Flexibility Needs Assessment report for Slovenia

Report

July 2026

Flexibility Needs Assessment report for Slovenia

July 2026

Version: 1.0

Find us at:

Energy Agency

E info@agen-rs.si
Strossmayerjeva ulica 30
2000 Maribor
Slovenia

www.agen-rs.si

The report is based on the non-binding ACER (© European Union Agency for the Cooperation of Energy Regulators) Flexibility Needs Assessment Report Template (May 2026).

Table of contents

Table of acronyms

Acronym	Meaning
AC	Alternating current
ACER	European Union Agency for the Cooperation of Energy Regulators
AMI	Advanced metering infrastructure
BESS	Battery energy storage system
BEV	Battery electric vehicle
CHP	Combined heat and power
COP	Coefficient of performance
DER	Distributed energy resources
DNDP	Distribution Network Development Plan
DNO	Distribution network operator (distribution company, for the purposes of this report)
DSM	Demand-side management
DSO	Distribution system operator
DTR	Dynamic thermal rating
DU-OVE	Additional Measures – Renewable Energy Sources scenario
EC	Elektro Celje (distribution company)
ED	Economic dispatch
EG	Elektro Gorenjska (distribution company)
EL	Elektro Ljubljana (distribution company)
ELES	Electricity Transmission System Operator of the Republic of Slovenia
EM	Elektro Maribor (distribution company)
ENTSO-E	European Network of Transmission System Operators for Electricity
EP	Elektro Primorska (distribution company)
ERAA	European Resource Adequacy Assessment
EU	European Union
EV	Electric vehicle
EVA	Economic Viability Assessment

FCA	Flexible connection agreement
FCR	Frequency Containment Reserve
FNA	Flexibility Needs Assessment
FOR	Forced outage rate
FRR	Frequency Restoration Reserve
GMM	Gaussian Mixture Model
HP	Heat pump
HV	High-voltage
LN	Line
LV	Low-voltage
MTTR	Mean Time to Repair
MTU	Market Time Unit
MV	Medium-voltage
NECP	National Energy and Climate Plan
NRA	National regulatory authority
NRAA	National Resource Adequacy Assessment
NTC	Net Transfer Capacity
OLTC	On-load-tap-changer
P	Probability
PC	Passenger cars
PHEV	Plug-in hybrid electric vehicle
PV	Photovoltaic power plant
PyPSA	Python for Power System Analysis
RES	Renewable energy source
RL	Residual load
RTE	Round Trip Efficiency
SONDSEE	System Operating Instructions for the Electric Power Distribution System
STF	Short-Term Flexibility
SURS	Statistical Office of the Republic of Slovenia

TETOL	Ljubljana Combined Heat and Power Plant (TE-TOL)
TPP	Thermal Power Plant
TR	Transformer
TS	Transformer station
TSO	Transmission network operator
WS	Weather scenarios

Executive summary

Slovenia's electricity system is undergoing a major structural transformation driven by decarbonisation, electrification, and the rapid integration of renewable energy sources (RES). The national Flexibility Needs Assessment (FNA) [33], a technical study prepared in accordance with Regulation (EU) 2019/943 [16] and the ACER Flexibility Needs Assessment methodology, evaluates how the Slovenian power system can maintain reliability, security, and operational efficiency under increasingly variable generation and consumption conditions. The assessment covers the target years 2030 and 2035 and combines both transmission system operator (TSO) and distribution system operator (DSO) perspectives into a coordinated national framework.

The analysis is based on the Slovenian National Energy and Climate Plan (Nacionalni energetski in podnebni načrt, NEPN) DU-OVE scenario, which assumes accelerated deployment of photovoltaic (PV) generation, increasing electrification of transport and heating, widespread deployment of battery storage, and the gradual phase-out of coal-fired generation. Installed PV capacity is projected to grow from approximately 1.6 GW in 2025 to 3.45 GW in 2030 and 5.7 GW in 2035. At the same time, the number of heat pumps is expected to increase from approximately 119,000 in 2025 to more than 216,000 in 2035, while battery electric vehicles (BEVs) could exceed 280,000 by 2035. These developments fundamentally change the operation of both transmission and distribution networks and create a growing need for operational flexibility across all voltage levels.

Key findings

The Slovenian assessment identified RES integration targets of 4,909 GWh for 2030 and 7,931 GWh for 2035. Across all analysed scenarios, the total curtailed energy is equal to the total uncovered RES integration need.

RES integration targets are summarised in Table 1, while the identified RES integration needs are presented in Table 2.

Table 1: Key findings - RES integration targets

Type	Flexibility need	Indicator	Target [GWh]	Target [% of RES generation]	Target year
System needs	RES integration	RES integration target	4,909	100	2030
System needs	RES integration	RES integration target	7,931	100	2035

The values presented in Table 1 refer to an analysis conducted at the TSO level. The values shown in Table 1 are identical for all analysed Weather Scenarios (WS), as they all took into account the same level of RES integration. The scenarios differ in terms of the time-dependent profiles, and not the underlying annual values themselves.

Table 2: Key findings - RES integration needs

Type	Flexibility need	Total curtailed energy [GWh][1]	Total uncovered RES integration need [GWh]	WS	Target year
System needs	RES integration	396.25	396.25	Base	2030
System needs	RES integration	666.45	666.45	WS23	2030
System needs	RES integration	867.83	867.83	WS25	2030
System needs	RES integration	688.29	688.29	WS18	2030
System needs	RES integration	755.89	755.89	WS27	2030
System needs	RES integration	718.61	718.61	WS35	2030
System needs	RES integration	542.47	542.47	Base	2035
System needs	RES integration	712.3	712.3	WS23	2035
System needs	RES integration	826.44	826.44	WS25	2035
System needs	RES integration	737.25	737.25	WS18	2035
System needs	RES integration	753.77	753.77	WS27	2035
System needs	RES integration	724.74	724.74	WS35	2035

The identified uncovered RES integration needs vary considerably across the analysed Weather Scenarios, reflecting differences in weather-dependent renewable generation and demand patterns.

For 2030, the uncovered RES integration need ranges from 396.25 GWh (Base) to 867.83 GWh (WS25). For 2035, the corresponding range is from 542.47 GWh (Base) to 826.44 GWh (WS25). Among the analysed Weather Scenarios, WS25 consistently exhibits the highest uncovered RES integration need, whereas the Base scenario results in the lowest uncovered RES integration need in both target years.

Interpretation of key findings

The summary of ramping needs, short-term needs and network needs for both the DSO and TSO levels is provided in Table 3 for target year 2030 and in Table 4 for target year 2035.

[1] In the present assessment, total curtailed energy equals total uncovered RES integration need.

Table 3: Summary of ramping needs, short-term needs and network needs – Target year 2030

Type	Flexibility need	Indicator	Average amount of uncovered needs [MW]	Uncovered need [MWh]	WS
System needs	Ramping needs	Downward ramping rate need	133.8	36,134	Base
	Short-term needs	Downward uncovered short-term needs	112.2	5,814	
	Ramping needs	Downward ramping rate need	148.7	45,489	WS23
	Short-term needs	Downward uncovered short-term needs	113.1	5,940	
	Ramping needs	Downward ramping rate need	178.5	63,365	WS25
	Short-term needs	Downward uncovered short-term needs	118.2	6,996	
	Ramping needs	Downward ramping rate need	157.5	52,909	WS18
	Short-term needs	Downward uncovered short-term needs	111.7	6,803	
	Ramping needs	Downward ramping rate need	180.6	60,145	WS27
	Short-term needs	Downward uncovered short-term needs	107	6,089	
	Ramping needs	Downward ramping rate need	185.1	59,034	WS35
	Short-term needs	Downward uncovered short-term needs	112.6	5,237	
Network needs	DSO network needs	Downward DSO network flexibility needs	133	53,182	N/A
	TSO network needs	Downward TSO network flexibility needs	0[2]	0	All WS

Table 4: Summary of ramping needs, short-term needs and network needs – Target year 2035

Type	Flexibility need	Indicator	Average amount of uncovered needs [MW]	Uncovered need [MWh]	WS
System needs	Ramping needs	Downward ramping rate need	166.2	54,168	Base
	Short-term needs	Downward uncovered short-term needs	182.9	14,690	
	Ramping needs	Downward ramping rate need	207.4	83,993	WS23
	Short-term needs	Downward uncovered short-term needs	182	14,811	
	Ramping needs	Downward ramping rate need	303.5	131,396	WS25

[2]No TSO network flexibility needs were identified under N conditions for any of the analysed weather scenarios (WS) for target year 2030.

	Short-term needs	Downward uncovered short-term needs	201.5	22,854	
	Ramping needs	Downward ramping rate need	227.9	103,679	WS18
	Short-term needs	Downward uncovered short-term needs	184.3	18,426	
	Ramping needs	Downward ramping rate need	267.2	115,444	WS27
	Short-term needs	Downward uncovered short-term needs	186.9	19,547	
	Ramping needs	Downward ramping rate need	298	107,585	WS35
	Short-term needs	Downward uncovered short-term needs	187.7	15,974	
Network needs	DSO network needs	Downward DSO network flexibility needs	243	138,326	N/A
	TSO network needs	Downward TSO network flexibility needs	0[3]	0	All WS

TSO interpretation of key findings

The results consistently show that the Slovenian power system is transitioning from a system primarily concerned with generation adequacy towards one where operational flexibility becomes the dominant challenge. This transition is driven by the substantial increase in PV generation foreseen in the national energy scenario, resulting in more frequent periods of negative residual load and consequently increasing uncovered RES integration needs. The identified system needs are therefore predominantly associated with the capability to absorb renewable generation surplus.

The identified maximum uncovered RES integration need reaches approximately 1 GW in 2030 and approximately 0.5 GW in 2035, while the corresponding annual uncovered RES integration energy remains significant in both target years. Although its peak value decreases in 2035 following the assumed retirement of conventional thermal generation, the increasing installed photovoltaic capacity increases the duration of negative residual load conditions, maintaining substantial annual flexibility requirements.

To support the assessment required by Article 8(10) of the FNA Methodology, the benefit of additional flexibility resources was evaluated using a technology-neutral approach. Additional flexibility resources were characterised by installed power, energy-to-power ratio, availability and round-trip efficiency. The analysis demonstrates that additional flexibility resources substantially reduce uncovered RES integration needs, with most of the achievable benefit obtained for energy-to-power ratios of approximately eight hours. Increasing storage duration beyond this point provides only limited additional reduction of uncovered RES integration needs, indicating that future flexibility requirements are predominantly associated with intraday balancing of renewable generation.

The assessment of uncovered ramping needs confirms that increasing renewable generation also results in significantly larger changes in residual load between consecutive market time units (MTUs). While upward ramping capability remains largely sufficient under the analysed scenarios, downward uncovered ramping needs become the dominant operational constraint. These events occur primarily during periods of rapidly increasing photovoltaic generation, when conventional generation cannot decrease its output sufficiently fast because of technical operating limitations. Consequently, future flexibility resources will need to provide not only sufficient energy capacity but also adequate dynamic capability to accommodate increasingly steep residual load ramps.

[3] No TSO network flexibility needs were identified under N conditions for any of the analysed weather scenarios (WS) for target year 2035.

Short-term flexibility (STF) needs were assessed using a probabilistic Monte Carlo framework based on historical residual load forecast errors and stochastic availability of generation and transmission assets. The assessment indicates that downward uncovered short-term flexibility needs are consistently more pronounced than upward needs, reflecting the dominant contribution of photovoltaic generation to residual load forecast uncertainty. In addition to flexibility capacity, the analysis quantifies the expected annual uncovered flexibility energy and the expected number of hours with uncovered short-term flexibility needs, providing a comprehensive representation of operational flexibility requirements under uncertain system conditions.

Transmission network flexibility needs were evaluated using detailed AC load-flow simulations based on generation dispatch obtained from the economic dispatch simulations. The comparison of simulations performed with and without transmission network constraints shows that transmission network constraints do not materially affect the identified uncovered RES integration needs. The calculated uncovered RES integration energy remains unchanged, indicating that the impact of transmission network constraints is below the relevance threshold specified by the FNA Methodology. Consequently, the identified system needs are primarily driven by the balance between renewable generation and electricity demand rather than by limitations of the transmission network.

Overall, the assessment demonstrates that future flexibility requirements in Slovenia will be predominantly associated with downward flexibility. The increasing penetration of photovoltaic generation simultaneously increases uncovered RES integration needs, uncovered downward ramping needs and uncovered short-term flexibility needs, while transmission network constraints do not materially alter the identified system needs under the analysed scenarios. The performed analyses further demonstrate that appropriately dimensioned additional flexibility resources can substantially reduce uncovered RES integration needs and therefore represent an effective measure for supporting the integration of renewable electricity generation into the Slovenian power system.

DSO interpretation of key findings

The identified flexibility needs differ by voltage level: Low-voltage (LV) needs are primarily driven by electrification of heating and transport (MV/LV transformer loading), while medium-voltage (MV) needs are mainly driven by distributed PV generation (voltage rise).

Where available explicit flexibility is insufficient, network reinforcement is required. The flexibility needs remaining after considering the realistically implementable reinforcement measures are reported as uncovered flexibility needs.

Expected explicit flexibility remains limited in both target years. For downward flexibility, the expected contractual means is the application of Flexible Connection Agreements (FCAs) for PV generation.

Implicit flexibility, particularly EV charging shifted outside peak tariff periods, creates additional nighttime demand peaks that should be considered in future distribution network planning.

Barriers to flexibility, regulatory recommendations and actions

Barriers to flexibility – summary assessment

The barriers to non-fossil flexibility were assessed in accordance with the ACER Recommendation on NRAs' reporting on barriers to non-fossil flexibility and on the basis of the national evidence available at the time of preparation of the report. The table provides an indicative summary of the **residual restrictive effect** of each assessed barrier.

- **Green** indicates that no material residual barrier was identified or that a previously identified barrier has been effectively removed. Minor implementation, monitoring or operational-development issues may remain, but they are not expected to materially restrict market access, participation or the deployment of non-fossil flexibility.

- **Amber** indicates a partial, moderate or actor-, product- or location-specific barrier. The barrier may be partly mitigated, subject to an ongoing reform, or dependent on further implementation and monitoring.
- **Red** indicates a material barrier that has not yet been adequately mitigated and currently restricts, or is reasonably expected to restrict, market access, competition, investment, activation or the scalable use of non-fossil flexibility.

The classification reflects the practical implementation of the relevant framework and the status of mitigation measures, rather than legal compliance alone. It is an indicative synthesis and does not replace the detailed indicator-level assessment.

Main regulatory and market-design barriers

Barriers	Indicators		Traffic-light assessment and concise justification
Lack of proper legal framework for market access to new entrants and small actors	Main roles and responsibilities of new actors not defined		The principal rights, roles and responsibilities of active customers, aggregators, independent aggregators and energy communities are defined in national legislation. Practical limitations of the independent aggregation model are assessed separately under market-access procedures.
	Market access restricted due to lack of legal eligibility		No relevant actor or technology was identified as legally ineligible to participate in wholesale markets or system-operation services. Minimum bid sizes may limit direct participation by small resources, but participation through aggregation is legally available.
	Unclear framework for access to final customer data		The national framework for access to metering and consumption data is implemented, and the relevant national practices were reported to the European Commission in July 2025. Planned NRA validation represents a monitoring action rather than a material market-access barrier. Operational and flexibility-related interoperability issues are assessed separately under the additional barriers.
	Ownership restrictions for energy storage and electro-mobility		National legislation implements the relevant ownership restrictions. No unresolved derogations or discriminatory ownership arrangements were identified.
	Restrictions on trade in day-ahead and intraday markets		Fifteen-minute products are available, the minimum order quantity is 0.1 MW and the imbalance settlement period is 15 minutes.
Lack of enablers and incentives to provide flexibility	Lack of adequate metering systems		Smart-meter deployment and standard functionalities are highly developed. Remaining gaps concern detailed requirements for dedicated measurement devices, access to near-real-time data and the operational integration of metering data for distribution-network observability and flexibility activation.
	Absence of price signals		Dynamic retail contracts and time-differentiated network tariffs are available, but uptake of dynamic and flexibility-oriented retail products remains very low. Dominant legacy retail products may weaken the effect of network-tariff signals, while locational incentives are not yet broadly applied.

Restrictive requirements to provide balancing services	Non-market-based balancing products		Balancing capacity and balancing energy are procured on a market basis. No non-market-based balancing products were identified.
	Restrictions in the prequalification of reserve providing groups		Reserve providing groups are permitted, and combinations of generation, demand and storage are not restricted. Separate prequalification procedures apply to technically different balancing products and are justified by product-specific performance requirements. The proportionality of the requirements is reviewed through the NRA approval process.
	Large minimum eligible capacity		The 1 MW threshold is aligned with the applicable European framework but prevents small distributed resources from participating individually and makes aggregation necessary. The barrier is therefore limited but relevant to smaller DER.
	Unregulated duration or long prequalification process		The period for the final decision following confirmation of a complete application is regulated, but no maximum period is defined for confirming completeness. This may reduce the predictability of the total market-entry process.
	Large minimum bid size		The applicable 1 MW minimum bid size is aligned with the European target model. Smaller resources may participate through aggregation.
	Long validity period of balancing energy bids		The applicable validity periods are aligned with European standard products and the PICASSO and MARI platform rules.
	Symmetric balancing capacity products		Upward and downward aFRR and mFRR capacity are procured separately. The symmetric FCR product reflects the relevant standard product design and is not a national barrier.
	Restrictions in the price settlement rule of balancing energy		The previous pay-as-bid limitation was removed following ELES' integration into the PICASSO and MARI platforms in July 2026. The applicable settlement arrangements are aligned with the European target model.
	Non-contracted balancing energy bids not allowed		Non-contracted balancing energy bids are allowed.
	Too short predefined minimum duration between consecutive activations		No restrictive predefined minimum duration between consecutive activations was identified. Activations follow the applicable European platform rules.
	Long procurement lead time and long duration of balancing capacity contracts		No relevant derogations apply. Balancing capacity is procured through daily and monthly arrangements, and no contractual periods longer than one month were reported.
Restrictive requirements to provide congestion management	Unjustified lack of market-based TSO congestion management		ELES applies market-based, pay-as-bid redispatching based on voluntary energy bids. The procedure remains largely manual and is being modernised through new terms and conditions, but this does not constitute an unjustified absence of market-based redispatching.
	Unjustified lack of market-based DSO congestion management		The necessary legal basis exists, but operational market-based procurement is used only to a limited extent. Local markets remain immature, while flexible connection agreements are

			currently the more readily applicable instrument for several location-specific constraints.
	Constraints in local markets for TSO/DSO congestion management		Local flexibility markets have not yet reached sufficient maturity to provide stable competition and predictable procurement opportunities. Limited local liquidity, uncertain continuity of procurement and incomplete operational readiness may materially constrain participation and investment.
Complex, lengthy and discriminatory administrative requirements	Inefficient grid connection procedures		Information and electronic application channels are available, general administrative deadlines apply, indicative connection capacity is published, and a simplified-notification procedure exists for renewable self-supply. No material procedural barrier was identified on the basis of the available assessment.
	Disproportionate procedures and requirements for market access		The existing independent aggregation model has significant limitations. Smaller market participants face the same collateral, access-fee and transaction-fee structures as larger actors and bear proportionately high fixed onboarding, contractual, technical and reporting costs.
Lack of regulatory incentives to system operators to consider non-wire alternatives	Lack of incentives for system operators to consider non-wire alternatives		The regulatory framework provides cost recovery and includes performance-based smart-grid incentives, project-oriented incentives, R&I arrangements and a benefit-sharing mechanism. Further monitoring of effectiveness and the transition from pilots to wider deployment remains appropriate, but no lack of regulatory incentives was identified.

The assessment identifies near-finished rollout of smart metering, low uptake of dynamic retail products, product-specific pre-qualification, market-based TSO redispatching in development, and the continued immaturity of local distribution markets.

Network-tariff aspects potentially restricting demand response

Network-tariff aspect		Traffic-light assessment and concise justification
Network-tariff basis		No material restrictive potential was identified. Time-of-use capacity and energy charges are applied, and the tariff basis is assessed as broadly aligned with cost-reflectivity and demand-response objectives.
Differentiation between active and non-active customers		No unjustified differentiation was identified. Double charging is avoided, and the available assessment did not justify additional differentiated treatment.
Exemptions, discounts and other differentiated tariff treatments		Blanket exemptions introduced by legislator in Energy Supply Law for storage and certain legacy differentiated arrangements distort cost signals and the competitive position of flexibility resources. NRA disagreed and requested elimination or at least conditional redesign of these exemptions, however, there is no will on the legislator side to perform corrective measures.

Blanket storage exemptions are expressly identified in the detailed assessment as a distortion of the flexibility market, while the mitigation measures remain uncertain.

Additional barriers relevant to Slovenia

Additional barrier		Traffic-light assessment and concise justification
Limited liquidity and predictability of local flexibility markets		The barrier is assessed as moderate–high and remains insufficiently mitigated. The small number of suitable providers within individual network areas and limited predictability of procurement may prevent effective competition and scalable participation.
Limited availability and use of locational incentives for distribution-network flexibility		Time-differentiated network tariffs and the regulatory basis for local dynamic tariffs exist, but locational incentives and local procurement remain limited, immature or pilot-based.
Insufficient operational observability and automated activation of distributed flexibility at MV/LV level		High smart-meter penetration has not yet translated into sufficiently timely, spatially detailed and operationally integrated observability and automated activation across distribution areas. Relevant AMI, ADMS and DER-management upgrades are ongoing or planned.
Insufficient integration and interoperability of operational, metering and flexibility-related data systems		The legal data-access framework and several component systems exist, but end-to-end data flows, harmonised interfaces and common models for prequalification, activation, verification and settlement are not yet fully integrated.
Multi-layered governance and insufficiently integrated coordination for distribution flexibility		The national organizational structure is not a barrier in itself, but integrated procedures for data exchange, constraint validation, procurement and activation between ELES and the distribution companies are not yet fully developed.

The detailed assessment classifies two of these additional barriers as moderate–high and three as moderate, with most mitigation measures still under development, planned or only gradually implemented.

Digitalisation enabling factors – implementation status

Digitalisation is presented separately from the barrier traffic-light table. It is primarily an enabling factor under Article 19e(2)(d), although incomplete Digitalisation also contributes to some of the identified barriers.

Digitalisation aspect		Traffic-light assessment and concise justification
Active system management		**Partially deployed.** Active system management is established at transmission level but remains at an early stage of effective operational deployment in the distribution system. ADMS solutions are reported as largely deployed, but their operational effects have not yet been demonstrated.
Advanced monitoring and observability		**Developing.** Transmission-level observability is relatively mature. Distribution-level observability is progressively improving, but further integration of sensors, smart-meter data, state estimation and near-real-time information into operational processes is required.
Dynamic line and thermal rating		**Uneven deployment.** DLR and DTR are broadly used on transmission assets. Distribution-level application remains limited, although national deployment of DTR on selected distribution transformers has been announced.
Availability of near-real-time metered data from network users		**Project initiation.** The initial AMI roll-out is complete, but the targeted upgrade for central and selective access to near-real-time measurements remains at the CBA and project-initiation stage.

The digitalisation assessment confirms the contrast between relatively mature transmission-level solutions and still-developing distribution-level active management, observability, DTR deployment and near-real-time AMI access.

On-going and planned regulatory actions to overcome barriers for flexibility

- Local flexibility markets remain at an early stage of maturity. Therefore, development of common criteria for assessing when market-based flexibility procurement is technically and economically feasible; inclusion of forward-looking flexibility needs in NDPs; standardization of local procurement processes and products; improvement of operational observability and aggregation; periodic assessments of market liquidity and procurement outcomes are the key ongoing processes for facilitating market development. Also, full alignment of the next version of the NDPs with ACER FNA methodology further contributes to overcoming previously identified barriers. As local DSO markets mature, the proportionality of baseline, metering, communication, testing and portfolio-management requirements is planned to be assessed specifically for small and aggregated DER. Also, periodic assessments of effectiveness of current regulatory incentives for use of market-based flexibility procurement (output-based regulation using SG KPIs) are on-going.
- The current (independent) aggregation model in Slovenia is an initial solution with significant limitations. The market operator is enforced to introduce the new model according to CBA analysis performed in 2024. We expect to have an upgraded aggregation model enforced in 2027. Also, in order to alleviate market access to smaller participants, introduction of standardised contractual templates and onboarding procedures; digital one-stop registration where feasible; avoiding duplication of data submissions across market and system operators; application of proportionate collateral, testing and reporting requirements; facilitation of portfolio-level compliance by aggregators, is planned. Standardised service-specific contract templates; harmonised registration steps; published data requirements; clear allocation of responsibilities; indicative approval timelines are also going to be introduced in order to further contribute to overcoming previously identified barriers.
- Distribution companies are biased towards the use of of flexible connection agreements (FCAs) in contrast of using market-based congestion management solutions for (non-wire) resolution of local congestion in their networks. The root causes for the situation described are following:
    - Network code on demand response has not been adopted yet: it hinders/delays the needed developments (Flexibility Register etc.).
    - DSO mindset still biased onto “business as usual” *modus operandi.*
    - Expected low liquidity requires intra-market integrations and consequently solutions of bigger complexity (forwarding of non-activated bids to other markets).
- Blanket and full-scale exemptions for network charges introduced by Slovenian Government for storage are distorting the flexibility market. Further actions are needed to unleash the full potential of the already implemented network charges reform:
    - The elimination of the blanket exemption for storage or, alternative, the introduction of conditional exemptions based on location and operational regime (based on CBA for network).
    - When introducing the exemptions, assessment of the impact of RES levies exemptions onto the distortion of the cost signals to network users or their diminishing impact.

Other short- and mid-term regulatory actions, to be implemented until the year 2030, to boost flexibility

- The progressive evolution of incentive output-based regulation based on selection of KPIs as well as benefit-sharing incentive scheme based on impact monitoring.
- Gradual introduction of publishing forward-looking information on expected flexibility needs by location, direction and indicative period; standardization of local flexibility products and procurement procedures; facilitation of aggregation of small resources; coordination of local procurement with distribution NDPs; assessment whether multi-year or periodically repeated procurement products could provide more predictable revenue opportunities.
- High smart-meter penetration has not yet translated into sufficiently timely, spatially detailed and operationally integrated observability and automated activation across distribution areas. Relevant AMI, ADMS and DER-management upgrades are ongoing or planned.

Structural regulatory solutions to integrate more flexibility in the long term, beyond 2030

- Further gradual evolution of incentive output-based regulation based on selection of KPIs as well as benefit-sharing incentive scheme based on impact monitoring.

- In case of insufficient “natural” development of local flexibility markets the introduction of regulatory framework aimed to assure “level-playing-field” for flexibility platform service providers and appropriate incentives for new entrants.
- A new methodology for network charges based on long-term incremental costs and residual costs is planned to be enforced on the long-term horizon because of the currently not achievable computation and measurement infrastructure requirements. Although, the current methodology, which is based on ToU capacity and ToU energy network charges, already provides strong incentives for the flexible use of the system.

1. Introduction

The increasing integration of variable renewable energy sources, the electrification of energy demand and the growing role of distributed energy resources are changing the conditions under which electricity systems are planned and operated. These developments increase variability in generation and consumption and place greater demands on the ability of the electricity system and networks to respond to changing operating conditions. Flexibility is therefore becoming an increasingly important element of a secure, efficient and decarbonised electricity system.

This chapter sets out the purpose and scope of the national Flexibility Needs Assessment report, its legal and regulatory basis, the governance arrangements for its preparation and adoption, and the key definitions used throughout the report.

1.1. Purpose and scope of the national report

Article 19e of Regulation (EU) 2019/943 [16] establishes a common framework for the periodic assessment of flexibility needs at national level over a period of at least the next five to ten years. The resulting national report is intended to provide an evidence-based assessment of the flexibility required under the expected future conditions of the electricity system. It must be consistent with the European resource adequacy assessment and, where applicable, national resource adequacy assessments, and must be based principally on the data and analyses provided by the relevant transmission and distribution system operators in accordance with the common methodology adopted by ACER.

The report provides the basis for the Member State to define an indicative national objective for non-fossil flexibility pursuant to Article 19f of Regulation (EU) 2019/943 [16], including the respective contributions of demand response and energy storage. Its findings are also intended to inform electricity-system and network planning and to contribute to the subsequent assessment of flexibility needs and barriers at Union level. The report does not itself establish the national objective or prescribe particular flexibility technologies, support measures or investment decisions.

In accordance with the ACER Flexibility Needs Assessment Methodology, the assessment covers system flexibility needs and network flexibility needs. System flexibility needs comprise renewable energy source integration needs, ramping needs and short-term flexibility needs and are quantified at bidding-zone level. Network flexibility needs are assessed separately for the transmission and distribution networks and reflect the flexibility required in relation to grid availability and operational constraints. The assessment also considers the capability of different sources of flexibility to cover the identified needs, together with relevant barriers to flexibility in the market and the contribution of electricity-network digitalisation.

This report applies that framework to the Slovenian electricity system and brings together the relevant system-level and network-level analyses within a coordinated national assessment. The remainder of this chapter explains the purpose and scope of the report, its legal and regulatory basis, the governance arrangements for its preparation and adoption, and the principal definitions used throughout the report. The scenarios and assumptions, analytical methodologies, results and their interpretation are presented in the subsequent chapters.

1.2. Legal and regulatory context

The national flexibility needs assessment is grounded primarily in Regulation (EU) 2019/943 [16] on the internal market for electricity, as amended by Regulation (EU) 2024/1747. Article 19e requires the regulatory authority, or another authority or entity designated by the Member State, to adopt a national report on estimated flexibility needs covering a period of at least the next five to ten years. The report is to be based on data and analyses provided by transmission and distribution system operators, prepared in accordance with the methodology adopted by ACER and consistent with the European resource adequacy assessment and, where applicable, the national resource adequacy assessment. Article 19e also establishes the principal requirements concerning preparation, stakeholder consultation, adoption, periodic updating and submission of the report.

The assessment is performed in accordance with the Flexibility Needs Assessment Methodology adopted by ACER Decision No 05/2025 [12]. The methodology establishes the harmonised framework for preparing national flexibility needs assessment reports, including the applicable data and scenario requirements, the assessment of system and network flexibility needs, the distinction between covered and uncovered needs, the treatment of limitations affecting the availability of flexibility resources, and the assessment of barriers to flexibility and the contribution of electricity-network digitalisation.

The results of the assessment form the basis for the subsequent national process under Article 19f of Regulation (EU) 2019/943 [16]. On the basis of the national flexibility needs assessment report, the Member State is to define an indicative national objective for non-fossil flexibility, including specific contributions from demand response and energy storage. Articles 19g and 19h establish the framework for possible non-fossil flexibility support schemes where investment in flexibility is insufficient to achieve that objective.

At national level, the principal statutory framework is established by the Slovenian Electricity Supply Act (Zakon o oskrbi z električno energijo, ZOEE [34]). The Act governs the participation of demand response, aggregation and energy storage in electricity markets, the procurement and use of flexibility by system operators, and the consideration of flexibility as an alternative to conventional network expansion. It also provides the national legal basis for adopting the indicative objective for non-fossil flexibility following the national flexibility needs assessment.

The relationship between flexibility needs and electricity-network planning is further specified in the Act on the Methodology for the Preparation of Electricity System Operators' Development Plans (Akt o metodologiji za izdelavo razvojnih načrtov elektrooperaterjev). For distribution-system planning, the Act requires demand and generation forecasts to take account of an analysis of the flexibility potential within the relevant distribution area. Distribution investment plans must include the use of demand response, an assessment of medium- and long-term flexibility-service needs, energy storage and other resources used as alternatives to system expansion. Measures improving the efficiency and utilisation of existing infrastructure are to be prioritised where they constitute an equally or more cost-effective alternative to system expansion or reinforcement. Investments concerning advanced system operation and the use of flexibility must also be separately disclosed.

For transmission-system planning, the same Act requires the assessment of future reserve requirements to include an analysis of flexibility potential. It also requires the transmission system operator to examine deep electrification and sector integration, to consider measures improving the efficiency and utilisation of existing infrastructure where these constitute cost-effective alternatives to reinforcement, and to disclose investments relating to advanced system operation, flexibility, deep electrification and sector coupling.

The statutory and planning framework is complemented by national secondary legislation and operational rules governing the practical market participation, activation and settlement of flexibility resources. The Rules on the Operation of the Electricity Market adopted by the Slovenian market operator regulate, inter alia, participation in the balance scheme, balance responsibility, the registration of market transactions and imbalance settlement. These arrangements form part of the market environment within which suppliers, aggregators and other flexibility providers operate.

At network level, the System Operating Instructions for the Transmission System and the System Operating Instructions for the Distribution System [32] establish detailed technical and operational requirements concerning system operation, connection, metering, data exchange and the provision of system or flexibility services. The distribution-system instructions are particularly relevant to network flexibility because they regulate the technical and operational conditions applicable to distributed resources and the provision and use of flexibility services in the distribution system.

The national framework is further complemented by the Rules and Terms and Conditions for Balancing Service Providers on the ELES Balancing Market. These rules govern the technical qualification, bidding, activation and settlement of balancing service providers and implement the requirements of Commission Regulation (EU) 2017/2195 [17] establishing a guideline on electricity balancing. The current rules, approved by the Energy Agency on 30 June 2026, form part of Slovenia's integration into the European balancing arrangements, including the platforms for automatic and manual frequency restoration reserves.

Taken together, these instruments perform different but complementary functions. Article 19e of Regulation (EU) 2019/943 and the ACER methodology govern the preparation of the national flexibility needs assessment. The ZOEE establishes the wider national statutory framework for flexibility and the subsequent national objective. The development-plan methodology determines how flexibility potential and flexibility-based alternatives are incorporated into transmission and distribution planning, while the market, system-operation and balancing rules determine the practical conditions under which flexibility resources may participate, be qualified, activated and settled. These latter instruments are therefore particularly relevant to the interpretation of resource availability, covered and uncovered flexibility needs, and barriers to the effective deployment of flexibility.

1.3. Governance: designated bodies involved in the FNA report

The Energy Agency is the national regulatory authority responsible for preparing and adopting the Slovenian Flexibility Needs Assessment report. In accordance with Article 19e of Regulation (EU) 2019/943, the report is based on data and analyses supplied by the transmission and distribution system operators. Following its adoption, the Agency is also responsible for publishing the report and submitting it to ACER and the European Commission.

The Agency prepares the national report independently, using ACER's non-binding reporting template. The technical study commissioned by ELES constitutes the principal analytical source for the report but is not itself the national FNA report. The Agency reviews and validates the data, analyses and findings from the study that are used in preparing the national report and, where necessary, requests updates, additional information or methodological clarifications through ELES. This process may result in amendments or supplements to the underlying analytical material but does not constitute formal approval or endorsement of the ELES-commissioned study as a separate publication.

During this assessment cycle, ELES performed the functions of both the transmission system operator (TSO) and the distribution system operator (DSO). Its contributions were nevertheless organised separately for the transmission and distribution levels, in line with the respective requirements of the FNA Methodology. As the combined system operator, ELES was responsible for coordinating and providing the operator data and analyses required for the assessment and for ensuring the correctness and completeness of the operator-level contribution. The FNA Methodology assigns each TSO and DSO responsibility for providing the required data and analyses and for ensuring their correctness, completeness and compliance with the applicable data requirements.

In its capacity as distribution system operator, ELES obtained the necessary distribution-network data from the five distribution companies. These companies own the distribution networks and perform network operation and related services for ELES under contractual arrangements governing the provision of the distribution public service. For the FNA, they supplied the network models, measurements and other technical information required for the distribution-level analysis. These operational arrangements did not transfer responsibility for the consolidated distribution-level contribution from ELES in its capacity as distribution system operator.

ELES commissioned a technical study covering the system, transmission-network and distribution-network components of the assessment. The study was prepared by an external consortium comprising the Faculty of Electrical Engineering of the University of Ljubljana and the Milan Vidmar Electric Power Research Institute. The consortium performed the technical modelling and analysis but had no responsibility for drafting, approving or adopting the national FNA report. The study itself identifies ELES as the contracting entity, the two institutions as its authors and its status as a working report.

The respective roles in the preparation process are summarised below.

Body or entity	Role in the FNA process
Energy Agency	Prepares, amends and adopts the national FNA report; validates the analytical content used in the report; requests additional information or updates where necessary; publishes the adopted report and submits it to ACER and the European Commission.
ELES as TSO	Coordinates and provides the data and analyses required for the assessment of system flexibility needs and transmission-network flexibility needs.

ELES as DSO	Coordinates and provides the data and analyses required for the assessment of distribution-network flexibility needs, drawing on network information supplied by the distribution companies.
Distribution companies	Supply distribution-network models, measurements and other technical data within the contractual arrangements under which they operate the networks and perform related services for ELES.
UL FE–EIMV consortium	Performs the technical modelling and analysis under the study commissioned by ELES; has no responsibility for adopting or approving the national report.

The national implementation process was organised through a staged exchange of data and analyses. The initial timetable envisaged the submission of distribution-level analyses by early March 2026, followed by system and transmission-level analyses by early April, the fine-tuning and cross-cutting assessments by mid-April, and final delivery in early May. The planned stages covered distribution-network needs, system needs, renewable energy integration, ramping and short-term flexibility needs, transmission-network needs, the fine-tuning process, market barriers, digitalisation and the capability of flexibility resources. Delays in completing individual analytical components required the timetable to be adjusted, and the Agency continued to receive updated data, analyses and supplementary information during July 2026.

The resulting data flow reflected the Slovenian institutional model. Distribution-network data were supplied by the distribution companies to ELES in its capacity as distribution system operator and were used by ELES and the external consortium for the distribution-level assessment. The TSO data and assumptions were provided and coordinated by ELES in its transmission-system role. The resulting analytical components and subsequent updates were submitted to the Agency, which assessed their suitability for use in the national report and consolidated the relevant content into its own FNA report. This arrangement reflects the requirement of Article 4 of the FNA Methodology that the system operators and the designated authority agree on the scope of the data and analyses, their respective responsibilities, the target years and the timetable for exchanging information.

No public consultation specifically dedicated to the preparation of this FNA report was carried out during the assessment cycle. The documented preparation process involved technical collaboration between the Energy Agency, ELES, the distribution companies and the external study consortium. No broader stakeholder participation formed part of the process known to the Agency. This technical collaboration should therefore be distinguished from a formal public consultation or wider stakeholder-engagement procedure.

No disagreement requiring application of the procedure under Article 4(7) of the FNA Methodology arose or was identified during the preparation process. Updates and methodological clarifications requested by the Agency were addressed through the iterative exchange of information with ELES and the study consortium. The editorial requirements for this section—including the identification of the bodies responsible for data and analysis, drafting, amendment, approval and adoption, together with the organisation of operator contributions, timelines, data flow, stakeholder engagement and potential disagreements—are thereby covered.

1.4. Key definitions

For the purposes of the FNA methodology, the definitions in Article 2 of the Electricity Directive, Article 2 of the Electricity Regulation, and Article 2 of the ERAA methodology apply.

In addition, the following definitions apply:

- ‘climate year’ means a climatic year or weather scenario simulated within ERAA or NRAA. For the purpose of the FNA methodology, the terms ‘climate year’ and ‘weather scenario’ are given the same meaning;
- ‘congestion issue’ means a situation in which the electric current flow through a physical asset exceeds operational limits;

- ‘covered DSO flexibility needs’ means flexibility needs that are expected to be resolved within the planning horizon through the combination of non-wire solutions and realistically implemented network reinforcement measures considered in the assessment;
- ‘D-1’ refers to the latest forecast reported at, in local time of the bidding zone, 12:00 the day before real-time observation in the same bidding zone;
- ‘daily timeframe’ means a timeframe for the characterisation of flexibility needs which occur at the level of the single day of the year. Depending on the specific indicator, daily values can be further characterised (e.g. cumulated, averaged, etc.) to provide statistical insight on flexibility needs;
- ‘demand’ means the total instantaneous electricity consumption observed in the transmission and distribution systems, including the network losses;
- ‘demand response’ means a change in electricity consumption by consumers in response to market signals, contractual activation or system needs;
- ‘designated authority or entity’ means the regulatory authority or another authority or entity designated by a Member State to receive the data and analysis submitted by TSOs and DSOs pursuant to Article 19e(3) and adopt the FNA report pursuant to Article 19e(1) of the Electricity Regulation;
- ‘dispatchable assets’ refers to assets (as individual units or aggregated) which are controllable by market participants or system operators to manage system or network needs;
- ‘downward flexibility needs’ means the needs whose solution requires either decreasing injection into the network or increasing demand from the network;
- ‘DNO area’ means the geographical service area of one of the five Slovenian electricity distribution companies;
- ‘energy storage’ means an asset capable of withdrawing electricity from the system, storing it and subsequently reinjecting it or otherwise making the stored energy available;
- ‘economic dispatch (ED)’ means a mathematical optimisation model as described in Article 7 of the ERAA methodology;
- ‘economic viability assessment (EVA)‘ means a model assessing the profitability of capacity resources, informing decisions on retirement, mothballing and re-entry, renewal/prolongation and new-build of a capacity resource as described in Article 6 of the ERAA methodology;
- ‘ERAA’ means the most recent European resource adequacy assessment conducted by ENTSO-E pursuant to Article 23 and approved by ACER pursuant to Article 27 of the Electricity Regulation;
- ‘ERAA methodology’ means the methodology for the European resource adequacy assessment developed by ENTSO-E pursuant to Article 23(3) of the Electricity Regulation;
- ‘explicit flexibility’ refers to the controllable adjustment of electricity consumption, generation or storage that can be contractually procured and activated to provide a specific system or network service;
- ‘fast flexibility’ means the capacity able to react to aggregated D-1 or shorter error variations (15 to 60 minutes before real-time);
- ‘forecast error’ means the difference between the forecast and realised value of electricity demand or generation for a given timeframe:
- ‘forced outage’ means the unplanned unavailability of a generation, storage or network asset;
- ‘flexibility resource’ means a generation, demand, storage or interconnection resource capable of adjusting its injection into or withdrawal from the electricity system in response to system or network needs;
- ‘FNA report’ means a report on the estimated flexibility needs for a period of at least the next 5 to 10 years adopted at national level pursuant to Article 19e(1) of the Electricity Regulation;
- ‘hourly timeframe’ means a timeframe for the characterisation of flexibility needs which occur at the level of the single hour of the year. Depending on the specific indicator, hourly values can be further characterised (e.g. cumulated, averaged, etc.) to provide statistical insight on flexibility needs;

- ‘implicit flexibility’ refers to the adjustment of electricity consumption, generation or storage resulting from predefined technical characteristics, local control functions, economic signals or autonomous customer behaviour, without direct contractual procurement or activation by the system operator;
- ‘local service’ means energy or capacity procured by a TSO or DSO to solve congestion or voltage issues they have identified in their systems;
- ‘local maximum value’ means the maximum flexibility (expressed in MW) needed to solve a congestion or voltage issue on a given asset during a given time block;
- ‘market time unit (MTU)’ means the time interval used for scheduling, dispatch and the calculation of flexibility needs. In this assessment, the MTU is one hour;
- ‘must-run generation’ means generation that is assumed to operate independently of the economic-dispatch result due to technical, operational or other constraints;
- ‘NECP’ means an integrated national energy and climate plan pursuant to Regulation (EU) 2018/1999;
- ‘network flexibility needs’ means the flexibility needed to adjust for grid availability, by means of preventing or solving congestion or voltage issues, across relevant timeframes;
- ‘non-dispatchable generation’ refers to assets which are constrained in controllability of injections following weather or other conditions such as wind, solar and run-of-river hydro generation;
- ‘NRAA’ means the most recent national resource adequacy assessment pursuant to Article 24 of the Electricity Regulation. If an NRAA is subject to ACER's opinion pursuant to Article 24(3) of the Electricity Regulation, it shall only be considered for the purposes of the FNA methodology once it is amended in accordance with ACER’s opinion or accompanied by a report detailing the reasons for not fully incorporating ACER's opinion;
- ‘ramping needs’ refer to needs associated with variations of the residual load assuming perfect forecast conditions;
- ‘reference network’ refers to a representative network model developed to reflect the characteristics of a group of real distribution networks, used for the simulation of future network operation and flexibility needs;
- ‘RES curtailment’ means limiting the generation or transmission of renewable power for system operational reasons or grid-capacity reasons;
- ‘RES integration needs' refers to the quantity of flexibility required for the Member State to achieve its annual RES integration target;
- ‘RES integration target’ refers to the maximum RES curtailment amount or share compatible with the RES target for the Member State. It is expressed either as a maximum RES curtailment in absolute terms, or as a maximum RES curtailment in relative terms to the total RES generation or to the total electricity demand, or symmetrically as the minimum effectively integrated (i.e., non-curtailed) RES generation in absolute terms or in relative terms to the total RES generation or to the total electricity demand;
- ‘RES target’ refers to the national target for RES in the electricity sector of the most recent NECP or from another relevant official national document consistent with the most recent NECP. It is either expressed as a RES volume in absolute terms or as a share of RES production in relative terms to the total electricity demand;
- ‘residual load’ refers to the total demand minus non-dispatchable generation (as individual units or as aggregated units), such as from wind or solar as well as generation, subject to must-run conditions per market time unit;
- ‘rule-based operational measures’ refers to predefined automatic control actions implemented according to fixed technical rules or settings, without real-time optimisation or direct activation by the system operator;
- ‘seasonal timeframe’ means a timeframe for the characterisation of flexibility needs which occur at the level of the single month of the year. Depending on the specific indicator, monthly values can

be further characterised (e.g. cumulated, averaged, etc.) to provide statistical insight on flexibility needs;

- ‘short-term flexibility needs’ means needs associated with unexpected variations of the residual load such as forced outages of assets during the intraday or balancing timeframe;
- ‘slow flexibility’ means the capacity able to react to aggregated D-1 or shorter horizons forecast error (60 minutes to 24 hours before real-time);
- ‘system flexibility needs’ means the flexibility needed by the electricity system to adjust to the variability of generation and consumption patterns, across relevant market timeframes;
- ‘target year’ means a year for which data and analysis are provided within the framework of the FNA methodology;
- ‘uncovered flexibility needs’ means the additional flexibility needs identified by the FNA methodology, not expected to be met by new or existing resources based on ERAA or NRAA inputs;
- ‘uncovered DSO flexibility needs’ means flexibility needs that remain unaddressed after considering the combination of non-wire solutions and realistically implemented network reinforcement measures included in the assessment;
- ‘upward flexibility needs’ means needs whose solution requires either increasing injection into the network or decreasing demand from the network;
- ‘voltage issue’ means a situation when voltage levels are not within the operational limits;
- ‘non-wire DSO solutions’ comprise all measures applied to mitigate network constraints prior to network reinforcement. Within this assessment, they include rule-based operational measures, smart-grid functionalities and explicit flexibility resources, which are evaluated as alternatives to conventional reinforcement for maintaining secure network operation.

