poland have not implemented a national resource adequacy assessment based on the ERAA methodology[64].

3.3. Seasonal and short-term adequacy assessments

93 The Risk Preparedness Regulation sets the framework for the short-term adequacy assessments, used to detect possible adequacy-related problems in shorter timeframes, namely seasonal adequacy assessments (up to six months ahead) and week-ahead to at least day-ahead adequacy assessments. These assessments use the latest available information regarding demand for electricity and availability of resources, including weather dependent renewable energy sources. They focus on identifying potential adequacy concerns, signalling the need for the development of mitigation measures.

94 The section discusses the European seasonal adequacy assessment performed by ENTSO-E (sub-section 3.3.1) and the short-term, rolling seven-days-ahead assessments performed by the regional coordination centres (RCCs) (sub-section 3.3.2).

3.3.1. European seasonal adequacy assessments

95 The European seasonal adequacy assessments, or seasonal outlooks, performed by ENTSO-E, investigate the security of supply ahead of each winter and summer period. Considering the unique context of last year, ENTSO-E showed flexibility and readiness to address implementation challenges and an extended scope of the assessments. Moreover, ENTSO-E engaged in enhanced cross-border cooperation at the European level and supported and ensured coordination at the regional level, while also supporting the TSOs that conducted regular national studies[65].

96 Despite the advancement of the seasonal outlooks the assessments need also to be further improved to properly consider the contribution of interconnection capacity to security of supply. In particular, the implementation of flow-based modelling still lags behind.

97 The summer 2022 outlook revealed limited risks in islands (Crete, Cyprus, Malta) linked to higher demand expectation, in Greece under extremely adverse conditions (high electricity demand combined with low resource availability), as well as in Ireland and Denmark due to planned outages of network and generation, but only in worst-case operational conditions (high electricity consumption combined with low renewable generation and numerous generators being on unplanned outage). The summer outlook suggested that all the risks however could be addressed by non-market measures or adaptation of maintenance planning.

98 The winter 2022/2023 outlook identified higher adequacy risks compared to regular winter periods. Apart from Malta and Cyprus, where risks often appear in the seasonal assessments due to the isolated character of their systems, the outlook detected higher than usual risks in Finland, France and Sweden, due to the foreseen unavailability of nuclear power plants. In addition, the assessment of a combination of stress factors regarding coal supply limitations, prolonged nuclear unavailability and failure to reduce demand resulted in high risks, indicating the need for enhanced monitoring of these factors. In response to the uncertainty caused by the unstable gas supply during 2022, ENTSO-E evaluated the dependency of the European electricity system on natural gas, reaffirming its high level in all scenarios.

60 Article 21(6) of the Electricity Regulation.

61 Article 21(4) of the Electricity Regulation.

62 See Section 4.1.1 for more details on the status of capacity mechanisms.

63 ACER did not examine in depth the level of compliance of the actual implementation of the national resource adequacy assessments with the Electricity Regulation or the ERAA methodology.

64 In Ireland the TSOs published a generation capacity assessment for the years 2021-2030 and they are currently working to implement a national resource adequacy assessment according to the requirements of the Electricity Regulation by 2024.

65 Already since spring 2022, there were enhanced coordination efforts. At the European level the European Commission initiated frequent coordination meetings of the Electricity Coordination Group, including joint coordination meetings with the Gas Coordination group. Enhanced trilateral (European Commission, ACER, ENTSO-E) interaction for the development of the winter outlook scenarios also took place. Weekly operational coordination between TSOs and RCCs to enable fast communication and alignment were also established.

99 The experience from last year's requirements for an enhanced scope of the seasonal adequacy assessments provides an opportunity to reflect on the need to make some of the new features a permanent part of the process and introduce further improvements.

100 ACER finds that enhanced coordination and cooperation between European stakeholders in the context of last year's seasonal outlooks process proved to be extremely valuable for increasing the quality of assessment, identifying new needs early on, setting up the assumptions for the examined scenarios, and ensuring data are up-to-date, of good quality and widely accepted by the market. In this respect the Electricity Coordination Group's active role in the process is crucial and should be maintained and further developed. Similarly, the close coordination between ENTSO-E and the European Network of Transmission System Operators for Gas (ENTSO-G) has become an essential part of the process and the two organisations should seek ways to enhance the synergies of their various security of supply workstreams.

3.3.2. Short term adequacy assessments

101 In 2022, the daily, seven-days-ahead short-term adequacy assessments performed by the Regional Coordination Centres (RCCs) in cooperation with ENTSO-E, indicated only one incident on April 4 in France. Mitigating measures included the increase of generation and of cross-border capacity[66]. While no load shedding took place, eventually, stressed condition of the system resulted in a day-ahead price of over 2,700 euros/MWh for two hours[67]. This was enough to trigger an increase in the harmonised maximum clearing price for the single day-ahead coupling (SDAC) from 3,000 euros/MWh to 4,000 euros/MWh, affecting all of the European single electricity market[68].

66 The French NRA, CRE, published a report analysing the incident in detail. The report can be found here.

67 The average day-ahead market price for that day in France was 548 euros/MWh.

68 According to ACER Decision 04/2017, valid at the time of the incident,".. the harmonised maximum clearing price for SDAC shall be increased by 1,000 EUR/MWh in the event that the clearing price exceeds a value of 60 percent of the harmonised maximum clearing price for SDAC in at least one market time unit in a day in an individual bidding zone or in multiple bidding zones". The isolated character of the incident led the Nominated Electricity Market Operators (NEMOs) to propose an amendment to the Decision. Following the formal procedural acts ACER issued Decisions 01/2023 and 02/2023 amending the former Decisions on the harmonised maximum and minimum clearing price methodology for the single day-ahead and intraday coupling, respectively.

4. Security of supply measures

102 Member States are required to monitor resource adequacy for their territory through the ERAA and may complement this assessment with a national one[69]. When these assessments indicate resource adequacy concerns[70], Member States must first identify any potential regulatory or market distortions[71] that create or exacerbate these concerns. To remedy the distortions or market failures, the Member States must develop a reform plan outlining the scope and timeline of measures[72]. If adequacy concerns remain, Member States may implement temporary capacity mechanisms. In this case, they need first to evaluate whether a capacity mechanism in the form of a strategic reserve is capable of addressing the identified resource adequacy concerns. Only where this is not the case can a Member State implement a different type of capacity mechanism[73].

103 This chapter discusses measures that Member States implement to tackle structural security of supply issues. While it largely focuses on capacity mechanisms (section 4.1), it also covers other measures that may be used to address security of supply issues. These measures include interruptibility schemes (section 4.2.1), and network reserves (section 4.2.2).

4.1. Capacity mechanisms

104 A capacity mechanism is a temporary measure introduced by Member States to remunerate capacity resources (e.g., generators, demand-response or storage units) for security of supply services. Capacity resources receive payments to be available to generate electricity when the system needs them; these revenues are on top of any revenues from the wholesale electricity market. Based on the Electricity Regulation, a Member State can introduce or maintain a capacity mechanism only if it has identified a resource adequacy concern. While capacity mechanisms are national support mechanisms, they must be, in principle, open to cross-border participation.

4.1.1. Status of capacity mechanisms

105 There are eight EU Member States with active capacity mechanisms: Belgium, Finland, France, Germany, Ireland (SEM), Italy, Poland, and Sweden. Three of them (Finland, Germany, and Sweden) have strategic reserves in place, while the five other Member States maintain market-wide capacity mechanisms. Spain and Portugal do not have an active capacity mechanism in place, but some long-term legacy contracts (targeted capacity payments) still apply[74]. Figure 3 shows the status of capacity mechanisms in the EU.

69 See footnote 56.

70 As per Article 8 of the ERAA methodology, an adequacy concern is identified by comparing the resulting adequacy indicator (LOLE) of the assessment for the reference case scenario with the reliability standard defined according to the VOLL/CONE/RS methodology.

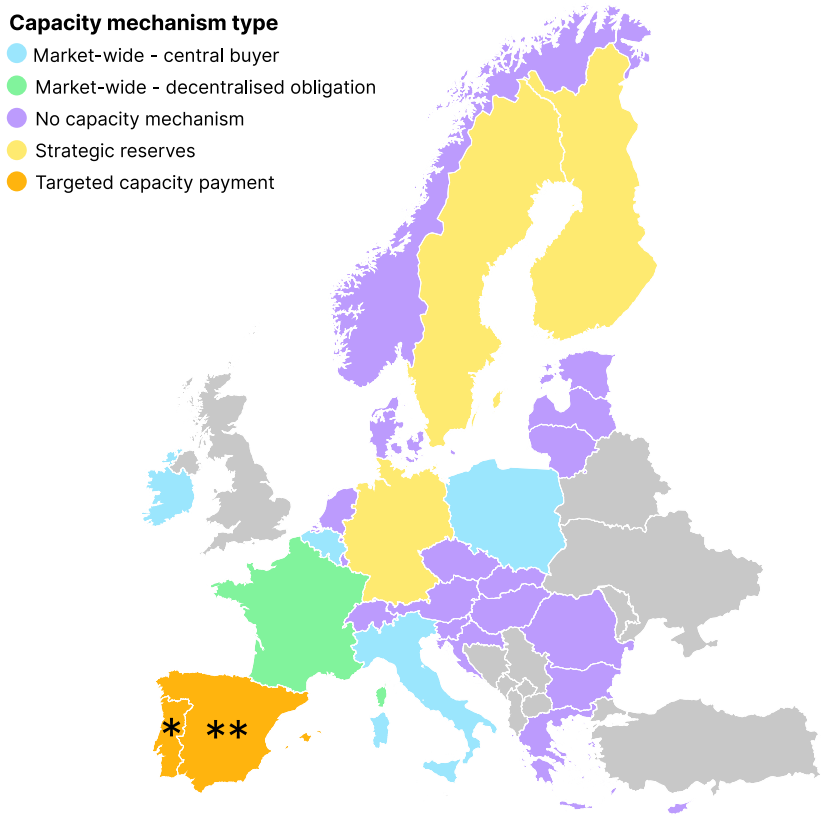
71 Among such distortions are e.g. the presence of price caps and an inefficient pricing of balancing energy, as well as, notably, inadequate interconnection capacity and a failure to fully enable demand side elasticity.

72 The timeline for adopting measures to eliminate market distortions is defined in the published national implementation plan. Information on the implementation plans can be found here.

73 Article 21(3) of the Electricity Regulation.

74 The status of capacity mechanisms in Spain and Portugal is further described in the Note under Figure 3.

Figure 3: Status of capacity mechanisms in the EU — 2022



Source: ACER based on NRA data.

Note: In France, a complementary scheme with capacity auctions targeting demand response has also been in place since 2018. In Portugal, a targeted capacity mechanism was introduced in 2017, and was revoked in 2018, but some capacity payments are still allocated to some hydro power plants due to "legacy" contracts. In Spain**, the capacity mechanism used to comprise "investment incentives" and "availability payments". The availability payments were removed in June 2018, and investment incentive payments apply only to generation capacity installed before 2016.*

106 Some developments regarding the status of national capacity mechanisms occurred in 2022. In Finland, the strategic reserve scheme expired in July 2022 and was replaced by a new one. The first auction of the new scheme took place in summer 2022 and awarded no capacity (nevertheless, the capacity that participated at the auction remained available in the energy market). In Italy, delivery started in the new market-wide capacity mechanism that replaced the previous scheme, which was active until 2021. Results[75] of recent auctions[76] in the Member States' capacity mechanisms are discussed in Box 3.

75 The auction results can be accessed online (see weblinks for Belgium, Finland, France, Germany, Ireland, Italy, and Poland).

76 Normally auctions of capacity mechanisms take place some years ahead of the delivery year. In the rest of the report auctions are characterised as T-4, T-1 etc with T denoting the delivery year, i.e. T-4 refers to auctions held four years prior to the delivery year.

Box 3: Results of auctions concluded in Member States' capacity mechanisms in 2022

In Belgium, the second auction of the new capacity mechanism (approved in 2021) took place in October 2022. The four years ahead (T-4) auction for delivery in 2026/27 resulted in no awarded capacity. The capacity requirement was fulfilled by the capacity contracted for the same period at the previous auction, the extended operation of two nuclear reactors, and existing capacity, some of which confirmed its availability during the delivery period but chose not to participate in the T-4 auction. This existing capacity will be able to participate in the year-ahead (T-1) auction for delivery in the same period.

In Finland, only one bid was submitted in the first auction (in October 2022) of the new strategic reserve. The bid was deemed inadmissible by the operator of the auction due to non-compliance with the national legislation. The capacity corresponding to the non-awarded bid continued to participate in the energy market. The low participation in the auction is partly explained by stricter requirements for participation of gas power plants in the strategic reserve, implemented in the context of the shortage of natural gas.

In France, unavailability of a substantial share of nuclear power plants impacted the EU energy landscape in general. As nuclear availability is not expected to reach the usual levels before 2024, the decrease in the volume offered on the capacity market led to an increase in auction prices. While from 2018 to 2021 prices in T-1 auctions were in the range of 20,000–30,000 euros/MW, prices increased to more than 40,000 euros/MW in all six T-1 auctions that took place in 2022. The latest of these auctions (and the most important in terms of volume) reached the price cap of 60,000 euros/MW. Prices in T-2 auctions for 2024 were lower and close to the historical levels, suggesting that the market expects greater capacity availability going forward. In addition to the auctions for delivery in the future, auctions for delivery years 2019, 2021 and 2022 also took place in 2022 (the French capacity market enables participants to adjust their positions after capacity delivery).

In Ireland, auctions for delivery in 2024/25 and 2025/26 took place in 2022. The T-3 auction for delivery in 2024/25 (initially planned for 2021 but actually taking place in January 2022) reached a record price of 147,000 euros/MW (equal to the price cap). There was an acute need to procure additional capacity for the delivery period in question, as the bulk of capacity contracted in the T-4 auction in 2019 failed to be commissioned on time. The topic of the incentives in the cases of non-delivery or non-performance in Member States' capacity mechanisms is discussed in more detail in Section 5.3 of this report. The auction for delivery in 2025/26 cleared at 46,000 euros/MW, back in the historical price range.

In Italy, the auction calendar is not pre-determined. Instead, auctions take place when the national authorities deem them necessary. In 2022, an auction took place for delivery in 2024 and awarded 42 GW of capacity. The auction cleared at the price cap – 33,000 euros/MW for existing capacity and 70,000 euros/MW for new capacity.

In Poland, the main (T-5) auction for delivery in 2027 procured 5.4 GW of capacity at a price of just under 87,000 euros/MW. The price level was similar in the 2021 auction for delivery in 2026 but contrasts starkly with the prices seen in the 2019 and 2020 auctions (55,000 and 37,000 euros/MW respectively). Additional (T-1) auctions are organised on a quarterly basis (i.e., four such auctions took place in 2022 for delivery in the four quarters of 2023). Prices varied between 41 and 78 thousand euros per MW, and capacity procured ranged from around 0.4 GW to 1.3 GW.

In 2022, no auction took place in Germany and Sweden. In Germany, capacity in the strategic reserve is procured for two years – the last auction took place in 2021 and the next auction is expected to take place in December 2023. In Sweden, production capacity was last procured in 2017 (for delivery up to 2024/25) under contracts of the capacity mechanism that was in place at the time.

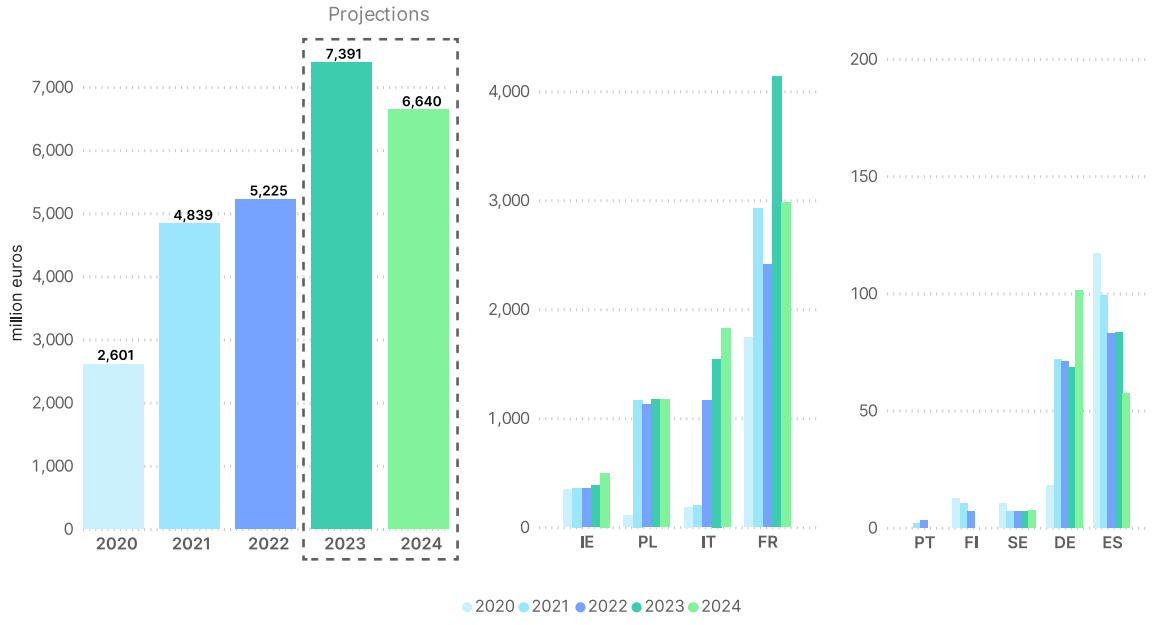
107 All capacity mechanisms discussed in this chapter have been approved by the European Commission under State Aid rules[77], with the exception of the Swedish strategic reserve, where a single capacity contract was signed in 2017 and runs until 2025[78]. Some additional Member States are considering implementing a capacity mechanism in the future[79], while France is considering overhauling its existing capacity mechanism[80].

4.1.2. Costs of capacity mechanisms

108 This section discusses the costs of capacity mechanisms. The Member States' capacity mechanisms are financed by the users of the electricity system (for example by end users through network tariffs or levies, or by suppliers or balance responsible parties)[81]. The costs are analysed per delivery year, both aggregated in the EU, as well as per Member State. Additional insights are shown by normalising the costs of the capacity mechanism – over the capacity procured and over the national electricity demand.

109 Figure 4 shows the costs of capacity mechanisms per delivery year. In absolute terms, the total costs of capacity mechanisms increased in 2022 and 2023. The total payments for delivery of capacity in 2022 amounted to more than 5.2 billion euros per year, up from 4.8 billion in 2021. In 2023, costs are projected to increase by another 40% year-on-year, reaching 7.4 billion euros. This is largely due to higher 2023 costs of the French and Italian capacity mechanisms. For 2024, the cost values shown are indicative, as the results of any T-1 auctions taking place in 2023 are not included in the cost projections for 2024[82].

Figure 4: Incurred and projected costs to finance capacity mechanisms in the EU-27 (left) and per Member State (centre and right) — 2020–2024 (million euros)



Source: ACER calculations based on data provided by NRAs.

Note 1: NRAs report costs in nominal terms and no adjustment to consider inflation is performed by ACER.

Note 2: In Belgium, payments within the new capacity mechanism start with winter 2025/2026, as per the four year ahead (T-4) auction in 2021. The overall costs for France are an approximation considering that all capacity certificates are valued at the market reference price (PRM). A significant share (which varies year-on-year) of the capacity certificates is implicitly valued through the "Accès Régulé à l'Electricité Nucléaire Historique" (ARENH) mechanism, a scheme that enables suppliers to purchase electricity from nuclear generators at a regulated price. Therefore, the actual costs for France are dependent on the reference used to value the capacity

77 Most recently, the Finnish strategic reserve was approved in October 2022.

78 The contract included an extension option, which was called in 2019.

For example, the implementation of a strategic reserve has been called for by the Estonian TSO.

80 France's current capacity mechanism is approved until 2026. Discussions are taking place in France regarding a new capacity mechanism that would apply in 2026 and beyond (see e.g. the French TSO's consultation on the future outlook of the electricity system).

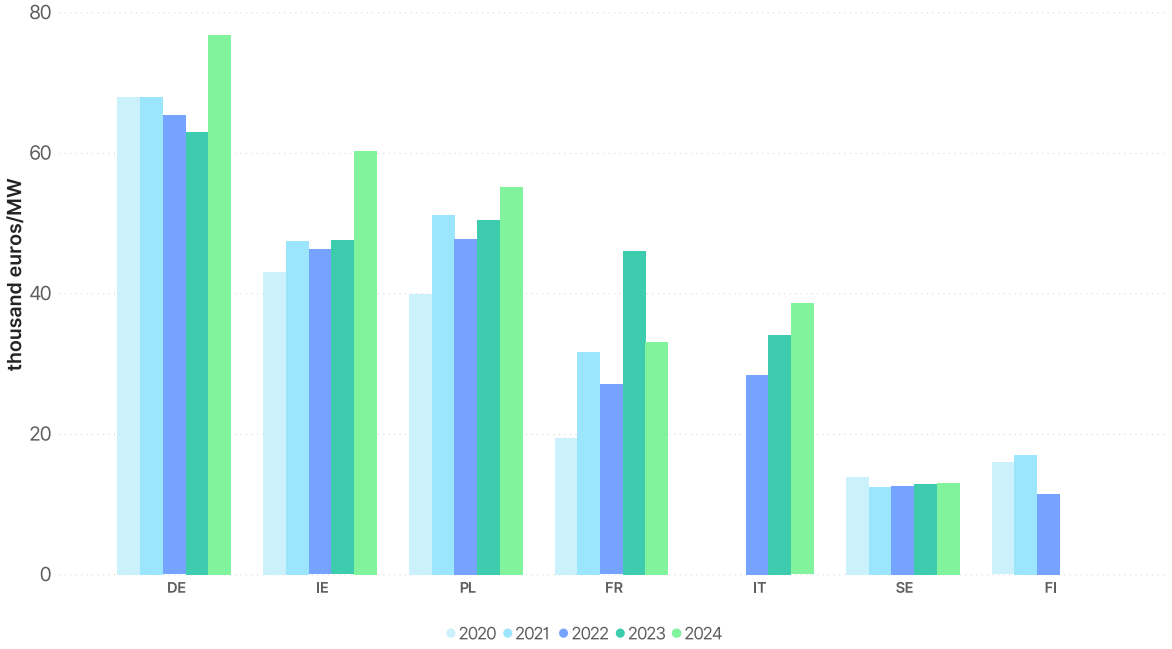
81 For details on the financing of the capacity mechanisms, see Table 2 in ACER's 2021 SOS monitoring report on security of supply.

82 The projected 2024 costs for the French mechanism are based on the results of the first two T-1 auctions that took place in 2023 and reflect the market participants' perceived risks at that time. It is also assumed that the procured capacity remains the same as in 2023. Therefore, the actual costs may vary.

certificates related to the ARENH mechanism. The costs of the French capacity mechanism for 2024 are calculated on the presumption that the same volumes of capacity continue being awarded, and using a reference price that corresponds to the results of auctions that took place up to May 2023. For Italy, costs until 2021 correspond to legacy contracts in place until that year; for 2022 and beyond, the costs correspond to the new capacity mechanism. For Germany, the 2024 costs assume that maximum costs will result from the 2023 strategic reserve auction with delivery starting in October 2024. In Portugal, at the time of data collection, Government approval was still pending regarding the capacity mechanism payments, therefore, no costs are considered for 2023.

110 Figure 5 shows the costs of capacity mechanisms per unit of procured capacity. The 'unit costs' are derived by dividing the total incurred or projected costs in a delivery year by the capacity remunerated in the same year. In several Member States, the unit costs are increasing. In France, the nuclear unavailability experienced in 2022 increased the capacity auction prices and thus the projected unit costs of the capacity mechanism in 2023. In Germany, the increase in 2024 is attributed to the German NRA's assumption that maximum remuneration will result from the auction that is to take place in 2023. In Ireland, the increase in the costs in 2024 is partly a consequence of the results of the T-3 auction for winter 2024/25 (discussed in Box 3 above).

Figure 5: Costs of capacity mechanisms over total capacity procured — 2020–2024 (thousand euros/MW)



Source: ACER calculations based on data provided by NRAs.

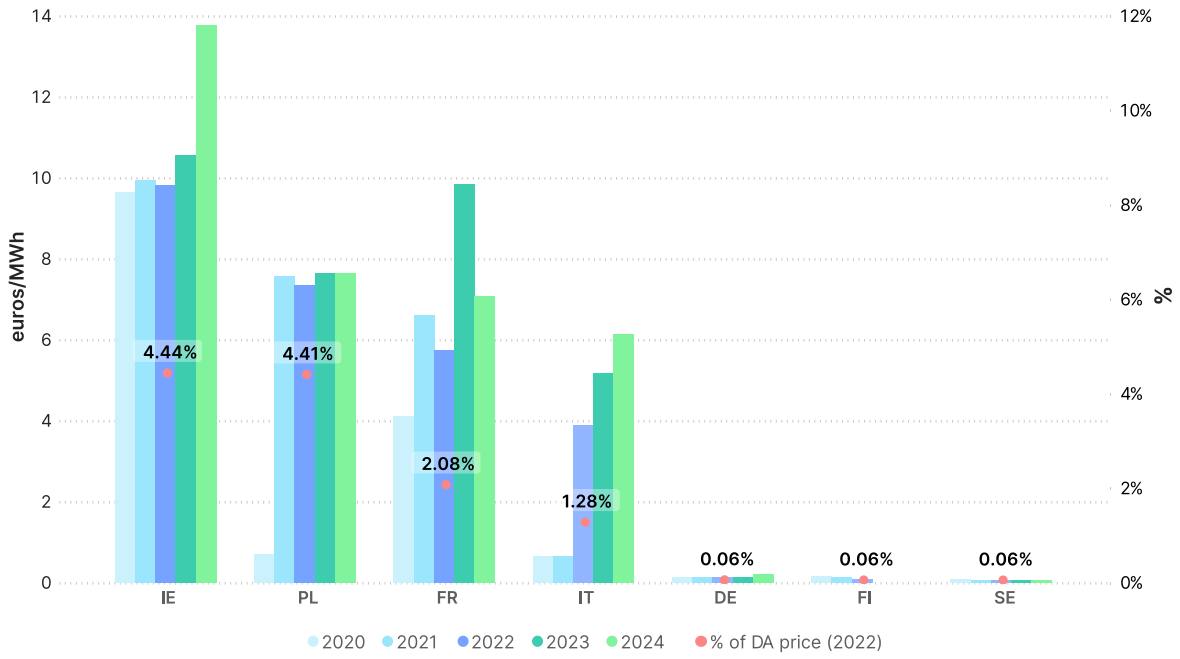
Note: The Notes under Figure 4 also apply to this figure. The unit costs are calculated by dividing total annual payments and the total capacity remunerated and hence do not necessarily depict individual auction results accurately. For Italy, only unit costs related to the new capacity mechanism (with delivery starting in 2022) are shown, since no information on the volume of capacity that was remunerated in 2021 under the previous mechanism was provided. Unit costs for Portugal (legacy contracts) and Spain (long term investment incentives) are not shown in this figure; they are included in Figure 10 in the 2021 edition of the SOS monitoring report.

111 Figure 6 shows the costs of capacity mechanisms per unit of electricity demand[83]. It provides an indication of the relevance of these costs in the electricity bill[84]. The percentage value in the figure shows these costs expressed as a percentage of the average day-ahead price in the bidding zone(s) where the respective capacity mechanism applies. Due to the high wholesale prices experienced in 2022, the costs expressed as a percentage of the wholesale price are lower than in 2021.

83 Demand data is based on Eurostat data and is complemented, if necessary, by data from the ENTSO-E Transparency platform. If for any Member State and calendar year, Eurostat data was unavailable, the following methodology applies. If for a given Member State, Eurostat data was available for the two preceding years of the calendar year in question, a 'correction factor' was calculated as the ratio between Eurostat and ENTSO-E data for these two preceding years. The demand data for the year in question was then calculated by multiplying the ENTSO-E Transparency Platform data for this year with the correction factor. If, however, Eurostat data was unavailable for the two preceding years of the calendar year in question, the demand data was taken from the ENTSO-E Transparency Platform data without any adjustment.

84 The figure does not depict actual tariffs or levies, but only a simple indication assuming the costs are equally distributed to consumers according to their electricity consumption. As capacity mechanisms only remunerate availability of capacity and not generated electricity, these unit costs should not be confused with actual electricity generation costs.

Figure 6: Costs incurred or projected to finance capacity mechanisms per unit demand (2020–2024), and expressed as a percentage of the annual average day-ahead price in the respective Member States — 2022 (euros per MWh of demand and %, respectively)



Source: ACER calculations based on NRA, ENTSO-E and EUROSTAT data.

Note 1: The Notes under Figure 4 also apply to this figure. Costs per unit demand are based on total annual realised or projected payments to capacity providers for delivery of capacity in the relevant year and the total national demand in the same year. Demand data is derived from Eurostat data and the ENTSO-E Transparency Platform. For the projected unit costs in 2023 and 2024, demand data for 2022 was used. For Ireland (where the capacity mechanism applies to the Single Energy Market, comprising also Northern Ireland), demand data for 2020 was used for all the years considered on the figure. Costs for Portugal (legacy targeted capacity payments) and Spain (long-term investment incentives) are not shown in this figure; they are included in Figure 10 in the 2021 SOS monitoring report.

Note 2: The percentage value refers to the costs of the capacity mechanism per unit demand in 2022, divided by the 2022 average wholesale day-ahead price in the corresponding bidding zone(s). For Italy, the Single National Price is considered; for Sweden, the arithmetic average of the annual prices in the Member State's four bidding zones is used).

112 From the perspective of the electricity consumer (Figure 6), the costs of the strategic reserves (in place in Finland, Germany, and Sweden) are substantially lower than the costs of the four market-wide capacity mechanisms. The three strategic reserve schemes do, however, differ substantially regarding the average payment to beneficiaries, with the German scheme seeing much larger remuneration levels per MW of awarded capacity (Figure 5).

4.1.3. Technologies remunerated by capacity mechanisms

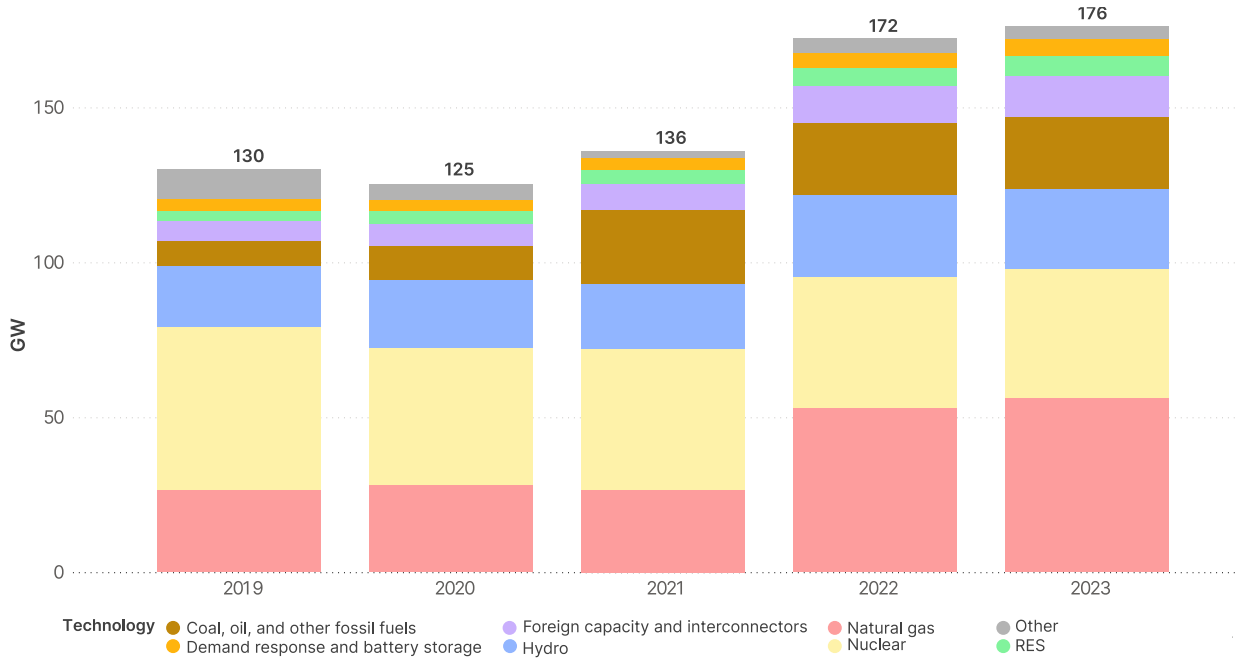
113 Figure 7 shows the breakdown of technologies remunerated through capacity mechanisms across the EU from 2019 to 2023. In total, around 174 GW of capacity was remunerated in 2022, mostly corresponding to natural gas, nuclear and coal power plants. The increase of natural gas capacity remunerated in 2022 and 2023 compared to 2021 is largely attributed to the introduction of the new capacity mechanism in Italy[85]. A detailed breakdown of the categories is available in (Figure 16 in Annex I).

114 Figure 7 also shows that in 2022, around 5 GW of capacity were procured from demand-side response and battery storage. The share of capacity procured from these non-traditional capacity providers is low compared to established technologies, but the share is rising – for example, the share of demand response and battery storage capacity over the total capacity procured for delivery year 2026 is close to 10% in the Irish and Polish capacity mechanisms. These trends are discussed in more detail in Box 4.

85 The data on the exact technology breakdown for Italy is not available to ACER, so an approximation was used (as described in the Note under Figure 7).

115 In addition, around 12 GW of cross-border capacity (both foreign and interconnection capacity)[86] were procured in 2022. The topic of cross-border participation in capacity mechanisms is discussed in more detail in Section 5.2.

Figure 7: Total capacity remunerated in EU capacity mechanisms, per type of technology — 2019–2023 (GW)



Source: ACER based on data provided by the NRAs and the ENTSO-E Transparency Platform.

Note: Since the Italian capacity mechanism auctions are portfolio-based, distribution of the capacity procured in the Member State in 2022 and beyond is an approximation based on the results of the capacity auctions and the breakdown of the 2022 generation fleet in Italy according to ENTSO-E transparency platform. No information on the capacity remunerated under the previous mechanism (in place until 2021) was available.

