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REGULATORY AGENCY**
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Flexibility Needs Assessment Report for the Republic of Croatia (FNA HR) Article 19.e. Regulation 2024/1747

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Table of acronyms

Acronym	Meaning
ACER	Agency for the Cooperation of Energy Regulators
AMICOS	Advanced Metering Infrastructure Control and Operation System
BA	Bosnia and Herzegovina
BESS	Battery Energy Storage System
CAGR	Compound Annual Growth Rate
CCGT	Combined Cycle Gas Turbine
CfD	Contract for Difference
CO₂	Carbon Dioxide
DNDP	Distribution Network Development Plan
DSO	Distribution System Operator
DSR	Demand-Side Response
ED	Economic Dispatch
EIHP	Energy Institute Hrvoje Požar
EMD	Electricity Market Directive
ENS	Energy Not Served
ENTSO-E	European Network of Transmission System Operators for Electricity
EOTRP	Optimal technical connection study (cro. <i>Elaborat optimalnog tehničkog rješenja priključenja</i>)
ERAA	European Resource Adequacy Assessment
EUR	Euro
EVA	Economic Viability Assessment
FiT	Feed-in Tariff
FNA	Flexibility Needs Assessment
GW	Gigawatt
GWh	Gigawatt-hour
HEP ODS	Croatian Distribution System Operator (cro. <i>HEP Operator distribucijskog sustava</i>)
HERA	Croatian Energy Regulatory Agency (cro. <i>Hrvatska energetska regulatorna agencija</i>)
HES	Head-End System

Acronym	Meaning
HOPS	Croatian Transmission System Operator (cro. <i>Hrvatski operator prijenosnog sustava</i>)
HPP	Hydroelectric Power Plant
HR	Croatia
HROTE	Croatian Energy Market Operator (cro. <i>Hrvatski operator tržišta energije</i>)
HU	Hungary
HV	High-voltage
KKE	Combined Cycle Cogeneration Power Plant (cro. <i>Kombi kogeneracijska elektrana</i>)
KMS	Key Management System
LOLE	Loss of Load Expectation
MC	Monte Carlo
MDM	Meter Data Management System
MV	Medium-voltage
MTU	Market Time Unit
MW	Megawatt
MWh	Megawatt-hour
NECP	National Energy and Climate Plan
NRA	National Regulatory Authority
NRAA	National Resource Adequacy Assessment
NRMSE	Normalised Root Mean Square Error
NTC	Net Transfer Capacity
OTDF	Outage Transfer Distribution Factor
OV. COST	Overall System Cost
PECD	Pan-European Climate Database
PEMMDB	Pan-European Market Modelling Database
PSHPP	Pumped-Storage Hydropower Plant
PTDF	Power Transfer Distribution Factor
RAM	Remaining Available Margin
RED III	Renewable Energy Directive
RES	Renewable Energy Sources

Acronym	Meaning
RS	Serbia
RTE	Réseau de Transport d'Électricité
SEE	South-East Europe
SEW	Social Economic Welfare
SI	Slovenia
TE-TO	Combined Heat and Power Plant
TPP	Thermal Power Plant
TSO	Transmission System Operator
TYNDP	Ten-Year Network Development Plan
VOLL	Value of Lost Load
VRE	Variable Renewable Energy
WS	Weather Scenario

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Executive summary

The purpose of this Flexibility Needs Assessment (FNA) is to identify the areas and periods in which system flexibility is needed to support the integration of variable renewable energy sources (RES) while maintaining operational reliability.

The analysis covers two scenarios. The Referent scenario is aligned with the draft National Resource Adequacy Assessment (NRAA) as well as with the current NECP and is mandatory under the FNA Methodology. In addition, Alternative scenario 2 was analysed as it places greater stress on the system through higher demand and RES integration, and indicates adequacy issues through elevated Loss of Load Expectation (LOLE) and Energy Not Served (ENS) values. This allowed different system configurations and operating conditions to be explored within this report. Both scenarios were analysed for the target years 2030 and 2035, in line with the draft NRAA and the European Resource Adequacy Assessment (ERAA) published by the European Network of Transmission System Operators for Electricity (ENTSO-E).

The flexibility needs addressed in this report follow the FNA Methodology and include both system and network needs. All types of system needs defined in the methodology were analysed, including RES integration needs, ramping needs and short-term needs. Regarding network needs, transmission system operator (TSO) needs are seen as voluntary and were therefore not covered. Consequently, the analysis focuses on the distribution system operator (DSO) network needs.

Key findings

One of the key outcomes of the FNA is the analysis of whether the required RES target is achieved. This is calculated as the ratio of delivered RES generation to total electricity demand, taking into account curtailment and any uncovered flexibility needs. The required RES target is defined in Croatia's National Energy and Climate Plan (NECP) and amounts to 76.7% of RES share in the final consumption.

The results of this assessment are presented in the tables below. As seen in Table 1, in the Referent scenario, the RES target is met in both analysed years.

Table 1: Key findings - RES integration targets for the Referent scenario

Type	Flexibility need	Indicator	Year	Required RES target [%]	Achieved RES target [%]
System needs	RES integration needs	RES target	2030	76.7	78.9%
			2035		77.9%

In Table 2 can be seen that for Alternative scenario 2, the target is achieved in 2030 but not in 2035, primarily due to a significant increase in consumption that is not accompanied by a corresponding increase in generation capacity.

Table 2: Key findings – RES integration targets for Alternative scenario 2

Type	Flexibility need	Indicator	Year	Required RES target [%]	Achieved RES target [%]
System needs	RES integration	RES target	2030	76.7	79.2%
			2035		70.8%

The next two tables present the RES integration needs and are described by two parameters: total RES curtailment and uncovered RES integration gaps. Total curtailed energy is the portion of RES generation that could not be injected into the system due to network or operational constraints and was therefore not utilised. These values are derived from the Antares simulation results, in which national adequacy analysis was performed. The total uncovered RES integration need quantifies the additional flexibility requirement identified by the FNA analysis that cannot be met.

As seen in Table 3, the Referent scenario shows a big difference between the two analysed target years. RES curtailment is substantially higher in 2035 than in 2030, increasing by around seven times over the period. The uncovered RES integration needs show an even stronger increase, with the 2035 value being 75 times higher than in 2030.

Table 3: Key findings - RES integration needs for the Referent scenario

Flexibility need	Target year	Total curtailed energy [GWh]	Total uncovered RES integration need [GWh]
RES integration	2030	280.67	18.37
	2035	2,033.59	1,341.35

In Alternative scenario 2, curtailed RES energy is slightly higher than in the Referent scenario, as shown in Table 4. A similar trend is observed, with curtailment in 2035 being almost seven times higher than in 2030. Although total uncovered needs increase less strongly than in the Referent scenario over the same period, rising by 15 times, they are higher in absolute terms in Alternative scenario 2: around ten times higher in 2030 and two times higher in 2035 compared to the Referent scenario.

Table 4: Key findings - RES integration needs for Alternative scenario 2

Flexibility need	Target year	Total curtailed energy [GWh]	Total uncovered RES integration need [GWh]
RES integration	2030	500.85	181.75
	2035	3,379.09	2,775.56

This leads to one of the key conclusions of this FNA analysis: despite the presence of curtailment and uncovered needs, the RES target is achieved in the Referent scenario, meaning that no additional flexibility resources are required.

Interpretation of key findings

Several key factors drive the system's flexibility needs. High penetration of RES increases the variability and uncertainty of operation and flexibility requirements. Demand growth and changing load profiles also influence flexibility needs by altering residual load patterns and peak periods. Other operational considerations, including the availability of dispatchable generation, storage capacities, and interconnection limits, further shape the magnitude and timing of flexibility requirements. The following tables summarise the flexibility needs identified in this national FNA analysis and provide an overview of ramping needs, short-term needs, and DSO network needs for the analysed scenarios and target years.

When looking at the Referent scenario in the table below, a clear exponential increase in uncovered needs can be observed. Ramping needs are comparatively lower, particularly in 2030, while short-term needs increase significantly in 2035. DSO network needs are generally lower, which is expected

because they account only for grid-related constraints, while system needs encompass variability in supply and demand.

Table 5: Summary of ramping needs, short-term needs and DSO network needs for the Referent scenario

Type	Flexibility need	Indicator	Target year	Average amount of uncovered needs [MW]	Uncovered need [GWh]
System needs	Ramping needs	Downward ramping rate need	2030	68	0.06
			2035	122	16.50
	Short-term needs ¹	Downward uncovered short-term needs	2030	216	17.89
			2035	675	1,338.36
Network needs	DSO network needs	Downward DSO network flexibility needs	2030	199 ²	0.49
			2035	579 ²	2.99

The following table presents the indicators for Alternative scenario 2. As shown, the level of uncovered needs is generally higher compared to the Referent scenario, while the overall behaviour remains similar. This is related to the higher demand assumed in Alternative scenario 2; however, the RES and demand profiles remain the same as in the Referent scenario and are only scaled accordingly, so this explains the similar behaviour of uncovered needs.

Table 6: Summary of ramping needs, short-term needs and DSO network needs for Alternative scenario 2

Type	Flexibility need	Indicator	Target year	Average amount of uncovered needs [MW]	Uncovered need [GWh]
System needs	Ramping needs	Downward ramping rate need	2030	78	0.51
			2035	105	16.44
	Short-term needs ¹	Downward uncovered short-term needs	2030	331	181.26
			2035	949	2,772.56
Network needs	DSO network needs	Downward DSO network flexibility needs	2030	199 ²	0.49
			2035	579 ²	2.99

The following two tables present the data used to calculate the achieved RES target, based on the ratio of delivered RES generation to total electricity demand. Delivered RES generation accounts for curtailment identified in the Antares hourly simulations for various weather scenarios, as well as additional curtailment resulting from uncovered ramping, short-term flexibility and DSO network flexibility needs.

In the Referent scenario, RES curtailment increases from 2% of total RES generation in 2030 to 11% in 2035.

¹ According to the FNA Methodology, Article 10(6)(c), the analysis of short-term flexibility needs shall include the total amount of expected energy resulting from uncovered short-term flexibility needs events.

² These values were provided by the DSO and represent aggregated sums.

Table 7: Parameters for calculating RES target for the Referent scenario

Target year	Parameter	Unit	Total
2030	RES generation (A)	MWh	14,781,008
	RES curtailment (B)	MWh	280,668
	RES curtailment addition – due to uncovered ramping needs	MWh	61
	RES curtailment addition – due to uncovered short-term needs	MWh	17,885
	Maximum RES curtailment addition (C)	MWh	17,885
	RES curtailment addition – downward DSO network needs (D)	MWh	486.75
	RES generation minus curtailment (E = A – B – C – D)	MWh	14,481,968
	Load (F)	MWh	18,360,809
	Achieved RES target (E / F)	%	78.9%
2035	RES generation (A)	MWh	18,818,429
	RES curtailment (B)	MWh	2,033,585
	RES curtailment addition – due to uncovered ramping needs	MWh	16,496
	RES curtailment addition – due to uncovered short-term needs	MWh	1,338,362
	Maximum RES curtailment addition (C)	MWh	1,338,362
	RES curtailment addition – downward DSO network needs (D)		2,992.53
	RES generation minus curtailment (E = A – B – C – D)	MWh	15,443,489
	Load (F)	MWh	19,815,487
	Achieved RES target (E / F)	%	77.9%

A similar trend is observed in Alternative scenario 2, where curtailment rises from 3% to 15% over the same period, indicating significantly higher RES integration challenges in 2035.

Table 8: Parameters for calculating RES target for Alternative scenario 2

Target year	Parameter	Unit	Total
2030	RES generation (A)	MWh	16,545,122
	RES curtailment (B)	MWh	500,859
	<i>RES curtailment addition – due to uncovered ramping needs</i>	<i>MWh</i>	<i>505</i>
	<i>RES curtailment addition – due to uncovered short-term needs</i>	<i>MWh</i>	<i>181,264</i>
	Maximum RES curtailment addition (C)	MWh	181,264
	RES curtailment addition – downward DSO network needs (D)		486.75
	RES generation minus curtailment (E = A – B – C – D)	MWh	15,862,526
	Load (F)	MWh	20,040,193
	Achieved RES target (E / F)	%	79.2%
2035	RES generation (A)	MWh	22,470,070
	RES curtailment (B)	MWh	3,379,094
	<i>RES curtailment addition – due to uncovered ramping needs</i>	<i>MWh</i>	<i>16,441</i>
	<i>RES curtailment addition – due to uncovered short-term needs</i>	<i>MWh</i>	<i>2,772,564</i>
	Maximum RES curtailment addition (C)	MWh	2,772,564
	RES curtailment addition – downward DSO network needs (D)		2,992.53
	RES generation minus curtailment (E = A – B – C – D)	MWh	16,315,419
	Load (F)	MWh	23,049,631
	Achieved RES target (E / F)	%	70.8%

As can be seen from these results, the RES target is achieved in the Referent scenario and partially in the Alternative scenario 2. Therefore, the guiding criteria defined in Article 16 of the FNA Methodology were not applied, as the available flexibility resources were sufficient to meet the identified needs and no additional resources were required.

Regarding the available flexibility in Croatia, this FNA assess a portfolio of flexibility resources including reservoir hydropower plants (HPP), cross-border interconnections, demand-side response (DSR), and battery energy storage systems (BESS). Reservoir HPPs and interconnections provide the largest contribution to flexibility. Furthermore, DSR and BESS also support the fulfilment of flexibility needs, but to a lesser extent. It should be noted that the capacities of reservoir HPPs and BESS considered in the conducted hourly simulations and flexibility needs assessment already account for the reservation of part of their capacity for balancing and reserve provision, meaning that additional capacity remains available to provide an extra margin of flexibility. Together, these resources provide a diverse portfolio of non-fossil flexibility options that support system adequacy and operational flexibility.

Barriers to flexibility, regulatory recommendations and actions

The Croatian electricity system has a established legal and regulatory framework that deals with the integration of flexibility resources, including active customers, aggregators, energy storage, and renewable energy communities. Nevertheless, several barriers remain that may limit the full deployment of flexibility solutions. These include gaps in independent aggregation and market access for new market participants, incomplete implementation of existing legal provisions, restrictions in balancing and congestion management participation, and complex or lengthy administrative procedures. Digitalisation and data availability, including smart metering and efficient data exchange between Croatian Transmission System Operator (cro. *Hrvatski operator prijenosnog sustava* - HOPS), Croatian Distribution System Operator (cro. *HEP Operator distribucijskog sustava* – HEP ODS), and market participants, are key enablers for the provision of flexibility. Ongoing and planned regulatory developments are expected to further facilitate flexibility provision, encourage the use of non-wire alternatives, improve market signals, and enhance system operation, both in the short and medium term (up to 2030) and for longer-term structural improvements.

1. Introduction

1.1. Purpose and scope of the national report

The objective of this report is to analyse and define flexibility needs for the Republic of Croatia, supporting reliable planning of future system flexibility while ensuring decarbonisation and maintaining security and adequacy of supply.

The report is prepared having in mind provisions in the FNA Methodology, approved by the Agency for the Cooperation of Energy Regulators (ACER) on 25th July 2025, which provides a harmonised framework for evaluating flexibility needs across European power systems. Following this methodology aims that the Croatian assessment is consistent with other European studies and allows for a standardised evaluation of flexibility needs.

The analysis is performed for two scenarios for the target years 2030 and 2035. The analysis includes RES integration, ramping, and short-term flexibility needs, as well as DSO network needs, and considers the impact of available resources, network limitations, forecast errors, etc.

The end goal is to inform on the system's ability to integrate variable renewable energy sources, manage residual load variations, and maintain operational reliability. It is designed to support decision-making on operational planning, investment priorities, and potential policy measures to enhance flexibility.

1.2. Legal and regulatory context

The assessment of flexibility needs in Croatia is grounded in the European legal framework, primarily Article 19e of Regulation (EU) 2019/943 on the internal electricity market, which requires each Member State to prepare a national report every two years. This methodology is further specified in the FNA Methodology, approved by ACER on 25th July 2025, which provides a harmonised approach for the collection, analysis, and reporting of system and network flexibility needs across European power systems.

At the national level, the FNA implementation is based on obligations assigned to HOPS and HEP ODS, in accordance with national legislation and regulatory requirements.

The legal and regulatory framework for flexibility needs assessment is founded primarily on the Law on Electricity Market (*lex specialis*), the Law on Energy as the framework law for the energy sector, and the Law on Renewable Energy Sources and High-Efficiency Cogeneration as well as the relevant implementing regulations and other subordinate legislation governing the flexibility assessments in the Republic of Croatia.

From a strategic and planning perspective, the assessment aims to be consistent with Energy Development Strategy of the Republic of Croatia until 2030 with a view to 2050, NECP, draft NRAA 2026, transmission and distribution network development plans, including the Ten-Year Network Development Plans prepared by HOPS and HEP ODS, and other national planning documents.

1.3. Governance: designated bodies involved in the FNA report

Croatian Energy Regulatory Agency (cro. *Hrvatska energetska regulatorna agencija* – HERA) is responsible issuing the final FNA report, submitting it to the European Commission and ACER, and publishing it. HOPS and HEP ODS provided the necessary data, analyses, and system insights to support the assessment of flexibility needs at both system and distribution network levels, and EIHP run the analysis.

Throughout the preparation of the FNA, EIHP held several coordination meetings were held with representatives of HOPS, HEP ODS, and HERA. These meetings supported a consistent approach to data collection, methodological alignment, clarification of open questions, interpretation of data, etc. The close collaboration and coordination among the involved institutions contributed to the consistency and transparency of the national assessment process, while supporting the provisions of Article 19e of the Electricity Regulation and the FNA Methodology, and assured the agreement between entities involved.

1.4. Key definitions

There are two main categories of flexibility needs defined in the FNA Methodology: system flexibility needs and network flexibility needs. They are further divided, as illustrated in the following figure.

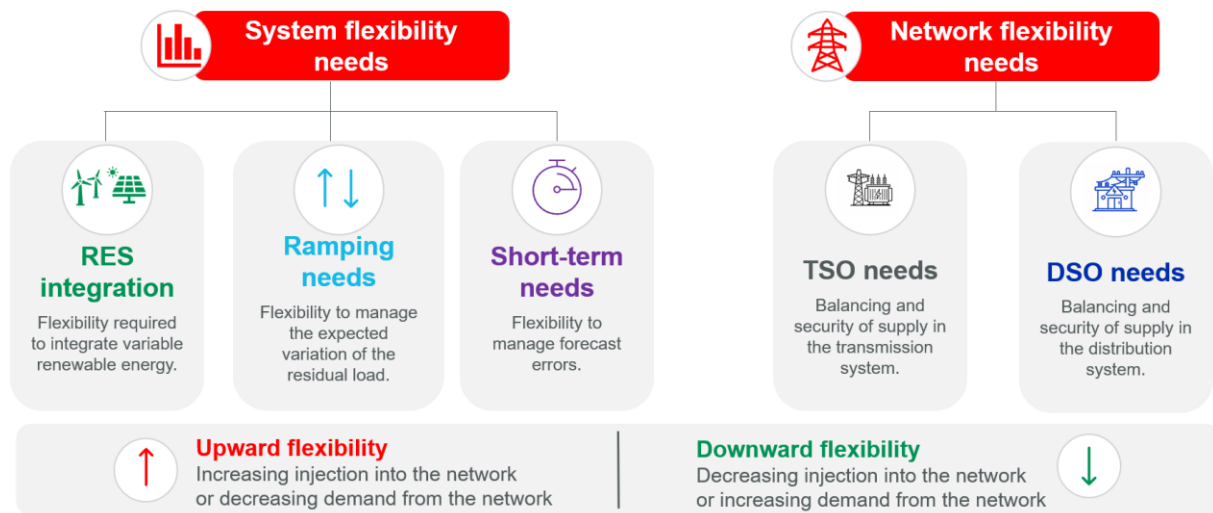


Figure 1: Flexibility needs overview

System flexibility needs reflect the electricity system's ability to adapt to variations in generation and consumption. They are described by three indicators: RES integration, ramping, and short-term needs. RES integration needs represent the flexibility required to effectively use variable renewable generation and minimise curtailment to enable achieving the national renewable targets defined in the NECP. Ramping needs quantify the flexibility necessary to cover expected variations in residual load over consecutive hourly intervals. Short-term needs capture the flexibility required to manage unexpected deviations due to demand and RES generation forecast errors. Network flexibility needs refer to the capability of the grid to prevent or resolve congestion considering temporal, spatial and voltage granularity.

Directional flexibility also needs to be distinguished. Upward flexibility is required when the system needs additional energy during unexpected drops in RES output or sudden increases in demand, which can be addressed by increasing generation or reducing load. Downward flexibility is needed when the system has excess energy during periods of high-RES production or low demand, requiring a reduction in generation or an increase in consumption to maintain system balance. Downward flexibility ensures the required (low) level of RES curtailment and fulfilment of the required RES integration target.

2. Methodological aspects

2.1. Data sources

The process of developing the FNA consists of several stages, the first of which is the collection, systematisation, and processing of the required input data. This step is particularly important, as the quality of the analysis largely depends on the quality and completeness of the input data. For the Croatian FNA, the assessment relies on a combination of official national and European documents and reports, as well as simulations performed using the Antares Simulator as part of the NRAA 2026 preparation process.

The sources of input data used for this FNA are shown in the following figure.

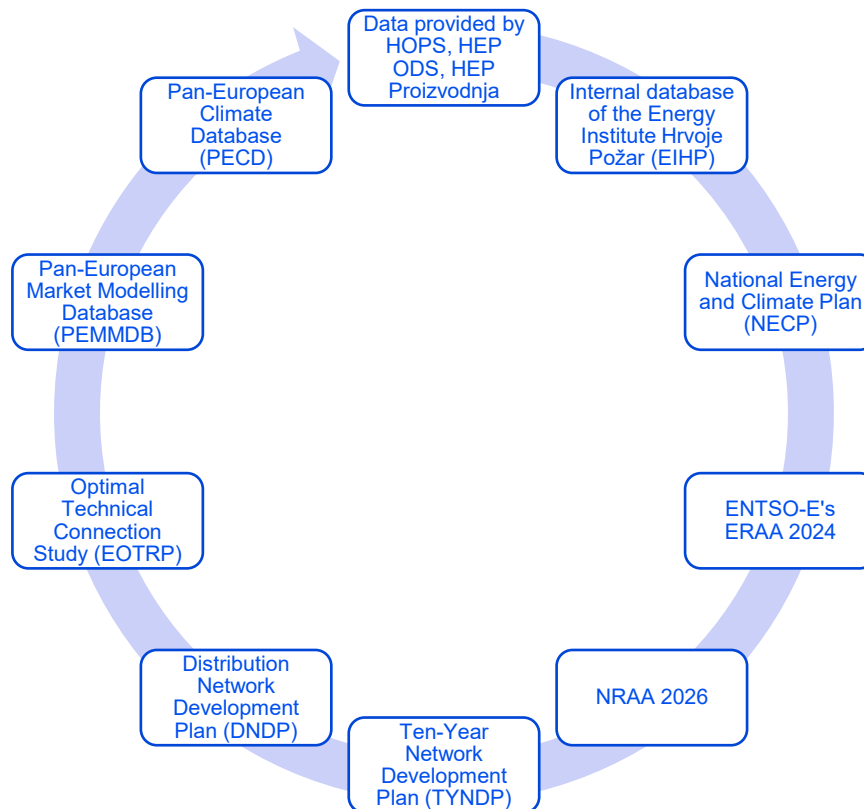


Figure 2: Sources of input data for the FNA

2.2. Target years considered

The FNA simulations and analyses for Croatia focus on the target years 2030 and 2035. These years were selected in accordance with ERAA 2024 and are aligned with draft NRAA 2026, as well as with the requirements of the FNA Methodology, which stipulates that at least two target years must be included in the first submission and should reflect relevant EU policy milestones and system planning horizons (FNA Methodology, Articles 4(1)(d) and 6(1)). The choice of 2030 and 2035 also aligns with key national and European planning documents, including the NECP, TYNDP, and DNDP, which provides consistency and comparability across projected demand, capacities, RES deployment, and planned grid infrastructure.

By selecting these target years, the assessment captures both near-term and mid-term flexibility needs, supporting strategic planning of the Croatian electricity system while ensuring compliance with FNA Methodology and comparability with EU-wide analyses.

2.3. Modelling approach

The FNA analysis is based on the draft NRAA 2026, which builds on ERAA 2024. For NRAA 2026, an Economic Dispatch (ED) model was built in the Antares Simulator tool. 36 weather scenarios (WS) from the Pan-European Climate Database (PECD) were combined with 15 outage patterns representing thermal power plant (TPP) unavailability, which resulted in simulated 540 Monte Carlo (MC) years. These detailed outputs from the adequacy assessment, including RES generation, load, curtailment and related indicators, were then used as inputs for the FNA. More details on this setup and the tool itself can be found in Annex 5.

The geographical scope of the analysis included the whole of Europe, with different levels of modelling details, as depicted in the following figure.

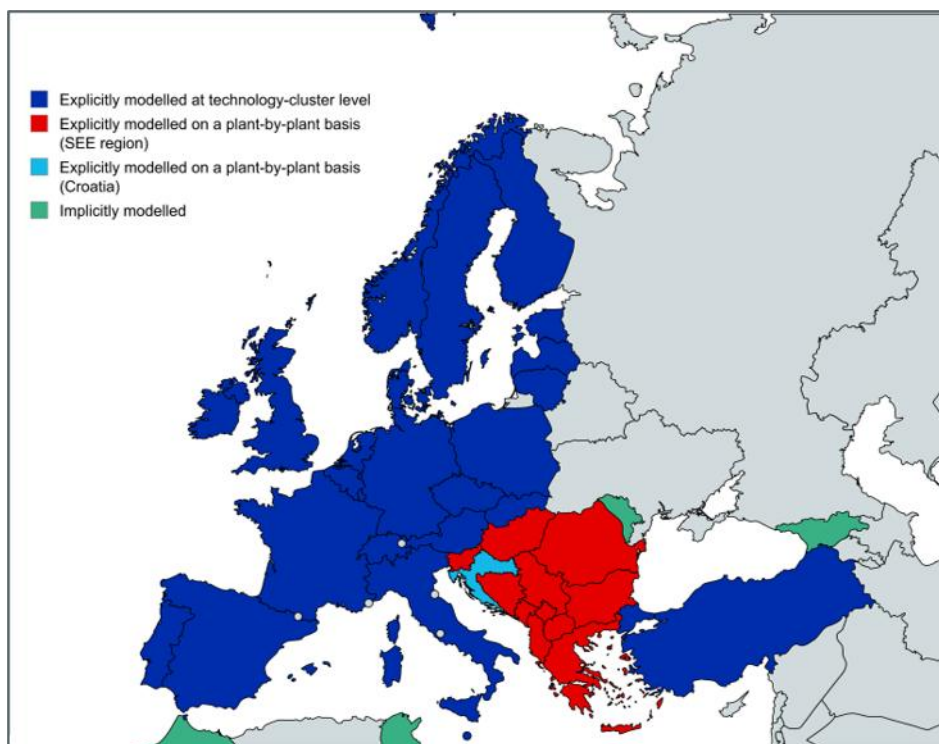


Figure 3: Geographical scope of the national adequacy assessment analysis

The modelling process began with the development of a pan-European model based on the ERAA 2024 dataset. Following verification of the model against ENTSO-E's results, the model was “frozen” for all study zones outside the South-East Europe (SEE) region and subsequently used consistently across all scenarios analysed.

More granular input data were then incorporated for the SEE region. Specifically, the SEE countries were modelled at the plant-by-plant level, rather than at the technology-cluster level used in ENTSO-E's ERAA 2024, based on available internal data. The countries included in this detailed regional modelling were Albania, Bosnia and Herzegovina, Bulgaria, Greece, Hungary, Kosovo, Montenegro, North Macedonia, Romania, Serbia, and Slovenia. These countries were selected due to their geographical proximity to Croatia and the relevance of regional interconnections and cross-border exchanges for assessing electricity supply security.

Croatia was also modelled at the plant-by-plant level, using input data provided by HOPS and HEP Proizvodnja. Several scenarios were developed to simulate the behaviour of the Croatian power system under different operating conditions. The scenario development process relied on relevant national planning documents listed in the chapter 2.1.

All other methodological data and approaches used in adequacy assessment are available in the draft NRAA 2026, which provides detailed assumptions, data sources, and modelling approaches.

According to the FNA Methodology, if the RES integration target is not achieved, the level of additional flexibility resources needed to reach the required target should be determined. In this FNA, the required

level is achieved, as elaborated in detail in the following chapters. Therefore, no additional calculation of flexibility resources was needed.

The estimation of the 0.1 and 99.9 percentiles of the probability distribution of the residual load forecast errors (as per FNA Methodology, Article 10(1)) has been based on historical data provided by HOPS. Data included 15-minute demand, solar and wind generation deviations between day-ahead forecasts and real-time measurements realised in 2024 and 2025. These deviations have been adjusted to the following Normalised Root Mean Square Error (NRMSE) levels:

- Demand: 2.85%
- Wind generation: 4.19%
- Solar generation: 3.50%

They were subsequently scaled to the projected demand levels and installed wind and solar capacities for 2030 and 2035 under both analysed scenarios.