Unless the context clearly indicates otherwise, any reference in the FNA methodology to legislation, regulations, directives, orders, instruments, codes, guidance documents or any other enactments shall be deemed to include any amendments, extensions, or re-enactments thereof in force at the relevant time.

2. Methodological aspects

This chapter describes the methodological framework underpinning the national flexibility needs assessment. It presents the data sources, target years, scenarios and key assumptions adopted for the assessment, together with the common modelling framework applied to evaluate system and network flexibility needs. The chapter further describes the independent Economic Dispatch (ED) model, the analytical methodologies used to assess system, transmission network and distribution network flexibility needs, and the fine-tuning approach applied, where applicable, to integrate transmission and distribution network assessments. It also presents any additional national data, assumptions and analyses incorporated into the assessment. Together, these elements constitute the methodological basis for the national flexibility needs assessment presented in this report.

2.1. Data sources

The system flexibility needs assessment uses ERAA 2025 [2] as the reference resource adequacy assessment in accordance with Article 6(4) of the FNA Methodology. In accordance with Article 7(3)(b) of the FNA Methodology, economic dispatch simulations (ED) were conducted independently of the ED results of the ERAA or NRAA. However, all input data used for the ED simulations were aligned with the ERAA/NRAA assumptions in order to ensure methodological consistency, in accordance with Article 6(4). Input data were aligned with the assumptions and datasets of ERAA 2025.

Scenario consistency was ensured through alignment with:

- European resource adequacy assessments (ERAA) reference scenarios – considered versions of ERAA 2024 [1] and 2025 [2],
- ERAA 2025 weather scenarios (climate years) [2],
- Slovenian National Energy and Climate Plan (NECP 2024) [11].

The network needs assessment was based on the following primary planning documents and data sources:

- Transmission System Development Plan of the Republic of Slovenia for the period 2025–2034 [4];
- Data on cross-border transmission capacity provided by TSO;
- Distribution network development plan (DNDP) 2025–2034 – October 2025 [5];
- Slovenian National Energy and Climate Plan (NECP 2024) [11].

The DSO network needs assessment was primarily based on the Distribution Network Development Plan (DNDP) 2025–2034 [5] and the updated National Energy and Climate Plan (NECP, 2024) [3]. During the preparation of the FNA, the DSO was simultaneously preparing the forthcoming DNDP (2027–2036), which was, at that time, undergoing public consultation [9]. Consequently, where the information contained in the final version of their latest adopted DNDP (2025–2034) was considered insufficient to adequately represent the expected future state of the distribution system, updated or additional assumptions, methods and input data were applied in accordance with Article 6(7) of the FNA Methodology. These included methodological refinements and updated input datasets that became available after the adoption of the DNDP 2025–2034 but before publication of the DNDP 2027-2036 (expected in January 2027). Their use was considered necessary to provide a more realistic representation of the future development and operation of the distribution network, while maintaining consistency with the planning assumptions being developed for the forthcoming DNDP (2027–2036).

In addition to these primary planning documents, the DSO assessment relied on supplementary data sources and scientific literature to develop the underlying modelling assumptions for building characteristics and heating electrification [11], [24]–[26], electric vehicle charging behaviour [10], [27]–[31], additional implicit flexibility due to the effect of network charge [20]-[23], annual growth rate in consumption at the LV level [9]. These supporting data sources are documented in the underlying technical study and its bibliography [33] and were used to ensure a technically robust representation of future distribution network operation.

A detailed description of the modelling approach, including the methodological enhancements and the underlying assumptions, is provided in Sections 2.3.7.2 and 3.1.2.1.

2.2. Target years considered

The assessment considers two target years:

- 2030, representing the EU policy target year; and
- 2035, representing an additional assessment year.

Both target years are assessed using the DU-OVE (Additional Measures) national scenario defined in the National Energy and Climate Plan (NECP 2024 [11]) and the selected Weather Scenarios (WS) described in Section 2.3.1.

2.3. Modelling approach

This section describes the modelling approach applied to assess flexibility needs in the national Flexibility Needs Assessment. It presents the application of weather scenarios, the independent Economic Dispatch (ED) model used to simulate future power system operation, and the modelling of additional flexibility resources, cross-border exchanges and residual load forecast errors. The section further describes the methodologies applied to assess system, transmission and distribution network flexibility needs, together with the fine-tuning approach used, where applicable, to integrate transmission and distribution network assessments.

2.3.1. Weather scenarios

The TSO system and network flexibility needs assessment is performed using the assumptions from DU-OVE (Additional Measures) national scenario from the National Energy and Climate Plan (NECP) - The Second version from year 2024 [11], representing significant deployment of solar PV as the predominant RES technology and electrification of demand. Considered five Weather Scenarios (WS) comply with European Resource Adequacy Assessment (ERAA) 2025 [2].

The analysis is performed for target years 2030 and 2035. For each target year, multiple WS consistent with the assumptions of ERAA 2025 are considered. WS correspond to the climate years used in economic dispatch simulations in ERAA and ensure compliance with Article 6(5) of the FNA methodology. The considered WSs do not represent predictions of the future but rather represent weather and energy conditions for stress testing the system.

The considered WS were selected through a screening of the full 36 scenarios provided by ERAA 2025 based on residual load indicators, ensuring representation of extreme surplus, high demand, high ramping and the most typical conditions. In general, ERAA WS represent three possible evolutions of climate, each with 12 weather conditions, resulting in a total of 36 WS. The considered WS in the analysis were the following: WS18, WS23, WS25, WS27 and WS35.

The WS selected were not predefined by qualitative labels (i.e., descriptive names such as 'High demand' or 'Typical conditions'), but were interpreted based on indicators such as residual load, ramping requirements and surplus generation, ensuring a consistent and data-driven characterisation. These qualitative labels were assigned for easier interpretation. WS23, WS27 and WS35 were also selected as WS for the cost-minimisation EVA in ERAA 2025, aiming to select the most representative sub-group of WS.

The selected WS are characterised as follows:

- WS18 (High demand conditions): Reflects elevated residual load associated with high demand levels.

- WS23 (High surplus conditions): Characterised by low residual load levels and significant surplus generation.
- WS25 (High variability conditions): Represents the highest residual load variability and ramping requirements.
- WS27 (Typical conditions): Represents median system conditions across the full set of weather scenarios.
- WS35 (Representative conditions): Selected in line with the ERAA methodology as a representative weather scenario.

The time series values for the selected scenarios were adjusted based on the values of the baseline (base) scenario NECP 2024 DU-OVE. The adjustment was made to preserve the averages and aggregated values for both target years while maintaining the fluctuations due to weather conditions. The ERAA 2025 time series used were related to PV production, load, and hydrology.

2.3.2. Economic Dispatch modelling

In accordance with Article 7(3)(b) of the FNA methodology, Economic Dispatch (ED) simulations were conducted independently of the ED results of the ERAA or NRAA. However, all input data used for the ED simulations were aligned with the ERAA/NRAA assumptions in order to ensure methodological consistency, in accordance with Article 6(4). Input data were aligned with the assumptions and datasets of ERAA 2025. It should be noted that the FNA input templates are designed for analyses based on the ERAA dataset. The Slovenian assessment was carried out using its own modelling framework and ED tool with dedicated input datasets. As a result, certain input parameters requested by the methodology templates are not available in the same format. Where required, equivalent values from the ERAA dataset may be used as reference information to complete the templates.

The assessment is based on:
- an independent economic dispatch (ED) - unit commitment and economic dispatch - simulation consistent with ERAA 2025 reference scenarios [2],
- a structured integration of the Economic Viability Assessment (EVA) and
- explicit modelling of technical constraints.

As the basic building block of the mathematical model for ED, the Python library PyPSA (Python for Power System Analysis) [13] is used. PyPSA is an open-source software library intended for the simulation and optimization of advanced power systems.

The assessment of system needs is performed in accordance with Article 7(3)(b) through an independent economic dispatch simulation consistent with ERAA scenario assumptions and enhanced with additional technical parameters such as ramping constraints, minimum up/down times, start-up/shut-down constraints and planned maintenance schedules.

In addition, the availability of generation units and transmission lines to some extent is modelled probabilistically through the forced outage rate (FOR).

2.3.3. Approach to compute additional flexibility resources to meet the RES integration target

The assessment was performed as a post-processing analysis based on the hourly residual load time series obtained from the ED simulation, which in this analysis served as the basis for quantifying potential RES curtailment. Technology-neutral additional flexibility resources were layered on the residual load time series to evaluate their capability to absorb periods of negative residual load (RES surplus) and thereby reduce the remaining RES surplus and the associated potential RES curtailment.

The assessment was carried out for the most critical WS in each target year, defined as the scenario with the highest identified RES integration needs. The installed power of the additional flexibility resources was selected to approximately correspond to the identified maximum uncovered RES integration needs.

The additional flexibility resources were characterised by:

- installed power,
- energy-to-power (E/P) ratio,
- availability, and
- round-trip efficiency.

The assessment considered E/P ratios of 2, 4, 8, 20, 50, 100 and 200 hours, in accordance with Article 8(10) of the FNA methodology. The corresponding energy capacities were determined as the product of the installed power and the selected E/P ratio. Representative round-trip efficiencies (RTEs) were assigned to each E/P ratio. The corresponding values are presented together with the assessment results.

The additional flexibility resources were operated using a simple rule-based strategy. Charging occurred whenever the residual load was negative, limited by the available charging power and the remaining energy capacity of the resources. Discharging occurred whenever the residual load became positive, using the same power rating and accounting for the specified RTE. The remaining capacity was tracked continuously throughout the simulation, allowing multiple charge/discharge cycles over the analysed year. The charge/discharge cycles were not limited.

The benefit of the additional flexibility resources was quantified through the reduction of the remaining maximum RES surplus, RES surplus energy, and the number of hours with remaining surplus, resulting in lower RES integration needs.

2.3.4. Consideration of cross-border flexibility

Cross-border energy exchange was represented in the economic dispatch and therefore influenced the dispatch of domestic generation. However, cross-border flexibility was not considered as an available flexibility resource for covering the identified flexibility needs. Due to the high level of interconnection of the Slovenian power system, cross-border exchange could potentially contribute to covering part or even the whole of the identified flexibility needs. Nevertheless, the objective of this assessment was to quantify national flexibility needs and the capability of domestic flexibility resources to meet those needs. Furthermore, an adequate assessment of cross-border flexibility would require modelling the flexibility resources, network constraints and market interactions across the interconnected European power system. Such an assessment was not feasible within the scope of this study and was therefore not performed. Consequently, cross-border flexibility was not considered as a resource available for covering the identified national flexibility needs.

The transmission capacities are determined based on actual commercial flows for the year 2025 (95th percentile), as provided by the TSO, and updated in accordance with the Slovenian Transmission System Development Plan. Energy exchanges are represented using Net Transfer Capacities (NTC).

As a methodological simplification, cross-border exchange capacities are not explicitly modelled in the ramping margin calculation or in the short-term flexibility margin calculation. Furthermore, neighbouring transmission systems are not explicitly represented in the transmission network simulations. These simplifications were adopted due to the limited availability of reliable cross-border exchange data and the relatively low impact of cross-border exchanges on the assessment of national flexibility needs.

2.3.5. Modelling of residual load forecast errors

Residual load forecast errors are defined at Market Time Unit (MTU) granularity as the difference between the D-1 forecast of residual load and its real-time observations:

$$\varepsilon(t) = RL_{D-1}(t) - RL_{real}(t), \tag{1}$$

where:

- $RL_{D-1}(t)$ denotes the day-ahead forecast of residual load and
- $RL_{real}(t)$ denotes the realised residual load observed in real time.

For Slovenia, load and solar generation forecasts are considered the primary sources of forecast uncertainty affecting residual load. Other RES technologies (e.g. wind and hydro) are not explicitly modelled as sources of forecast uncertainty affecting residual load and Short-Term Flexibility Needs due to limited data availability. Their impact is implicitly captured within residual load variability. This simplification is considered acceptable given the dominant contribution of solar generation to uncertainty in the analysed scenario.

A methodological question concerns the choice of forecast error horizon. Although market participants adjust their positions until intraday gate closure, the adopted approach uses D-1 forecast errors. Using D-1 errors reflects the system's need for flexibility after day-ahead market closure, while using intraday or H-1 errors would implicitly assume that sufficient market-based flexibility is always available through intraday trading. The use of D-1 errors therefore provides a conservative and system-oriented estimate of short-term flexibility requirements.

Historical day-ahead forecasts and realised values of load and solar generation published on the ENTSO-E Transparency Platform and provided by the TSO (ELES) are used to construct empirical forecast error series. The data are cleaned to remove missing values, inconsistencies and obvious outliers. The resulting dataset is statistically characterised through mean, variance, skewness, kurtosis and percentile analysis, and differentiated according to meteorological seasons and system conditions. At least two years of historical data are used in accordance with Article 10(1).

Based on information provided by the TSO (ELES), new forecasting models for electricity consumption (load) and PV generation have been implemented since the beginning of 2026. The new forecasting models for the beginning of 2026 did not show any significant differences in their forecasts compared to the old ones. In accordance with the FNA methodology, the historical datasets for the years 2024 and 2025 were used.

Forecast errors are subsequently adjusted for the analysed target years to reflect the assumptions adopted in this assessment regarding projected demand growth, increases in installed solar capacity and expected improvements in forecasting techniques. Monte Carlo simulation is then applied to generate synthetic forecast error time series that are statistically consistent with empirical distributions derived from historical observations. Monte Carlo simulation thus generates synthetic sequences $\varepsilon^*(t)$ preserving:

- empirical variance and skewness,
- autocorrelation structure,
- seasonal dependence and patterns,
- hour-of-day dependence.

In addition to forecast errors, generation availability is also treated probabilistically through the forced outage rate (FOR). Within the Monte Carlo framework, unit and line availability states are sampled to reflect random forced outages of generation units and lines. This results in time-varying available generation and transmission capacity across simulations and ensures that short-term flexibility needs capture not only forecast uncertainty but also stochastic generation and line outages. The combined representation of forecast errors and forced outages provides the stochastic input for the assessment of short-term flexibility needs.

The resulting statistical representation forms the basis for generating synthetic forecast error scenarios representing possible future realisations of forecast errors. These scenarios constitute the stochastic input for the assessment of short-term flexibility needs described in Section 2.3.6.3.

2.3.6. Methodology for the assessment of system flexibility needs

This section describes the TSO methodology used to assess system flexibility needs, including:

- RES Integration Needs;
- Ramping needs; and
- Short-term flexibility needs.

The assessment is based on independent economic dispatch (ED) as explained in section 2.3.2.

Although Article 7(4)(i) allows the use of ERAA or NRAA economic dispatch results for ramping and short-term needs, the present methodology performs an independent assessment of these flexibility needs. The methodologies applied for the assessment of ramping needs and short-term flexibility needs are described in the following sections.

The assessment was performed using an independent ED simulation consistent with ERAA scenario assumptions and enhanced with additional technical parameters including ramping constraints, minimum up/down times, start-up/shut-down constraints, planned maintenance schedules and probabilistic modelling of generation and transmission availability through forced outage rates (FOR).

The Economic Viability Assessment (EVA) was structurally integrated into the assessment. The methodology relies on the resulting equilibrium generation portfolio derived from the ERAA EVA process and does not independently re-run the EVA assessment. The EVA assessment, adopted as the structural baseline for this methodology pursuant to Article 7(1), can be mathematically described as a dynamic portfolio optimization equilibrium process. The EVA convergence condition can be expressed as:

$$G^* = \Phi(G^*), \tag{2}$$

where G^* denotes the equilibrium generation portfolio and $\Phi(.)$ represents the profitability-driven portfolio update operator.

The iterative steps are as follows:

- perform economic dispatch given portfolio G^*;
- compute revenues R_i and total costs C_i for each unit i;
- remove units with $R_i - C_i < 0$ over the evaluation horizon;
- update G^* and repeat until portfolio stability is achieved.

This ensures that the structural generation mix used in the flexibility needs assessment reflects long-term market equilibrium conditions consistent with ERAA.

Implementation of Article 7(1)

A formal EVA was not performed due to its high complexity and the need for a comprehensive market-based analysis that would require consistent modelling of neighbouring countries. Such an assessment is currently not feasible due to limited data availability. Previous ERAA assessments that included EVA have consistently indicated the phase-out of coal/lignite generation in Slovenia together with a moderate increase in demand-side response. These characteristics are reflected in the assumptions adopted in this assessment. Consequently, the adopted generation portfolio is intended to remain structurally consistent with the expected outcome of the ERAA Economic Viability Assessment (EVA), although a formal EVA was not performed. The only intentional deviation concerns Thermal power plant Šoštanj unit 6, hereinafter referred to as TES6 in 2030. Following its designation as a public service obligation, its operation is no longer determined solely by market profitability. For this reason, TES6 is retained in the model as a non-market must-run generation unit operating at its minimum technical output, taking into account its role in district heat supply.

2.3.6.1. RES Integration Needs

Renewable Energy Sources (RES) integration needs are evaluated using residual load time series derived from the economic dispatch (ED) simulations. In the implemented assessment, RES integration needs are determined directly from the residual load time series, while explicit RES curtailment time series are not derived from the economic dispatch results.

In accordance with the derogation provided for the first FNA report under Article 8(3) of the FNA Methodology, the quantified RES integration needs remain based solely on negative residual load conditions and do not include the additional RES curtailment resulting from ramping needs and short-term flexibility needs.

Residual load time series are derived as demand minus non-dispatchable generation (wind, solar and other RES subject to forecast errors). Negative residual load represents periods during which available RES generation together with must-run generation exceeds demand, indicating the need for additional downward flexibility to enable RES integration.

The Slovenian NECP does not define an acceptable or maximum level of RES curtailment for the analysed scenarios. Therefore, this assessment adopts a zero-curtailment assumption, meaning that. the power system is assumed to be able to integrate all available RES generation. Consequently, the entire negative residual load is treated as the RES integration need before any RES curtailment is considered.

All considered RES generation is treated as non-dispatchable and is therefore not an optimisation variable in the economic dispatch model. Consequently, explicit RES curtailment is not obtained as an optimisation result. Instead, negative residual load is used to identify periods of surplus generation requiring additional flexibility and is therefore used as the indicator of RES integration needs before any RES curtailment is considered**.** Since the available cross-border transfer capacity is sufficient to accommodate the simulated RES surplus in the analysed target years, interconnection capability does not constitute a limiting factor in this assessment. Furthermore, the economic dispatch model does not explicitly represent the underlying causes that could lead to RES curtailment, such as network constraints.

For reference, potential RES curtailment may generally be expressed as the remaining surplus after accounting for exports and existing flexibility resources. However, this relationship is not applied in the present assessment. Instead, negative residual load is used as the indicator of RES integration needs.

The residual load time series derived in this step also provide the basis for the assessment of ramping needs and short-term flexibility needs described in Sections 2.3.6.2 and 2.3.6.3.

2.3.6.2. Ramping Needs

With regard to Article 7(4), the adopted modelling approach embeds both ramping constraints and short-term forecast error representations directly within the economic dispatch simulation.

Ramping needs are quantified by analysing consecutive Market Time Unit (MTU) variations of residual load under perfect forecast conditions. Upward and downward ramping requirements are compared with the available ramping capability of dispatchable generation, as determined by the economic dispatch results.

The residual load variation between consecutive MTUs is defined as:

$$\Delta RL(t) = RL(t) - RL(t-1). \quad (3)$$

The available ramping margin $M_{ramp}(t)$ is derived from the realised dispatch obtained from the economic dispatch simulation. It represents the aggregated feasible ramping capability of dispatchable generation while respecting the technical constraints represented in the economic dispatch model.

The assessment uses an hourly MTU, consistent with the temporal resolution of the available input datasets and the continued hourly discretisation of cross-border transfer capacity allocation. Generation availability is adjusted using forced outage rates (FOR), ensuring that the available ramping capability reflects the capacity expected to be operational in each MTU.

Uncovered ramping needs are identified whenever the corresponding residual-load variation exceeds the available ramping capability.

The uncovered ramping need in each MTU is mathematically defined as:

$$U_{ramp}(t) = \max\left(0, |\Delta RL(t)| - M_{ramp}(t)\right). \quad (4)$$

Reserve capacities (FCR, aFRR, mFRR) are excluded from the ramping margin calculation to avoid double counting. Cross-border exchanges are not explicitly represented in the national ramping assessment.

In accordance with the derogation provided for the first FNA report under Article 8(3) of the FNA Methodology, downward uncovered ramping needs were quantified separately and were not incorporated into the quantified RES integration needs.

No formal fine-tuning of ramping needs related to the temporary unavailability or prequalification limitations of flexibility resources was performed because the required information was not available for the analysed target years.

2.3.6.3. Short-Term Flexibility Needs

The stochastic input described in Section 2.3.5 is used in the assessment of short-term flexibility needs. The assessment evaluates whether the remaining short-term flexibility available after the day-ahead economic dispatch is sufficient to accommodate forecast errors under the simulated operating conditions.

The calculation of short-term flexibility needs is performed using a two-stage assessment procedure. The assessment is performed using annual time series (8760 hours) in order to capture both short-term dynamics and seasonal effects. Where computational complexity becomes excessive in terms of computation time, memory or processing capacity, representative weeks may be used instead of full annual time series while preserving the principal seasonal characteristics of system operation.

In the first stage, economic dispatch is performed using the day-ahead forecast of residual load in order to determine the economically optimal generation schedule. The optimisation is subject to the technical constraints represented in the economic dispatch model. Following the day-ahead dispatch, part of the technically available generation capacity may remain unused. This remaining available capacity represents the short-term flexibility available to respond to forecast errors.

In the second stage, the remaining short-term residual margins resulting from the day-ahead economic dispatch are compared with the simulated forecast errors. Where the available residual flexibility is insufficient to accommodate the forecast error, the remaining imbalance is quantified as an uncovered short-term flexibility need.

This procedure is executed for all generated synthetic time-series realisations. The resulting flexibility needs are then statistically evaluated in order to determine their distribution under different system conditions. This allows the identification of both typical and extreme flexibility requirements.

The 0.1 and 99.9 percentiles of the resulting short-term flexibility need distributions define downward and upward short-term flexibility needs, respectively. These requirements are compared against the short-term residual margins of dispatchable assets in order to determine potential uncovered flexibility needs.

Frequency Containment Reserve (FCR) capacity is excluded from the available short-term residual margin in this analysis. The reason is that FCR is already reserved for maintaining system frequency stability in case of disturbances and cannot be simultaneously relied upon to manage forecast errors without risking double counting of flexibility resources. Excluding FCR therefore ensures a consistent and conservative estimation of the flexibility available for balancing forecast errors.

The uncovered short-term flexibility need in each MTU is defined as:

$$U_{ST}(t) = \max\big(0, \varepsilon(t) - M_{ST}(t)\big). \tag{5}$$

where:

- $M_{ST}(t)$ denotes the available short-term residual margin,
- $\varepsilon(t)$ denotes the forecast error,
- $U_{ST}(t)$ denotes uncovered short-term flexibility needs.

Cross-border exchanges are not explicitly represented in the national short-term flexibility assessment.

In accordance with the derogation provided for the first FNA report under Article 8(3) of the FNA Methodology, downward uncovered short-term flexibility needs were quantified separately and were not incorporated into the quantified RES integration needs.
No formal fine-tuning of short-term flexibility needs related to the temporary unavailability or prequalification limitations of flexibility resources was performed because the required information was not available for the analysed target years.

Uncovered short-term flexibility needs are further analysed in terms of frequency, duration, magnitude and energy in accordance with Article 10(6).

2.3.7. Consideration of network needs

This subsection is further divided into two parts – one for the transmission system and the other for the distribution system.

2.3.7.1. Consideration of transmission network needs

The assessment of Network Flexibility Needs is based on a model of the existing Slovenian transmission system (110 kV, 220 kV and 400 kV), as shown in Figure 1. The model is further developed by incorporating investments that are expected to be commissioned by the target years. A detailed list of these investments is provided in the Transmission System Development Plan of the Republic of Slovenia for the period 2025–2034 [4].

Figure 1: Existing and planned HV electric power network of Slovenia

The model includes cross-border connections to neighbouring power systems; however, these systems are not modelled explicitly. At boundary nodes, such as 400 kV Kainachtal, 220 kV Obersielach, and 110 kV Nedeljanec, virtual generators and loads are connected, depending on whether electricity is imported into or exported from Slovenia at a given moment. The limitation of the model is therefore that neighbouring transmission systems are not explicitly represented.

Power plant generation is determined through economic dispatch, which is the result of the system flexibility needs analysis presented in this document. In addition to generation, electricity demand and RES generation are defined by the development scenario used in the FNA analysis. The demand and RES generation apply to the entire Slovenian system, but for the purpose of power flow calculations and the assessment of network flexibility needs, it is necessary to allocate both across the network nodes. The allocation is based on historical electricity consumption patterns. Specifically, data from the year 2024 were used, assuming that the consumption pattern remains valid for the target years 2030 and 2035.

The network flexibility needs assessment is based on AC power-flow simulations evaluating:

- overloading of transmission lines and transformers;
- voltage violations (overvoltage and undervoltage) at network nodes.

Congestion situations are identified where operational limits are exceeded. In addition to thermal constraints, voltage conditions are explicitly assessed, identifying situations where voltage levels deviate from acceptable operational limits. Upward and downward local flexibility requirements are determined in terms of maximum power (MW), energy (MWh), duration and recurrence. A thermal overload is identified when the loading of a line or transformer exceeds 100% of its rated or allowable thermal capacity. A voltage violation is identified when the nodal voltage falls below 0.90 p.u. or exceeds 1.10 p.u.
In the simulations, battery energy storage systems are used as the reference technology for mitigating network issues. The calculation approach assumes virtual storage units with unlimited power and energy capacity connected at all nodes of the network model. These units are optimally activated as needed to eliminate line and transformer overloads or voltage violations. Storage units can operate in both charging and discharging modes, thereby directly influencing power flow directions and network loading. Additionally, they impact voltage conditions in the network.

If network constraints limit the operation of existing flexibility technologies or renewable energy sources, these constraints must be fed back into the System Flexibility Needs assessment and the results adjusted accordingly. The updated results are then used again in the Network Flexibility Needs assessment. The procedure is repeated until convergence is achieved. This iterative procedure reflects the fine-tuning procedure defined in Article 14 of the FNA Methodology.

Figure 2 illustrates the overall calculation process and the interdependencies between the steps.

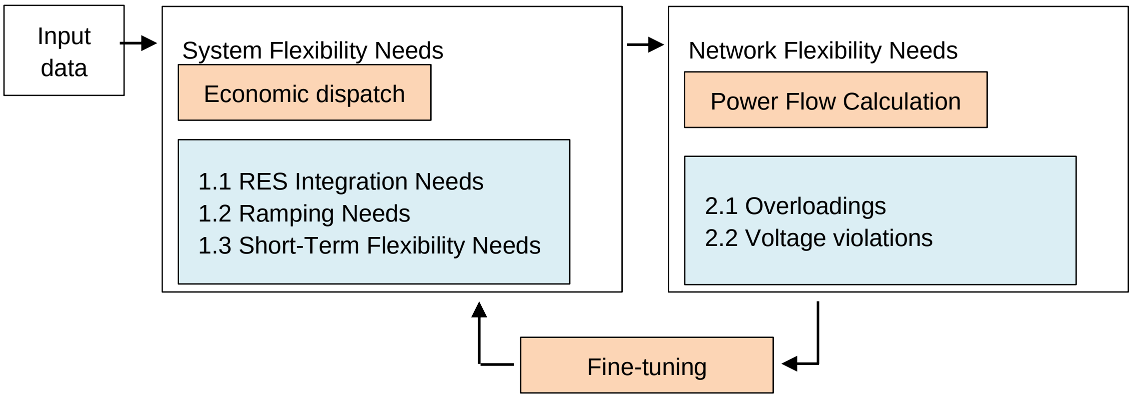


Figure 2: Network Flexibility Needs assessment process including fine-tuning.

The assessment considers both normal operating conditions (N) and contingency situations (N−1) to ensure compliance with the transmission-network security criterion.

For N conditions, the Network Flexibility Needs analysis is based on power-flow simulations for the target years 2030 and 2035, covering the entire annual period from 1 January to 31 December of the respective year. The simulation time step is one hour, consistent with the Market Time Unit (MTU) applied in other analyses.

Due to the computational complexity, for N−1 conditions, the Network Flexibility Needs analysis is based on power-flow simulations for the week with the highest electricity residual demand in the target years 2030 and 2035. The simulation time step is one hour, aligned with the MTU used in other analyses.

The analysis considers outages of 110 kV lines and all transformers at the transmission level. Outages of 220 kV and 400 kV lines are not taken into account, as the model represents only the Slovenian electricity system without neighbouring systems, which are essential for accurately assessing the impact of 220 kV and 400 kV line outages on power flows.

2.3.7.2. Consideration of distribution network needs

The Slovenian distribution network was represented using a set of reference network models covering the medium-voltage (MV) and low-voltage (LV) distribution system. Rather than modelling every individual network, representative network models were developed separately for each of the five Slovenian distribution network operators to capture the characteristic topologies and operating conditions occurring across the Slovenian distribution system.

The definition of reference models assumes that individual networks exhibit similar characteristics, allowing them to be grouped into classes and represented by a single model for each group. Simulations are performed only for the representatives of the defined groups, and the simulation results are subsequently generalised to the entire group and, ultimately, to the whole distribution network using an appropriate methodology. Accordingly, the voltage granularity of the assessment comprised the MV and LV distribution network levels, represented by reference MV feeders and LV distribution networks. The spatial granularity of the assessment corresponded to the level of individual lines and nodes within the individual reference network model, whereas the final reported results were aggregated by representative network type and distribution network operator (DNO) area. For the purposes of this report, DNO areas correspond to the service areas of the five Slovenian electricity distribution companies (Elektro Celje, Elektro Gorenjska, Elektro Ljubljana, Elektro Maribor and Elektro Primorska).

Reference network models were established separately for the MV feeder network and the LV distribution network using a clustering approach based on the k-medoids algorithm with the Euclidean or squared Euclidean distance metric. Four representative clusters were identified for each voltage level. The LV reference models were derived from 11,127 LV network models, provided for all five DNO areas. For the purposes of the FNA, these network models were updated using the latest planning data prepared during the development of the forthcoming DNDP 2027–2036. The MV reference feeders were derived from the complete Slovenian MV network model, and are consistent with the published DNDP 2025–2034. The reference network groups used in the assessment of the distribution network flexibility needs are presented in Table 5.

Table 5: Classification of LV reference network groups and MV reference feeder groups.

LV reference network groups	MV reference feeder groups
urban networks	urban feeders
larger town and suburban networks	industrial feeders
smaller urban and industrial networks	long rural feeders
small rural networks	short rural feeders

The developed reference network models formed the basis of the probabilistic simulation framework used to assess future network operation and identify the DSO network flexibility needs, under projected operating conditions, incorporating future demand, distributed generation, customer technologies and network development assumptions. The platform, presented in Figure 3, combines network models with statistical representations of customer demand, distributed generation and storage, enabling time-series power-flow simulations of representative MV feeders and LV distribution networks.

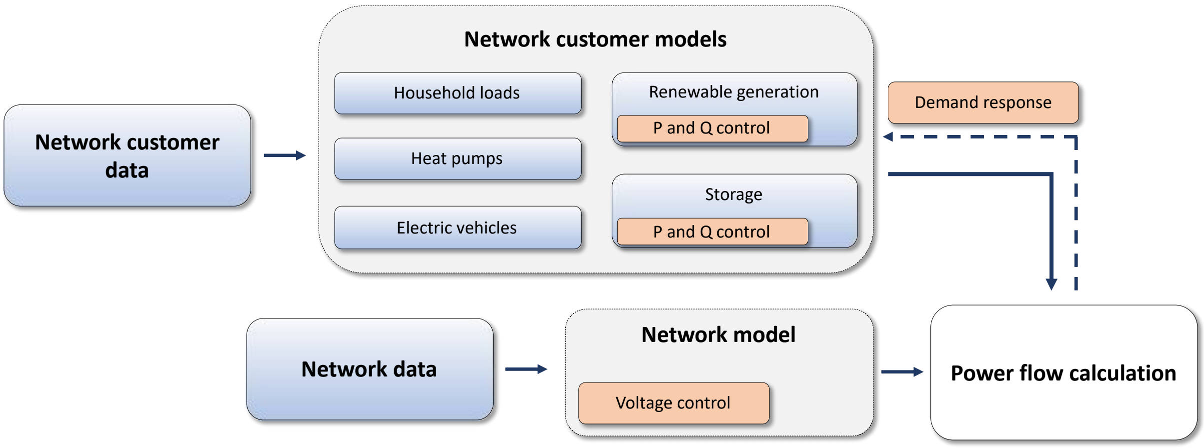


Figure 3: Basic structure of the network simulation tool

The simulation framework comprises two principal components: (i) network models representing the electrical characteristics of the distribution system and (ii) customer models representing electricity demand, distributed generation and battery energy storage systems (BESS). Network models include the electrical topology and technical characteristics of network elements, while customer models represent the behaviour of household demand, heat pumps, electric vehicles, photovoltaic generation and battery energy storage systems. The customer models incorporate implicit and explicit flexibility through the operational characteristics of individual technologies. The generated customer models are allocated to the representative network models and subsequently used as inputs to the probabilistic three-phase power-flow simulation for different operating conditions. The underlying assumptions and input datasets for the network and customer models, including the projected development of demand, distributed energy resources and flexibility resources, as well as the treatment of uncertainties related to the future deployment of EVs, heat pumps, PV systems and BESSs, are presented in Section 3.1.2.1*0*.

The assessment was based on probabilistic sequential Monte Carlo simulations combined with detailed network power-flow analysis with a 15-minute temporal resolution. The resulting flexibility needs are aggregated into representative time blocks and quantified in accordance with Article 11(2)(a) of the FNA Methodology, which expresses flexibility needs in terms of power (MW) and energy (MWh) for each target year. Future operating conditions are represented through multiple probabilistic simulation runs for each representative network, target year and season. The probabilistic approach captures the uncertainty associated with future network operation by varying the spatial allocation of future distributed energy resources and electrified demand, the statistical characteristics of load and generation profiles as customer behavioural diversity, and meteorological conditions represented through temperature and solar irradiation profiles.

Each simulation produces time-series of power flows and voltages throughout the representative network. The calculated operating conditions are evaluated against predefined line and substation thermal loading and voltage criteria to identify network constraints and determine the corresponding flexibility needed in case of violations of these constraints. All simulations are performed using three-phase network models that account for balanced and unbalanced network operation. Customer technologies are represented according to their electrical characteristics and control behaviour, including active and reactive power control where applicable. The simulation procedure for MV networks is similar to that used for LV networks, with the difference that customers are represented by MV/LV distribution substations.

To reflect an acceptable level of planning uncertainty, the assessment is based on the 95th percentile of the probabilistic simulation results, as agreed with the network operator. This percentile represents the agreed level of planning risk adopted for the assessment. This represents an additional methodological deviation from the latest adopted DNDP (2025–2034), which applied the 99.7th percentile.

The simulation framework provides the time-series of network operating conditions that serve as the input to the flexibility needs assessment workflow presented in Figure 4. For each target year, the workflow comprises a sequence of assessment steps, starting with the preparation of future operating conditions and a baseline assessment of the existing distribution network, followed by the evaluation of non-wire alternatives, network reinforcement measures and the determination of realistic flexibility needs. The individual steps of the assessment are described below.

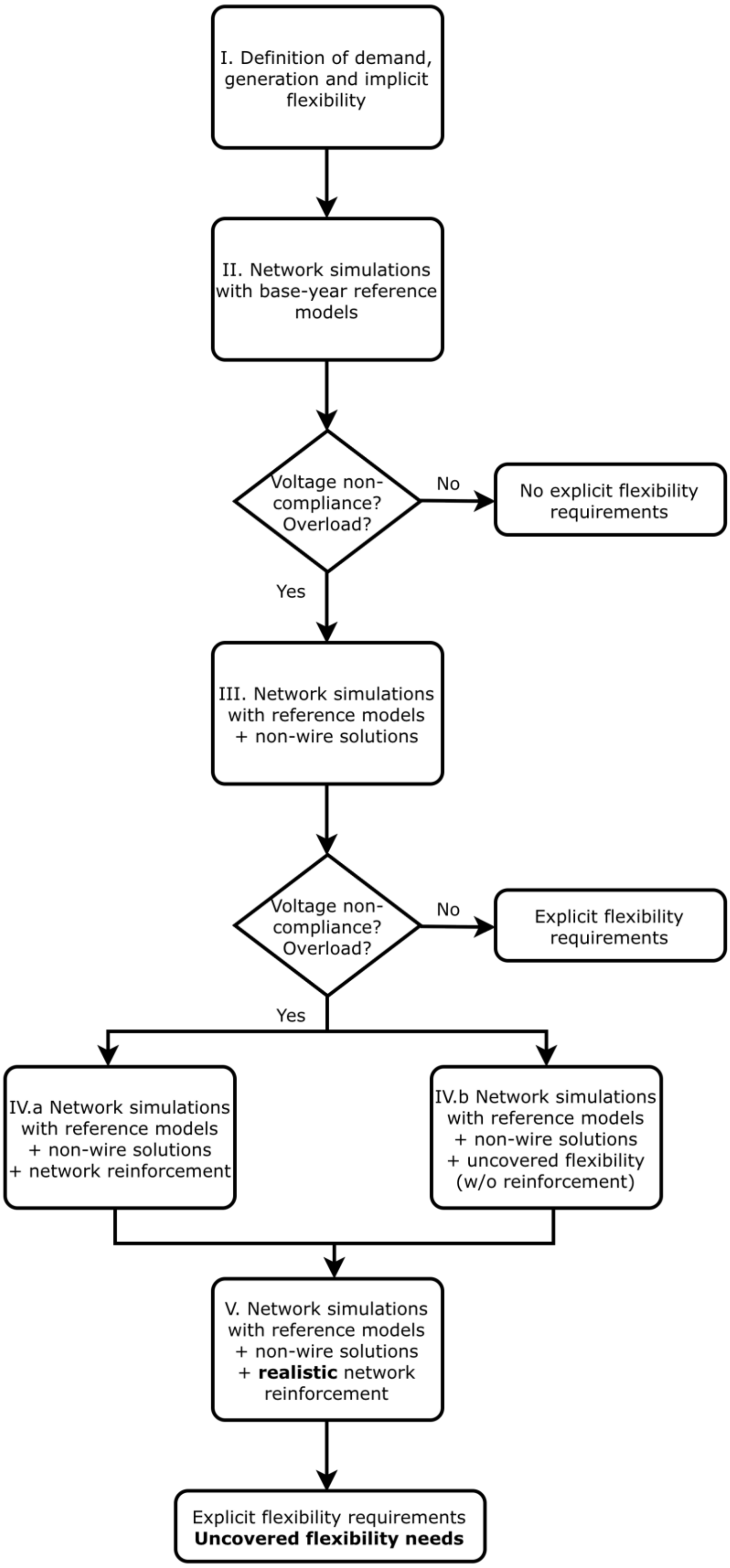


Figure 4: Simulation procedure using reference networks

- *Step I – Definition of demand, generation and implicit flexibility*

Load and generation profiles are generated for each target year, incorporating the projected penetration of distributed energy resources (DER), electric vehicles, heat pumps, battery storage and implicit flexibility assumptions. Rule-based approaches, such as voltage control through reactive power control (Q(U) characteristics) and flexible connection agreements (FCAs), are also included, depending on the target year, resulting in representative operating conditions for the analysed target year.

- *Step II – Baseline assessment of future network operation*

Probabilistic power-flow simulations are performed using the reference network models representing the existing distribution network, while applying the projected demand, distributed generation and implicit flexibility corresponding to the analysed target year. The resulting simulations establish the baseline operating conditions of the existing network under future operating conditions, assuming that no explicit flexibility, smart grid solutions or network reinforcement measures are applied. Accordingly, flexibility needs are determined only where network constraints are identified.

- *Step III – Assessment with non-wire alternatives*

For existing networks exhibiting voltage or thermal constraints, the simulations are repeated, but now considering the applicable non-wire alternatives, which include smart grid solutions (e.g. advanced voltage control), and explicit flexibility (i.e. managed electric vehicle charging and heat-pump demand response). The outputs quantify the required explicit flexibility needs (power, energy and activation duration), residual voltage violations, and residual thermal constraints.

Where the non-wire solutions fully resolve the identified network constraints, the corresponding power, energy and duration are classified as covered flexibility needs, and no further assessment of network reinforcement or uncovered flexibility needs is required. Where residual voltage or thermal constraints remain, these indicate that expected non-wire solutions and available explicit flexibility are insufficient to fully resolve the identified network constraints. The remaining constraints are subsequently assessed through:

  - Step IV.a – Assessment of reinforcement measures

The reinforcement measures required to eliminate the identified voltage and thermal constraints are determined. These include conventional network reinforcement measures such as transformer uprating (replacement with a higher-rated unit at the existing location), installation of new substations, line replacement, underground cabling or deployment of OLTC transformers. This step establishes the technical reinforcement baseline assuming full compliance with the planning criteria. Since network reinforcements affect the required volume of explicit flexibility, the flexibility assessment is repeated following the identified reinforcements.

  - Step IV.b – Assessment of flexibility needs without reinforcement

This step evaluates the flexibility required to resolve all identified voltage and thermal constraints without network reinforcement. Steps IV.a and IV.b are performed in parallel and provide the basis for determining the realistic reinforcement scenario and the remaining uncovered flexibility needs.

- Step V – Assessment of realistic implementation scenario

Since not all technically required reinforcement measures can realistically be implemented within the planning horizon, a realistic implementation rate is assumed, reflecting financial constraints, investment planning cycles, permitting delays and implementation priorities. The final assessment of network-driven flexibility needs is then determined by combining:

- the share of representative network groups in which identified constraints are resolved through realistically implemented reinforcement measures; and
- the remaining representative networks, in which constraints are assumed to be resolved through uncovered flexibility needs.

Finally, the simulation results obtained for the representative network groups of five DNO areas are generalised to the entire Slovenian distribution system using statistical scaling approaches. This provides national estimates of covered and uncovered flexibility needs, transformer reinforcement and replacement needs, feeder reinforcement needs, expected investment costs, and the regional distribution of flexibility demand and network reinforcement needs. While the FNA primarily reports covered and uncovered flexibility needs, the latter outputs provide essential information for long-term distribution network planning and investment prioritisation.

Such multi-step methodology extends traditional deterministic distribution network planning by integrating probabilistic simulations, explicit flexibility resources and other non-wire alternatives into the assessment of future network development. Furthermore, the simulations distinguish between downward flexibility needs arising from renewable generation curtailment and those originating from other network constraints, enabling the reporting of their respective contribution to the total downward flexibility needs.

2.3.8. Fine-tuning approach

The assessment included a partial evaluation of the inputs relevant for the fine-tuning procedure defined in Article 14 of the FNA Methodology. However, the complete fine-tuning procedure was not performed.

The impact of transmission network needs was evaluated by comparing simulation results obtained with and without transmission network constraints for all WS and both target years. The impact of transmission network constraints on uncovered RES integration needs is 0%. Therefore, the relevance threshold of 10% specified in Article 14 of the FNA Methodology is not reached. Consequently, no additional fine-tuning due to transmission network needs was required.