116 Figure 8 shows the breakdown of capacity remunerated under long-term contracts between 2027 and 2035, together with the associated costs. Long-term contracts[87] are a common feature of European market-wide capacity mechanisms[88]. On the one hand, long-term contracts can facilitate the commissioning of new capacity and facilitate competition by reducing investment risks and lowering financing costs. On the other hand, long-term contracts can also represent a barrier to the entry of new types of capacity providers if long-term support is instead directed at conventional resources. Furthermore, long-term contracts can imply additional costs for consumers, as support may be inefficiently allocated to capacity resources, even for periods when no adequacy-related issues are foreseen. Importantly, long-term contracts can also compromise the EU emission and climate-neutrality targets: through such contracts, Member States will continue supporting fossil-fuelled power plants far beyond 2030.

117 Notably, the volume of capacity with long-term contracts has increased substantially since the last reporting period. Approximately 13 GW of new capacity signed such contracts in the Irish, Italian, and Polish capacity mechanisms, adding up to a billion euros per year to the long-term capacity bill[89].

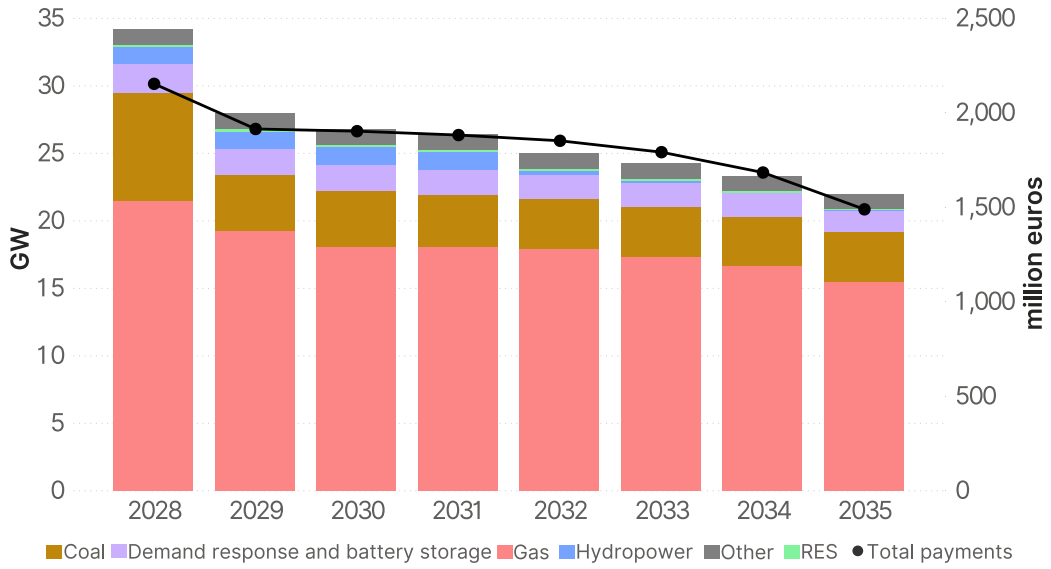
86 On this figure, 'foreign capacity' corresponds to capacity procured directly from resources located outside of the borders of the Member State administering a capacity mechanism, whereas 'interconnector capacity' refers to capacity procured from interconnectors between the Member State and the neighbouring bidding zones.

87 For this analysis, ACER considers contracts with a duration of more than five years as long-term.

88 Long-term contracts have a duration of 8 or 15 years in Belgium, 7 years in France, 10 years in Ireland, 15 years in Italy, and up to 17 years in Poland. In Spain, the contracts correspond to legacy payments (see the Note under Figure 3).

89 See Figure 12 in the 2021 SOS monitoring report. Per the data available to ACER at the time of the 2021 publication, 21 GW of capacity had signed long-term contracts that include delivery in 2028, at a cost of 1.1 billion euros (for this delivery year). One year later, 13 GW of capacity has been added, and the total cost for delivery in 2028 has doubled.

Figure 8: Long-term contracted capacity and relevant costs by type of technology in the EU-27 — 2027–2035 (GW and million euros, respectively)



Source: ACER calculations based on data from NRAs and, in the case of Italy, also from publicly available information on auction results.

Note: Long-term contracts exist in Belgium, France, Ireland, Italy, Poland, and Spain.

Box 4: Participation of demand response and storage in market-wide capacity mechanisms

Demand-side response and storage are considered key technologies to achieve the EU's decarbonisation targets and at the same time secure supplies in a decarbonised power system. As shown in Figure 7, the participation of these non-conventional capacity providers has been growing but remains limited compared to traditional thermal generation technologies. This text box takes a closer look at the experience across market-wide capacity mechanisms so far.

Figure 9 shows the contracted capacity of demand response and storage across four market-wide capacity mechanisms (France, Italy, Ireland, and Poland) in MWs of de-rated capacity, and as a share of the total contracted volume in each capacity mechanism. The figure presents data for both historical and future years, up to the latest delivery year for which auctions have already taken place. One can draw two key conclusions from these graphs.

Firstly, the participation of demand response and storage has been steadily increasing over time. For example, participation of demand response and storage in the Polish capacity mechanism has grown from around 0.5 GW for delivery year 2021 to more than 1.5 GW for delivery year 2027. The pace of growth is higher for storage capacity, particularly in the most recent auctions.

Secondly, the participation of demand response and storage varies significantly across the different capacity mechanisms. For example, their participation is expected to reach a share of just under 10% in the Irish and Polish capacity mechanisms in the future. On the other hand, the combined participation of demand response and storage in the Italian capacity mechanism is expected to reach a significantly lower share of 2.5% in 2024, while no demand response has secured contracts so far.

Figure 9: Contracted capacity of demand response and storage in the French, Italian, Irish, and Polish market-wide capacity mechanisms (GW)

4.2. Other measures

4.2.1. Interruptibility schemes

118 The trend observed in 2021 regarding the phase out of interruptibility schemes[90] continued in 2022. Out of the six schemes in operation in 2021[91] four schemes were operational in 2022, in France, Germany, Italy, and Poland. The German scheme was terminated in July 2022. Table 14 in the Annex I provides a description of the main characteristics of the schemes. Box 5 provides further information on the newly introduced schemes in Poland, Portugal, and Spain.

119 Total cost sof the French and Italian schemes remained at the same levels as previously (63 million euros and 326 million euros respectively), while the cost for the German scheme accounted to 13 million euros. The time-series evolution of the costs is shown in Figure 15 in Annex I. There were sixty-six activations in the German scheme and three activations in Italy. There were no activations of the scheme in France.

90 Interruptibility schemes normally refer to national programmes dedicated to demand response, organised by TSOs for temporary load interruption or reduction. According to the State Aid Guidelines, interruptibility schemes aim to ensure a stable frequency in the electricity system or address short-term security of supply problems. An interruptibility scheme typically pools large industrial consumers from energy intensive industries with processes that can be suspended for a limited amount of time.

91 See Section 4.2 of the 2021 SOS monitoring report.

Box 5: Ancillary service-related schemes – the successors of interruptibility schemes

As interruptibility schemes come to their end, some TSOs introduced demand response schemes that provide non-standardised ancillary services and, at times, resource adequacy support. Three such schemes, in Poland, Portugal, and Spain, are briefly discussed hereunder. Germany also seeks to replace its interruptibility scheme with a similar measure based on ancillary services.

The Polish scheme that replaced the previous interruptibility scheme in April 2021 is now part of the ancillary services procured by the Polish TSO for balancing purposes. It is based on day-ahead auctions where qualified participants are selected on the basis of submitted energy (reduction) bids, i.e., no capacity payments are included. In 2022 six such auctions took place, but there was no actual activation in real time. Hence, there were no costs to consumers.

The termination of the interruptibility scheme in Portugal in 2021 coincided with the phase out of electricity generation from coal raising adequacy concerns. In response to these concerns, the Portuguese TSO introduced a new scheme in the end of 2021, called the "regulatory reserve band" (RRB), that targets demand response. The scheme awards annual availability payments through a competitive process to large (at least 4 MW) consumers. The successful capacity providers are contractually obliged to be available to provide services similar to manual frequency restoration reserve (mFRR) balancing services when called upon by the TSO. As communicated by the NRA, the annual capacity needs for this scheme are determined based on the TSO's security of supply studies, so that compliance with the reliability standard is assured. The TSO has identified a need for 425 MW for all hours of 2022 and a need of 800 MW throughout 2023. The auction for delivery in 2022 procured just over 304 MW at a total cost of 53 million euros (the auction reached the price cap of 175,000 euros/MW). The capacity was activated 402 times during the year providing 1.5 GWh at an average cost of 228 euros/MWh. For delivery in 2023, the price cap was set at 385,000 euros/MW.

A very similar scheme was introduced in Spain in autumn 2022. The "active demand response service" is used to procure demand response capacity that is obliged to provide balancing services in pre-defined periods. These periods correspond to around 30% of the hours of the year. The scheme is classified as a "specific balancing product" and was adopted by the Government as a Royal Decree-Law. An evolution of this product, aligned with the approval procedure of the Balancing Regulation, is being considered by the Spanish NRA at the time of finalising this report. The stated purpose of the scheme is to complement the standard mFRR and RR service, in times when the upwards regulation energy procured through these channels is insufficient. For the period from 1 November 2022 to 31 October 2023, the capacity need was set at 2,700 MW for each of the 2,714 hours where availability is required (this is during workdays between 18h and midnight during the warmer months, and between 6h and 24h during the colder months). Only offers of at least 1 MW were eligible. A total of 497 MW of demand capacity was procured at a price of 190,000 euros/MW. No energy payments took place as there has been no activation yet (as of June 2023).

4.2.2. Network congestion measures

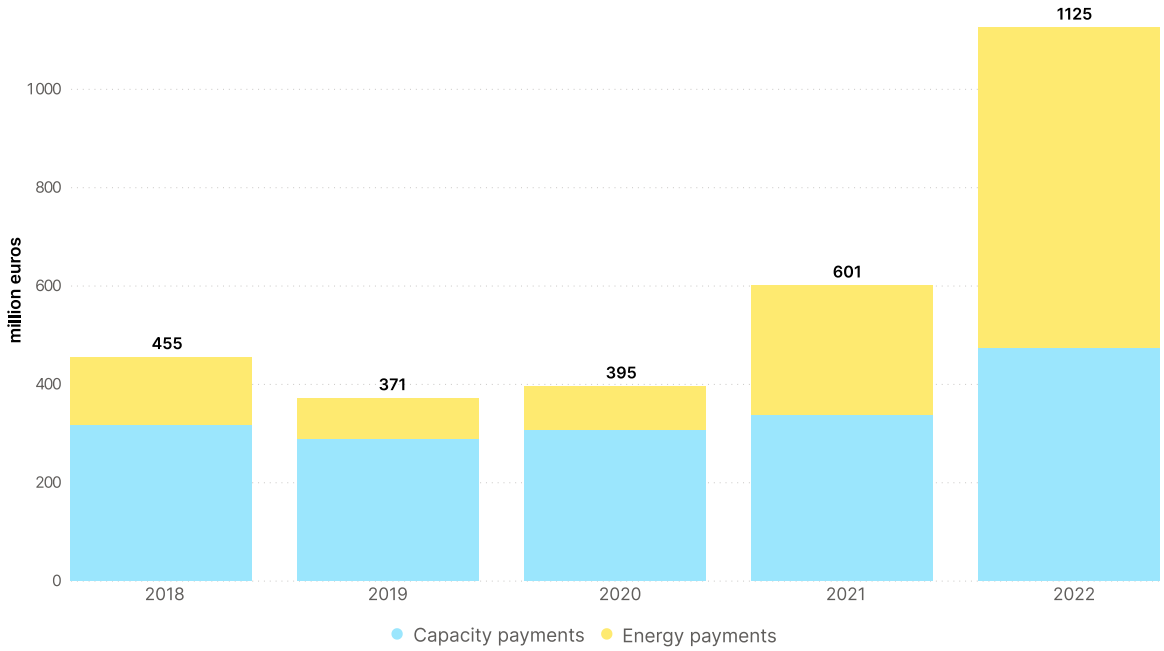
120 There are two operational network reserve schemes[92] in the EU, in Austria and in Germany. They provide additional capacity to TSOs to perform re-dispatching when necessary[93]. A description of the main characteristics of the schemes is presented in Table 15 in Annex I.

92 Network reserves are network congestion measures remunerating resources that provide the necessary reserves to mitigate local congestion issues, essentially enabling re-dispatching when existing capacity in the system is not sufficient or is not in the location where it is needed. The resources are typically held out of the market – they cannot receive remuneration from the wholesale electricity market or balancing markets. According to the Electricity Regulation, network reserves do not fall within the definition of capacity mechanisms. However, according to the State Aid Guidelines they are subject to similar criteria as capacity mechanisms when it comes to assessing their compatibility with the internal market.

93 From July 2022 onwards, power plants that participate in the German network reserve network reserves may also be used to provide support to the system in the case of adequacy issues. Similarly, the German strategic reserve may also be activated to mitigate network congestion issues; this is also the case in Sweden.

121 In 2022 the total capacity of network reserves from the two schemes amounted to 8.5 GW. This came at a total cost of around 1.1 billion euros (Figure 10), 92% of which correspond to the German scheme. Almost all the capacity came from fossil fuelled power plants; only 35 MW of demand response capacity was procured in Austria (the capacity breakdown is shown in Figure 14 in Annex I).

Figure 10: Total cost of network reserves in Austria and Germany – 2018-2022 (million euros)



Source: ACER based on information provided by the NRAs.

Box 6: Various out-of-market measures are implemented by Member States

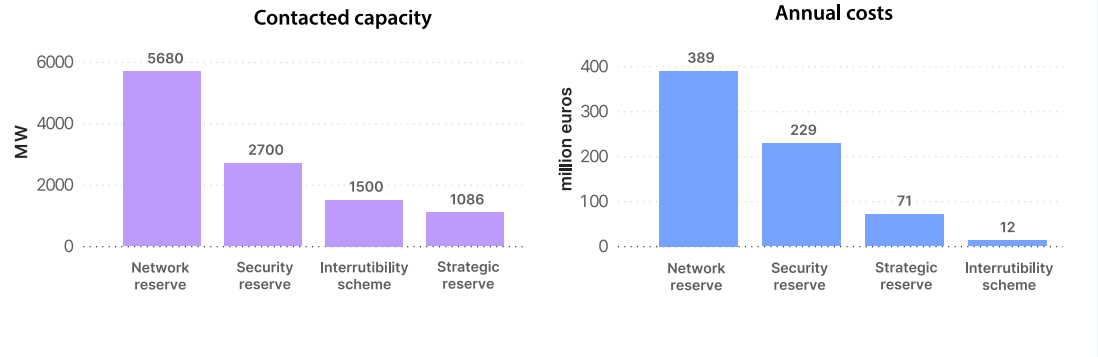
Some Member States have several out-of-market measures in place, implemented in different contexts but all awarding the availability of various resources to address various system needs. For example, in Germany in 2022, four such out-of-market measures applied.

The strategic reserve (discussed in Section 4.1) is used to resolve adequacy issues. The network reserve (Section 4.2.2) is primarily designed to deal with internal network congestion issues in the event that market-based redispatching is insufficient. The interruptibility scheme (Section 4.2.1), targeting large consumers, could be used for various purposes such as balancing and congestion management. In 2022, all three measures could be used for resource adequacy.

The "security reserve" was introduced in 2016. Eight lignite plants with a total capacity of 2.7 GW were gradually entered into this stand-by reserve, where they received remuneration in return for their readiness to support the system if needed, for a maximum of 240 hours per year. In October 2022, five of these power plants were transferred to a newly created "supply reserve", together with several other oil and coal-fired power plants. The supply reserve is in place until March 2024 and the contracted power plants should be available to support the system at any time. The estimated total costs of the scheme are 1.6 billion euros for the period of 2016-2022.

Figure 11 shows the capacity contracted within the schemes as of 2022, together with the corresponding (estimated) annual costs.

Figure 11: Contracted capacity and annual costs of out-of-market measures in Germany — 2022 (MW and million euros)



Source: ACER calculations based on data provided by the NRA.

Note: The figure does not include the costs of activations (energy costs) of the network reserve and the interruptibility scheme. The annual costs of the security reserve are an estimation.

In addition to the four measures described above, delivery of the grid stability service will start in 2023. The service was introduced in 2017 to deal with network congestion in cases of failure of grid elements. The estimated total costs of the scheme (approx. 2.5 billion euros or 2 million euros per MW) encompass the construction and operation of four new generation facilities (total capacity of 1,200 MW) that will operate as part of the service for 10 years.

5. Focal topic: Design features of capacity mechanisms

5.1. Introduction

122 Capacity mechanisms must follow certain design principles as prescribed in the Electricity Regulation. For example, they must be transparent, competitive, open to all technologies able to provide the required technical and environmental performance, and must not go beyond what is necessary to address the adequacy concerns, amongst others[94].

123 This chapter examines two design principles of capacity mechanisms, namely, cross-border participation and the application of penalties on beneficiaries. It reviews current practices across national mechanisms and draws lessons from them.

5.2. Cross-border participation

124 Cross-border participation in capacity mechanisms has historically been enabled through the participation of interconnection capacity[95]. The Electricity Regulation introduced new rules aiming at the direct participation of foreign capacity resources in capacity mechanisms and harmonising the rules for their participation across capacity mechanisms[96]. For the purposes of the Electricity Regulation, foreign capacity refers to capacity located in another EU Member State[97]. To this end, in December 2020, ACER approved the common rules and methodologies governing such direct participation[98]. As set out in the Electricity Regulation, capacity mechanisms had to enable the direct participation of foreign capacity by December 2022[99].

125 The purpose of this section is firstly to provide an update on the implementation status of direct foreign participation in capacity mechanisms. In addition, the section describes how the relevant national authorities estimate the contribution of foreign resources to the security of supply in capacity mechanisms and the alignment of their methodologies with the applicable rules. Finally, this section discusses the current rules for the participation and remuneration of foreign capacity or interconnectors in capacity mechanisms and examines whether the current designs enable a level-playing field between domestic and foreign resources. The data and information presented in this section were primarily provided by the TSOs and national regulatory authorities of the Member States with capacity mechanisms in place – in all cases, these TSOs are also the operators of the capacity mechanisms.

5.2.1. Direct foreign participation in capacity mechanisms

126 While cross-border participation is mandatory for market-wide capacity mechanisms, strategic reserves should apply cross-border participation if it is technically feasible[100]. As of 2022, no strategic reserve scheme allowed the participation of foreign capacities. This section therefore focuses on the market-wide capacity mechanisms of Belgium, France, Italy, and Poland.

127 Ireland, the only other Member State currently implementing a market-wide capacity mechanism, is expected to connect with another EU Member State by 2026, with the commissioning of the Celtic

94 Article 22 of the Regulation. For more details, see Box 6 in ACER's 2021 SOS monitoring report.

95 Alternatively, Member States have considered the benefits of the interconnected market to their security of supply by discounting the expected contribution of foreign resources from the capacity requirement of a capacity mechanism.

96 Article 26 of the Electricity Regulation.

97 This chapter contains information about non-EU countries too, where relevant, without however exploring in detail the conditions of cross-border participation in these cases.

98 ACER Decision 36-2020 on technical specifications for cross-border participation in capacity mechanisms and its Annex I.

99 Article 26(2) of the Electricity Regulation set the deadline to either July 2023 or to two years after the approval of the technical specifications, whichever was to come first. As the technical specifications (referred to in footnote 98) were approved in December 2020, the effective deadline was December 2022.

100 Article 26(1) of the Electricity Regulation.

interconnector with France[101]. In light of this, the Irish authorities have commenced work to develop the detailed rules for direct foreign participation. The Irish NRA, CRU, anticipates that the development of the rules will require a few years, and direct foreign participation will only be possible at some point in the second half of the decade. Currently, the Irish capacity mechanism does not allow the participation of the Celtic interconnector either, but rather considers the contribution of foreign resources by reducing the capacity requirement of domestic resources. Depending on when the detailed rules will be in place, it is possible that the reserved capacity will be sold to foreign capacities from the first year of the Celtic interconnector's operations (e.g., through the T-1 auction for 2027/2028 delivery)[102].

128 Regarding the current status of cross-border participation in capacity mechanisms, only Poland has implemented the direct participation of foreign capacities in its capacity mechanism in line with the Electricity Regulation. Italy currently allows the direct participation of foreign capacity through a simplified approach where foreign capacities have limited obligations. This is due to the authorities' concerns regarding the technical equivalence of foreign units, i.e., the ability of foreign resources to provide the same service as domestic resources[103]. The Italian authorities have expressed their intention to allow a fully-fledged direct foreign participation, however, there is no concrete plan yet in place.

129 Implementation is ongoing in the other Member States with market-wide capacity mechanisms. Belgium is expected to allow the direct participation of foreign capacities from the first delivery year of its capacity mechanism, i.e., from winter 2025/2026[104]. In France, while there are rules for the direct participation of foreign capacity, they have not been implemented, and only interconnector participation is currently possible. The French authorities plan to implement the direct participation of foreign capacities with the first delivery year of the new capacity mechanism, planned for winter 2026/2027[105].

130 The existing rules allow foreign capacity providers to be located anywhere in the interconnected EU network. Nevertheless, Member States can decide which Member States they allow to participate in their capacity mechanism. As a minimum, the set of Member States must include those directly connected to the Member State implementing the capacity mechanism. As of 2022, the capacity mechanisms of Belgium, Italy, and Poland only allow the direct participation of foreign capacity located in the Member States that have a direct connection to their national networks[106].

131 Whether capacity providers of one Member State can directly participate in a given Member State's capacity mechanism is subject to the existence of an agreement between the TSOs of the two Member States. The agreements govern the contractual relationship between the TSO of the national capacity mechanism and the foreign TSO in whose area the foreign capacity provider is located. They define, for example, the financial responsibilities related to eligibility and availability checks performed by the foreign TSO. Currently, such agreements are only in place between the Polish TSO and its neighbouring TSOs. In Belgium and France, the discussions on the agreements are ongoing (with varying levels of progress). The Belgian TSO expects to conclude the agreements with the relevant foreign TSOs in 2023, including the bidirectional agreement with the French TSO[107]. The timeline for the rest of the TSO-TSO agreements related to the French capacity mechanism is unknown. In Italy, no agreement is in place, and no discussions on potential agreements have been initiated so far[108]. ACER notes that there can be challenges impeding the conclusion of agreements between TSOs[109].

101 For more information on the Celtic interconnector see for example, the project's website. According to the project developers, the interconnector is due to be completed by the end of 2026. Currently, the Irish mechanism allows the participation of the interconnectors with Great Britain.

102 This is essentially the same approach followed in the Belgian capacity mechanism. For more information, see paragraph (131).

103 The Italian authorities consider foreign resources as incapable of providing the same technical performance that domestic resources can provide. Among the concerns is the lack of control that the Italian TSO has over the operation and maintenance of foreign units (while for domestic resources, the TSO does have control over these aspects). Furthermore, the Italian TSO cannot influence the foreign TSO's network maintenance schedule. The implementation of foreign capacity participation in the Italian capacity mechanism is in line with the Decision of the European Commission C(2018) 617.

104 Auctions in the Belgian capacity mechanism take place four (T-4) and one (T-1) year before delivery. For delivery in winters 2025/26, 2026/27 and 2027/28, direct foreign participation will be allowed in the respective T-1 auctions. Starting with delivery in 2028/29, direct foreign participation will also be allowed in the T-4 auctions.

105 A new capacity mechanism is being discussed in France (see footnote 80).

106 This point is still under examination for the new French capacity mechanism.

107 This means that the agreement will allow the participation of French resources in the Belgian capacity mechanism, and vice-versa (i.e., Belgian resources in the French capacity mechanism).

108 While no steps have yet been taken, the Italian TSO does not exclude the possibility that discussions on agreements take place in the future.

109 For example, the French TSO observed that the conclusion of an agreement requires considering the specific rules that are in place in the neighbouring country.

132 For the purpose of registering foreign capacity providers that are eligible[110] for cross-border participation in a particular capacity mechanism, a dedicated registry is maintained by ENTSO-E, as required by the Electricity Regulation[111]. At the moment, the registry only contains the foreign capacities eligible to participate in the Polish capacity mechanism, as direct foreign participation is not yet implemented elsewhere[112].

133 Table 2 summarises the key information regarding the status of direct foreign participation, the eligibility of foreign bidding zones, and the status of the agreements between domestic and foreign TSOs. Detailed information on the status of TSO-TSO agreements can be found in Table 16 in Annex I.

Table 2: Current status of direct foreign participation, eligibility of foreign bidding zones, and TSO-TSO agreements in the capacity mechanisms of Belgium, France, Italy, and Poland

Member State implementing the capacity mechanism	Status of direct foreign participation as of 2022	Foreign bidding zones eligible to participate	Status of TSO-TSO agreements	Next steps in the implementation of direct foreign participation
Belgium	Implementation in development	FR, DE/LU, NL	Agreements expected to be signed by the end of 2023	Implementation planned with the first delivery year (i.e., delivery year 2025/2026)
France	Interconnector participation implemented in current capacity mechanism (but rules for direct foreign participation in place)	BE, DE/LU, ES, IT, GB	Pending (bidirectional agreement with Belgian TSO expected by the end of 2023)	Planned for the new capacity mechanism (i.e., from winter 2026/2027)
Italy	Implemented in a simplified manner	AT, FR, GR, SI, CH, ME	No agreements in place and no discussions initiated	No next steps determined for fully-fledged implementation
Poland	Implemented	CZ, part of DE, LT, SE, SK	Agreements in place	Already in place

Source: ACER based on information from NRAs and TSOs.

Note: "ME" refers to Montenegro. CH, GB and ME are not EU bidding zones, but capacities from these zones or the relevant interconnectors may participate in the capacity mechanism auctions.

5.2.2. Maximum entry capacity

134 As an important part of the framework for foreign participation in capacity mechanisms, the Electricity Regulation introduced the concept of 'maximum entry capacity' (MEC). The MEC determines the maximum amount of foreign capacity that can participate in the capacity mechanism of a Member State. It essentially represents the expected contribution of foreign resources to the security of supply of a Member State with capacity mechanism, at times of system stress. The Electricity Regulation stipulates that the relevant authorities assess the MEC for each bidding zone border[113].

135 The MEC intends to reflect the likelihood of simultaneous scarcity between two Member States, and the availability of interconnection capacity to transfer energy between them[114]. The methodology for estimating the MEC is defined in the Technical Specifications for cross-border participation in capacity

110 I.e., fulfil the technical performance requirements of the capacity mechanism.

111 Article 26(11) of the Electricity Regulation and Title 6 of the Technical Specifications.

112 The registry currently contains information on the capacity providers that are eligible to participate in the Polish capacity mechanism, in the delivery periods 2026 and 2027. It follows from the registry that only capacity providers located in Sweden, Slovakia and Lithuania are eligible to participate in the Polish CM in these delivery periods. For delivery in 2027, more than 2 GW of foreign capacity providers (from Lithuania and Slovakia) have been registered.

113 Article 26(7) of the Electricity Regulation.

114 For example, a higher probability of simultaneous scarcity between two Member States, means that the Member State with capacity mechanism can count to a lesser extent on imports from the other Member State, or effectively a lower MEC. Similarly, a higher outage rate of interconnectors means a lower MEC.

mechanisms. The Specifications mandate that the MECs must be calculated by RCCs, based on the results of the ERAA or a similar regional resource adequacy study[115].

136 Currently, in the absence of an approved ERAA, most capacity mechanisms use national assessments for the purpose of calculating the MEC (or an equivalent), with significant divergence in the approaches. Only in Poland have the national authorities used EU-wide (ENTSO-E's) resource adequacy studies to estimate the MEC, in the absence of a national resource adequacy assessment[116, 117].

137 The Technical Specifications provide two possible methodological approaches to estimate the MEC[118]. The majority of capacity mechanisms use one of these two approaches: Belgium uses the approach under Article 7 of the Specifications, while France and Poland use the approach under Article 8. On the other hand, the Italian authorities use their own approach, where the MEC is based on historical, realised flows during relatively tight hours[119].

138 An important parameter for the calculation of the MEC is the selection of periods used to estimate the expected contribution of foreign resources to the security of supply of a Member State with capacity mechanism. The Technical Specifications define system stress hours (i.e., hours of expected supply deficit or load shedding) as the default periods for estimating the MEC. The responsible authorities may, however, select a broader set of periods if properly justified. Currently, the rules of the Belgian, French, and Polish capacity mechanisms are aligned with the default option for estimating the MEC[120]. The Italian capacity mechanism uses a broader set of relevant periods, that likely includes near-scarcity hours too[121].

139 The Electricity Regulation anticipates the calculation of the MECs by the Regional Coordination Centres (RCCs) and that the national TSOs consider the recommendation provided by the RCCs when setting the final values. Based on the information provided by the TSOs, national authorities do not intend to use the RCCs' MEC recommendations by default. Instead, the authorities intend to scrutinise the recommended values, and only utilise them if they deem them appropriate. For example, the authorities in Belgium and France have set as a prerequisite that the MEC values be based on a scenario that is consistent with the scenario used to determine the other parameters of a capacity mechanism auction. The Italian TSO, for its part, does not envisage the use of the RCC recommendations, since the Italian capacity mechanism determines the maximum contributions of foreign capacity using a methodology based on historical data.

115 Being a result of a (probabilistic) adequacy study, the MEC is based on simulated future states of the electricity system.

116 For example, for the latest auction in December 2022, the Polish authorities used the ERAA 2021. Prior to that, the MEC was estimated based on the ERAA's predecessor, the Mid-Term Adequacy Forecast.

117 All rules regarding the cross-border participation and MEC calculation are defined within the European Commission's State Aid Decision on the Polish CM.

118 The Technical Specifications determine two possible ways to estimate the MEC: i) the first method is based on net positions (Article 7); and ii) the second method is based on cross-zonal exchanges (Article 8).

119 To determine the maximum levels of foreign capacity, the Italian TSO, Terna, considers recent import statistics. Firstly, a time series is built comprising periods that could be generally concerning from an adequacy standpoint (mainly corresponding to weekday hours during the winter and summer seasons). Secondly, the maximum import contribution to the CM auction is then defined as a percentile of the time series.

120 The Polish TSO has indicated that a broader set of periods could be used to estimate the MEC, if the number of periods with a supply deficit is negligible or limited in the simulations.

121 For more information, see footnote 119.

Table 3: Approaches for the estimation of maximum entry capacity in Belgium, France, Italy, and Poland - 2022

Member State	Assessment used to estimate MEC for the latest auction	Approach used to estimate the MEC	Periods used to estimate the MEC	Intention to use RCC recommendation
Belgium	National assessment	Article 7 of Technical Specifications	As determined in methodology (i.e., loss of load hours)	In principle, but it may deviate. Consistency with other auction parameters essential
France	National resource adequacy assessment	Article 8 of Technical Specifications	As determined in methodology (i.e., loss of load hours)	In principle but it may deviate. Consistency with other auction parameters essential
Italy	Historical data	Statistical analysis of historical flows (not based on Technical Specifications)	Scarcity and near-scarcity hours	No
Poland	European resource adequacy assessment	Article 8 of Technical Specifications	As determined in methodology (i.e., loss of load hours), but a broader set of hours may be selected	In principle, but it may deviate

Source: ACER based on information from TSOs.

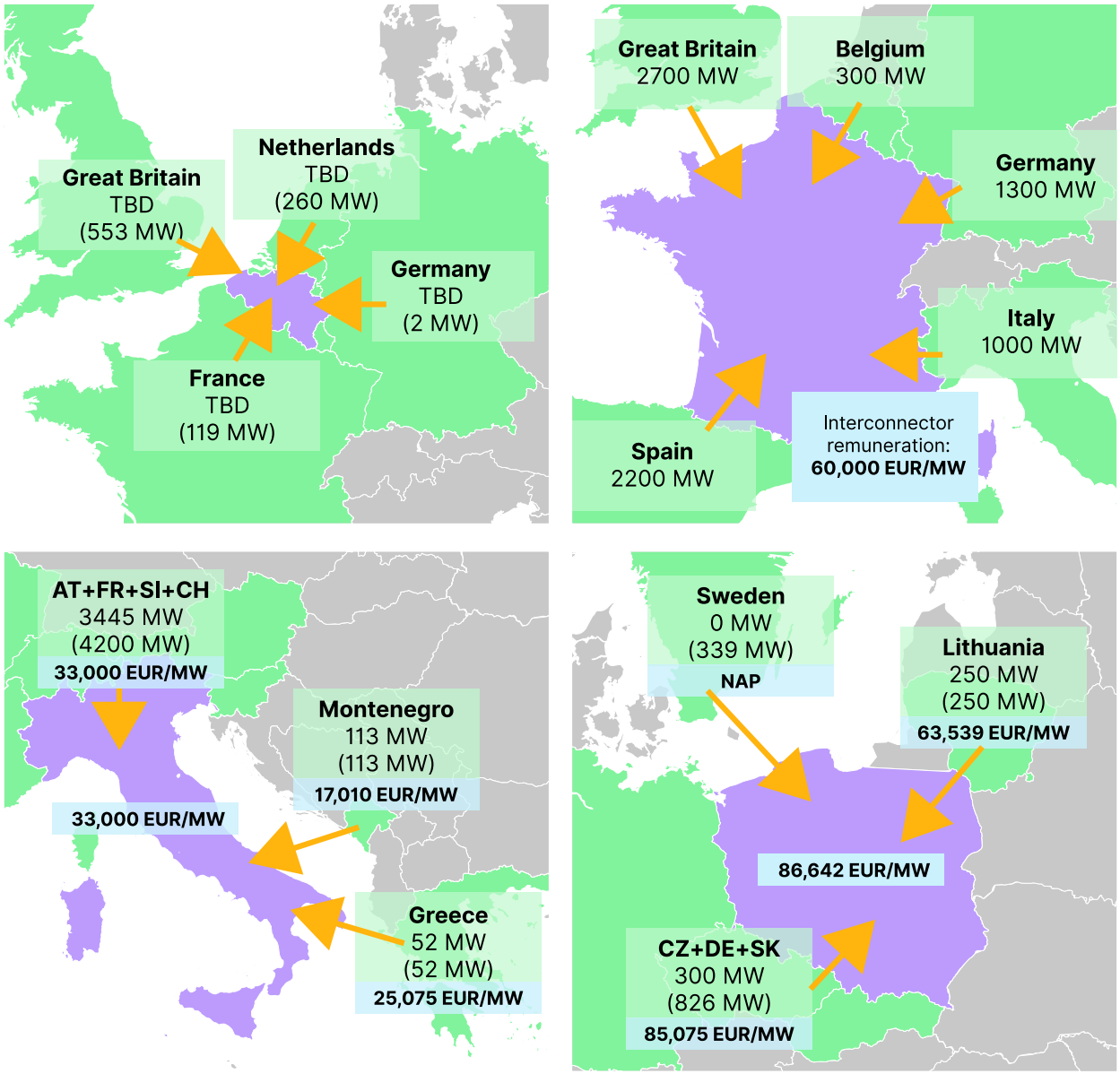
Note: Belgium undertakes an annual calibration analysis of the auction parameters on the reference scenario of the corresponding capacity mechanism auction. The latest annual calibration analysis ans report can be downloaded here. The approach for setting the MEC in Belgium is detailed in Article 14 of the Royal Decree on the determination of CM auction parameters (available here). The Decree describes the methodology to determine the auction parameters for the Belgian capacity mechanism and specifies the calculation method for the MEC on the reference scenario, which is published as part of the annual calibration report. For France, the national assessment refers to the French TSO's Bilan prévisionnel, available on the project's dedicated webpage.