Based on deviations defined in line with explanations above, upward and downward short-term flexibility needs have been determined as 0.1 and 99.9 percentiles of the residual load deviations. The resulting requirements are shown in the following table.

Table 9: Short-term flexibility needs per scenario and target year

Short-term flexibility needs (MW)	2030		2035	
	Upward	Downward	Upward	Downward
Referent scenario	547	-818	921	-1,348
Alternative scenario 2	748	-1,085	1,215	-1,781

Regarding the consideration of network needs under Articles 11 and 12 of the FNA Methodology, TSO network needs were not included within the scope of this FNA. For DSO network needs, the distribution system operator provided the relevant data, which was based on the Distribution Network Development Plan (DNDDP).

Lastly, the fine-tuning methodology, as defined in Article 14 of the FNA Methodology, is applied to refine system-level flexibility needs by considering network flexibility needs. In this report, fine-tuning was performed taking into account DSO network needs only. A description of the fine-tuning approach is provided in Annex 2.

3. Scenarios and assumptions description

3.1. Scenarios used to assess system and network needs

The scenarios of system and network needs assessment are aligned with the draft NRAA 2026 scenarios, which encompass the relevant conditions needed to provide reliable results for the expected adequacy of the regional power systems. That analysis included scenarios with different development of demand, as well as variations in thermal and RES capacity and different levels of cross-border capacities. This approach enabled investigations of a wide range of operating circumstances in Croatia:

- 1) **Referent scenario:** This scenario is based on the latest national NECP, as well as plant-by-plant data for the whole SEE region and Net Transfer Capacities (NTC) for that same region. This detailed data is from the internal database of the Energy Institute Hrvoje Požar (EIHP) who supported the development of the NRAA and FNA as an external consultant. It is also important to note that the Referent scenario results that were used as input for this FNA are the ones after the Economic Viability Assessment (EVA), more to be found in the draft NRAA 2026 Report.
- 2) **Alternative scenario 1:** Compared with the Referent scenario, this scenario assumes higher RES integration and changes in electricity demand. It includes a medium level of solar power plant integration at the distribution level³. It also assumes a medium level of integration of solar and wind power plants from the optimal technical connection study (cro. *Elaborat optimalnog tehničkog rješenja priključenja* – EOTRP), with 30% of the planned capacity integrated by 2030 and 90% by 2035. Demand projections were developed by extrapolating historical values using the Compound Annual Growth Rate (CAGR) method.
- 3) **Alternative scenario 2:** This scenario assumes the highest level of RES integration and electricity demand. It includes a higher level of solar power plant integration at the distribution level³. In addition, it also assumes a higher level of integration of solar and wind power plants from the EOTRP, with 40% of the planned capacity integrated by 2030 and 100% by 2035. Finally, demand in this scenario is significantly higher than in the first two scenarios. Therefore, this scenario tested the system's reliability under the most demanding conditions.

As required by the FNA Methodology, the Referent scenario is mandatory for inclusion in this assessment.

Furthermore, an additional scenario was also analysed, and it was jointly decided to select Alternative scenario 2 due to the occurrence of very high LOLE and ENS values in its 2035 setup, as well as a high level of RES curtailment. This scenario highlights potential stress situations in the system.

The following tables in this chapter summarise the main input data for the two selected scenarios.

As shown in Table 10, the electricity demand increases in both scenarios between 2030 and 2035, with the growth being more pronounced in Alternative scenario 2. In the Referent scenario, demand rises by approximately 8.2%, while in Alternative scenario 2, it increases by about 14.9%. When making comparisons between the scenarios, demand in Alternative scenario 2 is already 9.2% higher in 2030, and by 2035, this difference increases to about 16.1%. This shows the mentioned substantial demand growth in Alternative scenario 2, testing the system under significantly higher strain.

Table 10: Demand per scenario and target year

Demand (TWh)	2030	2035
Referent scenario	18.4	19.9
Alternative scenario 2	20.1	23.1

The following tables present the production mix in Croatia.

³ HEP ODS (July 2025), *Ten-Year (2025–2034) Distribution Network Development Plan of HEP ODS with Detailed Elaboration for the Initial Three-Year and One-Year Periods*, Table 2-4, p. 35.

Table 11 provides an overview of thermal power plant capacities expected in 2030 in the Referent scenario, together with their key technical parameters. It is important to note that, as per the FNA Methodology, to ensure cost-effectiveness, the methodology relies on the EVA conducted as part of the draft NRAA 2026, which itself is based on the ERAA methodology. Following the initial adequacy simulations, the EVA was conducted for the Referent scenario. For 2030, among the decommissioning candidates - which included EL-TO Zagreb Units H and J and Plomin 1 - only Plomin 1 was retained in operation. From the new candidates, one new 85 MW Combined Cycle Gas Turbine (CCGT) unit and a 5 MW DSR were chosen. Post-EVA adequacy simulations were then performed for this updated generation portfolio, and these results were used as input for the FNA analysis of the Referent scenario. Therefore, the available TPP capacities for the Referent scenario in 2030 amount to 1,067 MW.

Table 11: Croatian TPP capacities and parameters in the Referent scenario in 2030

Thermal power plant	Fuel	Installed capacity	Specific fuel consumption at maximum power	CO ₂ emission factor	Variable maintenance costs	Fuel price	Marginal cost of production of TPP	Fixed operating and maintenance costs
		MW	GJ/MWh	t CO ₂ /MWh	EUR/MWh	EUR/GJ	EUR/MWh	EUR/kW/y
TE-TO Zagreb unit K	Gas	200	6.5	0.367	2.5	6.22	92.97	34.7
TE-TO Zagreb unit L	Gas	100	6.4	0.367	4.5	6.22	94.35	34.7
TE Plomin 1	Oil	105	10.5	1.040	4	2.34	170.38	52.9
TE Plomin 2	Oil	199	9.75	0.984	4	2.34	160.99	96.8
EL-TO Zagreb unit L KKE	Gas	143.2	7.7	0.354	2	6.22	98.17	39.0
TE Sisak blok C	Gas	235	6	0.342	1.6	6.22	85.56	82.6
A new CCGT unit selected in EVA	Gas	85	6.2	0.354	1.6	6.22	88.45	39.0

Table 12 summarises the TPP capacities and their associated parameters for 2035. The EVA results were again taken into account. Accordingly, the candidate resources selected in 2030 - the new 85 MW CCGT unit and 5 MW of DSR capacity - were retained in 2035, together with an additional two-hour 150 MW battery storage system that was selected through the EVA process in 2035. As a result, the total available TPP capacity in 2035 amounts to 563 MW, representing a reduction of 50% compared to 2030.

Table 12: Croatian TPP capacities and parameters in the Referent scenario in 2035

Thermal power plant	Fuel	Installed capacity	Specific fuel consumption at maximum power	CO ₂ emission factor	Variable maintenance costs	Fuel price	Marginal cost of production of TPP	Fixed operating and maintenance costs
		MW	GJ/MWh	t CO ₂ /MWh	EUR/MWh	EUR/GJ	EUR/MWh	EUR/kW/y
TE-TO Zagreb unit L	Gas	100	6.4	0.367	4.5	6.22	100.10	14.66
EL-TO Zagreb unit L KKE	Gas	143.2	7.7	0.354	2	6.22	103.31	39.0
TE Sisak blok C	Gas	235	6	0.342	1.6	6.22	90.90	19.0
A new CCGT unit selected in EVA	Gas	85	6.2	0.354	1.6	6.22	88.45	39.0

For Alternative scenario 2, no EVA calculations were conducted. Therefore, the following tables summarise the TPP capacities based solely on data provided by HOPS and HEP Proizvodnja. As shown in Table 13, the total available TPP capacity for Alternative Scenario 2 in 2030 is 1,030 MW:

Table 13: Croatian TPP capacities and parameters in Alternative scenario 2 in 2030

Thermal power plant	Fuel	Installed capacity	Specific fuel consumption at maximum power	CO ₂ emission factor	Variable maintenance costs	Fuel price	Marginal cost of production of TPP	Fixed operating and maintenance costs
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		MW	GJ/MWh	t CO ₂ /MWh	EUR/MWh	EUR/GJ	EUR/MWh	EUR/kW/y
EL-TO Zagreb Unit H	Gas	24	12	0.367	3	6.22	127.68	92.7
EL-TO Zagreb Unit J	Gas	24	12	0.367	3	6.22	127.68	92.7
TE-TO Zagreb unit K	Gas	200	6.5	0.367	2.5	6.22	92.97	34.7
TE-TO Zagreb unit L	Gas	100	6.4	0.367	4.5	6.22	94.35	34.7
TE Plomin 1	Oil	105	10.5	1.04	4	2.34	170.38	52.9
TE Plomin 2	Oil	199	9.75	0.984	4	2.34	160.99	96.8
EL-TO Zagreb unit L KKE	Gas	143.2	7.7	0.354	2	6.22	98.17	39.0
TE Sisak Unit C	Gas	235	6	0.342	1.6	6.22	85.56	82.6

By 2035, the thermal power plant fleet in Alternative scenario 2 is projected to decrease significantly - to 526 MW and the corresponding capacities and parameters are presented in Table 14.

Table 14: Croatian TPP capacities and parameters in Alternative scenario 2 in 2035

Thermal power plant	Fuel	Installed capacity	Specific fuel consumption at maximum power	CO ₂ emission factor	Variable maintenance costs	Fuel price	Marginal cost of production of TPP	Fixed operating and maintenance costs
		MW	GJ/MWh	t CO ₂ /MWh	EUR/MWh	EUR/GJ	EUR/MWh	EUR/kW/y
EL-TO Zagreb Unit H	Gas	24	12	0.367	3	6.22	131.98	92.7
EL-TO Zagreb Unit J	Gas	24	12	0.367	3	6.22	131.98	92.7
TE-TO Zagreb unit L	Gas	100	6.4	0.367	4.5	6.22	100.10	14.66
EL-TO Zagreb unit L KKE	Gas	143.2	7.7	0.354	2	6.22	103.31	39.0
TE Sisak Unit C	Gas	235	6	0.342	1.6	6.22	90.90	19.0

Moving on to RES capacities, they are shown in Table 15. Total installed capacity is projected to increase in both scenarios, from 5.7 GW in 2030 to 8.4 GW in 2035 in the Referent scenario and from 7 GW in 2030 to 10.7 GW in 2035 in Alternative scenario 2. This corresponds to growth rates of approximately 47% and 52%, respectively. Alternative scenario 2 assumes a more ambitious renewable deployment pathway, resulting in total installed capacities that are approximately 23% higher in 2030 and 28% higher in 2035 than in the Referent scenario.

Wind and solar capacities reach 5.3 GW in the Referent scenario and 6.7 GW in Alternative scenario 2 by 2030, increasing to 7.8 GW and 10.2 GW, respectively, by 2035. This represents a growth of approximately 48% in the Referent scenario and 54% in Alternative scenario 2 between 2030 and 2035. When comparing the scenarios, wind capacity is only slightly higher in Alternative scenario 2 in 2030 (+7%), but the gap widens to 34% by 2035, mainly due to the deployment of 510 MW of offshore wind capacity, which is not present in the Referent scenario.

Solar power represents the largest renewable technology in both scenarios and is the main contributor to the higher installed RES capacities. Solar capacity is projected to reach 4.9 GW in Alternative scenario 2 compared to 3.7 GW in the Referent scenario in 2030, corresponding to a difference of 34%. By 2035, solar capacity increases to 7.7 GW and 6 GW, respectively, with Alternative scenario 2 remaining approximately 30% higher. As a result, wind and solar together account for more than 90% of total installed capacity in all scenarios, making them the key drivers of future RES integration and the subsequent flexibility analyses.

Table 15: RES capacities per scenario and target year

Installed capacities (MW)		2030	2035
Referent scenario	Batteries	66	66
	Onshore wind	1,624	1,863

	Offshore wind	0	0
	Solar	3,667	5,969
	Geothermal energy	68	191.5
	Small hydropower plants	73	73
	Biomass and biogas	194	194
Alternative scenario 2	Batteries	66	66
	Onshore wind	1,744	1,983
	Offshore wind	0	510
	Solar	4,907	7,745
	Geothermal energy	139	318
	Small hydropower plants	73	73
	Biomass and biogas	95	19

The total installed hydropower capacity in Croatia amounts to 2,166 MW in 2030 and 2035 in both scenarios. This includes 1,485 MW of reservoir hydropower plants, 389 MW of run-of-river hydropower plants, and 292 MW of closed-cycle pumped-storage hydropower plants (PSHPP). Reservoir hydropower represents the largest share of the hydropower fleet, accounting for approximately 69% of the total installed HPP capacity.

Finally, NTC values between Croatia and neighbouring SEE countries are in the following table.

Table 16: NTC values between Croatia and neighbouring countries

NTC (MW)	2030	2035
BA-HR	500	500
HR-BA	500	500
HR-HU*	450	450
HR-RS	300	300
HR-SI*	650	650
HU-HR*	550	550
RS-HR	300	300
SI-HR*	650	650

*Borders within the Core region where grid constraints were modelled using the flow-based approach

For DSO network needs, the DSO provided data on the need for downward flexibility, based on the assumptions and data used in the DNDP.

3.2. Target for RES integration

The RES integration target used in this assessment is based on Croatia's NECP, which foresees a 76.7% RES share. This value represents the ratio of RES generation and final electricity demand. No additional calculations were required to derive the target under Articles 8(7) and 8(8) of the FNA Methodology, as its adoption for 2030 and 2035 was agreed during consultations between HERA and HOPS. The target was therefore adopted directly from the NECP, as it is aligned with Croatia's national energy and climate objectives.

3.3. Portfolio of flexibility resources available

The flexibility resources considered in the draft NRAA 2026 and this FNA are reservoir HPPs, cross-border interconnections, DSR, and BESS. Among these, reservoir HPPs and cross-border interconnections contribute the most to system flexibility in Croatia. As presented in the chapter 3.1, reservoir HPPs account for the largest share of hydropower generation capacity in Croatia. In the

Antares model for 2030, a capacity of 1,246 MW is represented, while 239 MW are retained for reserve provision and therefore excluded from the adequacy simulations. Similarly, in 2035, the model includes 1,196 MW of reservoir HPP capacity, while an additional 289 MW of reserves for balancing are not considered in adequacy assessment. In addition, Croatia benefits from multiple cross-border interconnections, as shown in Table 16. The maximum export capacity amounts to 1,900 MW, while the maximum import capacity reaches 2,000 MW. These values remain unchanged in both 2030 and 2035.

Other flexibility resources considered in the assessment, namely DSR and BESS, provide a smaller, though still relevant, contribution to system flexibility.

Table 17 presents the DSR capacities and their characteristics, which are the same for both 2030 and 2035 in the Referent scenario. In the Alternative scenario 2, only DSR1 is present in both 2030 and 2035. DSR1 represents the input data adopted from the ERAA 2024 and subsequently translated for application in the draft NRAA 2026, while DSR2 corresponds to the 5 MW candidate selected through the EVA.

Table 17: DSR capacities and characteristics in the Referent and Alternative scenario 2 for 2030 and 2035

Technology	Scenario	Target year	Installed capacity	Activation price	Maximum hours
			MW	EUR/MWh	h
DSR1	Referent, Alternative 2	2030, 2035	57	2,999	24
DSR2	Referent		5	2,999	6

Finally, Table 18 summarizes the BESS capacities assumed for both scenarios and assessment years. As shown, BESS1 is present in both scenarios and in both years. It should be noted that the reported capacity of 33 MW represents the capacity available for adequacy purposes after accounting for reserves, meaning that an additional 33 MW is retained for reserve provision. BESS2 appears only in the Referent Scenario in 2035, as it was selected by the EVA.

Table 18: BESS capacities and characteristics in the Referent and Alternative scenario 2 for 2030 and 2035

Technology	Scenario	Target year	Turbining/pumping capacity	Reservoir volume	Overall efficiency
			MW	MWh	%
BESS1	Referent, Alternative 2	2030, 2035	33	66	92
BESS2	Referent	2035	150	300	92

Overall, the flexibility resources represented in the draft NRAA 2026 provide a diverse portfolio of options for supporting system flexibility. As noted above, the capacities of reservoir HPPs and BESS included in the draft NRAA simulations and this FNA already account for the reservation of part of their capacity for balancing and reserve provision. Consequently, the reserves excluded from the flexibility resources remain available to the Croatian power system and provide an additional margin of operational flexibility and system security.

4. Results of flexibility needs assessment

4.1. System-wide flexibility needs

As described in the first chapter, system flexibility needs are classified into three main categories: RES integration needs, ramping needs, and short-term needs. The results of the FNA analysis for each category are presented and discussed in the corresponding sections of this subchapter.

4.1.1. RES integration needs

4.1.1.1. Characterisation of RES integration needs

The key indicator for assessing RES integration needs is whether the RES target can be achieved after accounting for all available flexibility resources and any remaining uncovered flexibility needs. The RES target considered in this analysis is the one defined in the NECP, which for Croatia amounts to 76.7%⁴, as described in chapter 3.2.

The following two tables present the data used to calculate the RES integration ratio. The relevant ratio shown in the tables is calculated as the ratio between delivered RES electricity generation and total electricity demand. Delivered RES generation refers to RES generation after curtailment has been taken into account. Curtailment includes the values obtained from the Antares simulation results, as well as the additional curtailment resulting from uncovered ramping and short-term flexibility needs, which are further analysed in chapters 4.1.2 and 4.1.3. To avoid double-counting, the maximum of the two additional curtailment values resulting from uncovered ramping and short-term needs is taken, in accordance with Article 8(3) of the FNA Methodology, which is then summed with the DSO network needs.

As shown in Table 19, in the Referent scenario, **the RES target is achieved in both 2030 and 2035.**

Table 19: Parameters for calculating RES target for the Referent scenario

Target year	Parameter	Unit	Total
2030	RES generation (A)	MWh	14,781,008
	RES curtailment (B)	MWh	280,668
	RES curtailment addition – due to uncovered ramping needs	MWh	61
	RES curtailment addition – due to uncovered short-term needs	MWh	17,885
	Maximum RES curtailment addition (C)	MWh	17,885
	RES curtailment addition – downward DSO network needs (D)	MWh	486.75
	RES generation minus curtailment (E = A – B – C – D)	MWh	14,481,968

⁴ Integrated National Energy and Climate Plan for the Republic of Croatia for the Period 2021–2030 (March 2025), Table 2-1, p. 78.

Target year	Parameter	Unit	Total
	Load (F)	MWh	18,360,809
	Achieved RES target (E / F)	%	78.9%
2035	RES generation (A)	MWh	18,818,429
	RES curtailment (B)	MWh	2,033,585
	<i>RES curtailment addition – due to uncovered ramping needs</i>	<i>MWh</i>	<i>16,496</i>
	<i>RES curtailment addition – due to uncovered short-term needs</i>	<i>MWh</i>	<i>1,338,362</i>
	Maximum RES curtailment addition (C)	MWh	1,338,362
	RES curtailment addition – downward DSO network needs (D)		2,992.53
	RES generation minus curtailment (E = A – B – C – D)	MWh	15,443,489
	Load (F)	MWh	19,815,487
	Achieved RES target (E / F)	%	77.9%

In Alternative Scenario 2, the target is achieved in 2030 but not in 2035. This is primarily due to the significant increase in electricity demand, as shown in Table 10, combined with high RES curtailment, i.e. curtailment visible in the following table.

Table 20: Parameters for calculating RES target for the Alternative scenario 2

Target year	Parameter	Unit	Total
2030	RES generation (A)	MWh	16,545,122
	RES curtailment (B)	MWh	500,859
	<i>RES curtailment addition – due to uncovered ramping needs</i>	<i>MWh</i>	<i>505</i>
	<i>RES curtailment addition – due to uncovered short-term needs</i>	<i>MWh</i>	<i>181,264</i>
	Maximum RES curtailment addition (C)	MWh	181,264
	RES curtailment addition – downward DSO network needs (D)		486.75

Target year	Parameter	Unit	Total
	RES generation minus curtailment (E = A – B – C – D)	MWh	15,862,526
	Load (F)	MWh	20,040,193
	Achieved RES target (E / F)	%	79.2%
2035	RES generation (A)	MWh	22,470,070
	RES curtailment (B)	MWh	3,379,094
	<i>RES curtailment addition – due to uncovered ramping needs</i>	<i>MWh</i>	<i>16,441</i>
	<i>RES curtailment addition – due to uncovered short-term needs</i>	<i>MWh</i>	<i>2,772,564</i>
	Maximum RES curtailment addition (C)	MWh	2,772,564
	RES curtailment addition – downward DSO network needs (D)		2,992.53
	RES generation minus curtailment (E = A – B – C – D)	MWh	16,315,419
	Load (F)	MWh	23,049,631
	Achieved RES target (E / F)	%	70.8%

As explained in the introductory part of this chapter, the ratio takes into account the reduced RES generation actually absorbed by the system. Therefore, even under this security margin where potential issues could arise, the target is achieved in most scenarios. Alternative scenario 2 in 2035 as target year is the only case in which the RES target of 76.7% is not met, due to the system configuration assumptions described in the chapter 3.1.

Although uncovered flexibility needs appear, quantified and further analysed in chapters 4.1.2 and 4.1.3, they do not jeopardise the overall achievement of the RES target in most scenarios, meaning that for them, no additional flexibility resources are required from the perspective of RES target achievement.

Table 21: Summary of RES targets per scenario and target year

Target year and scenario	Total
2030 Referent scenario	78.9%
2035 Referent scenario	77.9%
2030 Alternative scenario 2	79.2%

Target year and scenario	Total
2035 Alternative scenario 2	70.8%

When the RES target is achieved, no additional flexibility resources are required.

4.1.1.2. Characterisation of residual load time series

As defined in the FNA Methodology, residual load “refers to the total demand minus non-dispatchable generation (as individual units or aggregated units), such as from wind or solar as well as generation, subject to must-run conditions per market time unit”. In other words, it represents the portion of electricity demand that remains to be supplied by dispatchable resources, which include thermal power plants, hydro storage, and pumped storage hydro plants, as well as batteries. Put simply, residual load is calculated as total demand minus non-dispatchable RES generation. The remaining load is the demand that dispatchable resources, together with cross-border exchanges, need to cover.

Traditionally, when variable renewable energy (VRE) sources such as wind and solar constituted a small share of total demand, conventional power plants easily adjust their output according to the demand curve. As VRE penetration increases, its generation increasingly affects the residual load profile, which influences the balance of supply and demand.⁵ Residual load is therefore an important indicator in power system analysis, providing information on how dispatchable units should operate to maintain system balance.

The results of the residual load for the Referent scenario for 2030 are shown in Figure 4. The left graph shows how residual load evolves relative to native load percentiles. Residual load is moderate during the lowest percentiles of native load, which correspond to nighttime hours when demand is low and there is no solar production. It then declines to its minimum levels around the 30th to 60th percentile of native load, representing midday hours when solar generation is at its peak. As the native load rises to its maximum, residual load increases and reaches its peak. These are the evening hours when demand is high but solar output is lower or zero, reflecting a need for dispatchable generation to jump in.

The right graph illustrates the impact of wind and solar generation on residual load. Residual load is highest when renewable output is low, approximately up to the 50th percentile, indicating periods when conventional generation must supply most of the demand due to very low or no wind and solar generation. As renewable output increases, residual load gradually decreases. Beyond the 80th percentile of wind and solar generation, residual load drops sharply, even becoming slightly negative at the highest RES production hours (98th and 100th percentile). These are periods of surplus renewable generation where curtailment may be required.

⁵ https://energypedia.info/wiki/Residual_Load

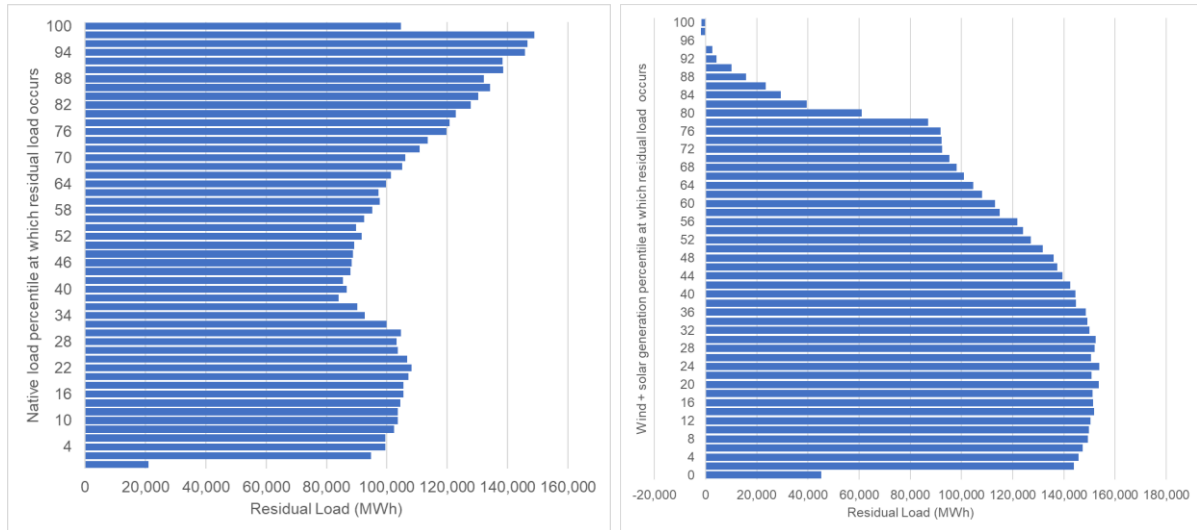


Figure 4: Residual load correlations for the Referent scenario in 2030

In 2035, the residual load graphs show significantly higher values compared to 2030, with markedly different shapes. Up to the 40th percentile of native load, residual load is negative, indicating there is enough renewable capacity to exceed demand. Beyond this period, residual load steadily increases, reaching its peak near the highest load hours. The negative residual load during low-demand periods is roughly six times smaller than the peak positive residual load, highlighting that periods of surplus generation are minor compared to peak system requirements.

The residual load profile relative to wind and solar generation shows the opposite behaviour. At the lowest percentiles of wind and solar output, residual load reaches its highest positive values, emphasising that conventional dispatchable generation must cover most of the demand. As renewable generation increases, residual load gradually declines, becoming negative during the periods of higher RES production, which illustrates times when curtailment may be necessary to maintain system balance.

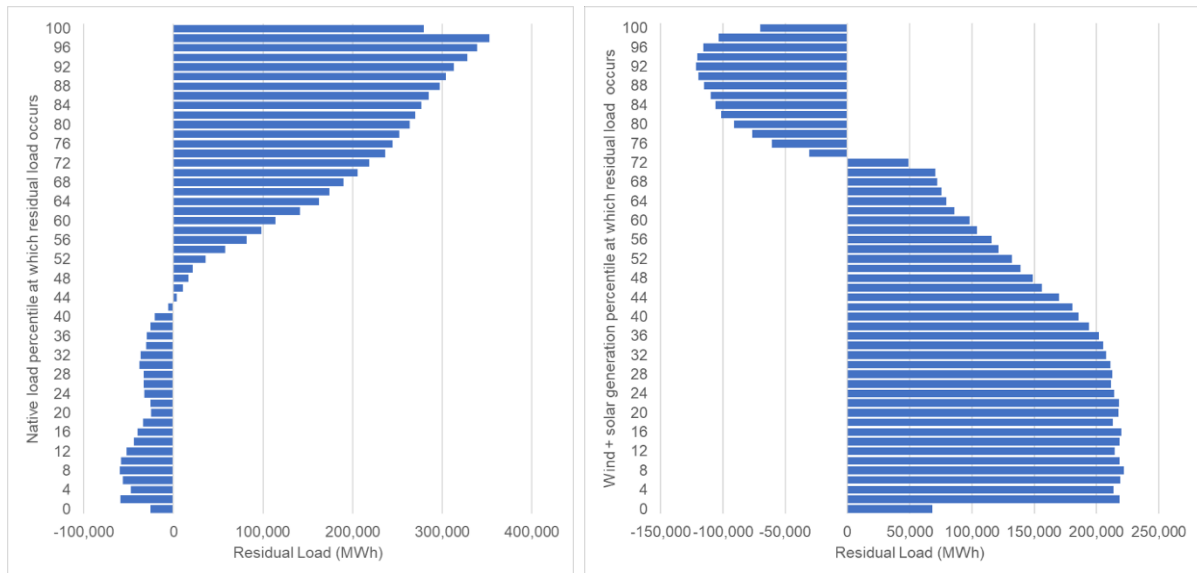


Figure 5: Residual load correlations for the Referent scenario in 2035

When comparing Alternative Scenario 2 with the Referent Scenario, the residual load curve in relation to native load shows a broadly similar shape in both 2030 and 2035. In 2030, residual load values in Alternative scenario 2 are approximately 11% higher than in the Referent Scenario for native load values below the 40th percentile, i.e. during lower-load periods. For native load values above the 40th percentile, residual load values are on average around 4% lower than in the Referent Scenario, while at the highest load levels, from the 80th percentile onwards, the values are on average the same. These variations from positive to negative differences can be explained by the comparison of demand and installed capacities between the two scenarios, as presented in chapter 3.1. In Alternative scenario 2,

demand is 9% higher than in the Referent scenario, while wind capacity is only 7% higher and solar capacity is 34% higher. Therefore, while higher solar capacity reduces residual load during periods of strong solar output and high demand (around midday), it covers a smaller share of demand in the morning and evening hours compared to the Referent scenario.