Distribution network needs were quantified using the methodology described in Section 2.3.7.2, including the distinction between covered and uncovered downward flexibility needs resulting from RES generation curtailment. For the purposes of the assessment, a time series of covered flexibility resources from the DSO part was considered. These resources do not constitute distribution network needs in the sense of Articles 11 and 14 of the FNA methodology and thus results were not presented.

No data on the unavailability of flexible resources due to prequalification and temporary limits were available for the analysed target years. Consequently, this input was not considered in the fine-tuning procedure.

2.4. Additional data and analysis

The following section presents the additional data and analyses applied in the national Flexibility Needs Assessment (FNA) in accordance with Article 4 of the FNA Methodology.

No additional data or analyses pursuant to Article 1(6) of the FNA methodology were used for the assessment of system flexibility needs, TSO network flexibility needs or DSO network flexibility needs.

The assessment of DSO network flexibility needs was, however, based on certain justified deviations from the data sources referred to in Article 6(6) of the FNA methodology, implemented in accordance with Article 6(7). These deviations were introduced to reflect the most recent information available during the parallel preparation of the FNA and the forthcoming Distribution Network Development Plan (DNDP) 2027–2036, thereby providing a more detailed and realistic representation of future distribution network operation. The implemented deviations include:

- the use of updated electricity demand and distributed energy resource (DER) development projections prepared for the forthcoming DNDP 2027–2036;
- the use of updated low-voltage reference network models, while the medium-voltage reference feeder models remained consistent with those used in the DNDP 2025–2034;

- updated customer and technology modelling representation including electric vehicles, heat pumps, photovoltaic generation, battery energy storage systems, accounting for implicit and explicit flexibility or rule-based operation;
- methodological enhancements to the probabilistic simulation framework, including the specifics of modelling the future network operation and flexibility assessment; and
- updated network planning assumptions, including the consideration of non-wire alternatives and realistic reinforcement implementation scenarios.

A detailed description and justification of these deviations, together with their compliance with Article 6(7), is provided in Section *3.1.2 Scenarios for network needs.*

3. Scenarios and assumptions description

This chapter describes the scenarios, targets and key assumptions applied in the national Flexibility Needs Assessment. It presents the scenario framework adopted for the assessment of system and network flexibility needs, based on the national NECP 2024 DU-OVE scenario and aligned with the relevant ERAA reference scenarios and selected ERAA 2025 Weather Scenarios, together with the target for renewable energy source (RES) integration and the portfolio of flexibility resources considered in the assessment. The chapter further describes the principal technical, operational and planning assumptions that define the assessment conditions and provide the basis for the flexibility needs assessment results presented in the following chapter.

3.1. Scenarios used to assess system and network needs

This section describes the scenarios adopted for the assessment of system and network flexibility needs. It presents the reference scenario and the corresponding assumptions adopted for the system flexibility assessment, together with the scenarios and input data applied for the transmission and distribution network flexibility assessments

3.1.1. Scenarios for system needs

The scenario framework includes assumptions concerning demand evolution (electrification of transport, heat, industry), RES deployment (PV, wind, hydro), storage capacities, sector-coupling, cross-border exchanges and interconnection availability. The national scenario assumptions are aligned with the ERAA 2024 [1] and ERAA 2025 [2] reference scenarios, the ERAA 2025 weather scenarios, the updated Slovenian NECP 2024 [3] and the national Transmission System Development Plan of the Republic of Slovenia for 2025–2034 [4].

The NECP 2024 DU-OVE (Additional Measures – Renewable Energy Sources (RES)) scenario was selected as the baseline (base) national scenario. The DU-OVE scenario represents Slovenia's most ambitious pathway for the energy transition, focusing on accelerated deployment of solar and wind energy to meet "Fit for 55" targets.

The model focuses on 2030 (medium-term transition) and 2035 (post-coal phase-out). Main assumptions are:

- Nuclear - In both target years 2030 and 2035, the model assumes the continued operation of the existing NEK (Nuclear power plant Krško). However, following official timelines, the planned JEK2 (New Nuclear power plant Krško) is not included in the generation mix for these horizons, as it is not expected to be commissioned before the early 2040s, and it is also not part of the DU-OVE scenario.
- Coal Phase-out: Alignment with the national strategy to fully retire Thermal power plant Šoštanj, unit 6 (TES6) by 2033, therefore the 2035 assessment represents a Slovenian system without coal-fired generation.

Comparison: DU-OVE vs. ERAA 2024 Reference Scenario

While both scenarios share the same national strategic foundation, they differ in several aspects of their implementation within the modelling environment, as summarised in Table 6.

Table 6: Comparison of the NECP DU-OVE and ERAA 2024 Reference Scenarios

Feature	NECP DU-OVE (Our Employed Model)	ERAA 2024 Reference Scenario
Primary Goal	Achievement of specific **policy-driven RES targets**.	Identification of **resource adequacy gaps** on a pan-European scale.
Economic Filter	Fixed capacities based on national strategic plans and EVA.	Subject to EVA; non-profitable units may be retired early.
New Investments	Pre-defined based on the DU-OVE roadmap.	Model-driven; the system "builds" new capacity (e.g., gas or batteries) only if economically justified.
Interconnections	**Isolated Node:** Slovenia is simulated without imports in order to assess the self-sufficiency of flexibility needs coverage. However, imports and exports are included in the ED simulations (through NTC-based exchanges) in order to represent market conditions as realistically as possible.	**Market Coupled:** Assumes full exchange with neighbouring countries (AT, HR, IT, HU). Modelling of the broader network is needed.

Although the economic dispatch simulations were performed independently of the ERAA and NRAA economic dispatch results, all input data were aligned with the ERAA/NRAA assumptions in accordance with Article 6(4) of the FNA Methodology.

Regarding the TSO input data, key datasets include:

- economic and technical data on power plants – Data provided by power plants owners and the TSO. Apart from basic technical parameters such as installed capacity, the data is not publicly available. Data provided in Table 6 (Annex I data category).
- data on cross-border transmission capacity for each neighbouring country – Values determined based on actual commercial flows for the year 2025 (95th percentile), data provided by TSO, capacity increases in accordance with the transmission network development plan – Table 9 (Annex I data category). The analysis took into account energy exchange based on the capacity of interconnections (Net Transfer Capacities – NTC). Flow-based domains are therefore not provided in Table 9 (Annex I data category).
- electricity market prices for neighbouring markets – Assuming full integration of electricity markets in the future, a uniform price is applied across the region SEE and therefore the considered electricity prices are the same in all neighbouring countries – Table 11 (Annex I data category). The prices used represent market price forecasts and not the production units' (power plants) marginal prices. The price forecast used in the analysis is available to the study authors (UL FE–EIMV consortium) and is not publicly accessible.
- Considered future projections of installed renewable energy capacity and new power plants are in accordance with NECP 2024 (DU-OVE scenario – additional measures RES). Considered projections are provided in Tables 11 and 12,
- projections of electricity generation and demand – In accordance with NECP 2024 (DU-OVE scenario),
- historical profiles of electricity generation and consumption, including must-run generation
- Consumption (load) and PV production forecasts – Data (Time series) published on ENTSO-E Transparency platform.
- ERAA 2025 Weather Scenarios used for the selection and characterisation of the analysed weather scenarios [7].

The implementation of the data categories defined in Annex I of the FNA Methodology [12] is documented in Table 7. In accordance with Article 7(2), the dataset used for the assessment combines data sourced from ERAA and/or NRAA with data collected by the TSO at national level. Since the system flexibility needs assessment was performed using an independent national economic-dispatch model pursuant to Article 7(3)(b), Table 7 also identifies the national input data used for each relevant Annex I data category. The comments provided for Tables 1–12 describe the source and implementation of each data category and identify cases where individual template fields were not applicable or were not available in the same format.

Table 7: Implementation of the Annex I data categories

Table	Name	Description	Comment
1	Demand	Time series of demand used as an input for economic dispatch simulations	Time series derived from historical profiles published on the ENTSO-E Transparency platform
2	Reserve requirements	Balancing reserves requirements (FCR, FRR)	Data provided by TSO
3	Installed capacities	Installed Capacities of RES generation and power profiles	Data from NECP, profiles based on the publicly available data from TSO and ENTSO-E Transparency platform
4	Hydraulic generation	Hydraulic generation – Dispatchable hydro generation	Results from ED simulation for hydro production
5	Must run generation	Time series of must-run generation	Data provided by TSO
6	Technical and economic characteristics of dispatchable generation	Input data for ED simulations	Data provided by power plants owners and TSO—fields filled in for all data used in the analysis. Data not publicly available.
7	Investment data	Investment data for new generation units per technology	Investment data in the analysis was not considered, therefore, not all template fields were fulfilled
8	Commodities	Commodities data	Commodities prices included in economic characteristics of dispatchable generation
9	Interconnections	Interconnections capacities – NTC-based	Flow-based domains not used and therefore not provided.
10	Market dispatch per unit	Generation per technology	Results of the economic dispatch
11	Other market dispatch output	Market clearing - Price for neighbouring markets	Electricity market price forecast. Assuming full integration of electricity markets in the future, the price is the same in all neighbouring countries. Data not publicly available.

12	Forecast error	Forecast errors for demand and PV generation[4] forecast for years 2024 and 2025.	Forecast errors defined as the difference between actual and forecast values. All values are publicly available at ENTSO-E Transparency

It should be noted that the FNA input templates are primarily designed for assessments based on ERAA datasets. Since the Slovenian assessment uses an independent national modelling framework and economic dispatch tool, certain template fields are not available in the same format. Where appropriate, equivalent ERAA-based information is used for consistency and completion of the templates.

The production time series of installed PV capacities were determined based on average solar radiation values for Slovenia available in [8]. The official NECP document does not include a complete technology-specific breakdown of RES capacities required for the analysis. Missing values were therefore obtained directly from the entities responsible for preparing the NECP.

A formal EVA was not performed. Instead, the assessment relies on the structural integration of the ERAA Economic Viability Assessment (EVA), as described in Section 2.3.6.

3.1.2. Scenarios for network needs

This subsection is further divided into two parts – one for the transmission system and the other for the distribution system.

3.1.2.1. Scenarios for DSO data

The DSO network flexibility needs assessment is based on input data and scenario assumptions describing the expected evolution of electricity demand, distributed energy resources, flexibility resources and distribution network development operation over the planning horizon. These assumptions define the future operating conditions used to parameterize the probabilistic simulation framework described in Section 2.3.7.2. The assessment covers the target years 2030 and 2035, consistent with the planning horizon defined by the FNA Methodology.

This section describes the principal assumptions applied in the DSO assessment. Unless stated otherwise, the scenario assumptions are based on the Distribution Network Development Plan 2025–2034 (DNDP 2025–2034) [5] and the National Energy and Climate Plan (NECP, 2024) [3]. Where more recent assumptions and datasets became available during the preparation of the forthcoming DNDP 2027–2036 [9], they were incorporated into the scenario definition in accordance with Article 6(7) of the FNA Methodology.

The future network operating conditions were derived from projections of electricity demand and the expected deployment of distributed energy resources. The scenarios reflect the continued electrification of transport and heating, increasing penetration of photovoltaic generation and battery energy storage systems, together with the corresponding evolution of household electricity consumption. The principal quantitative assumptions used in the assessment are summarised in Table 8. The table includes both baseline values for parameters representing the existing electricity system (2025) and planning assumptions that are introduced only for the future target-year scenarios. Consequently, values are provided for 2025 only where a meaningful baseline exists, whereas assumptions relating to the deployment of new technologies or operational concepts are reported only for 2030 and 2035.

[4]Since PV is by far the dominant RES technology, errors in renewable energy production forecasts are taken into account only for PV.

Table 8: Principal quantitative scenario assumptions for the DSO network flexibility needs assessment

Scenario parameter	Unit	2025	2030	2035	Deviation from DNDP 2025–2034
Annual growth in remaining household consumption*	%	1.1% annually over 2025–2035			✓
Heat pumps	Number	118,590	173,150	216,957	—
Battery electric vehicles	Number	28,098	118,681	281,509	✓
Installed PV capacity (LV)	MW	1,191	1,786	2,394	✓
Installed PV capacity (MV)	MW	455	1,341	2,461	✓
Newly connected PV systems equipped with BESS (LV)	%	–	100	100	✓
Newly connected PV systems equipped with BESS (MV)	%	–	50	100	✓
Installed stand-alone BESS capacity (MV)	MW	–	1,000	1,500	✓

**Remaining household consumption, i.e. household electricity consumption excluding heat pumps, battery electric vehicles, and photovoltaic generation.*

The projections of heat pump deployment are consistent with those adopted in the DNDP 2025–2034 and therefore do not constitute a deviation from the published planning basis. The projected number of heat pumps was derived from the updated NECP (2024) and allocated to the representative distribution networks according to the projected number of household customers.

Unlike the DNDP 2025–2034, the updated dataset distinguishes between battery electric vehicles (BEVs) and plug-in hybrid electric vehicles (PHEVs), enabling a more realistic representation of future charging demand within the distribution network. While PHEVs contribute to the overall demand projections, only BEVs were explicitly considered in the modelling of charging behaviour within the representative network models.

The assumptions regarding the deployment of photovoltaic generation, battery energy storage systems and the evolution of remaining household electricity consumption were likewise updated to reflect the most recent national planning assumptions available at the time of the assessment. Distributed energy resources other than photovoltaic generation were not explicitly represented in the assessment, as the DNDP 2025–2034 concluded that their projected penetration is insufficient to have a significant impact on network voltages or the loading of network elements.

The future operating conditions represented in the probabilistic simulations incorporate a range of operational assumptions describing the expected behaviour of considered technologies and the application of network operational measures. These assumptions influence the simulated network operation and, consequently, the identification of network constraints and the corresponding flexibility needs. The DSO assessment distinguishes between implicit flexibility, rule-based and smart-grid operational measures, and explicit flexibility, each serving a different role within the assessment methodology.

Implicit flexibility is embedded within the demand and generation profiles of individual customer technologies and reflects their expected autonomous or market-driven operation under future conditions, without direct activation by a system operator or flexibility service provider. It therefore forms part of the baseline operating conditions described in Section 2.3.7 and is not considered separately as an available flexibility resource.

Rule-based and smart-grid operational measures represent predefined network operating functions that influence network operation independently of flexibility activation. These measures include, where applicable, flexible connection agreements (FCAs), as a rule-based approach to limit active power output in accordance with prevailing network conditions, voltage control through Q(U) characteristics, advanced voltage control at HV/MV substations, use of on-load tap-changer (OLTC) equipped transformers and line voltage regulators, and other operational measures applied in accordance with the planning assumptions for each target year. Similar to implicit flexibility, these measures are incorporated directly into the network simulations and therefore affect the resulting operating conditions rather than constituting flexibility resources.

Explicit flexibility represents controllable flexibility resources that are available to the DSO for mitigating thermal loading and voltage constraints. Within the assessment, explicit flexibility is provided through managed electric vehicle charging and heat-pump demand response, taking into account the applicable planning assumptions for each target year. Consequently, the available flexibility considered in the assessment refers exclusively to explicit flexibility resources.

The technology-specific operational assumptions governing the representation of customer technologies, flexibility mechanisms and network operational measures in the simulations are summarised in Table 9. The second column identifies technologies whose behaviour or operational characteristics are incorporated directly into the network simulations, either through implicit flexibility or through predefined operational measures, while the third column identifies technologies that are assumed to provide explicit flexibility and are therefore considered as available flexibility resources in the assessment. The remaining columns summarise the principal modelling assumptions and their evolution between the 2030 and 2035 target years.

Table 9: Technology-specific operational assumptions applied in the DSO network flexibility needs assessment

Technology	Implicit flexibility / operational measures	Explicit flexibility	Technology-specific modelling assumptions	2030	2035
Remaining household consumption	✓	–	Implicit flexibility driven by consumer response to network tariffs.	3% peak demand reduction through load shifting from the highest to lower network tariff periods	5% peak demand reduction through load shifting from the highest to lower network tariff periods
Heat pumps	✓	✓	Implicit flexibility through 1 °C thermostat setback during the highest tariff period; Explicit flexibility through temporary power reduction preceded by pre-heating, while maintaining acceptable indoor comfort.	Implicit: 10% of HPs; Explicit: 5% of HPs.	Implicit: 20% of HPs; Explicit: 15% of HPs.
Battery electric vehicles	✓	✓	Implicit flexibility through statistical charging behaviour (some vehicles charge during the day, some overnight, the rest according to a probability distribution); Explicit flexibility through controlled shifting of charging from the evening peak to the night period, with full charge required by 05:30.	Implicit: 80% of BEVs; Explicit: 10% of BEVs.	Implicit: 80% of BEVs; Explicit: 20% of BEVs.
Photovoltaic generation (LV)	✓	–	Rule-based active power curtailment P(U), where supported by the applicable planning assumptions.	Existing and new PVs: no voltage control.	Existing PVs: no voltage control. New PVs: P(U) through FCA or DSM*
Photovoltaic generation (MV)	✓	–	Voltage regulation through Q(U) characteristics in accordance with SONDSEE* Rule-based Explicit flexibility through active power curtailment P(U), where supported by the applicable planning assumptions.	Q(U) according to SONDSEE; New PVs: P(U) through FCA or DSM.	Q(U) according to SONDSEE; New PVs: P(U) through FCA or DSM.
Battery energy storage systems (LV)	✓	–	Implicit flexibility through optimisation of self-consumption, market-price arbitrage and network charges.	Customer batteries coupled with PV. Stand-alone batteries operate without FCA.	Customer batteries coupled with PV. Stand-alone batteries connected under FCA.
Battery energy storage systems (MV)	✓	–	Implicit flexibility through peak shaving and market-price arbitrage.	Industrial PV-coupled batteries; Stand-alone BESS (1,000 MW) connected under FCA.	Industrial batteries additionally consider network charge tariffs; Stand-alone BESS (1,500 MW) connected under FCA.

**FCA: Flexible Connection Agreements; DSM: Demand-Side Management; SONDSEE: distribution network operating rules*

The DSO assessment assumes that future distribution network development will be achieved through a combination of conventional network reinforcement and non-wire alternatives. Accordingly, the planning assumptions define both the expected evolution of network infrastructure and the operational measures available to mitigate thermal loading and voltage constraints, including the progressive implementation of non-wire alternatives and flexibility-based network management solutions.

The operational assumptions presented in Table 9 and Table 10 are complemented by network planning assumptions that describe the expected evolution of distribution network operation over the planning horizon. These assumptions determine the availability and applicability of network operational measures and flexibility-based solutions in the 2030 and 2035 target years.

The planning assumptions reflect the progressive implementation of advanced network operation and control capabilities, including voltage control, flexible connection arrangements and the increasing availability of technology-specific explicit flexibility resources. While the overall planning approach remains based on a combination of conventional network reinforcement and non-wire alternatives, the assumed operational capabilities evolve between the target years in accordance with the expected development of distribution network operation and the applicable regulatory framework. The principal planning assumptions adopted for the assessment are summarised in Table 10.

Table 10: Distribution network planning assumptions by target year

Planning assumption	2030	2035
Advanced voltage control at HV/MV substations	Not considered	Considered
Voltage control of photovoltaic generation	LV PV: no voltage control. MV PV: Q(U) in accordance with SONDSEE and P(U) through FCA or DSM	Existing LV PV: no voltage control. New LV PV: P(U) through FCA or DSM MV PV: Q(U) in accordance with SONDSEE and P(U) through FCA or DSM
Flexible Connection Agreements (FCA)	Stand-alone MV BESS; New MV PV generation.	Stand-alone LV and MV BESS; Newly connected LV and MV PV generation.
Availability of technology-specific explicit flexibility	Initial technology-specific participation of explicit flexibility resources (Table 9)	Expanded technology-specific participation of explicit flexibility resources (Table 9)
Realistic implementation of network reinforcement	Applied	Applied

The DSO assessment considers flexibility needs arising from thermal loading and voltage constraints throughout the medium-voltage and low-voltage distribution network under the scenario assumptions described in the previous sections. The assessment quantifies both upward and downward flexibility needs required to maintain secure network operation in accordance with the methodology described in Section 2.3.7.2. Upward flexibility is associated with increasing generation or reducing demand where necessary to alleviate network constraints, while downward flexibility is associated with reducing generation or increasing demand, where necessary to maintain network operation within the applicable planning criteria.

The identified flexibility needs are evaluated under the realistic network development scenario, which combines the assumed availability of explicit flexibility resources with the realistic implementation of network reinforcement measures. Consequently, the assessment distinguishes between:

- covered flexibility needs, representing the portion of identified flexibility requirements that can be met through the explicit flexibility resources assumed to be available under the adopted planning assumptions; and

- uncovered flexibility needs, representing the remaining flexibility requirements after considering both the available explicit flexibility resources and the realistic implementation of network reinforcement measures.

In accordance with the FNA Methodology, the assessment additionally distinguishes the share of downward flexibility needs associated with the curtailment of renewable energy sources, enabling separate reporting of renewable generation curtailment within the overall downward flexibility requirements.

The resulting flexibility needs constitute the basis for the DSO network flexibility needs presented in the following chapter.

3.1.2.2. Scenarios for TSO data

The transmission network flexibility needs assessment is based on the same national scenario and the same set of selected ERAA 2025 Weather Scenarios (WS) as the system flexibility needs assessment. The assessment uses the NECP 2024 DU-OVE (Additional Measures – Renewable Energy Sources (RES)) national scenario described in Section 3.1.1 together with the selected ERAA 2025 Weather Scenarios [2] (WS18, WS23, WS25, WS27 and WS35) described in Section 2.3.1. All considered scenarios were used to assess both system flexibility needs and transmission network flexibility needs.

The reference grid conditions are based on the existing Slovenian 110 kV, 220 kV and 400 kV transmission network, including the network reinforcements assumed for the respective target years. A detailed list of these investments is provided in the Transmission System Development Plan of the Republic of Slovenia for the period 2025–2034 [4].

The transmission network assessment further uses the economic dispatch (ED) results together with the relevant TSO input data described in Section 3.1.1 and Table 7. Energy exchanges are represented based on the capacity of interconnections (Net Transfer Capacities – NTCs), while flow-based domains are not considered. The use of ED result in the transmission network assessment, together with representation of cross-border exchanges, is described in Section 2.3.7.1.

The ED results provide the dispatch of generation units, while electricity demand and RES generation are defined by the development scenario.

A formal EVA was not performed. Instead, the assessment relies on the structural integration of the ERAA Economic Viability Assessment (EVA), as described in Section 2.3.6.

3.2. Target for RES integration

The national RES integration targets applied in the FNA assessment are 4,909 GWh for 2030 and 7,931 GWh for 2035, as presented in Table 1 of the Executive Summary. They correspond to 100% of the projected annual RES generation in each target year. The same annual target values are applied to all analysed weather scenarios.

The targets are based on the projections of electricity generation under the Slovenian NECP 2024 Additional Measures – RES scenario (DU-OVE). The projections of installed RES capacity, electricity generation and electricity consumption used in assessment are aligned with this scenario. The technology-specific projections used for the target years are presented in Table 11 and Table 12 below.

Table 11: Total installed PV capacity and production – Based on NECP 2024 scenario DU-OVE.

Year	2030	2035
Total installed PV capacity [MW]	3,454	5,704
PV production [GWh]	3,757	6,314

As shown in Table 11, the installed PV capacity is projected to increase from 3,454 MW in 2030 to 5,704 MW in 2035, while the corresponding annual PV production increases from 3,757 GWh to 6,314 GWh.

Table 12: Other RES generation.

	2030	2035
Total installed power small hydro power plants [MW]	171	181
Total installed power wind [MW]	150	328
Total installed power Biomass and Biogas [MW]	68	73
Estimated production Small hydro power plants [GWh]	425	450
Estimated production wind [GWh]	356	697
Estimated production Biomass and Biogas [GWh]	371	470

Table 12 presents the corresponding projections for small hydropower, wind, biomass and biogas. CHP production is not included in the table, as the fuel used may be from renewable or non-renewable sources (CHP is treated in some NECP contexts as non-renewable generation based on the fuel type). However, projected CHP production for both target years is included in the calculations and assessment and treated as must-run generation, in the same manner as RES generation.

3.3. Portfolio of flexibility resources available

At the TSO level, the portfolio assessed as potentially capable of providing flexibility includes technically flexible generating units, battery energy storage systems and demand response associated with heat pumps and electric vehicles.

The power plants included in the economic dispatch model and their main technical parameters are presented in Table 13. The parameters include installed capacity, minimum down and up times, forced outage rate, mean time to repair, and ramp-up and ramp-down capability. In the analysis, the units marked in green were considered potential flexibility resources within the limits of their technical capabilities. Since the table also contains fossil-fired units, these should not be interpreted as part of the non-fossil flexibility portfolio. The non-fossil resources identified as potential flexibility providers in the table primarily comprise hydropower and pumped-storage units.

Table 13: Power plants data

Power plant	Technology	Power [MW]	Min. down time [h]	Min. up time [h]	FOR[5] [%]	MTTR[6] [days]	Ramp up [pu]	Ramp down [pu]
TEB	gas	141	1	1	4	1	1	1
PE51	gas	42	1	1	1	1	1	1
PE52	gas	42	1	1	14	1	1	1
TETOL	gas	190	1	1	3	1	1	1
TETOL_BLOK1	gas	42	1	1	2	1	1	1
PE500	gas	500	1	1	8	1	1	1
TES6	coal	497	1	1	2	1	0.216	0.216
HEBLA	hydro	39	1	1	3	1	1	1
HEBOS	hydro	32.1	1	1	3	1	1	1
HEBREZ	hydro	48	1	1	3	1	1	1
HEDOB	hydro	81.4	1	1	3	1	1	1
HEDRA	hydro	28.8	1	1	3	1	1	1
HEFAL	hydro	56.8	1	1	3	1	1	1
HEFOR	hydro	116	1	1	3	1	1	1
HEKRS	hydro	39	1	1	3	1	1	1
HEMAR_O	hydro	62.4	1	1	3	1	1	1
HEMAV	hydro	38	1	1	3	1	1	1
HEMED	hydro	25	1	1	3	1	1	1
HEMOS	hydro	21	1	1	3	1	1	1
HEOZB	hydro	72	1	1	3	1	1	1
HEPLA	hydro	37	1	1	3	1	1	1
HESOL	hydro	32.4	1	1	3	1	1	1
HEVRH	hydro	34	1	1	3	1	1	1
HEVUH	hydro	72.3	1	1	3	1	1	1
HEVUZ	hydro	55.5	1	1	3	1	1	1
HEZLA	hydro	153	1	1	3	1	1	1
HEMOK	hydro	28	1	1	3	1	1	1
HESUH	hydro	35.5	1	1	3	1	1	1
HEREN	hydro	33	1	1	3	1	1	1
HETRB	hydro	32.5	1	1	3	1	1	1
NEK	nuclear	348	24	48	1	7	0.026	0.323
CHEAVC	pump	180	1	1	2	1	1	1
KOZ	pump	420	1	1	2	1	1	1

[5] Force outage rate – FOR

[6] Mean Time To Repair – MTTR

As shown in Table 13, the dispatchable non-fossil portfolio contains a range of hydropower units with ramp-up and ramp-down parameters of 1 pu. It also includes the CHEAVC and KOZ pumped-storage units, with installed capacities of 180 MW and 420 MW, respectively. These units were considered potential sources of flexibility within their technical limits. In addition to the generating units presented in Table 13, battery energy storage systems and demand response were considered potential sources of flexibility. The main demand-response sources considered were heat pumps and electric vehicles. Their capacities or associated electricity consumption for the two target years are presented in Table 14.

Table 14: Capacity of flexibility sources

	2030	2035
Power BHEE [MW]	185	309
Capacity BHEE [MWh]	560	935
DR – Demand HPs [GWh]	871	1,935
DR – Demands EVs [GWh]	1,852	2,115

As shown in Table 14, the assumed battery storage power capacity increases from 185 MW in 2030 to 309 MW in 2035, while its energy capacity increases from 560 MWh to 935 MWh. This indicates an increase in the battery storage resources considered within the TSO flexibility portfolio.
Demand response was also considered as a potential source of flexibility at the TSO level, with heat pumps and electric vehicles identified as the main demand-response categories. The electricity demand associated with heat pumps increases from 871 GWh in 2030 to 1,935 GWh in 2035, while the electricity demand associated with electric vehicles increases from 1,852 GWh to 2,115 GWh. These values represent the electricity demand associated with these categories and should not be interpreted as the amount of fully available flexible energy.

Cross-border interconnections were included in the TSO assessment on the basis of net transfer capacities derived from actual commercial flows in 2025 and planned increases in transmission capacity.

For the DSO assessment, the portfolio of non-fossil flexibility resources considered in the analysis is described in detail in Section 3.1.2.1*0*. This includes the quantitative deployment assumptions for demand-side resources, distributed generation and battery energy storage (Table 8), together with the technology-specific operational and flexibility assumptions applied in the assessment (Table 9) and the corresponding implementation assumptions (Table 10). These assumptions define the non-fossil flexibility resources available to address identified distribution network flexibility needs and therefore are not repeated in this section.

3.4. Other assumptions

Assumptions applied in the TSO assessment

TES6 treatment - In the Slovenian context, the specific treatment of TES6 as a non-market must-run unit is implemented as an exogenous constraint without altering the fundamental EVA equilibrium logic. In previous ERAA cycles, the EVA results for Slovenia have typically reflected:

- a moderate increase in demand-side response (DSR), indicating a growing role of flexibility resources; and
- the progressive phase-out of coal and lignite-fired power plants. For Slovenia, this implied the economic exit of TES6 under purely market-based profitability assumptions.

However, due to the recent transition of TES6 into a public economic service of heat provision (service of general economic interest), its operation is no longer determined exclusively by electricity market profitability. In order to reflect national regulatory and security-of-supply considerations, the unit is retained in the 2030 modelling horizon with a minimum operational level represented as a non-market must-run constraint during the winter (October-March). This treatment represents a justified national regulatory refinement while maintaining consistency with the ERAA reference scenarios and the structural assumptions resulting from the EVA process.

Market Time Unit (MTU) - Although a 15-minute Market Time Unit (MTU) was introduced in the European day-ahead market from October 2025, the assessment was performed using a one-hour MTU. This reflects the continued hourly discretisation of cross-border transfer-capacity allocation together with the temporal resolution of the available historical and forecast datasets used in the assessment.

Assumptions applied in the DSO assessment

The assessment of DSO network needs assumes different applicability of selected non-wire solutions in 2030 and 2035, reflecting the planning assumptions adopted for each target year. Consequently, the availability of smart-grid functionalities, network operational measures and flexibility-based solutions increases over the planning horizon, reflecting the expected development of DSO control systems, planning methodology and the applicable regulatory framework.

The implementation of certain network operational measures is assumed to be constrained by the existing regulatory framework and the current distribution network planning methodology. In particular, advanced voltage control is not considered applicable in the 2030 assessment, as the current planning methodology evaluates voltage performance primarily through feeder voltage drops rather than voltage compliance at individual customer connection points. Since advanced voltage control mainly optimises the overall voltage profile without reducing feeder voltage drops, it is not compatible with the current reinforcement criteria. Its implementation is therefore assumed only in the 2035 scenario, reflecting the expected evolution of the planning methodology.

The assessment further assumes that advanced active network management capabilities, including coordinated real-time control of distributed energy resources based on MV and LV state estimation, are not yet available within the considered planning horizon. Accordingly, flexibility is represented through predefined operational measures rather than dynamic optimisation of distributed resources. Flexible Connection Agreements (FCAs) are modelled as rule-based operational arrangements that enable active power limitation under predefined network conditions and are therefore considered as planning measures rather than market-based flexibility services. Their application is assumed to expand progressively in line with the expected development of distribution network operation.

Furthermore, the FNA incorporates methodological refinements and updated input datasets developed during the preparation of the forthcoming DNDP 2027–2036, on the assumption that these refinements will be adopted in the final version of the DNDP. As the DNDP 2027–2036 had not yet been published at the time of the assessment, there remains a risk that the final DNDP may differ from the planning assumptions adopted in the FNA. Such differences could affect the consistency between the FNA results and the subsequently published DNDP, although they are not expected to materially alter the overall assessment methodology.

Other DSO-specific technology and operational assumptions are provided in Tables 9 and 10.

4. Results of flexibility needs assessment

This chapter presents the results of the national Flexibility Needs Assessment in accordance with Regulation (EU) 2019/943 (the Electricity Regulation), Article 19e(2), and the Flexibility Needs Assessment Methodology, Articles 8 to 12. It summarises the initial system flexibility needs and the transmission and distribution network flexibility needs under the selected assessment scenarios. As the conditions for fine-tuning were not met (see Section 2.3.8), adjusted (fine-tuned) system flexibility needs in accordance with Article 14 of the FNA Methodology are not presented.

4.1. System-wide flexibility needs

In this section, the results related to the System Flexibility Needs assessment are provided. According to the methodology, the results are structured as follows:

- RES Integration Needs
- Ramping Needs
- Short-Term flexibility Needs

4.1.1. RES integration

This section presents the results of the assessment of RES integration needs in accordance with Article 8 of the FNA Methodology. It characterises the identified RES integration needs, presents the quantified uncovered RES integration needs under the analysed scenarios, and assesses the potential contribution of additional flexibility resources to reducing the identified uncovered RES integration needs.

4.1.1.1. Residual load as the characterisation of RES integration needs

As described in Section 2.3.6.1, the assessment applies the derogation permitted under Article 8(3) of the FNA Methodology for the first FNA report, whereby the additional RES curtailment resulting from uncovered ramping and short-term flexibility needs is not included in the quantified RES integration needs. Consequently, the characterisation presented in this section is based directly on the residual load time series, with RES integration needs determined directly from the negative residual load.

Figure 5 shows the residual load time series for the Base scenario, while Figure 6 presents the residual load duration curves for all analysed scenarios. For clarity of presentation, the negative residual load in Figure 5 is also expressed with positive values.

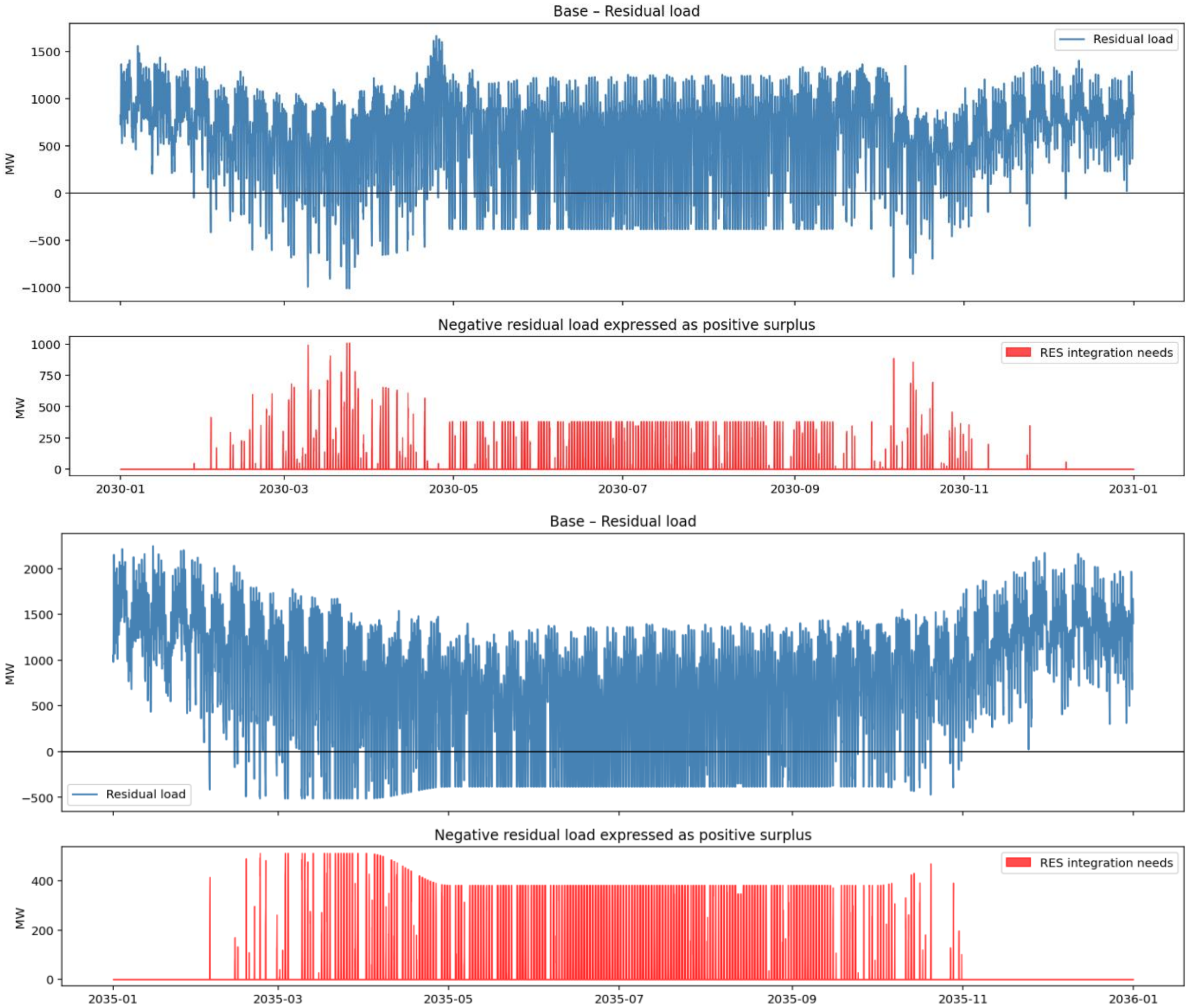
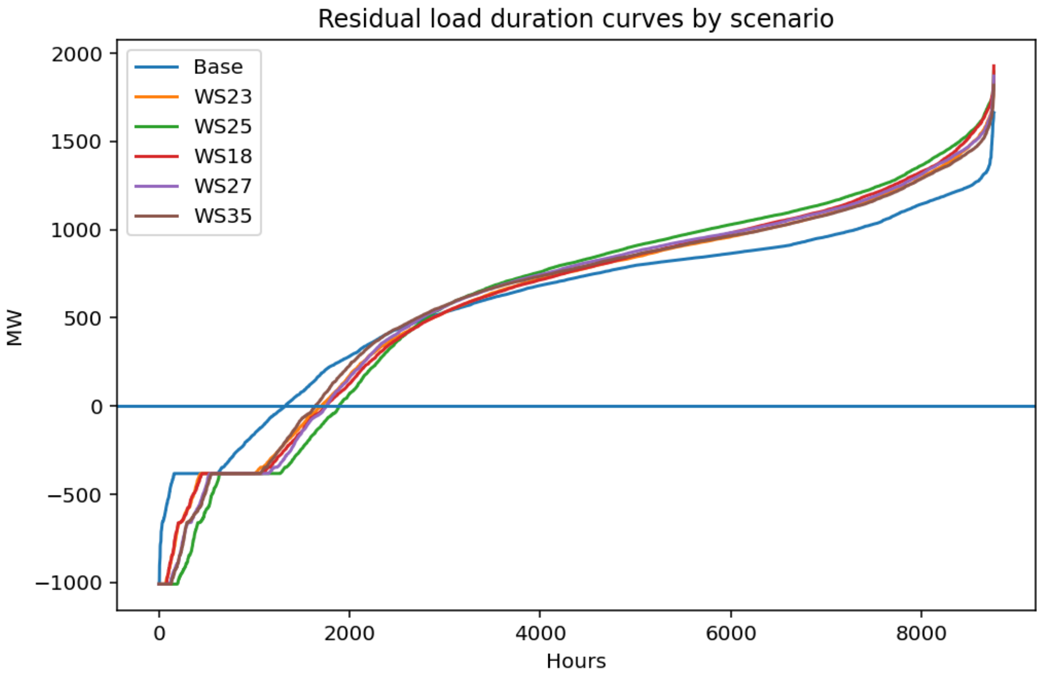


Figure 5: Residual load time series - target year 2030 (above), 2035 (below)

An observable decrease in residual load is observed during the summer period when TES6 and TETOL are not in operation, as their operation is linked to heat supply. During transitional periods (spring and autumn), the combination of must-run thermal generation and still significant solar PV output leads to the most pronounced negative residual load conditions.



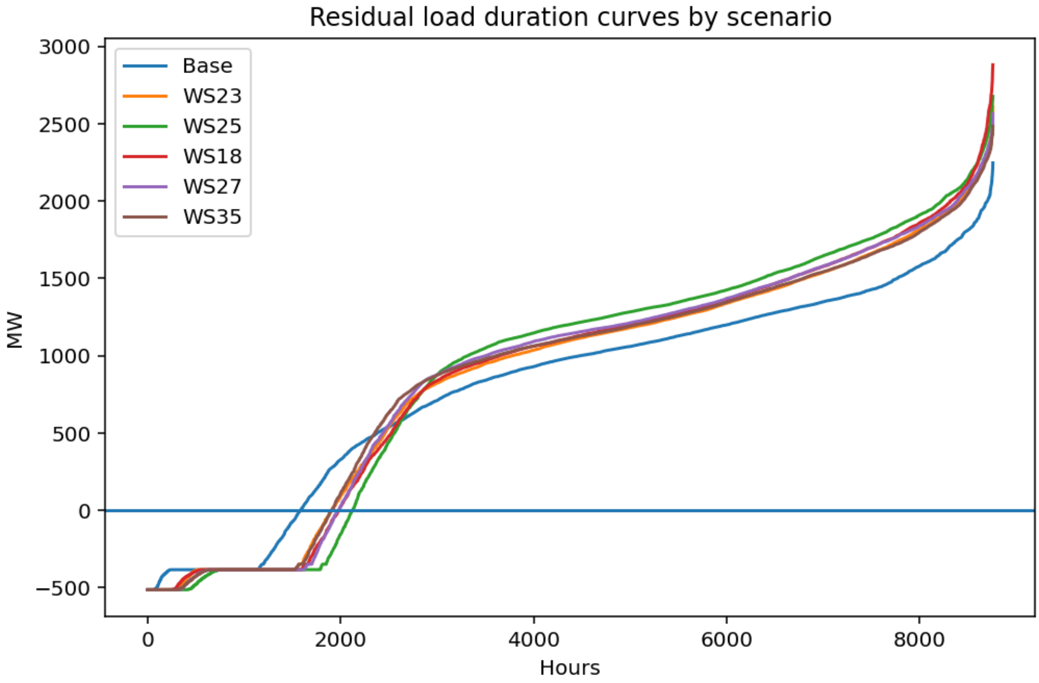
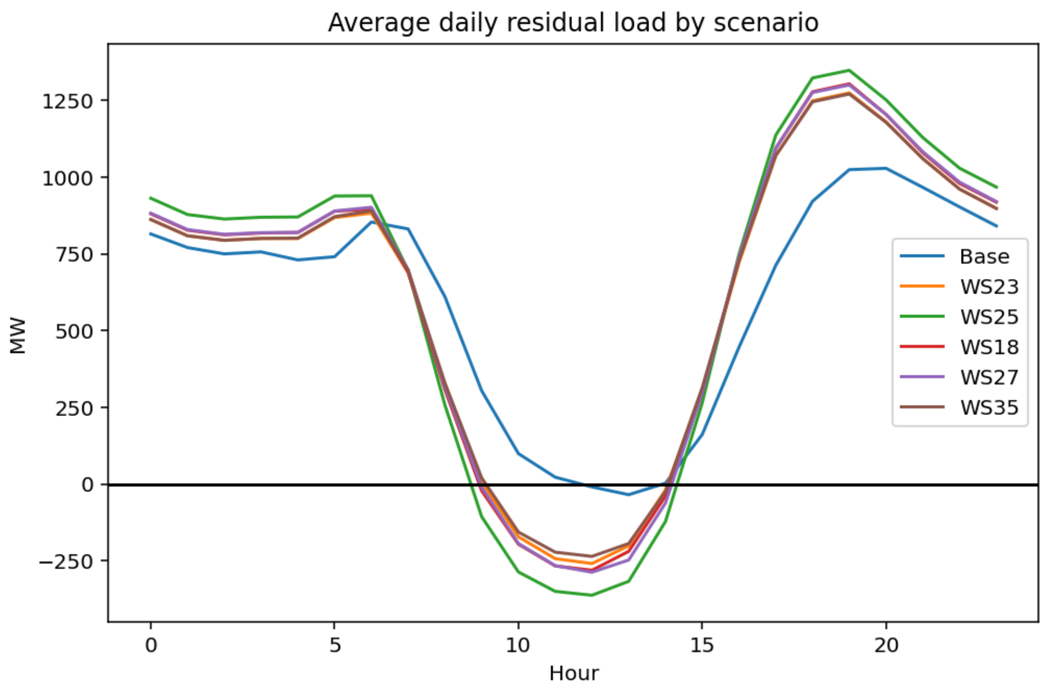


Figure 6: Residual load duration curve – target year 2030 (above), 2035 (below)

Selected RES integration needs indicators derived from the residual load are summarised in Table 15 for all analysed weather scenarios and both target years. Figure 12 presents the corresponding average daily residual load profiles.