140 Figure 12 shows the MECs and the contracted capacities for each of the bidding zones in the four market-wide capacity mechanisms examined in this section. The values presented in these graphs correspond to the most recent auctions[122, 123]. The complete dataset (contracted capacity, MECs and remuneration) corresponding to all delivery years for which data was available can be found in Table 17 and Table 18 in Annex I.

122 In the case of Belgium, the provided figures do not represent auctioned MECs, but rather reserved MECs. Since foreign resources will only be able to participate in the T-1 auction for the first three years of delivery (i.e., from delivery winter 2025/25 to winter 2027/28), this capacity has simply been reserved for the future T-1 auctions. As is typical with capacity mechanisms, the capacity requirement and other relevant parameters will be recalculated for the T-1 auctions. As such, the reserved MECs are subject to change.

123 In the case of Italy, the maximum levels of foreign capacity shown are based on historical flows and are therefore comparable but not equivalent to the MECs according to the Technical Specifications (Title 2 of the Technical Specifications; see footnote 98).

Figure 12: Maximum entry capacity and capacity actually contracted abroad in the most recent auction of the capacity mechanisms of Belgium, France, Italy, and Poland



Source: ACER based on information from NRAs and TSOs.

Note 1: Each arrow corresponds to participation of one bidding zone (or a group thereof). The first numerical value is the actual capacity contracted, while the second value (in brackets) is the MEC (or its analogue) assigned to the (group of) bidding zone(s). Where applicable, the remuneration for each (group of) bidding zone(s) or interconnectors is shown in light blue rectangles.

Note 2: For Belgium, the MECs on the figure represent the reserved capacity for the T-1 auction for delivery in winter 2027/2028. Foreign resources from Great Britain cannot participate in the Belgian capacity mechanism, however their contribution to security of supply (represented in this figure) is considered when estimating the volumes to procure. For France, the values correspond to the T-1 auction for 2023 delivery (MECs and remuneration relate to interconnector participation). The interconnector remuneration refers to 2023 and is based on the results of the reference auction that took place in December 2022. Only regulated interconnection capacity between France and Great Britain is considered on the figure. For Italy, the values correspond to the maximum levels of foreign capacity that could be contracted for delivery year 2024 and the results of the corresponding auction that took place in 2022. For the purpose of foreign capacity participation, the Italian TSO considers the four bidding zones connected to Italy North (Austria, France, Slovenia, and Switzerland) as a single zone, and calculates a single corresponding maximum import value. For Poland, the values shown correspond to the MECs for delivery year 2027 and the corresponding T-5 auction results for this year. Poland uses a single value for the synchronous zone comprising the Czech Republic, Germany, and Slovakia. Original values for Poland were provided in the local currency; for conversion, the exchange rate of 1 euro = 4.69 PLN was used.

5.2.3. Obligations and remuneration of foreign resources

141 This section reviews the obligations on foreign resources for their participation in capacity mechanisms and how their remuneration is determined, particularly when there is a divergence with that of domestic resources. It examines whether the existing capacity mechanism designs, including the auction constructs, ensure a level playing field between domestic and foreign resources.

142 The Electricity Regulation prescribes that foreign capacity that can provide the same technical service as domestic capacity, should be able to participate in the same competitive auctions. The participation of cross-border capacity should be implemented in a transparent, non-discriminatory and market-based way[124].

143 In Belgium and Poland, the obligations on foreign resources and the eligibility criteria for their participation, are, in principle, the same for both foreign and domestic resources[125]. In Italy, the obligations and eligibility criteria for foreign resources are substantially less demanding than the obligations for domestic capacity. Foreign resources only need to be registered with the Italian power exchange, for financial purposes, to be allowed to participate in the Italian capacity mechanism. They are also subject to the payback obligation[126], but otherwise have no further obligation. For example, unlike domestic resources, foreign resources do not need to prove physical availability in any of the market timeframes. According to the Italian authorities, foreign resources are unable to provide equivalent technical performance, which justifies their different treatment compared to domestic resources[127].

144 The participation of foreign resources in the competitive auctions of the capacity mechanisms differs between Member States. The capacity mechanisms of Belgium and Poland include pre-auctions to identify the cheapest foreign resources per bidding zone border, up to the MEC[128]. The foreign resources that clear the pre-auction can then participate in the main auctions alongside domestic resources[129]. On the other hand, in Italy and France, foreign resources and interconnectors participate directly in the main capacity mechanism auctions respectively.

145 In addition to the differences in the auction construct, the remuneration rules for foreign resources also vary across the capacity mechanism designs. In the French capacity mechanism, the remuneration of interconnectors and domestic resources is the same[130]. The same is true for the Italian capacity mechanism, unless the amount of contracted foreign capacity matches the MEC for certain bidding zone(s)[131]. In this case, the remuneration of foreign resources from the relevant bidding zone(s) is equal to the highest accepted bid from that zone[132]. In the case of Poland, the remuneration of foreign resources is lower than that of domestic resources by design. Specifically, foreign resources receive the highest accepted bid associated with the bidding zone (or area) that the foreign resource is located in[133]. The Belgian capacity mechanism is different than the other market-wide mechanisms, in that it uses the pay-as-bid, instead of the pay-as-clear, principle. Resources, both domestic and foreign, are

124 As set out in Article 26(8) of the Electricity Regulation.

125 The French TSO, RTE, has communicated that the obligations on foreign resources will be the same with the obligation for domestic ones, once direct foreign participation is implemented.

126 This means that foreign resources need to compensate the capacity market operator, and ultimately the Italian consumers, with the difference between the market (or reference) price of the Italian bidding zone they are connected to and the pre-determined strike price, when the former is higher than the latter. This feature applies to domestic resources too and is characteristic of the reliability option type of capacity mechanism.

127 For more information, see footnote 103.

128 This means that a separate pre-auction takes place for each of the foreign bidding zones (or areas) that participate in a capacity mechanism.

129 In both cases, foreign resources are unable to change the bids submitted in the pre-auctions. For Belgium, the capacities selected in the pre-auction still need to pass the full prequalification before entering the main auction.

130 Regulated interconnectors are price takers in the French capacity auctions and always offer their capacity in the last auction prior to the year of delivery, i.e., the T-1 auction that takes place in December before the delivery year. Their participation and valuation are managed by the French TSO and any revenues arising from their participation are ultimately passed on to consumers through reduced network tariffs. Merchant interconnectors, on the other hand, can sell the capacity guarantees like any other capacity provider.

131 The remuneration of foreign resources is capped at the same level with that of existing resources, i.e., 33,000 euros/MW/year. Similarly, when the foreign participation is lower than the allocated MEC, the remuneration of foreign resources is set at the same level as that of existing resources of the interconnected Italian bidding zone.

132 Or in other words equal to the bid of the marginal foreign unit that cleared the auction, as in a pay-as-clear mechanism.

133 The only case where foreign resources receive the same remuneration as domestic resources, is when a foreign resource clears the overall auction. In this case, foreign resources belonging to same bidding zone and domestic resources receive identical remuneration. For more information, see section 5.2.4.

remunerated based on their submitted bids[134].

146 The existing capacity mechanisms treat the participation of foreign resources differently when this is lower than the MEC. The French and Italian capacity mechanisms assume that the contribution of foreign resources equals the MEC, even if this is not fully allocated to foreign resources, i.e., participation is lower than the MEC. On the contrary, the Polish capacity mechanism procures additional domestic resources to compensate for any lack of foreign resources in case their participation is lower than the MEC. A decision related to this point is still pending in the Belgian capacity mechanism.

147 The Electricity Regulation stipulates that capacity mechanisms should allocate the MEC in a market-based manner and that revenues may arise from this allocation[135]. These revenues effectively represent the value that foreign resources place on the right to participate in a capacity mechanism. Currently, no revenues arise from the allocation of the MEC except for the Polish capacity mechanism. In the latter case, the revenues are calculated ex-post and depend on the capacity auction clearing prices for the Polish and foreign bidding zones[136].

148 Table 4 summarises the key features of market-wide capacity mechanisms regarding the obligations of foreign resources and the ways in which they are remunerated.

134 According to the Belgian capacity mechanism regulations, the Belgian TSO is tasked with investigating the pay-as-clear alternative in the future. A change in the remuneration principle is not envisaged at this stage.

135 Article 26(9) of the Electricity Regulation.

136 The revenues are split based on a 50-50 rule between the Polish TSO and the TSO where the foreign capacity is based.

Table 4: Obligations and remuneration of foreign resources in Belgium, France, Italy and Poland - 2022

Member State	Obligations on foreign resources compared to domestic ones	Pre-auctions to select foreign resources	Foreign and domestic resources receive same remuneration	Foreign contribution assumed always to be equal to MEC	Revenues arising from allocation of MEC
Belgium	Same	Yes	No All resources remunerated based on pay-as-bid principle	Not defined yet	No
France	NAP	No	Yes	Yes	No
Italy	Limited obligations	No	Yes, if contracted foreign capacity is lower than the MEC. Lower remuneration if they match each other	Yes	No
Poland	Same	Yes	No Foreign resources receive lower remuneration, by design (with one exception)	No	Yes

Source: ACER based on information from TSOs and NRAs.

Note: The French TSO has communicated that the obligations on foreign resources will be the same with the obligation for domestic ones, when direct foreign participation is implemented.

149 Figure 12 presents the MEC and realised allocated capacities per foreign bidding zone, alongside the remuneration received from foreign resources for each capacity mechanism. ACER observes that foreign participation has at instances been lower than the MEC. For example, in the case of the latest Polish auctions, participation of foreign resources was lower for both Sweden and the synchronous zone of the Czech Republic, Germany and Slovakia[137]. Similarly, foreign participation from the synchronous zone connected to the North-Italy bidding zone was lower than the allocated MEC in the latest Italian auction. With regard to the remuneration of foreign resources, Figure 12 clearly shows that this is often lower than the remuneration received from domestic resources, as was the case in both the latest auctions of the Italian and Polish capacity mechanisms. Remuneration data for all concluded auctions is available in Table 18 in Annex I: Additional figures and tables.

5.2.4. Case Study: Auction construct and foreign capacity remuneration in the Polish capacity mechanism

150 The Polish capacity mechanism is the first one that allowed direct foreign capacity participation, as of 2020 (first delivery year 2025). In 2020, only resources from Lithuania could take part in the Polish capacity mechanism, while the following year resources from Sweden were also eligible to participate. Geographical participation in the capacity mechanism was extended to the Czech Republic, Slovakia, and a part of Germany (resources connected to the network of one of the TSOs, 50Hertz) in the 2022 T-5 auction. All German resources are expected to be able to participate as of the next T-5 auction[138]. All German resources are expected to be able to participate as of the next T-5 auction. The mechanism considers participation from Lithuania and Sweden separately, while resources from the Czech Republic, Germany, and Slovakia participate jointly through a synchronous profile. This means that the Polish capacity mechanism essentially determines one MEC for the synchronous profile, whereby resources

137 In other words, the only foreign bidding zone that fully utilised the allocated MEC, was the Lithuanian bidding zone.

138 Specifically, the next T-5 auction is planned in December 2023, for 2028 delivery.

from all three Member States compete against each other.

151 The capacity mechanism selects successful foreign resources in two steps. In the first step, foreign resources participate in dedicated pre-auctions per participating country or zone. Foreign resources bid their capacity and offered price, and the pre-auction selects the cheapest resources up to the MEC for each of the participating zone, similar to a merit order type of auction clearing. The outcome of the pre-auctions is therefore accepted pairs of capacities and offered prices.

152 The foreign resources that were successful in the pre-auctions then participate in the main auction, in direct competition with domestic resources and foreign resources from the other zones. The objective of the main auction is to select the cheapest resources across both domestic and foreign resources that satisfy the targeted capacity requirement; the auction is indifferent to where a resource is based. However, unlike domestic resources, foreign resources cannot alter their bids, either from the pre-auction or between rounds of the main auction[139].

153 Ultimately, the main auction determines one clearing price for the Polish bidding zone and one for each participating, foreign zone. Unless the marginal unit that cleared the main auction is from a foreign zone, the clearing price (or reward) deviates for domestic and foreign resources and is lower for foreign resources. The clearing price for each foreign zone is determined by the marginal offer accepted[140].

154 As explained, the main auction aims at selecting the cheapest resources for meeting the total capacity requirement independent of whether these are located within Poland or abroad. This is also the case if participation of foreign resources is lower than the MEC. In other words, the Polish capacity mechanism would procure additional domestic resources to compensate for the lower-than-expected procurement of foreign resources. This effectively lowers the pre-determined MEC, even though the latter is independent of foreign participation in the capacity mechanism (i.e., the calculated MEC does not consider additional revenues for foreign capacities and therefore is independent of them).

155 ACER considers that this construct can lead to the increase of the costs to Polish consumers in two ways:

a. by procuring more domestic capacities, thus paying more than if one considered that foreign resources would deliver the MEC; and

b. by increasing the auction price for all cleared capacities, as by definition the auction would select more expensive capacities to meet the capacity requirement.

156 The latest Polish auction did not fully utilise the allocated MEC for two of the three foreign zones as can be seen on Figure 12. This outcome can be considered surprising, given the significant number of capacities located in these bidding zones compared to the available MEC[141]. ACER believes that the capacity mechanism auction should consider that the MEC is fully utilised in the event of limited foreign participation to avoid unnecessary cost increases to Polish consumers[142]. This approach is currently followed in the Italian capacity mechanism for example. In any case, the calculated MEC does not consider additional revenues for foreign capacities and therefore, it should be independent of them.

157 Lastly, ACER considers that the current auction construct of the Polish capacity mechanism puts foreign resources at a disadvantage. Foreign resources must decide on their offered prices well in advance of the main auction, with partial information compared to domestic resources, e.g., in terms of the pre-selected resources[143]. Moreover, while domestic resources can adjust their bids between consecutive rounds of the main auction, foreign resources are prohibited from doing so. ACER notes, however, that the main

139 The Polish capacity mechanism follows a Dutch (or "descending-clock") auction type to determine the clearing price.

140 For more information on the rules for the participation of foreign capacity resources in the Polish capacity mechanism, see the Polish TSO's associated guidance.

141 The Polish authorities were unclear about the reasons for the limited participation of foreign resources. This might simply be for practical reasons, e.g., because foreign resources were unfamiliar with the rules of the capacity mechanism, which could be particularly true in the early years of implementation.

142 This does not mean that foreign resources should not be rewarded for the service they provide. ACER anticipates that as direct foreign participation becomes more commonplace and capacities familiarise themselves with capacity mechanism rules, the issue of limited foreign participation will likely fade away. In the meantime, it is prudent to closely monitor foreign participation and where this is limited, investigate the reasons for it and consider if there might be a need for changes to the rules of a capacity mechanism.

143 According to the mechanism's rules, the pre-auction must be organised between 16 and 18 weeks before the main auction.

auction enables the direct competition between domestic and foreign resources[144].

158 ACER considers that the auction construct could improve by focusing the pre-auction on allocating MEC tickets, i.e., foreign resources would compete against each other for the purchase of MEC-capacity[145]. Following this, the second step would consist of a competitive auction between all resources, as currently the case, with the difference being that foreign resources could adjust their bids like domestic resources. Ultimately all successful resources would receive the same remuneration from the capacity market auction, while foreign resources would pay for the allocation of MEC tickets based on the pre-auction results.

5.2.5. Future developments

159 Beside continuing to monitor the implementation of direct foreign participation in national capacity mechanisms and drawing lessons from national practices, ACER will also follow progress in the tasks allocated to ENTSO-E and RCCs. As described in Section 5.2.2, the Electricity Regulation prescribes that the MECs are to be calculated by the RCCs. Beside an ACER-approved ERAA (discussed in Section 3.3.1), a MEC calculation procedure (including a dedicated calculation tool) put forward by ENTSO-E is a prerequisite for a harmonised MEC calculation process. ENTSO-E expects that the tool and the procedure will be in place in 2024 and that in the same year, the RCCs will be able to provide the MEC recommendations.

160 ACER will also monitor the status of the registry of foreign capacity providers maintained by ENTSO-E, which should be expanded beyond its current status (it currently covering only units eligible for the Polish capacity mechanism).

5.3. Penalties in capacity mechanisms

5.3.1. Introduction

161 Capacity mechanisms remunerate resources to be available when needed to secure supplies. Conversely, beneficiaries of capacity mechanisms failing to provide the paid service during these periods incur financial penalties. This incentivises beneficiaries to be available when needed and deters them from disregarding their obligations. Ultimately, a well-designed penalty regime aims to ensure that unreliable capacity providers, who do not deliver on their commitments, face appropriate consequences for not contributing to security of supply.

162 The Electricity Regulation specifies that any capacity mechanism should apply appropriate penalties to capacity providers that are not available in times of system stress[146]. The State Aid Guidelines offer further instructions. In the document, the Commission prompts to efficiently incentivise beneficiaries to contribute to the security of supply, by linking these incentives with VOLL. When translating this guidance to penalties, a capacity provider unavailable at the time of scarcity should face a penalty related to VOLL, as it adequately represents the value of uninterrupted supply.

163 For the purpose of this analysis, ACER categorises penalties into two types: non-delivery penalties and non-performance penalties. Non-delivery penalties apply when new resources are not commissioned for the contracted delivery period or part of it. Non-performance penalties are commonly incurred by beneficiaries when their contracted capacity is unavailable during a scarcity (or near-scarcity) event. It matches the capacity mechanisms' aim to remunerate reliable resources.

164 This section focuses on the current practices regarding penalties as a design feature of capacity mechanisms implemented in the Member States. It is divided into two subsections, outlining non-delivery and non-performance penalties, respectively. The objective of this section is to offer a thorough insight

144 The direct competition essentially mitigates any potential concerns about foreign resources exerting market power following the pre-auctions. As a result of the pre-auction only a limited amount of foreign capacity can participate in the main auctions, up to the MEC at maximum, which could raise such concerns.

145 As it stands, the MEC ticket prices are determined at the very end of the process, after the remuneration for foreign and domestic resources has been determined. This approach essentially uses reverse engineering to assess the value of the MEC. The proposed alternative approach closely resembles the allocation of cross-zonal capacity in the forward market, through auctions of the Joint Allocation Office.

146 Article 22(1)(i) of the Electricity Regulation.

into various penalties' arrangements and draw lessons based on current practices.

5.3.2. Non-delivery penalties

165 Penalties for non-delivery refer to penalties for new resources that are not in place for the delivery period they have been contracted for, or part of it. As they refer to new resources, they are specific to market-wide capacity mechanisms. Strategic reserves normally target existing capacities (e.g., existing thermal generation) and none of the mechanisms currently in place apply non-delivery penalties.

166 Some of the common characteristics of non-delivery penalties, described in this section, relate to the way the penalties are determined, when and the period for which they apply and the conditions under which a contract is terminated[147]. In addition, this section examines whether non-delivery penalties consider the cost of procuring new capacity to compensate for the undelivered capacity, what happens in the event of non-delivery and other safeguards in place to ensure the timely reaction to non-delivered capacity. The section closes with a case study from the Irish capacity mechanism.

167 Regarding the determination for non-delivery penalties, the analysis identifies two main approaches. In the first approach, which is applicable in the Belgian and Irish capacity mechanisms, the penalties are fixed and pre-determined[148]. The second and more common approach, however, is that of variable penalties linked to a reference price. This reference price normally represents the cost for securing capacity for a delivery year. For example, in the case of the Polish capacity mechanism, the penalty is determined for each delivery year and is equal to the highest auction price corresponding to this year[149]. In the French capacity mechanism, the penalty is linked to the last T-1 auction prior to the year of delivery[150].

168 A further distinction concerning the second approach is that the penalties can be determined as a price differential between the reference price and the awarded price secured by the beneficiary. The Italian and French capacity mechanisms follow this latter approach[151], [152]. In these cases, the penalty may vary within a significant range, essentially from zero to the price cap.

169 Penalties commonly apply from the start of a beneficiary's contract and in proportion to the time the contracted capacity is unavailable in a year. For example, in the Polish capacity mechanism beneficiaries that have failed to deliver their capacity on time, face a penalty for each month of delayed commissioning. For the first year of non-delivery, the monthly penalty is 5% of the equivalent annual penalty, while the penalties increase for subsequent years[153]. Similarly, in the French capacity mechanism, the total non-delivery penalty is determined in proportion to the critical days within a year for which the resource was not yet delivered[154].

170 Ultimately if a beneficiary is unable to deliver its capacity within a pre-determined period, its contract is

147 Another common characteristic of non-delivery penalties is that new resources must pay a collateral as security to the system operator. This topic is not explored further in this report.

148 The Belgian rules specify the penalty rates depending on the project type (new capacities incur higher penalties than additional capacities), project progress and time remaining to the delivery period. The non-delivery penalties for new capacities vary between 10,000 and 20,000 euros/MW/year. The low end of the range applies if the beneficiary can demonstrate they have made every effort to obtain the relevant permits but did not receive them. The Irish capacity mechanism applies pre-determined penalties that increase the closer the termination of a beneficiary's contract occurs to the start of their contract's delivery period. For more information, see section 5.3.2.1.

149 For example, the penalty for the delivery year 2023, is set at around 79,000 euros/MW/year, based on the clearing price of the additional T-1 auction for the fourth quarter of this year.

150 In the case of the French capacity mechanism, the December auction prior to the delivery year is considered the reference auction for the delivery year. This is because it is the most liquid auction and the one that interconnector capacity participates, among other reasons.

151 In the Italian capacity mechanism, beneficiaries that had their contracts terminated are also responsible for the payback obligation for the entire duration of their original contract.

152 In the French capacity mechanism, the non-delivery penalties apply to capacities contracted through the AOLT (offering seven-year contracts to demand response and storage capacities) and AOE (offering one-year contracts to demand response capacities, and since 2023 ten-year long contracts too) support mechanisms. Currently, a significant part of demand response is contracted through the AOE support mechanism.

153 Essentially, if a resource is unavailable for the first year of its contract's duration, the beneficiary pays 5% of the equivalent annual income. The monthly penalty rate increases to 15% and 25% for the second and third year of the contract's delivery period.

154 In the French capacity mechanism, the non-delivery penalties are measured with reference to the resources' availability during critical days, the so-called PP1 and PP2 days that are applicable for implicit and explicit demand response respectively. For example, the capacity mechanism rules determine 15 PP1 days per year: 11 are selected from the 1 January to 31 March, and four are selected from the 1 November to 31 December. There are 10 PP1 hours per day: from 7 a.m. to 3 p.m. and from 6 p.m. to 8 p.m. For example, a resource that is unavailable during just one of the PP1 days in a year will pay 1/15th of the annual penalty. The PP1 and PP2 days are notified on the national TSO's website.

terminated. For example, in both the Italian and Irish capacity mechanism, the contract is terminated if a beneficiary fails to make available the bulk of its capacity within a certain period from the start of their contract's delivery[155, 156].

171 When the contract is terminated, beneficiaries are usually subject to multi-year penalties, in some cases up to a certain threshold. Resources that had their contract terminated pay a maximum of four years' worth of penalties from the date of the contract termination in the French capacity mechanism, and three years of penalties in the Polish capacity mechanism. The rules of the Italian capacity mechanism essentially mean that beneficiaries must pay the non-delivery penalties for the entirety of their originally contracted period, while in the Irish capacity mechanism the penalty applies for one year only. In the Belgian capacity mechanism, a beneficiary's contract is terminated if it fails to meet the intermediate milestone requirements for three years in a row. The beneficiary is subject to multi-year penalties in this case[157]. Naturally, beneficiaries that delayed the commissioning of their contracted capacity or had their contract terminated lose any rewards from their capacity mechanism contract for the respective period.

172 The way penalties are determined essentially means they do not generally relate to the costs incurred for replacing the non-delivered capacity. In the Italian capacity mechanism, the non-delivery penalties are linked to the cost of procuring replacement capacity in the secondary market (for more information, see recital (176)). In this case, developers that failed to deliver on time are responsible for the incremental cost only, of procuring new capacity; this incremental cost can vary within a significant range. For example, the first two auctions of the Italian capacity mechanism cleared at the auction price cap, essentially rendering this part of the non-delivery penalty ineffectual (beneficiaries are still subject to the payback obligation for the entirety of their original contract)[158]. In the Polish capacity mechanism, non-delivered capacities may face a penalty linked to the auction prices of the quarterly year-ahead auctions, if the latter is higher than the price of the T-5 auction. The year-ahead auctions are the default option to seek any replacement capacity, if needed (see also recital (176)).

173 To assess the risk of non-delivery, national authorities monitor the development of new resources in most of the existing market-wide capacity mechanisms. This commonly takes the form of regular, progress development reports by the developer to the capacity market operator. For example, in the Belgian and Italian capacity mechanisms developers must deliver quarterly progress reports, and in the Irish capacity mechanism half-annual reports. Moreover, in the Irish and Polish capacity markets developers need to meet certain milestones and report on their fulfilment[159]. In the French capacity market, the TSO is responsible for signing contracts for new capacities and monitors their development, whereby beneficiaries have to inform the TSO in case they are facing any issues with the commissioning of their resources[160]. In addition, beneficiaries are responsible for certifying their capacities and inform the TSO accordingly.

174 In the event of non-delivery, there is a general lack of special arrangements to compensate for the undelivered capacity. The approach followed in the Irish and Polish capacity markets is to seek additional

155 In the Italian capacity mechanism, the contract is terminated if the beneficiary uses three temporary non-fulfilment permits, determined as delivery of less than 80% of the contracted capacity for more than 25% of the time in a month. This would likely translate to the termination of a contract if a beneficiary fails to deliver the bulk of its contracted capacity within the first three months from the start of its contract. Some exceptions apply to this rule, for example in relation to non-availability due to maintenance.

156 In the Irish case, the non-delivery penalties apply if a beneficiary is unable to deliver 90% of its contracted capacity by 18 months after the start of the contract for a T-4 contract, or one month after the start of the contract for a T-1 contract.

157 Beneficiaries have to meet the intermediate milestone requirements (e.g., signature of the EPC contract, permits for the construction of the project delivered in the last administrative instance) 26 months ahead of the start of the delivery year. If a beneficiary fails to meet these requirements, the start of its contract is delayed by one year while the end period remains the same, essentially shortening the overall duration of the contract. Beneficiaries that have their contract terminated face penalties for not meeting the intermediate milestone requirements, the so-called pre-delivery penalties, which are half the penalties applying for non-delivery at the end of the predelivery period. In addition, they are subject to the non-delivery penalties for one year (the first year of delivery). Similarly to the Italian capacity mechanism, beneficiaries that had their contract terminated are also subject to non-performance penalties for the rest of the of their contract duration (for more information, see section 5.3.3). Beneficiaries have to right to terminate their contract 30 days after the deadline for the intermediate milestone, upon which they only face the applicable penalties until that point in time.

158 The auction price cap also sets the ceiling for procuring any replacement capacity through the secondary market.

159 For example, in the Polish capacity market, the developer of a new resource needs to provide evidence within 24 months of concluding the contract that: i) it has reached a capital expenditure of at least 10% of the required investment; and ii) it has concluded agreements related to the investment with a total value of at least 20% of the required investment. Failure to provide the necessary evidence leads to the termination of the beneficiary's contract.

160 As already noted, non-delivery penalties only apply to demand response and storage in the French capacity mechanism, as new fossil fuel power stations cannot participate in the mechanism.

capacity in the complementary T-1 auction if needed, that is closest to the delivery year[161]. In the Italian capacity mechanism, the TSO is responsible for procuring replacement capacity in the event of non-delivery through the secondary market, where it acts as a price taker[162]. Finally, in the French market-wide capacity mechanism that differs from the rest, in that it is a decentralised one, the obligation to acquire capacity certificates rests with the suppliers[163].

Table 5: Key characteristics of non-delivery penalties across market-wide capacity markets in Belgium, France, Italy, Ireland and Poland – 2022

Member State	Determination of non-delivery penalties	Conditions for contract termination	Duration of penalties applying upon contract termination	Penalties consider the cost of procuring replacement capacity	Active monitoring of beneficiaries' delivery in place	Procedure in place to compensate undelivered capacity
Belgium	Pre-determined fixed penalties	Failure to meet intermediate milestone requirements for three years in a row	Pre-delivery penalties for maximum of three years plus non-delivery penatly for one year	No	Yes	Normally through T-1 auction
France	Variable – linked to a reference price for a delivery year and contract price	On the initiative of beneficiary	Maximum four years' worth of penalties	No	Yes	Obligation rests with suppliers
Italy	Variable – linked to the premium for contracting replacement capacity	Failure to make bulk of capacity available for three months	Original contract duration	Only incremental cost	Yes	TSO purchases replacement capacity in secondary market if available
Ireland	Pre-determined, fixed penalties	Failure to make bulk of capacity available within 18 months	One year	No	Yes	Normally through T-1 auction
Poland	Variable – equal to highest auction price for a delivery year	Failure to commission bulk of capacity within three years	Three years' worth of penalties	Share of replacement costs, under conditions (implicit)	Yes	Normally through T-1 quarterly auctions

Source: ACER based on information from NRAs and TSOs.

Note 1: Commonly, beneficiaries can terminate their contract on their own initiative, for example, in the Belgian, French and Irish capacity mechanisms.

Note 2: For the Irish capacity mechanism, the contract termination rule applies for resources that have won a contract at the T-4 auction. For resources in the T-1 auction, the cut-off date is one month after the start of the delivery period.

Note 3: For the French capacity mechanism, the penalties in case of contract termination apply to beneficiaries of the AOLT support mechanism.

Note 4: For the Polish capacity mechanism, on top of the penalties applying upon contract termination, the capacity market operator also seizes the collateral paid by the beneficiary. For unconfirmed demand side-response in particular, the contract is terminated if the capacity provider has not obtained the confirmation of the demand reduction capacity test before the start of the delivery period.

Note 3: For the Polish capacity mechanism, on top of the penalties applying upon contract termination, the capacity market operator also seizes the collateral paid by the beneficiary.

161 The T-1 auction is a common feature in most market-wide capacity markets, aimed at refining the capacity requirement based on updated and recent information (e.g., on the expected demand levels and available capacity).

162 Essentially, the Italian TSO would buy replacement capacity at any price up to the price cap for new resources as defined in the mechanism's rules. The Italian TSO can also run an adjustment auction prior to the delivery year if deemed necessary.

163 Non-delivered capacity cannot sell certificates in the capacity mechanism auctions, and as such, it does not affect a supplier's certificates position.

5.3.2.1. Case study: Non-delivery penalties in the Irish capacity mechanism

175 The Irish market-wide capacity mechanism has been in operation since 2018, replacing the capacity payment mechanism that was in place since 2007. The first T-4 auction was for delivery year 2022/2023 and procured just over 700 MW of new (de-rated) capacity. Around 500 MW of this capacity, predominantly gas-fired power plants, failed to be commissioned on time and the relevant contracts were terminated around one and a half years prior to the start of the delivery year[164]. As a result, the undelivered capacity faced a penalty of 10,000 euros/MW[165].

176 In the short-term, the security of supply outlook further deteriorated by the accelerated growth of demand, primarily from data centres, and lower-than-projected availability of older, existing generation. In addition, some of the subsequent capacity market auctions failed to attract the required capacity, thus further exacerbating the situation in the future. As a result, the TSOs of the all-island Single Electricity Market projected a significant capacity deficit in their 2021 Generation Capacity Statement[166]. The projected supply deficit was expected to grow rapidly from around 260 MW in delivery year 2022/2023 to 1850 MW in delivery year 2024/2025[167].

177 In reaction to the potential capacity shortfall, the Irish authorities employed a plan to address the increased risks in the short- and medium-term and strengthen the country's security of electricity supply over the longer-term. For the short-term, the most important measure applied is the procurement of temporary emergency generation. Specifically, the national TSO procured 250 MW of capacity for the 2022/23 and 2023/24 winters and have signed initial equipment contracts for an additional 450 MW for winter 2024/25[168]. This capacity consists primarily of gas-fired power generation and the total procurement cost is expected to vary/exceed XYZ[169, 170].

178 In addition, the national authorities, have put a number of other temporary measures in place to address the potential capacity shortfall in the short-term. These include retaining existing generation units that would otherwise shut down primarily due to environmental legislation, for emergency use only, and implementing changes to the regulatory framework for demand response (e.g., enabling the participation of demand response in the energy market) to enhance its participation and responsiveness in the wholesale market[171].

179 For the long term, the Irish authorities have determined the development of new gas-fired generation out to 2030 as a key overarching goal, alongside the deployment of new resources, such as storage and demand-side response[172]. To achieve these goals, the authorities have refined the design of the capacity market to ensure successful delivery of this capacity and are contemplating further adjustments for the future.

180 Regarding the non-delivery penalties, the new rules introduce higher and more gradual penalties. They establish different penalty rates for the termination of contracts, depending on the timing of the contract

164 The reasons for the failure to deliver the new capacity vary. For example, some of the new capacity could not guarantee it would meet the environmental requirements of the applicable legislation, and other faced lengthy delays with receiving the necessary permits. For more information, see for example, Ernst and Youngs's Review of the Performance of the Irish capacity market, commissioned by the Irish NRA.

165 Some of the undelivered capacity participated in later auctions and received significantly higher remuneration than the original contract price. Ibid.

166 EirGrid and SONI, All-Island Generation Capacity Statement 2021-2030.

167 For more information, see for example, CRU's 2021 Information Paper on Security of Electricity Supply –Programme of Actions

168 Ultimately, the temporary generation procured for winter 2022/2023 was not delivered on time. Work is underway involving multiple stakeholders (e.g., site owners and developers, system operators), to deliver this temporary generation capacity as quickly as possible, with the majority aimed for delivery in the last quarter of 2023.