The residual load curves in relation to wind and solar output are also broadly similar between the scenarios, though there is an observable difference between Figure 6 and Figure 4: negative residual load values in Alternative scenario 2 occur earlier and reach higher magnitudes than in the Referent Scenario. This is mainly due to the significantly higher solar capacity in Alternative scenario 2, which leads to stronger generation during peak solar hours. During these periods, renewable generation exceeds demand, resulting in deeper negative residual load values and indicating a higher likelihood of curtailment.

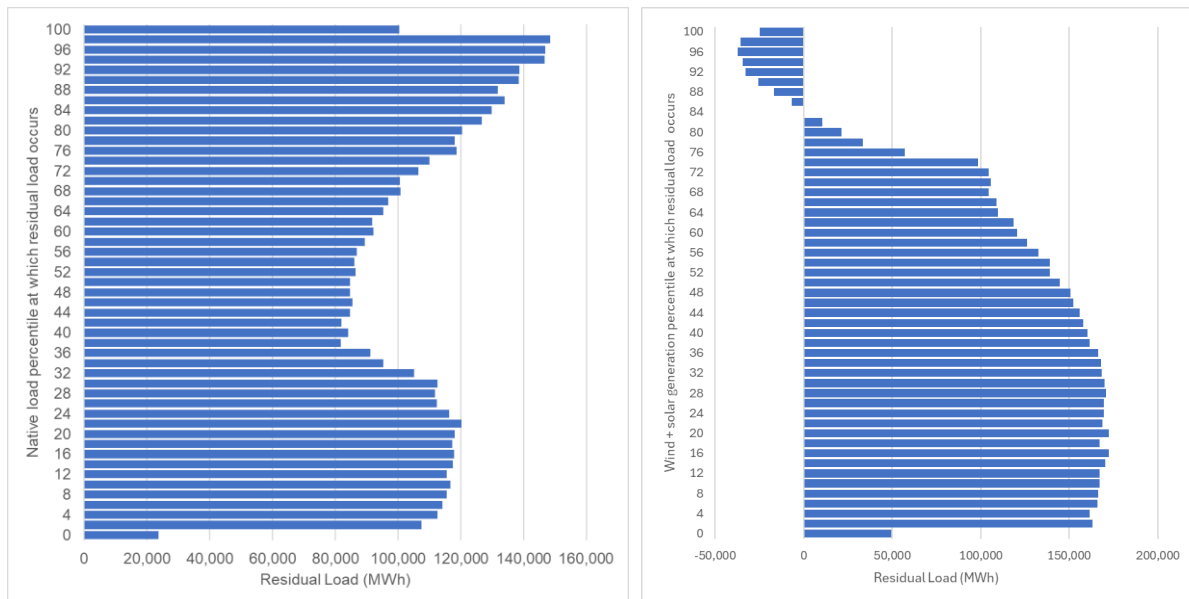


Figure 6: Residual load correlations for Alternative scenario 2 in 2030

In 2035, the overall shape of the curve in Figure 7 remains similar to the one in Figure 5, but residual load values in Alternative Scenario 2 are higher across the full range, on average by around 11%. This reflects the combined effect of higher demand and the capacity mix in this scenario. Compared to the Referent scenario, solar capacity is 30% higher, but wind capacities are also 34% higher. This stronger increase in wind capacity helps provide additional generation outside peak solar hours. This shows that, compared to 2030, the renewable generation profile in 2035 is more balanced, with wind generation complementing solar output and moderating the effect of high solar penetration on residual load.

Residual load curve in relation to wind and solar output in Alternative scenario 2 is almost the same as that in the Referent scenario, but also only with higher values across the observed range, on average by 12%.

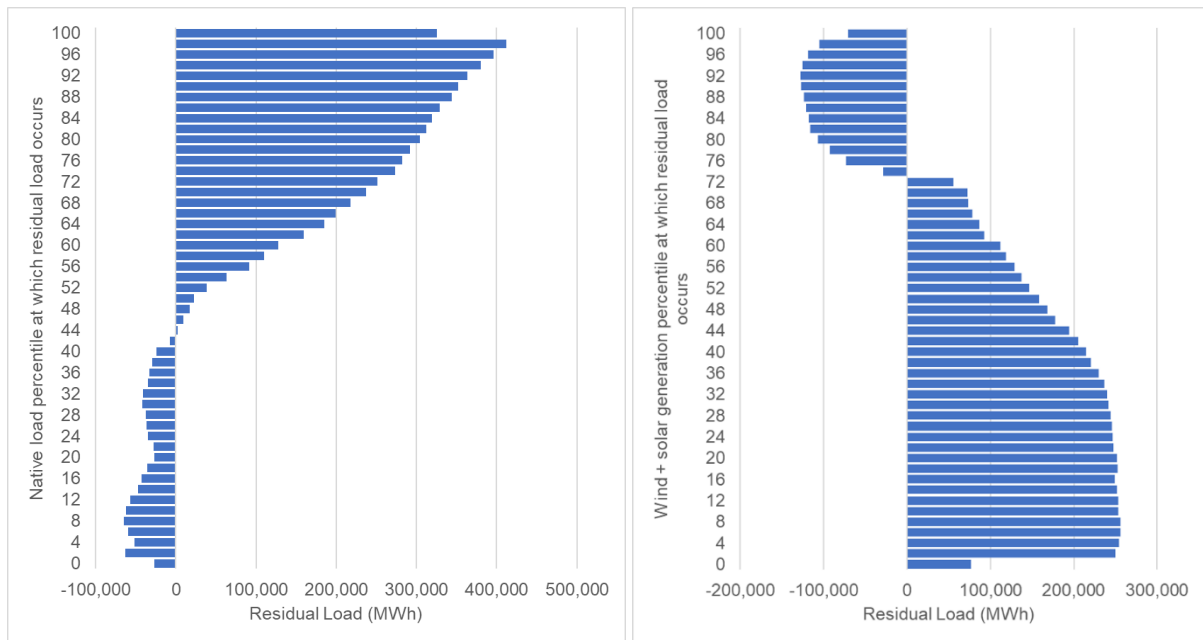


Figure 7: Residual load correlations for Alternative scenario 2 in 2035

Residual load is influenced by demand patterns and variable renewable generation:

1. When residual load is high → more dispatchable generation is required to meet demand.
2. When residual load is low → non-dispatchable generation (RES) covers most of the demand, so less must be provided by dispatchable units.
3. When residual load is zero or negative → there is surplus non-dispatchable generation (without curtailment); this surplus could exceed system demand, potentially causing congestion and imbalance.

Residual load = an important indicator for scheduling and operating dispatchable resources.

The following graphs show the minimum, maximum, and average values of the residual load for each hour of the day by season, calculated across 540 MC years. Four seasons are considered: spring includes March to May, summer June to August, autumn September to November, and winter December to February.

The results show that, in spring, residual load frequently reaches negative values, while in winter, this occurs to a lesser extent and with lower magnitudes.

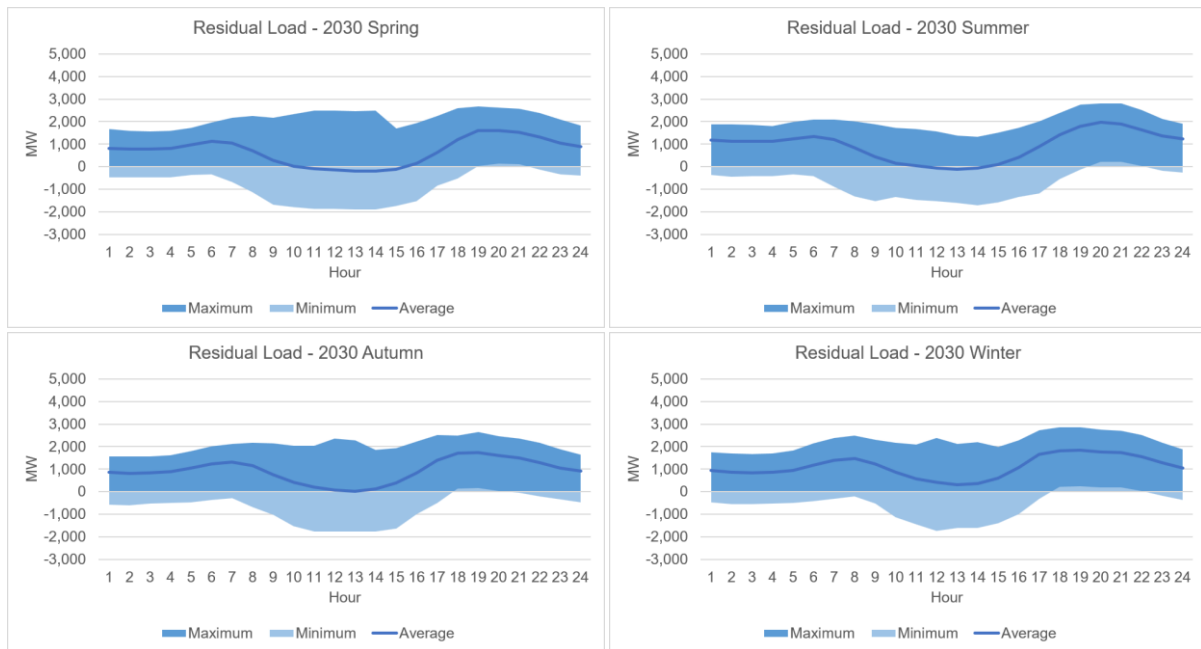


Figure 8: Daily residual load by season for the Referent scenario in 2030

For 2035, the same scale as in 2030 is used to enable direct comparison between the two target years. The results show that the range between the minimum and maximum residual load values is larger in 2035 than in 2030, meaning that there is a higher dispersion of residual load values. Additionally, more pronounced drops in the average residual load can be observed, primarily during summer, but also during autumn and spring.

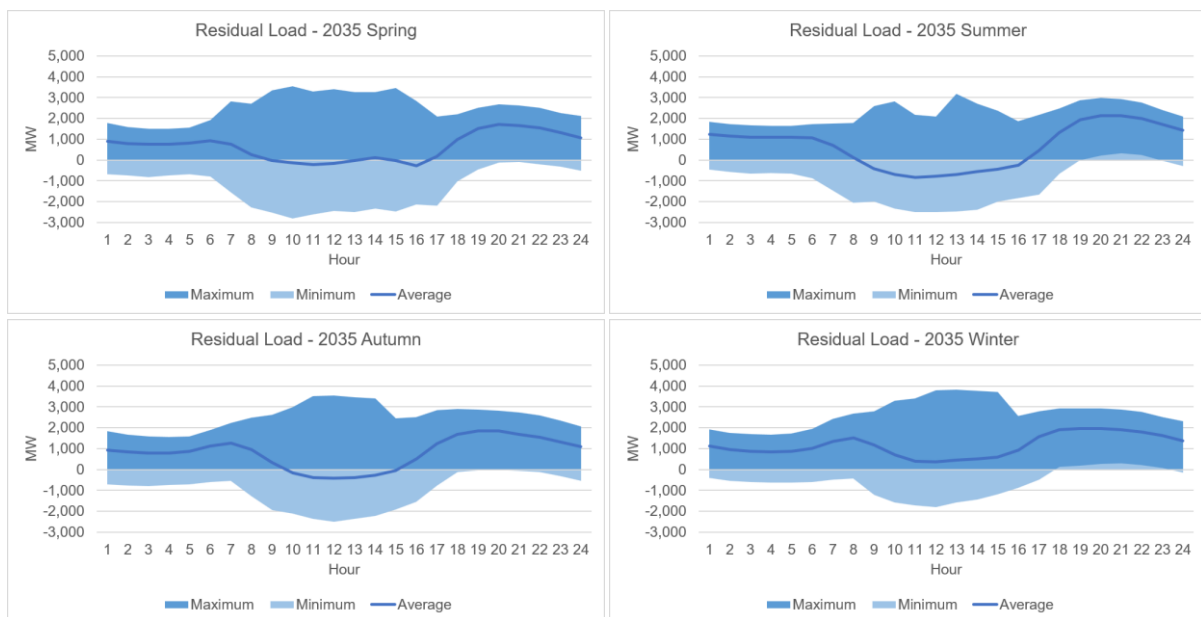


Figure 9: Daily residual load by season for the Referent scenario in 2035

For Alternative scenario 2, the two figures lead to similar conclusions, with values generally slightly higher than in the Referent scenario.

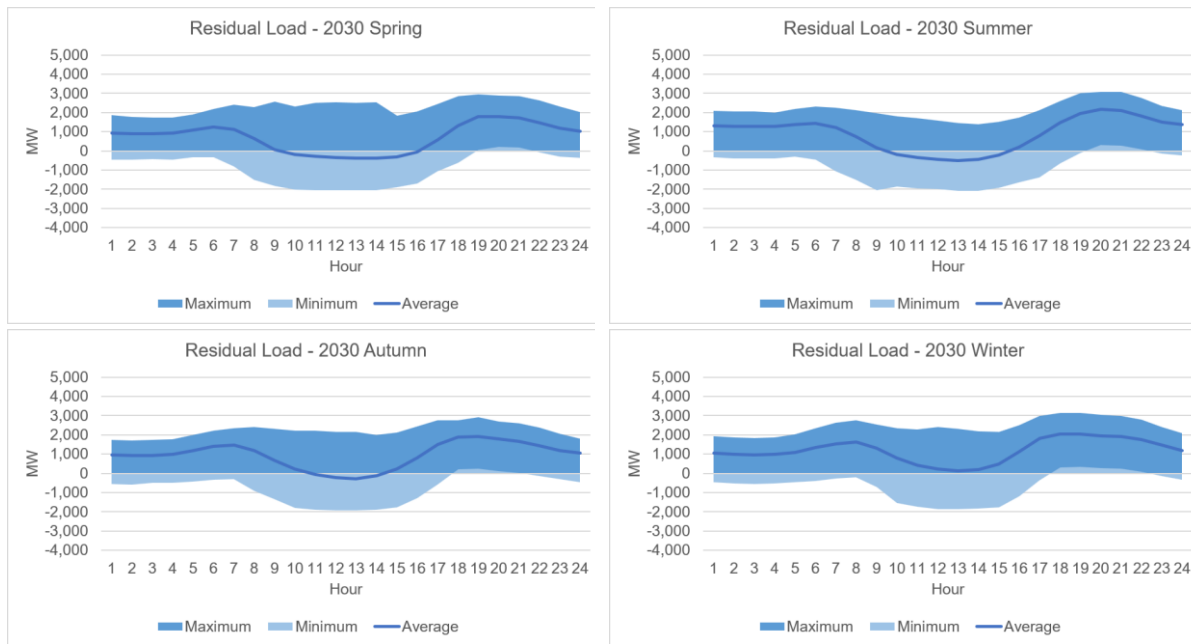


Figure 10: Daily residual load by season for Alternative scenario 2 in 2030

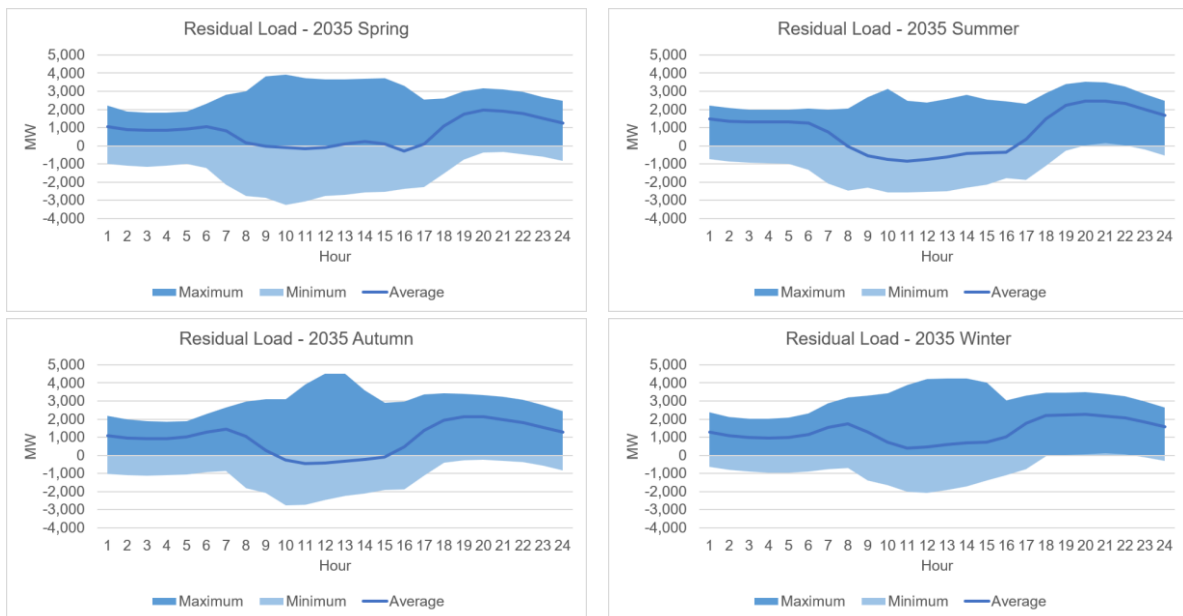


Figure 11: Daily residual load by season for Alternative scenario 2 in 2035

4.1.1.3. Characterisation of RES generation curtailment

The RES generation curtailment correlation diagrams shown in this chapter are of similar type as diagrams related to the residual load in the previous subchapter.

The left-hand graph in Figure 12 shows that curtailment is highest when native load is around 40%, which corresponds to midday hours with the highest solar generation. This indicates that the greatest curtailment occurs under moderate demand conditions, rather than during low load periods.

The right-hand diagram further confirms this relationship - curtailment is close to zero at low renewable output, while very high curtailment appears at the highest renewable generation percentiles. So, the results in 2030 showcase midday solar production as the main driver of curtailment.

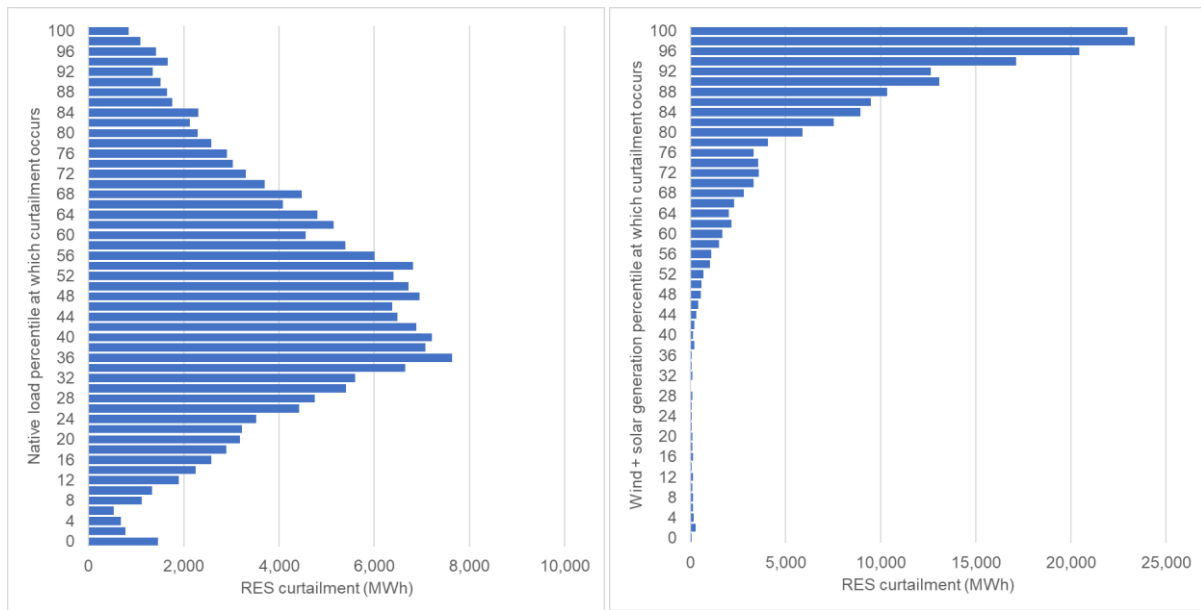


Figure 12: RES generation curtailment correlations for the Referent scenario in 2030

In 2035, RES curtailment increases significantly but peak curtailment stays around 40-50% of the native load peaks. The shape of the right-hand graph remains the same, but the values have increased sevenfold.

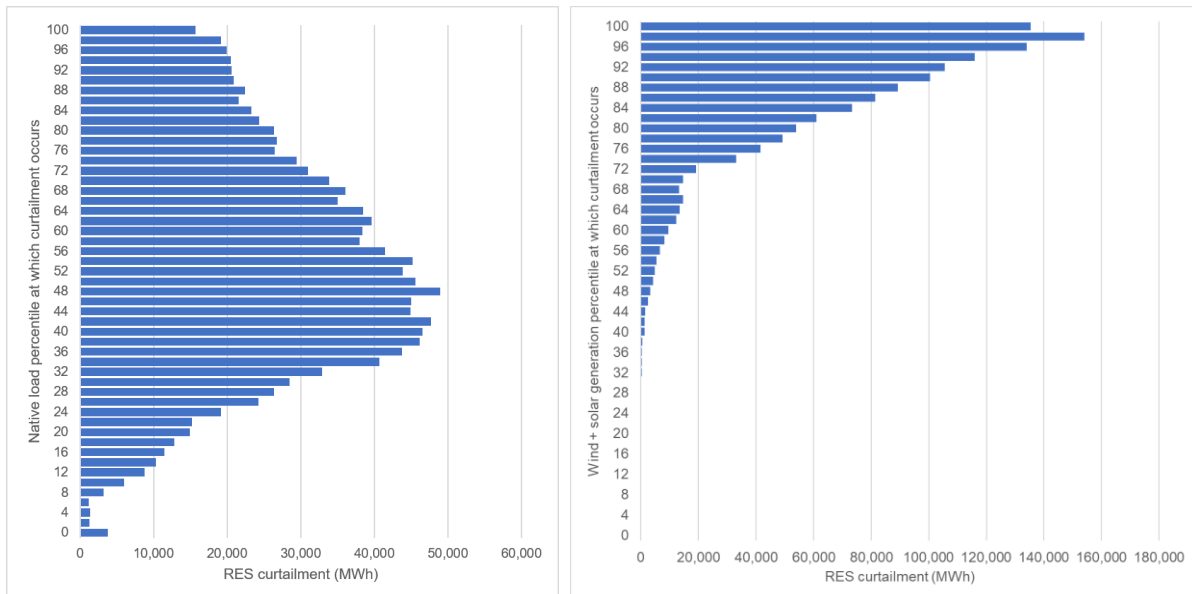


Figure 13: RES generation curtailment correlations for the Referent scenario in 2035

In both years, the Alternative scenario 2 follows the same pattern as in the Referent scenario, but results in higher levels of RES curtailment.

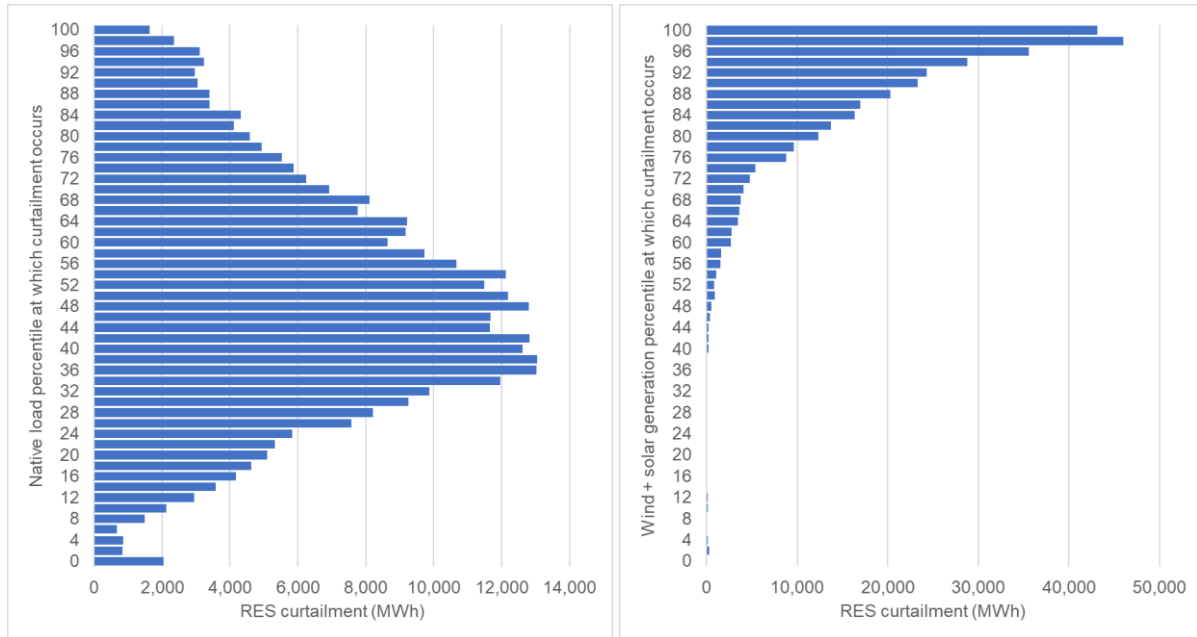


Figure 14: RES generation curtailment correlations for Alternative scenario 2 in 2030

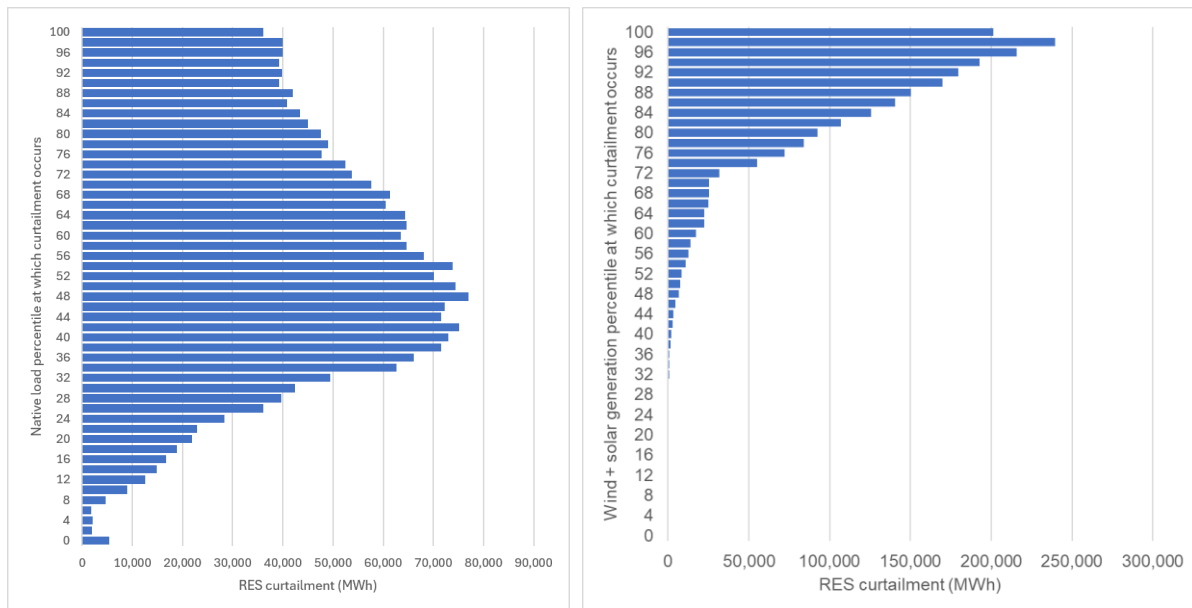


Figure 15: RES generation curtailment correlations for Alternative scenario 2 in 2035

Similar to the residual load by season analysis, the following graphs show daily curtailment profiles by season. These profiles represent daily patterns for each season. It is important to note that the charts show the maximum and average values of the maximum curtailment values across 540 MC years. This approach was used because many values are equal to zero, as shown by the parameter “Probability of RES generation curtailment greater than zero” in Table 23 to Table 26. Consequently, if the averages were used instead, the resulting graphs would provide limited insights, as the values would be much lower, and usually zero during the morning and evening hours. For example, there may be only one single hour in spring, across all 540 simulations, in which the value reaches the maximum of 4,647 MW, while many other hours have a value of zero.