Table 15: RES integration needs indicators

Target year 2030				
WS	**Maximum RES integration need [MW]**	**Potential curtailed energy [GWh]**	**Hours with RES integration needs**	**Average RES integration need [MW]**
Base	1,010	396.25	1,327	298.61
WS23	1,010	666.45	1,706	390.65
WS25	1,010	867.83	1,891	458.92
WS18	1,010	688.28	1,755	392.18
WS27	1,010	755.89	1,758	429.97
WS35	1,010	718.61	1,639	438.44
Target year 2035				
WS	**Maximum RES integration need [MW]**	**Potential curtailed energy [GWh]**	**Hours with RES integration needs**	**Average RES integration need [MW]**
Base	513	542.47	1,584	342.47
WS23	513	712.3	1,904	374.11
WS25	513	826.44	2,122	389.46
WS18	513	737.25	1,982	371.98
WS27	513	753.77	1,977	381.27
WS35	513	724.74	1,906	380.24



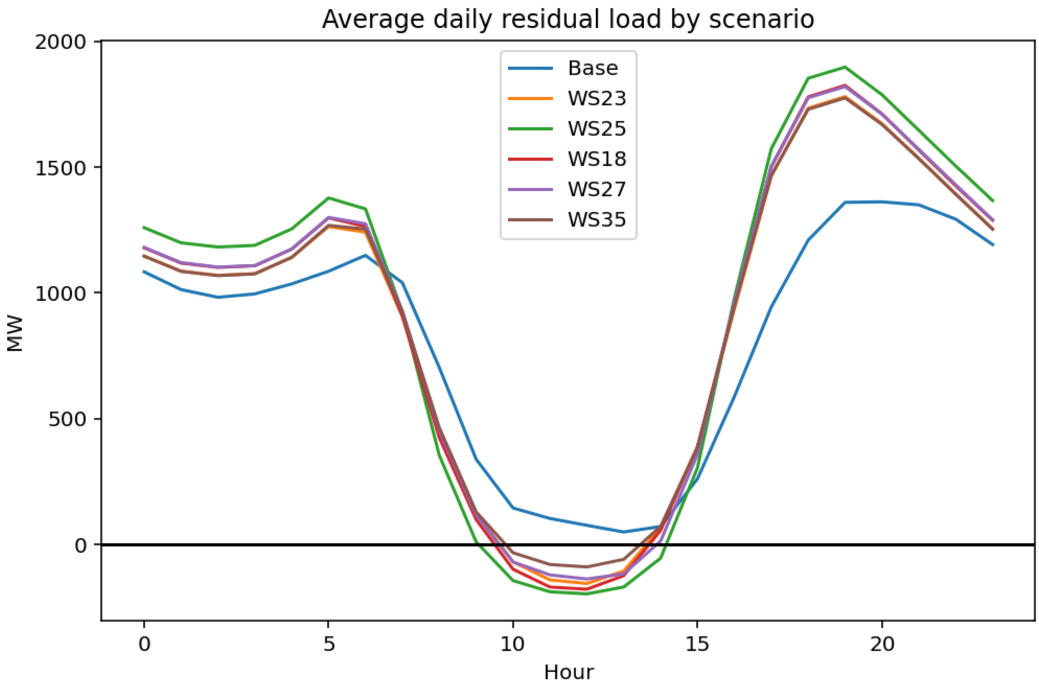


Figure 7: Average daily residual load – target year 2030 (above), target year 2035 (below)

The average daily residual load profile exhibits a pronounced midday decline caused by (mainly) PV generation. At a certain time of the day, residual load becomes negative, indicating a surplus of generation that cannot be absorbed by demand. These periods correspond to RES integration needs identified through negative residual load. It should be highlighted that the graphs in the Figure 7 present the average daily profile of residual load based on the whole target year and for each analysed scenario, while the RES Integration Needs are determined by days with a lot higher PV production, resulting in much higher negative values of Residual load and consequently much higher RES integration Needs. The graphs in Figure 7 also show the impact of the WS considered, clearly illustrating RES integration needs based on the assumption of negative residual load, as they highlight the typical "duck curve", characterised by a sharp decline in residual load during hours of high PV production.

It can be observed that during the early morning hours (0–8), the system requires generation due to positive residual load. Between hours 9 and 14, a sharp decline in residual load occurs as a result of PV production. At a certain time of the day, depending on the scenario, residual load becomes negative, and RES integration needs emerge. After hour 15, a very steep afternoon–evening ramp appears, indicating the need for flexible generation.

Figure 8 shows the residual load heatmap for the entire target year.

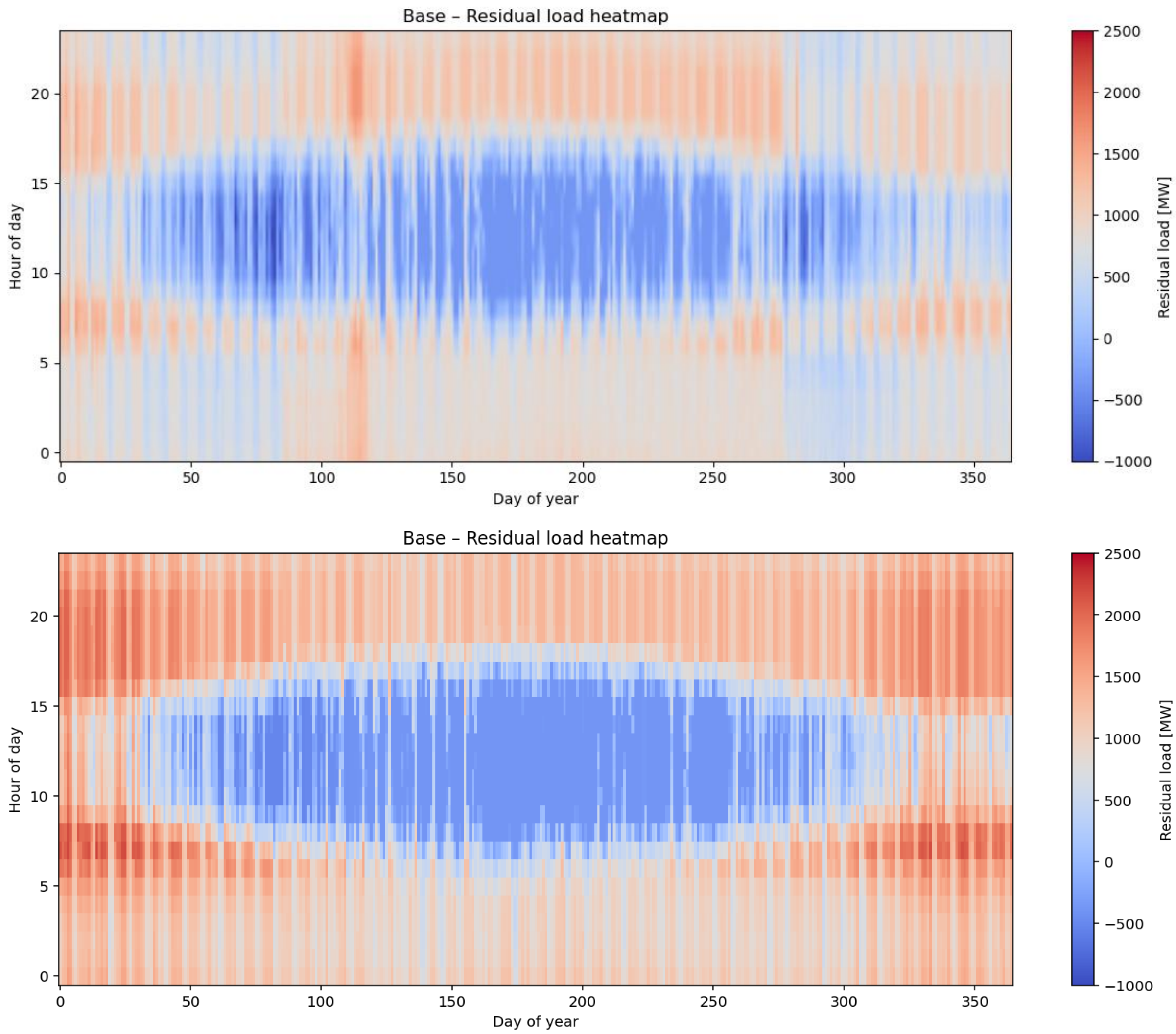


Figure 8: Residual load heatmap – target year 2030 (above), 2035 (below)

Unlike the average daily profile (Figure 7), the graphs in Figure 8 show that the residual load can decrease to as low as 1000 MW (for the target year 2030), while in the target year 2035, the value is significantly lower due to less must-run production (TES6 not operating anymore)-more clearly visible in the Figure 6. However, as can be seen from Figure 8, the negative values occur primarily during periods of PV generation.

4.1.1.2. Characterisation of RES generation curtailment

In accordance with the methodology described in Section 2.3.6.1, explicit RES generation curtailment time series are not derived from the economic dispatch results. Therefore, potential RES generation curtailment is characterised through the temporal distribution of negative residual load (potential curtailed energy), in accordance with Article 8(3) of the FNA Methodology.

The probabilistic characterisation of potential RES generation curtailment is based on the probability distribution of residual load and percentile-based indicators across the analysed scenarios. These distributions characterise the frequency and magnitude of negative residual load conditions throughout each target year, reflecting periods of increased RES integration stress and downward flexibility requirements.

The detailed hourly, daily and seasonal indicators required under Article 8(1–5) of the FNA Methodology are provided in Annex I, while the main probabilistic indicators are presented in Table 16 and Figure 9.

Table 16: Probabilistic indicators of negative residual load representing potential RES generation curtailment

Target year 2030						
WS	**P[7](RL<0) [%]**	**RL p05 [MW]**	**RL p50 [MW]**	**RL p95 [MW]**	**Surplus p95 [MW]**	**Surplus p99 [MW]**
Base	15.15	-383	727.24	1,207.69	383	549.15
WS23	19.47	-383.41	766.32	1,391.18	383.41	967.57
WS25	21.59	-656.38	816.49	1,470.75	656.38	1,010
WS18	20.03	-402.67	769.67	1,429.98	402.67	974.65
WS27	20.07	-541.37	797.28	1,410.45	541.37	1,010
WS35	18.71	-570.56	781.76	1,375.12	570.56	1,010
Target year 2035						
WS	**P(RL<0) [%]**	**RL p05 [MW]**	**RL p50 [MW]**	**RL p95 [MW]**	**Surplus p95 [MW]**	**Surplus p99 [MW]**
Base	18.08	-383	988.17	1711.91	383	504.29
WS23	21.74	-421.56	1,099.45	1,945.09	421.56	513
WS25	24.22	-507.73	1,202.22	2,048.92	507.73	513
WS18	22.63	-414.49	1,115.21	2,001.51	414.49	513
WS27	22.57	-451.29	1,142.4	1,959.3	451.29	513
WS35	21.76	-454.79	1,113.51	1,932.34	454.79	513

The table presents the probability of negative residual load conditions, selected residual load percentiles and high-percentile surplus indicators characterising the magnitude and frequency of RES integration stress conditions. The residual load probability distribution is presented in Figure 9.

[7] Probability

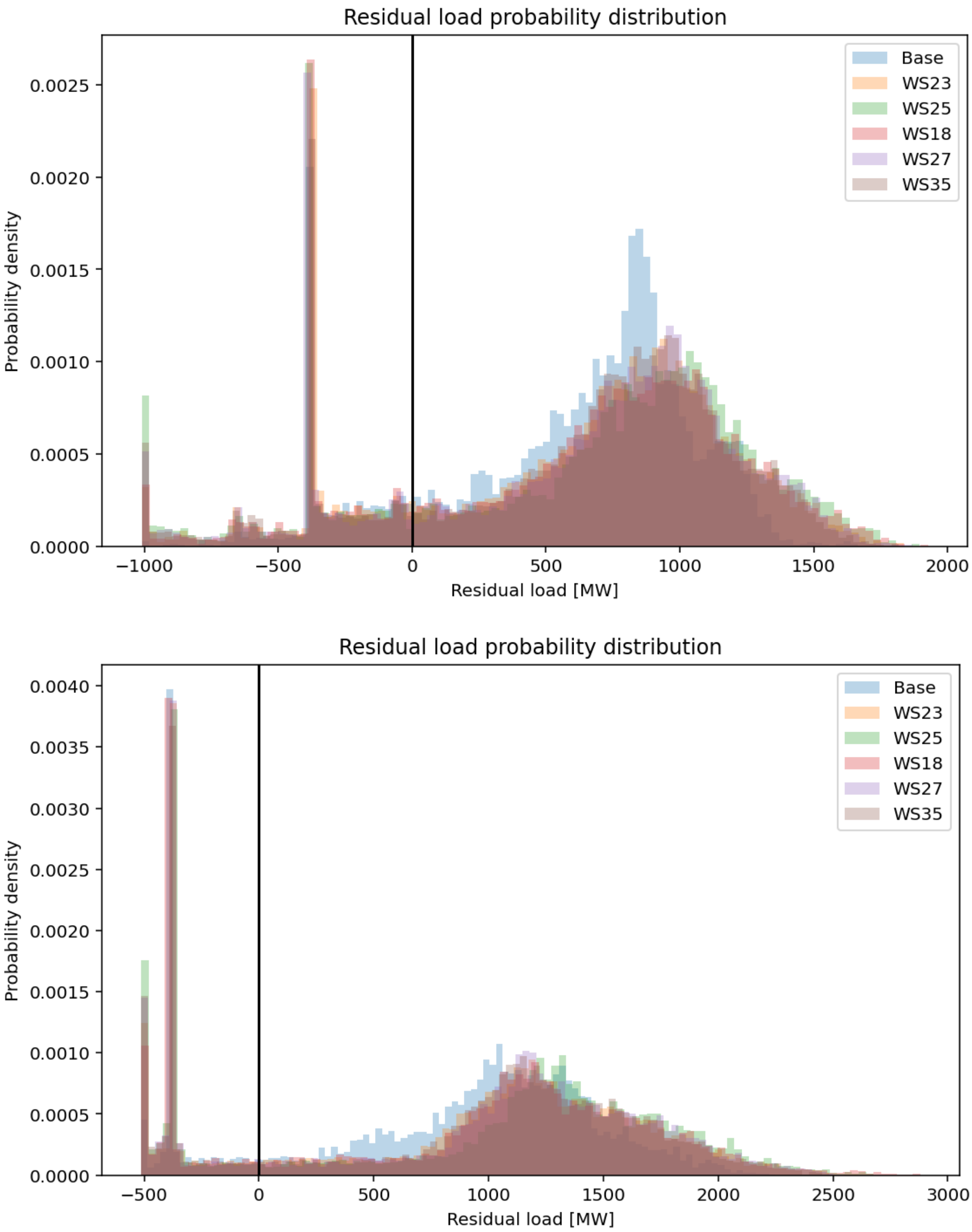


Figure 9: Residual load probability distribution – target year 2030 (above), 2035 (below)

Similar to Figure 5, the highest probability density is observed around 500 MW. This reflects periods with reduced or non-operational must-run generation. In 2035, although must-run generation is lower due to the absence of TES6 operation, the higher installed PV capacity shifts the distribution towards lower residual load values and increases the occurrence of low and negative residual load conditions.

Table 17 provides additional indicators required under Article 8(4)(d) and Article 8(5) of the FNA methodology for the characterisation of RES integration needs and residual load variability.

Wind generation was not assessed separately due to its limited contribution. Correlations are therefore reported only for PV generation and demand covered by the ED.

The correlation coefficients quantify the relationship between RES integration needs, represented by periods of negative residual load (expressed as positive surplus), and key system conditions, namely PV generation and demand. The results provide an indication of the main drivers of surplus generation conditions and the occurrence of RES integration needs.

In addition, residual load variability indicators are calculated for the hourly, daily and seasonal timeframes in accordance with Article 8(5). The hourly indicator is calculated as the sum of absolute variations between hourly residual load and its daily average, the daily indicator as the sum of absolute variations between daily residual load and the weekly average, and the seasonal indicator as the sum of absolute variations between monthly residual load and the annual average. These indicators provide a quantitative assessment of residual load variability across different time horizons and support the identification of flexibility needs associated with RES integration.

Table 17: Additional indicators for the characterisation of RES integration needs in accordance with Article 8 of the FNA methodology

Target year 2030			
WS	Corr surplus–PV	Corr surplus–demand	Corr surplus-wind
Base	0.739	-0.688	N/A
WS23	0.76	-0.708	N/A
WS25	0.782	-0.724	N/A
WS18	0.763	-0.708	N/A
WS27	0.779	-0.719	N/A
WS35	0.787	-0.707	N/A
Target year 2035			
Base	0.851	-0.785	N/A
WS23	0.884	-0.815	N/A
WS25	0.912	-0.843	N/A
WS18	0.89	-0.818	N/A
WS27	0.903	-0.831	N/A
WS35	0.907	-0.827	N/A

The correlation analysis confirms that RES integration needs are primarily driven by PV generation, with correlation coefficients between surplus conditions and PV generation ranging from 0.74 to 0.91 across the analysed scenarios for both target years. Conversely, demand exhibits a strong negative correlation with surplus conditions. The hourly variability indicator is significantly larger than the daily and seasonal indicators, indicating that residual load variability is predominantly driven by intra-day fluctuations. Increasing PV penetration results in higher hourly residual load variability and a stronger relationship between surplus conditions and PV generation.

The complete set of RES integration assessment results, including RES integration targets, RES generation curtailment, and residual load variability indicators at hourly, daily, and seasonal timeframes for all target years and weather scenarios, is provided in Annex I (Tables 33–44).

4.1.1.3. Uncovered needs

As described in Section 2.3.6.1, Slovenia applies the derogation in accordance with Article 8(3) of the FNA Methodology. The Slovenian NECP does not define an acceptable or maximum level of RES curtailment for the analysed target years and weather scenarios. All considered RES generation is treated as non-dispatchable and is therefore not an optimisation variable in the economic dispatch model. Consequently, explicit RES curtailment is not obtained as an optimisation result. Furthermore, the economic dispatch model does not explicitly represent the underlying causes of RES curtailment, such as transmission or distribution network constraints. Therefore, no explicit RES curtailment time series is derived from the economic dispatch results. In the present assessment, (potential) RES curtailment is represented by the negative residual load, which reflects surplus RES generation and corresponds to the identified RES integration needs. Accordingly, under the adopted methodology, the indicators Total curtailed energy, Total uncovered RES integration need, Potential curtailed energy and RES generation curtailment have identical values, as they represent the same surplus RES generation from different methodological perspectives. Therefore, the total uncovered RES integration needs correspond to the identified RES curtailment represented by the negative residual load. The corresponding results are presented in Section 4.1.1.2 and Table 15, while the complete results for all target years and weather scenarios are provided in Annex I.

4.1.1.4. Flexible resources needed to meet the uncovered needs

In accordance with Article 8(10) of the FNA Methodology, an assessment of additional flexibility resources was performed. The objective of the assessment was to quantify the potential benefit of additional flexibility resources in reducing the identified RES integration needs. The assessment methodology is described in Section 2.3.3. The results are presented in Table 18 for target year 2030 and in Table 19 for the target year 2035.

The assessment shows that additional flexibility resources substantially reduce the identified uncovered RES integration needs in both target years. For the analysed most critical weather scenario WS25, an additional generic flexibility resource with an installed power of 1,000 MW was assessed for 2030 and 500 MW for 2035.

For the target year 2030, increasing the energy-to-power (E/P) ratio from 2 h to 8 h increased the reduction of surplus energy from 62.3% to 99.8%, while further increases in the E/P ratio did not provide any significant additional reduction of uncovered RES integration needs.

For the target year 2035, the reduction of surplus energy increased from 37.5% for a 2 h E/P ratio to more than 99.3% for E/P ratios of 20 h and above. Most of the achievable reduction was already obtained with an 8 h E/P ratio (99.3%), while longer-duration flexibility resources provided only marginal additional benefits.

The assessment results show that increasing the energy-to-power ratio beyond approximately 8 hours provides only limited additional reductions of uncovered RES integration needs under the analysed conditions.

Table 18: Additional flexible resources to meet uncovered RES integration needs – Target year 2030

Target year	WS	Additional installed capacity [MW]	Energy-to-power ratio [h]	Energy capacity [MWh]	Remaining surplus energy [GWh]	Reduction of surplus energy [GWh]	Reduction of surplus energy [%]	Hours with remaining surplus	Average remaining surplus [MW]	Maximum remaining surplus [MW]	Base surplus energy [GWh]	Base hours with surplus	Base maximum surplus [MW]	RTE [%]	Availability [%]
2030	WS25	1,000	2	2,000	327.22	540.61	62.29	639	512.08	1010	867.83	1,891	1,010	90	100
2030	WS25	1,000	4	4,000	96.48	771.35	88.88	330	292.35	1010	867.83	1,891	1,010	90	100
2030	WS25	1,000	8	8,000	1.97	865.85	99.77	200	9.86	10	867.83	1,891	1,010	85	100
2030	WS25	1,000	20	20,000	1.97	865.85	99.77	200	9.86	10	867.83	1,891	1,010	75	100
2030	WS25	1,000	50	50,000	1.97	865.85	99.77	200	9.86	10	867.83	1,891	1,010	45	100
2030	WS25	1,000	100	100,000	1.97	865.85	99.77	200	9.86	10	867.83	1,891	1,010	40	100
2030	WS25	1,000	200	200,000	1.97	865.85	99.77	200	9.86	10	867.83	1,891	1,010	35	100

Table 19: Additional flexible resources to meet uncovered RES integration needs – Target year 2035

Target year	WS	Additional installed capacity [MW]	Energy-to-power ratio [h]	Energy capacity [MWh]	Remaining surplus energy [GWh]	Reduction of surplus energy [GWh]	Reduction of surplus energy [%]	Hours with remaining surplus	Average remaining surplus [MW]	Maximum remaining surplus [MW]	Base surplus energy [GWh]	Base hours with surplus	Base maximum surplus [MW]	RTE [%]	Availability [%]
2035	WS25	500	2	1,000	516.83	309.61	37.46	1566	330.03	513	826.44	2,122	513	90	100
2035	WS25	500	4	2,000	228.62	597.82	72.34	1010	226.36	513	826.44	2,122	513	90	100
2035	WS25	500	8	4,000	6.06	820.38	99.27	458	13.24	290.4	826.44	2,122	513	85	100
2035	WS25	500	20	10,000	5.72	820.72	99.31	456	12.54	13	826.44	2,122	513	75	100
2035	WS25	500	50	25,000	5.72	820.72	99.31	456	12.54	13	826.44	2,122	513	45	100
2035	WS25	500	100	50,000	5.72	820.72	99.31	456	12.54	13	826.44	2,122	513	40	100
2035	WS25	500	200	100,000	5.72	820.72	99.31	456	12.54	13	826.44	2,122	513	35	100

Assessment pursuant to Article 16(5) of the FNA Methodology

To further characterise the identified system needs, the uncovered flexibility needs time series were analysed by identifying continuous flexibility-needs events, defined as consecutive MTUs with uncovered needs. For each event, the duration, maximum power requirement and energy volume were determined. These event characteristics provide additional technical information on the identified flexibility needs and support the assessment of the capability of different flexibility resources to address them, in accordance with Article 16(5) of the FNA Methodology.

Figure 10 presents the technical characteristics of identified flexibility-needs events for RES integration, ramping and STF needs in terms of the above-listed indicators, thereby illustrating the technical characteristics of the identified system needs. The results are presented for WS25 demonstrating the highest needs.

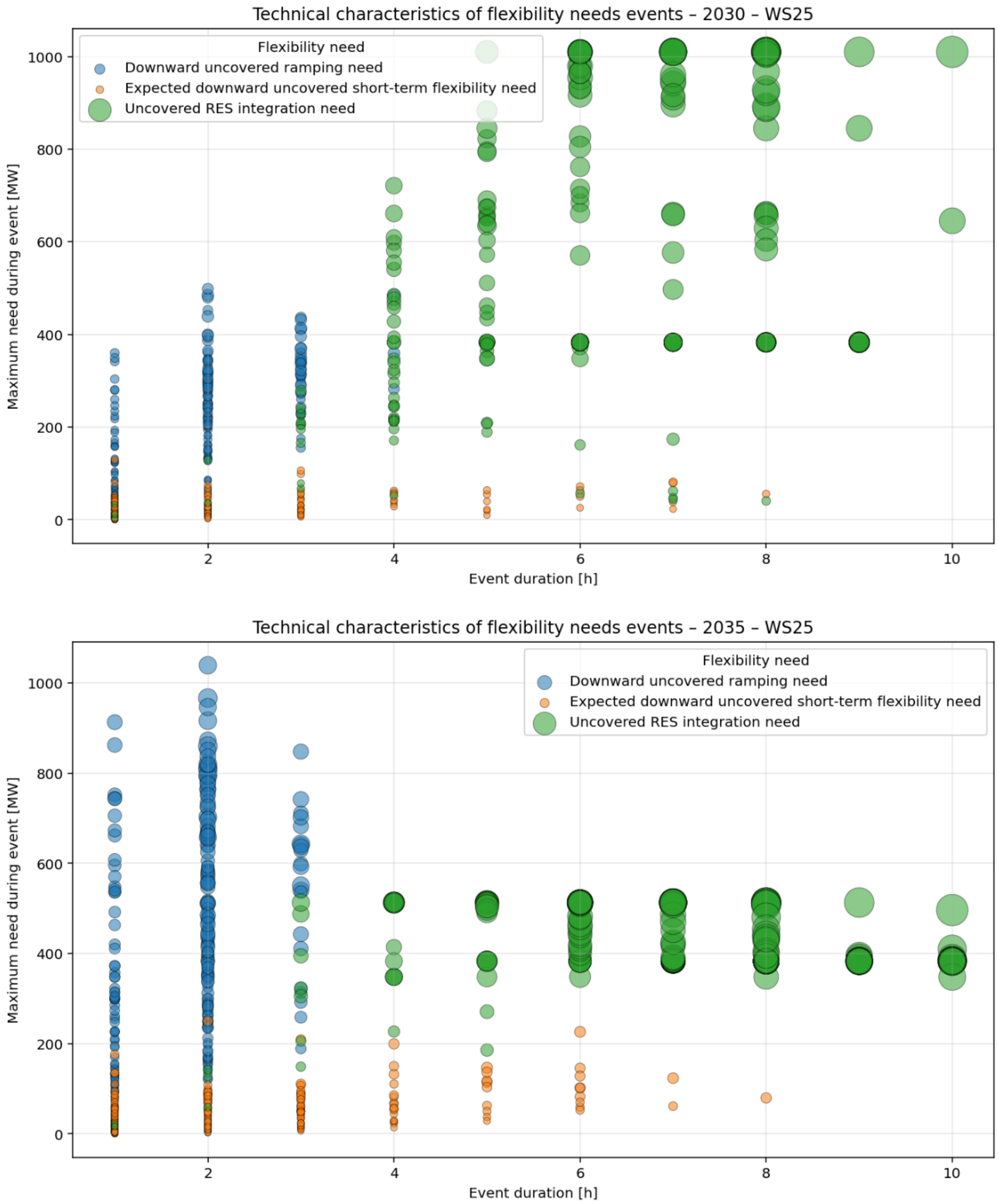


Figure 10: Contribution of additional flexibility resources to reducing uncovered RES integration needs, target year 2030 above, 2035 below

Assessment pursuant to Article 16(6) of the FNA Methodology

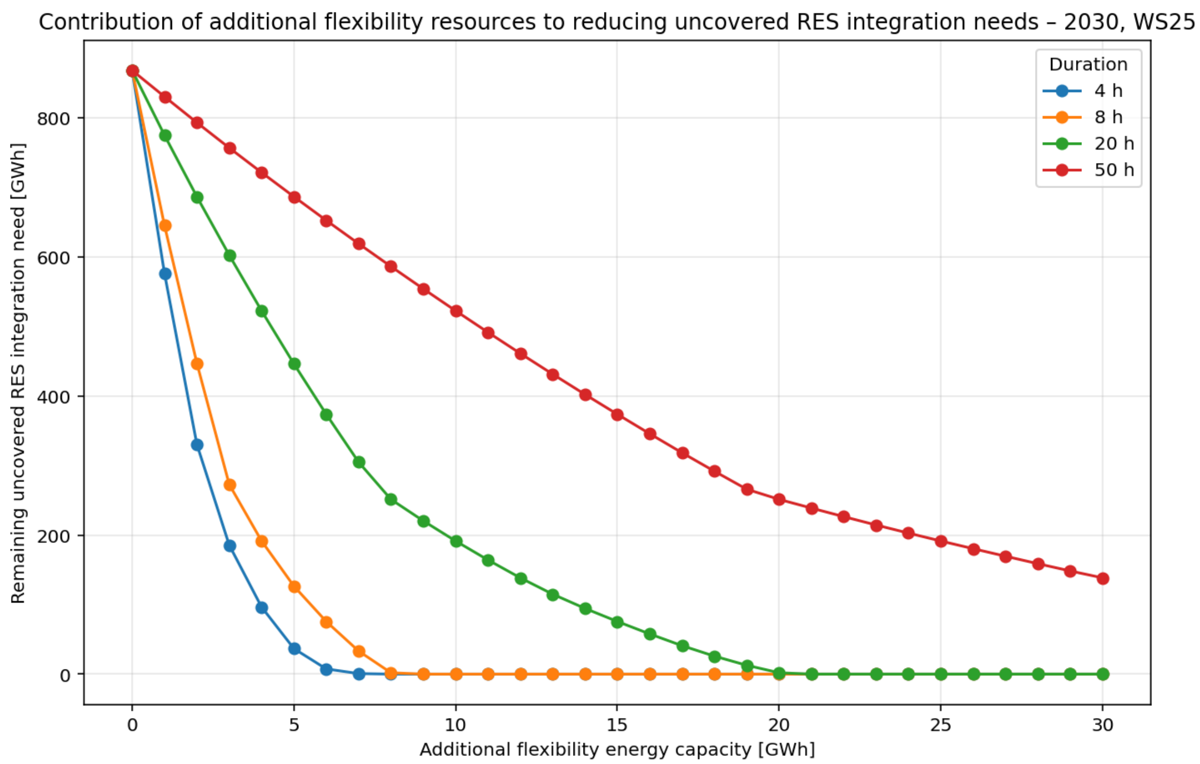
In accordance with Article 16(6) of the FNA Methodology, the capability of additional flexibility resources to reduce uncovered RES integration needs was assessed using a technology-neutral generic flexibility resource, as described in Section 2.3.3. The generic resource does not represent a specific flexibility technology but rather a common mathematical representation applicable to different flexibility resources, such as battery energy storage systems, pumped-storage hydropower, aggregators, prosumers, electric vehicles and other demand-side flexibility resources.

The generic flexibility resource was characterised by its installed power, energy capacity, energy-to-power ratio, availability and representative round-trip efficiency, consistent with the same assumptions adopted for the assessment pursuant to Article 8(10) of the FNA Methodology. Different technical characteristics were represented through different energy-to-power ratios while maintaining a technology-neutral approach.

Within the adopted modelling framework, the different flexibility technologies are represented by the same generic mathematical model, while differences in the activation cost of individual technologies were not considered, as the assessment focuses on their technical capability rather than their economic performance.

The resulting contribution curves provide a technology-neutral basis for assessing the marginal contribution of additional flexibility capacity to reducing uncovered RES integration needs, in accordance with Article 16(6) of the FNA Methodology.

The resulting contribution curves for weather scenario WS25 are presented in Figure 11.



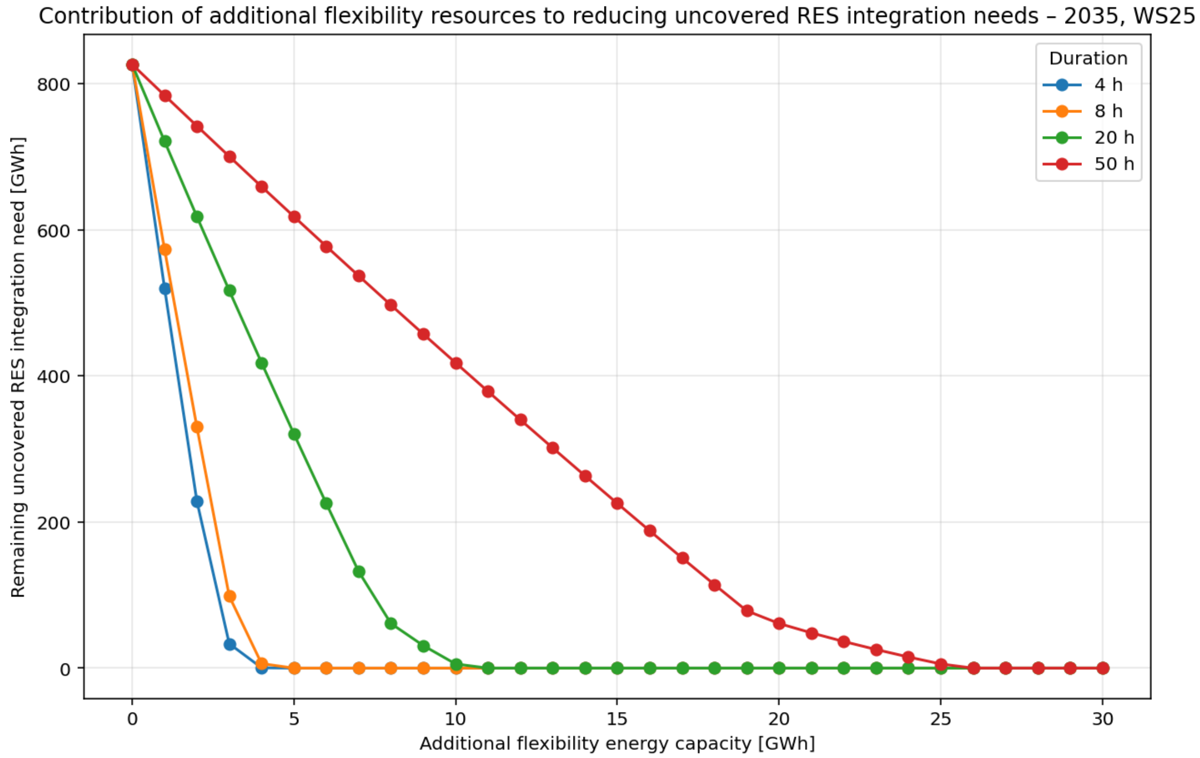


Figure 11: Contribution of additional flexibility resources to reducing uncovered RES integration needs, target year 2030 above, 2035 below

As shown by the event-characterisation results presented previously pursuant to Article 16(5), the identified uncovered RES integration events are predominantly short in duration. Consequently, flexibility resources with shorter duration characteristics exhibit a higher technical capability to reduce uncovered RES integration needs. As illustrated by the contribution curves, increasing the duration of flexibility resources beyond the observed event lengths results in diminishing marginal reductions of uncovered RES integration needs under the analysed conditions.

The slope of the contribution curves represents the marginal contribution of additional flexibility capacity to reducing uncovered RES integration needs. Generic flexibility resources characterised by shorter energy-to-power ratios provide steeper contribution curves and therefore achieve a greater reduction of uncovered RES integration needs per additional unit of flexibility energy capacity under the analysed conditions.

Assessment pursuant to Article 16(7) of the FNA Methodology

The analyses presented in Sections 4.1.2, 4.1.3, and 4.2.2 indicate that the capability of the flexibility resources represented in the assessment is generally sufficient to meet the quantified upward flexibility needs. For ramping and short-term flexibility needs, upward uncovered needs are either not identified or are limited to isolated events of negligible magnitude. For transmission network flexibility, no upward needs were identified under normal operating conditions (N). The identified upward flexibility needs arise only under contingency conditions (N-1), where they are a direct consequence of network constraints following unit outages rather than a lack of system-wide flexibility capability. Such needs are considered to be covered through the procurement of balancing and ancillary services. The results therefore do not indicate a systematic lack of upward flexibility capability under the analysed scenarios.

4.1.2. Ramping needs

The ramping needs have been calculated as described in Section 2.3.6.2.

In general, ramping needs measure the rate of change in residual load and thus indicate the requirement for flexibility resources capable of rapidly increasing or decreasing power output. Consequently, a low or even zero energy surplus may still result in a significant ramping challenge, while a large energy surplus may correspond to relatively moderate ramping needs.

While RES integration needs (evaluated in the previous chapter) capture hours of generation surplus through negative residual load values, ramping needs capture the rate of change of residual load between consecutive MTUs. The former indicates the need for absorbing surplus energy, whereas the latter reflects the requirement for flexible resources capable of rapidly increasing or decreasing output.

Figure 12 presents the calculated residual load ramping requirements for the Base scenario, Figure 13 presents the ramping duration curve (upward and downward) for the Base scenario, and Figure 14 presents the average daily ramping needs (also presented separately for upward and downward ramping) for the Base scenario. Table 20 summarizes the characterisation of residual load ramping requirements for all analysed scenarios.

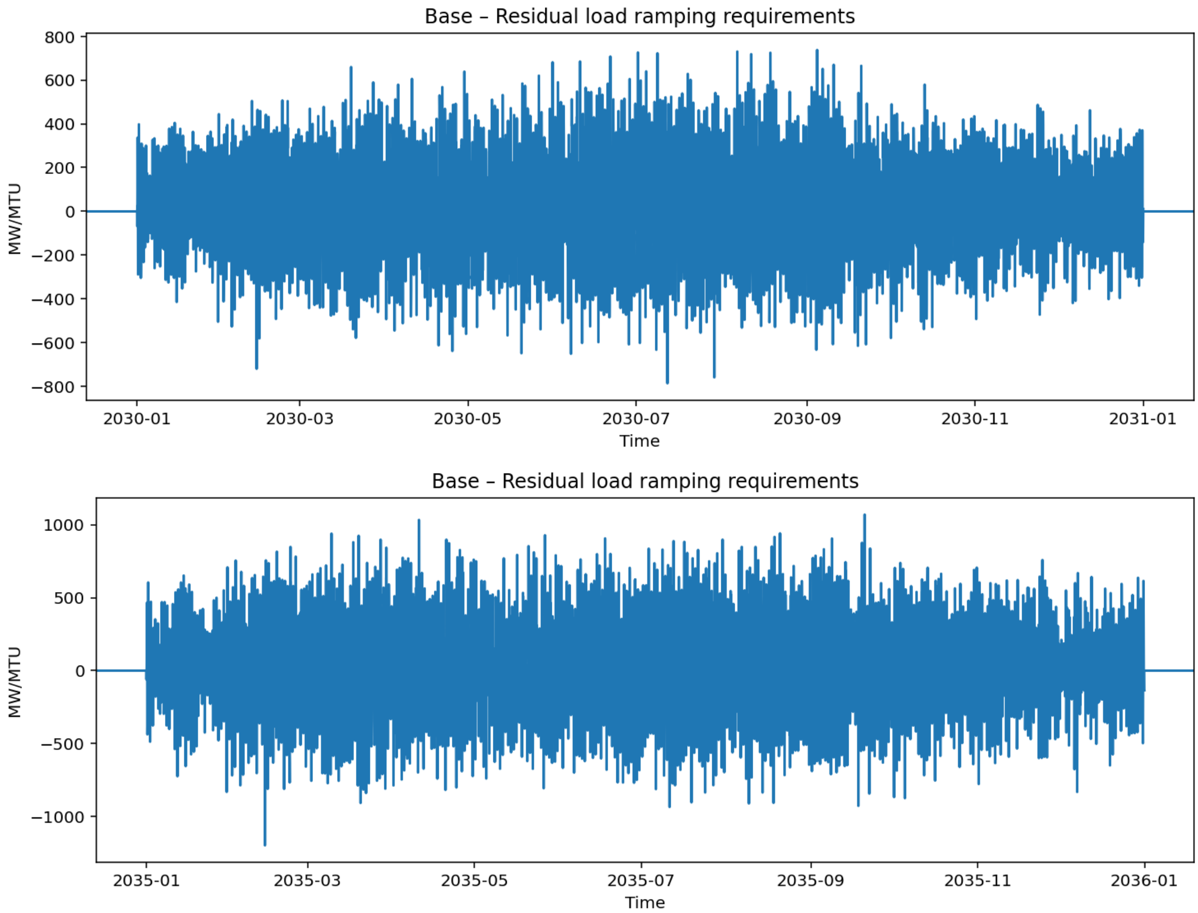


Figure 12: Residual load ramping requirements – target year 2030 (above), 2035 (below).

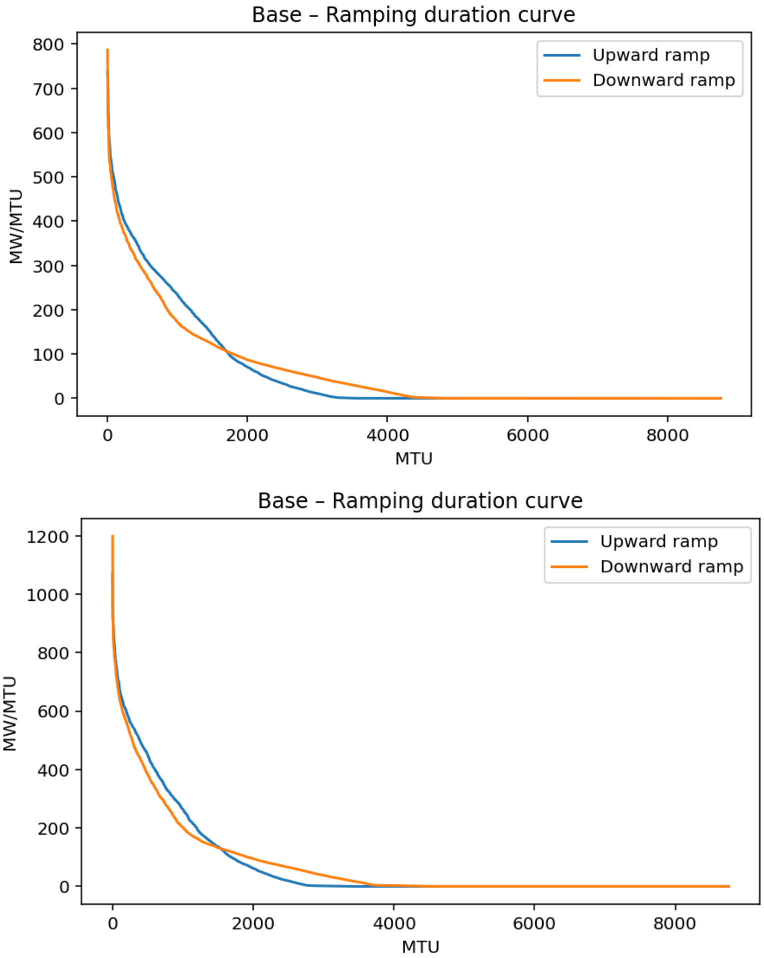
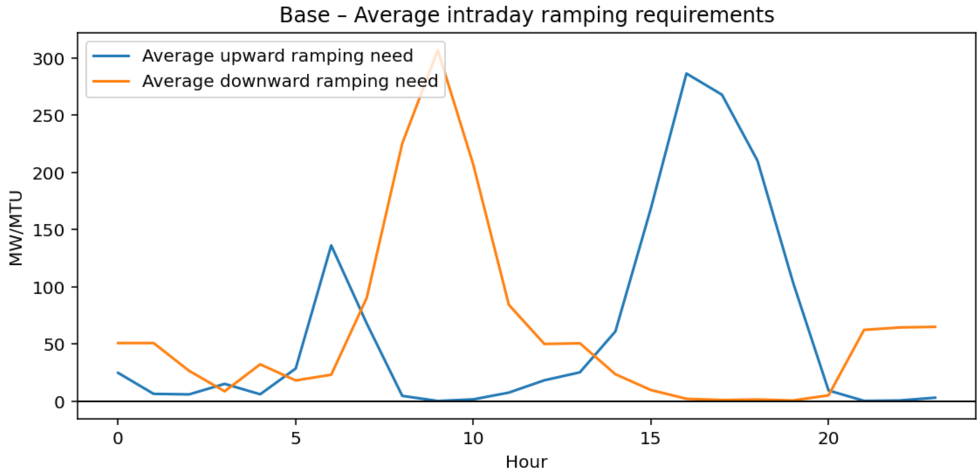


Figure 13: Ramping duration curve – target year 2030 (above), 2035 (below).



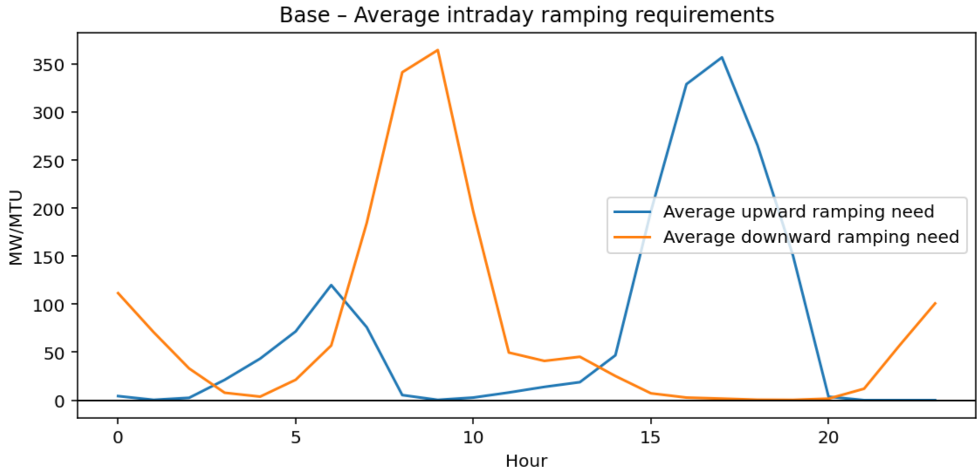


Figure 14: Average daily ramping needs – target year 2030 (above), 2035 (below).