169. The Irish NRA, Electricity Transmission Network Allowed Revenues for 2023 And Demand Transmission Use of System (D-TUoS) Tariffs 2022/23. For 2022, the projected costs for the procurement of temporary generation were 115 million euros, and for 2024, the projected costs for temporary generation amount to around 372 million euros. For reference, the total cost of the Irish market-wide capacity mechanism (concerning the All-Island Single Electricity Market) has historically been around 350 million euros for a delivery year (see also Figure 4 for more information).

170 In terms of operation, the temporary emergency generation is placed outside the wholesale market, meaning it cannot participate in either the energy market, capacity market or the ancillary services market. According to the associated rules of operation, the temporary emergency generation should only be utilised by the national TSO when it is clear that market resources will be insufficient to meet expected demand.

171 For a more complete description of the short-term measures introduced by the national authorities, see for example the Commission for Regulation of Utilities' dedicated webpage on the Electricity Security of Supply Programme of Work (including the original work programme and update notes).

172 Ibid.

termination with regards to the start of the contract's delivery[173]. Table 6 below presents the applicable non-delivery penalties for the first (2022/2023 delivery) and latest (2027/2028 delivery) T-4 auctions[174].

Table 6: Non-delivery penalties in the Irish capacity mechanism for two delivery years

Non-delivery penalties (euros/MW) – expressed with regards to beginning of delivery year	T-4 auction for 2022/2023 delivery	T-4 auction for 2027/2028 delivery
Prior to 27 months	10,000	20,000
Between 27 and 13 months prior		30,000
From 13 months prior, to beginning of delivery year	30,000	40,000
From beginning of delivery year	40,000	50,000

Source: ACER based on information from NRAs and TSOs.

181 To complement the changes to the non-delivery penalties, the Irish authorities have introduced more rigorous assessment of the risks to non-delivery and enhanced monitoring of the development progress for new resources. Moreover, they have decided to perform the T-4 auctions earlier to provide for a more realistic timeline for the development of new resources[175]. Finally, they are considering further changes to the rules of the capacity mechanism, such as a requirement for new resources to have all necessary permissions to prequalify in the capacity market auctions.

182 The Irish case study offers some important insights. The non-delivery of new resources has undermined security of supply in Ireland and led to a flurry of emergency actions to deal with the increased risks to security of electricity supply. These actions, such as the procurement of temporary generation, have come at a significant cost to consumers, a multiple of the original cost for securing new resources. This can be primarily attributed to the short timeframe to deploy these resources, limiting the available options and competition, consequently leading to the deployment of more expensive solutions overall. Moreover, some of these measures could have adverse effects on the country's emissions budget and emissions reduction trajectory, as they rely on running more polluting, or less efficient, generation technologies[176].

183 This case study provides strong evidence about the benefits of well-designed, non-delivery penalties to ensure developers have the right incentives in place to ensure their capacities are delivered on time[177]. On the other hand, lenient penalties could lead to less robust offers by market participants[178]. Ultimately, if new resources fail to be commissioned on time, this could have severe repercussions for security of supply and lead to significantly higher costs for consumers. ACER is of the view that non-delivery penalties should be set at an adequate level to deter non-robust or speculative bidding. Additional safeguards in the form of ongoing monitoring and risk assessments related to the delivery of new resources can also play an important role to mitigate risks and react in a timely manner.

173 The gradually increasing penalties aim at providing an incentive to beneficiaries to terminate their contract before the cut-off date for the next time-step.

174 For more information, see for example the applicable penalties for the latest T-4 auction (Table 20 of the 2027/2028 T-4 Capacity Auction - Initial Auction Information Pack).

175 The new rules have brought forward the T-4 auction by around 4 months, essentially allowing around four years for the completion of new projects, i.e., from the announcement of the auction results to the start of the delivery year.

176 As explained, the temporary generation would only run as a last-resort solution, if the market is unable to meet demand. As a result, its operation can be expected to be limited.

177 Stringent penalties may also have downsides, such as lead to overall higher bids to account for the risk associated with higher penalties. On the other hand, capacity mechanisms already imply a transfer of risk from investors to consumers, through the implementation of long-term contracts (effectively, consumers have to pay for new investments for a long period, independent of the need for these resources). Moreover, investors are naturally better placed to manage the risks associated with their investments, and therefore should also face them. The rules could allow flexibility for risks that are outside the control of investors (e.g., risks associated with extreme external conditions, such as the ones experienced recently with COVID-19).

178 This is often referred to as winner's curse, whereby bidders are over-optimistic about their ability to deliver their capacity on time, to secure a contract.

5.3.3. Non-performance penalties

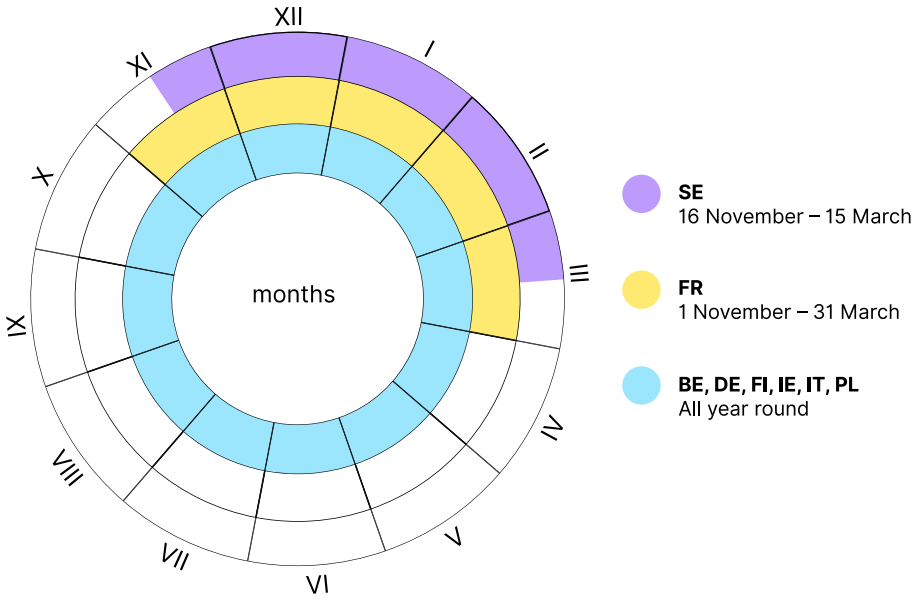
5.3.3.1. Delivery period and system stress

184 Resources unavailable within the period covered by the capacity contract are commonly subject to non-performance penalties. Capacity mechanism rules specify when relevant system or market operator has a right, or requirement, to call upon the providers to make their capacities available. In principle, a failure to fulfil the contractual obligation should be penalised when the system is in under stress[179] .

185 The European framework does not prescribe how to define system stress[180]. Therefore, it is up to the rules of each capacity mechanism to indicate when the beneficiaries are anticipated to fulfil their obligation, i.e., provide capacity. These rules first specify the delivery period, that is the time when contracted resources should remain available (see Figure 13). Second, national rules lay down conditions that trigger expectation of performance (see Table 7 and Table 8). In other words, these predefined triggering conditions indicate system stress such as anticipated market tightness. Only when a triggering event takes place within a delivery period, do capacity providers have an obligation to perform. Providers that do not fulfil such an obligation, incur non-performance penalties[181].

186 Figure 13 presents the delivery periods as currently defined in the national capacity mechanisms. In six Member States, beneficiaries have to remain available all year round. In principle, this implies that beneficiaries have a responsibility to provide required capacity, regardless of when the triggering condition occur[182]. In France and Sweden, the delivery period largely coincides with the winter months, during which the likelihood of resource adequacy risks materialising is higher, as both power systems are winter peaking[183].

Figure 13: Delivery periods across capacity mechanisms in the EU - 2022



Source: ACER based on information from NRAs.

187 The overview of triggering conditions exhibits divergent definitions of system stress. The rules for the Finnish strategic reserve differentiate between winter season (1 December to 28 February) and the rest

179 Article 22(1)(i) of the Electricity Regulation.

180 In 2014, the Council of European Energy Regulators carried out an analysis on the assessment of generation adequacy. It showed that before the adoption of current European legal framework Member States had diverging views on the definition of system stress (ref. https://www.ceer.eu/documents/104400/-/-/a9517a5f-5a98-2974-dd61-e085c7971b53). The most common indicator at the time related to system states (such as normal, alert, or emergency state) as laid down by Regulation (EU) 2017/1485.

181 In practice, if French capacity market operator expects tightness on 21 June and calls upon capacity providers, they do not have an obligation to perform and hence, do not incur penalties as June is outside the delivery period in France.

182 This does not mean that the delivery period is the same with the calendar year. For example. the Polish capacity mechanism defines the delivery period as the calendar year, while the Irish capacity mechanism defines the delivery period between the beginning of October and end of September of the next year.

183 This means that both Member States experience higher demand levels during the winter season, which is one of the key drivers of adequacy risks.

of the year, with the winter requirements being significantly more demanding[184]. The Finish TSO may request beneficiaries to provide contracted capacities, when it assesses that the balancing resources are likely to be exhausted in the given period. The German strategic reserve framework mandates providers to be available all year round with activation announced at times of scarcity. In Germany, scarcity is defined as a situation when there is no market clearing in day-ahead or intraday auctions. In Sweden, resources participating in the strategic reserve have to remain available for the winter season, when demand tends to be highest compared to the rest of the year.

188 Market-wide capacity mechanisms commonly apply some reference to scarcity or other limitations that could be considered system stress. In Poland and France, the capacity market operators call for availability when day-ahead forecasts indicate system tightness. Providers contracted on Polish capacity market are called upon when the forecast available generation in the day-ahead timeframe does not exceed projected demand by more than 4%[185]. In Poland, the operator can issue a capacity mechanism alert (requesting that all beneficiaries be available to generate electricity) at any time of the year. The French operator requires beneficiaries to be available on specific days of expected high demand or system tension, by sending them a performance request one day in advance. Rules in France stipulate that the operator can call beneficiaries between 15 and 25 days in the winter period.

189 According to the design of the Belgian, Italian and Irish reliability option capacity mechanisms, resources are expected to provide capacity at any time the system operates under tight conditions. Such tight conditions should be reflected in the wholesale prices, incentivising beneficiaries of these capacity mechanisms to perform as the market price rises against the strike price (for more information, see recital (196)). In addition, the Belgian capacity mechanism includes an explicit definition of system stress period, referring to hours when the day-ahead price exceeds a predetermined threshold[186].

5.3.3.2. Penalties for unavailability during system stress

190 Non-performance penalties or penalties for a failure to fulfil the obligation at times of system stress serve as a deterrent to unreliable capacity providers. Effective design of non-performance penalties stimulates appropriate reaction of resources to system tightness.

191 The State Aid Guidelines require to link non-performance penalties with VOLL. Thus, the consequences beneficiaries face for their unavailability reflects the value of energy not supplied during system stress. According to the responses provided by the relevant NRAs, none of the existing capacity mechanisms in the EU associates the amount of non-performance penalty with VOLL. Nevertheless, one can consider whether reasonably high penalty rates and well-crafted frameworks provide sufficient disincentives to be unavailable during system stress periods. Moreover, the State Aid Guidelines require that non-performance penalties generally accrue from imbalance settlement prices, to avoid distortions to the functioning of the wholesale market.

192 National schemes employ various calculation methods when penalising unavailability. Providers in Finland failing to fulfil their obligation for less than an hour, lose their remuneration for that hour. Should the failure last over an hour, the provider loses the remuneration for an entire day when the capacity was not provided. In addition, national rules consider beneficiaries responsible for their imbalances and impose relevant imbalance costs.

193 The remaining strategic reserve schemes do not include imbalance costs in cases of unavailability. In Germany, the non-performance penalty is equal to 15% of the annual remuneration received by the beneficiary and is applicable when the resource is not fully available at time of system stress. In Sweden the capacity mechanism operator applies a fixed rate to charge for any unavailable energy volumes, which is a fraction of the Member State's VOLL. Table 7 shows principal design elements of the non-performance penalties in the applicable strategic reserves.

184 During winter, resources should be available to provide capacity within 12 hours of the operator's call. Outside the winter season, the operator has the right to request capacity providers to achieve the 12-hour readiness in a month.

185 A call for availability is also possible when this discrepancy ranges from 5% to 9%.

186 Compared to the Polish and French capacity mechanisms, the Belgian rules specify a stress period more granularly as capacity providers are expected to remain available during every hour of expected scarcity.

Table 7: Key characteristics of non-performance penalties across strategic reserves in Finland, Germany and Sweden - 2022

Member State	Triggering conditions	Penalty for non-performance (per non-available volume)	Incurring imbalance costs	Application of penalty ceilings
Finland	Active throughout the obligation period	Loss of remuneration	Yes	Yes
Germany	Scarcity situation	15% of annual remuneration Penalty: 0.15X euros/MW Annual remuneration: X euros/MW/annum	No	Yes
Sweden	Active throughout the obligation period	Fixed rate Penalty: 170 euros/MWh	No	Yes

Source: ACER based on information from NRAs.

Note: For the comparison purposes, the penalty rate in Sweden was converted from Swedish kronas to euros at the rate 1 euro = 11.76 Swedish kronas.

194 Information provided by the relevant NRAs shows that reliability option capacity mechanisms apply a different approach to other types of existing market-wide mechanisms, regarding non-performance penalties[187]. In Belgium, Italy and Ireland, the implementation of reliability options involves the application of a payback obligation. At its core, the reliability option guarantees a fixed income for beneficiaries, based on the auction's clearing price, to compensate for insufficient revenues in the electricity market ("the missing money"). In return to these revenues, beneficiaries are required to pay the capacity mechanism operator the difference between a market reference price and a pre-determined strike price, when the former rises above the latter. In other words, the payback obligation provides consumers with a price hedge against high wholesale electricity prices.

195 In terms of performance, providers that generate electricity receive the market price and hence can cover the payback obligation from their revenue. However, non-performing providers do not receive the market price but are still responsible for covering the difference between the market price and strike price. The payback obligation essentially acts as a non-performance penalty. In principle, one would expect the market price to rise proportionally to market scarcity, resulting in a wider gap between the market price and strike price, and hence, an increasing penalty the tighter the system gets. In this way, the payback obligation incentivises beneficiaries to respond to increasing system tightness. In general, the non-performance penalties in the reliability option design are aligned with the State Aid guidelines.

196 On top of the payback obligation, the Belgian capacity mechanism applies a second type of non-performance penalties. Resources unavailable at times of system stress (as explained in recital (191)) incur additional non-performance penalties based primarily on a formula reflecting the actual remuneration of the unit, the season during which the beneficiary's capacity is unavailable (i.e., winter/non-winter) and potential notifications about unavailable capacity[188].

197 Unlike the reliability option type of capacity mechanisms, the Polish and French market-wide capacity mechanisms determine a non-performance penalty rate outside the wholesale electricity market. In Poland, the NRA calculates the penalty rate based on a formula that reflects the gross domestic product value per unit of electricity consumed for the same reference year. This formula essentially seeks to represent the economic benefit derived from electricity consumption. In France, a provider pays a

187 In all cases, the NRAs have reported that beneficiaries are subject to imbalance costs based on the national wholesale market rules. Essentially, non-performance penalties and imbalance costs are treated separately.

188 The formula is designed to impose a higher penalty on units that receive higher remuneration, units that are unavailable during the winter season, and units that have not notified their unavailability.

non-performance penalty in proportion to its unavailability during the critical days within the winter period[189]. The annual penalty rate is set at 120% of the reference price for a delivery year and is based on the difference between the declared and effective availability[190, 191]. As a result, beneficiaries that are unavailable at times of scarcity face a penalty that is a fraction of the VOLL and significantly lower than the costs faced by the power system[192].

198 Table 8 provides an overview of the key features of non-performance penalties in the market-wide capacity mechanisms.

Table 8: Key characteristics of non-performance penalties across market-wide capacity mechanisms in Belgium, France, Ireland, Italy and Poland - 2022

Member State	Triggering conditions	**Penalty for non-performance** (per non-available volume)	Application of penalty ceilings
Belgium	High day-ahead demand forecast	Formula taking account of the actual remuneration of a provider, notified/unnotified unavailable capacity and time of the year	Yes
	Market price above the reliability option strike price	Difference between market reference price and strike price	
France	High day-ahead demand forecast System constraints projected for day-ahead	120% of the price of the last T-1 auction	Yes
Ireland	Market price above the reliability option strike price	Difference between market reference price and strike price	Yes
Italy	Market price above the reliability option strike price	Difference between market reference price and strike price	No
Poland	High day-ahead demand forecast	Annually calculated rate Current penalty: 1,015 euros/MWh	Yes

Source: ACER based on information from NRAs.

Note: Polish NRA recalculates the applicable rate every year. Provided value is a 2023 penalty rate converted from Polish zlotys to euros by the reporting NRA.

189 For more information, see footnote 154. The rationale of the unavailability is the same with that used to determine the non-delivery penalties.

190 The framework essentially sets an annual ceiling. If a beneficiary's equivalent availability during the critical days is 95% of the contracted capacity, it would pay 5% of the annual ceiling. The reference price refers to the last T-1 auction price before a given delivery year. The price of this auction is considered a robust reference since it tends to draw the highest trading activity.

191 The penalty is calculated three years after the delivery year. Nevertheless, the provider has the possibility to redeclare (i.e., reduce) its availability in due time and pay a reduced penalty. The reduced penalty ranges up to 20% of the market reference price. When redeclaring, the provider must buy certificates to cover the difference between the originally contracted capacity and the redeclared one if it is less available than expected.

192 For example, the Polish regulator, URE, has estimated the current non-performance penalty rate to be equal to around 1,015 euros/MWh. This is significantly lower than the VOLL, as suggested by the current reliability standard in Poland, which is around 22,000 euros/MWh (the current Polish reliability standard, set before the approval of the relevant methodologies by ACER, is equal to a LOLE of 3 hours/year; the CoNE was estimated at around 65-70 euros/MW/year at the time of State Aid approval).

5.3.3.3. Other safeguards to ensure performance

199 Besides the penalties for non-availability at times of system stress, capacity mechanisms commonly feature additional measures to ensure the performance of concerned resources. According to the current schemes, relevant capacity market operators or other designated entities monitor the availability of capacity providers throughout the contracted period and run dedicated tests. Table 9 below presents these measures.

200 Most concerned NRAs reported the continuous tracking of resources' availability over the duration of the contract[193]. ACER considers such ongoing oversight a good practice, indirectly deterring any potential breach of the obligations since it allows to detect possible deviations from agreed-upon terms. Possibly, these deviations can be tracked before the actual system stress. As an accountability measure, monitoring fosters a sense of responsibility. In Sweden, where the delivery period is shortest in the EU, the transmission system operator does not resort to continuous oversight as a breach of obligation may result in contract termination. This is meant to incentivise beneficiaries to remain available throughout the winter months.

201 Dedicated tests on beneficiaries' performance and readiness, and associated penalties, further enhance accountability. For example, in Finland and Sweden, capacity providers are subject to tests prior to the obligation period, i.e., the winter season. Additionally, the Finnish system operator may test resources' availability one time during the obligation period. The Swedish capacity mechanism includes supplementary penalties if a provider fails a test. In Ireland, only new capacity has to prove itself before achieving substantial completion. While there is no testing regime in place for existing capacities, the Irish authorities are considering the introduction of additional testing obligations

202 The number of possible tests is usually limited. In Germany, beneficiaries are subject to two tests per year, whereas in Poland, there can be up to one test every three months of a calendar year. In both cases, providers that do not pass the test incur penalties. The French capacity mechanism includes tests for resources not scheduled to generate during the so-called critical days to ascertain their availability. For scheduled resources, the operator conducts relevant measurements during the critical days.

Table 9: Other measures ensuring performance across capacity in the EU.

Member State	Monitoring of availability	Testing	Consequences of failure
Belgium	Yes	Relevant tests are carried out	Associated penalties
Finland	Yes	Test ahead of obligation period; in addition, operator may test once during the obligation period	Associated penalties
Germany	Yes	Two tests per year	Associated penalties
Sweden	No	Test ahead of obligation period	Associated penalties
France	Yes	Relevant tests are carried out	Associated penalties
Ireland	Yes	No testing for existing capacity. Introduction of testing and penalties being considered at present	NAP
Italy	Yes	System operator does not perform any tests	NAP
Poland	Yes	Operator may test selected providers up to once a quarter	Associated penalties

Source: ACER based on information from NRAs.

193 In case of Sweden, when beneficiaries' availability falls below 95%, it may amount to the breach of contract and lead to its possible termination. The authorities consider this framework to be a sufficient safeguard.

Annex I: Additional figures and tables

This Annex provides additional figures and tables that are referred to in the main report.

Table 10: Adequacy metrics per Member State – status as of June 2023

Country	Single VOLL (EUR/MWh)	Fixed CONE		Reliability standard (hours/year)
		Technology	(EUR/MW)	
Belgium[a]	12,832	Demand response	30,000	3.00
Cyprus[b]	N/A	N/A	N/A	3.00
Czech Republic	4,016	OCGTc	57,958	15.00
Estonia[d]	7,300	OCGT	63,000	9.00
Finland[e]	8,000	Renewal & Prolongation	17,000	2.10
France	33,000	Demand response	60,000	2.00
Germany	12,240	OCGT/Demand response[f]	57,067 23,377/2,072	2.77
Greece	6,838	Demand response	18,735	3.00
Ireland (SEM)[g]	N/A	OCGT	115,990	8.00
Italy	20,000	OCGT	53,000	3.00
Latvia	N/A	N/A	N/A	Not in place[h]
Lithuania	N/A	N/A	N/A	Not in place
Luxembourg	12,240	OCGT/Demand response[i]	33,905	2.77
Netherlands	68,887	N/A	N/A	4.00
Poland	17,700	N/A	N/A	Not in place
Portugal[i]	N/A	N/A	N/A	5.00
Slovenia	10,700	Demand response	21,753	N/A
Sweden	8,132	Demand response	7,537	0.99

Sources: ACER based on information from NRAs and for Estonia the relevant study to establish a reliability standard.

*Notes 1: **a:** calculations for VOLL, CONE and the reliability standard updated in 2022 **b:** In Cyprus, three adequacy metrics are set: LOLE of 3 hours per year, reserve margin of 189 MW and expected energy not served at 0.001% of annual demand; **c:** OCGT stands for open cycle gas turbine; **d:** In Estonia, expected energy not served equal to 4,500 MWh/year and a capacity margin equal to 10% are also used; **e:** In Finland an additional reliability standard expressed as expected energy not served equal to 1,100 MWh/year is in place; **f:** In Germany the reliability standard is calculated as the average of annual reliability standards for a five year period. The reference technology alternates between demand response (23,377 euros/MW for commercial and 2,072 euros/MW for industrial) and OCGT (57,067 euros/MW); **g:** Ireland is currently re-calculating the VOLL and the reliability standard; **h: :** There is no reliability standard legally defined in Latvia, but a LOLE value of 3 hours is used by the TSO as a reference value. **i:** Luxembourg uses the same adequacy metrics as Germany; **i:** In Poland the CONE values for various reference technologies have been calculated by the NRA, yet the setting of the reliability standard is still pending.*

*Notes 2: In Spain, a 10% reserve margin for mainland and a LOLE of 2.4 hours per year for non-mainland is used. In Denmark a 7 'outage minutes' (OM) per year metric is used, estimated on the basis of the demand and the expected unserved energy (EUE) as OM = 8760 * 60 * EUE / Demand.*

Table 11: Competences for and status of the national resource adequacy assessments - 2022

Member State	Entity responsible for performing the NRAA	Entity responsible for approving the NRAA	Frequency of NRAA	NRAA implementation in 2022?	Link to the published NRAA
AT	No assessment performed currently				
BE	TSO	No approval	Every two years	No	-
BG	TSO	Government	Every year	Ongoing	Link
CY	No information provided				
CZ	TSO	No approval	Every year	Published	Link
DE	NRA	No approval. Published by Government.	Every two years	Published	Link
DK	TSO	TSO	Every year	Ongoing	Link
EE	TSO	TSO	Every year	Published	Link
ES	No assessment performed currently				
FI	NRA	NRA	Every two years	No	-
FR	TSO	No approval	Every two years	No	-
GR	TSO	No approval	Every one or two years	Completed, not published	-
HR	Government	No approval	Every year	Not published	-
HU	TSO	NRA	Every year	Published	-
IE	TSO	NRA	Performed yearly from 2024	No	-
IT	TSO	No approval	Every year	Published	Link
LT	TSO	NRA	Every two years	No	
LU	Government	Government	Every two years	Yes	Link
LV	TSO	TSO	Every year	Published	Link
NL	TSO	No approval	Every year	Published	Link
PL	Government	Government	Every two years	No	-
PT	Government	Government	Every year	Published	Link
RO	Government and TSO	Government	Not defined. Usually every two years.	Published	Link
SE	TSO	No approval	Every year	Published	Link
SI	TSO	NRA	Every two years	No	-
SK	TSO	Government	Every year	Ongoing	Link

Source: ACER based on information from NRAs.

Note: The figure shows information stemming from mid-/long-term national adequacy assessments, even if they are not performed

for the purposes laid out in the Electricity Regulation (i.e., complementing the ERAA and justifying a capacity mechanism). Austria is currently developing a security of supply strategy that will include the details of conducting a national adequacy assessment. In Croatia, the Government is entitled to issue an annual report on security of supply for previous calendar year with projection for next 10 years based on annual reports issued by TSO and DSO on which NRA gives its opinion. Cyprus is exempted from adequacy related provisions pursuant to Article 64(2) of the Electricity Regulation. Estonia relies on the ERAA for its adequacy assessment. In Hungary the TSO is obliged by law to include a study on the mid- and long-term adequacy in the annual network development plan, approved by the NRA. In Ireland the TSOs are currently producing an "All-Island Generation Capacity Statement" that indicated extensive deficit of generation capacity in the mid-term, yet they are also preparing for a national resource adequacy assessment from 2024 onward. Latvia uses primarily the ERAA for assessing the national resource adequacy (see annual statement for 2021 here). Similarly in Lithuania the TSO's bi-annual ten-year network development plan (TYNDP) report includes an analysis based on the ERAA results and a national resource adequacy assessment may be performed only if there is a need to analyse additional scenarios. There is no consensus among Lithuanian authorities on whether this adequacy assessment can be considered as a national resource adequacy assessment carried out in line with the Electricity Regulation. Furthermore, there is an ongoing legal discussion in Lithuania regarding changes in the national legislation governing national adequacy assessments. In Luxemburg the Government issues an adequacy and security of supply report that is not based on primary calculations and simulations but analyses information from other assessments (e.g., the 2022 report used information from the ERAA, the Pentalateral resource adequacy assessment, and the German resource adequacy assessment). In Slovenia, no national resource adequacy assessment was conducted in 2022. The TSO published an adequacy assessment in the ten year network development plan report, using primarily the ERAA results, and including a simple assessment of capacity development for different scenarios. In Spain, no national resource adequacy assessment has been published so far.

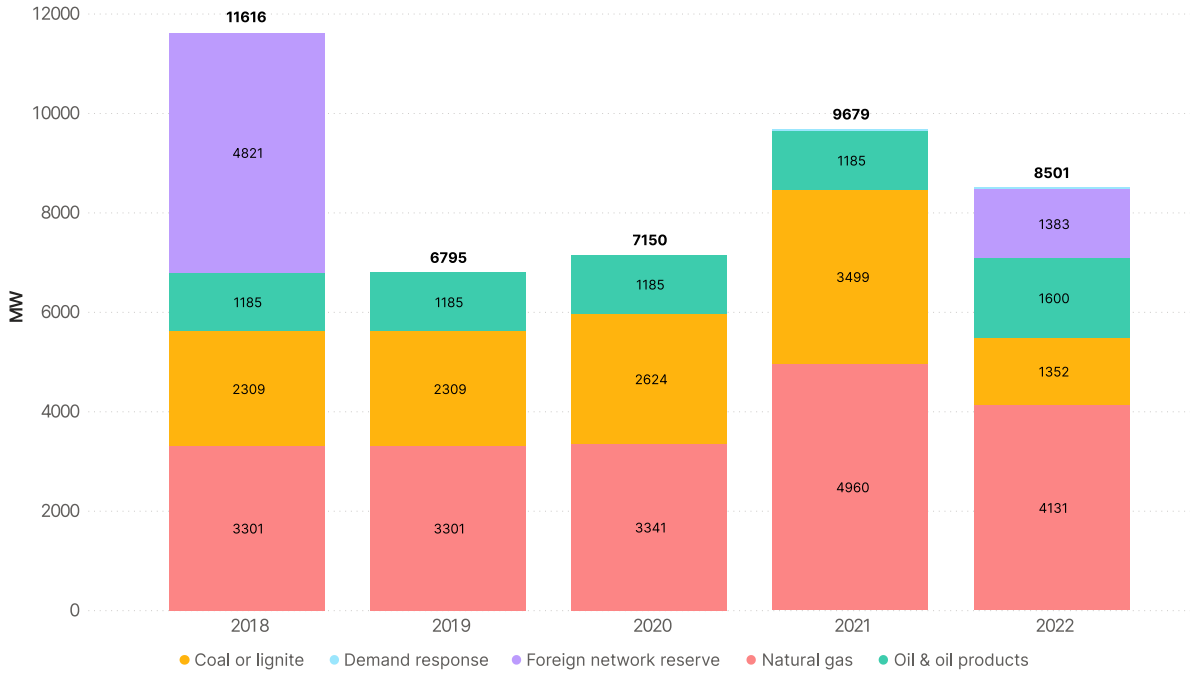
Table 12: High level methodological characteristics of the national resource adequacy assessments - 2022

Member States	Regional scope	Probabilistic calculations	Economic viability assessment	Additional scenarios and/or sensitivities	Market coupling approach	Demand response consideration (explicit – implicit)	Demand response consistent with VOLL/CONE
AT	No long-term assessment performed currently						
BE	Yes	Yes	Yes	Yes	Flow Based	Both	No
BG	Yes	Yes	No	Yes	NTC		No
CH	Yes	Yes	No	Yes	Flow Based	Only explicit	
CZ	Yes	Yes	No	Yes	Both FB and NTC	Both	Yes
DE	Yes	Yes	Yes, for the whole region	Yes	Flow Based	Both	Yes
DK	Yes	Yes	No	Yes	Flow Based	Both	No
EE	Yes	Yes	Yes, for the whole region	Yes	NTC	Only explicit	
ES	No long-term assessment performed currently						
FI	Yes	Yes	Yes, only for the country	Yes	NTC	Both	
FR	Yes	Yes	Yes, country and neighbouring countries	Yes	NTC	Both	Yes
GR	Yes	Yes	Yes, only for the country	Yes	NTC	Only explicit	Yes
HR	No long-term assessment performed currently						
HU							
IT	Yes	Yes	Yes, only for the country	Yes	NTC		Yes
NL	No	Yes	Yes, for the whole region	Yes	NTC	Only implicit	NAP
PL	No	Yes	No	Yes	No coupling	None	NAP
PT	No	Yes	No	Yes	NTC	Only explicit	NAP
RO	Yes	Yes	Based on ERAA	Yes	NTC	Only explicit	Yes
SE	Yes	Yes	Yes	Yes	NTC	None	NAP
SI	Yes	No	No	Yes	NTC	Only explicit	
SK	Yes	Yes	No	Yes	NTC	None	No

Source: ACER based on information from NRAs.

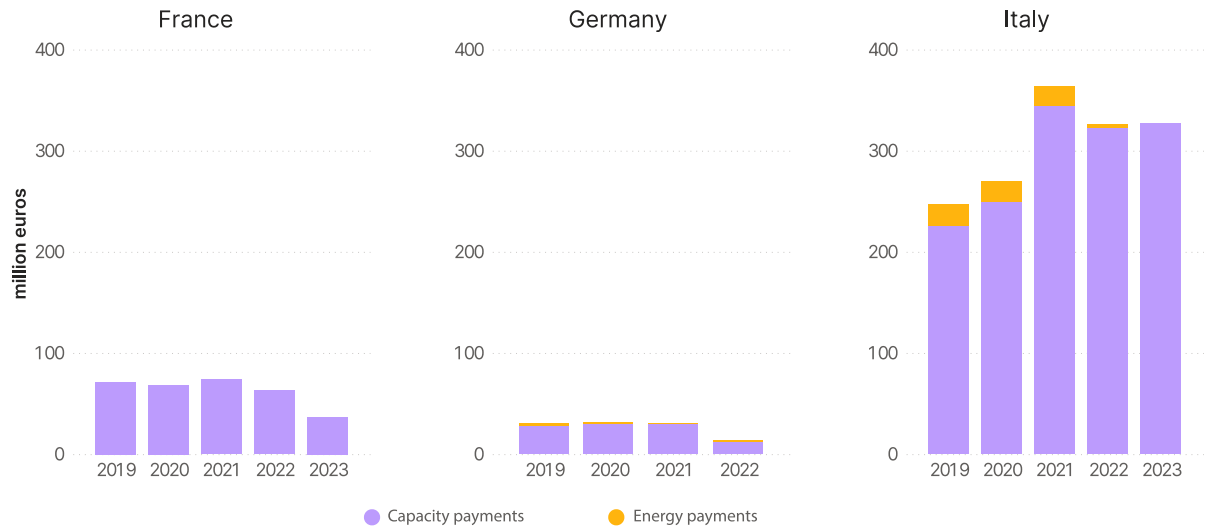
Notes: For Belgium and Poland the table shows information provided for the 2021 SOS monitoring report. The Note under Table 11 applies to this table.

Figure 14: Total capacity contracted as network reserves in Austria (from 2021 onward) and Germany — 2018–2022 (MW)



Source: ACER based on information from the NRAs.