We see in Figure 16 and Figure 17 that curtailment is generally low during the night, increases sharply in the morning, reaches its maximum around midday when solar generation is highest, and then decreases towards the evening, eventually falling back to lower values during the night.

The highest curtailment values are observed in spring. In that season, the highest curtailment occurs around midday and between 10h and 15h, where maximum curtailment is always higher than zero across all 540 MC years. In summer and autumn, maximum curtailment is lower, with zero maximum curtailment in certain MC years. In winter, maximum curtailment is generally lower; however, solar

generation appears to contribute to curtailment, as the maximum curtailment remains above zero at midday.

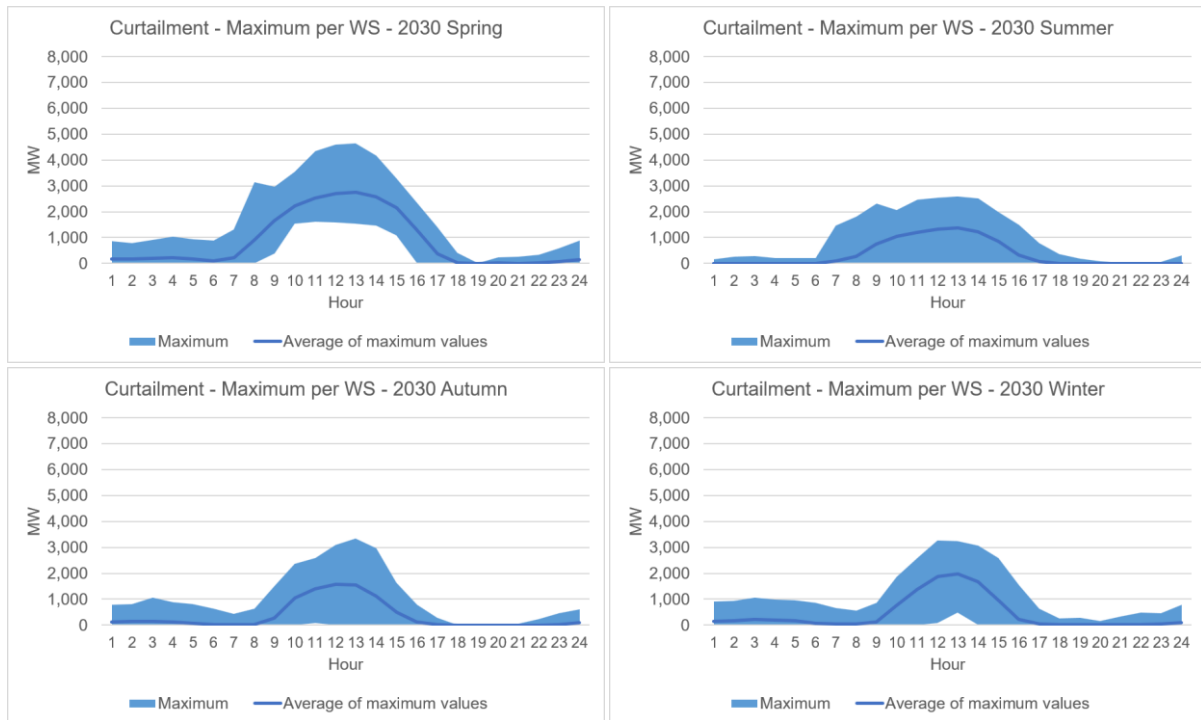


Figure 16: Daily curtailment by season for the Referent scenario in 2030

In 2035, maximum values roughly double and around midday maximum curtailment is always higher than zero across all 540 MC years in all seasons. But in comparison to 2030, periods outside of the midday show lower curtailment and there are hours in which no curtailment occur at all (e.g. 3h-7h in autumn season). This is consistent with the higher RES penetration assumed in the 2035 scenario.

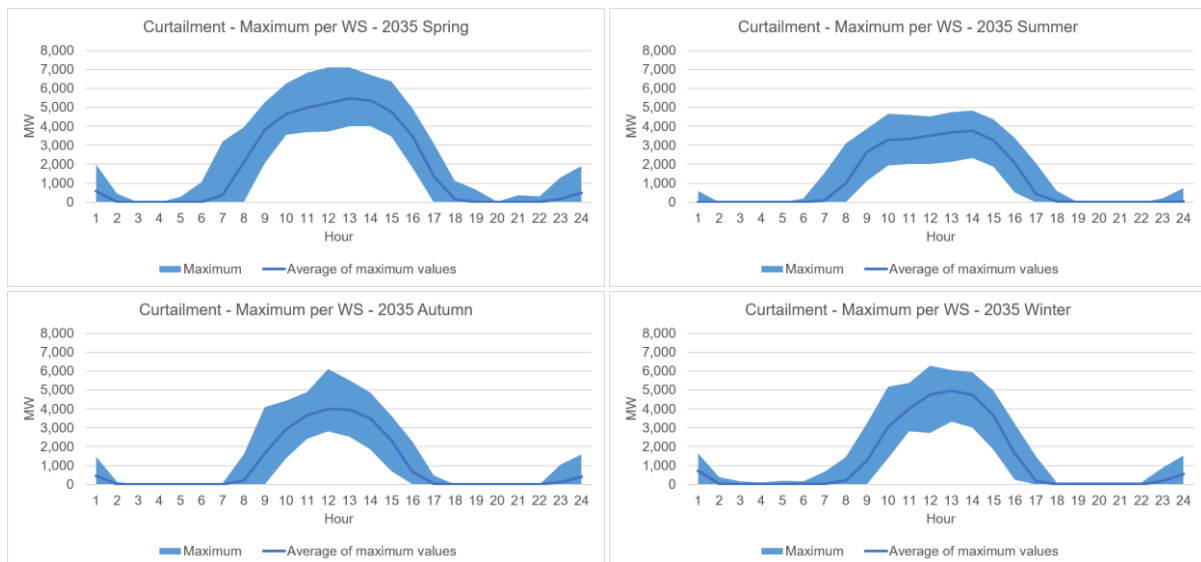


Figure 17: Daily curtailment by season for the Referent scenario in 2035

In Alternative scenario 2 shown in the following two figures, daily behaviours remain consistent with the Referent scenario, while all maximum values are elevated in comparison. This increase is particularly noticeable in 2035. Additionally, in 2030, there are no seasons with zero maximum curtailment at midday as opposed to the same year of the Referent scenario, again due to a higher volume of renewable energy generation.

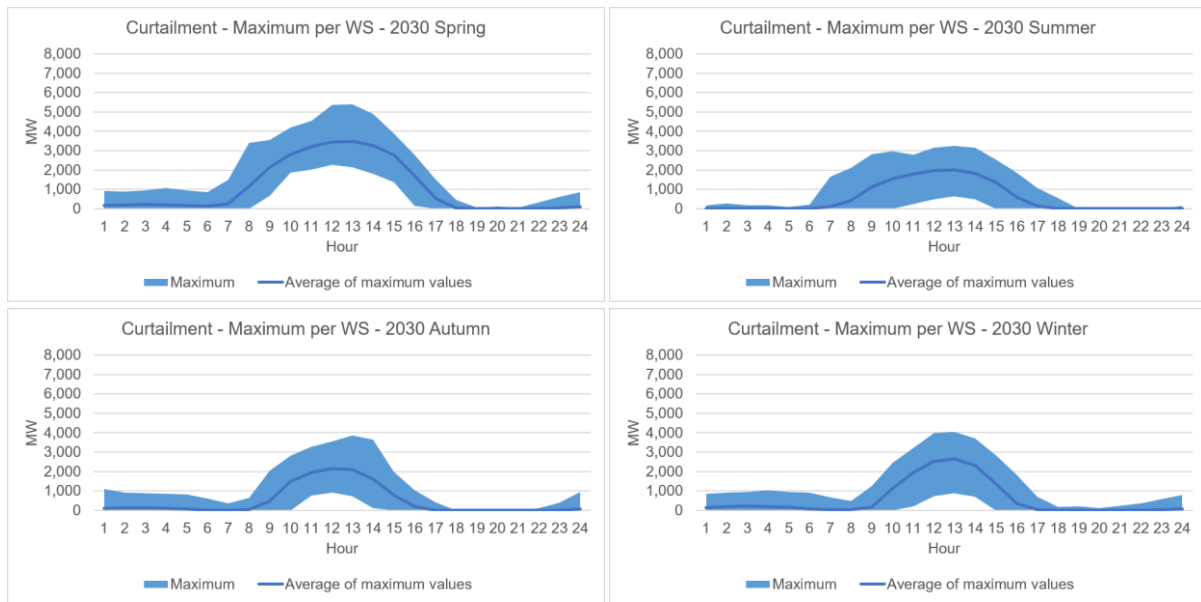


Figure 18: Daily curtailment by season for Alternative scenario 2 in 2030

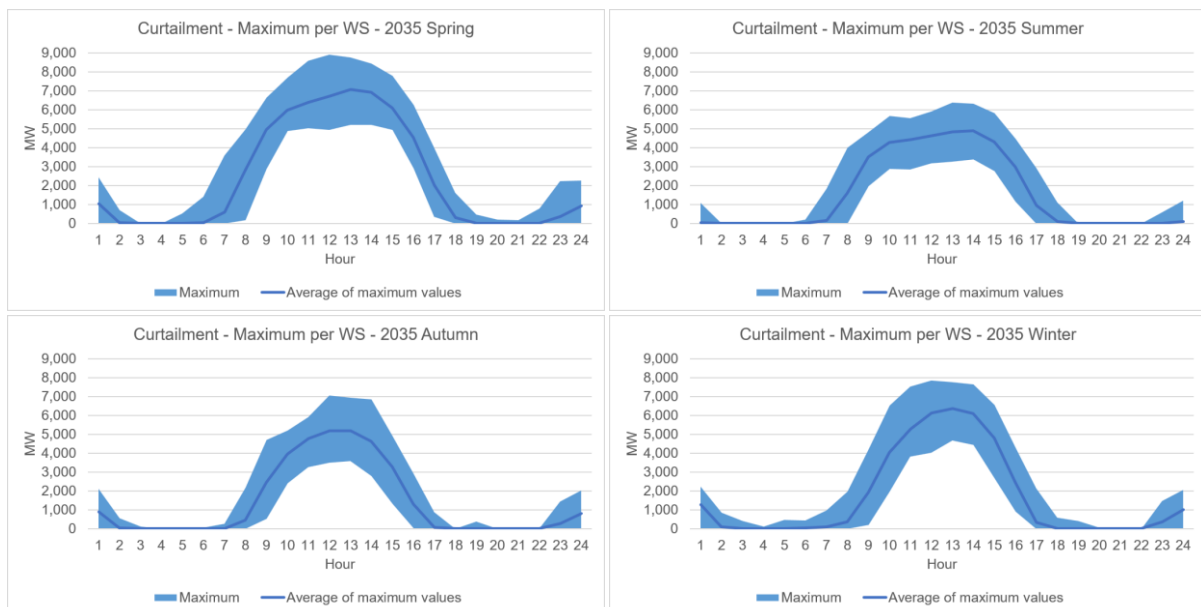


Figure 19: Daily curtailment by season for Alternative scenario 2 in 2035

4.1.2. Ramping needs

4.1.2.1. Characterisation of ramping needs

Ramping needs represent the flexibility required to cover expected variations in residual load between consecutive market time units. The assessment quantifies whether the available conventional resources (primarily hydropower storage plants were taken into account in this analysis) and interconnections can accommodate the expected residual load fluctuations. Detailed results for ramping needs across scenarios and target years are provided in tables in Annex 1, which are structured to first present the calculated ramping requirements, then show the available flexibility, and finally the uncovered ramping needs as the difference between the first two.

4.1.2.2. Uncovered ramping needs

The following figures present the uncovered upward and downward ramping needs derived from residual load variations for the Referent scenario in 2030 and 2035. The graphs show the relationship between ramping needs and native load and RES generation.

For 2030, the left-hand graph indicates that downward ramping issues are not primarily determined by the level of consumption. Instead, they tend to occur at medium native load levels. The right-hand graph shows a clear connection between uncovered downward ramping needs and higher shares of RES generation.

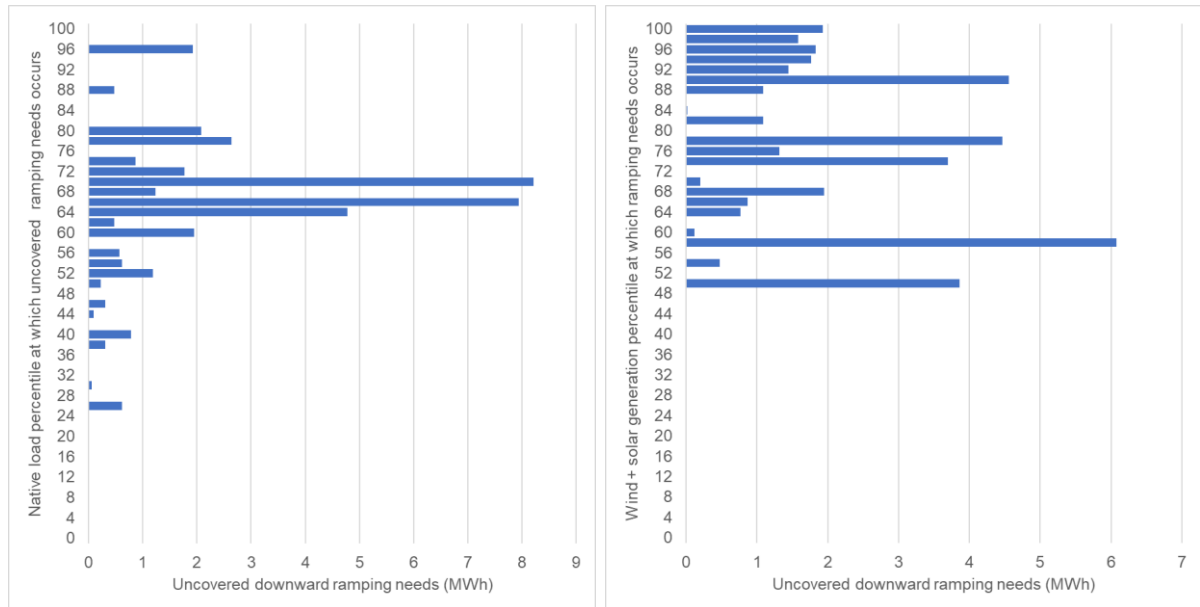


Figure 20: Uncovered downward ramping needs for the Referent scenario in 2030

In 2035, the dependence on RES generation becomes even more pronounced, while downward ramping needs in this target year tend to occur at lower levels of native load.

It should be noted that the available flexibility is relatively similar to that in 2030 because the system relies on the identical hydropower plants and very similar interconnection capacities. However, the system operation differs due to a different hourly dispatch, which leads to a different allocation of flexibility. This is why there is a different distribution between the 2030 and 2035 diagrams dependent on the native load.

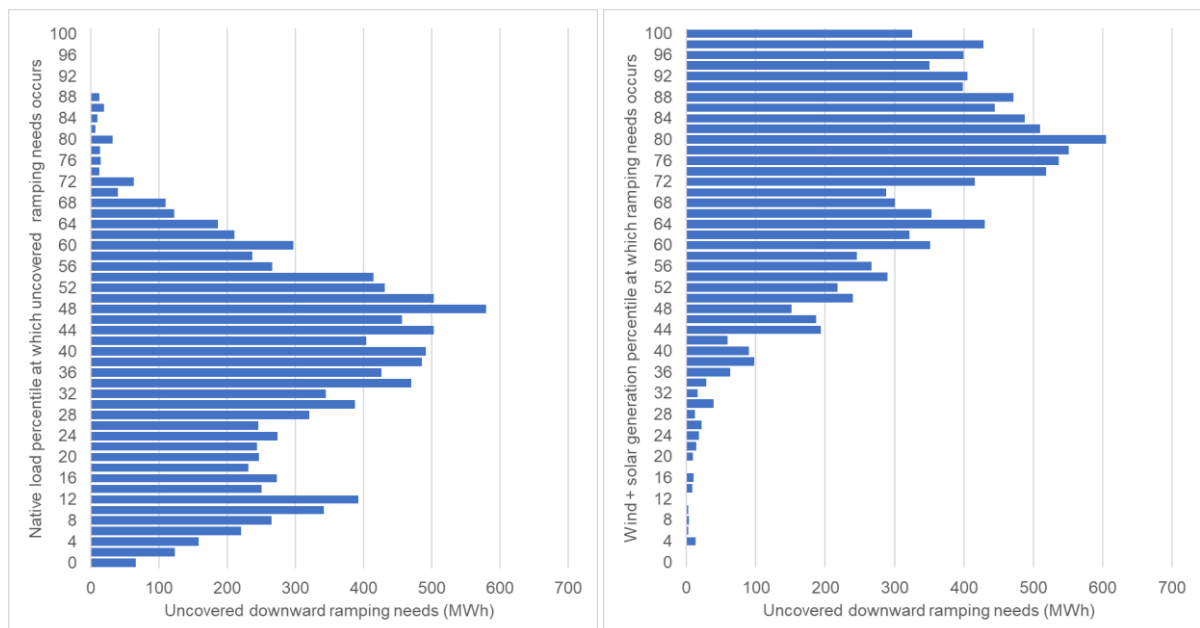


Figure 21: Uncovered downward ramping needs for the Referent scenario in 2035

When looking at upward ramping needs in 2035, the uncovered ramping needs are associated with higher percentiles of native load and with lower levels of RES generation.

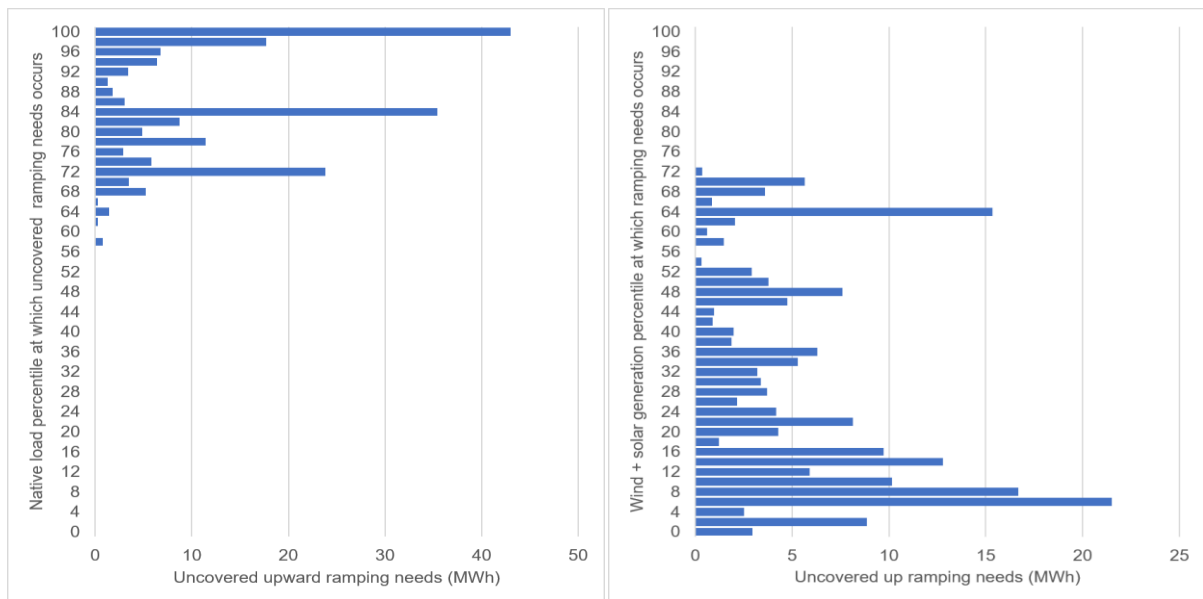


Figure 22: Uncovered upward ramping needs for the Referent scenario in 2035

In the Alternative scenario 2, similar conclusions can be drawn as for the Referent scenario, but with higher values.

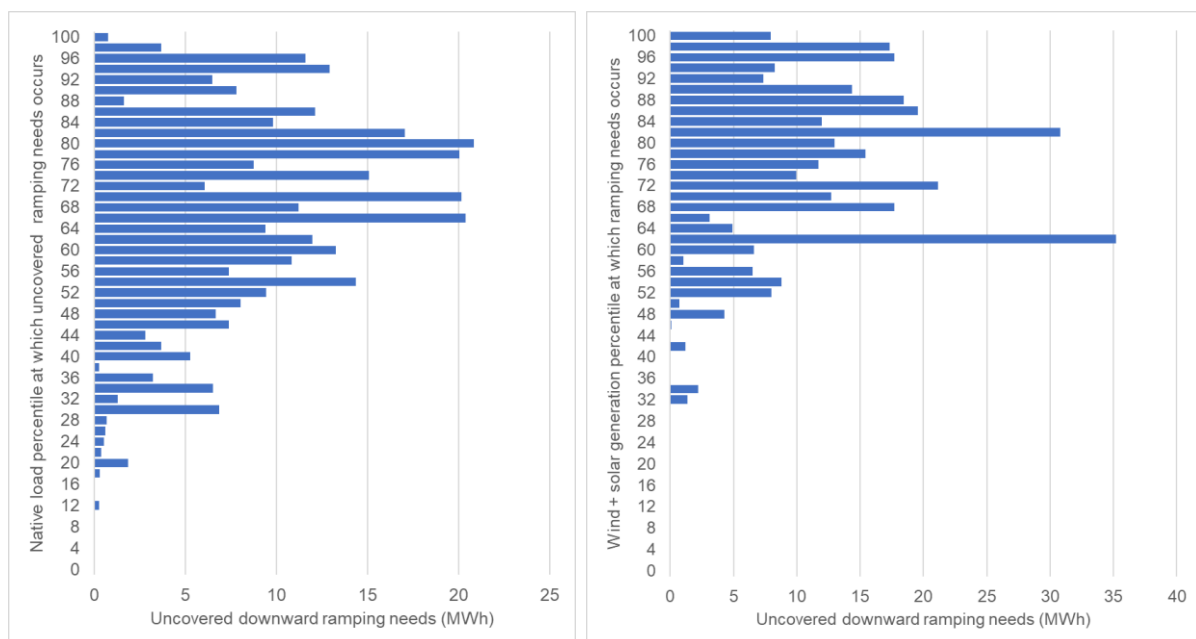


Figure 23: Uncovered downward ramping needs for Alternative scenario 2 in 2030

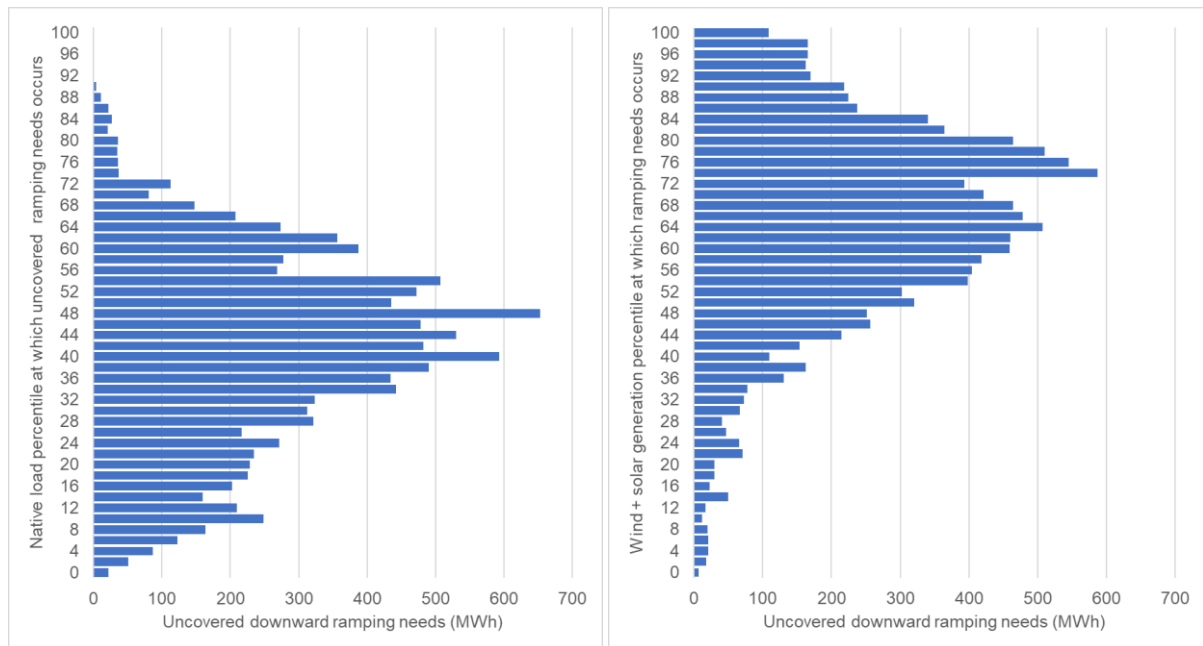


Figure 24: Uncovered downward ramping needs for Alternative scenario 2 in 2035

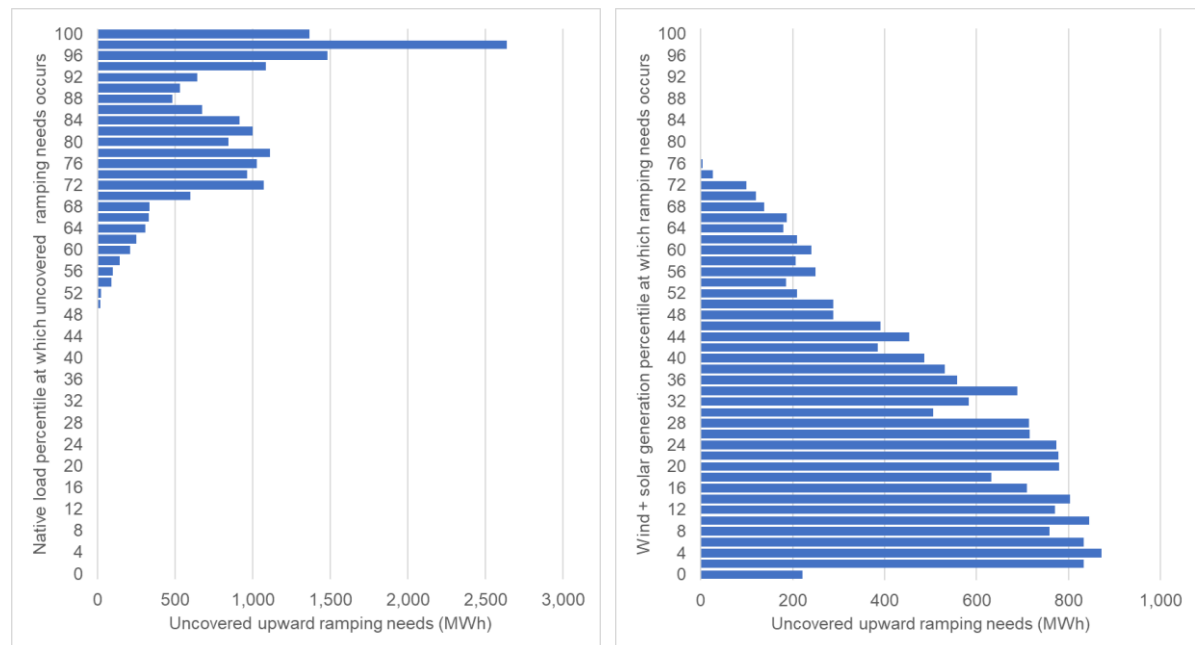


Figure 25: Uncovered upward ramping needs for Alternative scenario 2 in 2035

To further characterise the availability of ramping capacity, the daily distribution of uncovered upward and downward ramping needs is shown by season in the following graphs. These seasonal daily diagrams show when the system lacks required ramping capacity, and how this differs by season.

As in the curtailment charts, the diagrams show maximum values because the dataset contains many zero values. This means that the reported maximum represents the highest value observed across all 540 MC simulations.

In 2030, the main issues occur primarily in spring, and to a lesser extent in autumn and winter, while there are no uncovered needs during the summer. The critical period is around noon, when load is moderately high and solar generation is increasing.