4.1.2.1. Characterisation of ramping capacity

The ramping margin indicates how much additional ramping (capacity) the system could still accommodate beyond the already optimised solution obtained through unit commitment and ED. The ED simulations ensure that residual load is covered while respecting the technical constraints of power plants, including ramping limits. Ramping margins are subsequently derived to quantify the remaining flexibility available in each MTU. These margins indicate the system's capability to absorb additional variability arising, e.g. from forecast errors or higher RES penetration. In simplified terms, the simulation indicates whether the system operates feasibly, while the margin indicates the degree of robustness with which the system operates.

The ramping margin calculation therefore shows how much actual flexibility remains in the system after accounting for the realised dispatch. It indicates whether the system could handle additional variability and identifies the MTUs in which the system is constrained or operating at its capacity. Ramping needs and ramping margins are summarised in Table 20.

Table 20: Ramping needs KPIs

Target year 2030						
WS	**Base**	**WS23**	**WS25**	**WS18**	**WS27**	**WS35**
Average upward ramping needs [MW]	149.02	191.84	214.43	200.38	199.61	190.24
Average downward ramping needs [MW]	110.65	142.22	157.38	146.13	147.21	141.71
Maximum upward ramping needs [MW]	737.61	832.12	827.55	850.22	795.43	834.6
Maximum downward ramping needs [MW]	786.81	842.67	867.58	843.12	855.89	859.34
Minimum residual load variation [MW]	-786.81	-842.67	-867.58	-843.12	-855.89	-859.34
P95 upward ramping needs [MW]	344.82	422.23	492.22	445.89	471.72	442.47
P95 downward ramping needs [MW]	306.19	389.79	471.77	412.67	434.63	405.44
Minimum upward ramping margin after need [MW]	1098.1	820.11	786.49	763.09	719.43	762.66
Minimum downward ramping margin after need [MW]	-556.23	-460.87	-498.54	-470.04	-523.53	-623.23
MTUs with downward uncovered ramping needs	270	306	355	336	333	319
Average downward uncovered ramping needs [MW]	133.83	148.66	178.49	157.47	180.62	185.06
P95 downward uncovered ramping needs [MW]	333.4	358.63	386.73	356	378.39	422.51
Maximum downward uncovered ramping needs [MW]	556.23	460.87	498.54	470.04	523.53	623.23
Probability of downward uncovered ramping needs [%]	3.08	3.49	4.05	3.84	3.8	3.64
MTUs with upward uncovered ramping needs	0	0	0	0	0	0
Average upward uncovered ramping needs [MW]	0	0	0	0	0	0
P95 upward uncovered ramping needs [MW]	0	0	0	0	0	0
Maximum upward uncovered ramping needs [MW]	0	0	0	0	0	0
Probability of upward uncovered ramping needs [%]	0	0	0	0	0	0
Target year 2035						
WS	**Base**	**WS23**	**WS25**	**WS18**	**WS27**	**WS35**
Average upward ramping requirement [MW]	192.42	265.14	292.41	275.41	270.56	256.88
Average downward ramping requirement [MW]	139.47	199.12	216.8	205.54	202.31	195.73
Maximum upward ramping requirement [MW]	1069.94	1240.09	1327.62	1255.23	1265.7	1345.79

Maximum downward ramping requirement [MW]	1198.77	1264.16	1360	1344.47	1359.89	1341.75
Minimum residual load variation [MW]	-1198.77	-1264.16	-1360	-1344.47	-1359.89	-1341.75
P95 upward ramping requirement [MW]	475.79	587.25	690.07	608.05	632.21	579.44
P95 downward ramping requirement [MW]	414.1	541.4	613.08	560.45	544.87	513.48
Minimum upward ramping margin after need [MW]	296.48	-38.04	-67.15	-40.55	-74.67	42.8
Minimum downward ramping margin after need [MW]	-866.8	-963.05	-1039.31	-1079.98	-1024.16	-1153.5
MTUs with downward uncovered ramping needs	326	405	433	455	432	361
Average downward uncovered ramping needs [MW]	166.16	207.39	303.46	227.87	267.23	298.02
P95 downward uncovered ramping needs [MW]	419.09	558.52	764.35	602.93	691.58	868.08
Maximum downward uncovered ramping needs [MW]	866.8	963.05	1039.31	1079.98	1024.16	1153.5
Probability of downward uncovered ramping needs [%]	3.72	4.62	4.94	5.19	4.93	4.12
MTUs with upward uncovered ramping needs	0	1	3	1	1	0
Average upward uncovered ramping needs [MW]	0	38.04	40.69	40.55	74.67	0
P95 upward uncovered ramping needs [MW]	0	38.04	64.3	40.55	74.67	0
Maximum upward uncovered ramping needs [MW]	0	38.04	67.15	40.55	74.67	0
Probability of upward uncovered ramping needs [%]	0	0.01	0.03	0.01	0.01	0

4.1.2.2. Uncovered needs

As can be observed from Table 20 upward uncovered ramping needs were identified only in a limited number of MTUs in several 2035 scenarios, with maximum values below 75 MW. In the target year 2030, there were no identified uncovered upward ramping needs. Compared to downward uncovered ramping needs, both their frequency and magnitude are negligible and therefore the analysis focuses on downward ramping limitations.

Figure 15 presents the downward ramping capacity compared with the ramping needs for the Base scenario, while Figure 16 presents the downward uncovered ramping needs for the Base scenario.

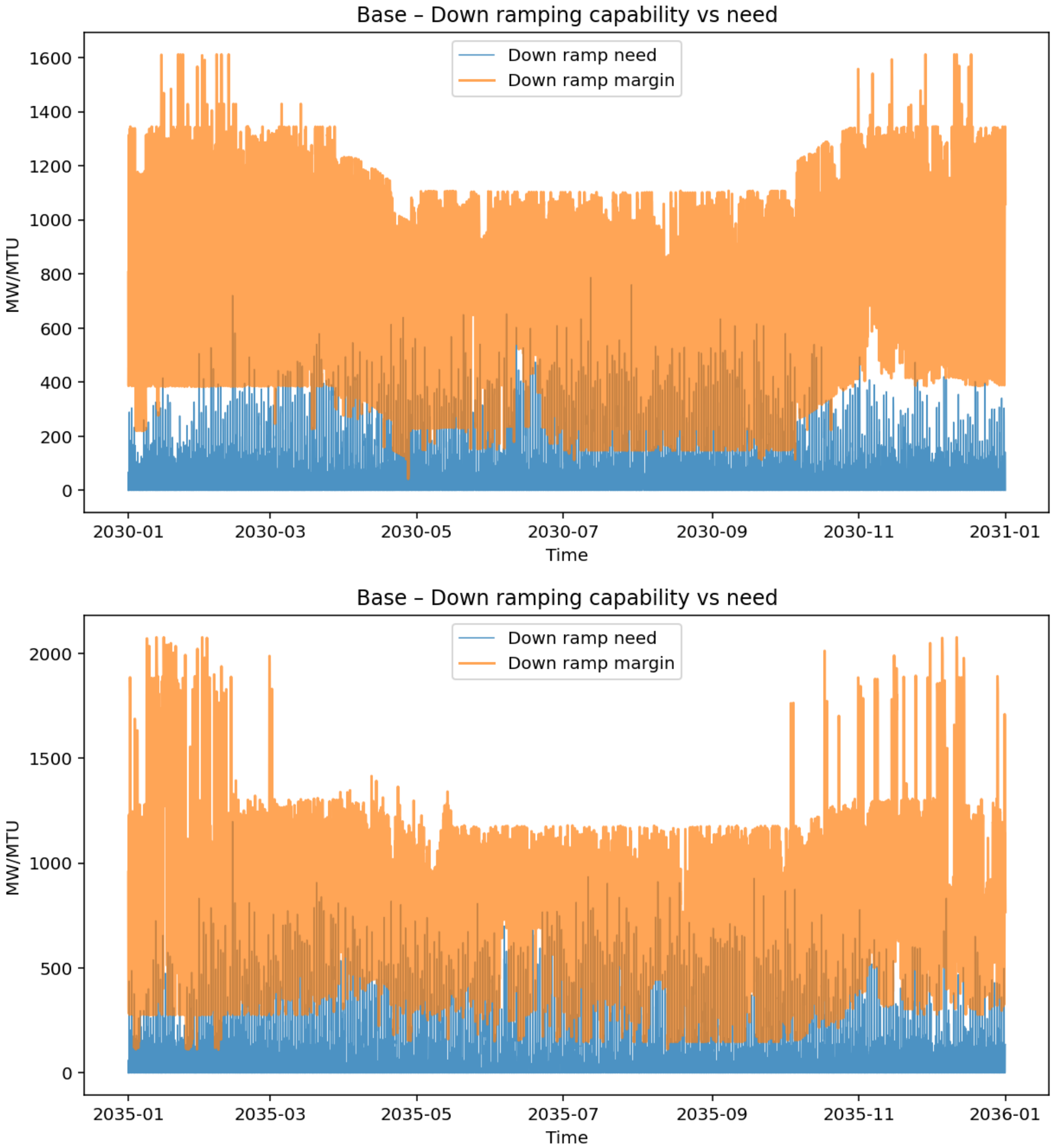


Figure 15: Downward ramping capacity vs needs – target year 2030 (above), 2035 (below).

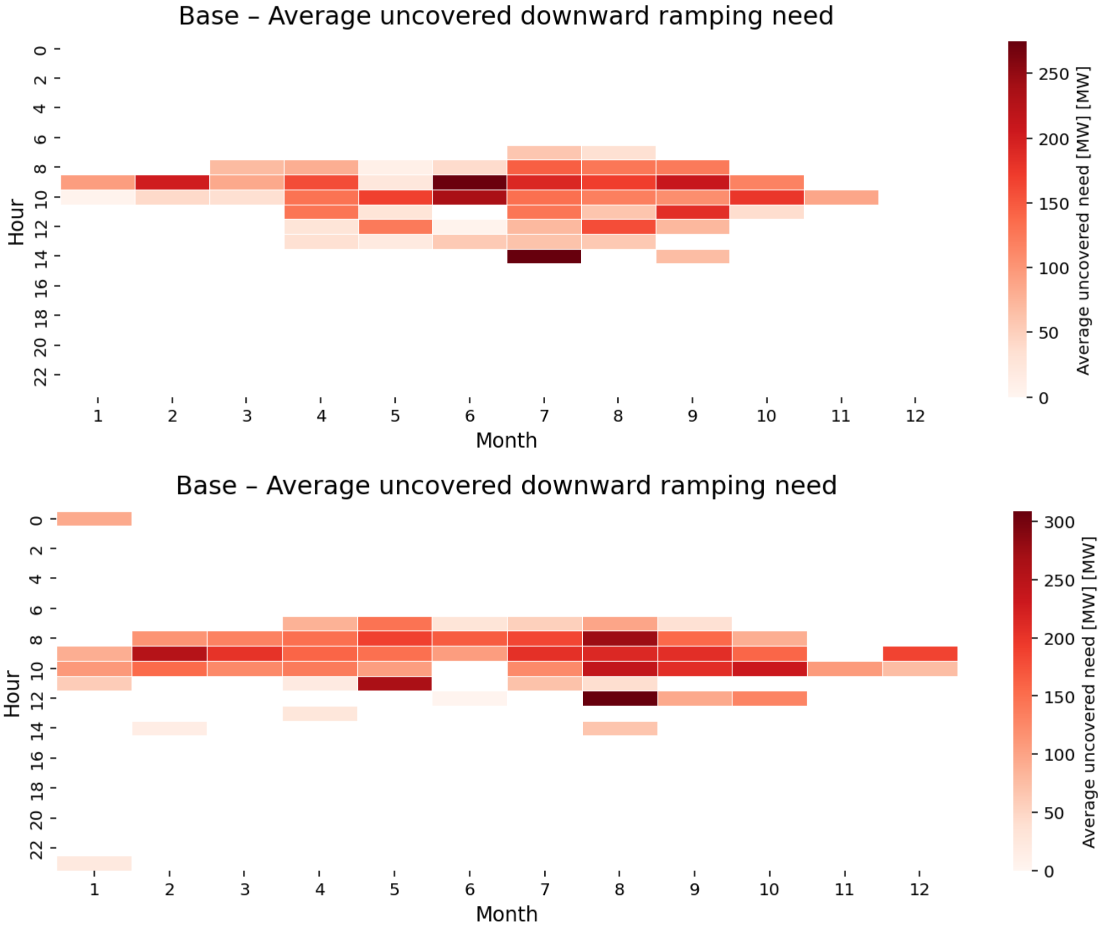


Figure 16: Average uncovered downward ramping needs – by month and hour - target year 2030 (above), 2035 (below).

The graphical representation confirms that downward uncovered ramping needs predominantly occur during periods of high PV generation combined with lower system demand. The results indicate that the system has sufficient upward ramping capability to accommodate increases in residual load. However, downward ramping limitations occur during periods of rapidly decreasing residual load, typically associated with high RES (PV) production and low demand. The results indicate limited system capability to reduce generation sufficiently quickly, highlighting the need for additional downward flexibility.

Downward uncovered ramping needs are mainly concentrated in the morning hours between 07:00 and 10:00 and occur predominantly during months with high solar generation, particularly from July to September. This pattern indicates that the system experiences the greatest flexibility stress during periods of rapid solar output increase, when conventional generation must quickly reduce output but is constrained by minimum generation levels and ramping limits.

The isolated night-time downward ramping needs observed in 2035 are limited to a small number of hours and are of relatively low magnitude. Compared to the downward ramping needs associated with high RES generation, their contribution is negligible, and they therefore have a negligible impact on the overall flexibility assessment.

Monthly probability of downward uncovered ramping needs for analysed scenarios is shown in Figure 17.

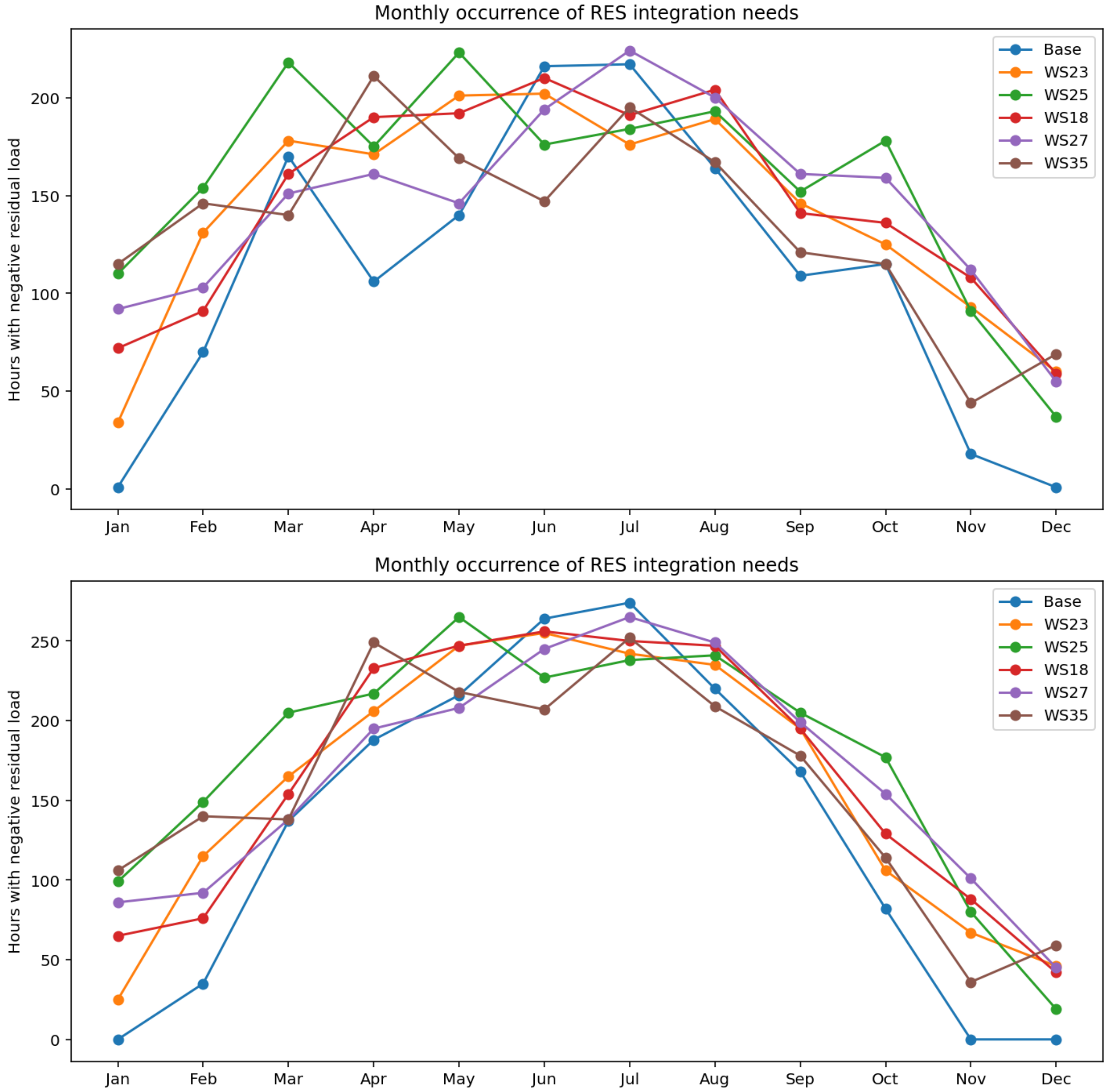


Figure 17: Monthly probability of downward ramping needs - target year 2030 (above), 2035 (below).

The monthly probability of downward uncovered ramping needs shows a pronounced seasonal concentration of flexibility inadequacy during summer and early autumn months. The highest probabilities are observed in scenarios characterised by elevated solar PV generation and prolonged negative residual load conditions. This indicates that downward flexibility limitations are primarily associated with midday RES surplus conditions during high solar production periods.

Table 21 presents the correlation between residual load variations, downward uncovered ramping needs and selected system conditions. The analysis aims to identify the main drivers of ramping requirements and potential ramping shortages by assessing their relationship with PV generation and demand.

For the purposes of this analysis, residual load variations are represented by the absolute changes in residual load between consecutive MTUs, while downward uncovered ramping needs correspond to situations where the available downward ramping capability is insufficient to cover the calculated downward ramping requirements. Correlation coefficients are reported for PV generation and demand, which represent the main drivers of residual load variability in the analysed system.

Table 21: Correlation between residual load variations, downward uncovered ramping needs and key system conditions

Target year 2030						
WS	Corr ramp–PV	Corr ramp–demand	Corr ramp-wind	Corr uncovered need–PV	Corr uncovered need–demand	Corr uncovered need-wind
Base	0.21	-0.137	N/A	0.232	-0.207	N/A
WS23	0.18	-0.09	N/A	0.209	-0.206	N/A
WS25	0.174	-0.1	N/A	0.214	-0.208	N/A
WS18	0.161	-0.075	N/A	0.205	-0.201	N/A
WS27	0.179	-0.101	N/A	0.209	-0.202	N/A
WS35	0.192	-0.101	N/A	0.214	-0.186	N/A
Target year 2035						
Base	0.043	-0.054	N/A	0.142	-0.155	N/A
WS23	-0.02	0.01	N/A	0.152	-0.186	N/A
WS25	-0.027	0.003	N/A	0.149	-0.196	N/A
WS18	-0.025	0.012	N/A	0.145	-0.178	N/A
WS27	-0.021	0.002	N/A	0.151	-0.191	N/A
WS35	-0.007	-0.003	N/A	0.145	-0.159	N/A

Only weak linear correlations were identified between residual load variations and the analysed system conditions. This indicates that ramping requirements are driven by the combined effect of hourly changes in residual load rather than by the absolute level of a single variable. Downward uncovered ramping needs show a weak positive correlation with PV generation and a weak negative correlation with demand, confirming that downward ramping constraints are more likely during periods of higher PV production and lower demand.

4.1.2.3. Flexible resources needed to meet the uncovered needs

As can be observed from the results in Table 20, the available ramping capability is sufficient to manage upward variations of residual load in almost all MTUs:

- no upward uncovered ramping needs arise in any 2030 weather scenario;
- no upward uncovered ramping needs arise in the 2035 Base and WS35 scenarios;
- only one to three affected MTUs occur in each of the other 2035 weather scenarios;
- the maximum identified upward shortfall is below 75 MW.

The ramping residual margins can therefore be characterised as providing adequate upward ramping capacity throughout virtually the entire assessed period. The few positive uncovered needs in 2035 indicate isolated combinations of dispatch position, unit availability and technical ramping constraints rather than a persistent lack of upward capability. However, it should be noted that the assessment was performed using a one-hour MTU, reflecting the hourly discretisation of cross-border transfer capacity allocation and the temporal resolution of the available input time series. Although a 15-minute MTU has been implemented across the common European day-ahead electricity market, the present assessment evaluates the capability of the considered flexibility resources to address the identified upward ramping needs on an hourly basis only. The assessment considered all flexibility resources included in the economic dispatch, according to their technical capabilities. Even though the results indicate that the available upward ramping capability is sufficient at a one-hour temporal resolution, this conclusion cannot be directly extended to a 15-minute MTU, where faster response capabilities from flexibility resources may be required, potentially resulting in uncovered upward ramping needs.

As no material uncovered upward ramping needs were identified for 2030 and only negligible uncovered upward ramping needs were identified for a limited number of MTUs in some 2035 WS, no further assessment of the technical capability of additional flexibility resources for upward ramping was considered necessary. Accordingly, no assessment of the cost-efficiency of additional flexibility resources was performed, as no additional flexibility resources were identified as necessary to address the analysed needs.

4.1.3. Short-term flexibility needs

The assessment identifies short-term flexibility needs in both upward and downward directions. However, the results show a clear asymmetry between the two directions: the Slovenian system has sufficient upward flexibility in the analysed scenarios, while downward flexibility is the limiting factor, particularly in 2035.

As shown in Table 22, "Short-term flexibility needs indicators", the maximum upward short-term flexibility requirement in 2030 ranges from approximately 798 MW to 911 MW, depending on the weather scenario, while the maximum downward requirement ranges from approximately 968 MW to 1,254 MW. By 2035, the maximum upward requirement increases to approximately 1,303–1,505 MW, and the maximum downward requirement rises to approximately 1,599–2,105 MW.

Table 22: Short-term flexibility needs indicators

Target year 2030						
WS	Base	WS23	WS25	WS18	WS27	WS35
Max upward short-term ramp need [MW]:	798.24	911.47	896.7	837.32	861.49	854.28
Max downward short-term ramp need [MW]:	1254.37	1073.17	1017.21	1130.34	1096.44	968.25
Max upward uncovered STF need	0	0	0	0	0	0
Max downward uncovered STF need	1086.9	900.43	535.23	798.98	862.77	791.06
MTUs with upward uncovered STF needs	0	0	0	0	0	0
MTUs with downward uncovered STF needs	495	493	615	637	621	447
Target year 2035						
WS	Base	WS23	WS25	WS18	WS27	WS35
Max upward short-term ramp need [MW]:	1302.82	1505.21	1480.82	1382.76	1422.67	1410.78
Max downward short-term ramp need [MW]:	2104.67	1772.26	1679.83	1866.67	1813.78	1598.99
Max upward uncovered STF need	0	0	0	0	0	0
Max downward uncovered STF need	1885.76	1546.62	1350.05	1263.89	1495.42	1223.9
MTUs with upward uncovered STF needs	0	0	0	0	0	0
MTUs with downward uncovered STF needs	746	745	1104	989	1063	829

The same table shows that no uncovered upward short-term flexibility needs are identified in either target year. This means that all simulated upward deviations can be accommodated by the flexibility assumed to be available in the system. In contrast, uncovered downward needs occur in every analysed weather scenario. In 2030, the maximum uncovered downward need ranges from approximately 535 MW to 1,087 MW, increasing to approximately 1,224–1,886 MW in 2035. The number of affected MTUs also rises from 447–637 MTUs in 2030 to 745–1,104 MTUs in 2035. These results indicate that downward short-term flexibility deficits become both larger and more frequent over time.

The percentile-based characterisation presented in Table 23, "Short-term flexibility needs and uncovered short-term flexibility needs percentiles", shows that most MTUs have no or relatively low short-term flexibility requirements, while substantially larger needs occur in a limited number of extreme situations. This is reflected in the zero P0.1 values and in the considerable difference between the high percentiles and the annual maximum values.

For 2030, the P99.9 upward short-term flexibility requirement ranges from approximately 412 MW to 506 MW, while the corresponding downward requirement ranges from approximately 403 MW to 530 MW. The P99.9 downward uncovered need ranges from approximately 151 MW to 227 MW, whereas the upward uncovered value remains zero in all scenarios.

In 2035, the upper percentiles of the distribution increase substantially, indicating more severe high-demand flexibility events. The P99.9 downward short-term flexibility requirement increases to approximately 673–871 MW, while the P99.9 downward uncovered need increases to approximately 335–479 MW. The P95 and P99 values show the same upward trend, confirming that both frequent high-flexibility events and more extreme events become more demanding by 2035.

Table 23: Short-term flexibility needs and uncovered short-term flexibility needs percentiles

Target year 2030						
WS	Base	WS23	WS25	WS18	WS27	WS35
P0.1 Upward STF ramp needs [MW]	0	0	0	0	0	0
P0.1 Downward STF ramp needs [MW]	0	0	0	0	0	0
P0.1 Upward uncovered STF needs [MW]	0	0	0	0	0	0
P0.1 Downward uncovered STF needs [MW]	0	0	0	0	0	0
P99.9 Upward STF ramp needs [MW]	431.48	411.58	506.22	429.59	483.4	459.91
P99.9 Downward STF ramp needs [MW]	402.52	430.54	529.6	453.05	506.58	483.78
P99.9 Upward uncovered STF needs [MW]	0	0	0	0	0	0
P99.9 Downward uncovered STF needs [MW]	167.32	150.57	227.26	200.64	214.9	163.15
P95 Upward STF ramp needs [MW]	95.93	99.59	113.14	102.24	105.48	100.01
P95 Downward STF ramp needs [MW]	94.9	97.66	110	100.84	101.86	98.01
P99 Upward STF ramp needs [MW]	214.83	225.97	261.67	234.92	246.51	237.84
P99 Downward STF ramp needs [MW]	216.24	227.11	266.7	236.7	249.59	233.72
Target year 2035						
WS	Base	WS23	WS25	WS18	WS27	WS35
P0.1 Upward STF ramp needs [MW]	0	0	0	0	0	0
P0.1 Downward STF ramp needs [MW]	0	0	0	0	0	0
P0.1 Upward uncovered STF needs [MW]	0	0	0	0	0	0
P0.1 Downward uncovered STF needs [MW]	0	0	0	0	0	0
P99.9 Upward STF ramp needs [MW]	732.31	670.36	837.41	710.84	806.3	759.81
P99.9 Downward STF ramp needs [MW]	672.59	709.68	871.06	744.66	837.23	803.26
P99.9 Upward uncovered STF needs [MW]	0	0	0	0	0	0
P99.9 Downward uncovered STF needs [MW]	361.41	335.48	479.42	404.43	476.68	395.01

P95 Upward STF ramp needs [MW]	149.12	152.48	176.68	157.32	161.74	150.61
P95 Downward STF ramp needs [MW]	147.28	148.28	170.88	154.09	155.84	148.93
P99 Upward STF ramp needs [MW]	357.65	370.69	430.36	384.3	404.95	390.82
P99 Downward STF ramp needs [MW]	356.93	370.82	438.09	388.36	405.77	385.47

The intraday distribution shown in Figure 18, demonstrates that downward short-term flexibility requirements are not distributed uniformly throughout the day. Their probability rises during the period of increasing and high PV generation and reaches its highest levels around midday.

During the night and evening, the probability is considerably lower because PV forecast deviations have little or no effect on residual load. The pattern becomes more pronounced in 2035, indicating a stronger dependence of short-term flexibility needs on solar-generation conditions.

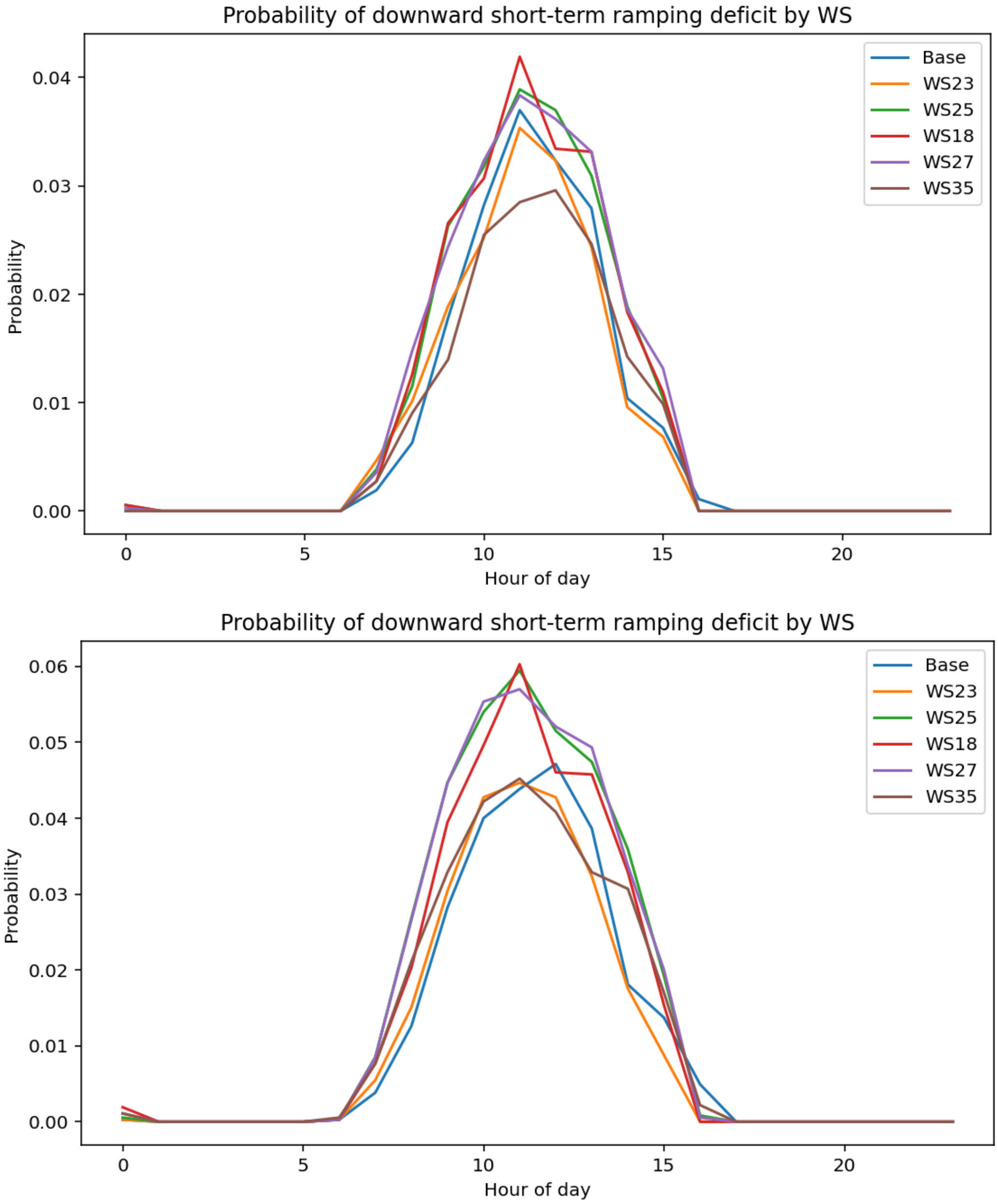


Figure 18: Average hourly probability of downward short-term flexibility needs by WS – target year 2030 (above), 2035 (below)

A more detailed seasonal and hourly pattern is presented in Figure 19. The figure shows that uncovered downward needs are concentrated mainly between approximately 09:00 and 13:00, while their probability is generally negligible outside this interval.
The highest probabilities occur in late summer and early autumn, particularly in August and September, and exceed 10% in the most critical hours. The stronger concentration of events in 2035 indicates that increasing installed PV capacity raises both the magnitude of forecast deviations and the likelihood that the available downward flexibility will be insufficient.
These conditions occur when actual PV production is higher than forecast or when demand is lower than expected, causing residual load to fall below the level anticipated in the day-ahead schedule.

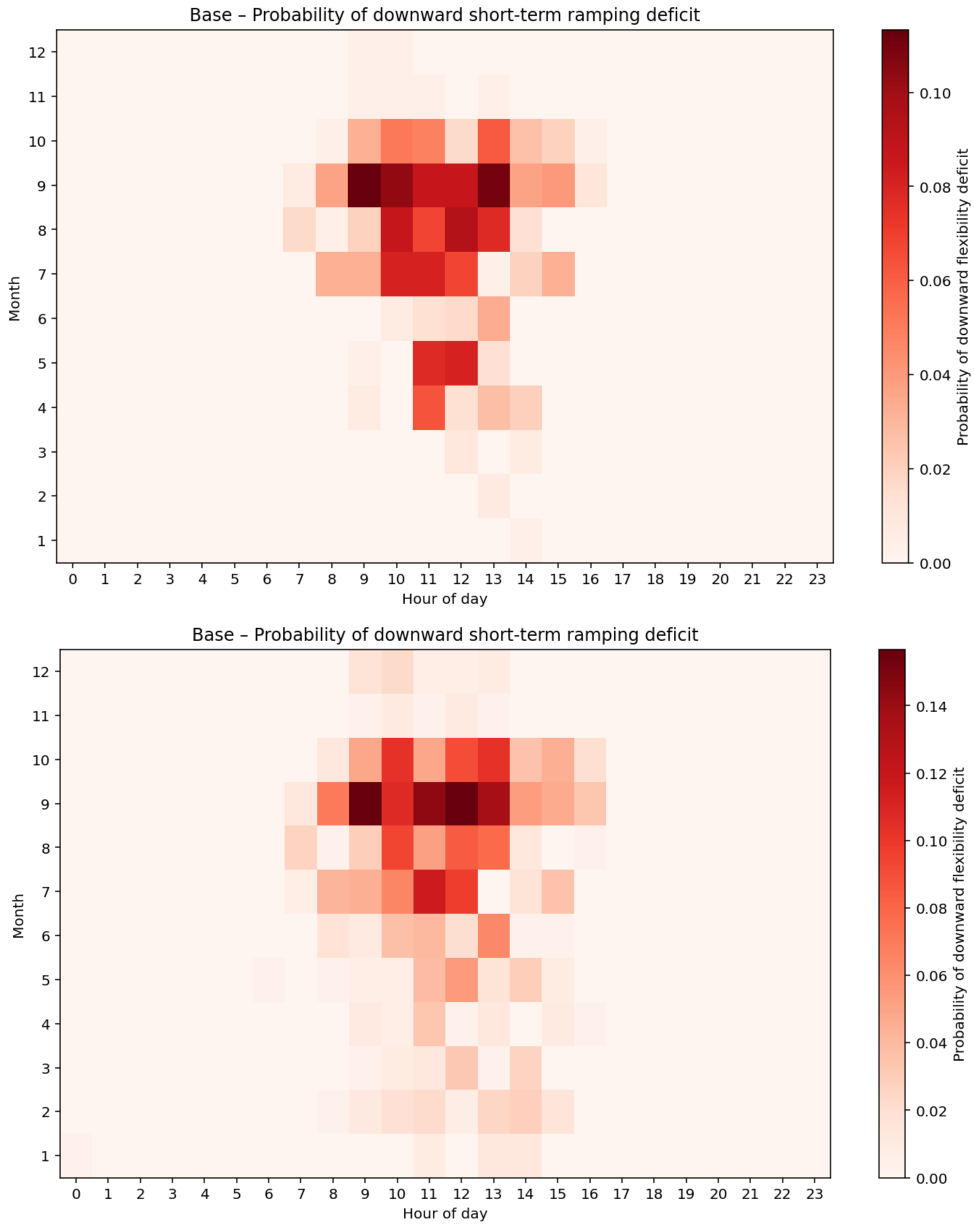


Figure 19: Probability of downward uncovered short-term flexibility needs– target year 2030 (above), 2035 (below)

The magnitude, frequency, energy and duration of uncovered needs are further quantified in Table *24*. In 2030, the average size of a downward uncovered event ranges from approximately 94 MW to 116 MW. The P95 value ranges from approximately 296 MW to 369 MW, while the P99 value ranges from approximately 444 MW to 630 MW.

The expected annual uncovered downward energy in 2030 ranges from approximately 4.5 GWh to 7.2 GWh, with approximately 45–64 hours per year affected by uncovered downward needs. The corresponding annual probability ranges from approximately 0.51% to 0.73%.

By 2035, the average event size increases to approximately 159–188 MW, while the P95 value rises to approximately 463–586 MW and the P99 value to approximately 790–926 MW. Expected annual uncovered downward energy increases to approximately 11.8–20.8 GWh, and the expected duration rises to approximately 75–110 hours per year. The probability of an uncovered downward need increases to approximately 0.85–1.26%.

The Table *24* therefore shows that the deterioration between 2030 and 2035 affects every relevant dimension of downward flexibility adequacy: event size, high-percentile capacity, annual energy, duration and probability.

Table 24: Uncovered STF needs indicators

Target year 2030												
WS	Average upward uncovered STF need per event [MW]	Average downward uncovered STF need per event [MW]	P95 upward uncovered STF need [MW]	P95 downward uncovered STF need [MW]	P99 upward uncovered STF need [MW]	P99 downward uncovered STF need [MW]	Total expected upward uncovered STF energy [MWh]	Total expected downward uncovered STF energy [MWh]	Expected hours with upward uncovered STF needs	Expected hours with downward uncovered STF needs	Probability of upward uncovered STF needs [%]	Probability of downward uncovered STF needs [%]
Base	0	105	0	333.27	0	629.51	0	5,197.65	0	49.5	0	0.57
WS23	0	94.13	0	296.15	0	479.28	0	4,640.66	0	49.3	0	0.56
WS25	0	116.29	0	369.35	0	477.15	0	7,151.82	0	61.5	0	0.7
WS18	0	102.4	0	306.02	0	534.15	0	6,522.78	0	63.7	0	0.73
WS27	0	111.36	0	343.82	0	532.05	0	6,915.42	0	62.1	0	0.71
WS35	0	100.08	0	319.23	0	443.95	0	4,473.73	0	44.7	0	0.51
Target year 2035												
Base	0	164.33	0	487.04	0	926.03	0	12,259.18	0	74.6	0	0.85
WS23	0	158.89	0	462.85	0	789.69	0	11,837.47	0	74.5	0	0.85
WS25	0	187.99	0	586.04	0	888.66	0	20,754.34	0	110.4	0	1.26
WS18	0	167.19	0	522.03	0	829.79	0	16,535.52	0	98.9	0	1.13
WS27	0	187.24	0	584.1	0	903.47	0	19,903.22	0	106.3	0	1.21
WS35	0	172.7	0	545.83	0	868.95	0	14,317.02	0	82.9	0	0.95

The annual distribution of these events is illustrated in the Figure 20 captioned “Expected uncovered STF needs for selected WS, 2030 above, 2035 below”. The figure shows that uncovered needs occur in concentrated clusters rather than continuously throughout the year. The 2035 profile contains both more frequent and larger events than the 2030 profile, confirming that the increase in annual uncovered energy results from a combination of higher individual deficits and a larger number of affected periods.

Figure 20: Expected uncovered STF needs for selected WS, 2030 above, 2035 bellow.

The relationship between uncovered needs and prevailing system conditions is presented in Table 25. The table shows a moderate positive correlation between downward uncovered short-term flexibility needs and PV generation. In 2030, the correlation coefficients range from approximately 0.244 to 0.281, increasing to approximately 0.306–0.341 in 2035.

The correlation with demand is negative, ranging from approximately −0.216 to −0.251 in 2030 and from approximately −0.246 to −0.297 in 2035. These results indicate that uncovered downward needs are more likely during periods of high PV production and low electricity demand. The stronger coefficients in 2035 show that PV generation becomes an increasingly important driver of short-term system uncertainty and downward flexibility deficits.

Wind correlations are reported as not available because wind forecast errors were not explicitly represented in the assessment. Correlations for upward uncovered needs are also not presented because no upward uncovered short-term flexibility needs were identified.

Table 25: Correlation between uncovered STF needs and system conditions

WS	Correlation downward uncovered STF needs–PV	Correlation downward uncovered STF needs–demand	Correlation downward uncovered STF needs–wind
Target year 2030			
Base	0.277	-0.239	N/A
WS23	0.274	-0.236	N/A
WS25	0.265	-0.248	N/A
WS18	0.281	-0.25	N/A
WS27	0.273	-0.251	N/A
WS35	0.244	-0.216	N/A
Target year 2035			
Base	0.306	-0.246	N/A
WS23	0.312	-0.255	N/A
WS25	0.318	-0.291	N/A
WS18	0.320	-0.275	N/A
WS27	0.341	-0.297	N/A
WS35	0.310	-0.264	N/A

4.1.3.1. Characterisation of short-term upward and downward flexibility

The magnitude, frequency and temporal distribution of upward and downward short-term flexibility needs are presented in Section 4.1.3. This subsection therefore focuses on the ability of the technically available residual margins to cover those needs.

The residual margins represent the technically feasible adjustment remaining after the day-ahead dispatch. The upward residual margin corresponds to the capability of available resources to increase their output, while the downward residual margin corresponds to their capability to reduce output. These margins are constrained by the scheduled operating point, minimum and maximum generation levels, ramping capability, minimum up- and down-times, start-up and shut-down constraints, energy limitations of storage and the availability of assets.

The modelled technical capability of dispatchable generation units is presented in Table 26. The table shows the assumed upward and downward ramping capability and the operating limits of the units included in the assessment.

Table 26: Upward and downward ramping rate capability (pu) of dispatchable generation units

Unit – Power plant	P_{max} [MW]	P_{min} [MW]	Ramp up [pu]	Ramp down [pu]
TEB	141	0	1	1
PE51	42	0	1	1
PE52	42	0	1	1
TETOL_BLOK1	42	0	1	1
PE500	500	0	1	1
HEBLA	39	0	1	1
HEBOS	32,1	0	1	1

HEBREZ	48	0	1	1
HEDOB	81,4	0	1	1
HEDRA	28,8	0	1	1
HEFAL	56,8	0	1	1
HEFOR	116	0	1	1
HEKRS	39	0	1	1
HEMAR_O	62,4	0	1	1
HEMAV	38	0	1	1
HEMED	25	0	1	1
HEMOS	21	0	1	1
HEOZB	72	0	1	1
HEPLA	37	0	1	1
HESOL	32,4	0	1	1
HEVRH	34	0	1	1
HEVUH	72,3	0	1	1
HEVUZ	55,5	0	1	1
HEZLA	153	0	1	1
HEMOK	28	0	1	1
HESUH	35,5	0	1	1
HEREN	33	0	1	1
HETRB	32,5	0	1	1
CHEAVC	180	0	1	1
KOZ	420	0	1	1

As shown in Table 26, the listed dispatchable units were assigned symmetrical upward and downward ramping capability. However, the effective residual margin available in an individual MTU depends on the scheduled operating point of each unit. A unit operating close to its maximum output has limited upward residual margin, whereas a unit operating close to its minimum stable output has limited downward residual margin. An unavailable unit provides no residual margin in either direction.

The results presented in Section 4.1.3 show that no uncovered upward short-term flexibility needs were identified in any analysed weather scenario for either 2030 or 2035. This demonstrates that the technically constrained upward residual margins were sufficient to cover all simulated positive residual-load deviations.

The available upward capability is provided by the unused headroom between the scheduled output and the maximum available output of dispatchable resources. Although Table 26 shows the technical ramping capability of the individual units, the actual upward contribution in each MTU depends on the remaining headroom after dispatch and on the availability of the unit.

The quantitative values of upward flexibility needs and uncovered upward needs are reported in Section 4.1.3 and are not repeated here.

The downward residual margins were not sufficient in all simulated conditions. As reported in Section 4.1.3, uncovered downward short-term flexibility needs occur in every analysed weather scenario and become more pronounced in 2035.

The main limitation is the technically feasible distance between the scheduled output and the minimum operating level of dispatchable units. During periods of high PV generation and low residual load, conventional units may already operate close to their minimum stable output. In such conditions, the downward ramping capability shown in Table 26 cannot be fully utilized because the remaining downward operating margin is small.

The occurrence of uncovered downward needs therefore indicates that the binding constraint is not only the speed at which units can reduce output, but also the amount of downward headroom remaining after the day-ahead dispatch. The increase in uncovered downward needs by 2035 shows that this residual margin becomes less adequate as PV penetration increases.