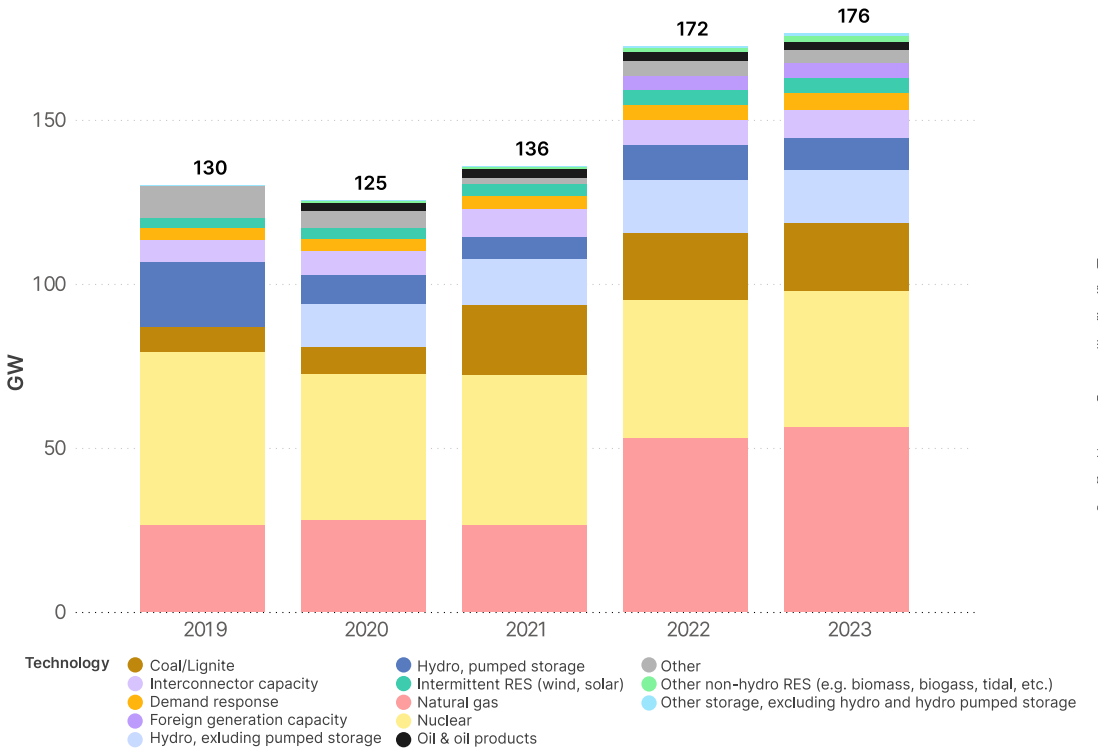
Figure 15: Realised and forecast costs of interruptibility schemes —2019–2023 (million euros)



Source: ACER based on information from the NRAs.

Note: In Germany, the scheme expired as of 30 June 2022. Since 2022, the French scheme is part of the TSO's defence plan in accordance with Article 18(5) of Regulation 2017/2196. The forecast capacity procurement for 2023 is 531 MW, down from 1131 MW in 2022. For Italy, only capacity costs are shown for 2023.

Figure 16: Detailed breakdown of the capacity remunerated in EU capacity mechanisms, per type of technology — 2019–2023 (GW)



Source: ACER based on data from NRAs and from the ENTSO-E Transparency Platform.

Note: The Note under Figure 7 also applies to this Figure.

Table 13: Characteristics of existing capacity mechanisms in the EU – 2022

Member States	Type of CM[a]	State Aid approval	Start	End	Delivery period	Long-term contracts[b]	Eligibility		Auction lead time[c]	Frequency of auctions	Minimum bid size	Min. eligible capacity	Auction clearing method[d]	CO_2 limits[e]	Secondary market	Cost recovery
							DSR, RES, Storage	Aggregators								
BE	MWCB	YES	2021	2031	annual	YES (8 or 15 years)	ALL	YES	T-1, T-4	annual	1 MW	1 MW	PAB	YES	YES	special levy
DE	SR	YES	2020	2025	annual[f]	NO	ALL[g]	DR only	T-2, T-1	every two years	5 MW	5 MW	PAC	NO[h]	NO	network tariffs
FI	SR	YES	2022	2031	annual[i]	NO	ALL	YES	T-1	annual	1 MW	1 MW	PAB	YES	NAP	network tariffs
FR	MW-DCO	YES	2016	2026	winter season (1 Nov – 31 Mar)	YES (up to 7 years)	ALL	YES	T-4, T-3, T-2, T-1, T, T+1 and T+3	annual (T-4), four per year (T-3 and T-2), six per year (T-1)	0.1 MW	0.1 MW	PAC	YES (only for new units)	YES	suppliers
IE SEM	MWCB	YES	2017	2027	annual	YES (up to 10 years)	ALL	YES	T-4, T-3, T-2 and T-1 auctions possible	annual	NA[j]	10 MW	PAC[k]	YES	NO	suppliers
IT	MWCB	YES	2018	2028	annual[l]	YES (15 years)	ALL	YES	T-4, T-3, T-2 and T-1 auctions possible	no fixed frequency (two auctions in 2019 and one in 2022)	1 MW	1 MW	PAC	YES	YES	suppliers
PL	MWCB	YES	2018	2030	annual	YES (up to 17 years)	ALL	YES	T-5, T-1	T-5 annual, T-1 four/year	0.001 MW[m]	2 MW	PAC	YES	YES	network tariffs
SE	SR	NO	2003	2025	winter season (16 Nov - 15 Mar)	YES[n]	ALL	YES	T-1	annual	5 MW	5 MW	PAC	NO	NO	BRPs

Source: ACER based on information from NRAs.

Explanatory notes:

a: *The categorisation of the schemes is based on the taxonomy of the European Commission's sector inquiry. Abbreviations refer to strategic reserves (SR), targeted capacity payments (TCP), market-wide central buyer (MWCB), market-wide decentralised capacity obligations (MW-DCO).*

b: *Long-term contracts refer to contracts with a duration of five years or more.*

c: *T refers to the delivery year the auctions concern.*

d: *Auction clearing methods are pay-as-clear (PAC) and pay-as-bid (PAB).*

e: *See Article 22(4) of the Electricity Regulation.*

f: *Non-availability is allowed for up to three months per delivery year. Contracts have a duration of two years.*

g: *There are no legal restrictions for renewable energy sources (RES) participation, however, intermittent RES likely don't fulfil the technical requirements. Furthermore, only resources that are linked to the high-voltage networks are eligible.*

h: *According to plans, emissions limits will be considered in the auction taking place in 2023.*

i: *The delivery period is one year, but different delivery lead times apply. From 1 December to 28 February, capacity has to assure dispatch within 12 hours from activation, while outside of this period, the lead time is one month.*

j: *In the Irish-SEM auctions, bids may consist of up to five quantity-price blocks with no minimum quantity size.*

k: *If capacity is contracted to satisfy locational capacity constraints, then the offered price rather than the clearing price is given.*

l: *RES and DR are obliged to be available during the peak hours of each working day, peak hours being the six hours with the highest load (they can change weekly).*

m: *The minimum total net capacity for participation in the auction is 2 MW, however bid blocks may start from as low as 1 kW.*

n: *Only one contract was signed in 2017 with an option for prolongation until 2025. The option was called in 2019.*

Note: In France, a targeted capacity payment is also provided for the commissioning of a 442 MW CCGT plant in the Britany region following a State Aid approval by the European Commission (SA.40454 2015/C (ex 2015/N)). For the Italian CM auction, the pay-as-bid method is used in the cases capacity is cleared due to network constraints. In Portugal, a targeted capacity mechanism was introduced in 2017, and has been revoked since 2018, yet some capacity payments are provided to hydro power plants due to "legacy" contracts. In Spain, the capacity mechanism used to be comprised of "investment incentives" and "availability payments". Such availability payments were removed in June 2018, and the investment incentives payments still apply only to generation capacity installed before 2016.

Table 14: Summary table of interruptibility schemes in the EU - 2022

Member States	Purpose	Product/ Programme	Activation criteria	Procurement	Remuneration	Total Contracted Capacity(MW)	Minimum Eligible Capacity (MW)	Aggregation	Availability	Maximum length/ number of interruptions	Number of participants	Status
DE	Adequacy / Balancing Reserves / Congestion Management	Immediately interruptible load	within 1 s or 350 ms at 49.7 Hz	Auction	Capacity & Energy (pay-as-bid)	750	5	YES	Whole week except 120 quarters of an hour per week	1 to max 32 quarters of an hour/week Min. 16 quarters of an hour a week	11	Terminated on 30 July 2022
		Quickly interruptible load	within 15 min			750						
FR	Contingency Reserves	Lot 1	Automatic activation upon frequency drop (49.82 Hz for 3 s).	Auction	Capacity	1200	25[a]	NO[b]	Availability at least 7500 hours/ year	Activation in 5 s, max 5 activations per year. Minimum duration of interruption is 1 hour	14	In place since 2014. Changes in 2016 and 2022.
IT	Contingency Reserves	Mainland	Automatic within 200 ms at 49.8 Hz or upon TSO instruction	Auction	Availability (pay-as-clear) and Energy (pay-as-bid)	4393	1	YES	24 hours/ day	No maximum duration of interruptions / No max number of interruptions	163	Start of the scheme in 2004, approval by NRA every 3 years.
		Islands of Sardinia and Sicily										
PL	Adequacy / Congestion Management / Balancing Reserves	IRP (Interven-tional Power Reduction)	Duration of reduction period from 1 to 15 hours within the range of 7:00 a.m. to 10:00 p.m.	Qualification system for the supplier conducted via the purchasing platform	Energy (bids optimised with algorithm)	Capacity becomes known to the TSO after a request for biding	Min. 1 Max. 100	YES	Request on previous day before 11:30 AM	voluntary response, no limit	5 (including aggrega-tors)	Annual procurement for a period 1 April – 31 March

Source: ACER based on information from the NRAs.

Explanatory notes:

***a:** Minimum eligible capacity was reduced to 10 MW for 2023 and onwards.*

***b:** A study is ongoing (conducted by the French TSO and DSOs) regarding the potential of extending the scheme to distributed resources connected to the distribution grid.*

Table 15: Characteristics of the network reserve schemes in Austria and Germany – 2022

	Austria	Germany
Issues addressed	Congestion management	Congestion management and voltage control
Remuneration type	Capacity and energy (including costs and incurred economic disadvantages)	Capacity and energy
Procurement type	Pay-as bid auction Aggregation is allowed, foreign units can participate	Administrative procurement – the TSO can transfer any power plant into the network reserve if the plant is planned to be decommissioned or has been awarded in the coal-exit auctions, but is deemed as system-relevant Foreign units are procured through a tender if domestic capacity does not fulfil the capacity requirement
Eligible participating technologies	No restrictions	No restrictions
Minimum eligible capacity	1 MW (individual units can be smaller if aggregated)	10 MW
Contract duration	Seasonal, annual, or bi-annual	Usually 24 months, but contracts with a different duration are possible
Activation process	Congestion management procedures	Congestion management procedures (activation outside of the electricity markets, based on forecasts available to TSO and the technical constraints)

Source: ACER based on information from the NRAs.

Note: From July 2022 onwards, the network reserve in Germany could also be used for adequacy purposes.

Table 16: Status of TSO-TSO agreements for direct foreign participation in capacity mechanisms

Capacity mechanism operator (MS)	Foreign TSO	Status in 2022
Elia (BE)	RTE (FR), TenneT (NL), all four TSOs in Germany	Agreements are expected to be signed in 2023
RTE (FR)	Elia (BE), all four German TSOs, Terna (IT), REE (ES)	Pending (discussions with Elia are at a more advanced stage, and RTE expects the bilateral agreement to be concluded in 2023)
Terna (IT)	NAP	No agreements are in place and no discussions on potential agreements have been initiated
PSE (PL)	CEPS (CZ), Litgrid (LT), SEPS (SK), Svenska kraftnät (SE)	Agreements are in place
	50Hertz (DE)	Agreement is in place (only for the main auction)
	all four TSOs in Germany	Agreements expected to be concluded in 2023

Source: ACER based on information from TSOs.

Note: In Poland, the agreements with CEPS, LITGRID, SEPS and Svenska Kraftnat cover delivery years 2025-2030. The agreement with 50 Hertz covers the delivery year 2027.

Table 17: Calculated MECs (or analogues) and foreign or cross-border capacity procured in the capacity mechanisms of Belgium, France, Italy and Poland (delivery 2019–2027) (MW)

Member State implementing the capacity mechanism	CM border	Value	Delivery period								
			2019	2020	2021	2022	2023	2024	2025	2026	2027
Belgium	**Total**	**Reserved MEC**	**No foreign capacity participation**						**1,935**	**1,428**	**934**
	France	Reserved MEC	No foreign capacity participation						4	196	119
	Germany	Reserved MEC							461	125	2
	Netherlands	Reserved MEC							599	646	260
	Great Britain	Reserved MEC							871	461	553
France	**Total**	**Regulated interconnector capacity sold**	**6,320**	**6,500**	**8,072**	**7,575**	**7,500**	**/**	**Auctions have not yet taken place**		
		Calculated MEC	**6,319**	**/**	**9,000**	**9,200**	**8,400**	**8,300**			
	Belgium	Calculated MEC	272	/	800	700	300	300	Auctions have not yet taken place		
	Germany	Calculated MEC	1,733	/	2,000	1,800	1,300	1,200			
	Italy	Calculated MEC	959	/	800	900	1,000	1,000			
	Spain	Calculated MEC	1,969	/	2,000	2,000	2,200	2,200			
	Great Britain	Calculated MEC	1,386	/	3,400	3,800	3,600	3,600			

Member State implementing the capacity mechanism	CM border	Value	Delivery period								
			2019	2020	2021	2022	2023	2024	2025	2026	2027
Italy	**Total**	**Contracted capacity**	**Previous capacity mechanism in place**			**4,394**	**4,394**	**3,610**	**Relevant auctions have not yet taken place**		
		Maximum level of foreign capacity				**4,394**	**4,394**	**4,365**			
	North (AT, FR, SI, CH)	Contracted capacity	Previous capacity mechanism in place			4,241	4,241	3,445	Auctions have not yet taken place		
		Maximum level of foreign capacity				4,241	4,241	4,200			
	Montenegro	Contracted capacity				104	104	113			
		Maximum level of foreign capacity				104	104	113			
	Greece	Contracted capacity				49	49	52			
		Maximum level of foreign capacity				49	49	52			
Poland	**Total foreign capacity**	**Contracted capacity**	**No foreign capacity participation**						**0**	**350**	**550**
		MEC							**2,166**	**1,176**	**1,415**
	Synchronous profile	Contracted capacity	No foreign capacity participation						NAP	NAP	300
		MEC							1,699	825	826
	Lithuania	Contracted capacity							0	0	250
		MEC							80	0	250
	Sweden	Contracted capacity							NAP	350	0
		MEC							0	351	339

Source: ACER based on information from TSO, ENTSO-E, and in the case of Italy, also publicly available auction reports.

Note: For Belgium, the delivery period commencing with the indicated year is considered (e.g. 2025 means delivery period 2025/26). The MECs have been reserved for the Y-1 auctions. For France, the MEC values correspond to auctions that took place in 2022 (T+3 auction for 2019, T+1 auction for 2021, T auction for 2022, T-1 auction for 2023 and T-2 auction for 2024). The interconnector capacity sold corresponds to regulated interconnectors only. For delivery in 2022, the quantity of capacity certificates sold was adjusted downwards to account for lower interconnector availability forecast for the beginning of the delivery year, which was the result of an interconnector outage in 2021. In Poland, in the auction for 2025, no capacity was contracted abroad. One unit located in Lithuania has participated in the auction, but its offer was rejected as it exceeded the clearing price in the main auction. In the auction for 2026, only capacity from Lithuania and Sweden could be contracted.

Table 18: Remuneration of foreign and cross-border capacity in the capacity mechanisms of France, Italy and Poland (2019–2027) (euros/MW)

<table>
<tr><th rowspan="2">Member State implementing the capacity mechanism</th><th rowspan="2">Remunerated party</th><th colspan="9">Delivery period</th></tr>
<tr><th>2019</th><th>2020</th><th>2021</th><th>2022</th><th>2023</th><th>2024</th><th>2025</th><th>2026</th><th>2027</th></tr>
<tr><td>France</td><td>Interconnectors</td><td>395</td><td>16,583</td><td>39,095</td><td>23,900</td><td>60,000</td><td colspan="4">Reference auction has not yet taken place</td></tr>
<tr><td rowspan="4">Italy</td><td>Existing domestic capacity</td><td colspan="3">Previous capacity mechanism in place</td><td>33,000</td><td>33,000</td><td>33,000</td><td colspan="3">Auctions have not yet taken place</td></tr>
<tr><td>North (AT, FR, SI, CH)</td><td colspan="3" rowspan="3">Previous capacity mechanism in place</td><td>4,400</td><td>4,400</td><td>33,000</td><td colspan="3" rowspan="3">Auctions have not yet taken place</td></tr>
<tr><td>Montenegro</td><td>3,449</td><td>4,949</td><td>17,010</td></tr>
<tr><td>Greece</td><td>4,000</td><td>3,999</td><td>25,075</td></tr>
<tr><td rowspan="4">Poland</td><td>Domestic capacity</td><td colspan="6">No foreign capacity participation</td><td>36,855</td><td>85,371</td><td>86,652</td></tr>
<tr><td>Synchronous profile</td><td colspan="6" rowspan="3">No foreign capacity participation</td><td>NAP</td><td>NAP</td><td>85,075</td></tr>
<tr><td>Lithuania</td><td>No capacity contracted</td><td>No capacity contracted</td><td>63,539</td></tr>
<tr><td>Sweden</td><td>NAP</td><td>85,075</td><td>No capacity contracted</td></tr>
</table>

Source: ACER based on information from TSOs, ENTSO-E, and in the case of Italy, publicly available auction reports.

Note: For Belgium, the capacity will only be contracted (and remunerated) in the T-1 auctions (starting with the T-1 auction for 2025/26). For France, interconnector remuneration is shown. The interconnector remuneration rate corresponds to the reference price of the last auction concluded before the delivery year. For Poland, foreign capacity participated in T-5 auctions. In the auction for delivery in 2025, no capacity was contracted abroad. One unit located in Lithuania has participated in the auction, but its offer was rejected as it exceeded the clearing price in the main auction. Original values were provided in the local currency; for conversion, the exchange rate of 1 euro = 4.69 PLN was used.

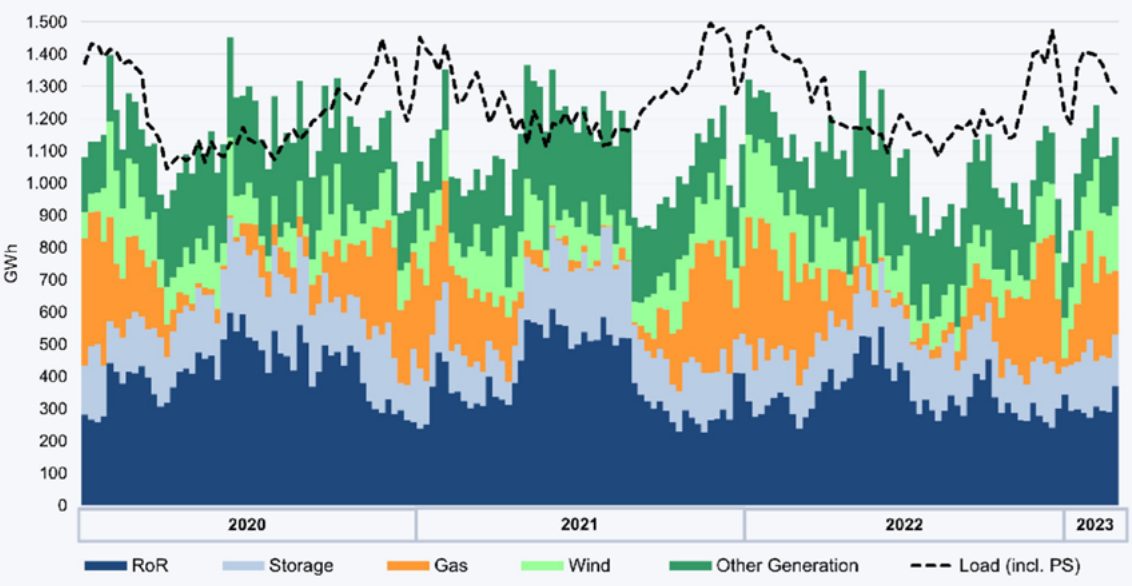
Annex II: Input from NRAs on lessons learnt from 2022/2023 winter

203 This Annex reproduces the input received from NRAs regarding the situation during the 2022/2023 winter. Only minor editorial changes were introduced by ACER. Any opinions expressed in the remaining text does not necessarily reflect ACER's view. Table 19 provides a brief summary of the main points for each Member State.

A-II. 1. Austria

204 The weather conditions experienced in Austria had opposing effects on security of supply in winter 2022/2023. On the one hand, the delayed heating period caused by the high temperatures in October and November helped to save gas reserves for power generation and, at the same time, reduce electricity demand. On the other hand, the persistently low hydro availability significantly reduced the renewable generation potential in Austria. In this context, the European market coupling process provided important flexibility to cover the corresponding higher residual demand without increasing gas demand for thermal power plants in Austria. Additionally, the prevailing high prices incentivised industrial consumers to reduce demand, and large-scale media coverage and state campaigns (see the Mission 11 campaign) raised general awareness among the community. Furthermore, a newly created demand side response product introduced by the Austrian TSO provided flexibility options. Figure 15 below shows an illustration of Austrian electricity generation and demand from 2020 to 2023.

Figure 17: Weekly aggregation of electricity generation in Austria - 2020-2023



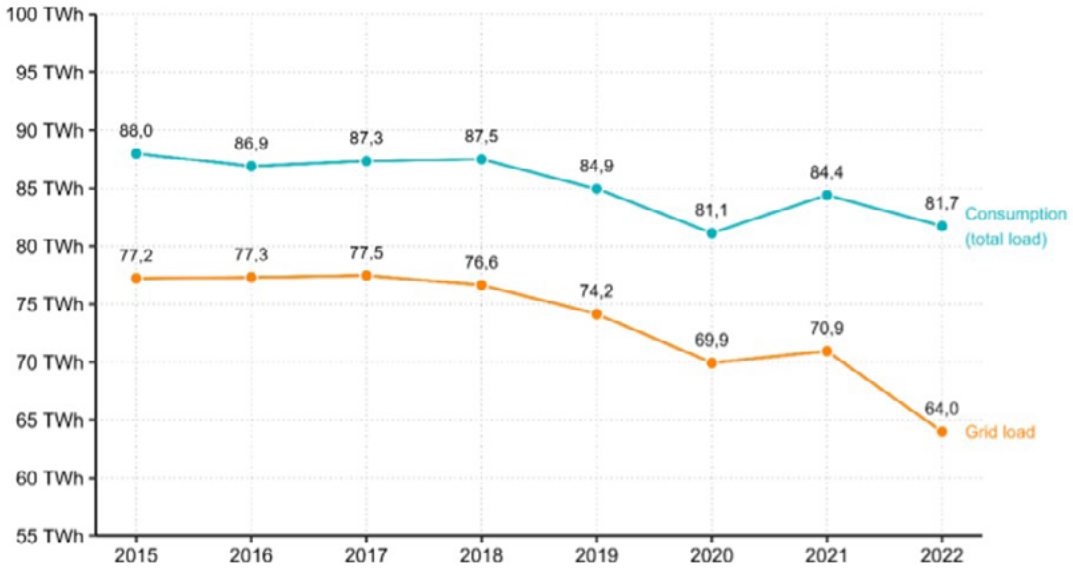
Source: Austrian NRA

A-II. 2. Belgium

A-II. 2.1. Electricity Consumption and Grid Load

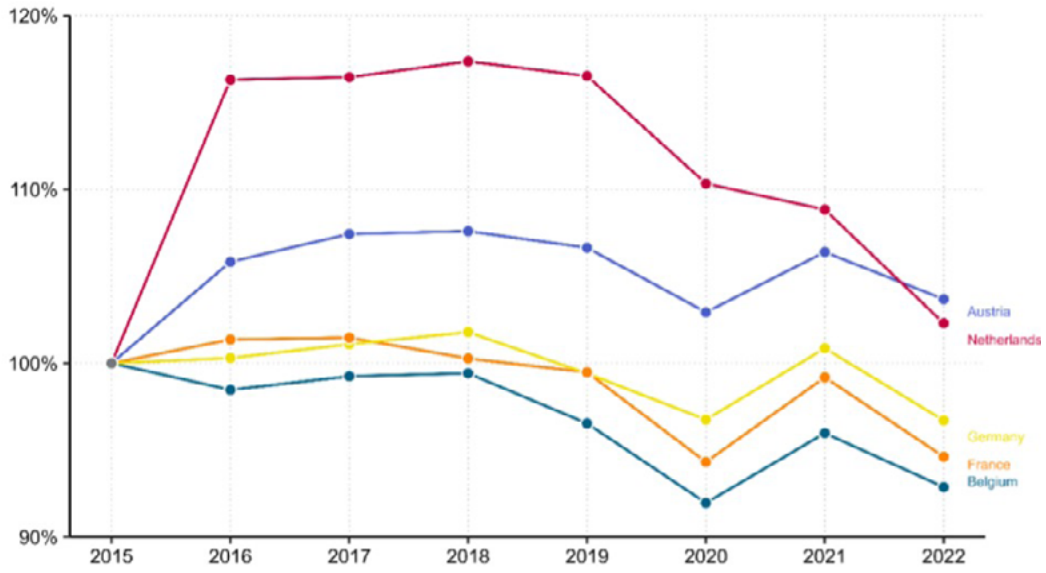
205 Belgium's total electricity consumption reached 81.7 TWh in 2022. This represents a 3.2% decrease compared to 2021 (84.4 TWh). The consumption was only slightly higher than the exceptionally low 81.1 TWh in 2020, which resulted from the confinement measures and economic contraction in the context of the COVID-19 pandemic. At the same time, the load from the transmission network amounted only to 64.0 TWh, a staggering 9.7% below the 70.9 TWh in 2021. The decline in grid load contrasts with the significant increase in unmetered, locally consumed electricity generation, for example through residential solar installations or distribution-connected wind generation.

Figure 18: Yearly total consumption and grid load on the transmission network in Belgium – 2015–2022 (TWh)



Source: Belgian NRA calculations based on data from the Belgian TSO.

Figure 19: Evolution of electricity load in Belgium and neighbouring countries – 2015–2022 (%, load in 2015 taken as the reference)



Source: Belgian NRA calculations based on data from ENTSO-E's transparency platform.

A-II. 2.2. Generation Capacity

206 The availability of electricity generation units decreased in 2022, mostly resulting from a lower availability of nuclear and hydro units. The planned maintenance of Tihange 1 led to a decrease in the availability rate for nuclear reactors from 90% in 2021 to 76% in 2022.

207 The total generated electricity volumes decreased by 3.7% year-on-year, from 93.4 TWh in 2021 to 89.9 TWh in 2022. The largest decrease by fuel type was observed for nuclear units (-6.2 TWh), while solar (+1.7 TWh), gas (+0.9 TWh) and wind (+0.1 TWh) increased their output.

A-II. 2.3. Cross border Flows

208 Cross-border flows of electricity remained a crucial tool to balance supply and demand of electricity, and to ensure that the dispatch of electricity production considers efficiently the price signal. At 19.2

TWh, the total exported volumes of electricity remained at a very high level in 2022, only slightly below the record-high values observed in 2021 (20.0 TWh). This led to 2022 being the fourth consecutive year where **Belgium was a net exporter of electricity**, with a net export position of 6.3 TWh. Since early 2019, Belgium has had a structural positive net export balance, indicating that more electricity was exported than imported, explaining the positive difference between electricity generation and electricity consumption.

A-II. 2.4. Projection for winter 2024-2025

209 In the framework of the Belgian CM (with the first delivery period in November 2025), the need to organise a specific auction for the period 2024/2025 was analysed. The analysis concluded that there was a positive margin (i.e. surplus of available capacity compared to forecast demand) of +100 MW for winter 2024/2025.

A-II. 2.5. Conclusion

210 In Winter 2022/2023, Belgium didn't face major adequacy issues. High prices on the electricity markets and the communication on this topic, led to a significant decrease in the grid load.

A-II. 3. Czech Republic

211 There were no significant problems with the transmission of electricity or the production of system power plants in the Czech Republic during the winter of 2022/2023. Overall, the Czech Republic produced slightly less electricity in 2022 in comparison to 2021 (-0.7%). This was primarily caused by a decrease in demand due to economic aspects. The decrease in electricity production was mainly due to a decrease in output from steam power plants, as perceived by a decrease in output of more than half year-on-year (-51.4%). Similarly, less electricity was also produced by pumped storage (-18.3%) and hydroelectric power plants (-13.1%). On the other hand, production from photovoltaic (+6.7%) and wind power plants (+6.6%) increased. However, thanks to the mild winter, a surplus in the amount of electricity generated was recorded, which still makes it possible to maintain a positive balance between electricity exports and imports. Exports of electricity during the months of December, January, and February amounted to 1,963 GWh, 1,226 GWh, and 934 GWh respectively.

212 Considering the imperative to reduce electricity demand, electricity consumption in the Czech Republic fell by 5.6% year-on-year during the winter months. Specifically, November, December, January, and February were down by 6.8%, 5.7%, 7.2%, and 2.8%. The reduction in electricity consumption was particularly evident among households, which accounted for an average decrease of 9% in 2022. It is clear from the statistics that households saved electricity last year. The 9% year-on-year drop in consumption in the Czech Republic was the largest in the past 20 years. Among the many reasons for this decline in electricity consumption are the Government's ongoing campaigns since the summer of 2022 to encourage electricity consumers to save money and to incentivise behavioural changes to consume less electricity. However, the biggest motivation to conserve electricity was undoubtedly its high price following Russia's invasion of Ukraine in February 2022.

213 Furthermore, the reduction of gross electricity consumption by at least 5% during peak hours in the winter season 2022/2023, which was set by the Energy Regulatory Authority based on the Council Regulation (EU) 2022/1854, was subject to evaluation. Based on preliminary results, a reduction of more than 6% in electricity consumption during peak hours has been achieved.

214 Overall, the above can be summarised by saying that from the point of view of the management of the electricity system, the mild course of winter 2022/2023, and the reduction in electricity consumption contributed to a large extent to the positive course of the winter 2022/2023. During the year, specific emergency measures were adopted by the Government of the Czech Republic, which had an impact on calming the situation of the energy market crisis. These included concessions on electricity payments and later government caps on electricity prices. Further developments in the next winter period 2023/2024 are difficult to predict, and although the Government of the Czech Republic has been strongly promoting the decentralization of electricity generation through the inclusion of small-scale renewables and the development of community energy since autumn 2022, the course of the next winter period will again depend mainly on consumer behaviour and the weather patterns.

A-II. 4. Denmark

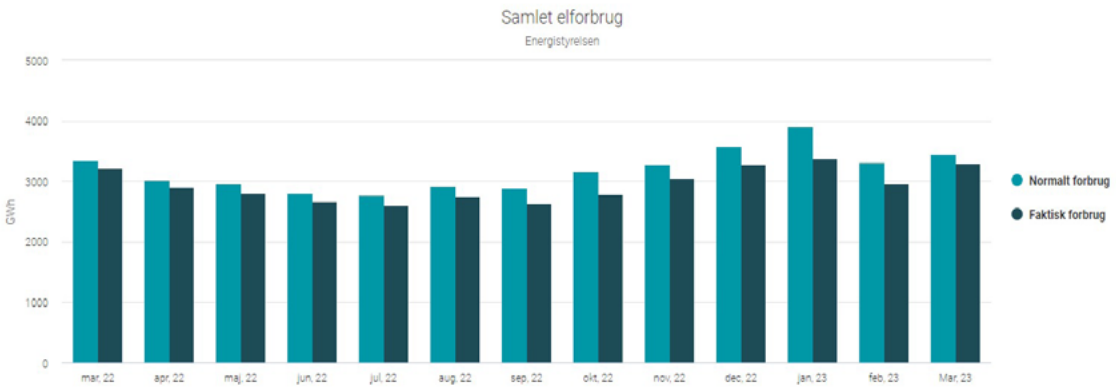
215 The electrical grid in Denmark is characterised by a very high level of security of supply, with an electricity consumer in Denmark experiencing an average of 20 minutes of interruption annually[194]. Although the Danish energy agency had not forecast the occurrence of brownouts and blackouts, it acknowledged the gravity of the situation of winter 2022/2023. It was recognised that risks would increase with a cold winter insofar as the war in Ukraine resulted in the cut-off of the Russian gas supply and the weather conditions leading to critically low hydro reserves for Nordic countries. Rivers running dry also caused nuclear power plants to reduce output, as well as they became impassable for coal barges. Cutting off electricity to consumers would only be used as a last resort.

216 The Danish energy agency launched a nationwide energy-saving campaign. The temperature in public buildings, with some exceptions such as hospitals and retirement homes, was lowered to 19 degrees. Some privately owned companies also voluntarily joined the cause. Similarly, decorative lighting was switched off.

217 The security of supply, not only now but also in the coming winter of 2023/2024, is dependent on the willingness of consumers to curtail consumption[195]. Even as the weather improved, the spring and summer periods are needed to fill the gas storage. The Danish energy agency does not expect to have to curtail gas consumers next winter, if the Danish population keeps up the reduced consumption.

218 Figure 20 shows the expected electricity usage (in turquoise) which is based on forecasts conducted before the energy crisis, along with the actual usage (in dark blue). By March 2023, Danes achieved a 4% reduction in electricity use compared to the normal level, indicating that the return to normality with respect to electricity prices led to consumption picking up again.

Figure 20: Expected and actual electricity consumption in Denmark - September 2022 - March 2023 (GWh)

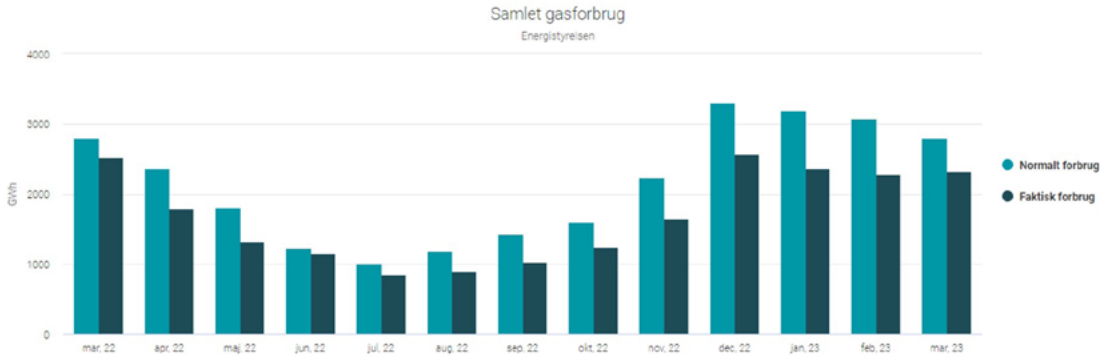


Source: Danish Energy Agency, Status of energy supply.

219 As highlighted in Figure 21 below, the reduction in the use of gas was especially pronounced with upwards of 25% savings in February 2023. The reduction in gas consumption was mainly driven by the replacement of gas in the manufacturing industries. Coming into 2023, the gas storages were better stocked than they normally would be at that time of year, due to the mild winter and reduced consumption. Russian gas went from covering about 35% of the consumption in 2021, to only covering 6-8%[196].