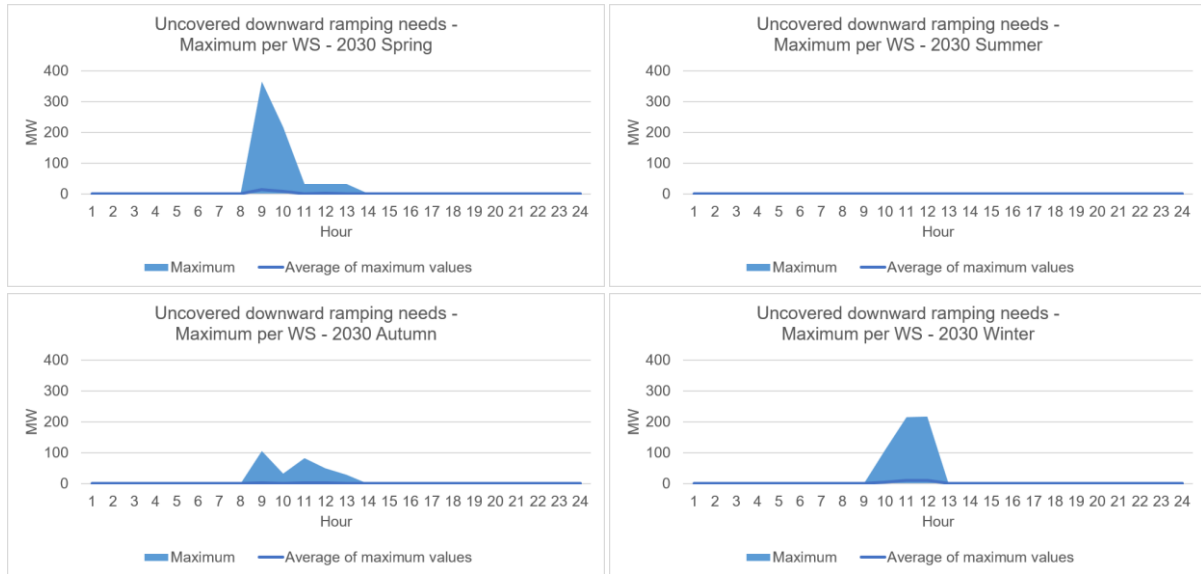


Figure 26: Daily uncovered downward ramping needs by season for the Referent scenario in 2030

In 2035, it can be seen that morning (close to noon) is the most problematic part of the day, while in the afternoon the uncovered needs decrease. However, now there are also issues in summer in addition to spring. In general, the values on these graphs are influenced by the availability of the flexibility resources and this may be the reason for the situations with uncovered ramping needs. For example, if hydropower plants are not operating during a certain summer period, the available downward flexibility may be limited, which can cause the value of uncovered needs to increase.

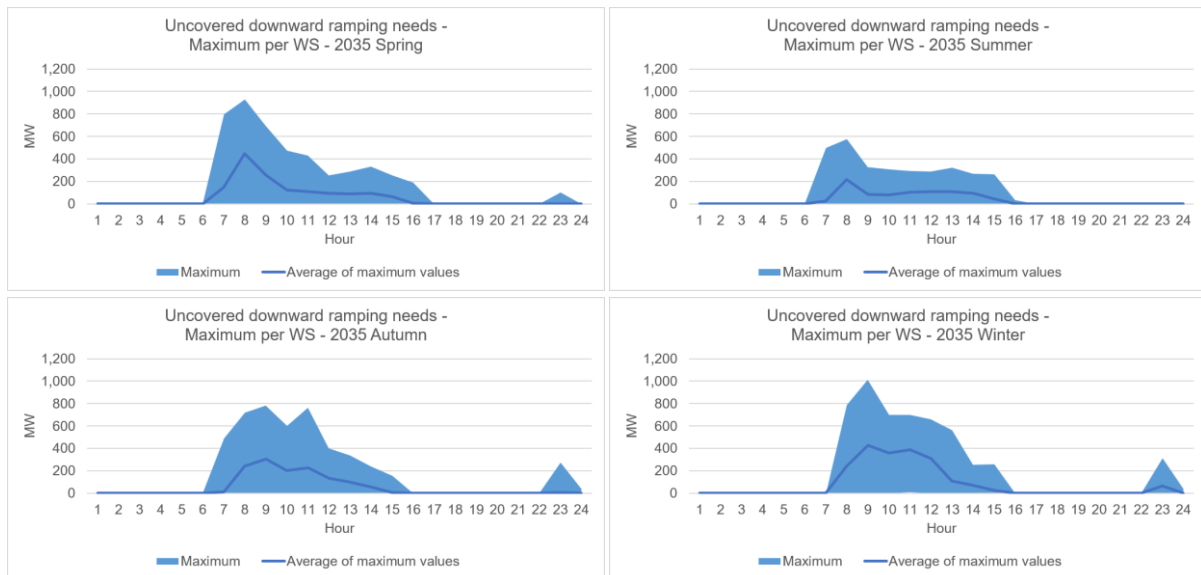


Figure 27: Daily uncovered downward ramping needs by season for the Referent scenario in 2035

Daily upward ramping needs shift towards night-time hours across all seasons. Also, their overall magnitude is generally lower compared to that of downward needs.

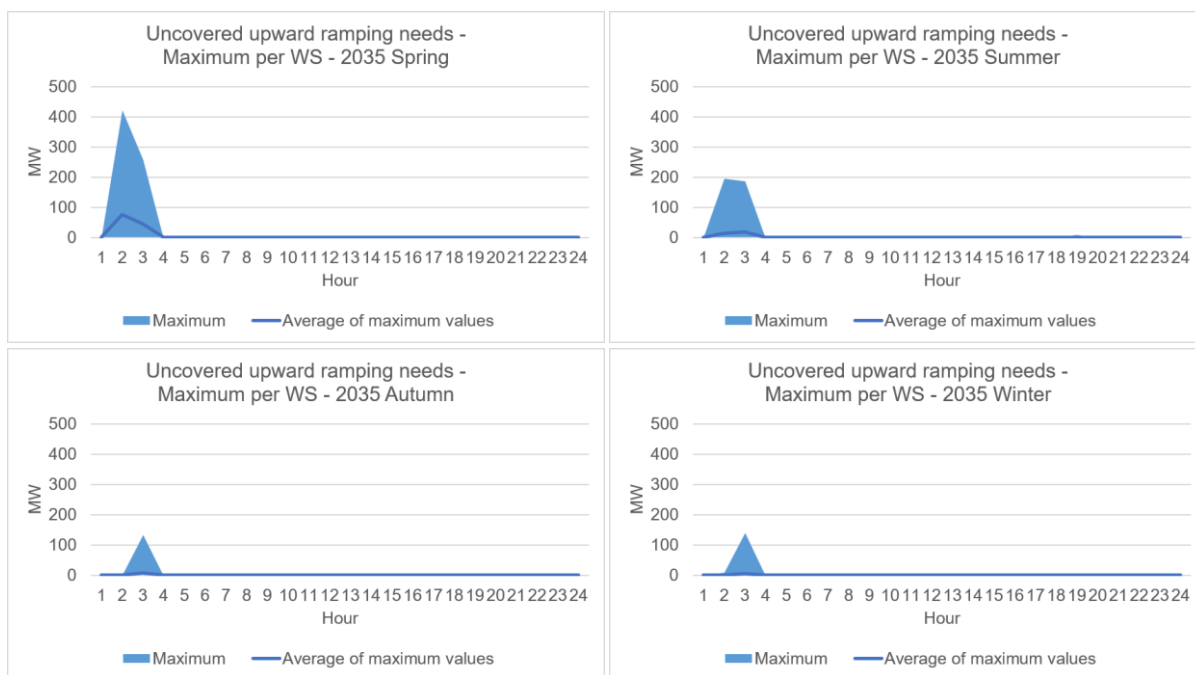


Figure 28: Daily uncovered upward ramping needs by season for the Referent scenario in 2035

In the Alternative scenario 2, uncovered needs already appear during the summer in 2030, and across all seasons in 2035. The patterns remain more or less the same compared to the Referent scenario, only with higher values.

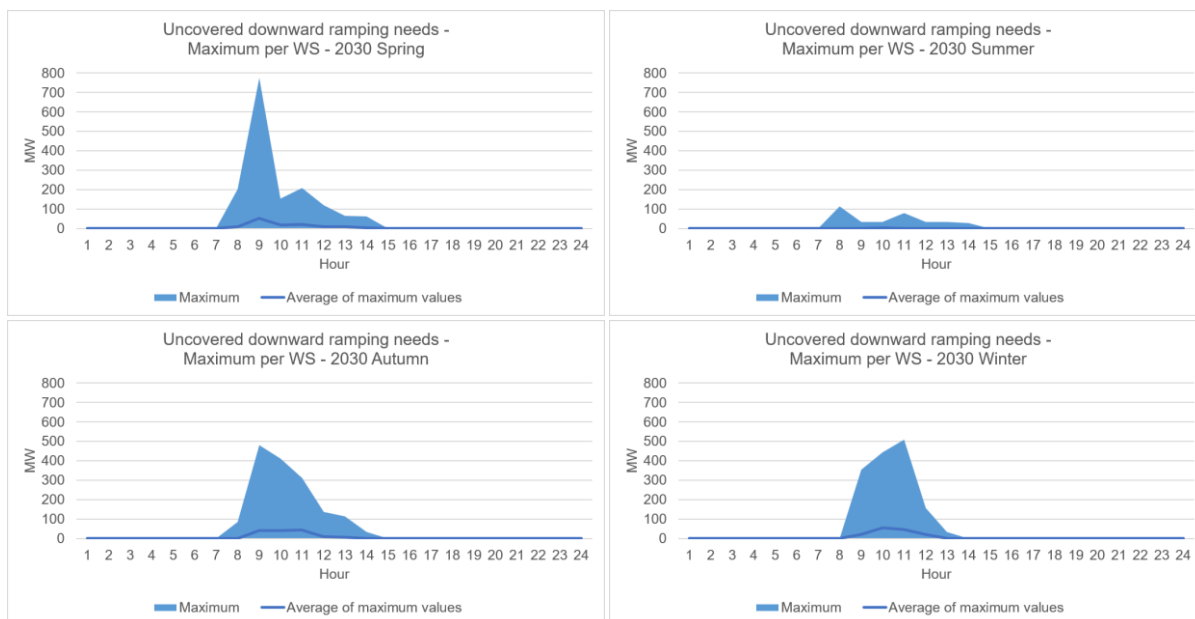


Figure 29: Daily uncovered downward ramping needs by season for Alternative scenario 2 in 2030

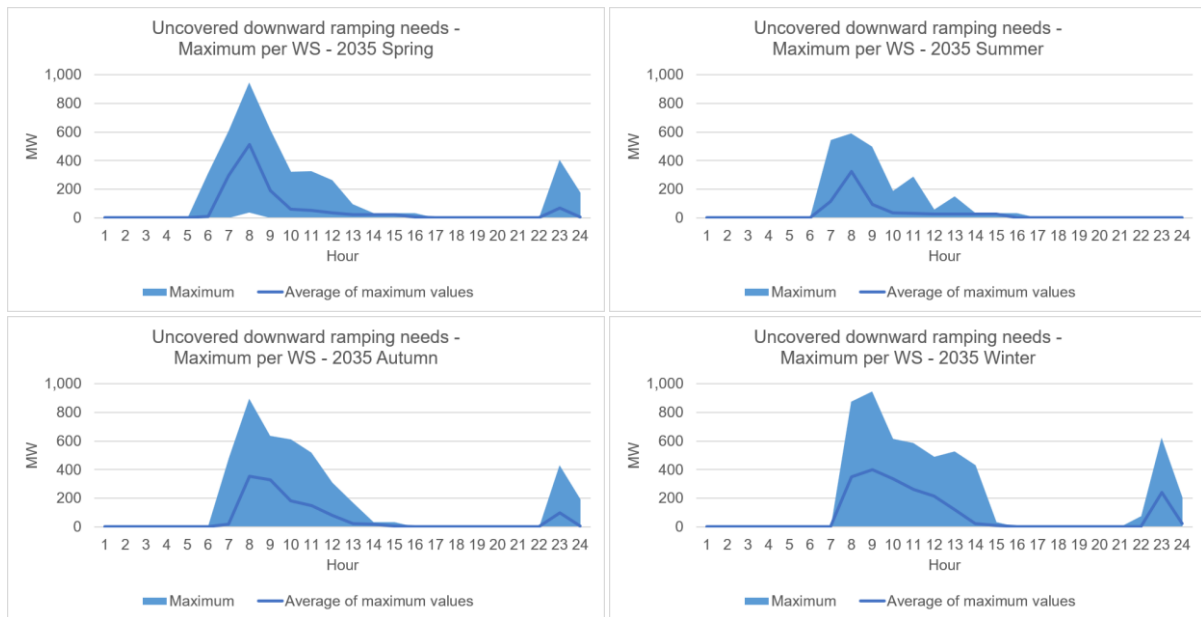


Figure 30: Daily uncovered downward ramping needs by season for Alternative scenario 2 in 2035

In 2035, upward ramping needs are somewhat similar but also show some values during evening hours.

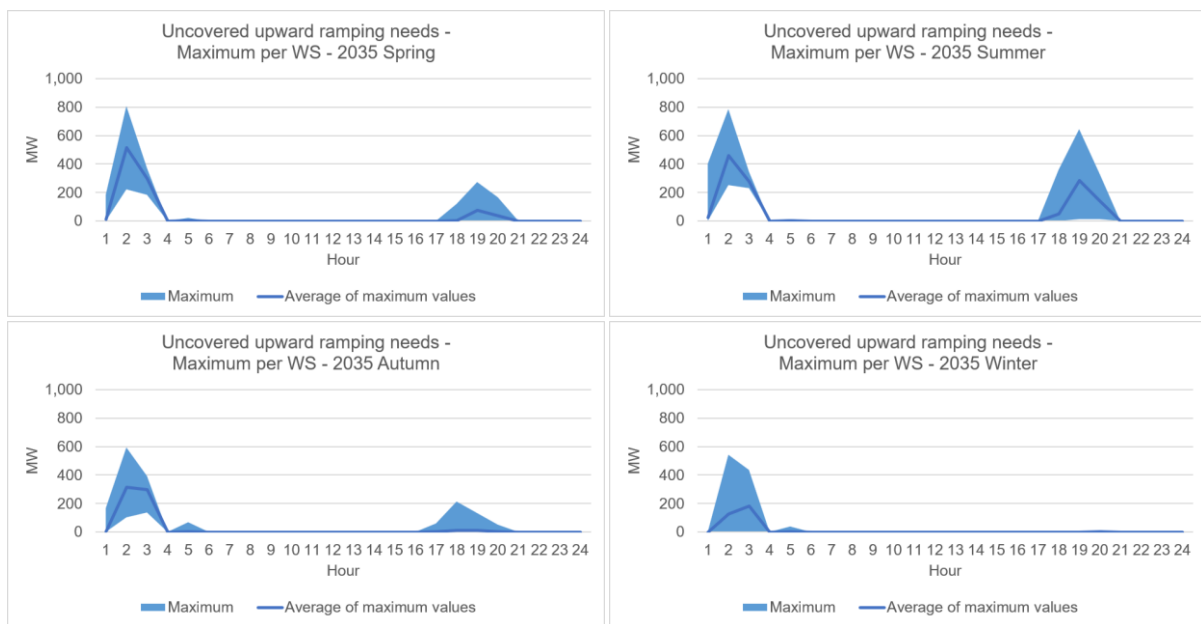


Figure 31: Daily uncovered upward ramping needs by season for Alternative scenario 2 in 2035

4.1.3. Short-term flexibility needs

4.1.3.1. Characterisation of short-term needs

Short-term flexibility needs represent the system's capability to manage unexpected, intra-day variations in residual load. These needs are connected to forecast errors in demand and non-dispatchable generation. For this analysis, forecast errors of 4.19 % for wind and 3.5 % for solar were used to calculate the variations and determine the corresponding short-term flexibility requirements. These criteria are then compared with the available flexibility (presented in Table 31 to Table 34) to determine whether any uncovered short-term flexibility needs exist, all of which is shown in detailed numerical results for short-term flexibility needs across scenarios and target years in Annex 1.

4.1.3.2. Uncovered short-term needs

The dependencies related to the occurrence of uncovered needs are again examined. In 2030, downward uncovered needs occur mainly in the central load range and under conditions of pronounced

RES generation. In 2035, the dependency on higher RES generation becomes even more evident. Looking at upward uncovered needs, they occur under conditions of lower RES generation and higher system load levels.

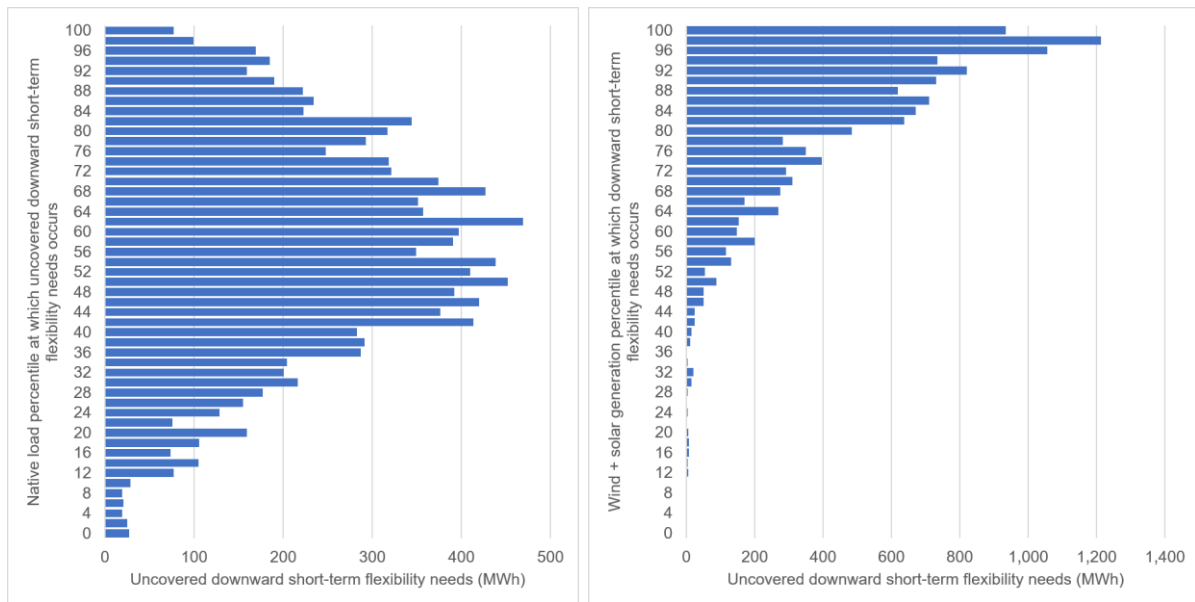


Figure 32: Uncovered downward short-term needs for the Referent scenario in 2030

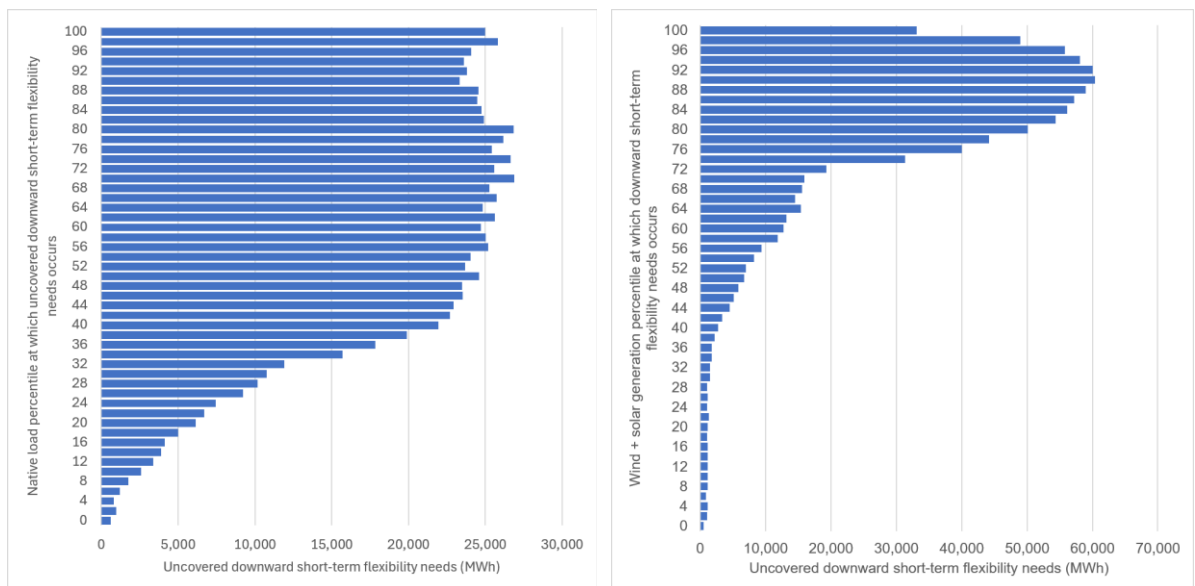


Figure 33: Uncovered downward short-term needs for the Referent scenario in 2035

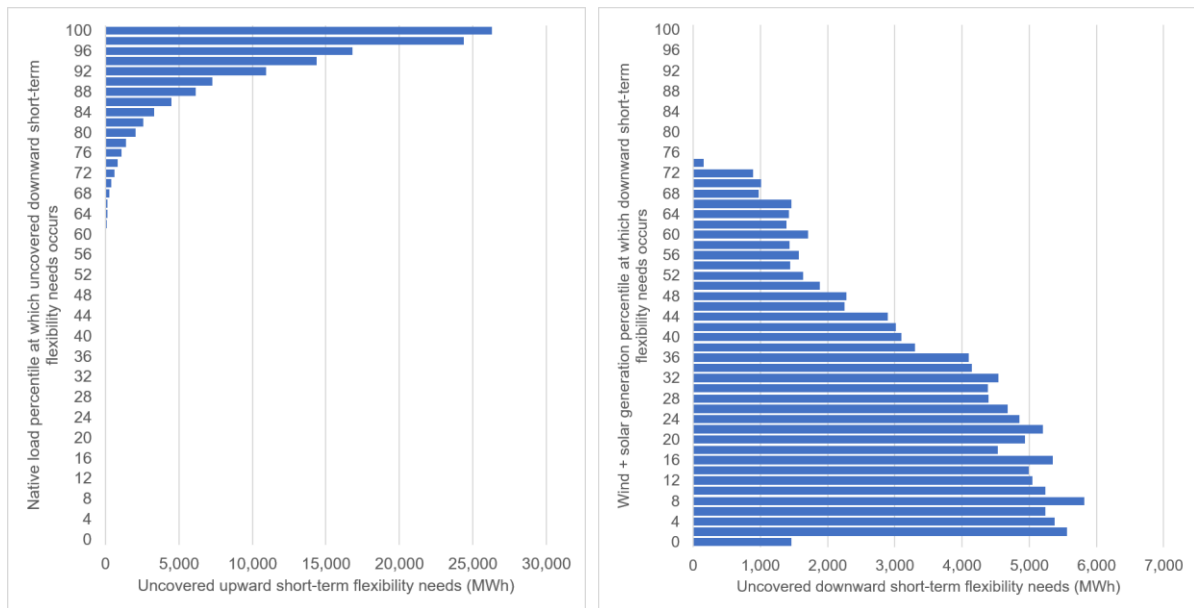


Figure 34: Uncovered upward short-term needs for the Referent scenario in 2035

In Alternative scenario 2, shown in the following three figures, the overall shape of the curves remains the same. However, the magnitude of the uncovered flexibility needs is substantially higher, as can be seen from the different x-axis. In 2030, uncovered downward flexibility needs are approximately ten times higher than in the Referent scenario. In 2035, uncovered downward flexibility needs are around twice as high, while uncovered upward flexibility needs are approximately four times higher.

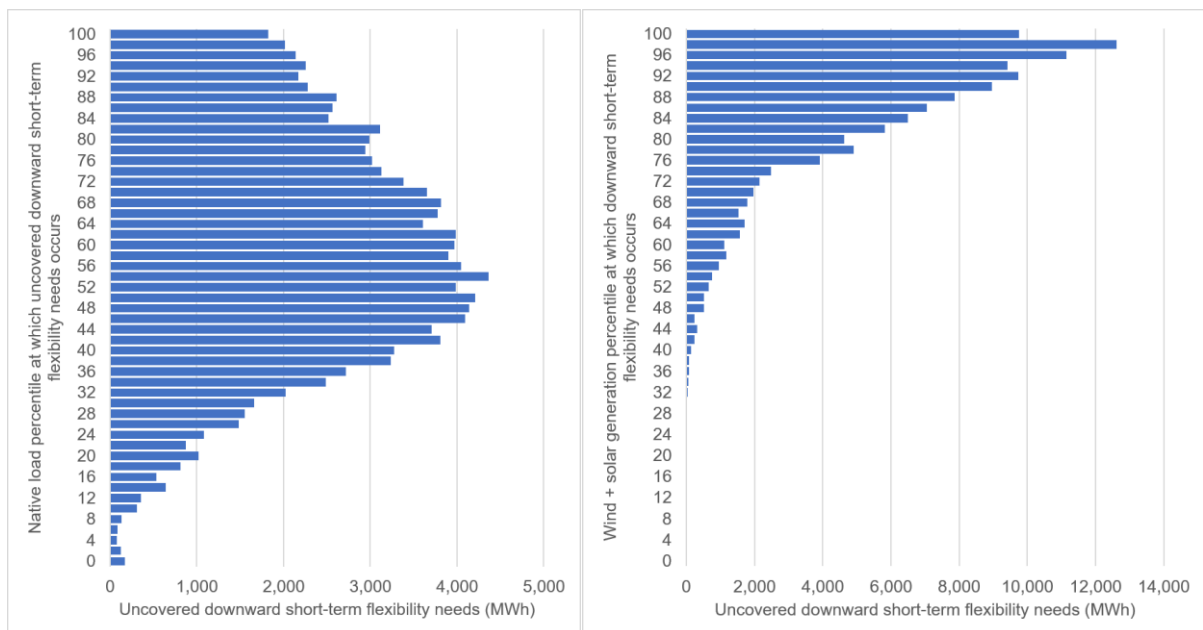


Figure 35: Uncovered downward short-term needs for Alternative scenario 2 in 2030

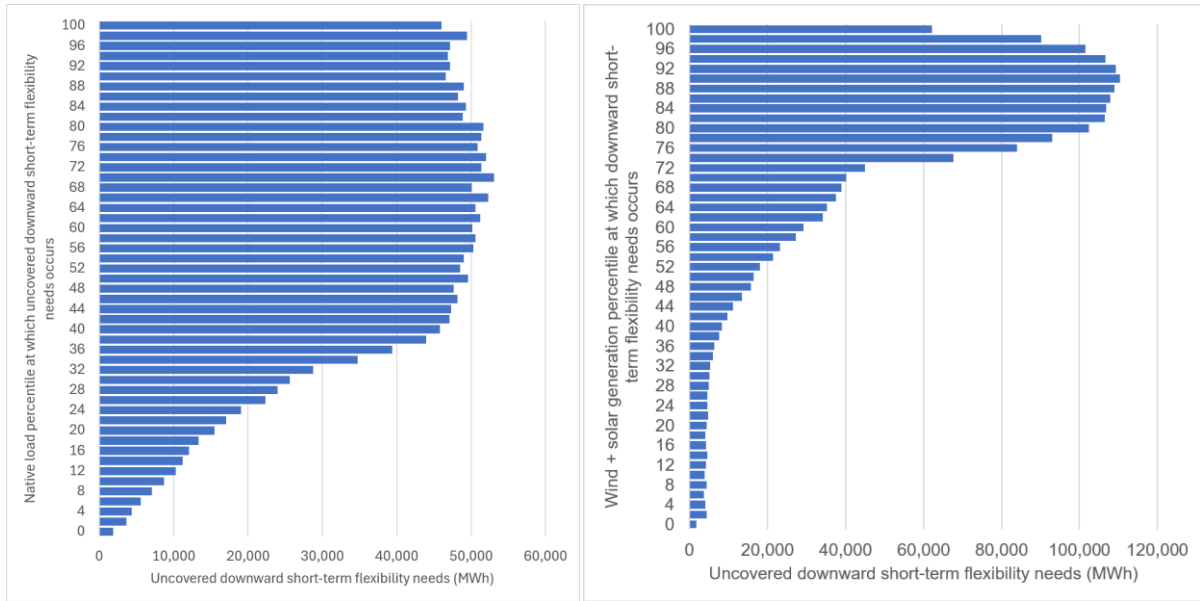


Figure 36: Uncovered downward short-term needs for Alternative scenario 2 in 2035

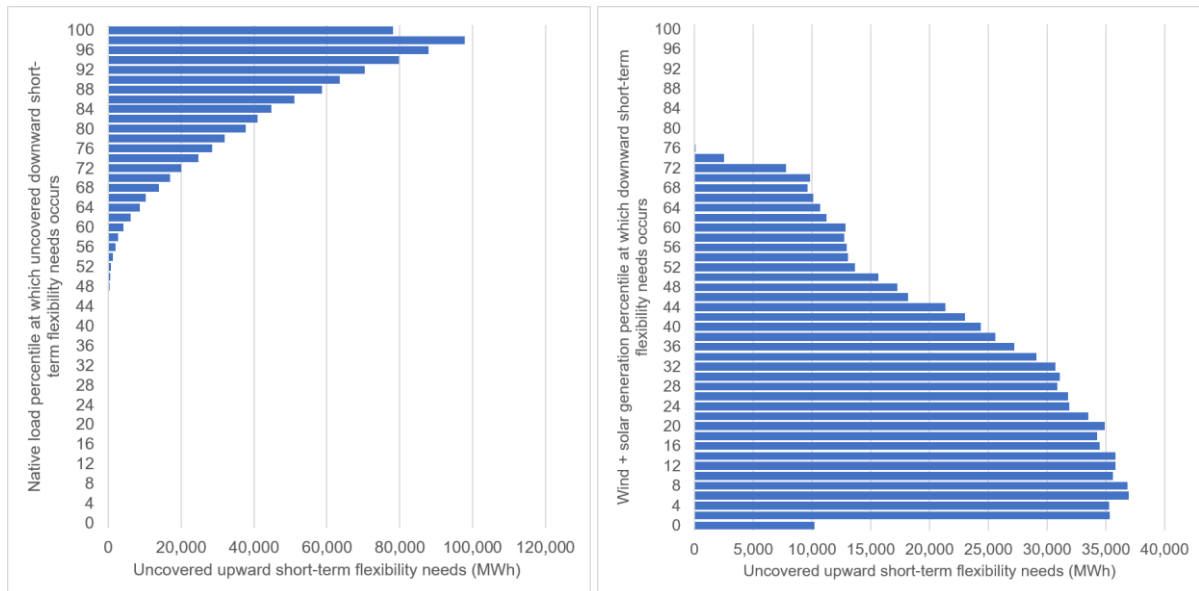


Figure 37: Uncovered upward short-term needs for Alternative scenario 2 in 2035

The daily profiles by season are shown in the following figures. Again, the focus is on maximum values. The most pronounced issue occurs during the middle of the day, when RES generation is at its highest. In 2030, in spring, uncovered downward short-term needs exist in 14h in all 540 MC years. By 2035, this becomes a regular occurrence, and the issue also appears during nighttime hours. In the upward direction, the issue occurs not only during the middle of the day, but also during the evening hours.