The magnitude, frequency and temporal distribution of these downward deficits are presented in Section 4.1.3, in particular in Table 22, Table *24* and Figure 18, and are therefore not repeated here.

The assessment considers the residual flexibility of domestic resources. Cross-border exchange margins and market-liquidity adjustments were not included. The possible contribution of interconnection capacity to upward or downward flexibility is therefore not reflected in the results.

The results apply to the assessed hourly timeframe, corresponding to slow short-term flexibility from one hour to D-1. They do not separately demonstrate the capability of the same assets to provide very fast or fast flexibility within shorter balancing intervals.

4.1.3.2. Uncovered needs

The analysis identifies no uncovered upward short-term flexibility needs in any of the assessed weather scenarios or target years. All identified uncovered needs are downward and mainly occur during periods of high PV generation, when forecast uncertainty coincides with insufficient downward flexibility.

For the Base weather scenario, the results are:

Table 27: Assessment of uncovered downward short-term flexibility needs for 2030 and 2035

Indicator	2030	2035
Maximum downward uncovered short-term need	346.7 MW	589.6 MW
Average capacity per uncovered event	112.2 MW	182.9 MW
Expected uncovered upward energy	0 MWh	0 MWh
Expected uncovered downward energy	5,814 MWh	14,690 MWh
Expected number of hours with uncovered needs	51.8 h	80.3 h

Across the other assessed weather scenarios, the average capacity of downward uncovered events ranges between approximately 107 and 118 MW in 2030 and between 182 and 202 MW in 2035.

The total expected downward uncovered energy ranges from approximately:

- 5.2 to 7.0 GWh in 2030;
- 14.7 to 19.5 GWh in 2035.

The expected number of hours with uncovered needs ranges from approximately:

- 46.5 to 60.9 hours in 2030;
- 80.3 to 104.6 hours in 2035.

The probability distributions and the hourly and daily annual representations confirm that uncovered needs occur during a limited number of hours but can reach substantial capacity levels. Both the average event capacity and the total expected uncovered energy increase considerably from 2030 to 2035.

The correlation with system conditions is consistent with the findings already presented regarding the drivers of short-term flexibility needs. Downward uncovered needs are primarily associated with high solar generation and lower residual demand. The relationship with wind generation is less pronounced because the applied forecast-error model primarily considers demand and PV uncertainty.

Regarding the required duration categories:

- Very fast uncovered flexibility needs, 5–15 minutes: not assessed because suitable forecast-error data at this time resolution were not available.
- Fast uncovered flexibility needs, 15–60 minutes: not assessed for the same reason.
- Slow uncovered flexibility needs, 1 hour to D-1: fully assessed. All quantified uncovered short-term flexibility needs fall within this category.

The results therefore indicate an increasing need for downward slow flexibility, particularly from resources capable of absorbing surplus electricity or reducing generation during periods of high PV output. However, the assessment was performed at an hourly resolution and above. Consequently, faster uncovered flexibility needs could not be identified and may therefore remain unquantified, potentially resulting in additional downward fast or very fast uncovered flexibility needs.

4.1.3.3. Flexible resources needed to meet the uncovered needs

As shown in Table 22, no uncovered upward short-term flexibility needs were identified for Slovenia in any of the analysed weather scenarios for either 2030 or 2035. The maximum uncovered upward need amounts to 0 MW in all assessed cases.

Consequently, no additional flexible resources are required to meet uncovered upward needs under the analysed scenarios. The available portfolio of domestic flexible resources is assessed as sufficient to cover the quantified upward short-term flexibility needs.

This conclusion is subject to the scope and assumptions of the assessment. Additional upward flexibility may nevertheless enhance system resilience in the event of extreme conditions, unforeseen outages, modelling uncertainties or future changes in the generation and demand structure. However, such resources do not constitute a quantified requirement resulting from the assessed uncovered upward needs, as Table 22 shows that these needs are fully covered in all analysed cases.

4.2. Network flexibility needs

This section presents the results of the assessment of network flexibility needs in accordance with Articles 11 and 12 of the FNA Methodology. It summarises the identified distribution and transmission network flexibility needs under the selected assessment scenarios, including their technical characterisation, direction, location and extent, together with the distinction between covered and uncovered network flexibility needs, where applicable.

4.2.1. DSO network needs

The DSO network flexibility needs assessment identifies the flexibility required to prevent or resolve thermal loading and voltage constraints in the Slovenian distribution network under the future operating conditions described in Section 3.1.2.10.

The detailed assessment results are presented in Table 28 (2030) and Table 29 (2035). The flexibility needs are reported separately for each Slovenian DNO area, voltage level and representative network group, distinguishing between upward and downward flexibility needs. For each representative time block identified in accordance with the methodology described in Section 2.3.7.2, the assessment reports the network flexibility needs in terms of power (MW) and energy (MWh) as a sum of covered and uncovered flexibility, together with the corresponding share of uncovered flexibility. Representative time blocks are derived from seasonal and day-type flexibility profiles and represent the periods during which the highest flexibility requirements are expected. Consecutive hours with similar characteristics are grouped into representative time blocks, while all remaining hours are aggregated into an "Other" category. In accordance with the FNA Methodology, the results additionally indicate the share of downward flexibility needs pertaining to renewable generation curtailment and the expected contractual means through which the required flexibility would be accessed. Annual (entire year) values are also reported, providing an aggregated representation of the assessed flexibility needs in addition to the representative time block results

For each DNO area, the results are reported separately for four representative LV network groups and four representative MV feeder groups. The spatial granularity presented in the tables combines the DNO area identifier with the corresponding representative network group, where:

- **EG** – Elektro Gorenjska,
- **EL** – Elektro Ljubljana,
- **EC** – Elektro Celje,
- **EM** – Elektro Maribor,
- **EP** – Elektro Primorska.

For LV networks, the representative network groups correspond to:

1. Urban networks;
2. Larger town and suburban networks;
3. Smaller urban and industrial networks; and
4. Small rural networks.

For MV feeders, the representative feeder groups correspond to:

1. Urban feeders;
2. Industrial feeders;
3. Long rural feeders; and
4. Short rural feeders.

To facilitate the interpretation of the reported results, the representative time blocks are classified according to the network constraint that determined their identification. Accordingly, the following reasons for defining the representative time blocks are distinguished:

- **reason a)** – voltage drop violation;
- **reason b)** – voltage rise violation; and
- **reason c)** – transformer overload violation.

The simulation results indicate that the nature of the identified flexibility needs differs between voltage levels. At the LV level, flexibility requirements are predominantly associated with increasing electricity demand resulting from the electrification of heating and transport, whereas at the MV level they are primarily associated with distributed generation. Correspondingly, LV flexibility needs mainly arise from MV/LV transformer, while MV flexibility needs are predominantly driven by excessive voltage rise resulting from distributed generation.

Where the explicit flexibility resources assumed to be available are insufficient to resolve the identified network constraints, network reinforcement is required. Since the assessment assumes that only a realistic share of technically identified reinforcement measures will be implemented within the planning horizon, the remaining flexibility requirements are reported as uncovered flexibility needs.

The assessment further indicates that the expected availability of explicit flexibility remains relatively limited in both target years. For downward flexibility, the expected contractual means to access flexibility is the application of Flexible Connection Agreements (FCAs) for photovoltaic generation, while battery storage operation is represented through implicit flexibility embedded in the simulated operating conditions. The assessment also shows that implicit flexibility, particularly shifted EV charging outside peak tariff periods, creates additional nighttime demand peaks that need to be considered in future network planning.

Table 28: Flexibility needs assessment according to Annex 2 – Year 2030 with time blocks

Direction of need	Target year	Time block	Reasoning to define the time block	Spatial granularity	Voltage level of congestion or voltage issue	Type of value	Network flexibility needs	Share of uncovered flexibility	Share of downward flexibility needs pertaining to RES generation curtailment	Expected contractual means to access flexibility
Upwards	2030	**Entire year**		**EG 1**	Low voltage 0.4 kV network	**Total energy over the year**	**596 MWh**	**100%**	**0%**	Local service
						Summation of maximum power	**5.4 MW**	**100%**	**0%**	
		Nov-Feb Mon-Fri 20:00 - 23:59	Reason c)			Total energy over the interval	177 MWh	100%	0%	
						Summation of maximum power	5.3 MW	100%	0%	
		Other	Reason c)			Total energy over the interval	419 MWh	100%	0%	
						Summation of maximum power	5.4 MW	100%	0%	
Upwards	2030	**Entire year**		**EC 1**	Low voltage 0.4 kV network	**Total energy over the year**	**1245 MWh**	**74%**	**0%**	Local service
						Summation of maximum power	**21 MW**	**57%**	**0%**	
			Reason c)			Total energy over the interval	240 MWh	64%	0%	

		Nov-Feb Mon-Fri 00:00 - 02:59				Summation of maximum power	15 MW	70%	0%	
		Nov-Feb Mon-Fri 20:00 - 22:59	Reason c)			Total energy over the interval	272 MWh	77%	0%	
						Summation of maximum power	19 MW	59%	0%	
		Other	Reason c)			Total energy over the interval	733 MWh	76%	0%	
						Summation of maximum power	21 MW	58%	0%	
Upwards	2030	**Entire year**		**EC 2**	Low voltage 0.4 kV network	**Total energy over the year**	**3093 MWh**	**100%**	**0%**	Local service
						Summation of maximum power	**8.4 MW**	**100%**	**0%**	
		Mar-Oct Mon-Fri 19:00 - 23:59	Reason a)			Total energy over the interval	398 MWh	100%	0%	
						Summation of maximum power	3.2 MW	100%	0%	
		Nov-Feb Mon-Fri 17:00 - 23:59	Reason a)			Total energy over the interval	663 MWh	100%	0%	
						Summation of maximum power	3.6 MW	100%	0%	
		Other	Reason a)			Total energy over the interval	2032 MWh	100%	0%	
						Summation of maximum power	8.4 MW	100%	0%	

Downwards	2030	**Entire year**		**EC 2**	Low voltage 0.4 kV network	**Total energy over the year**	**1320 MWh**	**100%**	**0%**	Local service
						Summation of maximum power	**20.8 MW**	**100%**	**0%**	
		Mar-Oct Mon-Sun 10:00 - 15:59	Reason b)			Total energy over the interval	987 MWh	100%	0%	
						Summation of maximum power	20.8 MW	100%	0%	
		Other	Reason b)			Total energy over the interval	333 MWh	100%	0%	
						Summation of maximum power	14.2 MW	100%	0%	
Upwards	2030	**Entire year**		**EM 1**	Low voltage 0.4 kV network	**Total energy over the year**	**3260 MWh**	**100%**	**0%**	Local service
						Summation of maximum power	**13.4 MW**	**100%**	**0%**	
		Nov-Feb Mon-Fri 17:00 - 23:59	Reason c)			Total energy over the interval	1221 MWh	100%	0%	
						Summation of maximum power	13.4 MW	100%	0%	
		Other	Reason c)			Total energy over the interval	2038 MWh	100%	0%	
						Summation of maximum power	13.4 MW	100%	0%	
Upwards	2030	**Entire year**		**EM 2**	Low voltage 0.4 kV network	**Total energy over the year**	**2917 MWh**	**77%**	**0%**	Local service

						Summation of maximum power	**15 MW**	**66%**	**0%**	
		Mar-Oct Mon-Fri 18:00 - 23:59	Reason a)			Total energy over the interval	464 MWh	67%	0%	
						Summation of maximum power	15 MW	58%	0%	
		Nov-Feb Mon-Fri 20:00 - 23:59	Reason a)			Total energy over the interval	626 MWh	91%	0%	
						Summation of maximum power	15 MW	67%	0%	
		Other	Reason a)			Total energy over the interval	1827 MWh	87%	0%	
						Summation of maximum power	14.4 MW	68%	0%	
Downwards	2030	**Entire year**		**EP 1**	Low voltage 0.4 kV network	**Total energy over the year**	**28 MWh**	**100%**	**0%**	Local service
						Summation of maximum power	**0.7 MW**	**100%**	**0%**	
		Mar-Oct Mon-Sun 12:00 - 16:59	Reason b)			Total energy over the interval	17 MWh	100%	0%	
						Summation of maximum power	0.7 MW	100%	0%	
		Nov-Feb Mon-Sun 09:00 - 15:59	Reason b)			Total energy over the interval	3 MWh	100%	0%	
						Summation of maximum power	0.6 MW	100%	0%	

		Other	Reason b)			Total energy over the interval	8 MWh	100%	0%	
						Summation of maximum power	0.7 MW	100%	0%	
Downwards	2030	**Entire year**		**EG 3**	Medium voltage 20 kV feeder	**Total energy over the year**	**3943 MWh**	**47%**	**53%**	Flexible connection agreement
						Summation of maximum power	**12.8 MW**	**51%**	**49%**	
		Mar-Oct Mon-Sun 09:00 - 15:59	Reason b)			Total energy over the interval	3518 MWh	47%	53%	
						Summation of maximum power	12.8 MW	51%	49%	
		Other	Reason b)			Total energy over the interval	425 MWh	46%	54%	
						Summation of maximum power	12.8 MW	49%	51%	
Downwards	2030	**Entire year**		**EL 3**	Medium voltage 20 kV feeder	**Total energy over the year**	**22654 MWh**	**57%**	**43%**	Flexible connection agreement
						Summation of maximum power	**53 MW**	**48%**	**52%**	
		Mar-Oct Mon-Sun 12:00 - 16:59	Reason b)			Total energy over the interval	15631 MWh	54%	46%	
						Summation of maximum power	51.8 MW	49%	51%	
			Reason b)			Total energy over the interval	2703 MWh	57%	43%	

		Nov-Feb Mon-Sun 12:00 - 16:59				Summation of maximum power	53 MW	47%	53%	
		Other	Reason b)			Total energy over the interval	4320 MWh	66%	34%	
						Summation of maximum power	40.1 MW	52%	48%	
Downwards	2030	**Entire year**		**EC 3**	Medium voltage 20 kV feeder	**Total energy over the year**	**11910 MWh**	**100%**	**0%**	Flexible connection agreement
						Summation of maximum power	**22.2 MW**	**100%**	**0%**	
		Mar-Oct Mon-Sun 09:00 - 15:59	Reason b)			Total energy over the interval	8996 MWh	100%	0%	
						Summation of maximum power	22.2 MW	100%	0%	
		Other	Reason b)			Total energy over the interval	2914 MWh	100%	0%	
						Summation of maximum power	22.1 MW	100%	0%	
Downwards	2030	**Entire year**		**EM 3**	Medium voltage 20 kV feeder	**Total energy over the year**	**30472 MWh**	**52%**	**48%**	Flexible connection agreement
						Summation of maximum power	**93.3 MW**	**44%**	**56%**	
		Mar-Oct Mon-Sun 09:00 - 15:59	Reason b)			Total energy over the interval	2703 MWh	57%	43%	
						Summation of maximum power	53 MW	47%	53%	

		Nov-Feb Mon-Sun 09:00 - 15:59	Reason b)			Total energy over the interval	4066 MWh	52%	48%	
						Summation of maximum power	93 MW	43%	57%	
		Other	Reason b)			Total energy over the interval	1405 MWh	62%	38%	
						Summation of maximum power	58.7 MW	40%	60%	
Downwards	2030	**Entire year**		**EP 3**	Medium voltage 20 kV feeder	**Total energy over the year**	**11978 MWh**	**54%**	**46%**	Flexible connection agreement
						Summation of maximum power	**32.6 MW**	**49%**	**51%**	
		Mar-Oct Mon-Sun 12:00 - 16:59	Reason b)			Total energy over the interval	9179 MWh	52%	48%	
						Summation of maximum power	32.6 MW	49%	51%	
		Nov-Feb Mon-Sun 12:00 - 16:59	Reason b)			Total energy over the interval	1238 MWh	56%	44%	
						Summation of maximum power	32 MW	49%	51%	
		Other	Reason b)			Total energy over the interval	1561 MWh	62%	38%	
						Summation of maximum power	30 MW	49%	51%	

Table 29: Flexibility needs assessment according to Annex 2 – Year 2035 with time blocks

Direction of need	Target year	Time block	Reasoning to define the time block	Spatial granularity	Voltage level of congestion or voltage issue	Type of value	Network flexibility needs	Share of uncovered flexibility	Share of downward flexibility needs pertaining to RES generation curtailment	Expected contractual means to access flexibility
Upwards	2035	**Entire year**		**EG 1**	Low voltage 0.4 kV network	**Total energy over the year**	**1640 MWh**	**100%**	**0%**	Local service
						Summation of maximum power	**8.6 MW**	**100%**	**0%**	
		Nov-Feb Mon-Fri 01:00 - 02:59	Reason c)			Total energy over the interval	170 MWh	100%	0%	
						Summation of maximum power	8.4 MW	100%	0%	
		Nov-Feb Mon-Fri 17:00 - 21:59	Reason c)			Total energy over the interval	483 MWh	100%	0%	
						Summation of maximum power	8.4 MW	100%	0%	
		Other	Reason c)			Total energy over the interval	987 MWh	100%	0%	
						Summation of maximum power	8.6 MW	100%	0%	
Upwards	2035	**Entire year**		**EG 2**	Low voltage 0.4 kV network	**Total energy over the year**	**550 MWh**	**54%**	**0%**	Local service
						Summation of maximum power	**10.5 MW**	**44%**	**0%**	
		Nov-Feb Mon-Fri 00:00 - 01:59	Reason c)			Total energy over the interval	86 MWh	38%	0%	
						Summation of maximum power	8.1 MW	52%	0%	

		Nov-Feb Mon-Fri 20:00 - 23:59	Reason c)			Total energy over the interval	224 MWh	48%	0%	
						Summation of maximum power	10.5 MW	44%	0%	
		Other	Reason c)			Total energy over the interval	240 MWh	66%	0%	
						Summation of maximum power	7.6 MW	59%	0%	
Upwards	2035	**Entire year**		**EL 1**	Low voltage 0.4 kV network	**Total energy over the year**	**2639 MWh**	**53%**	**0%**	Local service
						Summation of maximum power	**41.1 MW**	**49%**	**0%**	
		Nov-Feb Mon-Fri 00:00 - 04:59	Reason c)			Total energy over the interval	1002 MWh	48%	0%	
						Summation of maximum power	33.3 MW	58%	0%	
		Nov-Feb Mon-Fri 22:00 - 23:59	Reason c)			Total energy over the interval	738 MWh	39%	0%	
						Summation of maximum power	41.1 MW	49%	0%	
		Other	Reason c)			Total energy over the interval	899 MWh	71%	0%	
						Summation of maximum power	33.7 MW	60%	0%	
Upwards	2035	**Entire year**		**EL 3**	Low voltage 0.4 kV network	**Total energy over the year**	**157 MWh**	**54%**	**0%**	Local service
						Summation of maximum power	**15.3 MW**	**28%**	**0%**	
		Mar-Oct Mon-Fri 20:00 - 22:59	Reason c)			Total energy over the interval	19 MWh	71%	0%	
						Summation of maximum power	14.8 MW	25%	0%	

		Nov-Feb Mon-Fri 17:00 - 23:59	Reason c)			Total energy over the interval	65 MWh	52%	0%	
						Summation of maximum power	15.3 MW	28%	0%	
		Other	Reason c)			Total energy over the interval	73 MWh	51%	0%	
						Summation of maximum power	14.9 MW	27%	0%	
Upwards	2035	**Entire year**		**EC 1**	Low voltage 0.4 kV network	**Total energy over the year**	**2922 MWh**	**100%**	**0%**	Local service
						Summation of maximum power	**19.5 MW**	**100%**	**0%**	
		Nov-Feb Mon-Fri 17:00 - 22:59	Reason c)			Total energy over the interval	1032 MWh	100%	0%	
						Summation of maximum power	19.5 MW	100%	0%	
		Other	Reason c)			Total energy over the interval	1890 MWh	100%	0%	
						Summation of maximum power	19.4 MW	100%	0%	
Downwards	2035	**Entire year**		**EC 1**	Low voltage 0.4 kV network	**Total energy over the year**	**76 MWh**	**100%**	**0%**	Local service
						Summation of maximum power	**4.7 MW**	**100%**	**0%**	
		Mar-Oct Mon-Sun 09:00 - 15:59	Reason c)			Total energy over the interval	63 MWh	100%	0%	
						Summation of maximum power	4.7 MW	100%	0%	
		Nov-Feb Mon-Fri 00:00 - 23:59	Reason c)			Total energy over the interval	10 MWh	100%	0%	
						Summation of maximum power	4.2 MW	100%	0%	

		Nov-Feb Sat-Sun 09:00 - 15:59	Reason c)			Total energy over the interval	3 MWh	100%	0%	
						Summation of maximum power	3.7 MW	100%	0%	
Upwards	2035	**Entire year**		**EC 2**	Low voltage 0.4 kV network	**Total energy over the year**	**1274 MWh**	**100%**	**0%**	Local service
						Summation of maximum power	**2 MW**	**100%**	**0%**	
		Mar-Oct Mon-Fri 19:00 - 23:59	Reason a)			Total energy over the interval	175 MWh	100%	0%	
						Summation of maximum power	2 MW	100%	0%	
		Nov-Feb Mon-Fri 17:00 - 21:59	Reason a)			Total energy over the interval	204 MWh	100%	0%	
						Summation of maximum power	1.9 MW	100%	0%	
		Other	Reason a)			Total energy over the interval	895 MWh	100%	0%	
						Summation of maximum power	2 MW	100%	0%	
Upwards	2035	**Entire year**		**EM 1**	Low voltage 0.4 kV network	**Total energy over the year**	**5067 MWh**	**100%**	**0%**	Local service
						Summation of maximum power	**16.8 MW**	**100%**	**0%**	
		Mar-Oct Mon-Fri 19:00 - 23:59	Reason c)			Total energy over the interval	539 MWh	100%	0%	
						Summation of maximum power	16.5 MW	100%	0%	
		Nov-Feb Mon-Fri 17:00 - 21:59	Reason c)			Total energy over the interval	1324 MWh	100%	0%	
						Summation of maximum power	16.5 MW	100%	0%	

		Other	Reason c)			Total energy over the interval	3204 MWh	100%	0%	
						Summation of maximum power	16.8 MW	100%	0%	
Upwards	2035	**Entire year**		**EM 2**	Low voltage 0.4 kV network	**Total energy over the year**	**4464 MWh**	**100%**	**0%**	Local service
						Summation of maximum power	**19.4 MW**	**100%**	**0%**	
		Nov-Feb Mon-Fri 17:00 - 22:59	Reason a)			Total energy over the interval	1913 MWh	100%	0%	
						Summation of maximum power	19.4 MW	100%	0%	
		Other	Reason a)			Total energy over the interval	2551 MWh	100%	0%	
						Summation of maximum power	19.4 MW	100%	0%	
Upwards	2035	**Entire year**		**EP 2**	Low voltage 0.4 kV network	**Total energy over the year**	**107 MWh**	**31%**	**0%**	Local service
						Summation of maximum power	**9.5 MW**	**36%**	**0%**	
		Nov-Feb Mon-Fri 00:00 - 03:59	Reason c)			Total energy over the interval	32 MWh	26%	0%	
						Summation of maximum power	6.9 MW	40%	0%	
		Nov-Feb Mon-Fri 21:00 - 23:59	Reason c)			Total energy over the interval	38 MWh	24%	0%	
						Summation of maximum power	8.7 MW	40%	0%	
		Other	Reason c)			Total energy over the interval	37 MWh	41%	0%	
						Summation of maximum power	9.5 MW	34%	0%	

Downwards	2035	**Entire year**		**EG 3**	Medium voltage 20 kV feeder	**Total energy over the year**	**6536 MWh**	**100%**	**0%**	Flexible connection agreement
						Summation of maximum power	**15.8 MW**	**100%**	**0%**	
		Mar-Oct Mon-Sun 09:00 - 09:59	Reason b)			Total energy over the interval	832 MWh	100%	0%	
						Summation of maximum power	14.8 MW	100%	0%	
		Mar-Oct Mon-Sun 12:00 - 16:59	Reason b)			Total energy over the interval	4711 MWh	100%	0%	
						Summation of maximum power	15.8 MW	100%	0%	
		Other	Reason b)			Total energy over the interval	994 MWh	100%	0%	
						Summation of maximum power	15.8 MW	100%	0%	
Downwards	2035	**Entire year**		**EL 3**	Medium voltage 20 kV feeder	**Total energy over the year**	**36247 MWh**	**100%**	**0%**	Flexible connection agreement
						Summation of maximum power	**57.6 MW**	**100%**	**0%**	
		Mar-Oct Mon-Sun 09:00 - 09:59	Reason b)			Total energy over the year	3699 MWh	100%	0%	
						Summation of maximum power	48.9 MW	100%	0%	
		Mar-Oct Mon-Sun 12:00 - 16:59	Reason b)			Total energy over the interval	20550 MWh	100%	0%	
						Summation of maximum power	54.6 MW	100%	0%	
		Nov-Feb Mon-Sun 12:00 - 16:59	Reason b)			Total energy over the interval	4248 MWh	100%	0%	
						Summation of maximum power	57.6 MW	100%	0%	

		Other	Reason b)			Total energy over the interval	7750 MWh	100%	0%	
						Summation of maximum power	45.5 MW	100%	0%	
Downwards	2035	**Entire year**		**EC 3**	Medium voltage 20 kV feeder	**Total energy over the year**	**35109 MWh**	**89%**	**11%**	Flexible connection agreement
						Summation of maximum power	**59.5 MW**	**77%**	**23%**	
		Mar-Oct Mon-Sun 09:00 - 09:59	Reason b)			Total energy over the interval	4294 MWh	93%	7%	
						Summation of maximum power	58.6 MW	78%	22%	
		Mar-Oct Mon-Sun 12:00 - 16:59	Reason b)			Total energy over the interval	19505 MWh	83%	17%	
						Summation of maximum power	59.5 MW	77%	23%	
		Nov-Feb Mon-Sun 12:00 - 16:59	Reason b)			Total energy over the interval	3956 MWh	90%	10%	
						Summation of maximum power	59.4 MW	77%	23%	
		Other	Reason b)			Total energy over the interval	7354 MWh	99%	1%	
						Summation of maximum power	51.5 MW	77%	23%	
Downwards	2035	**Entire year**		**EM 3**	Medium voltage 20 kV feeder	**Total energy over the year**	**43404 MWh**	**100%**	**0%**	Flexible connection agreement
						Summation of maximum power	**82 MW**	**100%**	**0%**	
		Mar-Oct Mon-Sun 09:00 - 09:59	Reason b)			Total energy over the interval	4978 MWh	100%	0%	
						Summation of maximum power	72.2 MW	100%	0%	

		Mar-Oct Mon-Sun 12:00 - 16:59	Reason b)			Total energy over the interval	29130 MWh	100%	0%	
						Summation of maximum power	82 MW	100%	0%	
		Nov-Feb Mon-Sun 12:00 - 16:59	Reason b)			Total energy over the interval	4927 MWh	100%	0%	
						Summation of maximum power	82 MW	100%	0%	
		Other	Reason b)			Total energy over the interval	4369 MWh	100%	0%	
						Summation of maximum power	70.7 MW	100%	0%	
Downwards	2035	**Entire year**		**EP 3**	Medium voltage 20 kV feeder	**Total energy over the year**	**20816 MWh**	**100%**	**0%**	Flexible connection agreement
						Summation of maximum power	**37.1 MW**	**100%**	**0%**	
		Mar-Oct Mon-Sun 09:00 - 09:59	Reason b)			Total energy over the interval	2424 MWh	100%	0%	
						Summation of maximum power	36 MW	100%	0%	
		Mar-Oct Mon-Sun 12:00 - 16:59	Reason b)			Total energy over the interval	13682 MWh	100%	0%	
						Summation of maximum power	37.1 MW	100%	0%	
		Nov-Feb Mon-Sun 12:00 - 16:59	Reason b)			Total energy over the interval	2284 MWh	100%	0%	
						Summation of maximum power	36.8 MW	100%	0%	
		Other	Reason b)			Total energy over the interval	2426 MWh	100%	0%	
						Summation of maximum power	32.8 MW	100%	0%	

4.2.2. TSO network needs

Transmission-level network flexibility needs were assessed using AC power-flow simulations based on the dispatch results of the economic dispatch model, as described in Section 2.3.7.1. For each analysed target year and weather scenario, the resulting power flows were evaluated against thermal loading and voltage limits of the Slovenian transmission network to identify constraints and the associated network flexibility needs.

The results presented in this section are based on the simulations for the selected critical week. The analysis focuses on the magnitude, duration, frequency, and spatial distribution of flexibility needs.

The results distinguish between two model outputs:

- Upward network flexibility needs: flexibility requiring an increase of local net injection or a reduction of local demand.
- Downward network flexibility needs: flexibility requiring a reduction of local net injection or absorption of excess generation.

The results of the network flexibility needs assessment in

Table 30 and Table 31 indicate that flexibility requirements in the analysed system are almost entirely driven by contingency situations (N-1 conditions), while no flexibility needs are observed under normal operating conditions (N). This confirms that the identified flexibility requirements are not related to general system balancing or adequacy, but are instead a direct consequence of network constraints emerging under specific outage scenarios.

Table 30: Summary of upward transmission network flexibility needs by scenario and operating condition

Year	Scen.	Condition	No. of cases	Average upward need (MW)	P95 upward need (MW)	Max upward need (MW)	Total energy upward need (MWh)	Hours with upward need	Worst contingency
2030	Base	N	1	0.00	0.00	0.00	0.00	0.00	
2030	Base	N-1	307	3.64	6.41	6.72	40.06	11.00	TES6-POD
2030	WS18	N	1	0.00	0.00	0.00	0.00	0.00	
2030	WS18	N-1	307	8.57	17.40	17.58	334.08	39.00	TES6-POD
2030	WS23	N	1	0.00	0.00	0.00	0.00	0.00	
2030	WS23	N-1	307	5.00	9.93	10.64	104.98	21.00	TES6-POD
2030	WS25	N	1	0.00	0.00	0.00	0.00	0.00	
2030	WS25	N-1	307	7.29	15.75	18.50	277.12	38.00	TES6-POD
2030	WS27	N	1	0.00	0.00	0.00	0.00	0.00	
2030	WS27	N-1	307	3.92	8.11	8.44	101.89	26.00	TES6-POD
2030	WS35	N	1	0.00	0.00	0.00	0.00	0.00	
2030	WS35	N-1	307	3.42	5.79	6.42	34.20	10.00	TES6-POD
2035	Base	N	1	0.00	0.00	0.00	0.00	0.00	
2035	Base	N-1	307	3.88	11.35	15.81	131.88	34.00	CIR-RG_S
2035	WS18	N	1	0.00	0.00	0.00	0.00	0.00	
2035	WS18	N-1	307	13.87	26.54	28.67	998.29	72.00	CIR-RG_S
2035	WS23	N	1	0.00	0.00	0.00	0.00	0.00	
2035	WS23	N-1	307	10.26	21.48	24.07	544.04	53.00	CIR-RG_S
2035	WS25	N	1	0.00	0.00	0.00	0.00	0.00	
2035	WS25	N-1	307	13.29	30.14	34.23	1,023.49	77.00	CIR-RG_S
2035	WS27	N	1	0.00	0.00	0.00	0.00	0.00	
2035	WS27	N-1	307	9.93	20.83	21.66	605.44	61.00	CIR-RG_S
2035	WS35	N	1	0.00	0.00	0.00	0.00	0.00	
2035	WS35	N-1	307	8.71	17.18	18.87	304.94	35.00	CIR-RG_S

TES6-POD: 400 kV line TPP Sostanj - Podlog
CIR-RG_S: 110 kV line Cirkovce - Rogaska Slatina

Table 31: Summary of downward transmission network flexibility needs by scenario and operating condition

Year	Scen.	Condition	No. of cases	Average downward need (MW)	P95 downward need (MW)	Max downward need (MW)	Total energy downward need (MWh)	Hours with downward need	Worst contingency
2030	Base	N	1	0.00	0.00	0.00	0.00	0.00	
2030	Base	N-1	307	425.21	497.00	497.00	66,333.46	156.00	TES6-POD
2030	WS18	N	1	0.00	0.00	0.00	0.00	0.00	
2030	WS18	N-1	307	425.21	497.00	497.00	66,333.46	156.00	TES6-POD
2030	WS23	N	1	0.00	0.00	0.00	0.00	0.00	
2030	WS23	N-1	307	425.21	497.00	497.00	66,333.46	156.00	TES6-POD
2030	WS25	N	1	0.00	0.00	0.00	0.00	0.00	
2030	WS25	N-1	307	438.08	497.00	497.00	73,598.00	168.00	TES6-POD
2030	WS27	N	1	0.00	0.00	0.00	0.00	0.00	
2030	WS27	N-1	307	438.08	497.00	497.00	73,598.00	168.00	TES6-POD
2030	WS35	N	1	0.00	0.00	0.00	0.00	0.00	
2030	WS35	N-1	307	438.08	497.00	497.00	73,598.00	168.00	TES6-POD
2035	Base	N	1	0.00	0.00	0.00	0.00	0.00	
2035	Base	N-1	307	0.00	0.00	0.00	0.00	0.00	CIR-RG_S
2035	WS18	N	1	0.00	0.00	0.00	0.00	0.00	
2035	WS18	N-1	307	0.00	0.00	0.00	0.00	0.00	CIR-RG_S
2035	WS23	N	1	0.00	0.00	0.00	0.00	0.00	
2035	WS23	N-1	307	0.00	0.00	0.00	0.00	0.00	CIR-RG_S
2035	WS25	N	1	0.00	0.00	0.00	0.00	0.00	
2035	WS25	N-1	307	0.00	0.00	0.00	0.00	0.00	CIR-RG_S
2035	WS27	N	1	0.00	0.00	0.00	0.00	0.00	
2035	WS27	N-1	307	0.00	0.00	0.00	0.00	0.00	CIR-RG_S
2035	WS35	N	1	0.00	0.00	0.00	0.00	0.00	
2035	WS35	N-1	307	0.00	0.00	0.00	0.00	0.00	CIR-RG_S

TES6-POD: 400 kV line TPP Sostanj - Podlog
CIR-RG_S: 110 kV line Cirkovce - Rogaska Slatina

In 2030, the system is characterised by a pronounced asymmetry between upward and downward flexibility needs. The dominant feature of the results is a large downward flexibility requirement, reaching a maximum value of 497 MW across all analysed weather scenarios under N-1 contingency conditions. This value is consistently observed and is not scenario-dependent, indicating a structural constraint in the system rather than a stochastic or weather-driven effect. In contrast, upward flexibility needs remain relatively small, with maximum values below 20 MW.

The dominant downward flexibility need is interpreted as a generation-related constraint associated with TES6, especially in cases where the 400 kV line TPP Sostanj-Podlog is out of service.

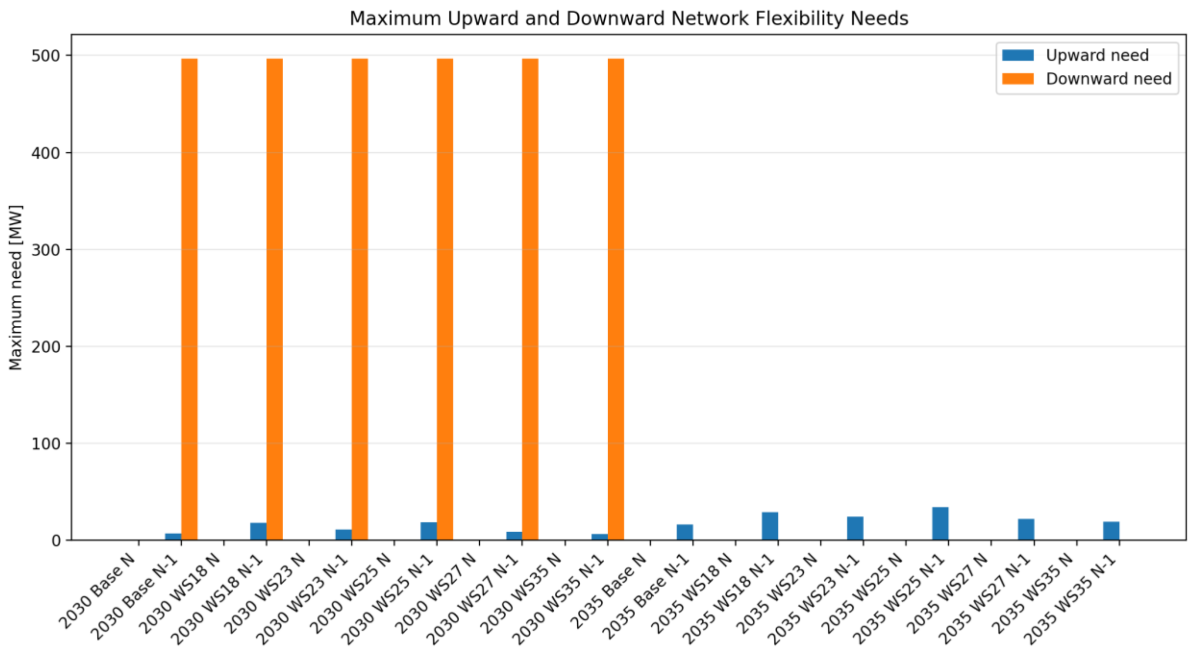


Figure 21: Maximum upward and downward transmission network flexibility needs (MW)

The same pattern is reflected in the energy dimension. Downward flexibility energy in 2030 reaches approximately 66 GWh - 74 GWh per scenario within the analysed critical week, while upward flexibility energy remains below 1 GWh. This clearly shows that the issue is not limited to isolated peak events but represents a persistent operational condition when specific contingencies occur.

It should be noted that these values correspond to the selected critical week and therefore represent high-stress system conditions rather than annual averages.

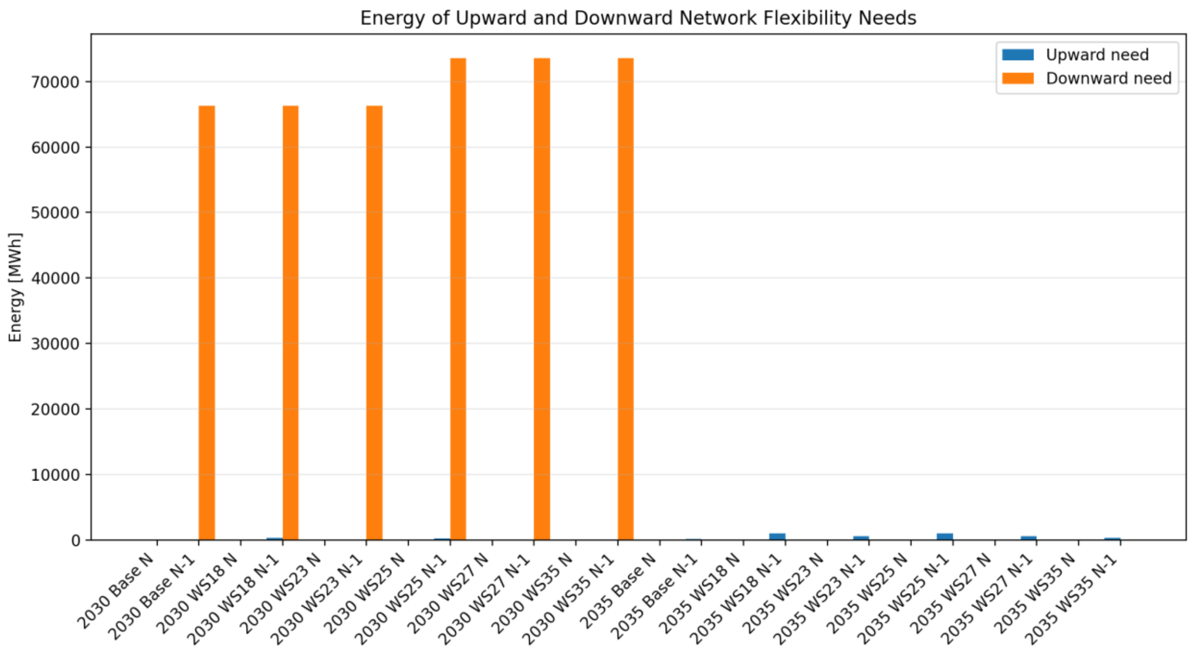


Figure 22: Energy of upward and downward transmission network flexibility needs (MWh)

In terms of frequency, flexibility needs occur in a very small share of hours. For 2030 under N-1 conditions, downward needs appear in approximately 0.3% of all simulated hours, while upward needs appear in less than 0.05% of hours. Despite this low frequency, the magnitude of the downward needs makes them highly relevant from a system planning perspective. This combination of low frequency and high impact is typical for contingency-driven congestion and must be explicitly considered in planning processes.

The comparison between N and N-1 conditions further reinforces the importance of contingencies. The transition from N to N-1 leads to an increase of up to 497 MW in required flexibility and approximately 66–74 GWh in energy. This demonstrates that network flexibility needs are fundamentally a security-of-supply issue rather than a normal operational feature.

The spatial analysis provides additional insight into the nature of the problem. In 2030, downward flexibility needs are extremely concentrated, with only six locations contributing to the total energy. The top three locations alone account for more than 50% of the total flexibility energy, and the top five for over 80%. This confirms that the issue is driven by a very limited number of structural bottlenecks in the network.

Upward flexibility needs are more distributed, involving 22 locations, but still show a non-uniform distribution, with a limited number of nodes contributing a significant share of the total energy.

Table 32: Spatial concentration of upward and downward transmission network flexibility needs under N-1 operating condition

Year	Condition	Direction	Active Locations	Total location energy (MWh)	Top 1 location share (%)	Top 3 location share (%)	Top 5 location share (%)	HHI location concentration	Largest location energy (MWh)	Largest location max (MW)
2030	N-1	downward	6	419794.39	17.53	52.60	84.20	0.17	73598.00	497.00
2030	N-1	upward	22	892.33	15.58	41.35	59.07	0.09	139.02	14.96
2035	N-1	upward	28	3608.07	12.23	32.68	46.04	0.07	441.41	32.02

The location-level analysis also reveals a clear distinction between two types of flexibility needs. Downward needs are dominated by a single large constraint, both in terms of peak power (497 MW) and total energy (approximately 74 GWh at the largest location). Upward needs, on the other hand, are spread across multiple locations, each contributing smaller amounts of power and energy. This distinction is important for defining appropriate flexibility solutions, as it implies fundamentally different system requirements.

The evolution from 2030 to 2035 shows a significant structural change. While 2030 is dominated by large downward flexibility needs, these are no longer present in 2035, as TES6 reaches the end of its operational lifetime in 2033. Instead, the system exhibits only moderate upward flexibility needs, with maximum values around 30 MW and total energy in the order of a few GWh. At the same time, the number of active locations increases, and the concentration of flexibility needs decreases, indicating a more distributed pattern of network constraints. This transition suggests that the system moves from a configuration characterised by a single dominant bottleneck to a more balanced and spatially distributed set of constraints. From a system perspective, this represents a reduction in overall stress and an improvement in network robustness.