194 More information here.
195 More information here.
196 More information here.

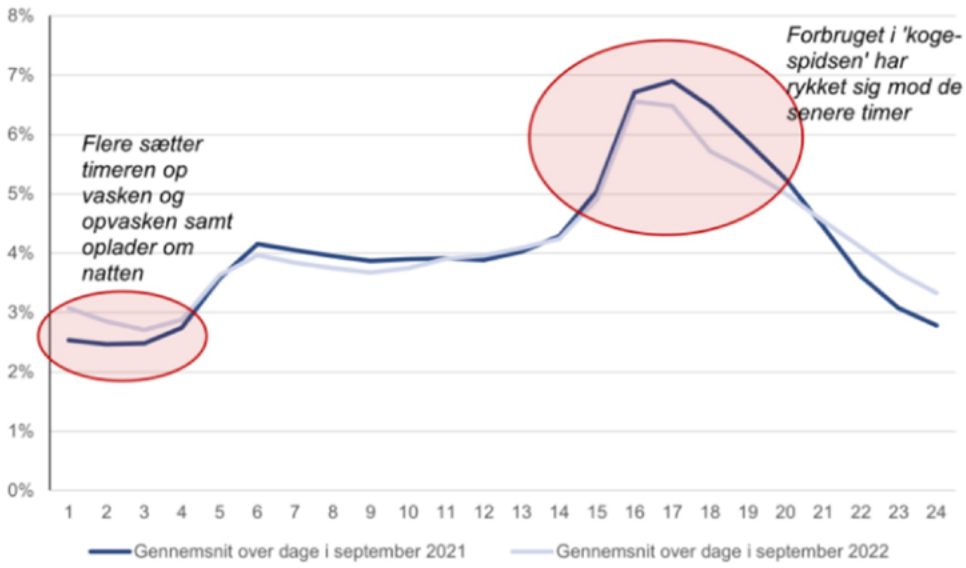
Figure 21: Expected and actual gas consumption in Denmark - September 2022-March 2023 (GWh)



Source: Danish Energy Agency, Status of energy supply.

220 Retail electricity users have shifted their consumption away from the most strained periods, and the introduction of new variable tariffs is meant to further incentivise this sort of behaviour. How the consumers adjusted their consumption depended largely on the type of subscription they had. If prices were linked to the spot price, there was a much greater willingness to shift one's consumption. This is reinforced in Figure 22, where the average distribution of electricity consumption over weekdays in September is seen. Denmark also saw many consumers switch from a fixed-price agreement to a variable-price product, presumably so they could save on their energy bill by shifting consumption.

Figure 22: Distribution of electricity consumption over weekdays in Denmark - September 2022



Source: Green Power Denmark.

A-II. 5. Finland

221 The situation in Finland was challenging before and during the winter for several reasons. The import of electricity and natural gas from Russia to Finland was suspended in May 2022, following Russia's invasion of Ukraine on 24 February 2022. Prior to these political changes, the electricity import capacity from Russia (1,400 MW) represented roughly 10% of the typical peak load in Finland and covered approximately 10% of electricity consumption in Finland in 2021. Additionally, the share of natural gas imported from Russia was around 60% of total natural gas consumption in Finland in 2021.

222 Similar to the lowered electricity and gas supply, the delay of the nuclear power unit Olkiluoto 3 (OL3) (1,600 MW) until April 2023 caused severe challenges to the security of supply in Finland. Test runs with variable power output were conducted throughout the winter, providing some help to ensure security of

supply during these periods. Finland targeted to acquire 600 MW of strategic reserve capacity for the 12-month period starting from November 2023. However, no capacity was acquired because the only tender was not acceptable. That coal-fired power plant however came back to the market after being several years in strategic reserve capacity.

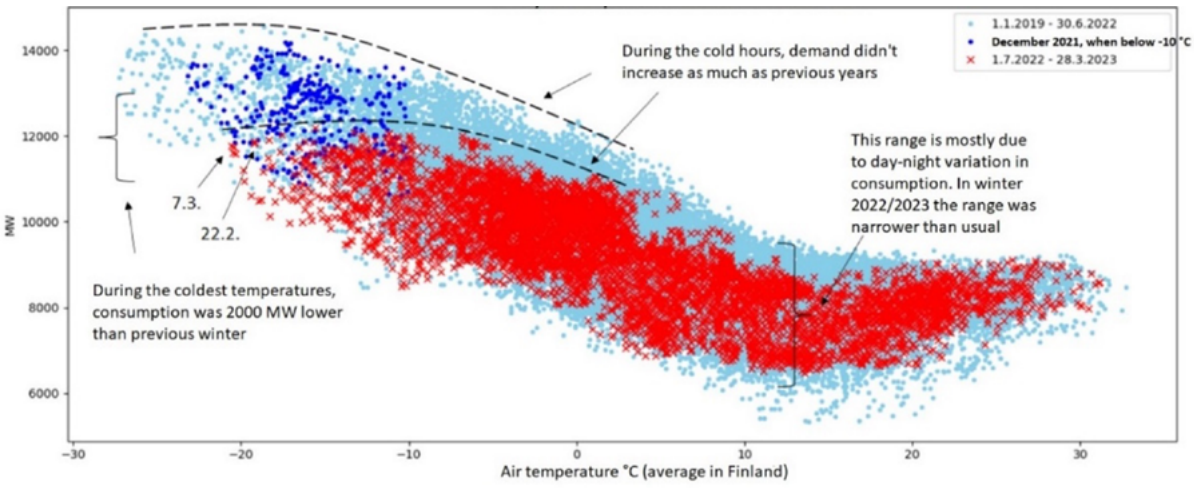
223 The Finnish Government launched a nationwide energy-saving campaign in October 2022 to encourage all Finns to save energy and to facilitate the security of supply. The short-term goal of this campaign was to get over 95% of Finnish households to save energy and cut down on their consumption by 5% during peak hours. Additionally, electricity was conserved because of the prevailing high electricity prices. This also resulted in some industrial processes shifting from daytime to nighttime to benefit from lower electricity prices. In December 2022, the Finnish TSO, Fingrid Oyj, introduced a new voluntary power system support procedure aimed at preventing electricity shortages. Approximately 500 MW of demand response and backup power plants participated voluntarily.

224 The winter of 2022/2023 turned out to be warmer than expected (apart from some challenging days) and there were no serious adequacy concerns. Given the unique socio-economic challenges of this period, monthly electricity savings were 5-10% compared to the previous winter. During the most challenging days, voluntary energy savings and demand response in peak hours by households and commercial electricity end users were remarkable – and thus played a critical role in keeping the electricity system functioning without any further actions.

225 The use of gas was also reduced and replaced by other fuels. To secure the supply of gas to the industry, energy production, and households, as well as to safeguard Finland's security of supply from winter 2023 onwards, the Finnish Government tasked the natural gas TSO in April 2022 to lease a floating LNG-terminal vessel and to build up necessary pier and mooring structures. A floating LNG-terminal vessel arrived in Finland at the end of 2022 and was connected to the Finnish gas grid. With LNG terminals and natural gas imports from Estonia, Finland now has enough supply to replace all the Russian gas.

226 The most challenging month in Finland was December, when the temperatures were the coldest, the gas supply was uncertain, and Olkiluoto 3 was mostly offline due to a feed-water pump fault. Figure 23 below, however, explains that the consumption was as much as 2 GW lower during the lowest temperatures compared to previous years (for the same level of temperature). Furthermore, the figure shows that the variation between day and night electricity consumption was lower than in the previous year, suggesting that businesses and households may have shifted part of their consumption from day to night hours. Finally, wind power produced well during some of the most challenging days.

Figure 23: Hourly electricity load in Finland - 2019-2023 (MW)



Source: Finish NRA with information from this link.

A-II. 6. France

A-II. 6.1. Adequacy risks identified ahead of the winter

227 The winter adequacy assessment published by the French TSO (RTE) in September 2022 concluded that the electricity security of supply in France was expected to be under unprecedented stress during the winter of 2022/2023 and that load shedding might occur if several risks were to materialise.

228 Ahead of the winter, several parameters contributed to reducing the margins of the French power system. Firstly, the availability of nuclear power generation was low due to planned maintenance and the replacement of fuel rods, as well as the unexpected corrosion problems detected on several reactors in December 2021. For instance, in September 2022, 27 GW of nuclear capacity was available out of the 61 GW total installed capacity. Secondly, hydropower stocks in September 2022 were below historical levels due to a long drought that had affected France in 2022 and was still ongoing at the time, affecting other European countries as well.

229 Additionally, multiple risks that could potentially contribute to a deterioration of the system's margins during the winter were identified in September 2022. These include the possibility of a gas supply shortage in France and Europe, the speed of return to operation of nuclear reactors that were shut down, the risk of a cold winter, and concerns regarding the possibility that hydropower stocks would not fill during the fall if the drought persisted. The gas supply shortages could pose a price and volume risk for gas supplies, which could limit gas-fired power production and electricity imports. Consequentially, a cold winter could have resulted in high power demand peaks. Given this context, RTE announced that the French power system was under high vigilance as of autumn 2022, and the highest risks were identified between November 2022 and January 2023.

A-II. 6.2. Preventive measures to cope with the risks

230 In this context, the French Government implemented several measures ahead of the winter. In the summer of 2022, the CO2 emissions cap that limited power production from thermal power plants was increased, enabling the Saint-Avold coal plant to restart producing electricity as of November 2022. In October 2022, the government unveiled a national Energy Sobriety plan, aimed at reducing energy consumption by 10% over the next two years compared to 2019. To monitor the situation, RTE expanded the scope of its winter adequacy assessment, with a deeper analysis of the security of supply situation, the publication of monthly updates, and weekly reviews of the evolution of French power consumption. In addition, RTE further developed its "EcoWatt" tool, downloaded by 2.5 million users as of December 2022, which notifies citizens in case of an anticipated tight situation on the supply-demand balance and encourages them to reduce or shift their power consumption.

A-II. 6.3. Interactions with market

231 Given the adequacy risks foreseen for winter 2022/2023, electricity wholesale prices reached unprecedented high levels. As depicted in Figure 24, average day-ahead prices remained above 200 euros/MWh in November and December 2022, before decreasing to around 150 euros/MWh in the following months

232 Forward prices for delivery during winter 2022/2023 significantly increased in the first half of 2022, as concerns over French security of supply for the coming winter intensified. Prices of baseload products for deliveries in the last quarter of 2022 and the first quarter of 2023 were higher than in neighbouring countries and peaked above 1,000 euros/MWh in the summer of 2022. They gradually declined from autumn onwards, yet still remained at very high levels until early December, before falling rapidly at the end of the year thanks to the rapid return to service of some nuclear power plants, the easing of the gas market, and the fall in structural power consumption.

233 CRE's preliminary analysis of forward prices for the winter 2022/2023, published in summer 2022[197], showed that forward prices reflected the market's anticipation of a particularly tight supply-demand balance in France. These forward prices included a risk premium that seemed very high compared with

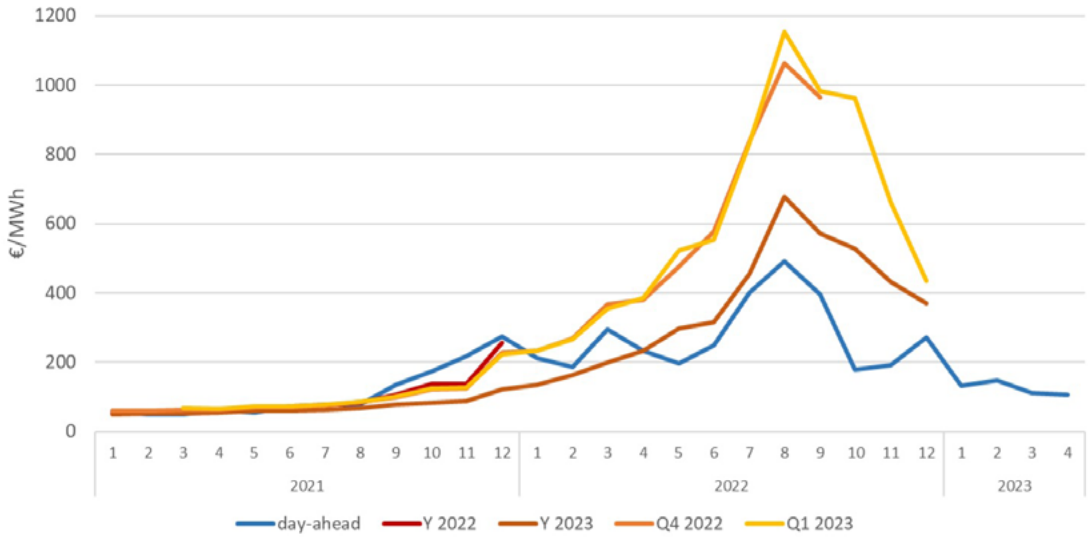
197 The preliminary analysis is available here.

a reasonable anticipation of future day-ahead prices. The final assessment[198] published in December 2022 concluded that two main factors explain the record-high prices reached during the summer. Hedging of risks linked to physical activities led to, on the one hand, purchases in excess of average anticipated needs and, on the other hand, reduced sales on the forward markets. In addition, while France was expected to be an importing country during the winter, the late allocation of the yearly 2023 interconnection capacity at French borders (except the UK-FR border), prevented market participants from buying the volumes corresponding to the imports required to ensure adequacy on the French forward market without risk before late November-early December 2022.

234 Market expectations of supply-demand imbalances in winter were also reflected in the French capacity mechanism. Capacity prices for the 2023 delivery year exceeded 40,000 euros/MW during all auctions conducted in 2022, and the price cap of 60,000 euros/MW was reached at the last auction of 2022, as highlighted in Figure 25.

235 While in theory, high wholesale energy prices could contribute to bringing capacity prices down as capacity owners would cover their costs with the sale of electricity, the anticipated capacity deficits for the winter led market participants to buy capacity at very high prices to avoid costly penalties.

Figure 24: Evolution of day-ahead and baseload forward prices in France - 2021-2023 (euros/MWh)



Source: French NRA

Figure 25: Evolution of capacity prices in the French capacity mechanism auctions - 2020-2022 (euros/MW)

Source: French NRA

198 The final assessment is available here.

A-II. 6.4. Materialisation of risks and lessons learnt from this winter

236 In March 2023, RTE published a review on how the French electrical system has gone through the winter 2022/2023. It concludes that while the risks identified in early winter were very high, the French system eventually benefited from favourable conditions. No "EcoWatt" red signal was issued, meaning that RTE did not anticipate any supply-demand imbalances in the short term during the winter.

237 According to RTE, the main drivers that enabled the French electricity system to avoid supply-demand imbalances were the following (ranked in order of importance with regard to RTE's analysis):

a. winter temperatures were relatively mild;

b. the weather-corrected power consumption was on average 8-9% lower than the historical average (Figure 26);

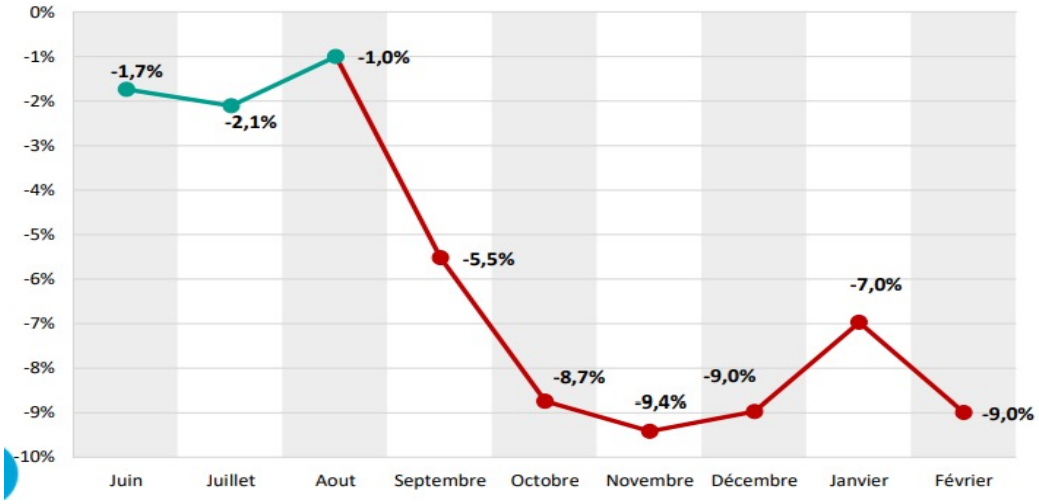
c. hydropower stocks recovered and reached normal levels ahead of the winter;

d. the fact that France was able to import electricity from neighbouring countries during peak hours;

e. the actual availability of nuclear reactors had been aligned with RTE's central scenario (Figure 27).

238 Focusing specifically on power consumption, one of the main lessons learnt from the winter was that the drop in structural consumption affected all sectors. It was mainly observed in the industrial sector, with a drop of around 10% to 12% compared with 2021, and, to a lower extent, in the services and residential sectors, reaching around 6% to 7%. For the residential sector, RTE carried out further work after the winter to investigate the underlying factors beyond this fall and the perspectives for a sustained drop in the following months and years. The results of a large-scale survey published on 7 June 2023 showed that residentials have reduced their consumption mainly in response to the rising cost of electricity, or to offset increases in other expenditure areas, and, to a lower extent, to avoid the risk of power shortages in the country[199].

Figure 26: Comparison of weather-corrected power consumption in France in winter 2022/2023 over historical average

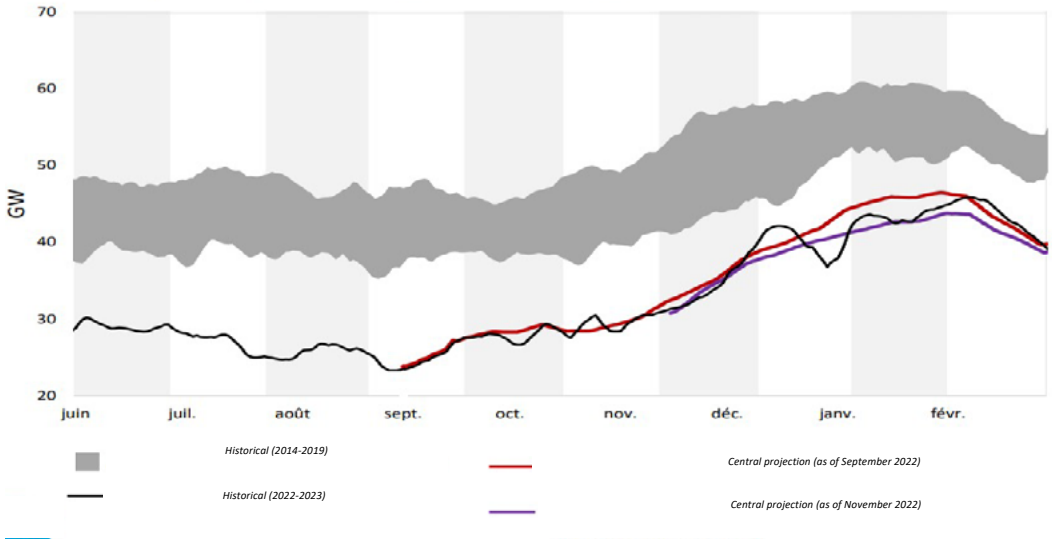


Source: RTE's Bilan de l'hiver 2022/2023.

Note: historical average refers to the years 2014–2019.

199 The survey was conducted on more than 10,000 people. The results of this study will be used by RTE to build consumption trajectories for the next National Resource Adequacy Assessment.

Figure 27: Availability of French nuclear generation in winter 2022/2023 (GW)



Source: RTE's Bilan de'lhiver 2022/2023.

239 According to RTE's short-term adequacy outlook[200] published in June 2023, the latest developments in power production and consumption resulted in the assessment of winter of 2023/2024 as significantly more favourable compared to the initial assessment made for winter 2022/2023. Still, the risk levels are higher than normal. The main risk factors have decreased compared to last winter: the reduced consumption levels observed during the winter continued through the spring, suggesting that they could be sustained over the next winter; nuclear availability is expected to be around 5 GW higher than last year (although still well below historical levels), hydropower stocks are filled at satisfactory levels; gas storage filling levels are high in all EU countries, and renewables continue to be deployed in France and in Europe. However, as of summer 2023, several uncertainties remain regarding the following months, in particular concerning the exact availability of nuclear reactors and the potential of sustaining the lower levels of demand.

240 Despite the more favourable situation expected for the winter 2023/2024, electricity prices on forward markets for the next winter are, like last year, very high in France and still include a substantial risk premium, reflecting the market's expectations of tensions on the French power system.

A-II. 7. Germany

241 Germany experienced relatively few adequacy issues during the winter of 2022/2023, much like other member states. However, certain risks were identified including the potential obstruction in the supply of gas (given the uncertain socio-economic climate), the need for increased exports due to France's reduced nuclear power availability, potential coal transportation difficulties resulting from low river levels, and an increase in demand due to the use of fan heaters. The German government took measures to mitigate the forecast risks by reducing gas demand by 20%, implementing gas storage targets and gas procurement, prioritizing coal transportation by rail, conducting additional national resource adequacy assessments, prolonging the generation of nuclear power plants until 15/04/2023, and the return of coal power plants into the market.

A-II. 8. Greece

242 The main risk identified in Greece was the possibility of severe gas shortages. The Government implemented measures aimed at mitigating the anticipated risk by increasing the regasification capacity in the Liquefied Natural Gas (LNG) terminal (lease of an FSU facility connected to the main LNG terminal increasing capacity from 222 mcm to 375 mcm), creating gas storage facilities in Italy and Bulgaria, committing to increasing diesel stocks for the gas power plants with double fuel obligation, revising the plan for lignite phase-out, and amending the gas curtailment plan. The Government also implemented measures targeted at improving energy efficiency by launching educational campaigns

200 Available here.

on social media to inform consumers about the favourable behavioural changes aimed at reducing consumption. A microsite was developed which allowed consumers to calculate their energy bills and their devices' consumption. Additionally, the Government further incentivised behavioural changes towards electricity consumption by awarding subsidies on electricity bills to consumers that reduced their average consumption by 15% year-on-year.

243 Overall, the concentrated effort to conserve electricity and gas consumption and the mild course of winter 2022/2023 contributed to the positive course and lack of adequacy issues during winter 2022/2023. Compared to winter 2021/2022, there was a significant decrease in the consumption of electricity for the months of November, December, January, February, and March, 9.96%, 13.32%, 13.58%, 2%, and 15.45% respectively. A similar trajectory was witnessed in the thermal power plant production, with January to March experiencing a 36.71% production reduction compared to the same period of 2022, and a RES production increase of 10.34%.

A-II. 9. Hungary

244 The main risks identified ahead of the winter in Hungary were that the cold winter could have led to a surge in consumption and a decrease in domestic production (e.g. due to forced outages), a gas supply shortage could have potentially led to a sharp decrease in electricity production, and the significant narrowing of import possibilities could also have led to a significant reduction in supply given that roughly 25-30% of Hungarian consumption is covered by imports.

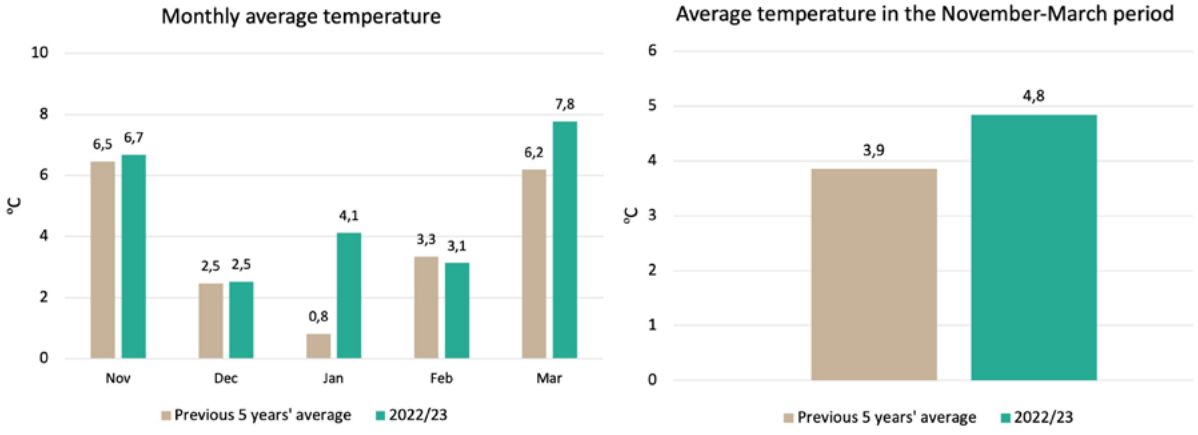
245 Numerous preventive measures were taken by the Government, including windfall profit tax, energy efficiency programs, increased fuel production/stocks (other than gas), reopening coal, lignite, oil, and nuclear power plants, assisting consumers through social policy and subsidies (the Energy Cost and Investment Support Program), Government loans (Factory Rescue Guarantee and Loan Program), increased stored gas levels, reduction in taxes, levies, and system charges on energy bills, regulated retail prices, accelerated RES deployment, and price limits at retail level.

246 The intense rise in wholesale prices led to an intense rise in retail prices. In the case of the residential segment, the Government raised the prices for consumption that would exceed past consumption in the past (by roughly 200%), thus the overall price increase was around 22%. In the case of the non-residential segment, the price increase reached the level of 54%.

247 There are numerous takeaways from this winter. Firstly, the gas supply remained reliable. The proportion of natural gas-based production reached 27% (952 MW hourly average) during the winter, whereas the previous winter average was 23% (1,242 MW hourly average).

248 The temperature has been mild, with the average temperature for this winter being 4.8 °C compared to 3.9 °C of the previous 5 years' average, as depicted in Figure 28. This reduced consumption and there were no production outages due to cold weather.

Figure 28: Monthly and average temperatures for the period November 2022 to March 2023 compared with five year average in Hungary (°C)

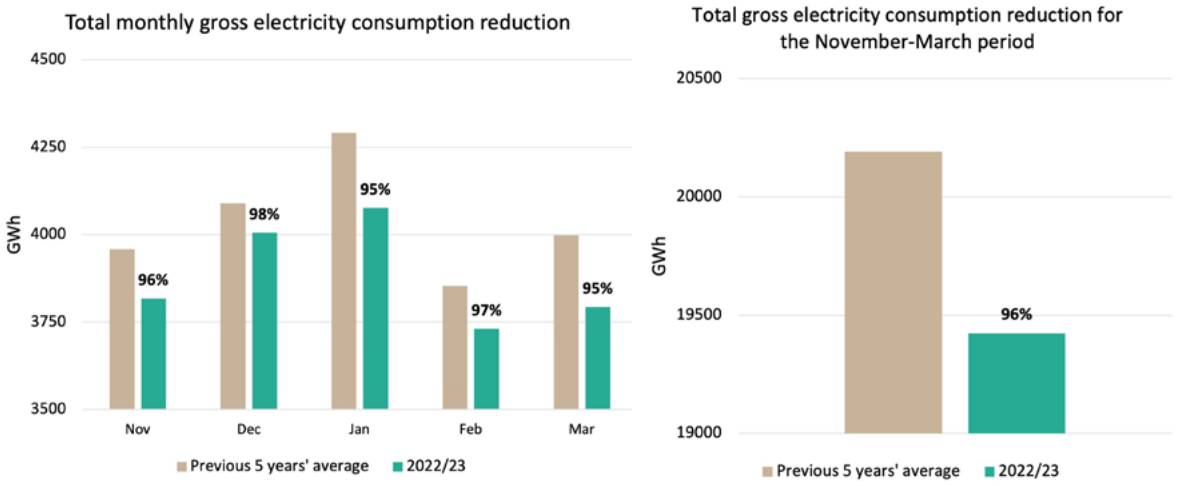


Source: Hungarian NRA

249 This winter has been favourable for import possibilities. The Hungarian import possibilities depend heavily on the hydro-based production of the Balkan region. This type of production increased by roughly 20% compared to the previous winter. This could create a south-north flow. This effect supported the Hungarian import possibilities during several weeks of November, December, January, and March.

250 Due to the price increase described above, consumption decreased significantly. According to our estimation, this effect was between 6% and 7% compared to the previous winter, as depicted in Figure 29.

Figure 29: Electricity consumption reduction in Hungary for the period November 2022 to March 2023 (GWh)



Source: Hungarian NRA

251 Finally, as for the effect of small-size household PV power plants, the number of these types of power plants increases constantly. The average installed capacity during the previous winter was 1,137 MW, while this figure reached 1,538 MW for this winter, roughly a 35% increase. Given that the production of these power plants decreases consumption directly, this creates downward pressure on the consumption trend. According to our estimation, the winter average of this effect was only 0.22%, however, in February this effect reached 0.9% of the total consumption.

A-II. 10. Ireland

A-II. 10.1. Challenges

252 The Winter Outlook for 2022/2023 prepared by EirGrid (TSO) for the Irish electricity sector indicated a very high LOLE value for the December-March period of 51 hours, a value well outside of the reliability standard of 8 hours. This calculation was influenced by high (recently increased) forced outage rates of conventional generation and a lack of available capacity during low wind spells. It was also understood that there was a risk of reduced imports being available from Great Britain via the interconnectors. The ongoing situation in Ukraine created a risk of potential gas security of supply consequences across Europe throughout the winter period.

A-II. 10.2. Achievements

253 The system experienced record peak demand during a cold snap in December 2022, and this demand was served with no system Alerts or Emergency states required to be declared. As highlighted in Figure 30, the exceptionally high demand was experienced on the 12th of December, and even though by a tight margin, available generation was still able to cover demand.

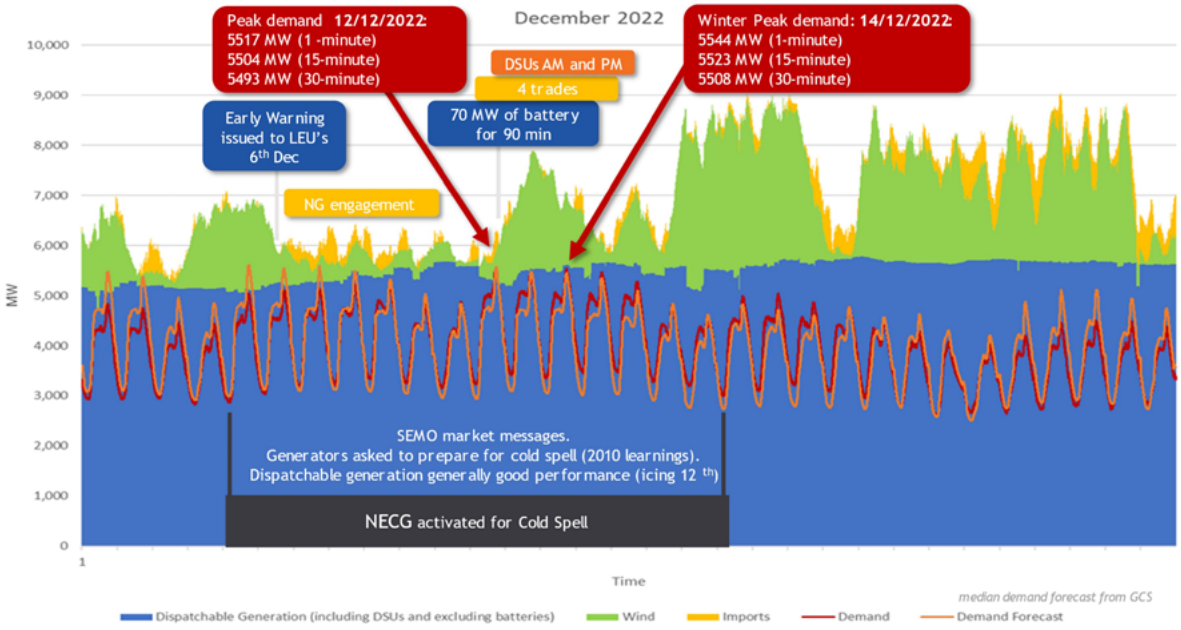
254 Two public campaigns were undertaken throughout the winter. The public 'Reduce your use' campaign used media messaging to appeal to consumers to reduce their use of energy where possible during the winter months. The 'Beat the Peak' campaign was run by the DSO (ESB Networks) and provided an opt-in service for consumers to receive notice of upcoming peak demand events via SMS and encouragement to reduce their electricity usage during these events.

255 Other measures taken included a collaboration between the TSO, DSO, and regulator to design and implement enhanced demand control procedures for large energy users, to be deployed if required in an emergency situation. This involved a large multi-stakeholder Emergency Test exercise, using a scenario involving gas, oil, and electricity to demonstrate the impacts across different sectors and test the responses, and the development of plans for replenishing secondary fuel supplies to gas generators to facilitate key sites to run for a prolonged period on oil during a gas shortage.

A-II. 10.3. Lessons Learnt

256 A significant effort was made to coordinate actions between the NRA, TSO, and Government departments to drive interventions to both prevent and mitigate security of supply issues. The TSO engaged daily with the Northern Irish and British TSOs to leverage interconnection, and this ensured optimal outcomes. The national Test Exercise was beneficial in terms of socialising the impacts of a disruption to the energy system and raising awareness across many different sectors. The opportunity was also taken to enhance planning in an area not previously considered, i.e., the replenishment of secondary fuel stocks.

Figure 30: Record peak demand in Ireland during a cold snap in December 2022



Source: Irish NRA

A-II. 11. Italy

A-II. 11.1. Outlook

257 During 2022, the situation for the incoming winter 2022/2023 was expected to be challenging, mainly because of the risks linked to uncertainties regarding the availability of imported natural gas from Russia. Roughly covering 40% of the national demand in 2021, Italy's dependence on the Russian commodity is necessary for heating, electricity generation, and industrial demand. Moreover, due to a record low rainfall level registered in the previous months, hydropower availability was expected to be extremely low. Finally, the reduced availability of nuclear generation capacity in France increased the uncertainties on the actual possibility of importing the usual amount of power from abroad.

258 The aforementioned scenario, in combination with prevailing adverse gas market conditions lowering the incentives of market participants to store gas for the upcoming winter season, led the Government to take preventive emergency measures[201] to ensure a high degree of natural gas storage filling for winter 2022/2023. Additionally, there was a goal to rapidly diversify the sources of imported natural gas, maximizing the use of the available infrastructures and at the same time increasing the national LNG regasification capacity.