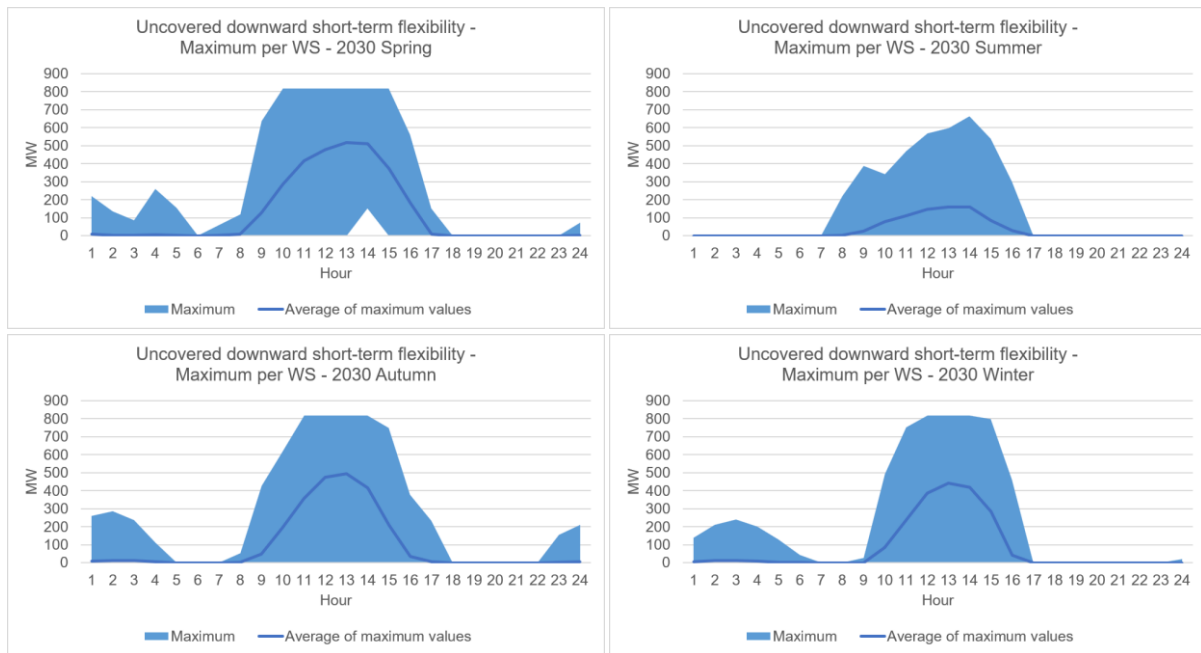


Figure 38: Daily uncovered downward short-term needs for the Referent scenario by season in 2030

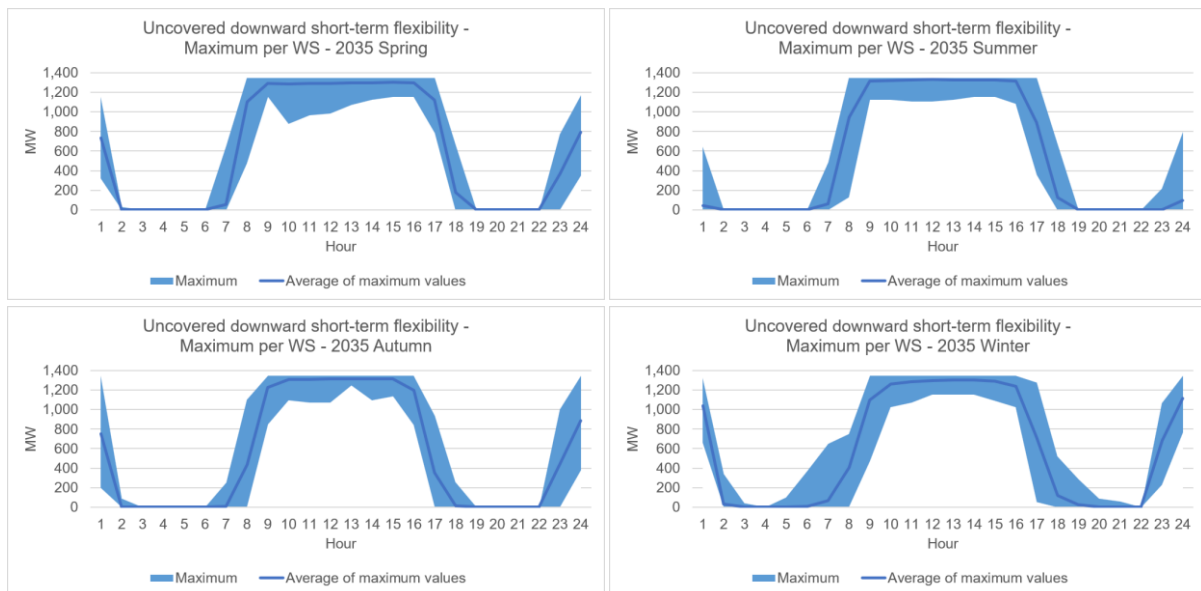


Figure 39: Daily uncovered downward short-term needs for the Referent scenario by season in 2035

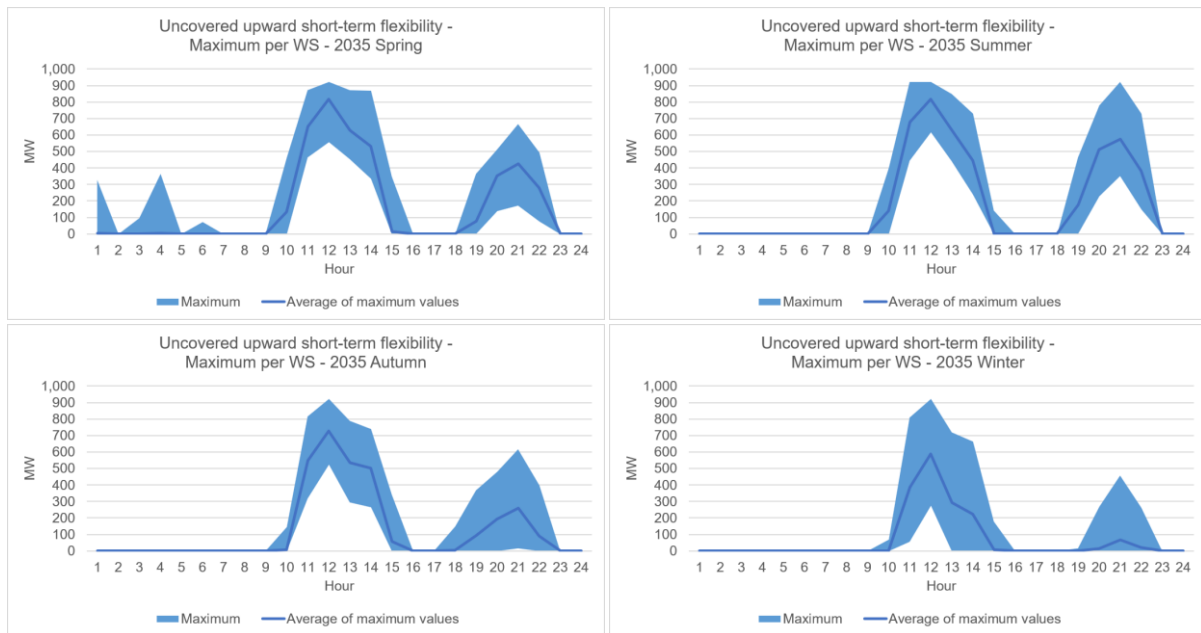


Figure 40: Daily uncovered upward short-term needs for the Referent scenario by season in 2035

Finally, the results for Alternative scenario 2 are presented in the following three figures. The observed patterns are again similar to those in the Referent scenario, with higher overall values. Particularly, the minimums show a noticeable increase in downward uncovered needs in 2030 and upward uncovered needs in 2035.

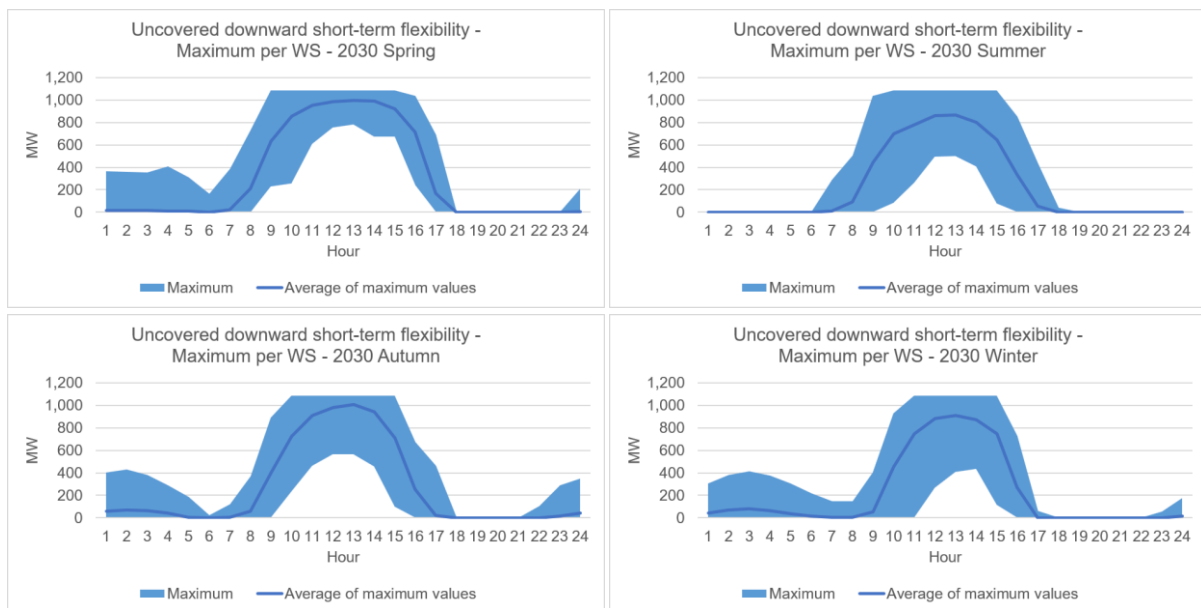


Figure 41: Daily uncovered downward short-term needs for Alternative scenario 2 by season in 2030

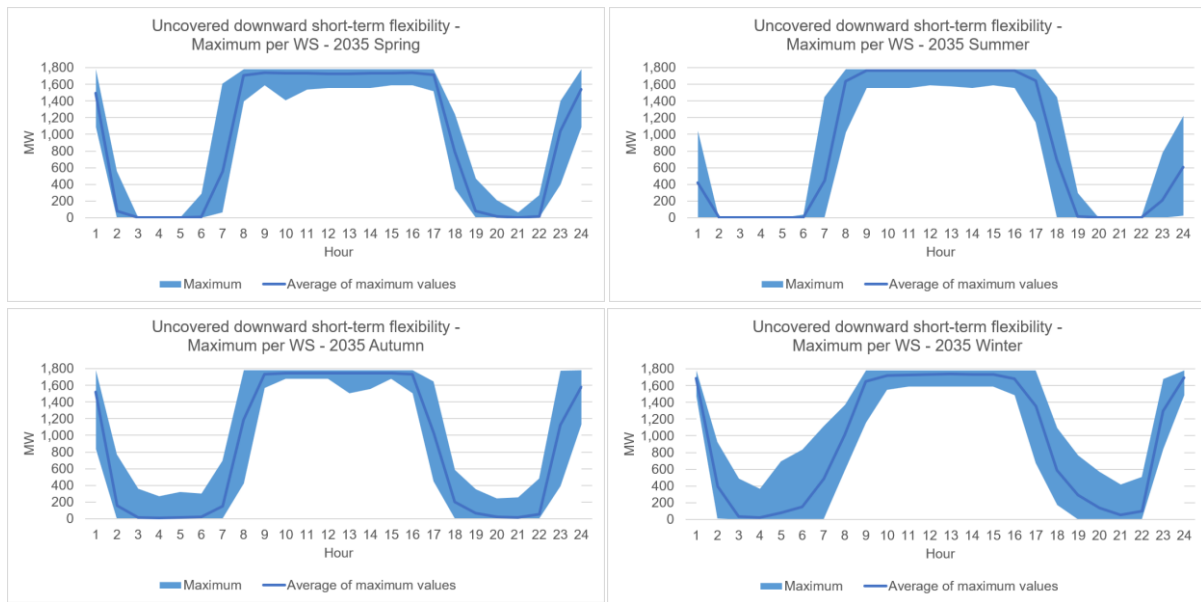


Figure 42: Daily uncovered downward short-term needs for Alternative scenario 2 by season in 2035

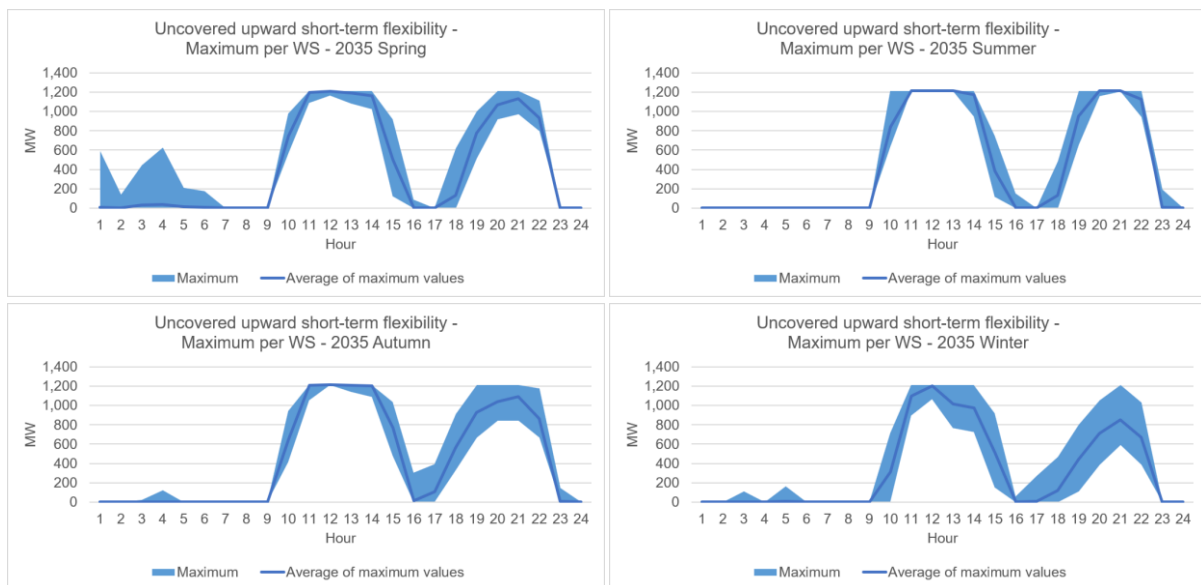


Figure 43: Daily uncovered upward short-term needs for Alternative scenario 2 by season in 2035

4.2. Network flexibility needs

As described in the first chapter, network flexibility needs are classified into two main categories: DSO and TSO network needs. The results for DSO network needs are presented in the following subchapter, while TSO network needs have not been analysed; the reasoning for this is provided in the corresponding subsequent subchapter.

4.2.1. DSO network needs

HEP ODS assessed the distribution network flexibility needs in both the downward and upward directions for the target years 2030 and 2035. The methodology applied to derive these needs is described in Annex 3 of this report.

No upward needs were identified, as the analysis showed that the anticipated constraints can be addressed through operational measures and the planned development of the distribution network. In contrast, downward flexibility needs arise from the expected increase in generation and the potential exceedance of the available transformation capacity under N-1 conditions. These needs are quantified in terms of both capacity and energy and are presented in Table 35 and Table 36 in Annex 1.

4.2.2. TSO network needs

Based on the interpretation of Article 12 of the FNA Methodology, TSO network flexibility needs are considered a voluntary element within the framework. In line with this, TSO network flexibility needs are not analysed as a quantitative component within this year's study. The focus of the current FNA cycle is therefore placed on system-level flexibility needs and DSO network needs, based on available distribution system data, documentation, and planning inputs.

4.3. Synthesis - Guiding criteria application outcomes

Article 16 of the FNA Methodology defines the guiding criteria used to identify cost-effective solutions and alternatives to new flexibility resources. The general approach to guiding criteria is briefly described in Annex 4. Since the analysis in this report shows that the available flexibility resources are sufficient to meet the required RES target, no additional flexibility resources were deemed necessary and have not been analysed.

5. Barriers for flexibility and contribution of digitalisation

The following sections elaborate on the regulatory and market design barriers in Croatia, having in mind associated indicators identified in Section 1 of the Annex to the ACER Recommendation on National Regulatory Authorities (NRA) reporting on barriers for non-fossil flexibility⁶, with a view to assessing their relevance and potential impact on the deployment of non-fossil flexibility solutions.

Lack of proper legal framework for market access to new entrants and small actors

The Republic of Croatia has established the fundamental regulatory framework for the participation of new entrants and small actors such as active customers, aggregators, citizen energy communities, renewable energy communities and energy storage facilities through the Electricity Market Act (Official Gazette, No. 111/21, 83/23, 17/25).⁷ Furthermore, the Renewable Energy Sources and High-Efficiency Cogeneration Act (Official Gazette, No. 138/21, 83/23, 78/25)⁸ provides the regulatory basis for renewable energy communities and self-consumers, while the Energy Act⁹ serves as the overarching framework law governing the energy sector.

Provisions of Directive (EU) 2019/944 on common rules for the internal market for electricity (Electricity Market Directive, EMD)¹⁰ are transposed in primary and secondary legislation. Nevertheless, in line with ACER Recommendation 01/2026, opportunities for further regulatory enhancement can be identified regarding independent aggregation, access to final customer data, market participation of energy storage facilities, and the removal of potential barriers affecting smaller and distributed flexibility resources. Emphasis should be placed on the effective implementation of existing legal provisions through network codes, market rules, balancing market rules and other implementing acts adopted by the relevant operators pursuant to the Electricity Market Act. Priority should be given to the adoption of the Market Rules in line with the Electricity Market Act.

It should be noted that amendments to the Electricity Market Act are currently under adoption to further reform the electricity market in line with the 2024 EU Electricity Market Design Reform Package. In parallel, a new Renewable Energy Sources and High-Efficiency Cogeneration Act is being prepared to transpose the Directive (EU) 2023/2413 (revised Renewable Energy Directive, RED III)¹¹ into the Croatian legal framework. Once adopted, these legislative developments are expected to further strengthen the framework for non-fossil flexibility, facilitate the integration of distributed energy resources, energy storage and demand response, improve market access for new market participants and contribute to the achievement of the objectives identified in the flexibility needs assessment. At the same time, it is essential to align the secondary legislation as quickly as possible to ensure effective implementation of the new rules in practice.

Lack of enablers and incentives to provide flexibility

The legal and regulatory framework recognises the importance of flexibility and already contains enabling provisions and market arrangements. However, the practical deployment of flexibility resources will depend on the continued development of implementing rules, market mechanisms and economic incentives that facilitate the participation of different flexibility providers and ensure effective price signals across relevant market segments.

⁶ ACER Recommendation 01-2026 on NRAs' reporting on barriers to non-fossil flexibility

⁷ Electricity Market Act (Official Gazette, No. 111/21, 83/23, 17/25)

⁸ Renewable Energy Sources and High-Efficiency Cogeneration Act (Official Gazette, No. 138/21, 83/23, 78/25)

⁹ Energy Act (Official Gazette, No. 120/12, 14/14, 102/15, 68/18 - Act on Amendments to the Act on Regulation of Energy Activities)

¹⁰ Directive (EU) 2019/944 of the European Parliament and of the Council of 5 June 2019 on common rules for the internal market for electricity and amending Directive 2012/27/EU

¹¹ Directive (EU) 2023/2413 of the European Parliament and of the Council of 18 October 2023 amending Directive (EU) 2018/2001, Regulation (EU) 2018/1999 and Directive 98/70/EC as regards the promotion of energy from renewable sources, and repealing Council Directive (EU) 2015/652

The key flexibility-enabling provisions of the Electricity Market Act relate to aggregation, active customers, energy storage, demand response, citizen energy communities, dynamic electricity price contracts, smart metering, the procurement of flexibility services by system operators, and non-discriminatory access to electricity and balancing markets. Their implementation is supported by secondary legislation and implementing acts adopted pursuant to the Act, including network codes, market rules, balancing market rules and other provisions that define the detailed conditions for market access, data management, system operation and the provision of flexibility services.¹²

Power system digitalisation, data availability and market-based price signals are expected to play an increasingly important role in the development of flexibility services. Smart metering infrastructure, access to consumption and generation data, and efficient data exchange among HOPS, HEP ODS and market participants represent key enabling elements for the participation of flexibility resources in electricity markets and system operation services.

Dynamic pricing schemes and other market-based mechanisms may further support the participation of consumers, aggregators, energy storage facilities and distributed energy resources in flexibility provision. In addition, tariff methodologies approved by HERA may contribute to the development of efficient price signals that encourage demand response and the utilisation of flexibility resources where these can deliver benefits to the electricity system. Currently, 8% of end-users' electricity consumption is exposed to dynamic prices on the wholesale electricity market (1,3 TWh), and 50% of households do not have a smart meter capable of interval metering. A key priority is to complete the rollout of advanced metering systems by the planned 2029 deadline. The comprehensive rollout of advanced metering systems, coupled with the withdrawal of state intervention in retail electricity pricing, will create the prerequisites for the development of pricing schemes that incentivize flexible electricity consumption.

Due to the expected significant increase in the deployment of advanced metering systems and the enhanced use of a much broader range of metering data, as well as the need to achieve interoperability and harmonization across various HES (Head-End System) platforms and to ensure a high level of security in the storage and exchange of metering data, the need has been identified to introduce the following systems: a Meter Data Management (MDM) system, an Advanced Metering Infrastructure Control and Operation System (AMICOS), and a Key Management System (KMS) for managing security keys and protecting communications with smart meters.

Furthermore, in line with the “Energy Efficiency First” principle and the associated objective of ensuring the optimal development of electricity networks, and also with document “Poticajni okvir za razvoj potrošnje vlastite energije iz obnovljivih izvora” approved in July 2026 by HERA¹³, Croatia is expected to undertake a reform of network tariffs for electricity grid usage.

Restrictive requirements to provide balancing services

Participation in balancing and ancillary services in Croatia is primarily governed by the Electricity Market Act and further elaborated through secondary legislation, including the Rules on Balancing the Electricity System (HOPS, adopted in 2023 and amended in 2026)¹⁴, and other implementing acts adopted by HOPS and approved by HERA. These provisions establish the framework for the participation of market participants and flexibility resources in balancing and ancillary service markets and provide the basis for the integration of aggregators, demand response and energy storage resources.

The participation requirements applicable to balancing and ancillary service providers are defined in the relevant rules and implementing acts including technical, operational and qualification criteria intended to ensure the secure and reliable operation of the electricity system and should be periodically reviewed to ensure that they remain proportionate, transparent and non-discriminatory.

In line with ACER Recommendation 01/2026, continued regulatory development may further facilitate the participation of non-fossil flexibility resources in balancing and ancillary service markets. Attention could be given to ensuring technologically neutral, transparent and non-discriminatory participation

¹² [Regulations - Electricity](#)

¹³ https://www.hera.hr/hr/docs/2026/Odluka_2026-07-16_01.pdf

¹⁴ [Rules on Balancing the Electricity System \(HOPS\)](#)

conditions, while supporting the effective integration of aggregators, energy storage facilities and demand response resources into balancing and ancillary service procurement mechanisms.

As regards the provision of balancing services, only a limited number of barriers have been identified. Nevertheless, consideration should be given to removing the remaining barriers that limit the participation of renewable energy sources (RES) operating under Feed-in Tariff (FiT) and Contracts for Difference (CfD) support schemes, with a view to enabling their effective participation in balancing markets and the provision of balancing services.

Restrictive requirements to provide congestion management

While the regulatory framework provides a basis for the use of flexibility resources in congestion management, certain requirements and market arrangements may limit their effective participation.

Although the Electricity Market Act provides for the adoption of Rules on Congestion Management in the Distribution System, such Rules have not yet been adopted. Meanwhile, Rules on Congestion Management for the Transmission System Operator's (TSO) grid are in force but are not being applied.

In line with ACER Recommendation 01/2026, further development of the regulatory framework could facilitate the use of local flexibility services, flexible connection agreements, market-based congestion management mechanisms and flexibility procurement by system operators. Particular attention may be given to the development of distribution-level flexibility markets and to strengthening coordination between HOPS and HEP ODS in order to support the efficient utilisation of flexibility resources for congestion management and network planning purposes. However, distribution network users already provide balancing services to HOPS, which is practical confirmation of the feasibility of the existing regulations in Croatia.

A key concern is the operator's strong reliance on forthcoming flexible connection agreements as a means of addressing flexibility challenges. While these agreements are a recognized and regulated measure for facilitating grid integration, they may reduce incentives for the development of local flexibility services. To address this issue, HERA plans to establish a regulatory framework aligned with the provisions of the Electricity Market Design (EMD).

Complex, lengthy and discriminatory administrative requirements

While the legal and regulatory framework establishes the procedures for grid connection and market participation, administrative procedures remain an important factor affecting the timely integration of renewable energy projects, flexibility resources and new market participants.

Grid connection procedures and market participation requirements are primarily governed by the Electricity Market Act, and the Renewable Energy Sources and High-Efficiency Cogeneration Act. Their implementation is further elaborated through governmental decree governing grid connection approvals, connection conditions and connection timeline, transmission and distribution network codes, grid connection rules, the general conditions for network use and electricity supply, electricity market organisation rules (adopted by HROTE and approved by HERA) as well as the relevant HERA methodologies governing connection charges and network tariffs.¹⁵

As the transposition of Directive (EU) 2023/2413 (RED III) is ongoing, further simplification and acceleration of permitting and administrative procedures for renewable energy projects and related infrastructure can be expected.

Despite recent regulatory developments, administrative and procedural challenges may continue to affect the timely market entry and grid connection of flexibility providers, energy storage facilities, active customers and energy communities.

Consistent with ACER Recommendation 01/2026 on addressing complex, lengthy and potentially discriminatory administrative requirements, further refinement of the regulatory framework, together with effective cooperation among the competent ministries, HERA, system operators, the market operator and other relevant stakeholders, may contribute to simpler and more transparent permitting and grid connection procedures, improved visibility of available network capacity and more effective market access for new flexibility providers and distributed energy resources.

¹⁵ Regulation electricity

There is a need to establish an effective queue management framework for grid connection procedures. In view of the disproportionate procedural requirements, the role and purpose of the energy approval (Croatian: *energetsko odobrenje*) warrant reconsideration.

Lack of regulatory incentives to system operators to consider non-wire alternatives

The regulatory framework for network development and system operation is established through the Energy Act, the Electricity Market Act, HERA's regulatory methodologies, and the network development plans prepared by system operators (HOPS, HEP ODS) approved by HERA^{16,17}. These instruments provide the basis for network planning and investment decisions, considering the objectives of the updated National Energy and Climate Plan¹⁸ and other strategic energy policy documents. Major capital investments should be evaluated against alternative non-wire solutions by means of a cost-benefit analysis.