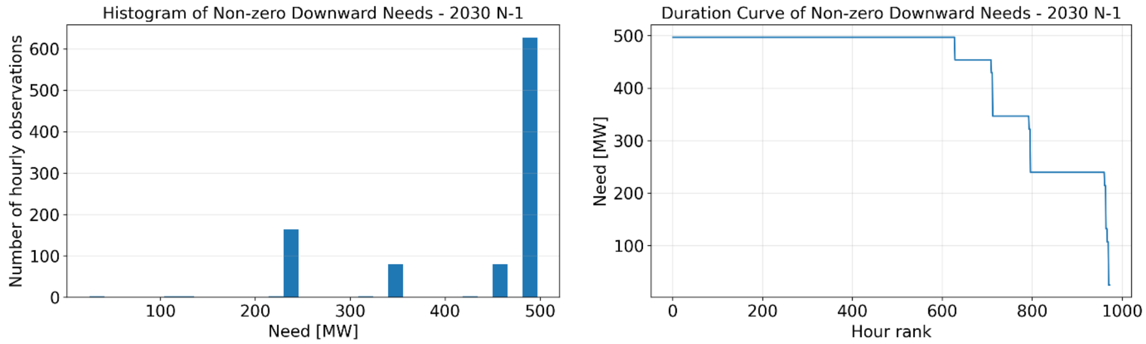


Figure 23: Downward Needs in 2030, N-1 condition

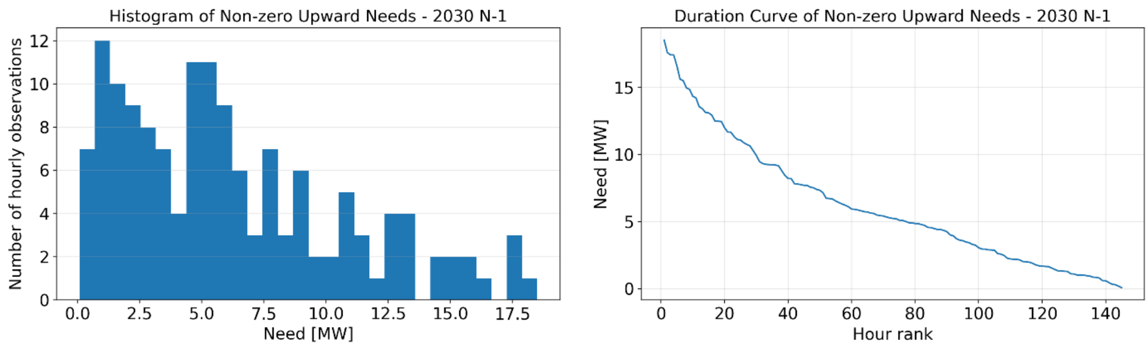


Figure 24: Upward Needs in 2030, N-1 condition

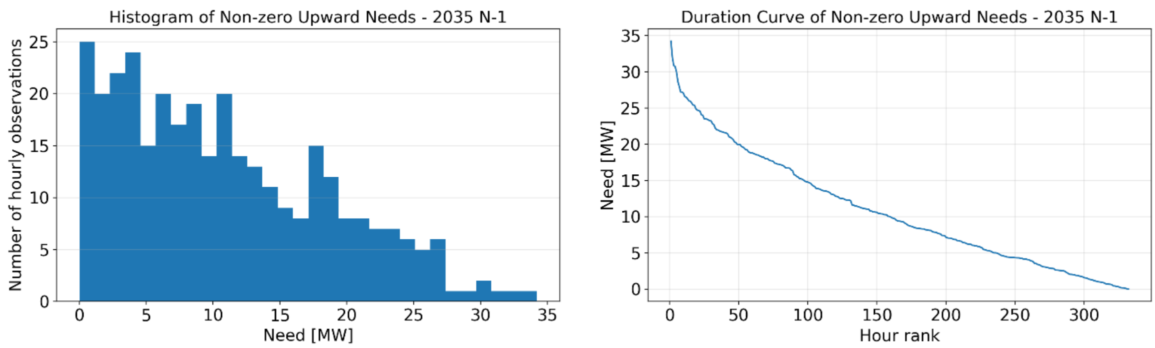


Figure 25: Upward Needs in 2035, N-1 condition

Histograms show that most hours do not require any flexibility, while a small number of hours exhibit significant needs. Duration curves further illustrate that downward flexibility needs in 2030 are persistent and occur at a constant high level when triggered, whereas upward needs are shorter in duration and more variable.

The results for 2035 N-1 downward flexibility needs are not shown because no non-zero downward flexibility requirements were identified in the corresponding simulation scenario. Figures are generated only for cases with non-zero hourly observations.

In the duration curve, the x-axis variable Hour rank represents the ordinal position of hourly observations after sorting all non-zero hourly flexibility needs in descending order according to their magnitude.

A lower rank therefore corresponds to higher flexibility requirements, while higher rank values correspond to progressively lower hourly needs. The ranking is derived from the complete set of hourly observations within the analysed year and operating condition.

The duration curve provides a compact representation of the statistical distribution and persistence of flexibility requirements over the analysed period. Specifically, it quantifies the cumulative number of hours during which the system experiences flexibility needs above a given magnitude.

As such, the Hour rank axis characterizes the frequency and duration of operating conditions associated with network flexibility needs, independently of their chronological sequence. This representation is particularly suitable for assessing the utilization intensity, persistence, and sizing requirements of flexibility resources and congestion management measures.

From a system operation and planning perspective, the results can be summarised as follows:

- Flexibility needs are not driven by energy imbalance, but by network constraints under contingencies.

- In 2030, the system is characterised by a large, structural downward flexibility requirement, concentrated in a small number of locations.
- In 2035, the system evolves towards smaller, more distributed upward flexibility needs.
- The dominant challenge shifts from evacuation of generation to local support and balancing.

The key implication for the TSO is that flexibility solutions must be locationally targeted, rather than system-wide. In particular, the 2030 results point towards the need for high-capacity solutions in specific nodes (e.g. curtailment, local demand increase, or network reinforcement), while the 2035 results indicate a greater relevance of distributed flexibility resources such as storage and demand response.

4.3. Synthesis - Guiding criteria application outcomes

The guiding criteria were applied to the flexibility needs retained following the assessment and fine-tuning process described in the preceding sections. Where the relevance assessment did not result in a material adjustment, the needs used for the application of the guiding criteria remained equal to the needs quantified before fine-tuning. In particular, the assessed transmission-network constraints did not materially change the identified uncovered system needs. Distribution-network needs retained their local geographical and voltage-level characteristics and were assessed separately from bidding-zone-level system needs.

At system level, the identified flexibility challenge is predominantly downward. Increasing photovoltaic generation contributes simultaneously to uncovered RES integration needs, downward ramping needs and downward short-term flexibility needs. By contrast, the available upward capability was sufficient to cover the upward requirements under the analysed scenarios, and no uncovered upward short-term flexibility needs were identified.

The technical characteristics of uncovered RES integration, ramping and short-term flexibility needs were further assessed by identifying continuous flexibility-needs events, defined as consecutive MTUs with uncovered needs. The duration, maximum power requirement and energy volume were determined for each event. The assessment was presented for WS25, which demonstrated the highest needs, and provides information on the technical characteristics that potential resources would need in order to cover the identified events.

The event-characterisation results indicate that the identified uncovered RES integration events are predominantly of limited duration. This finding is consistent with the broader assessment showing that additional flexibility resources with an energy-to-power ratio of approximately eight hours capture most of the achievable reduction in uncovered RES integration needs, while longer-duration configurations provide progressively smaller additional benefits.

The contribution of additional flexibility resources to reducing uncovered RES integration needs was assessed using a technology-neutral generic flexibility resource. The resource was characterised by installed power, energy capacity, energy-to-power ratio, availability and representative round-trip efficiency, consistently with the assumptions used for the assessment under Article 8(10). The common mathematical representation was considered conceptually applicable to battery energy storage systems, pumped-storage hydropower, aggregators, prosumers, electric vehicles and other demand-side flexibility resources.

The resulting contribution curves show the remaining uncovered RES integration need as the available energy capacity of the generic resource increases. Their slope represents the marginal contribution of additional flexibility capacity. Generic configurations with shorter energy-to-power ratios provide a steeper reduction per additional unit of flexibility energy capacity under the analysed conditions. Increasing the duration of the resource beyond the duration of the identified events results in diminishing marginal reductions.

The system-level assessment compares generic technical configurations rather than separately modelled technology categories. It therefore supports conclusions concerning the required power, energy and duration characteristics of suitable resources, but it does not demonstrate that one specific technology is generally superior to another. Technology-specific differences in availability, operating restrictions, user behaviour, rebound effects, cycling limitations, locational accessibility and activation costs were not separately assessed.

Differences in activation costs were explicitly outside the scope of the generic-resource analysis, which focused on technical capability rather than economic performance. The contribution curves therefore do not constitute a cost-effectiveness ranking or a least-cost hierarchy of flexibility technologies.

At distribution level, the application of the guiding criteria shows material differences between voltage levels. At LV level, the dominant need is for upward flexibility, largely resulting from thermal constraints associated with MV/LV transformer overloading. Transformer overloading is most severe during winter, although it is also observed in other seasons. The highest loading generally occurs in the evening, approximately between 19:00 and 24:00, primarily due to demand from heat pumps and electric vehicles, including EV charging shifted to off-peak tariff periods.

At MV level, the predominant need is for downward flexibility, primarily driven by voltage rise associated with high penetration of photovoltaic generation. These constraints occur predominantly outside the winter season during daylight hours. Their precise timing depends both on solar irradiance and on the presence, capacity and operating pattern of battery energy storage systems, which influence the net power injected into the network.

The assessed distribution-network flexibility needs increase between the 2030 and 2035 target years, while the expected and simulated availability of explicit flexibility remains relatively limited in both years. The results therefore indicate that both available flexibility and network development remain relevant for addressing future distribution constraints.

The representation of implicit flexibility through the shifting of EV charging to off-peak tariff periods results in the emergence of a new night-time demand peak. The possible use of a dynamic network tariff, available to the distribution system operator as a complementary network-energy tariff intended to mitigate this effect, was not simulated. Its potential contribution is consequently not reflected in the quantified covered or uncovered network flexibility needs.

Explicit flexibility was modelled separately for each technology category and was primarily used to mitigate the network constraints associated with that category. This reflects the expectation that, within the considered planning horizon, flexibility markets will not yet have reached sufficient maturity and liquidity to support technology-neutral procurement across all resource types. For example, flexibility from electric vehicles was not assumed to be available in sufficient volumes to mitigate voltage rise caused by photovoltaic generation.

Electric vehicles nevertheless represent a potentially significant flexibility resource, as charging schedules may be adapted to prevailing network conditions with limited impact on mobility requirements, provided that appropriate smart-charging capability, communication and control arrangements are available. Within the assessment, EV flexibility was primarily used to address demand-related constraints.

Heat pumps represent an important potential source of upward flexibility during winter demand peaks. Their usable flexibility depends materially on the thermal performance of the building and on the extent to which electricity consumption can be temporarily reduced without materially affecting indoor comfort. Improvements in building energy efficiency can therefore increase the technically usable flexibility potential of heat pumps.

Within the distribution assessment, downward flexibility was represented exclusively through active-power curtailment of photovoltaic generation under flexible connection arrangements and through battery-storage operation. Other potential sources of downward distribution flexibility were not modelled.

Battery storage influenced net demand and injection through autonomous operation based on predefined control strategies and was therefore represented as implicit flexibility rather than as available explicit flexibility. Battery storage is nevertheless a key prospective source of network flexibility. Its potential contribution as an explicitly procured and directly activated network service was not assessed and would depend on appropriate contractual, market-access, communication and control arrangements.

Under the assessed flexible connection arrangement, curtailment is automatically triggered by predefined network conditions and is therefore treated as a rule-based operational measure consistent with implicit flexibility. Photovoltaic curtailment would constitute explicit flexibility only where it is offered, procured and directly activated to provide a specified network service.

Flexible connection arrangements can facilitate the connection of distributed generation, demand and storage while increasing the utilisation of existing network infrastructure. However, as the share of connections operating under such arrangements increases, the associated volume of renewable-generation curtailment may also increase, particularly during periods of high renewable output and limited network capacity. Within the assessed planning framework, flexible connection arrangements are therefore treated as a transitional measure pending the implementation of adequate network reinforcement or the broader availability of technology-neutral flexibility procurement.

Available explicit flexibility and the represented non-wire solutions were first applied to mitigate the identified thermal and voltage constraints. Where these measures were insufficient, the technically required network reinforcement was identified. However, only the share of reinforcements expected to be realistically implemented within the planning horizon was taken into account.

The uncovered distribution-network flexibility needs consequently represent constraints that cannot be resolved through the assumed available explicit flexibility, other represented operational measures or the realistically implementable share of network reinforcement. The uncovered share reflects the combined effect of relatively limited expected explicit flexibility, the technical effectiveness of the represented non-wire solutions and implementation constraints affecting network reinforcement, including financial limitations, investment-planning cycles, permitting constraints and investment prioritisation.

At transmission-network level, the analysis incorporated the planned transmission-grid investments expected to be commissioned by the target years. No transmission-network flexibility needs were identified under normal operating conditions for any of the analysed weather scenarios in 2030 or 2035. Transmission-network constraints also did not materially affect the identified uncovered RES integration needs.

Consequently, the planned transmission-network development represents the relevant network solution within the assessed normal operating conditions, and no additional comparison of resources for non-zero transmission-network flexibility needs was required. Any N-1 results reported elsewhere should be interpreted consistently with their status in the transmission-network-needs assessment and should not be conflated with the zero result under normal operating conditions.

Relevant alternatives or complements to new flexibility resources represented in the assessment include network reinforcement, advanced voltage control, reactive-power control, flexible connection arrangements, demand-side flexibility, storage operation and, for system operation, cross-border exchanges. However, cross-border margins were not explicitly included in the ramping and short-term flexibility margins, which may result in conservative estimates for those system needs.

No integrated technology-neutral optimisation was performed to determine a cost-optimal portfolio of additional flexibility resources, non-wire alternatives and network reinforcement. The assessment therefore identifies technically relevant alternatives and illustrates their potential role, but does not establish a least-cost portfolio under Article 16(11).

A separate quantitative assessment of how uncovered short-term flexibility needs would first be covered through additional reserve capacity or further balancing participation was not performed. Reserve requirements were included among the study inputs, but the uncovered short-term needs were not directly mapped to additional FRR capacity, expanded balancing participation or other specific balancing arrangements.

The assessment also does not provide a comprehensive quantitative analysis of the interdependencies between all needs identified under Articles 8 to 12. The results show that increasing photovoltaic generation is a common driver of RES integration, downward ramping and downward short-term needs, but the extent to which the same events overlap, compete for the same resources or can be covered simultaneously was not quantified.

Future developments could broaden the range of resources capable of addressing distribution-network constraints. Relevant developments include smart charging of electric vehicles, improved building energy efficiency, arrangements enabling battery storage to provide explicit flexibility services and the progressive development of technology-neutral local flexibility procurement. These developments were not treated as additional available flexibility unless they were already reflected in the assumptions for the relevant target year.

Overall, the application of the guiding criteria provides a technically meaningful characterisation of the identified system and distribution-network needs and of the main types of solutions capable of addressing them. It should nevertheless be interpreted as a partial capability assessment rather than as a complete technology-specific and cost-optimised comparison of all flexibility resources and alternatives.

5. Barriers for flexibility and contribution of digitalisation

This chapter provides a holistic analysis of barriers for non-fossil flexibility and contribution of digitalisation in alignment with Article 19e(2) points (c) and (d) of Regulation (EU) 2019/943 as well as Article 15 of the FNA methodology.

5.1. Barriers, mitigation measures and incentives

In this chapter the evaluation of barriers for flexibility in the market and proposals for relevant mitigation measures and incentives, including the removal of regulatory barriers and possible improvements to markets and system operation services or products (as per Electricity Regulation, Article 19e(2)(c)) is provided. For all identified barriers it indicates the implementation status (i.e. completed /on-going /pilot /planned /under assessment, etc.) of identified /proposed/ adopted mitigation measures or reforms, if applicable.

The evaluation strictly follows the *ACER Recommendation on NRA's reporting on barriers for non-fossil flexibility*[8] and comprises evaluation of the following:

a. regulatory and market design barriers and associated indicators found in Section 1 of the Annex to the ACER Recommendation:

   i. Lack of proper legal framework for market access to new entrants and small actors
   ii. Lack of enablers and incentives to provide flexibility
   iii. Restrictive requirements to provide balancing services
   iv. Restrictive requirements to provide congestion management
   v. Complex, lengthy, and discriminatory administrative requirements
   vi. Lack of regulatory incentives to system operators to consider non-wire alternatives

[8] ACER Recommendation 01-2026 on NRAs' reporting on barriers to non-fossil flexibility

b. the potential of the following aspects of network tariffs to unduly restrict demand response, taking into account ACER's recommendations from its 2025 report on electricity network tariffs methodologies[9] and its 2023 report on barriers to distributed energy resources:[10]

    i. network tariffs basis;[11]

    ii. differentiation (or lack of) in network charges between active and non- active customers;[12] and

    iii. exemptions, discounts, and other differentiated tariff treatments.[13]

Some additional barriers considered relevant to the development of non-fossil flexibility were also identified and assessed.

---

[9] Getting the signals right: Electricity network tariffs methodologies in Europe, ACER report on network tariff practices, 2025

[10] ACER report on demand response and other distributed energy resources and the barriers that are holding them back, 2023.

[11] ACER considerations and recommendations, and information specific to this aspect are included in Section 5.2 of ACER 2025 report on network tariff practices and in Sections 11.5 and 12.8 of ACER 2023 report on demand response and other distributed energy resources and the barriers that are holding them back.

[12] ACER considerations and recommendations, and information specific to this aspect are included in Section 5.5.4 of ACER 2025 report on network tariff practices and in Sections 11.1 and 12.8 of ACER 2023 report on demand response and other distributed energy resources and the barriers that are holding them back.

[13] ACER considerations and recommendations, and information specific to this aspect are included in Section 5.5 of ACER 2025 report on network tariff practices and in Sections 11.4 and 12.8 of ACER 2023 report on demand response and other distributed energy resources and the barriers that are holding them back.

5.1.1. Evaluation of regulatory and market design barriers to the entry of non-fossil flexibility resources and associated indicators

Barrier 1: Lack of proper legal framework for market access to new entrants and small actors

Indicator 1.1: Main roles and responsibilities of new actors not defined

Active customers

Aspects	Legal reference	Justification and/or description of the situation in Slovenia	Mitigation measures
1. Is all necessary primary and secondary legislation[14] in effect to ensure that final customers are entitled to act as active customers and exercise the following rights: a. Consume and store electricity generated within their premises located within confined boundaries or self-generated or shared electricity within other premises b. Operate directly or through aggregation c. Sell self-generated electricity, including through power purchase agreements	Articles 2(8), 15(2)(a), 15(2)(b) and 15(5)(a) Electricity Directive[15]	a. In effect. (ZOEE, Article 4, Number 5) b. In effect. (ZOEE, Article 23, Paragraph 2) c. In effect. (ZOEE, Article 23, Paragraph 2) d. In effect. (ZOEE, Article 23, Paragraph 5)	No need.

[14] The term "primary legislation" refers to acts and laws formally enacted by the legislative body while "secondary legislation" refers to delegated legislation, rules, orders or any other legal instrument enacted by any regulatory authority or administrative body to help implement and enforce primary legislation.
[15] 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.

d. When they own an energy storage facility, they have the right to a grid connection within a reasonable time after the request, provided that all necessary conditions, such as balancing responsibility and adequate metering, are fulfilled			
1.1. If any primary or secondary legislation is still pending, please describe its subject and indicate when it is planned to enter into effect.		Nothing pending.	No need.

Aggregation

Aspects	**Legal reference**	**Justification and/or description of the situation in Slovenia**	**Mitigation measures**
2. Please indicate if and how the following activities and actors are defined in national legislation: a. 'Aggregation', if defined differently compared to the Electricity Directive b. 'Independent aggregator', if defined differently compared to the Electricity Directive c. 'Aggregator', if defined, or 'market participant engaged in aggregation', if defined differently compared to the Electricity Directive	Articles 2(17), 2(18), 13(2), 13(4) and 17(3)(e) Electricity Directive[21]	a. Equally. (ZOEE, Article 4, Number 4) b. Equally. (ZOEE, Article 4, Number 44) c. »Aggregator« is defined in national legislation as »a market participant engaged in aggregation« (ZOEE, Article 4, Number 3) There is slight deviation in the »aggregation« definition: Aggregation" means an activity performed by a natural or legal person who combines the electricity consumption or generation of multiple system users for the purpose of sale, purchase, or auction on any electricity market; (ZOEE, Article 4, Number 4)	No need.

3. Is all necessary primary and secondary legislation in effect to ensure that final customers: a. Can conclude an aggregation contract with any market participant engaged in aggregation, without the consent of the final customer's electricity undertakings (i.e. its supplier or its BRP) b. When they have an aggregation contract, they are not subject to undue payments, penalties or other undue contractual restrictions by their suppliers c. Are not subject to discriminatory technical and administrative requirements, procedures or charges by their supplier based on whether they have an aggregation contract		a. In effect. (ZOEE, Article 21, Paragraph 3) b. In effect. (ZOEE, Article 21, Paragraph 5) c. In effect. (ZOEE, Article 21, Paragraph 5)	No need.
3.1. If any primary or secondary legislation is still pending, please describe its subject and indicate when it is planned to enter into effect.		Nothing pending.	No need.

Energy communities

Aspects	Legal reference	Justification and/or description of the situation in Slovenia	Mitigation measures

4. Is all necessary primary and secondary legislation in effect to ensure that citizen energy communities: a. Can engage in generation, including from renewable energy sources, supply, consumption, aggregation, energy storage and charging services for electric vehicles b. Can access all electricity markets directly or through aggregation in a non-discriminatory manner c. Are treated in a non-discriminatory and proportionate manner with regard to their activities, rights and obligations as final customers, producers, suppliers or market participants engaged in aggregation	Articles 2(11)(c), 16(3)(a) and 16(3)(b) Electricity Directive[21]	a. In effect. (ZOEE, Article 4, Number 18) b. In effect. (ZOEE, Article 24, Paragraphs 6 and 7 + Pravila za delovanje trga z električno energijo, Article 4, Paragraph 1 + Akt o metodologiji za obračunavanje omrežnine za elektrooperaterje, Article 20) c. In effect. (ZOEE, Article 24, Paragraphs 8 and 9 + Article 69, Paragraph 13 + Article 98, Paragraph 2 + Article 124, Paragraph 3 + Pravila za delovanje trga z električno energijo, Article 4, Paragraph 1 + Akt o metodologiji za obračunavanje omrežnine za elektrooperaterje, Article 20 + SONDSEE, Articles 91, 231, 232.a)	No need.
4.1. If any primary or secondary legislation is still pending, please describe its subject and indicate when it is planned to enter into effect.		Nothing pending.	No need.
5. Is all necessary primary and secondary legislation in effect to ensure that renewable energy communities: a. Can produce, consume, store and sell renewable energy, including through renewables power purchase agreements. b. Can access all suitable energy markets directly or through aggregation in a non-discriminatory manner. c. Are not subject to discriminatory treatment regarding their activities, rights and obligations as final customers, producers, suppliers or as other market participants.	Articles 22(2)(a), 22(2)(c) and 22(4)(e) Renewable Energy Directive[22]	a. In effect. (ZSROVE-1, Article 64, Paragraph 4) b. In effect. (ZSROVE-1, Article 64, Paragraph 4) c. In effect. (ZSROVE-1, Article 64, Paragraphs 4 + Article 69, Paragraph 13 + Article 98, Paragraph 2 + Article 124, Paragraph 3 + Pravila za delovanje trga z električno energijo, Article 2, Number 10 + Article 4, Paragraph 1 + Akt o metodologiji za obračunavanje omrežnine za elektrooperaterje, Article 20 + SONDSEE, Articles 91, 231, 232.a)	No need.

5.1. If any primary or secondary legislation is still pending, please describe its subject and indicate when it is planned to enter into effect.		Nothing pending.	No need.

Energy storage behind-the-meter

Aspects	**Legal reference**	**Justification and/or description of the situation in Slovenia**	**Mitigation measures**
6. Are energy storage facilities permitted to be combined with the following facilities and connected to the same grid access point: a. Facilities producing renewable energy, as "co-located energy storage" b. Electric vehicle recharging points c. Final customers' demand facilities	Articles 2(44d) and 20a(5) Renewable Energy Directive[22]	Yes, all permitted. No restrictions. SONDSEE, Articles 82.-91.	No need.
6.1. Please explain any combinations that are not allowed, as well as any conditions or restrictions that may apply to allowed combinations (e.g. size or type of energy storage or combined facilities, restrictions to the operation of the energy storage or the combined facilities, etc.).		No such combinations, except: If the storage device is connected to the user's internal electrical system (SONDSEE 87, 88, 91, and 92), the power that can be fed into the grid is limited to 80% of the connection capacity specified in the connection contract.	No need.

Aggregation models

Aspects	**Legal reference**	**Justification and/or description of the situation in Slovenia**	**Mitigation measures**
7. Please indicate and briefly describe the aggregation model(s) with more than one balance responsible	Article 17 Electricity Directive[21]	Currently there is only one aggregation model in Slovenia. The model is an initial solution with significant limitations (detailed in Section 2 of the following document https://borzen.si/Portals/0/Trg%20z%20elektriko/Dokumenti/Studija_neodvisniagregator2024.pdf?ver=mzIDF8laCj7np2m3j_t7GQ%3D%3D) and it is the closest to the contractual model according to the USEF classification, but the conclusion of the	The market operator is enforced to introduce the new model according to CBA analysis performed in 2024 (https://borzen.si/Portals/0/Trg%2

party per connection point that are implemented in your country for each wholesale electricity market[23] and system operation service/product: <u>Markets and system operation services/products</u> - Day-ahead - Intraday - FCR - aFRR - mFRR - TSO congestion management - DSO congestion management		agreement itself is left to both parties (independent aggregator and supplier). In practice, the market operator registers the relevant closed contract only if both parties reach an agreement on the transaction. This can lead to the rejection of agreements, and both market parties (or their respective BRPs) having imbalances. More details are in the following Paragraph. A closed contract between the relevant market parties needs to be registered by the market operator. In case of operation of an independent aggregator, the energy quantities are taken into account in the balance sheet of the independent aggregator only in the case of appropriate registration of closed contracts between independent aggregator and supplier, in accordance with the Rules on the operation of the electricity market (https://pisrs.si/pregledPredpisa?id=AKT_1297) and Additional instructions for aFRR and mFRR (https://borzen.si/Portals/0/Dodatna%20navodila%20-%20proces%20ZP%20in%20ON%20ter%20BO_2025.pdf?ver=e5s-R7yZu-2x0iGGOwAtqw%3d%3d). If the contracting parties (supplier and independet aggregator) are unable to agree upon the details of the closed contract to be registered (Article 53 of the aforementioned Rules), the market operator shall not accept the registration of the contract. The independent aggregator must provide the supplier with at least notification and reliable data on activated energy within time frames that enable the correction of market positions if no closed contracts have been concluded (Article 68 of the aforementioned Rules). In doing so, the independent aggregator is not obliged to disclose the identities of individual delivery points or metering points. The supplier and independet aggregator should agree on the financial transfer price in the aforementioned closed contract - the financial transfer price can be zero. For services that the independed aggregator provides to the TSO, the above described issue does not really represent a problem, since the TSO is responsible for the imbalance settlements and can consider the service provision in the imballance settlement process. On the other hand, the market operator is not able to identify the existence of closed energy contracts related to independent aggregation, since they cannot be distinguished from other closed contracts on the market, which is therefore relevant for transactions on the DA and IA market, as well as for provision of DSO congestion management services. The requirement for bilateral contractual coordination between the independent aggregator and the supplier also generates legal, administrative and data-exchange costs that may be disproportionate for small aggregated portfolios.	0z%20elektriko/Dokumenti/Studija_neodvisniagregator2024.pdf?ver=mzIDF8laCj7np2m3j_t7GQ%3D%3D). We expect to have an upgraded model enfororced in 2027. ➢ <u>implementation status: planned</u>

7.1. Please indicate if any of the implemented aggregation models are not available to certain types of system users (e.g., system users connected to specific voltage levels, active customers with co-located energy storage, etc.) or are available subject to any specific conditions or restrictions.		No indications.	No need.

[22] Directive (EU) 2018/2001 of the European Parliament and of the Council of 11 December 2018 on the promotion of the use of energy from renewable sources.
[23] Wholesale electricity markets include day-ahead, intraday and balancing markets.

Indicator 1.2: Market access restricted due to lack of legal eligibility

Aggregation

Aspects	**Legal reference**	**Justification and/or description of the situation in Slovenia**	**Mitigation measures**
8. Are any of the following market participants not legally allowed to participate[16] in wholesale markets and system operation services/products:	Articles 2(18) and	No restrictions.	No need.

[16] This indicator concerns the legal eligibility of the specific actors to participate in electricity markets and system operation services. The indicator does not refer to whether the specific actors are capable of complying with the technical or financial requirements for participation. Legal eligibility means that all necessary primary and secondary legislation to allow this participation is in effect.

Market participant	Markets and system operation services/products	2(19) Electricity Directive[21]		
- Market participants engaged in aggregation, excluding independent aggregators - Independent aggregators	- Day-ahead - Intraday - FCR - aFRR - mFRR - TSO congestion management - DSO congestion management			
8.1. Please explain any restrictions (e.g., market participant XX is not legally eligible to access YY markets/services/products because of ZZ reasons etc.).				

Direct participation

Aspects		**Legal reference**	**Justification and/or description of the situation in Slovenia**	**Mitigation measures**
9. Are any of the following actors not legally allowed to participate directly[17] in wholesale markets and system operation services:		Articles 2(25), 6, 7 and 13 Electricity Regulation[18] Articles 15,	All actors are legally allowed to participate directly in wholesale markets and system operation services.	No need.
Actor	Markets and system operation services/products			

[17] Direct participation is understood as individual participation of the actor, as market participant, as opposed to participating through aggregation.
[18] Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity.

- Household final customers - Commercial final customers - Industrial final customers - Renewable producers - Energy storage operators - Citizen energy communities - Renewable energy communities	- Day-ahead - Intraday - FCR - aFRR - mFRR - TSO congestion management - DSO congestion management	16, 17, 32 and 40 Electricity Directive[21] Articles 21 and 22 Renewable Energy Directive[22]	However, the required minimum bid size of 0.1 MW on the DA/ID markets and the required minimum bid size of 1 MW for all TSO services do not allow household customers and small business customers to provide bids for other services than DSO congestion management by themselves – without aggregation. That is because, household customers and small business customers have a technical maximum connection capacity of 43 kW. This entry barrier is mitigated by electricity market model design introducing the concept of aggregation.	
9.1. Please explain any restrictions (e.g. actor XX is not allowed to participate directly in market YY for ZZ reasons; actors using resource/technology XX or actors combining resource/technology XX1 (e.g. renewable generation or demand) with resource/technology XX2 (e.g. energy storage) in the same facility are not allowed to participate directly in market YY for ZZ reasons, actors connected to XX network are not allowed to participate directly in market YY for ZZ reasons, etc.).				

Indicator 1.3: Unclear framework for access to final customer data

Aspects	**Legal reference**	**Justification and/or description of the situation in Slovenia**	**Mitigation measures**
10. Has your Member State implemented the reference model for metering and consumption data access, including the various roles, information exchanges, and procedures, in line with Article 3 of Commission Implementing Regulation (EU) 2023/1162?	Articles 3 and 4(1) Commission Implementing Regulation	Implemented (ZOEE, Article 4(21.), 19(2), 29(4), 30., 31., 104(2), 136(5), SONDSEE). The legal implementation of customer-data access does not necessarily cover all operational and flexibility-related data exchanges required for network prequalification, activation, verification and settlement. These cross-cutting	No need.

	(EU) 2023/1162[19]	interoperability aspects are assessed separately under the additional barriers.	
10.1. If so, please indicate if the national practices on implementing the interoperability requirements and procedures for access to data are reported in line with Article 10 of Commission Implementing Regulation (EU) 2023/1162.		Yes, the last report was provided by the relevant Ministry to EC on 4th of July 2025 and it is accessible here: https://www.tsodsoplatform.eu/electricity-data-interoperability/repository-national-practices. Slovenian NRA has not been involved in aforementioned reporting of national practices.	NRA Report validation ➢ implementation status: under consideration
11. If any charges are imposed by regulated entities providing data services to eligible parties for access to data, please explain how your Member State ensures that these are reasonable and duly justified.	Article 25(3) Electricity Directive[21]	According to ZOEE Article 129: The NRA determines the prices for other services—those not included in the network charge and billed to system users by the electricity system operator—by taking into account the actual costs of these services. Tariffs for data services for producers (Tariffs, Section A). These tariffs are approved by NRA.	No need.

Indicator 1.4: Ownership restrictions for energy storage and electro-mobility

Aspects	**Legal reference**	**Justification and/or description of the situation in Slovenia**	**Mitigation measures**

[19] Commission Implementing Regulation (EU) 2023/1162 of 6 June 2023 on interoperability requirements and non-discriminatory and transparent procedures for access to metering and consumption data.

12. The Electricity Directive prohibits DSOs from owning, developing, managing or operating energy storage facilities except for specific derogations:	Articles 36(2) and 36(3) Electricity Directive[21]	National legislation is in effect (ZOEE, Article 83).	No need.
12.1. If derogations exist to allow DSOs to own, develop, manage or operate energy storage facilities considered as either fully integrated network components or when they meet the conditions in points (a) to (c) of Article 36(2) of the Electricity Directive, please indicate the number of derogations and explain their scope (i.e. does the derogation refer to fully integrated network components or to other energy storage facilities? does the derogation refer to one or more DSOs? does the derogation refer to specific energy storage facilities?).		No derogations.	No need.
12.2. If derogations for fully integrated network components exist, please indicate if any open and transparent criteria or process have been defined based on which an energy storage facility owned and operated by a DSO can qualify as a fully integrated network component.		No derogations.	No need.
12.3. If derogations for energy storage facilities fulfilling the conditions in points (a) to (c) of Article 36(2) of the Electricity Directive exist, please indicate if any public consultations have been performed pursuant to article 36(3) of the Electricity Directive and whether a decision has been taken to phase out the respective DSO activities.		No derogations.	No need.
13. The Electricity Directive prohibits TSOs from owning, developing, managing or operating energy storage facilities except for specific derogations:	Articles 54(2) and 54(4) Electricity Directive[21]	National legislation is in effect (ZOEE, Article 51).	No need.

13.1. If derogations exist to allow TSOs to own, develop, manage or operate energy storage facilities considered as either fully integrated network components or when they meet the conditions in points (a) to (c) of Article 54(2) of the Electricity Directive, please indicate the number of derogations and explain their scope (i.e. does the derogation refer to fully integrated network components or to other energy storage facilities? does the derogation refer to one or more TSOs? does the derogation refer to specific energy storage facilities?).		No derogations.	No need.
13.2. If derogations for fully integrated network components exist, please indicate if any open and transparent criteria or process have been defined based on which an energy storage facility owned and operated by a TSO can qualify as a fully integrated network component.		No derogations.	No need.
13.3. If derogations for energy storage facilities fulfilling the conditions in points (a) to (c) of Article 54(2) of the Electricity Directive exist, please indicate if any public consultations have been performed pursuant to article 54(4) of the Electricity Directive and whether a decision has been taken to phase out the respective TSO activities.		No derogations.	No need.
14. The Electricity Directive prohibits DSOs from owning, developing, managing or operating recharging points for electric vehicles except where distribution system operators own private recharging points solely for their own use.	Articles 33(3) and 33(4) Electricity Directive[21]	National legislation is in effect (ZOEE, Article 77, Paragraph 2 + Article 78).	No need.
14.1. If derogations exist to allow DSOs to own, develop, manage or operate recharging points for electric vehicles that are not solely for their own use, please indicate the number of derogations and explain their scope (i.e. does the derogation refer to one or more DSOs? does the derogation refer to specific facilities?).		No derogations.	No need.
14.2. If such derogations exist, please indicate if any public consultations have been performed pursuant to article 33(4) of the Electricity Directive and whether a decision has been taken to phase out the respective DSO activities.		No derogations.	No need.

Indicator 1.5: Restrictions on trade in day-ahead and intraday markets

Aspects	Legal reference	Justification and/or description of the situation in Slovenia	Mitigation measures
15. What is the smallest minimum bid size of products for trading in the dayahead and intraday markets?	Articles 8(2), 8(3) and 8(4) Electricity Regulation[26]	Acording to BSP Energy Exchange LLC's (slovenian power exchange) Products Definition, minimum quantity interval for orders placed on Intraday Continuous, Day-ahead Auction and Intraday Auction Market is 0.1 MW.	No need.
16. What is the imbalance settlement period? If this is different than 15 minutes, has the regulatory authority granted a derogation or exemption. Please explain that derogation.		The imbalance settlement settlement interval is 15 minutes long, in accordance with the Art. 14 of the Rules for the Operation of the Electricity Market.	No need.
17. Do NEMOs enable market participants to trade in energy in time intervals which are at least as short as the imbalance settlement period for the dayahead and intraday markets?		Yes, it is possible to trade with 15-min products on Intraday Continuous, Day-ahead Auction and Intraday Auction Market.	No need.

Barrier 2: Lack of enablers and incentives to provide flexibility

Indicator 2.1: Lack of adequate metering systems

Low roll-out of smart meters – Lack of sub-meters and dedicated measurement devices

Aspects	Legal reference	Justification and/or description of the situation in Slovenia	Mitigation measures

1. What is the percentage share of household and non-household [20] final customers[21] equipped with smart meters[22]?	Article 19 Electricity Directive[21]	Status as of the end of 2025: Household = 98,8 % Non-household = 98,9% The high smart-meter roll-out does not by itself ensure operational observability of distribution networks. For flexibility activation, additional requirements relate to data timeliness, access to near-real-time data, spatial coverage, integration into operational systems and selective access to data from active users.	No need.
2. Are sub-meters or dedicated measurement devices[23] used by TSOs, DSOs, and market participants, including independent aggregators and, if defined, aggregators? a. If they are used, please explain the uses b. If they are not needed, please explain why (e.g. no need for data about specific end-uses inside final customers' facilities, no practical use cases exist for DMDs, all metering needs are covered by main utility meters or other systems/arrangements) c. If they are not used although they are needed or could be used, please describe the	Article 22 Electricity Directive[21] Article 7b Electricity Regulation[26]	Yes. SONDSEE, Articles 218 a. Submeters or DMDs are used for the real-time observability controllability purposes, and settlement of flexibility services currently by TSO and market participants. The DSO uses main utility meters for settlement of congestion management services it activates. The TSO also uses data from so called control meters, when there is a settlement dispute between the metering data obtained from TSO's meters and metering data obtained from market participant's meters.	More detailed provisions on the use and requirements for DMDs are needed in SONDSEE. ➢ implementation status: planned

[20] The terms 'household' and 'non-household' customers refer to the respective terms defined in Articles 2(4) and 2(5) of Directive (EU) 2019/944.
[21] 'Final customers' refers to customers who purchase electricity for own use, as defined in article 2(3) of Directive (EU) 2019/944. 'Share of final customers' refers to the number of metering points of final customers.
[22] It is noted that NRAs are typically asked to provide such data in the data collection process for ACER's Retail Market Monitoring Report.
[23] Submetering refers to the installation of additional meters downstream from the main utility meter of a final customer facility to obtain data about specific end-uses inside the facility or to allow billing of different final customers within a facility based on their individual actual use. 'Dedicated measurement device' or 'DMD' means, in accordance with article 2(78) of Regulation (EU) 2019/943, a device linked to or embedded in an asset that provides demand response or flexibility services on the electricity market or to system operators. Data from DMDs may be used for the observability and settlement of demand response and flexibility services.

needs or potential uses and explain why they are not used		b. DMDs are relatively new concept in Slovene legislation – there are case where submeters are installed despite the fact that DMDs could be »fit-for-purpose«. c. There are use cases for household customers (ex. contributing to ancillary services) with the requirement for the metered data of smaller time-granularity: in such cases special submeters or DMDs might be needed. For the ancillary services provided to TSO, most of these customers could use the access to near real-time measurements provided by local interface at smart-meter. By the end of May 2026 app. 63% of household customers have had smart meters installed with the mentioned and harmonized functionality.	

Lack of smart meters with minimum functionalities

Aspects	Legal reference	Justification and/or description of the situation in Slovenia	Mitigation measures
3. For the following minimum functionalities of smart metering systems, what is the percentage share of household and non-household final customers equipped with smart meters for which the functionality is available / in use[24]? a. Provision of information on actual electricity consumption and actual time of use b. Access to non-validated near real-time consumption data at no additional cost, through a standardised interface or through remote access	Articles 19 and 20 Electricity Directive[21]	a. 98,3% b. 98,3% c. 98,3% d. 100% e. 100% f. 92,4%** ** The stated percentage excludes legacy prosumers under the annual net-metering scheme. Although these customers are equipped with smart meters providing 15-minute metering data and are subject to 15-minute	No need.

[24] 'Functionality is available' means that final customers have been provided with appropriate information about the functionality and can readily access and use it, provided that all relevant technical, administrative, financial

c. Access to validated historical consumption data, including visualisation, on request and at no additional cost d. Accounting separately for electricity fed into the grid and electricity consumed from the grid by active customers' premises e. Data on final customers' electricity consumption and the electricity that they fed into the grid is made available to them on request or to a third party acting on their behalf at no additional cost, through a standardised communication interface or through remote access f. Final customers are metered and settled at the same time resolution as the imbalance settlement period in the national market		network tariff calculations, the settlement of electrical energy remains based on annual netting rather than the 15-minute imbalance settlement period. Therefore, they are not considered to be settled at the same time resolution as the national imbalance settlement period.	

Other functionalities and services enabling flexibility and demand response

Aspects	Legal reference	Justification and/or description of the situation in Slovenia	Mitigation measures
4. Are there any other functionalities or ICT services, related to or supported by smart metering data, that are available to final customers in your Member State, and considered helpful for enabling demand response and customer flexibility?	N/A	Yes. In addition to DSO and supplier customer portals, several commercial ICT solutions are available on the Slovenian market that utilise smart metering data to support demand response and customer flexibility. At the device level, Other Service Modules (OSMs) connected to the I1 local interface of smart meters enable real-time acquisition of metering data. Commercial examples include solutions, which provide real-time monitoring of electricity consumption and power, peak power management, and interfaces for controlling flexible loads. These data are further utilised by Home and Building Energy Management Systems (HEMS/BEMS/EMS). For example, platforms are offered that combine smart metering data with information from PV systems, battery storage, heat pumps, EV chargers and other distributed energy resources to optimise electricity consumption according to network tariffs, dynamic	No need.

		electricity prices and user-defined preferences. Their solutions support automated load shifting, energy optimisation and demand response functionalities. In addition, market participants are developing flexibility and aggregation services that enable distributed energy resources to participate in flexibility markets and ancillary service provision. Although the market is still evolving, these solutions demonstrate that smart metering data are already being used in Slovenia to deliver value-added ICT services that enhance customer flexibility beyond the regulated metering infrastructure.	

<u>Indicator 2.2: Absence of price signals</u>

Limited availability/uptake of retail electricity contracts with time differentiation and dynamic electricity price contracts

Aspects	**Legal reference**	**Justification and/or description of the situation in Slovenia**	**Mitigation measures**
5. Do all suppliers with more than 200,000 final customers offer dynamic price electricity contracts for all types of final customers with a smart meter[30]? a. Household customers b. Non-household customers	Article 11 Electricity Directive[21]	Article 17 of the Electricity Supply Act (Official Gazette of the Republic of Slovenia, Nos. 172/21 and 47/25) requires that any electricity supplier having electricity supply contracts with more than 100,000 final customers must offer electricity supply contracts with dynamic pricing. All electricity suppliers that exceed the threshold of 100,000 customers in the household or small business customer segments and are therefore required to offer dynamic electricity pricing contracts have published such offers on their websites and in the price comparison tool operated by the Energy Agency. Suppliers exceeding this threshold in the business customer segment report to the Agency the number of customers supplied under dynamic pricing contracts and, in their latest reports (for year 2025), confirmed that they offer such contracts.	No need.

or other requirements to be fulfilled by the final customers (which have been published) have been met. The way that the functionalities are made available (i.e. through an interface with the smart meter or as a service provided separately by the system operator supported by smart metering data) is not a criterion. 'Functionality is in use' refers specifically to 'metering and settlement at the same time resolution as the imbalance settlement period' for which 'availability' is not considered a relevant indicator, as this functionality is enabled and provided by system/market operators to final customers, without the need for some action on their side.

6. What is the availability to and uptake by household and non-household customers of different types of retail electricity contracts (market-based / regulated): a. Time-of-use fixed-price, fixed-term contracts b. Variable price contracts with one single price that varies between quarters / months / days c. Variable price contracts with time-of-use pricing that varies between quarters / months / days d. Dynamic price contracts e. Hybrid contracts (i.e. contracts combining elements of fixed and variable or dynamic contracts, contracts targeting consumers with specific assets, such as heat pumps or electric vehicles, or specific consumption profiles) f. Other (please describe) Proposed metrics: Availability (qualitative): contract type available / not available to household and non-household customers Availability (quantitative): number of suppliers offering each type of contract to household and non-household final customers; number of all retail electricity contract offers available to household and nonhousehold customers for each type of contract Uptake (quantitative): percentage share of household and non-household customers under different types of retail electricity contracts[30]	N/A	Household (Status as of 1 June 2026): a. Availability: yes; Nr. of suppliers: 5; Nr. of contract offers: 9; share of customers: 0,09% b. Availability: no c. Availability: yes; Nr. of suppliers: 1; Nr. of contract offers: 1; share of customers: NA d. Availability: yes; Nr. of suppliers: 6; Nr. of contract offers: 11; share of customers: 0,3% e. Availability: yes; Nr. of suppliers: 5*; Nr. of contract offers: 7; share of customers: 0,4% f. Availability: The majority of contracts are based on annual or multi-annual agreements, with possible price variations.; Nr. of suppliers: 10; Nr. of contract offers: 39; share of customers: 99,2% Non-household (Year-end 2025 data on % customers)**: a. Availability: yes; Nr. of suppliers: 13; Nr. of contract offers: 5; share of customers: 18,8% b. Availability: no c. Availability: yes; Nr. of suppliers: 1; Nr. of contract offers: 1; share of customers: NA d. Availability: yes; Nr. of suppliers: 13; Nr. of contract offers: 10; share of customers: 2,9% e. Availability: yes; Nr. of suppliers: 4; Nr. of contract offers: 5; share of customers:0,4% f. Availability: The majority of contracts are based on annual or multi-annual agreements, with possible price variations.; Nr. of suppliers: 21; Nr. of contract offers: 45; share of customers: 77,9%	No need.