201 For more information see here.

259 Regarding the first and most urgent measure, the Government established a national target to fill at least 90% of the storage capacity before the withdrawal season in March 2022. This measure had the incentive of suggesting (not imposing) market operators to anticipate the injection campaign and requesting the NRA to design a specific incentive mechanism to facilitate the process. Nevertheless, given both the unsatisfactory results of the daily monitoring of storage filling due to the reluctance of market participants, and the excessive price volatility, further centralised interventions became necessary. In particular, the Government identified SNAM, the main Italian gas TSO, as the entity of last resort supporting the system reaching a satisfactory level of gas storage. This service was then allocated to the state-owned company GSE. Thanks to this adjustment, the storage levels in autumn 2022 were considered satisfying.

260 With regard to the second measure, actions were taken to gradually increase the gas supply from Algeria and Azerbaijan through existing pipelines (Transmed and TAP). Moreover, the Government has been active in developing new LNG imports from Egypt, Qatar, Congo, and other routes. That goes along with the necessity to introduce new regasification terminals, given that the existing ones work at full capacity. A newly installed FSRU terminal in Piombino, purchased by SNAM and offered to the market at regulated conditions, entered operation in spring 2023.

261 Given natural gas has a significant role also for electricity generation as well, the Government requested the electricity TSO to maximise the utilization of power plants using coal, oil, and biofuel. The measure was supposed to be implemented from September 2022 up to March 2023 and was prolonged to September 2023.

262 Actions were also taken on the electricity consumption side. In December 2022, the Italian TSO, TERNA[202], published a call to procure a demand reduction service for the period lasting from February to December 2023, for a total of 2,500 MW. The results show that only 258 MW were awarded with an average premium of almost 59,200 euros/MW to 13 industrial operators and companies specialised in aggregation and flexibility services. A second auction was published with specific reference to January 2023 for a maximum reduction period of 91 hours and a total request of 3,000 MW. Twelve companies were awarded an average premium of almost 8,300 euros/MW for a total of 237 MW.

A-II. 11.2. Review

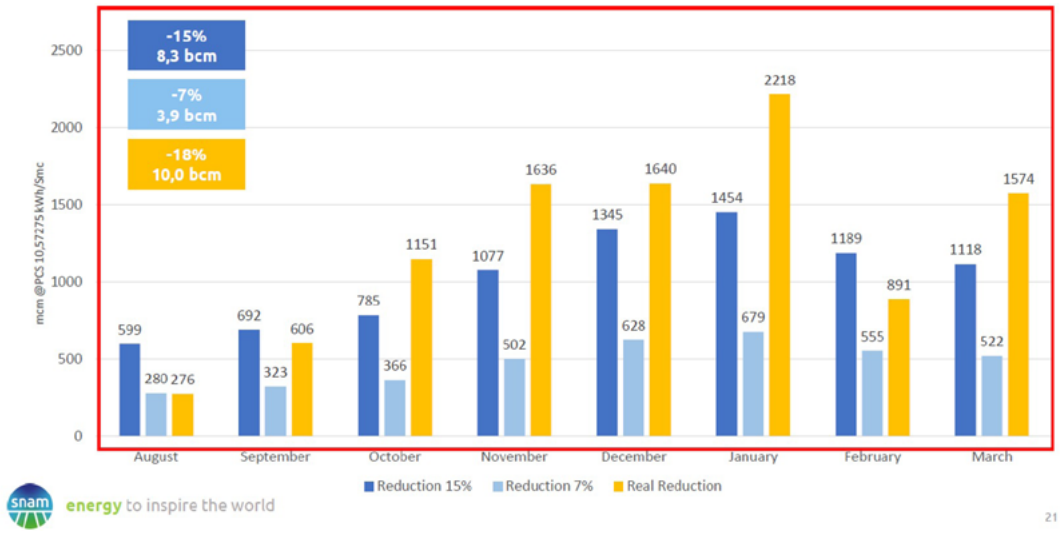
263 At a time period where data collection is being undertaken and elaborations at the national level are still ongoing; therefore, the following review should be considered preliminary and based on the information currently available.

264 **Gas demand reduction** over the period August 2022 – March 2023 was around 18%[203], higher than the 15% voluntary EU target. The major contraction was registered in January followed by December, November, and March. The cold season was almost always characterised by temperatures well above average, except for February 2023, when in fact consumption decreased less than the minimum target. The worst performance was registered in August 2022, when consumption by thermoelectric assets supported gas demand despite the decline in other consumption sectors, as depicted in Figure 31 below.

202 In December Terna launched also a communication campaign recommending energy savings (eco-clock)

203 Eurostat and SNAM

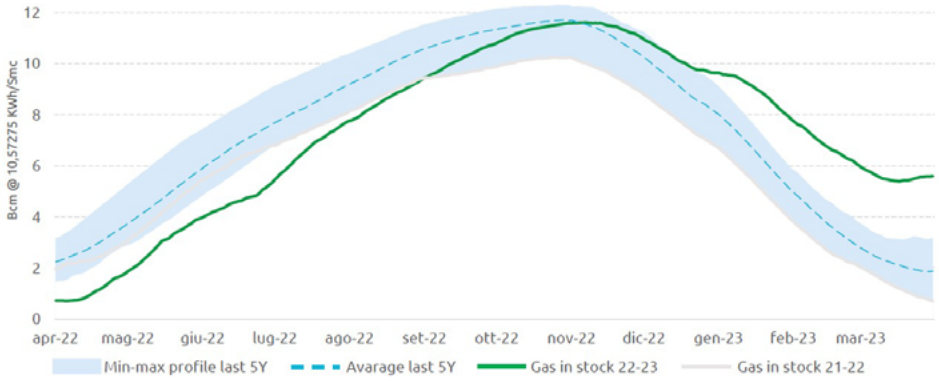
Figure 31: Monthly volumes of gas demand reduction in Italy - August 2022-March 2023 (mcm)



Source: Italian NRA

265 With reference to the level of gas storage, the situation at the end of the winter shows stocks around 58% of full capacity, higher than the previous 5 years, as corroborated in Figure 32.

Figure 32: Gas storage level development in Italy — April 2022–March 2023 (bcm)



Source: Italian NRA

266 With reference to the electricity sector, although official data is still under elaboration but according to preliminary information, electricity generation (to compensate for the reduced generation from gas) counted on an increase in generation from coal and renewables, with the exception being from hydropower because of the droughts that prevailed across Europe at the time[204]. Additionally, according to preliminary unverified data[205] electricity demand savings were about 4.7% over the period from November 2022 to March 2023, compared to the previous 5 years' average. Industrial demand is still low and did not recover to pre-crisis levels at the end of March 2023.

267 Average wholesale and retail prices for both gas and electricity[206] reached record levels for a sustained period from autumn 2021 throughout 2022 (highest monthly average of 543 euros/MWh in August 2022) up to March 2023, even with strong fiscal policies implemented by the Government, as the market internalised the worst scenarios. The unexpected mild weather (except for February), together with the reduction of demand both from households and industries due to the unfavourable price conditions, and the availability of imports, provided some relief moving to spring 2023. However, the reduced rainfall might create further tension in the market for the coming summer, especially if imports will not be fully available.

204 For and overview of 2022: https://www.terna.it/en/media/press-releases/detail/electrical-consumption-2022

205 ICIS Power Foresight analysis: EU achieves a 6.6% cut in Winter 2022/2023 power demand

206 Summary by the Italian nominated electricity market operator, GME.

A-II. 11.3. Preliminary conclusions

268 The importance of gas storage for the security of gas and electricity supply has been always acknowledged in the Italian legislative and regulatory framework.

269 Some of the related regulatory measures, such as strategic storage volumes, obligatory injection and withdrawal profiles, and the full regulated access, have been often criticized at the EU level for being too rigid.

270 The main lessons learnt from the last winter emergency are that the adoption of a similar storage regulation is vital to guarantee system security. Leaving such a strategic sector fully unregulated, as the case in many jurisdictions, where the main gas supplier had also full availability of storage capacity, is posing a serious threat not only to the local market itself but to the entire European integrated market.

271 Other important lessons learnt for the gas sector are related to the availability of LNG volumes and network congestion. Regasification terminals are not per se enhancing the security of supply in the absence of long-term procurement contracts, as spot LNG cargoes may not be available in the most critical periods of the year. For what concerns network congestions, the recent crisis has shown that a new "eastbound" supply scenario might suggest that new unexpected infrastructure investments are needed to make LNG volumes available for the whole of Europe, thus overcoming the several bottlenecks (structural or gas-quality related) present in the EU network.

272 For the electricity sector, the main lessons learnt are related to the importance of water availability for the security of supply of many EU countries. We may expect that climate change will bring more and more often extremely dry seasons, leading to variable water availability conditions. For the specific Italian situation, it is in particular critical the tendency of lower snow precipitation during winter which is affecting the water availability during the entire year and especially in summer. Low water levels affect not only the potential production of hydropower plants but also the availability of thermal generators that use the waters of rivers for cooling purposes.

273 Another precious lesson is related to the availability of import electricity to be considered in adequacy assessments as the last winter demonstrated that the available volumes may be much lower than the historical average.

A-II. 12. Latvia

274 With the Russian invasion of Ukraine on February 24, 2022, the necessary actions and decisions have been taken by the Latvian Government to ensure that the energy sector will be able to guarantee a secure and continuous energy supply.

275 Since 2009, the Baltic States have worked in close cooperation with the European Union purposefully to disconnect the electricity systems from the BRELL (Belorussia, Russia, Estonia, Latvia, Lithuania electricity systems) and prepare for synchronised work with the Continental Europe electricity systems by the end of 2025. After Russia's invasion of Ukraine in 2022, the Baltic States have taken a series of measures to distance themselves from the aggressor state and to ensure that the electrical systems can be managed even in case of urgent desynchronization from BRELL. The Baltic States stopped the commercial trade of Russian electricity in the wholesale market and TSOs continue only the minimum necessary technical operational cooperation within BRELL

276 The Latvian Government tasked a state-owned company JSC "Latvenergo" to purchase an additional amount of liquefied natural gas (LNG) from the Klaipeda LNG terminal to ensure the security of the natural gas supply, ensuring that the provision of energy supply safety reserves in the amount of 1.8-2.2 terawatt hours can be provided in 2023. Those reserves have been injected into the Inčukalns underground gas storage by 1 January 2023. Natural gas transmission and storage system operator JSC "Conexus Baltic Grid" started injection season into the underground gas storage facility already on 26 February 2022, although this would usually start only on 1 May. On 1 January 2023, Latvia banned the import of natural gas from Russia.

277 In September 2022, in the long-term capacity allocation procedure, Latvenergo acquired the right to use 6 TWh annual capacity of the Klaipeda LNG terminal for the next 10 years. Its purpose is to ensure

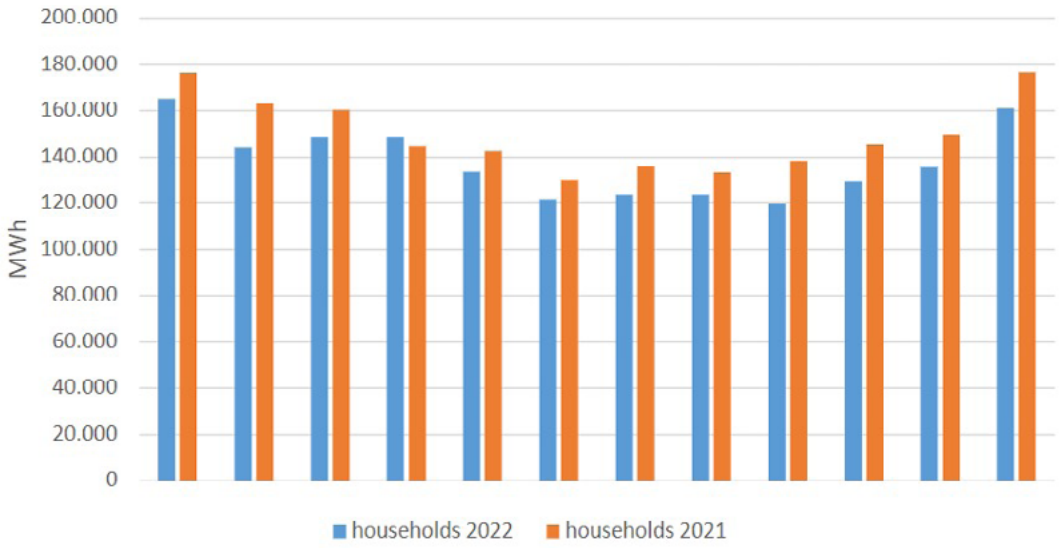
regular deliveries of natural gas for the safe production of electricity and heat, and for natural gas supply to consumers.

278 On 8 February 2022, the Latvian government approved a change in the maintenance model of safety reserves of oil products. It was determined that the amount of safety reserves to be stored on the territory of Latvia will be gradually increased over a three-year period, with 100% of reserves being stored in Latvia by 2025.

279 On 20 September 2022, the Latvian Government adopted energy-saving measures for public sector entities during the winter season 2022/2023 in order to save 9.7% on heating consumption, 4.2% on electricity consumption, 3.3% on natural gas consumption, and 1.8% on oil products consumption. In multi-apartment buildings, the temperature may not exceed 19 °C while keeping temperatures at least 18 °C. In addition, it was decided that the managers of multi-apartment buildings have the right to reduce the hot water temperature slightly or temporarily, but it should not be lower than 55 °C, a policy put into effect from 1 October 2022 until 30 April 2023.

280 Since May 2022, the amount of electricity consumed in Latvia has continually decreased as a result of the increased amount of microgeneration for self-consumption, as reinforced in Figure 33 below. Customers decided on installing microgeneration not only because of sustainability goals but also because of the associated economic gains since microgeneration became an appealing investment in times of increased electricity prices. Throughout 2022, the number of self-producing households grew from 2,000 microgenerators at the end of 2021 to almost 12,000 microgenerators in December 2022 (95 MW). The forecast shows that at the end of 2023, the installed microgeneration capacity for households will reach 200 MW.

Figure 33: Electricity consumption by households in Latvia - 2021-2022 (MWh)s

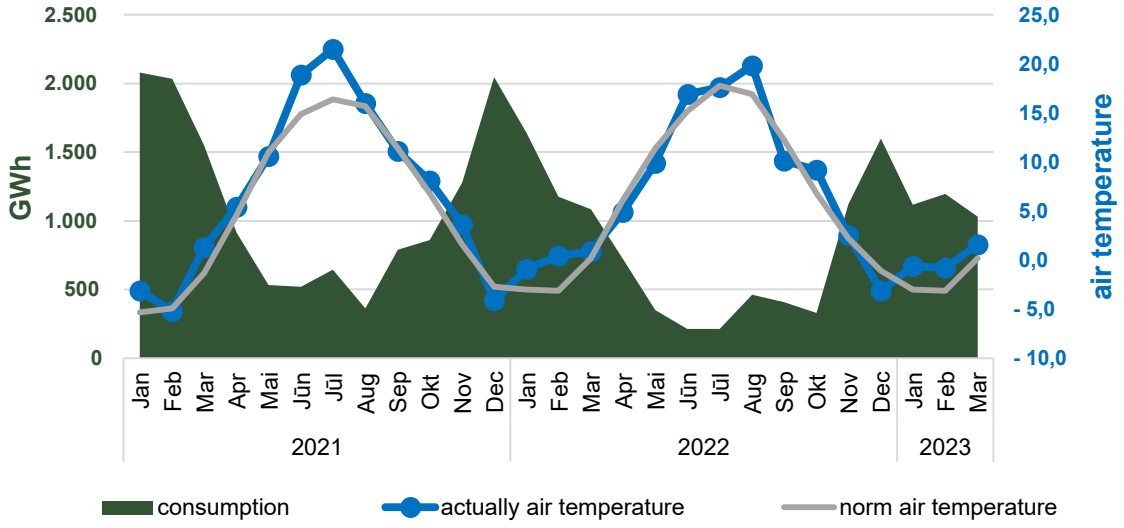


Source: Latvian NRA

281 The year 2022 was characterised by price fluctuations and anti-records, however, the first quarter of 2023 saw the stabilization of electricity prices at around 65-100 EUR/MWh.

282 The amount of natural gas consumed in Latvia decreased by approximately 30% in 2022, with this trajectory continuing in the first quarter of 2023, as depicted in Figure 34. The decrease in consumption was influenced by lower demand for natural gas from cogeneration plants due to the high natural gas prices and warm winter.

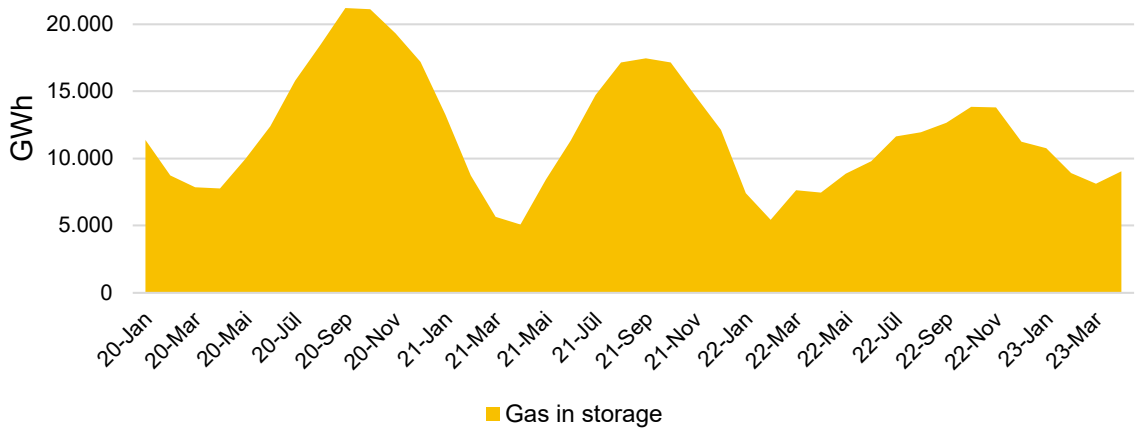
Figure 34: Natural gas consumption and average air temperature in Latvia - January 2021-March 2023 (GWh and °C)



Source: Latvian NRA

283 Additionally, natural gas transmission and storage system operator JSC "Conexus Baltic Grid" ended the gas extraction season with 9 terawatt hours (TWh) of natural gas stored in the Inčukalns underground gas storage. This is 21% more than last year at the end of the storage's natural gas withdrawal season, as reinforced in Figure 35.

Figure 35: Gas stored in the Inčukalns underground storage facility in Latvia - January 2020-March 2023 (GWh)



Source: Latvian NRA

A-II. 13. Poland

284 The general forecast for winter 2022/2023 was as follows. Firstly, there was no risk of a coal shortage in power plants. Secondly, there was the possibility of issues arising from keeping the reserve at the required level of 9% in the instance of longer periods of a cold winter with the simultaneous low wind farm generation. Finally, the stable operation of the system required wind generation or commercial import at the level of 2 GW.

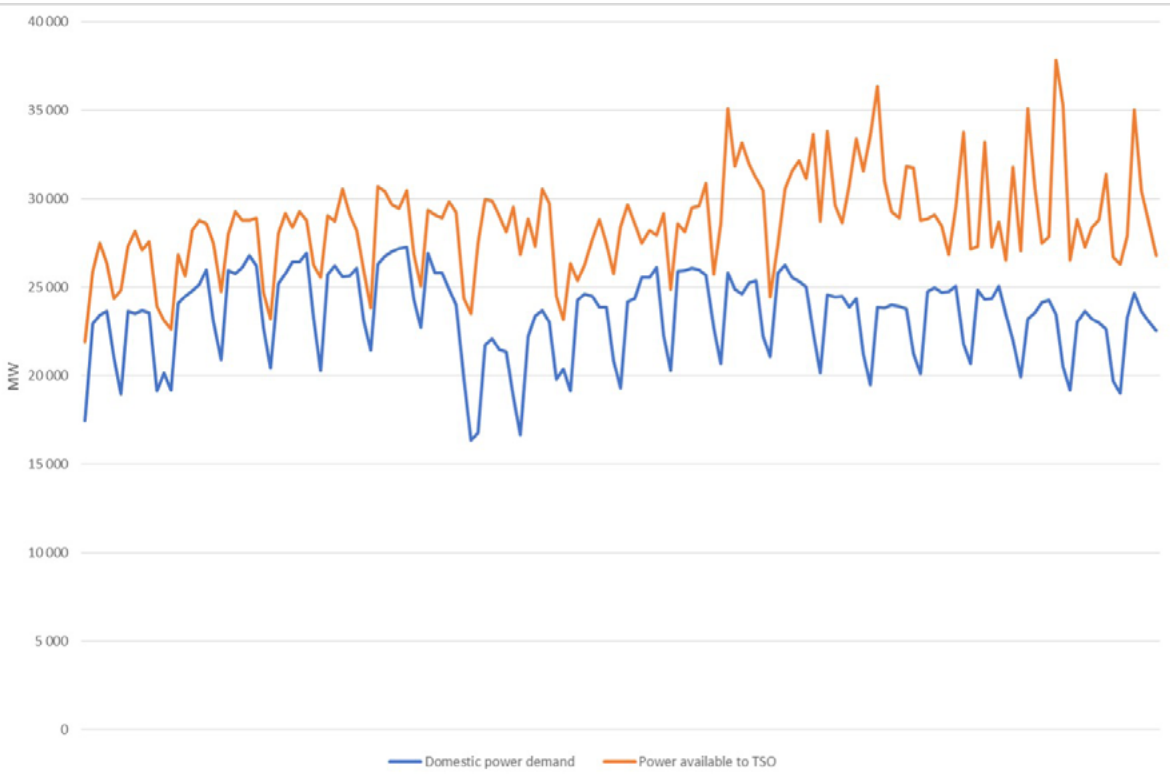
285 Due to the relatively warm winter, there were no major problems with the balancing of the system. Some difficulties were at the beginning of December 2022, which were caused by the cumulation of the low temperatures, inconsiderable wind generation, and the emergency and planned outage of unit generation. The security of supply was improved by the operator's import of energy from neighbouring countries.

286 There were also some problems with a surplus of generation caused by the low demand during

Christmas. On the 26th and 27th of December, the TSO had to decrease the wind generation by 400 to 800 MW at different hours because of the low demand. The total installed capacity in wind farms in Poland is 9 GW, the generation was at the level from 0.3 GW to 5.9 GW and the demand was from 11.8 to 16.7 GW during the Christmas period in Poland.

287 Figure 36 presents the domestic power demand and power available to TSO at power demand peaks between 1 November 2022 and 31 March 2023.

Figure 36: Power demand and available power in Poland - November 2022-March 2023 (MW)



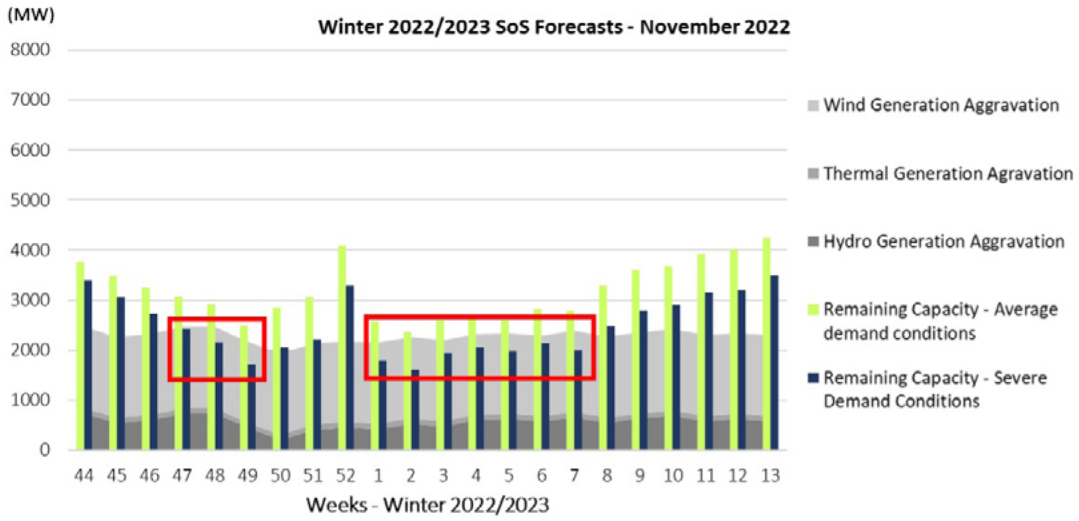
Source: Polish NRA

A-II. 14. Portugal

288 Although there is no seasonal resource adequacy assessment in Portugal, the Portuguese TSO presents every two months an update of its forecasts for the seasonal security of supply of the Portuguese system at the meeting of the Technical Committee for the Monitoring of the Operation of the Iberian Electric System. This assessment is done on a weekly basis and is based on an indicator that analyses the ability of the Portuguese generation units to cover the peak demand, in severe conditions of generation and demand (peak cover margin). For this assessment, the Portuguese TSO does not consider any contribution to the interconnection import capacity.

289 At the November meeting, the forecasts for winter 2022/2023 pointed to a total of 10 weeks in which the available generation would not be able to cover peak demand in severe conditions, as depicted in Figure 37. These forecasts were mainly justified by a lack of hydro resources. The water levels on the dams were very low due to a very dry summer and autumn and the expected unavailability of some CCGT power plants. The hydro resource conditions were so drastic that there was even a resolution of the Portuguese government that prevented electricity generation using the water of some damns, except in cases of security of supply emergency. There were also expectations of higher demand due to the forecast low temperatures.

Figure 37: Security of supply forecast for winter 2022/2023 in Portugal

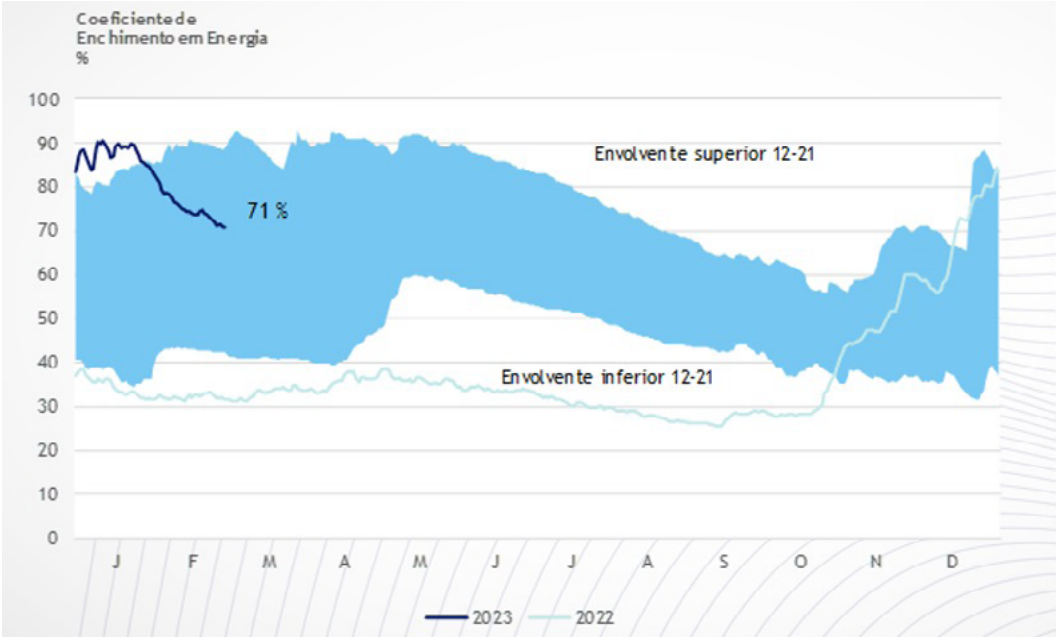


Source: Portuguese NRA based on Portuguese TSO data.

290 The two main measures taken to cope with the risks were the re-schedule of some CCGT power plants' maintenance and the implementation of a time-limited and market-based demand-side response product for large industrial consumers (about 300 MW).

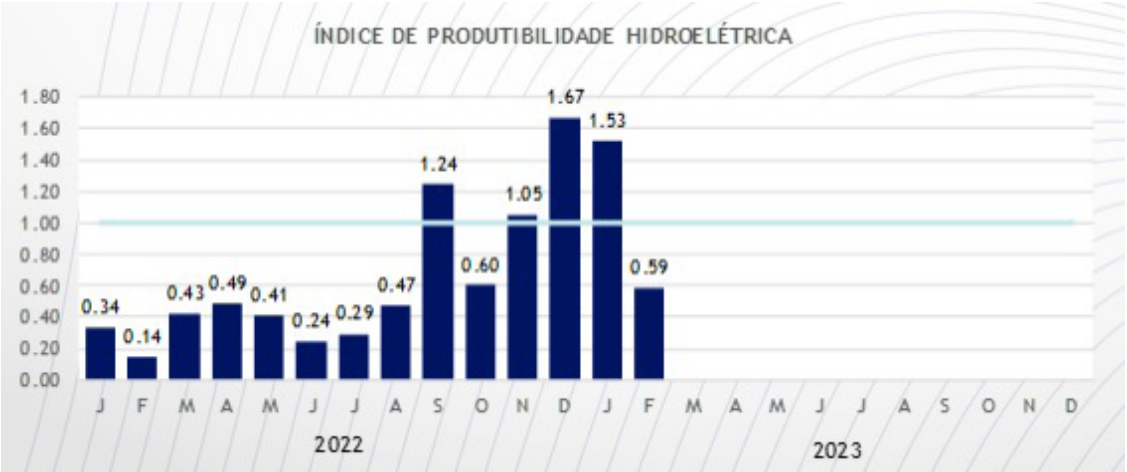
291 Contrary to the forecasts, the winter 2022/2023 progressed without any reports of stress situations. It rained more and the winter was less cold than expected. For instance, the water dams' filling level went from about 43% in October to 90% in January, as shown in Figure 38, and the hydro productibility index went from 0.60 in October to 1.53 in January (with 1.0 being the average of a year), as depicted in Figure 39.

Figure 38: Filling level of water dams in Portugal - 2022-2023 (%)



Source: Portuguese NRA.

Figure 39: Hydro productibility index in Portugal - 2022-2023



Source: Portuguese NRA (the figure is part of the TSO's report).

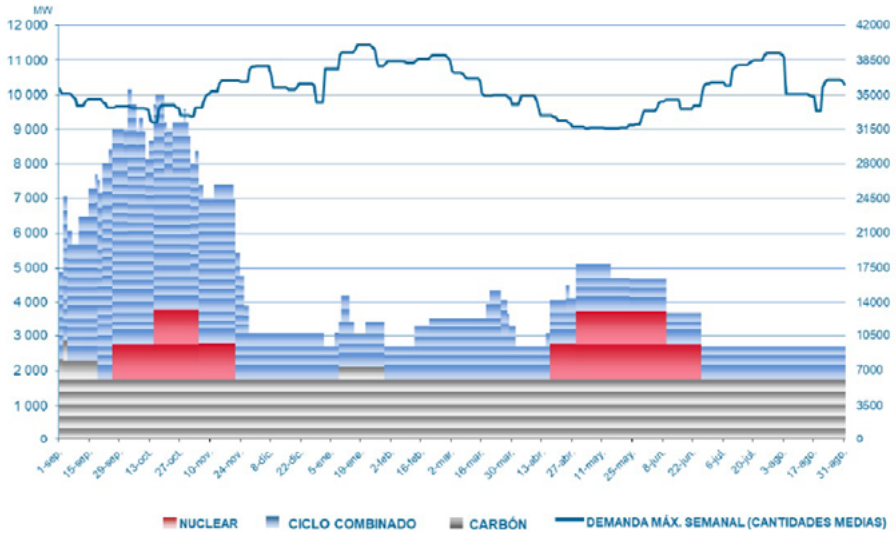
292 The situation observed this winter confirmed the importance of hydro generation in Portugal and the need to find suitable alternatives both to hydro and CCGT power plants.

293 Currently, there are no significant measures in place for next winter other than the demand response product referred to in the previous section, which is currently available only until the end of 2023. Other demand response options are still in a very early stage, however, the legal and regulatory framework is being developed to ensure that these solutions may appear. ERSE held a public consultation for the review of the electricity regulatory framework.

A-II. 15. Spain

294 The main adequacy risk identified in the Spanish electricity system occurred during last autumn 2022/2023, due to the significant unavailability of thermal (CCGT and coal) and nuclear power plants from the end of September to the beginning of November. In some cases, the unavailability of generation reached 10,000 MW, which represents almost a third of the estimated peak load of that period, as corroborated in Figure 40. Although the level of CCGT under maintenance was not high since it remained at the same level than previous years, the situation was more challenging last year because of a greater need for electricity generation in Spain, combined with a severe drought in the region which drastically reduced the availability of hydro generation. The need for extra production was motivated mainly by the increase in electricity exports to the neighbouring countries (France and Portugal) due to droughts that affected Portugal too, scarcity of natural gas in Europe, and nuclear unavailability in France.

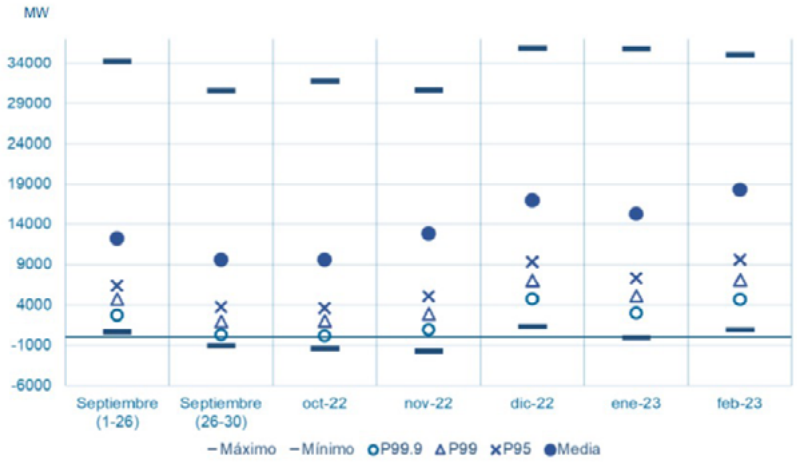
Figure 40: Predicted unavailability of power generation in Spain - September 2022-August 2023 (MW)



Source: Spanish NRA

295 Under the exposed circumstances, the seasonal security analysis conducted by the TSO in September concluded that there was a non-negligible probability of load shedding, as highlighted in Figure 41. To mitigate the risk, the Government of Spain adopted a plan (Plan +Seguridad Energética) in October to increase efficiency and saving in the energy sector. This included a set of measures fostering the reduction of electricity (and gas) demand, such as a reduction of temperature for heating to 19 ºC and increasing to 27 ºC for cooling in public buildings, shopping centres, airports, train stations, etc. The Government also launched a specific balancing product focused on demand, to facilitate demand response and alleviate the risk.