While the existing framework enables the use of flexibility resources, the systematic consideration of non-wire alternatives in network planning could be further strengthened. In practice, conventional network reinforcement and expansion remain the primary solutions, while flexibility-based options, such as energy storage, demand response, flexible connection agreements and local flexibility services, are still at an early stage of integration into network planning processes.

In line with ACER Recommendation 01/2026, further development of network planning and regulatory methodologies could support the application of the Flexibility First principle and a more systematic assessment of non-wire alternatives where these are appropriate from a technical and economic perspective. Continued cooperation between the competent ministry, HERA and system operators may support the further evolution of the regulatory and planning framework, considering network development needs, security of supply and the growing role of flexibility resources in the electricity system.

¹⁶ [HOPS network development plans](#)

¹⁷ [HEP ODS network development plans](#)

¹⁸ [Croatia - Final updated NECP 2021-2030 \(submitted in 2025\)](#)

6. Conclusions

6.1. Key findings

The most important indicator of flexibility assessment is the achievement of the defined RES target of 76.7%. As shown in Table 22, this target is achieved in the Referent scenario in both 2030 and 2035. In Alternative scenario 2, however, the target is not achieved in 2035. This outcome is primarily driven by the assumptions underlying the scenario, notably higher electricity demand combined with insufficient generation capacities, resulting in increased system stress. In addition, the high share of solar PV generation contributes to pronounced variability, the effects of which are reflected across all assessed categories of system flexibility needs.

Ramping needs are limited in 2030, with no uncovered upward ramping requirements identified and only minor downward ramping deficits. By 2035, uncovered ramping needs emerge in both directions, with downward uncovered ramping needs reaching approximately 16.4 GWh in both scenarios, while Alternative scenario 2 also shows a larger upward gap. This indicates an increasing requirement for flexibility resources capable of responding to rapid ramping variations.

The assessment also identifies short-term flexibility needs. In 2030, uncovered downward short-term flexibility needs amount to 17.9 GWh in the Referent scenario and a much higher 181.3 GWh in Alternative scenario 2. By 2035, the uncovered needs become bidirectional and significantly larger, with downward needs reaching around 1.4 TWh in the Referent scenario and 2.8 TWh in Alternative scenario 2.

Regarding the network needs, TSO needs were not quantified, as their assessment is seen as voluntary, while the DSO needs were provided by the DSO.

Overall, the results indicate that downward flexibility represents the main pressure point. The increasing deployment of solar PV generation leads to more pronounced periods of surplus generation and steeper ramps, as identified in uncovered flexibility needs. Nevertheless, the RES target is achieved in most of the analysed cases, indicating that the currently identified flexibility resources are generally sufficient to support the required level of RES integration.

6.1.1. Summary of additional flexibility needs

Table 22 summarises the identified uncovered flexibility needs and achieved RES targets after fine-tuning system with DSO network needs.

Table 22: Summary of ramping needs, short-term needs and DSO network needs

Type	Indicator	Referent scenario 2030	Referent scenario 2035	Alternative scenario 2 2030	Alternative scenario 2 2035
System needs	Uncovered downward ramping needs	0.06 GWh	16.50 GWh	0.51 GWh	16.44 GWh
	Uncovered downward short-term needs	17.89 GWh	1,338.36 GWh	181.26 GWh	2,772.56 GWh
Network needs	Downward DSO network flexibility needs	0.49 GWh	2.99 GWh	0.49 GWh	2.99 GWh
Achieved RES target after fine-tuning		78.9%	77.9%	79.2%	70.8%

This leads to one of the key conclusions of this FNA analysis: despite the presence of curtailment and uncovered needs, the **RES target is achieved in the Referent scenario, meaning that no additional flexibility resources are required.**

6.2. Next steps

Maintaining a cost-efficient and reliable transition towards a highly renewable electricity system requires continued monitoring of evolving flexibility needs. The experience gained during the preparation of this assessment highlighted the importance of ensuring consistency across the various planning documents and datasets used at both national and European levels. As flexibility needs, generation portfolios, network developments and RES targets are closely interconnected, the results of the FNA should be considered by both HOPS and HEP ODS when preparing future network development plans. In this way, assumptions used in network planning will be reflected in future FNAs, which ensures consistency across different planning processes. In general, better alignment of key planning documents, including the NECP, TYNDP, DNDP, NRAA and ERAA datasets, would improve methodological consistency, reduce discrepancies between studies, and improve future assessments.

Based on the results of this assessment, no immediate additional measures are required, as the RES target is achieved in all analysed cases except for Alternative scenario 2 in 2035, which represents a challenging sensitivity scenario. However, the results demonstrate that increasing RES penetration, particularly solar PV deployment, leads to growing flexibility requirements. In combination with higher demand levels, this places additional stress on the system, resulting in higher uncovered flexibility needs and a reduced ability to efficiently integrate renewable generation. This is why the future system planning should carefully consider the combined evolution of demand, RES deployment and flexibility resources to ensure secure system operation and maintain the capability to achieve national RES targets.

Looking ahead, the next edition of the FNA report may provide further clarity on TSO network needs. Continued improvements in data availability, methodological guidance, and national coordination between the TSO and DSO are expected to support more comprehensive analyses in future FNA cycles. Consolidation of additional inputs will also be crucial for aligning and harmonising data across stakeholders. Overall, this was the first cycle of the FNA for all Member States, and drawing on experiences from other TSOs and sharing best practices across Europe will likely refine the methodology application in subsequent editions, which will bring to consistent and comparable assessments.

7. References

- [1] Agency for the Cooperation of Energy Regulators (ACER). (2026) *Template for the Flexibility Needs Assessment reports*
- [2] Agency for the Cooperation of Energy Regulators (ACER). (2025). *Flexibility Needs Assessment (FNA) Methodology*. Ljubljana: ACER. Available at: <https://www.acer.europa.eu/sites/default/files/documents/Publications/ACER-flexibility-needs-assessment-methodology-2025.pdf>
- [3] Synergrid/ELIA. *Flexibility Needs Assessment (FNA) Workshop*, 13th February 2026. Available at: https://www.elia.be/-/media/project/elia/elia-site/users-group/ug/workshop/2026/20260213/09022026_workshop_synergridtemplate_send.pdf
- [4] Agency for the Cooperation of Energy Regulators (ACER). *Flexibility Needs Assessment Methodology - Frequently Asked Questions*. 12th June 2026. Ljubljana: ACER.

ANNEX 1 – Deep dive on flexibility needs results

System needs – RES integration results tables

The four tables in this subchapter present the RES integration results for the Referent and Alternative scenario 2 in 2030 and 2035.

Starting with the RES target indicator, it is compared with the RES target defined in the NECP (76.7%). The calculated RES indicator includes curtailed energy from renewable energy sources resulting from RES generation curtailment time series from the economic dispatch results and uncovered system flexibility needs, i.e. ramping and short-term flexibility needs in line with FNA Methodology (Article 8(3)). As noted in chapter 4.1.1, and shown in the tables of this subchapter, only one scenario does not meet the RES target, the Alternative scenario 2 in 2035. This is due to previously mentioned reasons, namely higher demand requirements and a higher curtailment of variable RES generation.

In general, RES generation curtailment occurs during a relatively limited number of hours over the year, as shown by the indicator “probability of RES generation curtailment being greater than zero”. In 2030, this value ranges between 4% and 5.5% in both scenarios, meaning that RES generation is curtailed during only a small number of hours of the year. In 2035, however, the probability increases, reaching 15.5% in the Referent and 21% in Alternative scenario 2.

RES curtailment is further reported through average, maximum, and minimum values for the hourly, daily, and seasonal¹⁹ timeframes. All values should be interpreted in the context of 8,760 hours simulated over 540 MC years. Zeros in the minimum-value rows indicate that there was at least one hour, day or month where no curtailment occurred.

The tables then present the residual load values, starting with the average annual energy total per MC year. As with curtailment, average, minimum and maximum values are shown for hourly, daily and seasonal timeframes.

The next set of parameters are hourly, daily, and seasonal indicators, showcasing variation ratios across different aggregation levels:

- a) The hourly indicator is calculated as the sum of the absolute variations between hourly residual load and its daily average.
- b) The daily indicator is calculated as the sum of the absolute variations between the daily residual load and the monthly average.
- c) The seasonal indicator is calculated as the sum of absolute variations between the monthly residual load and the annual average.

In essence, these indicators show the extent to which residual load varies at the hourly/daily/seasonal levels compared with the corresponding daily/monthly/annual averages. Across all scenarios and target years, the hourly indicator is the highest, while the seasonal indicator is the lowest. This means that residual load fluctuates most significantly from hour to hour, whereas variations are much smaller when aggregated over longer periods, i.e. days and months. In other words, short-term variability is more pronounced than long-term variability.

Finally, the 99.1 and 0.1 percentiles of residual load were calculated for both scenarios, and the values are again higher in 2035 than in 2030.

When comparing the target years within the Referent scenario, almost all indicators show higher values in 2035. In Alternative scenario 2, the values are even higher than in the Referent scenario, particularly in 2035, due to not only the greater RES integration but also significantly higher demand.

Detailed values are shown in Table 23 to Table 26.

¹⁹ Seasonal timeframe refers to monthly data.

Table 23: System needs - RES integration – Referent scenario in 2030

Type	Flexibility need	Indicator	Subindicator		Value	Unit	Target year	Scenario
System needs	RES integration (as per FNA Methodology, Article 8)	Required RES target	-		76.7	%	2030	Referent Scenario
		Achieved RES target	-		78.9	%		
		RES generation curtailment	RES generation curtailment Average		280.7	GWh		
			Probability of RES generation curtailment greater than zero		3.98	%		
			Hourly timeframe	Average	32	MW		
				Maximum	4,647			
				Minimum	0			
			Daily timeframe	Average	771	MWh/day		
				Maximum	32,465			
				Minimum	0			
			Seasonal timeframe	Average	23,386	MWh/month		
				Maximum	214,760			
				Minimum	0			
		Residual load	Residual load Average		7,958	GWh		
			Hourly timeframe	Average	911	MW		

Type	Flexibility need	Indicator	Subindicator		Value	Unit	Target year	Scenario		
				Maximum	2,859					
				Minimum	-1,892					
			Daily timeframe	Average	21,862	MWh/day				
				Maximum	48,842					
				Minimum	-12,836					
			Seasonal timeframe	Average	663,169	MWh/month				
				Maximum	1,039,520					
				Minimum	282,736					
			An hourly indicator						4,534	GWh
			A daily indicator						2,248	GWh
			Seasonal indicator						1,462	GWh
			Relevant percentile of residual load, 99.9%						2,558	MW
			Relevant percentile of residual load, 0.1%						-1,405	MW

Table 24: System needs - RES integration – Referent scenario in 2035

Type	Flexibility need	Indicator	Subindicator		Value	Unit	Target year	Scenario
System needs	RES integration (as per FNA Methodology, Article 8)	Required RES target	-		76.7	%	2035	Referent Scenario
		Achieved RES target	-		77.9	%		
		RES generation curtailment	RES generation curtailment Average		2,034	GWh		
			Probability of RES generation curtailment greater than zero		15.5	%		
			Hourly timeframe	Average	233	MW		
				Maximum	7,100			
				Minimum	0			
			Daily timeframe	Average	5,587	MWh/day		
				Maximum	55,563			
				Minimum	0			
			Seasonal timeframe	Average	169,472	MWh/month		
				Maximum	594,385			
				Minimum	0			
		Residual load	Residual load Average		7,051	GWh		
			Hourly timeframe	Average	807	MW		

Type	Flexibility need	Indicator	Subindicator		Value	Unit	Target year	Scenario
				Maximum	3,924			
				Minimum	-2,288			
			Daily timeframe	Average	19,372	MWh/day		
				Maximum	47,959			
				Minimum	-13,591			
			Seasonal timeframe	Average	587,609	MWh/month		
				Maximum	785,152			
				Minimum	407,520			
			An hourly indicator		11,042	GWh		
			A daily indicator		2,563	GWh		
			Seasonal indicator		1,139	GWh		
			Relevant percentile of residual load, 99.9%		3,721	MW		
			Relevant percentile of residual load, 0.1%		-2,228	MW		

Table 25: System needs – RES integration – Alternative scenario 2 in 2030

Type	Flexibility need	Indicator	Subindicator		Value	Unit	Target year	Scenario
System needs	RES integration (as per FNA Methodology, Article 8)	Required RES target	-		76.7	%	2030	Alternative Scenario 2
		Achieved RES target	-		79.2	%		
		RES generation curtailment	RES generation curtailment Average		500.9	GWh		
			Probability of RES generation curtailment greater than zero		5.5	%		
			Hourly timeframe	Average	57	MW		
				Maximum	5,392			
				Minimum	0			
			Daily timeframe	Average	1,372	MWh/day		
				Maximum	36,463			
				Minimum	0			
			Seasonal timeframe	Average	41,738	MWh/month		
				Maximum	305,621			
				Minimum	0			
		Residual load	Residual load Average		8,093.50	GWh		
			Hourly timeframe	Average	926	MW		

Type	Flexibility need	Indicator	Subindicator		Value	Unit	Target year	Scenario
				Maximum	3,148			
				Minimum	-2,070			
			Daily timeframe	Average	22,235	MWh/day		
				Maximum	53,398			
				Minimum	-14,544			
			Seasonal timeframe	Average	674,458	MWh/month		
				Maximum	1,119,637			
				Minimum	260,307			
			An hourly indicator		5,820	GWh		
			A daily indicator		2,370	GWh		
			Seasonal indicator		1,632	GWh		
			Relevant percentile of residual load, 99.9%		2,819	MW		
			Relevant percentile of residual load, 0.1%		-1,730	MW		

Table 26: System needs - RES integration – Alternative scenario 2 in 2035

Type	Flexibility need	Indicator	Subindicator		Value	Unit	Target year	Scenario
System needs	RES integration (as per FNA Methodology, Article 8)	Required RES target	-		76.7	%	2035	Alternative Scenario 2
		Achieved RES target	-		70.8	%		
		RES generation curtailment	RES generation curtailment Average		3,379	GWh		
			Probability of RES generation curtailment greater than zero		21	%		
			Hourly timeframe	Average	387	MW		
				Maximum	8,904			
				Minimum	0			
			Daily timeframe	Average	9,258	MWh/day		
				Maximum	71,999			
				Minimum	0			
			Seasonal timeframe	Average	281,591	MWh/month		
				Maximum	809,989			
				Minimum	1,391			
		Residual load	Residual load Average		8,185	GWh		
			Hourly timeframe	Average	937	MW		

Type	Flexibility need	Indicator	Subindicator		Value	Unit	Target year	Scenario
				Maximum	4,895			
				Minimum	2,191			
			Daily timeframe	Average	22,425	MWh/day		
				Maximum	64,715			
				Minimum	-29,076			
			Seasonal timeframe	Average	111,803	MWh/month		
				Maximum	484,513			
				Minimum	6			
			An hourly indicator		12,728	GWh		
			A daily indicator		3,033	GWh		
			Seasonal indicator		1,342	GWh		
			Relevant percentile of residual load, 99.9%		4,388	MW		
			Relevant percentile of residual load, 0.1%		-2,164	MW		

System needs – ramping needs results tables

Ramping needs presented in Table 27 to Table 30 were calculated based on the residual load and its hourly variation, i.e. hour-to-hour changes in residual load were calculated to determine the residual load ramping needs. Average values were calculated separately for negative and positive ramping needs, while minimum and maximum values were determined based on all 540 MC years and 8,760 hours. Additionally, the relevant percentiles were calculated for both upward and downward ramping needs.

Based on the dispatch results of the adequacy analysis, the available flexibility was calculated. This available flexibility refers to flexibility provided by hydropower storage plants and interconnections. It is important to note that all available flexibility calculations were performed without including secondary reserves, which had already been deducted from the available capacities of generation units in the adequacy simulations. This means that, in addition to the calculated available flexibility from HPPs and interconnections, additional flexibility remains available through capacities allocated for frequency regulation. For available flexibility, average, maximum, and minimum hourly values were calculated for both upward and downward flexibility across 540 MC years.

As mentioned above, the last two indicators were derived from the residual load ramping needs and the available flexibility, whose difference defined the uncovered ramping needs shown in the tables. In 2030, both scenarios show only downward uncovered needs, whereas in 2035 upward uncovered needs also appear, although their magnitude remains much smaller than the downward uncovered needs. Residual load ramping needs increase in 2035 and this increase corresponds to generally higher residual load values already observed in the previous chapter. Two averages were considered for downward needs. The first was calculated by identifying the maximum values for each of the 540 MC years and then averaging these maximum values. The second was calculated over the full matrix of uncovered needs events, covering all 540 MC years and 8,760 hours. Finally, the relevant percentiles of uncovered needs were calculated, and the energy equivalent was calculated as the average of the sums of uncovered needs for each of the 540 MC years.

Table 27: System needs - ramping needs – Referent scenario in 2030

Type	Flexibility need	Indicator	Subindicator	Value	Unit	Target year	Scenario	Comments (i.e. up/downward, covered/uncovered, etc.)
System needs	Ramping needs (as per FNA Methodology, Article 9)	Residual load ramping need	Average	-184 / 242	MW	2030	Referent Scenario	
			Maximum	3,496	MW			
			Minimum	-3,000	MW			
			Relevant percentile of upward ramp, 99.9%	1,016	MW			
			Relevant percentile of downward ramp, 0.1%	-986	MW			
		Available flexibility	Average upward flexibility	2,901	MW			
			Maximum upward flexibility	5,146	MW			
			Minimum upward flexibility	940	MW			
			Average downward flexibility	2,244	MW			
			Maximum downward flexibility	4,206	MW			
			Minimum downward flexibility	0	MW			
		Upward uncovered ramping needs	Upward uncovered ramping needs - average	0	MW			Average of maximum uncovered upward ramping needs
			Upward uncovered ramping needs - average	0	MW			Average in uncovered needs events
			Relevant percentile of uncovered upward need	0	%			

Type	Flexibility need	Indicator	Subindicator	Value	Unit	Target year	Scenario	Comments (i.e. up/downward, covered/uncovered, etc.)
		Downward uncovered ramping needs	Equivalent total uncovered energy - upward	0	MWh			
			Downward uncovered ramping needs - average	45	MW			Average of maximum uncovered downward ramping needs
			Downward uncovered ramping needs - average	68	MW			Average in uncovered needs events
			Relevant percentile of uncovered downward need	0.0045	%			
			Equivalent total uncovered energy – downward	60.5	MWh			

Table 28: System needs - ramping needs – Referent scenario in 2035

Type	Flexibility need	Indicator	Subindicator	Value	Unit	Target year	Scenario	Comments (i.e. up/downward, covered/uncovered, etc.)
System needs	Ramping needs (as per FNA Methodology, Article 9)	Residual load ramping need	Average	-566 / 573	MW	2035	Referent Scenario	
			Maximum	3,732	MW			
			Minimum	-3,637	MW			
			Relevant percentile of upward ramp, 99.9%	1,939	MW			
			Relevant percentile of downward ramp, 0.1%	-2,238	MW			
		Available flexibility	Average upward flexibility	2,675	MW			
			Maximum upward flexibility	5,096	MW			
			Minimum upward flexibility	0	MW			
			Average downward flexibility	2,420	MW			
			Maximum downward flexibility	5,096	MW			
			Minimum downward flexibility	0	MW			
		Upward uncovered ramping needs	Upward uncovered ramping needs - average	106	MW			Average of maximum uncovered upward ramping needs
			Upward uncovered ramping needs - average	91	MW			Average in uncovered needs events
			Relevant percentile of uncovered upward need	0.0115	%			

Type	Flexibility need	Indicator	Subindicator	Value	Unit	Target year	Scenario	Comments (i.e. up/downward, covered/uncovered, etc.)
			Equivalent total uncovered energy - upward	260.9	MWh			
		Downward uncovered ramping needs	Downward uncovered ramping needs - average	628	MW			Average of maximum uncovered downward ramping needs
			Downward uncovered ramping needs - average	122	MW			Average in uncovered needs events
			Relevant percentile of uncovered downward need	0.5	%			
			Equivalent total uncovered energy – downward	16,496	MWh			

Table 29: System needs - ramping needs – Alternative scenario 2 in 2030

Type	Flexibility need	Indicator	Subindicator	Value	Unit	Target year	Scenario	Comments (i.e. up/downward, covered/uncovered, etc.)
System needs	Ramping needs (as per FNA Methodology, Article 9)	Residual load ramping need	Average	-226 / 299	MW	2030	Alternative Scenario 2	
			Maximum	3,739	MW			
			Minimum	-2,934	MW			
			Relevant percentile of upward ramp, 99.9%	1,269	MW			
			Relevant percentile of downward ramp, 0.1%	-1,211	MW			
		Available flexibility	Average upward flexibility	2,852	MW			
			Maximum upward flexibility	5,146	MW			
			Minimum upward flexibility	740	MW			
			Average downward flexibility	2,293	MW			
			Maximum downward flexibility	4,406	MW			
			Minimum downward flexibility	0	MW			
		Upward uncovered ramping needs	Upward uncovered ramping needs - average	0	MW			Average of maximum uncovered upward ramping needs
			Upward uncovered ramping needs - average	0	MW			Average in uncovered needs events
			Relevant percentile of uncovered upward need	0	%			

Type	Flexibility need	Indicator	Subindicator	Value	Unit	Target year	Scenario	Comments (i.e. up/downward, covered/uncovered, etc.)
			Equivalent total uncovered energy - upward	0	MWh			
		Downward uncovered ramping needs	Downward uncovered ramping needs - average	190	MW			Average of maximum uncovered downward ramping needs
			Downward uncovered ramping needs - average	78	MW			Average in uncovered needs events
			Relevant percentile of uncovered downward need	0.022	%			
			Equivalent total uncovered energy – downward	505.1	MWh			

Table 30: System needs - ramping needs – Alternative scenario 2 in 2035

Type	Flexibility need	Indicator	Subindicator	Value	Unit	Target year	Scenario	Comments (i.e. up/downward, covered/uncovered, etc.)
System needs	Ramping needs (as per FNA Methodology, Article 9)	Residual load ramping need	Average	-663 / 661	MW	2035	Alternative Scenario 2	
			Maximum	3,790	MW			
			Minimum	-3,604	MW			
			Relevant percentile of upward ramp, 99.9%	2,298	MW			
			Relevant percentile of downward ramp, 0.1%	-2,620	MW			
		Available flexibility	Average upward flexibility	2,531	MW			
			Maximum upward flexibility	5,096	MW			
			Minimum upward flexibility	0	MW			
			Average downward flexibility	2,565	MW			
			Maximum downward flexibility	5,096	MW			
			Minimum downward flexibility	0	MW			
		Upward uncovered ramping needs	Upward uncovered ramping needs - average	556	MW			Average of max uncovered upward ramping needs
			Upward uncovered ramping needs - average	154	MW			Average in uncovered needs events
			Relevant percentile of uncovered upward need	0.9	%			

Type	Flexibility need	Indicator	Subindicator	Value	Unit	Target year	Scenario	Comments (i.e. up/downward, covered/uncovered, etc.)
		Downward uncovered ramping needs	Equivalent total uncovered energy - upward	26,567	MWh			
			Downward uncovered ramping needs - average	600	MW			Average of max uncovered downward ramping needs
			Downward uncovered ramping needs - average	105	MW			Average in uncovered needs events
			Relevant percentile of uncovered downward need	0.58	%			
			Equivalent total uncovered energy – downward	16,441	MWh			

System needs – short-term results tables

For short-term needs, the defined requirement shown in the first two rows of the table is checked for each hour. Two outcomes are possible. If the value of the uncovered short-term need is zero, this means that all available flexibility values are higher than the defined criterion and that there are no uncovered needs. The second possibility is that if an uncovered need exists, the table reports the value of the criterion, indicating that there is at least one hour in which the defined criterion is not met. The tables then further present the average capacity of those uncovered needs (excluding zero values), as well as the corresponding energy and the number of hours associated with these uncovered needs.

Similarly to the previous results, upward flexibility needs occur only in 2035 in both scenarios, with Alternative scenario 2 showing higher, i.e. stricter criteria.

Table 31: System needs - short-term needs – Referent scenario in 2030

Type	Flexibility needs	Indicator	Subindicator		Value	Unit	Target year	Scenario	Comments (i.e. up/downward, covered/uncovered, etc.)
System needs	Short-term needs (as per FNA Methodology, Article 10)	Upward residual load forecast errors	Relevant percentile of the forecast error = 99.9%	Very fast (5-15 min) timeframe	547	MW	2030	Referent Scenario	
		Downward residual load forecast errors	Relevant percentile of the forecast error = 0.1%	Very fast (5-15 min) timeframe	818	MW			
		Uncovered short-term flexibility needs	Upward uncovered short-term needs	Very fast (5-15 min) timeframe	0	MW			No uncovered upward short-term flexibility in any hour
			Downward uncovered short-term needs	Very fast (5-15 min) timeframe	818	MW			
			Average capacity per uncovered upward short-term flexibility need event		0	MW			
			Average capacity per uncovered downward short-term flexibility need event		215.7	MW			
			Total expected energy from uncovered upward short-term flexibility needs events		0	MWh			
			Total expected energy from uncovered downward short-term flexibility needs events		17,885	MWh			
			Number of hours with uncovered upward short-term flexibility need event		0	-			
			Number of hours with uncovered downward short-term flexibility need event		81	-			

Table 32: System needs - short-term needs – Referent scenario in 2035

Type	Flexibility needs	Indicator	Subindicator		Value	Unit	Target year	Scenario	Comments (i.e. up/downward, covered/uncovered, etc.)
System needs	Short-term needs (as per FNA Methodology, Article 10)	Upward residual load forecast errors	Relevant percentile of the forecast error = 99.9%	Very fast (5-15 min) timeframe	921	MW	2035	Referent Scenario	
		Downward residual load forecast errors	Relevant percentile of the forecast error = 0.1%	Very fast (5-15 min) timeframe	1,348	MW			
		Uncovered short-term flexibility needs	Upward uncovered short-term needs	Very fast (5-15 min) timeframe	921	MW			
			Downward uncovered short-term needs	Very fast (5-15 min) timeframe	1,348	MW			
			Average capacity per uncovered upward short-term flexibility need event			247	MW		
			Average capacity per uncovered downward short-term flexibility need event			675	MW		
			Total expected energy from uncovered upward short-term flexibility needs events			181,519	MWh		
			Total expected energy from uncovered downward short-term flexibility needs events			1,338,362	MWh		
			Number of hours with uncovered upward short-term flexibility need event			730	-		
			Number of hours with uncovered downward short-term flexibility need event			1,980	-		

Table 33: System needs - short-term needs – Alternative scenario 2 in 2030

Type	Flexibility needs	Indicator	Subindicator		Value	Unit	Target year	Scenario	Comments (i.e. up/downward, covered/uncovered, etc.)
System needs	Short-term needs (as per FNA Methodology, Article 10)	Upward residual load forecast errors	Relevant percentile of the forecast error = 99.9%	Very fast (5-15 min) timeframe	748	MW	2030	Alternative Scenario 2	
		Downward residual load forecast errors	Relevant percentile of the forecast error = 0.1%	Very fast (5-15 min) timeframe	1,085	MW			
		Uncovered short-term flexibility needs	Upward uncovered short-term needs	Very fast (5-15 min) timeframe	0	MW			No uncovered upward short-term flexibility in any hour
			Downward uncovered short-term needs	Very fast (5-15 min) timeframe	1,085	MW			
			Average capacity per uncovered upward short-term flexibility need event		0	MW			
			Average capacity per uncovered downward short-term flexibility need event		331	MW			
			Total expected energy from uncovered upward short-term flexibility needs events		0	MWh			
			Total expected energy from uncovered downward short-term flexibility needs events		181,264	MWh			
			Number of hours with uncovered upward short-term flexibility need event		0	-			
			Number of hours with uncovered downward short-term flexibility need event		544	-			

Table 34: System needs - short-term needs – Alternative scenario 2 in 2035

Type	Flexibility needs	Indicator	Subindicator		Value	Unit	Target year	Scenario	Comments (i.e. up/downward, covered/uncovered, etc.)
System needs	Short-term needs (as per FNA Methodology, Article 10)	Upward residual load forecast errors	Relevant percentile of the forecast error = 99.9%	Very fast (5-15 min) timeframe	1,215	MW	2035	Alternative Scenario 2	
		Downward residual load forecast errors	Relevant percentile of the forecast error = 0.1%	Very fast (5-15 min) timeframe	1,781	MW			
		Uncovered short-term flexibility needs	Upward uncovered short-term needs	Very fast (5-15 min) timeframe	1,215	MW			
			Downward uncovered short-term needs	Very fast (5-15 min) timeframe	1,781	MW			
			Average capacity per uncovered upward short-term flexibility need event		589	MW			
			Average capacity per uncovered downward short-term flexibility need event		949	MW			
			Total expected energy from uncovered upward short-term flexibility needs events		1,309,224	MWh			
			Total expected energy from uncovered downward short-term flexibility needs events		2,772,564	MWh			
			Number of hours with uncovered upward short-term flexibility need event		2,223	-			
			Number of hours with uncovered downward short-term flexibility need event		2,918	-			

Network needs – DSO network needs results tables

As described in the chapter 4.2.2, TSO network flexibility needs were not assessed within the scope of this analysis. Therefore, the following tables present only the DSO network flexibility needs identified for the target years 2030 and 2035.