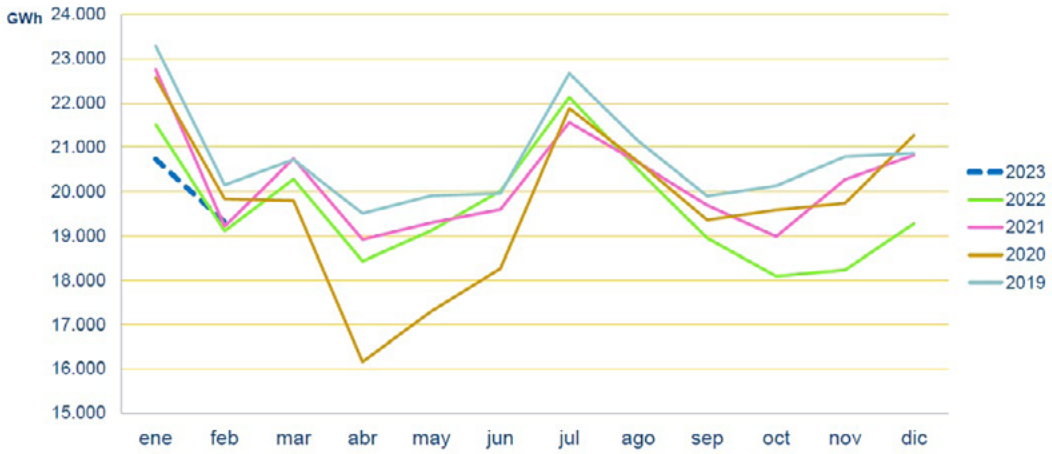
Figure 41: Probabilistic calculation of supply margin in Spain - September 2022-February 2023 (MW)



Source: Spanish NRA

296 Fortunately, the risk foreseen in the September 2022 security analysis never materialised because of several factors that contributed to the reduction in electricity consumption in Spain during autumn and winter 2022/2023, as outlined in Figure 42. The main factors for this positive course were the efficiency and saving measures approved by the Government of Spain, the mild temperatures of the region, and the reduction of demand due to the high retail electricity prices. Additionally, the months of December and January were characterised by periods of abundant rain in the Iberian Peninsula, replenishing in a significant way the reservoirs to increase the availability of hydropower and diminishing the risks for the rest of the winter.

Figure 42: Electricity demand in Spain — 2019–2023 (GWh)



Source: Spanish NRA

A-II. 16. Sweden

297 In the autumn, SVK predicted that due to reduced energy import opportunities caused by the war in Ukraine, the low water levels in Norwegian reservoirs, and reduced power production in France, there was a real risk of manual electricity consumption disconnection during winter 2022/2023. Despite entering the winter under worse-than-normal conditions, including the unavailability of the Ringhals 4 nuclear power plant and the delayed start of the Olkiluoto 3 plant in Finland, Sweden was able to avoid any electricity consumption disconnection. The highest consumption hour during the winter period was on December 16th from 9 to 10 AM, with a recorded consumption of 23,900 MWh/h, which was lower than the previous year. This was due to successful energy-saving campaigns and communication about the power situation. Although there was still a shortage of over 3,000 MWh during the peak load hour because of the Oskarshamn 3 nuclear power plant's brief shutdown, Sweden managed to overcome the situation through record-high imports from neighbouring countries.

A-II. 17. The Netherlands

298 The Netherlands took an integral approach towards electricity security of supply. They checked the preparedness of all stakeholders and procedures and stayed in touch with stakeholders to monitor risks and preparedness. The main risks identified were a shortage of gas, spillover effects from stress situations in nearby countries, and spillover effects from liquidity issues for BRP's/NEMO's/System operators. For preparedness, the focus was to check whether all SOs had load-shedding plans in place and whether the SLR procedure was in place. Before winter 2022/2023, no adequacy issues were foreseen (risks were low).

299 Overall, no adequacy issues materialised during winter 2022/2023. For monitoring electricity SoS in the Netherlands, the first thing to do is to monitor gas SoS. ACM monitored this closely. Some of the main indicators for that were the filling rate of gas storages and the availability of LNG. Another lesson learnt is that it is worth checking whether all SOs have the necessary procedures in place.

Table 19: Summary of the lessons learnt by Member States

Member State	Risks Identified	Mitigating Measures	Lessons Learnt
Austria	• Potential Gas Shortages in case of cold winter 2022/2023 or during the following winters if gas imports are continuously restricted • Low hydro availability leads to higher shares of power generation by gas-fired power plants • Market uncertainty leading to excessive prices	• State-owned gas reserve was established • Enhanced data collection, monitoring and coordination with other institutions and stakeholders • Media coverage and awareness campaigns to reduce demand • New products like the DR product introduced by the TSO to provide flexibility if necessary	• Mild winter reduced demand • Additional demand reduction occurred in segments affected by high prices • Market coupling provided an important contribution to substitute for low hydro-generation, mitigating the need to increase generation by gas-fired power plants in Austria
Belgium	• Low availability of nuclear and hydropower plants • Demand situation in neighbouring countries	• Awareness campaigns	• Significant decrease in demand due to price responsiveness and awareness
Czech Republic	• High electricity prices	• Awareness campaigns • Concessions on electricity payments • Government caps on electricity prices • Decentralisation of electricity generation by the inclusion of small-scale renewables • Development of community energy since autumn 2022	• The decrease in electricity production was due to a decrease in output from steam power plants • Electricity consumption significantly decreased, particularly evident among households • The biggest motive for the reduction in electricity consumption was the high energy price • The next winter period will depend on consumer behaviour and weather patterns
Denmark	• Gas shortages • Low hydro reserves • Generation reduction caused by low water availability in rivers	• Awareness campaigns • Energy efficiency programs • Replacement of gas in the manufacturing • Introduction of new variable tariffs where consumers switch from a fixed-price agreement to a variable-price product	• Security of supply is dependent on the willingness of consumers to curtail consumption

Member State	Risks Identified	Mitigating Measures	Lessons Learnt
Finland	• Risks of a reduced supply of electricity and gas • Delayed operation of the new nuclear plant (Olkiluoto 3)	• Coal-fired power plants came back to the market • Awareness campaigns • TSO introduced a new voluntary power system support procedure aimed at preventing electricity shortages • The government assigned the natural gas TSO to lease a floating LNG-terminal vessel and to build up the necessary pier and mooring structures • Gas usage was reduced • Industrial processes shifting from daytime to nighttime • Test run scenarios conducted with variable power output	• Voluntary energy savings and demand response in peak hours by households and commercial electricity end-users played a critical role • Warmer winter than anticipated
France	• Low availability of nuclear power generation • Low hydropower stocks • Gas shortage • Delays to nuclear reactors coming back into service • Risk of a cold winter	• CO_2 emissions cap was increased • Saint-Avold coal plant restarted producing electricity as of November 2022 • The National Energy Sobriety Plan was introduced • TSO expanded the scope of its winter adequacy assessment • Awareness campaign	• CO2 emissions cap was increased • Saint-Avold coal plant restarted producing electricity as of November 2022 • The National Energy Sobriety Plan was introduced • TSO expanded the scope of its winter adequacy assessment • Awareness campaign
Germany	• Gas shortage • The necessity for increased exports due to France's lowered nuclear power availability • Potential coal transportation difficulties resulting from low river levels • Increase in demand due to the use of fan heaters	• Reduced gas demand by 20% • The government prioritised coal transportation by rail • Conducting additional national resource adequacy assessments • Prolonging the generation of nuclear power plants • Return of coal power plants into the market	• Some issues in terms of electricity emissions or the production of system power plants

Member State	Risks Identified	Mitigating Measures	Lessons Learnt
Greece	• Gas shortages	• The government increased the regasification capacity in the LNG terminal • Creating gas storage facilities in Italy and Bulgaria • Committing to increasing diesel stocks for the gas power plants with double fuel obligation • Revising the plan for lignite phase-out • Amending the gas curtailment plan • Awareness campaigns • Awarding subsidies on electricity bills to consumers	• Concentrated effort to conserve electricity and gas consumption and the mild course of winter contributed to the positive course • There was a significant decrease in the consumption of electricity • Reduced thermal power plant production • RES production increased by 10.34%
Hungary	• Risk of a cold winter • Gas shortages • Narrowing of import possibilities • Dependence on imports	• Windfall profit tax • Energy efficiency programs • Increased fuel production • Reopening coal/lignite/oil/nuclear plants • Assisting consumers with social policy and subsidies • Increased stored gas levels • Reduction in taxes/levies/system charges on energy bills • Regulated retail prices • Accelerated RES deployment • Price limit at a retail level	• Gas supply remained reliable • Mild temperatures reduced consumption • Import possibilities depended on the hydro-based production of the Balkan region • Price increases resulted in a consumption decrease • Household PV power plants increased

Member State	Risks Identified	Mitigating Measures	Lessons Learnt
Italy	• Gas shortage • Low hydropower • Spillover effects from stress situations relating to the reduced availability of nuclear generation capacity in France	• Natural gas storage • Diversify the sources of imported natural gas • Increasing the national LNG regasification capacity • National target to fill at least 90% of the storage capacity before the withdrawal season • Cooperation through increasing gas supply from Algeria and Azerbaijan • TSO to maximise the utilization of power plants using coal, oil and biofuels • TSO published a call to procure a demand reduction service	• Gas demand reductions were higher than the 15% voluntary EU target • Electricity generation relied on an increase in coal and renewables • The adoption of a similar storage regulation is vital to guarantee system security • A new “eastbound” supply scenario might suggest that new unexpected infrastructure investments are needed to make LNG volumes available for the whole of Europe • Climate change will bring more extreme weather events and dry seasons • Availability of import electricity to be considered in adequacy assessments
Ireland	• Very high LOLE value indicated by the winter outlook • High forced outage rates of conventional generation • Lack of available capacity during low wind spells • Reduced imports available from Great Britain • Gas shortages	• Public awareness campaigns • Increased collaboration between the TSO, DSO and regulator • Large multi-stakeholder Emergency Test exercise • Development of plans for replenishing secondary fuel supplies to gas generators	• Coordinate actions between the NRA, TSO and the Government department is essential • National Test Exercise was beneficial for socialising the impacts of disruptions to the energy system and raising awareness across many different sectors • Opportunity taken to enhance planning in areas not previously considered such as the replenishment of secondary fuel stocks

Member State	Risks Identified	Mitigating Measures	Lessons Learnt
Latvia	• Gas shortages	• Suspended the commercial trade of Russian electricity in the wholesale market • Banned import of natural gas from Russia on 1 January 2023 • TSOs continue only the minimally necessary technical operational cooperation within BRELL • State-owned company JSC "Latvenergo" purchased an additional amount of liquefied natural gas (LNG) from the Klaipeda LNG terminal • Natural gas transmission and storage system operator JSC "Conexus Baltic Grid" in 2022 started injection season in the underground gas storage already on 26 February 2022 • Energy efficiency programs for public sector entities • Increased amount of microgeneration for self-consumption	• A decrease in electricity consumed resulted in an increased amount of microgeneration • The decrease in consumption was influenced by lower demand for natural gas from cogeneration plants due to high natural gas prices and warm winter
Poland	• Problems with keeping the reserve at the required level of 9% • Risk of a cold winter • Low wind generation • Planned outages of some generation units	• Import of energy from neighbouring countries. • TSO had to decrease the wind generation by 400 to 800 MW at different hours because of the low demand	• Due to the relatively warm winter, there were no major problems with the balancing of the system
Portugal	• Forecast 10 weeks in which the available generation would not be able to cover peak demand • Lack of hydro resources • Unavailability of CCGT power plants • Risk of cold winter	• Preventions to the electricity generation using the water of some dams • Re-schedule of some CCGT power plants' maintenance • Market-based demand-side response product for large industrial consumers	• It rained more and the winter was less cold than expected • The situation observed this winter confirmed the importance of hydro generation and the need to find suitable alternatives both to hydro and CCGT power plants
Spain	• Unavailability of thermal and nuclear power plants • Low hydro generation	• Energy efficiency programs • The government launched a specific balancing product focused on the demand	• Mild winter temperatures and high electricity prices had a direct impact on the reduced electricity consumption

Member State	Risks Identified	Mitigating Measures	Lessons Learnt
Sweden	• Low water levels in reservoirs • Spillover effects from stress situations relating to the reduction of power production in France • Risk of manual electricity consumption disconnection • Unavailability of nuclear power plant • Delayed start of the new nuclear power plant in Finland	• Energy-saving campaigns • Enhanced communication about the power situation • Emphasised high imports from neighbouring countries	• Sweden managed the situation through record-high imports from neighbouring countries
The Netherlands	• Gas shortage • Spillover effects from stress situations in nearby countries • Spillover effects from liquidity issues for BRP's/NEMO's/System operators	• Checked the preparedness of all stakeholders and procedures • Stayed in touch with stakeholders to monitor risks and preparedness • Check whether all SO's had load-shedding plans in place and whether the SLR procedure was in place	• TSO closely monitored the security of gas supply, which is seen as the first step to monitoring the security of electricity supply • Emphasised the importance of checking whether all SO's have the necessary procedures in place.

Source: ACER based on information from NRAs.

Annex III: Case studies: The role of demand response in winter 2022/2023 in Finland and France

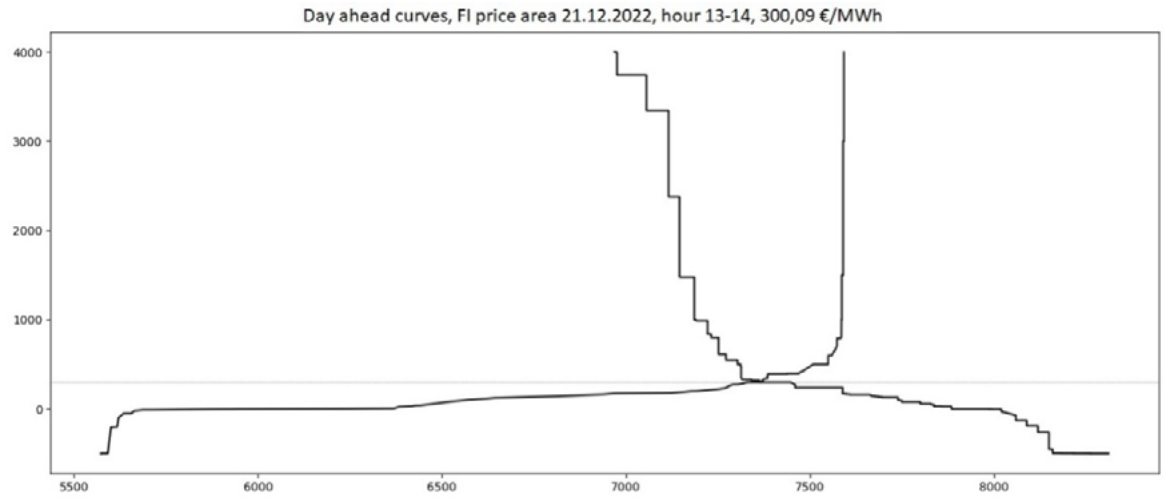
A-III. 1. Finnish case study

300 Typically, the peak load in Finland is reached during the coldest days of winter, especially if the cold period lasts for a long time. However, during the winter 2022/2023, even on the coldest days, consumption was significantly below its typical levels. Consumption was approximately 15% (2 GW) lower during the peak load hours compared to the same temperatures in previous years. On a monthly basis, consumption was 5-10% lower than the previous winter. An energy-saving campaign by the government and other forms of communication is understood to have influenced the behaviour of Finnish consumers during the winter. Additionally, increased electricity prices encouraged electricity users to save electricity.

301 Interest in demand response increased in Finland during the fall of 2022. Before the winter, a survey was conducted to assess companies' readiness for demand response[1]. The Energy Authority sent the survey to energy-intensive companies and received responses from 69 companies and 5 municipalities. Of those who responded, 25% were already implementing demand response on different market platforms, 20% of respondents had plans to increase demand response and 40% had plans in progress or were about to start. The survey participants had a total potential of nearly 400 MW for additional demand response.

302 Figure 43 presents the supply and demand curves in one of the most challenging hours last winter in terms of system balance. The figure shows there was still around 400 MW of unutilised flexible demand in the day-ahead market in the Finnish price area[2].

Figure 43: Day-ahead curves of a single hour in Finland in winter 2022/2023 (euros/MWh)



Source: Finnish NRA.

Note: The figure does not contain block-offers, so there was even more flexibility than that.

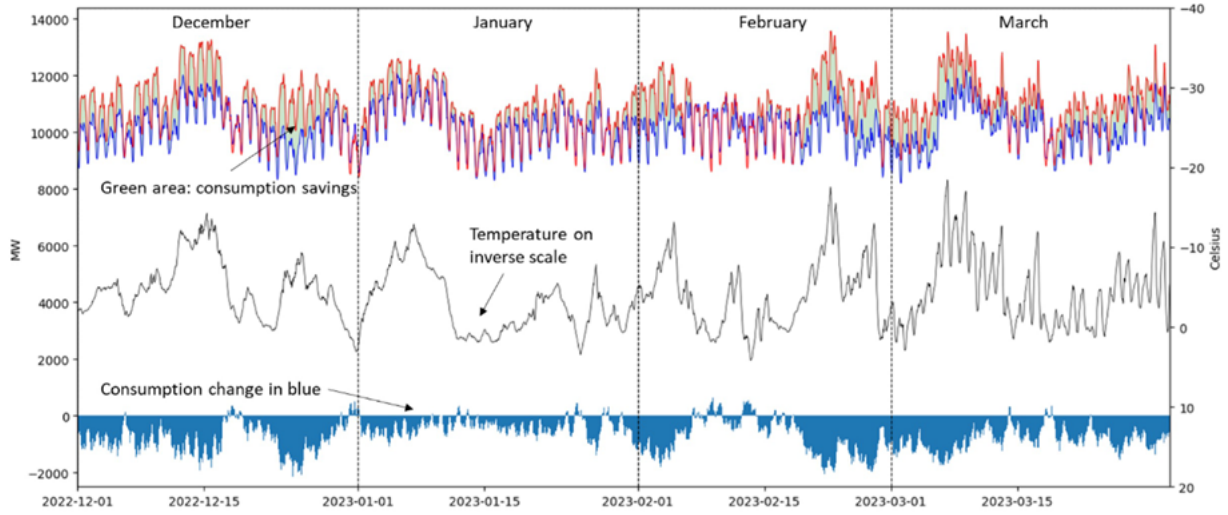
303 Figure 44 shows the typical demand pattern in Finland in wintertime; the electricity consumption correlates strongly with the temperature. That is, the electricity consumption increases when the weather gets colder, due to electric heating. However, the figure also shows that consumption reduction correlates with the temperature. The colder the weather, the more consumption deviated from the estimates based on previous years. On the coldest hours when the consumption was expected to be the highest, the electricity consumption was reduced the most. There are probably several reasons for

1 The survey is available in Finnish here.

2 The figure does not contain block-offers, so there was even more flexibility than that. Block offers cover several hours. Whether they are accepted or not depends on the prices of multiple hours, so they cannot be drawn in a one-hour figure.

this, including, for example, adjusting the timings of electric heating, improving energy efficiency of buildings, or using other heating methods where possible.

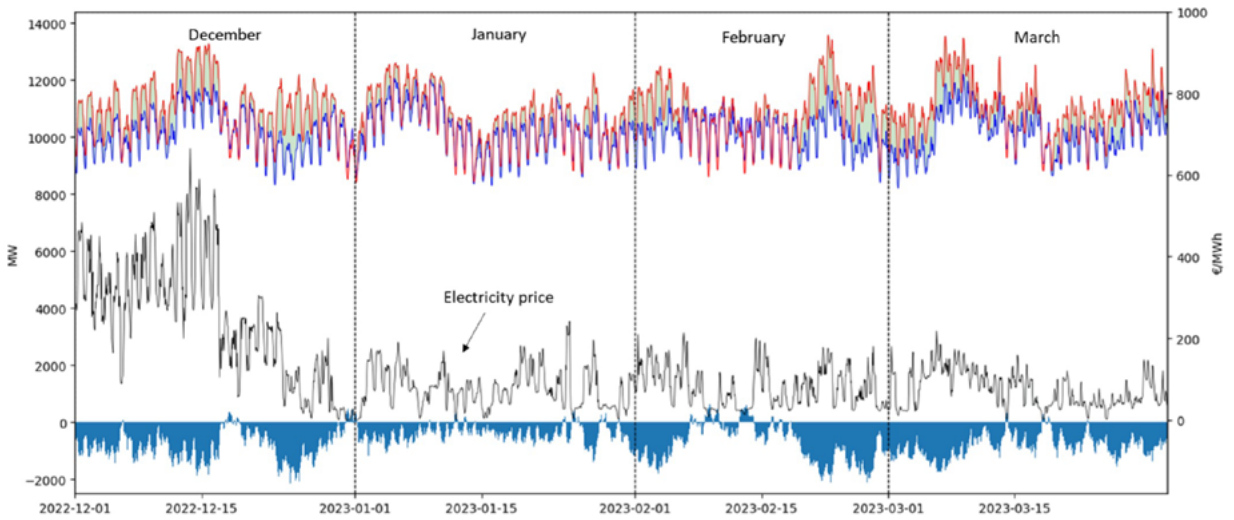
Figure 44: Metered electricity consumption (blue),), expected consumption given the experienced temperature - based on previous years' consumption data (red) and temperature (black, inverse scale) (MW and °C)



Source: Finnish NRA.

304 In Figure 45, the black curve denotes the day-ahead electricity price. While one must be careful when interpreting correlations, the figure suggests that the price was not the main driver in consumption reductions, but temperature was. The figure shows that prices dropped dramatically by the end of December, however, the consumption reduction patterns remained the same. For example, in March, when the coldest hours were as cold as in December, the consumption reductions were similar to December even if the prices were much lower.

Figure 45: Metered electricity consumption (blue), expected consumption given the realised temperature - based on previous years' consumption data (red) and electricity price (black) (MW and euros/MWh)



Source: Finnish NRA.

305 In conclusion, early analysis suggests that consumers' reaction played an important role in securing supplies in Finland last winter. Available information indicates that reduced electricity consumption for heating, for example in the form of structural savings and shifting of electric heating demand to off-peak hours, were the main reason for the lower overall consumption levels. Moreover, the interest and participation of demand response in the market increased throughout the winter. The impact of higher electricity prices on electricity consumption is less obvious in this preliminary analysis (probably more on the industrial and commercial sectors and less so on the household sector).

A-III. 2. French case study

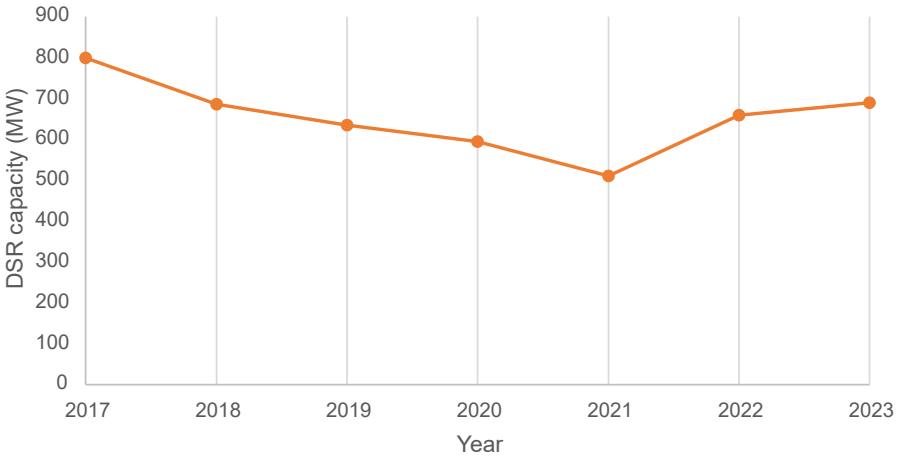
306 This section describes how demand-side response helped to "keep the lights on in the past winter" in France. Implicit and explicit demand response are treated separately, where implicit demand response refers to a consumer's consumption reduction in response to a price signal, and explicit demand response refers to a consumption reduction that is rewarded in the electricity market.

A-III. 2.1. Implicit demand response

307 A strong demand reduction was observed in France during winter 2022/2023. Power consumption was on average 8% to 9% lower than the historical average before 2019, excluding the effects of weather. The decline was mainly observed in the industrial sector, with a drop of around 10% to 12% compared with 2021 and, to a lower extent, in the services and residential sectors, reaching a reduction of around 6% to 7% compared to 2021. Nevertheless, it is not clear to what extent this consumption decrease was due to a price signal, or to collective efforts in response to communication actions, such as the call for citizens to lower the heating temperature to 19°C over the heating season[3] or the information campaign on the "Ecowatt" tool developed by RTE[4].

308 In France, suppliers declare implicit demand response for the capacity mechanism: the corresponding volume increased for years 2022 and 2023, compared to previous years, reaching around 700 MW in 2023 (Figure 46). Between 2017 and 2022, the general trend for declared implicit demand response in the capacity mechanism was decreasing.

Figure 46: Implicit demand response declared for the French capacity mechanism - 2017-2023 (MW)



Source: French NRA

A-III. 2.2. Explicit demand response

309 In France, explicit demand response can be remunerated for the available capacity and for the activation on the electricity markets.

310 Demand response providers can be remunerated for the available capacities through the capacity mechanism[5] and through the wholesale market. Under those mechanisms, demand response providers must ensure that the contracted capacity is available during specific moments of the year, when the French power system is considered tight. They can also be remunerated for the available capacity through the calls for tenders for balancing reserves.

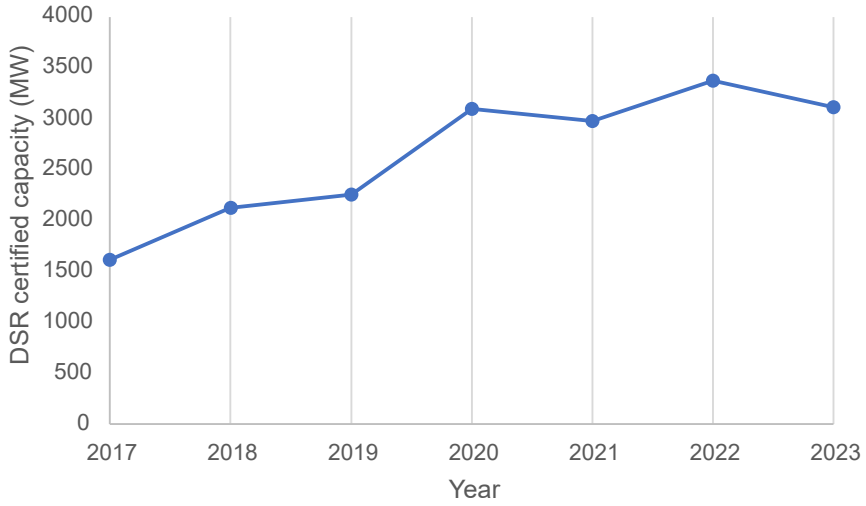
3 The communication campaign began on 10 October 2022 and aimed at encouraging actions to reduce energy consumption. More information can be found here.

4 The "Ecowatt" tool has been developed by RTE to inform in real time about the level of consumption in France and to signal periods of tensions on the power system in order to encourage citizens to reduce their consumption when the power system is strained. More information can be found here.

5 Under the French capacity mechanism, all capacities including demand response capacities receive a capacity payment for their availability in addition to the revenues received on the wholesale market when the electricity is produced or when demand response is activated. Specific support schemes exist, such as the "demand response call for tenders" and the long-term contracts for new capacities consisting in contracts for difference on capacity.

311 The demand response participation in the capacity mechanism (meaning its certified capacity) was continuously increasing between 2017 and 2022. It should be noted that certified capacity for delivery years 2021, 2022 and 2023 are not final data (which are known in March T+3) and might evolve.

Figure 47: Explicit demand response certified for the French capacity mechanism - 2017-2023 (MW)



Source: French NRA

312 Demand-side response providers can also sell "negative" electricity[6] in the day-ahead and intraday markets, through the so-called "NEBEF" mechanism[7], as well as in the balancing market. In the day-ahead and intraday electricity markets, the volume of reduced consumption corresponding to demand response is treated in the same way as an equivalent volume of electricity production. demand response providers sell the volumes they plan to activate on the day-ahead and intraday markets, and RTE controls afterwards that the estimated consumption reduction[8] during the delivery period equals to the volumes sold on the market. On the wholesale electricity market, demand response is usually activated in winter, when wholesale prices are higher. This is mainly due to the fact that demand response is characterised by higher marginal costs compared to generators, meaning that its activation is profitable only when prices peak in the electricity markets.

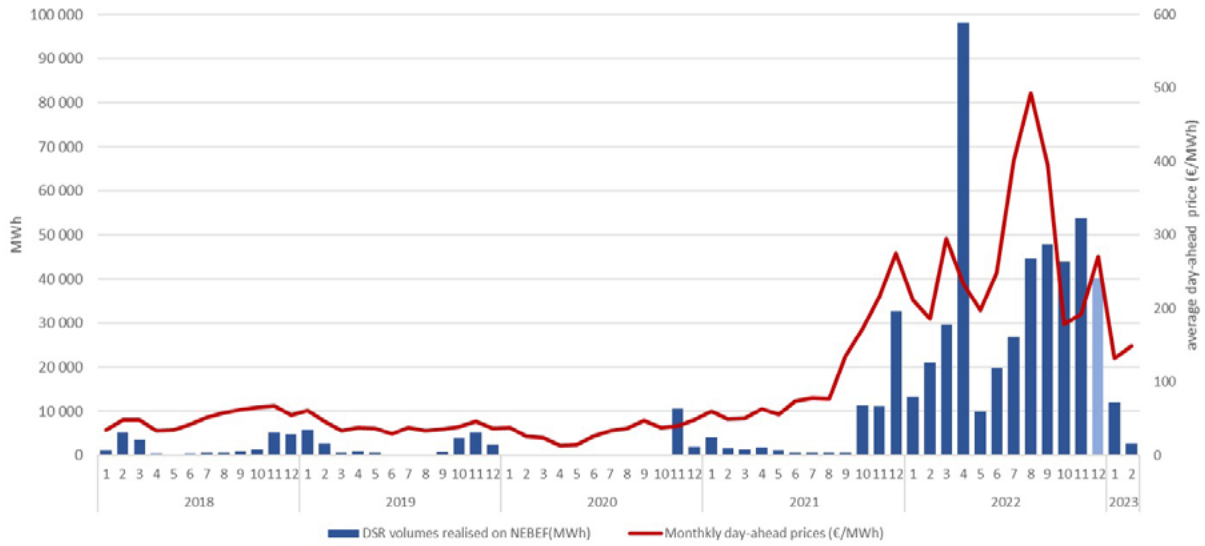
313 In the NEBEF mechanism, a large increase in activated volumes has been observed as of winter 2021/2022 (Figure 48), when electricity wholesale prices surged due to the growing tensions in the French electricity market. While in recent years demand response volumes on NEBEF were only activated on specific days in winter, with total monthly volumes below 10 000 MWh, historically high volumes were activated from the end of 2021 and throughout 2022, with monthly activated volumes above 40,000 MWh in autumn and early winter 2022/2023. This was linked to the high wholesale electricity prices resulting from the tensions on the supply-demand balance in France as of autumn 2022, with the low availability of nuclear power generation. Monthly activated volumes then declined in January and February 2023 as security of supply improved in France with the return to operation of several nuclear reactors, high filling gas storage levels and the maintained drop in consumption, translating in lower wholesale prices. The maximum demand response capacity that has been activated on the NEBEF market was also higher in winter 2022/2023 compared to previous winters. While a maximum of 150 MW demand response capacity was activated during the winter 2020/2021, more than 250 MW was activated on time over the months of September, October and November 2022. The maximum capacity was activated on 27 September 2022 at 9am (315 MW).

6 In theory, it is also possible for demand response providers to sell increased power consumption if it is helpful to the system, namely in case of negative wholesale prices. However, there is currently little interest from the market to propose such services in France. Only one demand response operator has the possibility to sell increased power consumption, through an experimental project starting in July 2023.

7 For more information on the NEBEF see here.

8 For each timestamp of the delivery period, RTE compares the capacity of a reference consumption curve (demand response operators can choose between several methods to establish this curve) which estimates the consumption without demand response, with the actual consumption curve of the site(s).

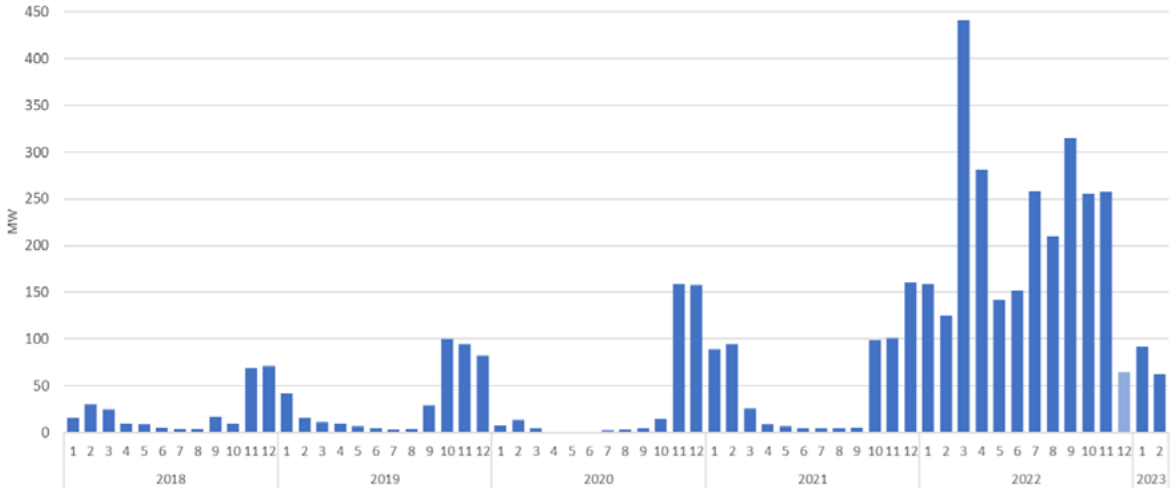
Figure 48: Monthly volumes of demand response realised on NEBEF, between 2018 and February 2023 (MWh)



Source: French NRA based on data from the French TSO.

Note: Data for December 2022 was unavailable. For this month, the volumes correspond to the programs declared by participants and not the actual volumes that have been realised.

Figure 49: Monthly maximum capacity activated on NEBEF, between 2018 and February 2023 (MW)



Source: French NRA based on data from the French TSO.

NB: Data for December 2022 was unavailable. For this month, the volumes correspond to the programs declared by participants and not the actual volumes that have been realised.