In accordance with the FNA Methodology, the results are reported separately for upward and downward flexibility needs and are expressed through two indicators: the sum of local maximum flexibility capacity needs (MW) and the total expected flexibility activation energy (MWh). While upward DSO flexibility needs were not identified, downward flexibility needs reflect the flexibility that may be required due to expected increase in generation and potential N-1 transformation capacity exceedances.

Table 35: DSO Network needs for the Referent and Alternative scenario 2 in 2030

Type	Flexibility needs	Indicator	Subindicator	Value	Unit	Target year	Comments (i.e., covered/uncovered, etc.)
Network needs	DSO network needs (as per FNA Methodology, Article 11)	Upward DSO network flexibility needs	Sum of local max. values of power	0	MW	2030	
			Total energy	0	MWh		
		Downward DSO network flexibility needs	Sum of local max. values of power (MW)	199.34	MW		
			Total energy	486.75	MWh		

Table 36: DSO Network needs for the Referent and Alternative scenario 2 in 2035

Type	Flexibility needs	Indicator	Subindicator	Value	Unit	Target year	Comments (i.e., covered/uncovered, etc.)
Network needs	DSO network needs (as per FNA Methodology, Article 11)	Upward DSO network flexibility needs	Sum of local max. values of power	0	MW	2035	
			Total energy	0	MWh		
		Downward DSO network flexibility needs	Sum of local max. values of power (MW)	579.08	MW		
			Total energy	2,992.53	MWh		

ANNEX 2 - Approach to fine-tuning

The fine-tuning process, as defined in Article 14 of the FNA Methodology, is designed to adjust system-level flexibility needs in consideration of network-level flexibility inputs. It is illustrated in the figure below.

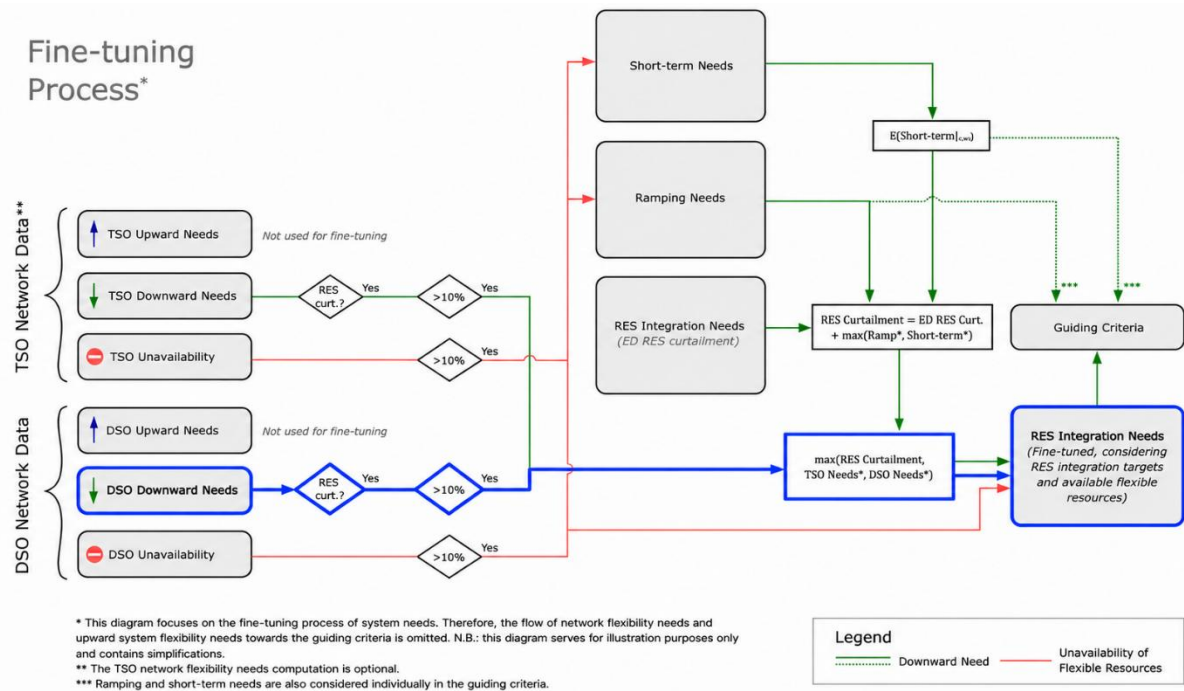


Figure 44: Fine-tuning process

In this analysis, certain elements of the fine-tuning workflow were not applicable. Network needs at the TSO level were not analysed, as described in the chapter 4.2.2, and therefore no fine-tuning could be applied for these. Additionally, the red lines in the schematic, representing unavailability of flexible resources due to grid prequalification and temporary limits, were not considered, in accordance with Article 13(2)(ii) of the FNA Methodology, which allows system operators to disregard such effects on the availability of flexible resources. Consequently, the only network-level input considered for fine-tuning was the DSO network needs, as provided by the DSO. This corresponds to the workflow highlighted in blue in the figure above. Only cases where the annual RES curtailment associated with DSO needs exceeded 10% of the average RES curtailment would normally be considered for adjustment according to the FNA Methodology. However, since data from the DSO was available, their influence is presented in this subchapter.

We now encounter an ambiguity in the FNA Methodology. The schematic in Figure 44 (Annex 3 in the FNA Methodology) suggests taking the maximum of system-level needs and DSO network needs. However, while Article 8(3) explicitly requires using the maximum of RES curtailment resulting from ramping and short-term system needs to avoid double-counting, Article 11 (which pertains to DSO needs), does not provide guidance on combining DSO needs with system-level requirements. Furthermore, it is not realistic for DSO network needs to reach magnitudes comparable to system-level requirements. In light of this, the approach adopted in this analysis was conservative, i.e. to sum the DSO network needs with the maximum of the system-level ramping and short-term needs. The resulting fine-tuned achieved RES targets, calculated according to this approach, are presented in the table below.

As can be seen, the RES target is achieved in both target years for the Referent scenario.

Table 37: Fine-tuning RES target for the Referent scenario

Target year	Parameter	Unit	Total
2030	RES generation (A)	MWh	14,781,008
	RES curtailment (B)	MWh	280,668
	RES curtailment addition – due to uncovered ramping needs	MWh	61
	RES curtailment addition – due to uncovered short-term needs	MWh	17,885
	Maximum RES curtailment addition (C)	MWh	17,885
	RES curtailment addition – downward DSO network needs (D)	MWh	486.75
	RES generation minus curtailment (E = A – B – C – D)	MWh	14,481,968
	Load (F)	MWh	18,360,809
	Achieved RES target (E / F)	%	78.9%
2035	RES generation (A)	MWh	18,818,429
	RES curtailment (B)	MWh	2,033,585
	RES curtailment addition – due to uncovered ramping needs	MWh	16,496
	RES curtailment addition – due to uncovered short-term needs	MWh	1,338,362
	Maximum RES curtailment addition (C)	MWh	1,338,362
	RES curtailment addition – downward DSO network needs (D)		2,992.53
	RES generation minus curtailment (E = A – B – C – D)	MWh	15,443,489
	Load (F)	MWh	19,815,487
	Achieved RES target (E / F)	%	77.9%

For Alternative scenario 2, the target is achieved in 2030 but not in 2035. This is primarily due to a significant increase in consumption that is not accompanied by a corresponding increase in generation capacity, as was shown in the previous sections.

Table 38: Fine-tuning RES target for the Alternative scenario 2

Target year	Parameter	Unit	Total
2030	RES generation (A)	MWh	16,545,122
	RES curtailment (B)	MWh	500,859
	<i>RES curtailment addition – due to uncovered ramping needs</i>	<i>MWh</i>	<i>505</i>
	<i>RES curtailment addition – due to uncovered short-term needs</i>	<i>MWh</i>	<i>181,264</i>
	Maximum RES curtailment addition (C)	MWh	181,264
	RES curtailment addition – downward DSO network needs (D)		486.75
	RES generation minus curtailment (E = A – B – C – D)	MWh	15,862,526
	Load (F)	MWh	20,040,193
	Achieved RES target (E / F)	%	79.2%
2035	RES generation (A)	MWh	22,470,070
	RES curtailment (B)	MWh	3,379,094
	<i>RES curtailment addition – due to uncovered ramping needs</i>	<i>MWh</i>	<i>16,441</i>
	<i>RES curtailment addition – due to uncovered short-term needs</i>	<i>MWh</i>	<i>2,772,564</i>
	Maximum RES curtailment addition (C)	MWh	2,772,564
	RES curtailment addition – downward DSO network needs (D)		2,992.53
	RES generation minus curtailment (E = A – B – C – D)	MWh	16,315,419
	Load (F)	MWh	23,049,631
	Achieved RES target (E / F)	%	70.8%

The table below illustrates the effect of including DSO network needs in the fine-tuning of the RES target. In 2030, the difference between the total RES target before and after fine-tuning can be seen

only at the third decimal place, while in 2035 the difference appears at the second decimal place. This indicates that the contribution of the DSO network needs to the overall fine-tuned RES target is negligible.

Table 39: Summary of fine-tuned RES targets per scenario and target year

Target year and scenario	Total before fine-tuning	Total after fine-tuning
2030 Referent scenario	78.877%	78.874%
2035 Referent scenario	77.952%	77.936%
2030 Alternative scenario 2	79.156%	79.154%
2035 Alternative scenario 2	70.797%	70.784%

ANNEX 3 - Approach to DSO data treatment

Future flexibility needs in the HEP DSO distribution electricity network for the target years 2030 and 2035 were assessed by the DSO. The analysis has been prepared in accordance with the FNA Methodology.

At the distribution level, the distribution system operator assessed flexibility needs that can contribute to preventing or alleviating congestion and voltage constraints, either independently or in combination with network development and reinforcement measures.

The FNA Methodology identifies distribution network development plans as the primary data source for assessing distribution network flexibility needs. Therefore, the current HEP DSO Ten-Year DNNDP²⁰ was used as the main basis for this analysis. Additionally, data from the current table of generation connection capacities, historical data on the connection of generation facilities, and measured 15-minute load and generation time series were used to assess future generation integration.

The target years 2030 and 2035 were selected in accordance with the FNA Methodology. The year 2030 represents the common target year for the first cycle of flexibility needs assessments at the European Union level and is aligned with the target year of the current NECP. The year 2035 was agreed with other stakeholders (HOPS and HERA), to ensure alignment with other parts of this analysis, i.e. system needs.

The assessment was conducted at the level of individual high-voltage (HV)/medium-voltage (MV) transformer substations. The results were subsequently aggregated and presented separately for both activation directions and both target years, as presented in the tables of Annex 1. Flexibility needs are expressed in terms of power (MW) and energy (MWh), in the format prescribed by the FNA Methodology.

Downward DSO network flexibility needs

The assessment of downward flexibility needs is based on identifying periods during which the export of electricity from the distribution network to the upstream network could exceed the available transformation capacity at the HV/MV substation.

The year 2025 was used as the base year, for which 15-minute time series of the actual load of HV/MV substations were available. Generation time series were determined by aggregating the exported power at all billing metering points of producers connected within the respective network area. By combining the net load time series and the measured generation, the time series of total consumption supplied from each HV/MV substation was reconstructed.

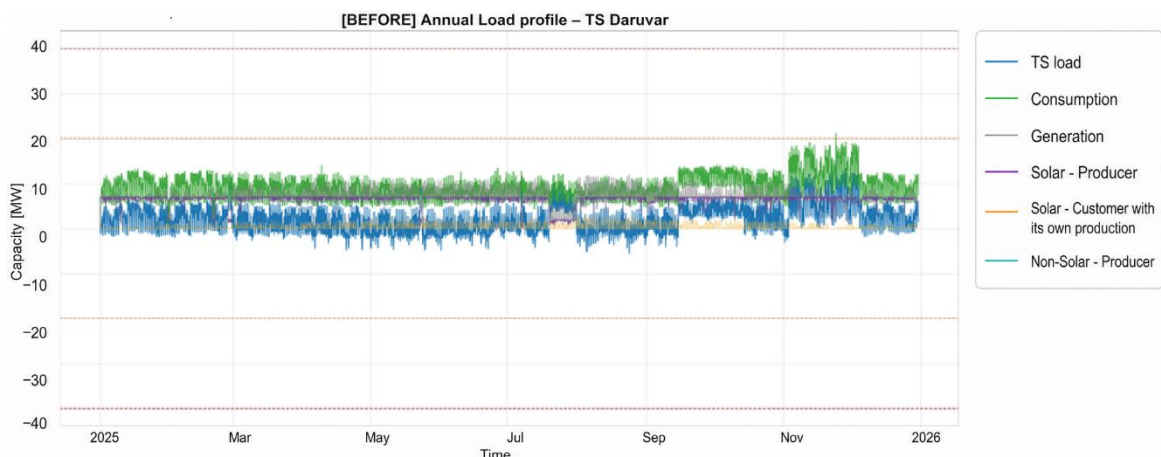


Figure 45: Example of consumption, generation, and load time series of an HV/MV substation in 2025

²⁰ HEP ODS (July 2025), Ten-Year (2025–2034) Distribution Network Development Plan of HEP ODS with Detailed Elaboration for the Initial Three-Year and One-Year Periods, Table 2-4, p. 35

The assessment of the installed capacity of new generation facilities for 2030 and 2035 is based on historical trends on their connection at individual HV/MV substations. At the level of the entire distribution network, a cumulative trend of **approximately 35 MW per month** of additional installed generation capacity is assumed, as identified in the current HEP ODS Ten-Year DNDP.

For the purposes of the projection, it was assumed that all future growth of generation during the analysed period would come **exclusively from solar power plants**.

For each HV/MV substation, a time-varying solar irradiation factor was determined. The factor was calculated as the ratio between the total exported power measured at billing metering points and their total installed capacity, for each 15-minute interval of the base year. This analysis includes only billing metering points of network users classified as producers (self-generation facilities were not considered).

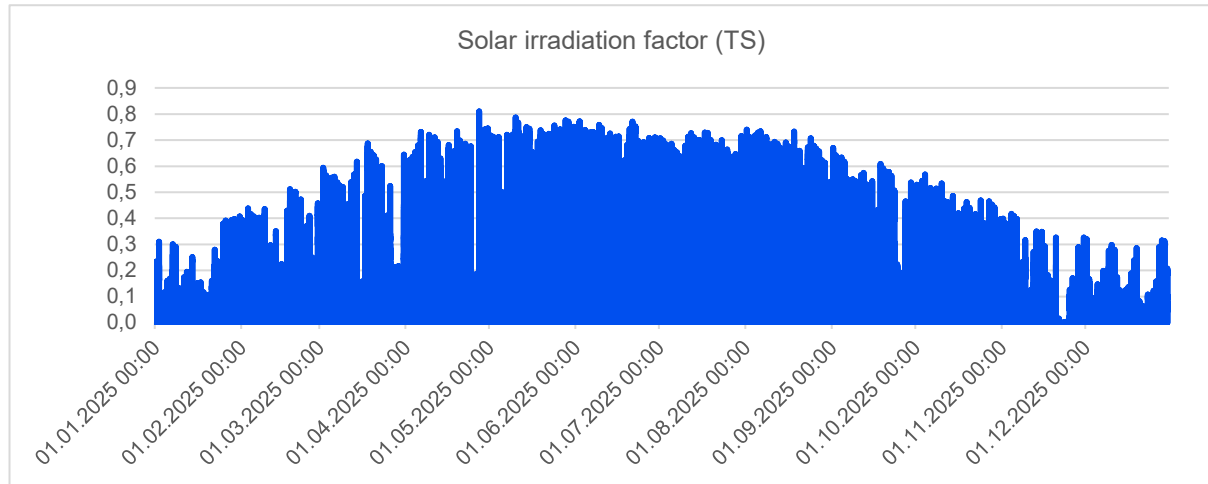


Figure 46: Example of the realised solar irradiation factor of producers connected to an HV/MV substation in 2025

The generation time series of future solar power plants was obtained by multiplying the estimated installed capacity of new generation facilities for the target year with the corresponding generation factor for each 15-minute interval. The resulting generation was added to the existing generation, while the consumption profile was maintained at the level reconstructed from the base year.

In this way, estimated time series of consumption, generation, and net load were determined for each HV/MV substation for the years 2030 and 2035.

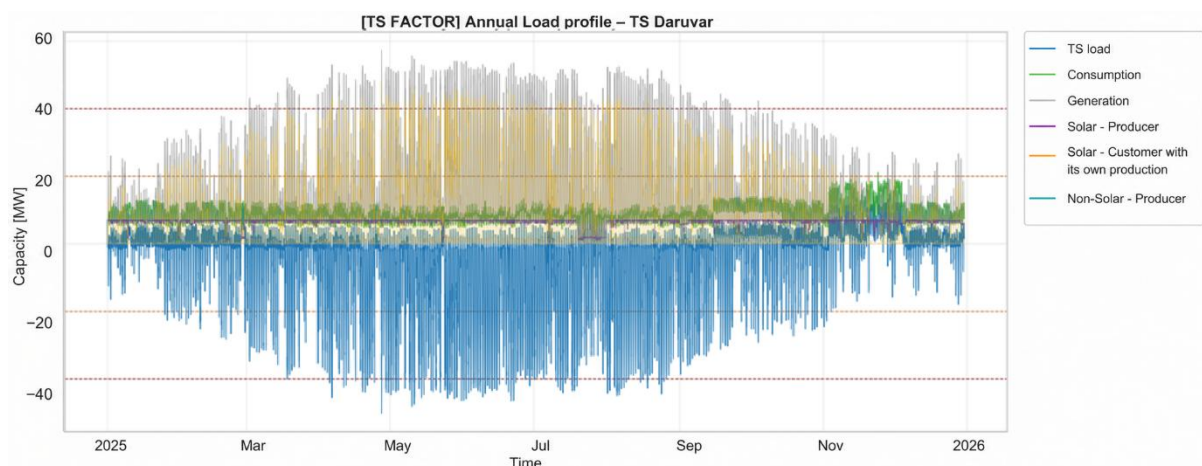


Figure 47: Example of estimated consumption, generation, and load time series of an HV/MV substation in 2035

The need for downward flexibility was **assessed based on maintaining the N-1 security criterion** at the HV/MV substation level. The available transformation capacity under N-1 conditions was determined assuming the unavailability of the transformer with the highest rated capacity. Any export in a given 15-minute interval exceeding this available capacity represents a potential need for downward flexibility.

Flexibility would only be activated during periods of actual transformer unavailability. For the purpose of estimating the annual activation volume, transformer unavailability was assumed to occur during 1% of the year. This assumption was applied when determining the expected flexibility energy, while the required flexibility capacity was determined based on the maximum identified exceedance of the available transformation capacity.

The described procedure was carried out separately for each HV/MV substation and for both target years. The results were then aggregated at the distribution network level and are presented in Annex 1 as:

- the sum of local maximum flexibility capacity needs, expressed in MW; and
- the total expected flexibility activation energy during the target year, expressed in MWh.

The tables in Annex 1 present the results obtained for 2030 and 2035 in the format defined by the FNA Methodology.

Upward DSO network flexibility needs

The assessment of upward flexibility needs is based on the current HEP ODS Ten-Year DNDP. The plan identifies HV/MV substations where, under existing load in the energy intake direction, the N-1 security criterion is not fully satisfied with respect to the installed transformer capacity.

However, exceedance of the available transformation capacity under N-1 conditions does not necessarily imply a need for flexibility activation. Therefore, for the identified substations, the actual operational capabilities of the distribution network were further assessed, in particular:

- the possibility of transferring part of the load through the MV network to neighbouring substations;
- the available capacity of neighbouring substations and interconnecting lines;
- transformer capacity reinforcements that have already been implemented; and
- planned investment activities aimed at increasing transformation capacity or enabling a more favourable redistribution of load.

The additional analysis showed that the identified constraints in the observed substations can be resolved either through load redistribution via the MV network to neighbouring substations or through the implementation of investment activities foreseen in the current Ten-Year DNDP. Therefore, **no reduction in consumption by the network users through the application of flexibility** is required to ensure secure network operation.

Consequently, for the substations covered by the current Ten-Year DNDP, **no need for upward flexibility was identified** for the purpose of meeting the N-1 criterion. Accordingly, the estimated upward flexibility capacity and energy requirements for 2030 and 2035 **are equal to zero**.

ANNEX 4 - Approach to guiding criteria

Guiding criteria as defined by Article 16 of the FNA Methodology describes the approach to assess the capability of different sources of flexibility to cover the various types of flexibility needs, including system and network needs. In such cases, TSOs and DSOs provide the relevant indicators.

For distribution network flexibility needs, the evaluation considers several key aspects, including the location of the flexibility need in terms of geographical and voltage level, the direction of the need (upward or downward), the local maximum power required during activation, and the timeframe during which the resource must be available. The latter encompasses the duration of continuous or discontinuous needs per time block, the frequency of activation, and the cumulated discontinuous need per time block. In cases where a portion of the identified need is not expected to be covered, the methodology requires that this be clearly indicated along with the justification.

For transmission network flexibility needs, sub-indicators represent technical requirements that help identify the most suitable resources to cover any uncovered needs.

For all system-level needs, including RES integration needs, ramping needs, and short-term flexibility needs, the required indicators are the same. They include the number of market time units (MTU) showing an uncovered need, the interval between uncovered needs, their duration, and the volume in terms of energy and power.

The results of this national FNA indicate that the RES target is achieved in most cases so no additional flexibility resources are required to meet the identified flexibility needs.

ANNEX 5 – Methodological approach to Economic Dispatch modelling

The economic dispatch modelling for the NRAA 2026 was performed using the Antares Simulator, a widely applied tool for system adequacy and market studies across European projects. Developed by the French TSO Réseau de Transport d'Électricité (RTE), this software supports the electricity market, adequacy and power system analyses. It performs economic dispatch optimisation on the basis of social welfare maximisation, taking into account technical and economic parameters of the generation portfolio such as hydro inflows and HPPs characteristics, thermal generation features, wind and solar power intermittency, chronological load profiles, as well as available cross-border transfer capacities.

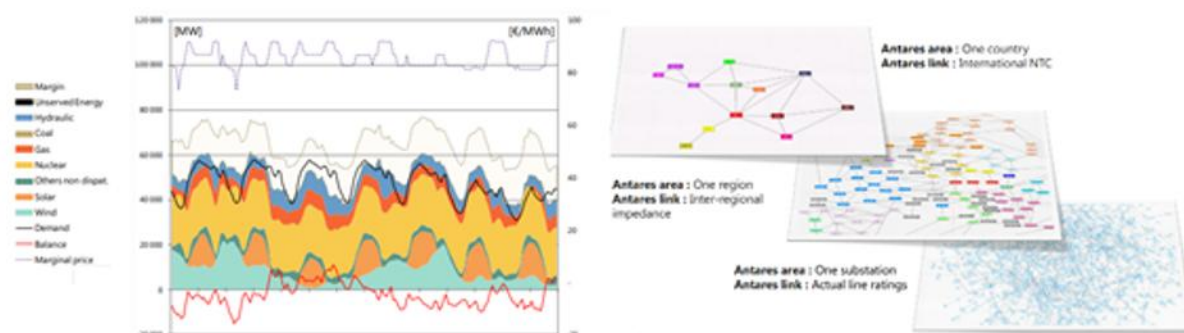


Figure 48: Antares software (illustration)

The goal of the optimisation within Antares is to maximise total social-economic welfare (SEW), which is traditionally defined as a sum of consumer surplus, producer surplus, storage surplus and congestion revenue:

$$SEW = \sum_{i=1}^m (VOLL - \pi_i)(L_i - ENS_i) + \sum_{i=1}^m \sum_{j=1}^{n_i} (\pi_i - c_{ij})(G_{ij} - SPILL_{ij}) + \sum_{i=1}^m \sum_{j=1}^{b_i} \pi_i (S_j^{in} - S_j^{out}) + \frac{1}{2} \sum_{i=1}^m \sum_{j=1}^m F_{ij} (\pi_j - \pi_i)$$

where:

- π_i - marginal price in i^{th} area
- L_i - demand in i^{th} area
- ENS_i - energy not supplied in i^{th} area
- c_{ij} - marginal cost of j^{th} unit in i^{th} area
- G_{ij} - generation of j^{th} unit in i^{th} area
- $SPILL_{ij}$ - curtailed energy from j^{th} unit in i^{th} area (only for non-dispatchable units)
- S_j^{in} - energy injected into system by j^{th} storage unit in i^{th} area (batteries and PSHPPs)
- S_j^{out} - energy absorbed from the system by j^{th} storage unit in i^{th} area
- F_{ij} - bilateral energy exchange between areas i and j
- $VOLL$ – value of lost load
- m - total number of modeled zones
- n_i - number of generating units in i^{th} area
- b_i – number of storages in i^{th} area

Previous formula can be written in the following equivalent form:

$$SEW = VOLL \cdot \sum_{i=1}^m L_i - \left\{ \sum_{i=1}^m \sum_{j=1}^{n_i} c_{ij} G_{ij} + \sum_{i=1}^m VOLL \cdot ENS_i \right\}$$

In other words, the goal of the optimization is to minimize overall system costs (OV. COST):

$$\min OV.COST = \sum_{i=1}^m \sum_{j=1}^{n_i} c_{ij} G_{ij} + \sum_{i=1}^m VOLL \cdot ENS_i$$

Antares is a software tool formulated on the basis of probabilistic sequential hourly simulation of power system operation with:

- Application of the MC method, which encompasses different combinations of wind, solar, hydro generation as well as different demand changes with respect to weather conditions (changes in wind speed, insolation, hydrology conditions, temperature) and different levels of unavailability of thermal units due to failures or maintenance;
- Hydro-thermal optimisation (“unit commitment” and “optimal hourly dispatching”) to minimise the overall system costs;

- Respect for the characteristics and constraints in the transmission network (NTC constraints with DC load flow in line with equivalent impedances or PTDF factors).

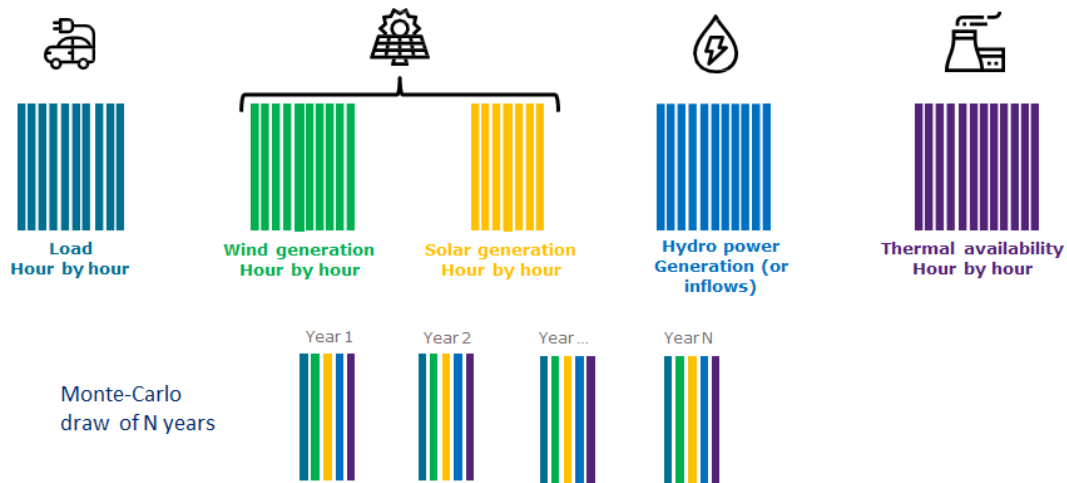


Figure 49: Creation of MC years in Antares

In Antares, there are four different approaches for modelling:

- **Market approach (zonal)** – one Antares area is one study zone, while the Antares link is commercial capacity or International Net Transfer Capacity (NTC)
- **Physical approach (zonal)** – one Antares area is one region, while the Antares link represents inter/regional equivalent impedances with corresponding grid capacities.
- **Flow-Based approach (nodal)** – one Antares area is every node from the transmission network, while Antares links are fictitious links representing net injections of each node into the transmission network. The transmission network is modelled using Power Transfer Distribution Factor (PTDF) / Outage Transfer Distribution Factor (OTDF) linear constraints.
- **Flow-Based approach (zonal)** - one Antares area is one study zone, while the transmission network is modelled using Flow-Based domains (zone-to-zone PTDFs/OTDFs and Remaining Available Margins (RAM)).

In conclusion, the Antares Simulator was used due to prior successful experience and its extensive application in various market modelling exercises across European projects and national assessments, making it a reliable and well-established tool for adequacy and flexibility evaluations.

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Zagreb, 22 July 2026