		* A supplier has been identified as offering additional benefits targeting customers with a specific asset (electric vehicle). The benefit is available to customers who enter into an electricity supply agreement with the supplier. However, the EV-related benefit is part of a broader set of optional benefits offered to customers concluding an electricity supply contract with the supplier and the number of customers opting for the EV charging benefit is not available to the Agency. ** Suppliers are required to publish offers for household customers and small business customers (with a connected load of 43 kW or less). Through its offer comparison tool, the Agency monitors the number of customers subscribed to the published offers. As offers for larger customers are not published, data on the number of customers under such offers are not available. In addition, a certain proportion of small business customers conclude individually negotiated contracts with suppliers, and no data on these contracts are available to the Agency.	
7. What is the estimated percentage share of household and non-household customers under collective metering and billing schemes or similar arrangements that do not allow final customers to be exposed to time-of-use or dynamic price signals (e.g. retail contracts, network tariffs, local flexibility markets etc.)?	Articles 19, 21 and 22 Electricity Directive[21]	Data is not available. Such arrangements are believed limited to specific situations when the owner of the metering point bills their subtenants (e.g. small businesses) for electricity costs via contracts for general services (rent, fixed and variable costs). However this subtenants are not registered in the national data hub as final customers, as owner of the connection point plays the role of final customer.	No need.

Lack of consideration of network tariffs with time differentiation[25]

Aspects	Legal reference	Justification and/or description of the situation in Slovenia	Mitigation measures
8. Are network tariffs with time-of-use (static or dynamic) elements applied to any customer categories connected to the transmission or the distribution system?	Article 18(7) Electricity Regulation[26]	Yes (static to all customer categories; dynamic (optional) to customers connected to distribution grid) - Network Tariff Act	No need.
8.1. If no time-of-use signals (static or dynamic) are introduced in network tariffs for any customer types connected to the transmission or distribution system, despite the presence of physical congestion in the system and the availability of fit-for-purpose metering systems, please indicate if there was an assessment to support this decision and explain the reasons for deciding against introducing time-of-use signals in network tariffs[26].	Article 18(7) Electricity Regulation[26]	Not applicable.	Not applicable.
8.2. If time-of-use signals are introduced in network tariffs, are these tariffs mandatory for network users to whom they apply (i.e. no possibility to opt-out and select a different tariff that does not include such signals)[27]?	N/A	Yes, they are mandatory for all users to whom they apply. No opt-out is possible. There are special regimes based on metered data quality requirements → in case the data quality is insufficient, the customers are charged based on simplified ToU tariffs (High, Low tariff).	No need.

[25] ACER considerations and recommendations, and information related to network tariffs with time differentiation are included in Section 6.6 of ACER 2025 report on network tariff practices.
[26] ACER considerations and recommendations specific to this aspect are included in ACER 2025 report on network tariff practices, p. 301, 309 and 315.
[27] ACER considerations and recommendations specific to this aspect are included in ACER 2025 report on network tariff practices, p. 299, 300 and 311.

8.3. If time-of-use signals are introduced in network tariffs, are suppliers allowed to 'bundle' charges related to the network component into fixed electricity price contracts with no flexible elements that they may offer to customers to which time-of-use network tariffs apply[28]?	N/A	Such supplier products are not prohibited by national legislation. NRA monitors the retail market and has not identified yet the existance of such dedicated products with the full-scale effect of shielding consumers from network signals, acting as a barrier to demand response, ultimately increasing the overall system costs that are to be paid by end consumers. However, NRA has identified the colision of ToU highly dominant (legacy) static retail supply products (High/Low tariff) with the network signals in place, particulary in the time period of low season – the static supply tariff during the day through the whole calendar year is high (at night low), while the network tariffs in low season are generaly lower (lower utilisation of the grid due to PV production) in comparison to tariffs in high season. So the dominant supply products shield the consumer from the incentivizing network signal which contributes to systemic inefficiencies. NRA has publicly requested the updated of these legacy retail products but the reaction of suppliers have been highly limited – the products remain in use and only one supplier decided to introduce the seasonal ToU supply product. This issue is distinct from the absence of locational network signals, but it can reduce the effectiveness of both time-differentiated network tariffs and future local flexibility incentives.	Propose the amendment of ZOEE for explicitly prohibit such products without distorting the competition. ➢ implementation status: under consideration

Barrier 3: Restrictive requirements to provide balancing services

Non-market-based procedures

[28] ACER considerations and recommendations specific to this aspect are included in ACER 2025 report on network tariff practices, p. 313.

Indicator 3.1: Non-market-based balancing products

For aFRR and mFRR, the indicator refers to the use of local balancing products, before starting using standard balancing products[29].

Aspects	Legal reference	Justification and/or description of the situation in Slovenia	Mitigation measures
1. If any TSO uses non-market-based procurement for balancing capacity or balancing energy: a. For which reserves (i.e. FCR, aFRR, mFRR) and types of products (i.e. capacity, energy) is this the case? b. How does the TSO procure/cover its balancing needs for these reserves and what is the current planning for implementing market-based procurement?	Article 40(4) Electricity Directive[21] Article 3(1) Electricity Balancing Regulation[38]	Balancing capacity and balancing energy are procured on a market basis in accordance with the ZOEE (ZOEE, Article 45.(2)5. & 6.; Rules for FSPs; more info: https://www.eles.si/Obratovanje/Sistemske-storitve/Zakonodajna-podlaga) and the National Terms and Conditions for BSPs. Balancing capacity and balancing energy are procured on a market basis in accordance with the ZOEE (ZOEE, Article 45.(2)5. & 6.; Rules for FSPs; more info: https://www.eles.si/Obratovanje/Sistemske-storitve/Zakonodajna-podlaga) and the National Terms and Conditions for BSPs. a) No. b) There is only market based procurement (ZOEE, Article 45.(2)5. & 6.; Rules for FSPs; more info: https://www.eles.si/Obratovanje/Sistemske-storitve/Zakonodajna-podlaga)	No need.

Prequalification

For prequalification, the indicators refer to all types of products that may be used in a Member State (i.e. local or standard and specific balancing products).

Indicator 3.2: Restrictions in the prequalification of reserve providing groups (RPGs)

[29] Standard balancing products refer to products for balancing energy and balancing capacity in accordance with article 25 of the Electricity Balancing Regulation. Specific balancing products refer to products for balancing energy and balancing capacity in accordance with article 26 of the Electricity Balancing Regulation. Local balancing products refer to products for balancing energy and balancing capacity that a TSO uses before starting to use standard balancing products for a certain reserve.

<table>
<tr><th>Aspects</th><th>Legal reference</th><th>Justification and/or description of the situation in Slovenia</th><th>Mitigation measures</th></tr>
<tr><td>2. Do all TSOs allow prequalification of reserve providing groups for FCR, aFRR and mFRR?</td><td rowspan="2">Articles 3(9), 3(10), 3(11), 154, 155, 158 and 159 System Operation Regulation[39]</td><td>2. Yes. There is only one TSO (ELES), which allows the prequalification of Reserve Providing Groups in accordance with the National Terms and Conditions for BSPs (https://www.eles.si/Obratovanje/Sistemske-storitve/Zakonodajna-podlaga; Pravila in pogoji za ponudnike storitev izravnave na izravnalnem trgu ELES)</td><td>No need.</td></tr>
<tr><td>3. For reserves where at least one TSO allows prequalification of reserve providing groups, are there any combinations of generation (G), demand (D) and storage (S) units under the same reserve providing group that are not allowed by one or more TSOs?
<table>
<tr><th></th><th>G&D&S</th><th>G&S</th><th>D&S</th><th>G&D</th></tr>
<tr><td>FCR</td><td></td><td></td><td></td><td></td></tr>
<tr><td>aFRR</td><td></td><td></td><td></td><td></td></tr>
<tr><td>mFRR</td><td></td><td></td><td></td><td></td></tr>
</table></td><td>No restrictions apply to the combination of generation, demand and storage units within a Reserve Providing Group.

3. No. There are no combinations of generation (G), demand (D) and storage (S) units under the same reserve providing group that would not be allowed.</td><td>No need.</td></tr>
</table>

3.1. Please explain why certain combinations are not allowed (e.g. aggregation of XX units is not allowed in YY reserve by WW TSO for ZZ reasons) and describe any specific restrictions that may apply with regard to any allowed combinations (e.g. locational or connection voltage level restrictions, restrictions on the type or size of facilities/units that can be aggregated, etc.) and the reasons for these restrictions.		3.1. Not applicable	
4. Are reserve providing units or reserve providing groups required to pass separate prequalification to provide balancing capacity and balancing energy for FCR, aFRR or mFRR? If so, please explain the reasons for requiring separate prequalification.		Yes. Reserve Providing Units (RPUs) and Reserve Providing Groups (RPGs) are required to undergo separate prequalification procedures for the different balancing products. The Rules and Conditions for Balancing Service Providers on the ELES Balancing Market prescribe dedicated technical qualification procedures for each balancing service through separate annexes, reflecting the different technical and performance requirements applicable to each product: • Annex B – Application for recognition of the technical capability of a Balancing Service Provider (BSP) to provide FCR; • Annex C – Application for recognition of the technical capability of a BSP to provide aFRR; • Annex D – Application for recognition of the technical capability of a BSP to provide mFRR. In addition to e.g. minimum capacity, the proportionality of telemetry, testing, communication and verification requirements should be periodically reviewed to ensure that requirements reflect the	Periodic assessment of the proportionality of telemetry, testing and verification requirements for aggregated DER; use of performance-based rather than technology-specific requirements; simplified requalification where changes to the portfolio do not affect the qualified service capability. ➢ implementation status: implemented

		technical characteristics of the balancing product and do not impose unnecessary fixed costs on aggregated DER portfolios. These vereifications are performed through the NRA approval process.	

38 Commission Regulation (EU) 2017/2195 of 23 November 2017 establishing a guideline on electricity balancing.
39 Commission Regulation (EU) 2017/1485 of 2 August 2017 establishing a guideline on electricity transmission system operation.

Indicator 3.3: Large minimum eligible capacity

Aspects	**Legal reference**	**Justification and/or description of the situation in Slovenia**	**Mitigation measures**
5. What is the minimum capacity (MW) required by each TSO in the prequalification process to be allowed to participate in the different local or standard and specific balancing products used for FCR, aFRR and mFRR?	Article 7(1) mFRRIF[30] Article 7(1) aFRRIF[31]	The minimum eligible capacity is defined in the Nation Terms and Conditions for BSPs for each balancing service (1 MW). Although the prequalification framework is technology-neutral and allows aggregation of generation, demand and storage resources, the minimum eligible capacity of 1 MW means that small distributed resources can participate only through aggregation.	No need.

Indicator 3.4: Unregulated duration or long prequalification process

30 Implementation framework for the European platform for the exchange of balancing energy from frequency restoration reserves with manual activation in accordance with Article 20 of Commission Regulation (EU) 2017/2195 of 23 November 2017 establishing a guideline on electricity balancing.
31 Implementation framework for the European platform for the exchange of balancing energy from frequency restoration reserves with automatic activation in accordance with Article 21 of Commission Regulation (EU) 2017/2195 of 23 November 2017 establishing a guideline on electricity balancing.

First time prequalification

Aspects	Legal reference	Justification and/or description of the situation in Slovenia	Mitigation measures
6. If a reserve providing unit (RPU) or reserve providing group (RPG) is required to pass a first-time prequalification to provide FCR, aFRR or mFRR, what is the regulated maximum duration (weeks), if any, for the following intermediate steps of the prequalification process for each reserve? a. From receipt of a formal application by a reserve provider, for the TSO to confirm if the application is complete b. From receipt of a request by the TSO for additional information, for the reserve provider to submit the additional information c. From confirmation of the completeness of the application, for the TSO to confirm to the reserve provider if the reserve providing unit/group has been prequalified	Articles 155 and 159 System Operation Regulation[39]	TSO prequalifies a respective BSP and not explicitly RPUs or RPGs. The prequalification process is described in the National Terms and Conditions for BSPs. a.) Not regulated. b.) Not Regulated. c.) Maximum 13 weeks (3 months from the time a TSO confirms the completeness of the application). Although the maximum duration after confirmation of completeness is regulated, the absence of a regulated period for confirming whether an application is complete may reduce the predictability of the overall market-entry process. The practical duration of the process should therefore be monitored from the date of the initial submission rather than only from the date on which the application is declared complete.	Define or publish indicative time limits for completeness checks; provide applicants with standardised application checklists; publish the main process steps and expected timelines; enable digital tracking of application status. ➢ <u>implementation status: planned</u>

Re-prequalification

Aspects	Legal reference	Justification and/or description of the situation in Slovenia	Mitigation measures

7. If a prequalified RPG is required to pass a new prequalification process for FCR, aFRR or mFRR due to the following changes, what is the maximum regulated duration (weeks) of the re-prequalification process, if any?	N/A	Changes affecting the composition or qualified capacity of the portfolio require a new qualification certificate for a BSP and not for a RPG. The maximum regulated duration is 3 months from receipt of a complete application. A light/simplified process is applied in this case.	No need.
7.1. After adding new connection points, adding new generation/demand/storage units in the existing connection points and/or increasing the capacity of existing units or their contribution to the prequalified capacity of the RPG.		A new qualification certificate is required where units are added or the qualified capacity is increased. Maximum duration: 3 months from receipt of a complete application. A light/simplified process is applied in this case.	No need.
7.2. After removing some connection points, removing some generation/demand/storage units in the existing connection points and/or decreasing the capacity of existing units or their contribution to the prequalified capacity of the RPG.		A new qualification certificate is required for a BSP and not for a RPG where units are removed or the qualified capacity is reduced. Maximum duration: 3 months from receipt of a complete application. A light/simplified process is applied in this case.	No need.
7.3. After changes to the composition or distribution[32] of units.		A change in the portfolio composition requires a new qualification certificate for a BSP and not for a RPG for the entire portfolio. Maximum duration: 3 months from receipt of a complete application. A light/simplified process is applied in this case.	No need.
8. If a prequalified RPU or RPG is required to pass a new prequalification process for FCR, aFRR or mFRR due to being switched to a different BSP for the same balancing product and without having undergone any changes, what is the maximum regulated duration (weeks) of this re-prequalification process, if any?		The qualification certificate is BSP- and portfolio-specific. Therefore, the new BSP must obtain a new qualification certificate for a BSP and not for a RPG. Maximum duration: 3 months from receipt of a complete application. A light/simplified process is applied in this case.	No need.

[32] Changes in the composition of a prequalified RPG always imply removing some connection points or units connected to these connection points while other connection points or units are added, while keeping the same prequalified reserve capacity of the RPG. Changes in the distribution of a prequalified RPG refer to changes to the connection points of the RPG or to the units connected to these connection points, while keeping the same prequalified reserve capacity of the RPG and the same technologies/features of the units the RPG consists of.

Product design and market architecture

Unless indicated otherwise, indicators in this section refer to local balancing products used before starting using standard products, or to any specific products that may be used in parallel with standard products. As regards specific balancing products, the aim is to gather some basic information on the use of specific balancing products across Member States and on any differences from standard products with respect to certain characteristics that are considered relevant as potential barriers to the participation of resources such as demand response and other small distributed energy resources.

Indicators for which information is required only in case of deviation from EU target model requirements

9. In the table below, please provide the following information for the local or specific products that are not in line with the respective requirements:

a. **Indicator 3.5: 'Large minimum bid size'**: The highest minimum bid size (MW)

b. **Indicator 3.6 'Long validity period of balancing energy bids'**: The shortest and the longest validity period

c. **Indicator 3.7 'Symmetric balancing capacity products'**: If a derogation is provided to allow symmetrical procurement of balancing capacity and when this derogation expires

d. **Indicator 3.8 'Restrictions in the price settlement rule of balancing energy'**: The price settlement rule applied

e. **Indicator 3.9 'Non-contracted balancing energy bids not allowed'**: Indicate any deviation from EU target model requirements also for standard products, if used.

In case products other than standard products are used, indicate if there are local or specific =>			Local / Specific	Local / Specific	Local / Specific	Local / Specific	Legal reference	**Justification and/or description of the situation in Slovenia**	**Mitigation measures**
Product or market design element	EU target model requirement [43]	FCR	Standard aFRR capacity product	Standard aFRR energy product	Standard mFRR capacity product	Standard mFRR energy product			No need.

a. Minimum bid size	≤ 1 MW	**1 MW**	**1 MW**	**TSO has joined PICASSO platform on 1 July. 2026 (before that local product with minimum bid size 1 MW)**	**1 MW**	**TSO has joined MARI platform on 15 July. 2026 (before that local product with minimum bid size 1 MW)**	Article 7(1) mFRRIF[40] and aFRRIF[41] Article 5(1) SPBC methodology 44	Alligned with EU target model requirements.	No need.
b. Validity period of balancing energy bids	15 min	NAP[45]	NAP	**TSO has joined PICASSO platform on 1 July. 2026 (before that local product with 15 min validity period)**	NAP	**TSO has joined MARI platform on 15 July. 2026 (before that for Scheduled Activation from T−25 min to T−7.5 min and for Direct Activation from T−25 min to T+7.5 min).**	Article 53 Electricity Balancing Regulation[38] Article 7(1) mFRRIF[40] and aFRRIF[41]	Alligned with EU target model requirements	No need

c. Procuremen t of upward /downward capacity	Separate	**symetrical**	**separate**	NAP	**separate**	NAP	Article 6(9) Electricity Regulation[26]	Upward and downward balancing capacity are procured separately in accordance with the national balancing market design.	No need.

[43] EU target model requirements should be updated to reflect the requirements that apply to the reporting period. [44] 'SPBC methodology' refers to the methodology for a list of standard products for balancing capacity for frequency restoration reserves and replacement reserves in accordance with Article 25(2) of Commission Regulation (EU) 2017/2195 of 23 November 2017 establishing a guideline on electricity balancing.
[45] Not applicable

d. Price settlement rule	Marginal pricing	NAP	NAP	**TSO has joined PICASSO platform on 1 July. 2026 (before that pay-as-bid pricing)**	NAP	**TSO has joined MARI platform on 15 July. 2026 (before that pay-as-bid pricing)**	Article 6(4) Electricity Regulation[26]	Alligned with EU target model requirements	The barrier was removed upon ELES' integration into the PICASSO and MARI platforms in July 2026.

e. Noncontracted balancing energy bids	Allowed	NAP	NAP	**TSO has joined PICASSO platform on 1 July. 2026 (before that was also allowed)**	NAP	**TSO has joined MARI platform on 15 July. 2026 (before that was also allowed)**	Articles 16(5) and 16(7) Electricity Balancing Regulation[38]	Alligned with EU target model requirements	No need.

Indicator 3.10: Too short predefined minimum duration between consecutive activations

Aspects	Legal reference	Justification and/or description of the situation in Slovenia	Mitigation measures
10. What is the shortest and the longest minimum duration (minutes) between the end of deactivation period and the following activation defined for local or standard and specific balancing energy products used by each TSO at national level for aFRR and mFRR.	Article 25(5)(d) Electricity Balancing Regulation[38]	No predefined minimum duration between consecutive activations is specified. Activations follow the applicable European balancing platform rules (PICASSO and MARI).	No need.

Indicator 3.11: Long procurement lead time and long duration of balancing capacity contracts

Aspects	Legal reference	Justification and/or description of the situation in Slovenia	Mitigation measures
11. Has the regulatory authority issued a decision for any of the following? a. To grant a derogation concerning the time between contracting and provision of balancing capacity, pursuant to article 6(9) of the Electricity Regulation b. To grant a derogation concerning the contractual period of capacity contracts, pursuant to article 6(9) of the Electricity Regulation c. To approve an extension of the contractual period of the balancing capacity that is contracted more than one day ahead of delivery, pursuant to article 6(10) of the Electricity Regulation, following a derogation granted pursuant to article 6(9) of the Electricity Regulation	Articles 6(9) and 6(10) Electricity Regulation[26]	a. No derogations. b. No derogation c. In Slovenia we have monthly auctions for mFRR and aFRR capacity as set forth in the Rules for FSPs; more info: https://www.eles.si/Obratovanje/Sistemske-storitve/Zakonodajna-podlaga) approved by the NRA.	No need.

12. What is the percentage of balancing capacity contracted within 'X' time before its provision, for all balancing reserves and balancing capacity products[33] used at national level[34]? a. a. One day ahead or less b. Between one day and one week ahead c. Between one week and one month ahead d. Between one month and one year ahead e. More than one year ahead		a) 57% b) 0 % c) 43% d) 0 % e) 0 %	No need.
13. What is the percentage of balancing capacity contracts with a contractual period no longer than 'X' time, for all balancing reserves and balancing capacity products[46] used at national level? a. No longer than one day b. Between one day and one week c. Between one week and one month d. Between one month and one year e. More than one year ahead		a) 57 % b) 0 % c) 43 % d) 0 % e) 0 %	No need.

Barrier 4: Restrictive requirements to provide congestion management

Indicator 4.1: Unjustified lack of market-based TSO congestion management

[33] If a derogation concerning the time between contracting and provision of balancing capacity or the contractual period of capacity contracts pursuant to article 6(9) of the Electricity Regulation, please also indicate separately the percentage of standard balancing capacity products.
[34] It is noted that NRAs are typically asked to provide such data in the data collection process for ACER's Market Integration Report.

Aspects	Legal reference	Justification and/or description of the situation in Slovenia	Mitigation measures
1. Please explain the main congestion management measures taken by TSOs to address physical congestions. When a TSO uses redispatching[35] to solve physical congestions in its transmission grid, please explain the type of procurement, i.e., market-based[36], non-market-based or a combination and under which conditions the TSO applies each procurement method.	Articles 13(1), 13(2) and 13(3) Electricity Regulation[26]	The Slovenian TSO ELES addresses physical congestions in a maket-based manner (pay-as-bid). At the moment ELES is using simplified tool for collecting and activating redispatch energy bids. Both processes are manual when there is a need for redispatczh. If collected redispatch energy bids are not sufficient, ELES rely also on balancing energy bids and other redispatch measures. ELES doesn't procure any capacit, only activates redispatch energy bids from service providers that voluntarily participate on this market. Currently, an Umbrella contract for redispatching is used by the TSO (https://www.eles.si/Portals/0/Novice/DOKUMENTI/Krovna%20pogodba%20o%20prerazporejanju%20elektricne%20energije%20za%20potrebe%20sistemskega%20operaterja%20prenosnega%20omrezja.pdf). According to Article 1 of the TSO's Umbrella contract, redispatching can be carried out between units of the same redispatch service provider, between units of different service providers, or between a service provider in Slovenia and one abroad. Article 2 stipulates that the TSO determines the need for electricity reallocation. In doing so, it also specifies at which delivery/receipt point(s) generation or consumption must be adjusted. The TSO notifies the service provider of the need for redispatch by telephone. It sends the details of the redispatch requirements via email (the “Request and Offer for Electricity Reallocation” form) before the start of the billing interval during which the redispatch begins or for which the redispatch request is being sent. The service provider shall	The aforementioned Umbrella contract is planned to be replaced by TSO's new Terms and Conditions for redispatch service providers, that were in public consultation in 2025 (https://www.eles.si/Portals/0/Obratovanje/Sistemske/Pravila_Pogoji/Pravila%20za%20RDCT%20v01%2018072025.pdf). ➢ implementation status: on-going

[35] Article 2(26) Regulation (EU) 2019/943: ‘redispatching’ means a measure, including curtailment, that is activated by one or more transmission system operators or distribution system operators by altering the generation, load pattern, or both, in order to change physical flows in the electricity system and relieve a physical congestion or otherwise ensure system security.

[36] For ‘market-based procurement’, the definition included in ACER recommendation 1/2025 on the network code for demand response (article 2(7)) is used: ‘market-based procurement’ or ‘market-based mechanism’ means a procurement process for a service provision where either the selection of the service providers or the activation of the service is based on a bidding process.

		complete the form with its offer and submit it to the TSO via email no later than 30 minutes after receiving the request for reallocation from TSO. During the redispatch process, the service provider may not, at the delivery/receipt point(s) involved in the redispatch , or at the delivery/receipt point(s) designated by the TSO, the service provider shall not make any changes to the generation or consumption of electricity that would reduce the effect of the redispatch , except for changes resulting from the provision of anciliary services, technical limitations of generation/consumption units and/or other unforeseen circumstances over which the service provider has no control and which affect the implementation of the redispatch of generation or consumption. For a delivery point or a group of delivery points for which schedules are not submitted (separately), the service provider shall submit the schedule via email at the request of the TSO. According to Article 3 of the TSO's Umbrella contract, if a service provider submits a redispatch offer, the TSO decides whether to accept the offer in full, in part, or to reject it. The agreement on redispatch between the TSO and the service provider is initially made by telephone and includes: determination of the delivery points, the date and time of the start of redispatching, the amount of redispatching power by individual time blocks in MW, the power and energy volume of the redispatch for each billing interval, the date and time of the end of the redispatch. Prior to the start of the redispatch, the TSO shall send the service provider written confirmation of the redispatch via email, using the form "Confirmation of Electricity Reallocation." The service provider shall complete the confirmation by filling out the remaining portion of the confirmation and return it to the TSO via email as soon as possible. Article 3 also stipulates that the redispatched energy is calculated based on the amount of redispatched power required and the start and end times of redispatching, and is equal to the product of the redispatched power required and the number of minutes of redispatching in the settlement interval, and is distributed among the settlement intervals, separating the first, last and all intermediate redispatching intervals. Article 4 of the TSO's Umbrella contract stipulates that for the purpose of financial settlement and as a general rule, the TSO and the service provider execute the transaction via the balancing market platform (Com Trader) under the OTC transaction type. If it is not possible to conclude the transaction on the balancing market platform, the "Confirmation of Electricity Reallocation",	

		completed by TSO and the service provider, shall be taken into account in the financial settlement.	
2. If a TSO uses non-market-based redispatching, please explain the reasons for applying this type of procurement: a. No market-based alternative is available b. All available market-based resources have been used c. The number of available power generating, energy storage or demand response facilities is too low to ensure effective competition in the area where suitable facilities for the provision of the service are located d. The current grid situation leads to congestion in such a regular and predictable way that market-based redispatching would lead to regular strategic bidding which would increase the level of internal congestion and the Member State concerned has		Not applicable. ELES applies a market-based redispatching approach; therefore, non-market-based redispatching is not used.	No need

adopted an action plan to address this congestion e. The current grid situation leads to congestion in such a regular and predictable way that market-based redispatching would lead to regular strategic bidding which would increase the level of internal congestion and the Member State concerned ensures that minimum available capacity for cross-zonal trade is in accordance with Article 16(8) of the Electricity Regulation f. Other (please explain)		
3. If a TSO uses non-market-based redispatching, please explain if this type of procurement only applies to solving physical congestions in specific grid areas or voltage levels, to specific congestion management products, to specific types of system users or technologies, time periods or other criteria.	Not applicable. ELES applies a market-based redispatching approach; therefore, non-market-based redispatching is not used.	No need.
4. If a TSO uses non-market-based redispatching, please explain the assessment process to set this type	Not applicable. ELES applies a market-based redispatching approach; therefore, non-market-based redispatching is not used.	No need

of procurement, including the following aspects: a. Initiation: who initiated the process b. Evaluation: type of evaluation, scope, who made the evaluation c. Stakeholders involvement: how the stakeholders were involved d. Decision: who approved the deviation from market-based procurement			
5. If a TSO uses non-market-based redispatching, please explain the process to reassess whether reasons to set non-market redispatching become no longer applicable.		Not applicable. ELES applies a market-based redispatching approach; therefore, non-market-based redispatching is not used.	No need.
6. If a deviation from market-based redispatching is not approved for a TSO, is there some primary or secondary legislation that needs to be approved or to enter into force in your country to ensure that the TSO can redispatch resources based on a market-based mechanism?		No. The current legal and regulatory framework already provides for market-based redispatching. No additional legislation is required.	No need.

<u>Indicator 4.2: Unjustified lack of market-based DSO congestion management</u>

Aspects	**Legal reference**	**Justification and/or description of the situation in Slovenia**	**Mitigation measures**

7. Please explain how DSOs solve physical congestions in their distribution grid. Please explain if all or some DSOs: a. use market-based redispatching b. implement non-market-based congestion management measures (e.g. non-market-based redispatching, flexible connection agreements [37], interruptible network tariffs, etc.) and/or c. take other measures, except network reinforcement and expansion or requesting the TSO to solve the physical congestion (please explain these measures).	Articles 13(1), 13(2) and 13(3) Electricity Regulation[26] Article 32(1) Electricity Directive[21]	In Slovenia there is currenlty only one combined system operator (TSO/DSO), which is not owner the distribution grid. The distribution grid is owned by 5 distribution companies each serving individual geographical regions. The needed primary and secondary legislation for market-based redispatch in the distribution system is in effect. a. Currently only 1 distribution company employs market-based redispatch (https://www.elektro-ljubljana.si/proznost), but its market exhibits liquidity problems. 2 of the other distribution companies used market-based redispatch only in pilot projects. Projections for 2030 show that local flexibility markets (LFMs) are going to be used to relieve congestions on low-voltage (LV) level predominatly with demand reduction by 3 distribution companies. Reduction of PV injections on the LV level is going to be needed in a minor energy share by 2 distribution companies. b. Flexible connection agreements (FCAs) are progressively in use and all 5 distribution companies are going to employ them. Projections for 2030 show that FCAs for the middle-voltage (MV) level are going to be used for reduction of PV injections. c. No other measures identified. The limited use of market-based congestion management is not primarily caused by the absence of a legal basis. It reflects the early stage of local market development, limited local liquidity, uncertainty regarding the frequency and duration of future procurement needs, and the operational	Alignemnt of next version of network development plans with ACER FNA ➢ <u>implementation status: ongoing</u>

[37] Article 2(24c) Directive (EU) 2019/944: 'flexible connection agreement' means a set of agreed conditions for connecting electrical capacity to the grid that includes conditions to limit and control the electricity injection to and withdrawal from the transmission network or distribution network.

		readiness required for the identification, validation and activation of distributed flexibility.	
8. If a DSO uses non-market-based congestion management, please explain the reason(s) for applying this type of procurement: a. Market-based procurement is not economically efficient b. Market-based procurement would lead to severe market distortions c. Market-based procurement would lead to higher congestion d. Other (please explain)		d. Other: Local flexibility markets remain at an early stage of maturity and may not provide sufficient competition or procurement certainty in all relevant network areas. Flexible connection agreements are therefore currently the more readily applicable instrument for some location-specific constraints, particularly where the number of potential flexibility providers is limited. The suitability of market-based procurement should nevertheless be periodically reassessed as aggregation, observability and market participation develop.	Develop common criteria for assessing when market-based flexibility procurement is technically and economically feasible; include forward-looking flexibility needs in network development plans; standardise local procurement processes and products; improve operational observability and aggregation; periodically assess market liquidity and procurement outcomes. ➢ implementation status: planned / ongoing
9. If a DSO uses non-market-based congestion management, please explain if this type of procurement only applies to solving physical congestions in specific grid areas or voltage levels, to specific congestion management products, to specific types of system users or technologies, time periods or other criteria.		Non-market-based congestion management exercised through FCAs only – location dependent, mostly applied to BHEE at MV.	No need.

10. If a DSO uses non-market-based congestion management, please explain the assessment process to set this type of procurement, including the following aspects: a. Initiation: who initiated the process b. Evaluation: type of evaluation, scope, who made the evaluation c. Stakeholders involvement: how the stakeholders were involved d. Decision: who approved the deviation from market-based procurement		Not applicable (FCAs are negotiated directly beetwen the system operator and the network user).	Not applicable.
11. If a DSO uses non-market-based congestion management, please explain the process to reassess whether reasons to set non-market redispatching become no longer applicable.		Not applicable	Not applicable

12. If a deviation from market-based congestion management is not approved for a DSO, is there some primary or secondary legislation that needs to be approved or to enter into force in your country to ensure that the DSO can use congestion management services based on a market-based mechanism?		Not applicable.	Not applicable.

Indicator 4.3: Constraints in local markets for TSO/DSO congestion management

Aspects	Legal reference	Justification and/or description of the situation in Slovenia	Mitigation measures
13. If local markets for congestion management (for TSOs and/or DSOs) are operational in your country, please describe whether you have identified any barrier to entry or participation of non-fossil flexibility resources and new entrants, such as flexible renewable generation, demand response, energy storage and aggregation, in the prequalification process (if applicable), product design and/or market design, e.g.: a. Restrictions in the prequalification of service providing groups (e.g. aggregation of generation/demand/storage under the same service providing group is not allowed, locational or connected voltage level restrictions in the aggregation of different units/resources, restrictions to	Articles 13(1) and 13(2) Electricity Regulation[26] Articles 31(8), 32(1) and 32(2) Electricity Directive[21]	The TSO and DSO, both use an technology-neutral approach in service procurement. Therefore, no identified technology-based entry barriers. As already mentioned above, the required minimum bid size for TSO services does not allow household customers and small bussiness customers to provide bids for that services by themselves – without aggregation. Household customers and small bussiness customers have a technical maximum connection capacity of 43 kW. No such enty barrier exist for DSO congestion management since there the required minimum bid size is 5 kW for capacity bids and 1 kWh for energy bids. In addition to entry requirements, the limited predictability and continuity of local procurement opportunities may constrain investment by flexibility providers. Where needs are expected to recur, indicative multi-year information on location, direction, volume and duration should be published, while avoiding commitments that would prejudge the outcome of future procurement.	Periodically assess the efficacy of current regulatory incentives for use of market-based flexibility procurement (output-based regulation using SG KPIs) ➢ implementation status: on-going a) As local DSO markets mature, the proportionality of baseline, metering, communication, testing and portfolio-management requirements should be assessed specifically for small and aggregated DER. ➢ implementation status: planned

facilities combining different types of units/resources such as demand or generation combined with storage, unjustified or disproportionate restrictions to aggregators' portfolio management, verification/testing requirements not justified by product requirements, etc.) b. Restrictive product or market design requirements (e.g. long validity period of congestion management bids, increasing demand response not allowed, long procurement lead time and long duration of congestion management capacity contracts, etc.) c. Unjustified or disproportionate restrictions applicable to resources with limited network access, such as resources connected with flexible connection agreements. d. Other (please explain)		a. For DSO the local markets has not yet reached the minimal maturity that would allow to assess the potential entry barriers based on their operation (see above). b. See above c. See above	

Barrier 5: Complex, lengthy, and discriminatory administrative requirements

Indicator 5.1: Inefficient grid connection procedures

Aspects	**Legal reference**	**Justification and/or description of the situation in Slovenia**	**Mitigation measures**
1. As regards the procedures to obtain a grid connection permit for renewables self-consumers, energy storage facilities (front-of-	Article 16 Renewable Energy	The procedure for connecting to the system is generally set forth in Articles 139–148 of the ZOEE, and in greater detail in Section V of the SONDSEE.	No need

the-meter, behind-the-meter including co-located energy storage) and installation of heat pumps: a. Is information about the procedures provided online? b. Can the procedures be carried out entirely in electronic form? c. Can the procedures run in parallel to other required authorisations to help speed up the overall permit-granting process? d. Are there clearly defined deadlines for all steps of the procedures?	Directive[22] Article 31(3a) Electricity Directive[21] Paragraphs 3 and 5 Commission Recommendation (EU) 2024/1343[38]	a. Information on connection procedures for users is published on the websites of the distribution operator or distribution companies, such as for example: https://www.elektro-maribor.si/za-uporabnike/priklju%C4%8Devanje/ b. All applications related to the connection process (issuance of a connection permit, connection to the system, etc.) can be submitted electronically or via online forms c. N/A d. The provisions of the General Administrative Procedure Act and the related deadlines apply to the connection process	
2. Do DSOs apply a simple-notification procedure for grid connections in accordance with article 17 of the Renewable Directive?	Article 17 Renewable Energy Directive[22]	The procedure for the simple-notification procedure is set forth in Article 63 of the Act on the Promotion of the Use of Renewable Energy Sources (ZSROVE).	No need
3. Do system operators publish online up-to-date information on available grid capacity for connections?	Article 50(4a) Electricity Regulation[26] Article 31(3) Electricity Directive[21] Paragraph 36 Commission	The distribution operator has developed the SODOKart web application, which provides a geographic overview of potential connection points based on the existing network's capacity to connect larger generation facilities (over 50 kW) directly to the existing electricity distribution network.	No need

[38] Commission Recommendation (EU) 2024/1343 of 13 May 2024 on speeding up permit-granting procedures for renewable energy and related infrastructure projects.

	Recommendation (EU) 2024/1343[51]		
4. Are there any measures in place to simplify grid connection procedures for renewables self-consumers, electric vehicle recharging points and for renewable generation and energy storage owned by renewable and citizen energy communities?	Paragraphs 8 and 11 Commission Recommendation (EU) 2024/1343[51]	The procedure for the simple-notification procedure for renewable self supply is set forth in Article 63 of the Act on the Promotion of the Use of Renewable Energy Sources (ZSROVE).	No need

Indicator 5.2: Disproportionate procedures and requirements for market access[52]

Aspects	**Legal reference**	**Justification and/or description of the situation in Slovenia**	**Mitigation measures**

5. As regards procedures and requirements to access wholesale electricity markets and local markets for congestion management: a. Have you identified or been made aware of any potentially unjustified differences in these procedures or requirements between new entrants and smaller actors (such as market participants engaged in aggregation, including independent aggregators, operators of energy storage, energy communities) and traditional market participants (such as producers and suppliers)? b. Are there any access options designed with smaller participants in mind (e.g. offering alternative collateral arrangements, reduced infrastructure requirements, proportionate market access fees, etc.)?	N/A	a. Limitation of existing independent aggregation model (IAM). b. No. All (also smaller) wholesale market participants must adhere to equal collateral arrangements and market access fees and transaction fees (DA/ID market, balancing, TSO congestion management). This presents a significant barrier for direct entry of smaller actors – i.e. for those wanting to provide wholesale market services without aggregation, but on the other side it promotes the use of aggregation. On the other hand, the DSO congestion management market is suitable for participation of smaller actors. In addition to formal market-access requirements, small DER and aggregated portfolios face fixed transaction costs related to registration, contract negotiation, prequalification, communication and data-exchange interfaces, baseline determination, metering validation, portfolio management and compliance reporting. These costs may be proportionately higher for small resources because they are largely independent of the volume of flexibility offered. The barrier therefore concerns the cumulative effect of several fixed procedural and technical requirements rather than a single discriminatory charge. The absence of sufficiently standardised onboarding processes and contractual documentation may further increase uncertainty regarding the sequence of approvals, data requirements and responsibilities of the parties involved. This is particularly relevant for aggregated DER and new entrants that must coordinate with several entities before commercial participation is possible.	Please see the section »Aggregation models« ➢ <u>implementation status: new IAM planned</u> Introduce standardised contractual templates and onboarding procedures; enable digital one-stop registration where feasible; avoid duplication of data submissions across market and system operators; apply proportionate collateral, testing and reporting requirements; facilitate portfolio-level compliance by aggregators. Standardised service-specific contract templates; harmonised registration steps; published data requirements; clear allocation of responsibilities; indicative approval timelines.

			➢ implementation status: planned

Barrier 6: Lack of regulatory incentives to system operators to consider non-wire alternatives

Indicator 6.1: Lack of incentives for SOs to consider non-wire alternatives

Aspects	Legal reference	Justification and/or description of the situation in Slovenia	Mitigation measures
1. Does the regulatory framework in your country ensure that TSOs and DSOs are able to procure[53] flexibility services, including congestion management in their areas[54], in particular from generation, demand response or energy storage facilities, as needed for an efficient and secure system operation? If no, please explain why.	Articles 31(7), 32(1) and 40(5) Electricity Directive[21] Articles 13(1) and 13(2) Electricity Regulation[26]	The access to flexibily market is ensured by the regulatory framework.	No need.

52 These refer to procedures and requirements to become market participant in wholesale electricity markets and in local markets for congestion management.
53 The terms ‘procure’ and ‘procurement’ are meant to refer to both market-based and non-market-based procedures.

[54] Based on the combination of articles 31(6)-(8), 32(1) and 40(5) of the Electricity Directive, the term 'flexibility services' is understood to mean non-frequency ancillary services and congestion management that are necessary to ensure the efficient, reliable and secure operation of the system. For clarity, flexible connection agreements are not included in flexibility services for the purpose of assessing this indicator.

2. Is there a legal or regulatory requirement for TSOs and DSOs to assess the procurement of flexibility services as an alternative to grid expansion when preparing the network development plans? If so, please explain the requirements (e.g. do they apply to certain types of grid expansion, do they apply to investments above a certain threshold, type of assessment, assessment criteria etc.)	Articles 32(1), 32(3) and 51(3) Electricity Directive[21]	Yes. Act on the Methodology for Preparing Electricity System Operators' Development Plans (https://pisrs.si/pregledPredpisa?id=AKT_1255) – Article 8. The investment plan for electricity distribution infrastructure includes the use of demand-side response and an assessment of needs for medium- and long-term flexibility services; electricity storage facilities approved by the Agency and other resources used by the distribution system operator as an alternative to system expansion and the investments in information and communication technology systems, smart grids, operational investments, and other investments aligned with the distribution system operator's development strategy. The TSO and DSO need to assess the potential and reveal the exploitation of flexibility in their network development plans as an alternative to grid expansion: when planning the infrastructure the distribution system operator shall prioritize measures to increase the efficiency and utilization of existing infrastructure whenever these represent a cost-effective alternative—or one of equal cost-effectiveness—to system expansion or reinforcement. The distribution system operator shall present and justify the selected solutions using excerpts from cost-benefit analyses based on the simulation, taking into account broader benefits.	No need.
3. Does the regulatory framework in your country ensure that TSOs and DSOs can fully recover the reasonable costs efficiently incurred when procuring flexibility services or investing in digitalisation of the system, including any related CAPEX or OPEX costs?	Article 18(8) Electricity Regulation[26] Articles 32(2) and 40(6) Electricity Directive[21]	Yes. The costs for procuring flexibility are eligible costs. The recovery of costs related to investments (CAPEX/OPEX) is regulated by core incentive regulation and the comprehensive incentive scheme that applies to smart grid investments (https://pisrs.si/pregledPredpisa?id=AKT_1280).	No need.

4. Does the regulatory framework in your country provide incentives to TSOs and DSOs: a. to procure flexibility services, including congestion management in their areas, in particular from generation, demand response or energy storage facilities, as an efficient alternative to grid expansion? b. to invest in smart grids, grid optimisation and other innovative technologies (e.g. active network management), as an efficient alternative to grid expansion?	Article 18(8) Electricity Regulation[26] Article 32(1) Electricity Directive[21]	The NRA provides a general performance incentive for efficient smart grid investments for DSOs and TSOs, which are linked to monitoring of a series of KPIs in the following areas (but current KPIs do not necessarily cover all these areas): 1. exploitation of flexibility; 2. network capacity utilisation; 3. increasing transmission capacity; 4. hosting capacity and the level of integration of distributed elements; 5. voltage quality; 6. losses (where network losses due to transit energy flows are not considered); 7. asset lifetime; 8. forecast accuracy; 9. provision of real-time information to interested stakeholders; 10. openness to third-party innovation; and 11. environmental impacts. Two types of key performance indicators are used to monitor the performance of smart grid investments, namely: - key preparedness indicators; and - key performance indicators. An individual KPI is defined as a weighted composite of indicators. The assessment of the performance of investments on the basis of the KPIs may be conditional on the achievement of an appropriate level of each KPI or individual preparedness indicator. Based on the KPIs of each type, an umbrella preparedness KPI and an umbrella efficiency KPI is calculated. The principles of performance-based regulation of smart grid investments are:	No need.

		- public publication of performance indicators, which shall include the publication of indicators in the context of the development plans of the distribution system operator and the system operator; - a functional link between the performance of smart grid investments and the eligible costs of the distribution system operator or the transmission system operator; - the definition of minimum standards for the preparedness of the distribution and transmission networks. Performance based regulation for smart grid investments referred to in the second and third indents of the previous paragraph represent a feedback management process, where the NRA influences the process by adjusting the eligible costs in such a way that it seeks to maximise the level of efficiency. The NRA provides also a project-oriented incentive for smart-grid projects: Investments in qualified specific smart grid projects with the aim of enabling the introduction of new technologies are incentivised in addition to the previously described incentives. These investments projects are intended to solve specific problems in certain parts of the network. The NRA has defined following minimum criteria for qualification as one of the key conditions for projects to be included in the incentive scheme: 1. in line with standardized definition of smart grids and smart grid infrastructure; 2. projects with focus on at least 1 out of 11 target domains which include DSO and TSO relevant topics: - improving the utilization of the existing power system; - ensuring transmission capacity in terms of local congestion management; - increasing system transmission capacity; - efficient integration of RES into the grid; - setting operational requirements for generating units, coordinated curtailment of generating units and others; - ensuring island operation (micro grids) using RES generation;	

		- use of advanced market and other appropriate mechanisms in terms of ensuring the active participation of users in measures, such as demand response programmes; - promoting energy efficiency in the sense of reducing electricity consumption, connection power, peak power, losses in the network and others; - efficient integration of charging infrastructure for charging electric vehicles into the grid by including smart charging infrastructure in demand response programmes with the aim of encouraging increased use of electricity in transport; - optimization and coordination of cross-domain integration (district heating, gas) with the aim of better utilization of the existing infrastructure and RES as well as low-carbon and energy-efficient solutions, or - improving or maintaining the level of continuity of power supply and voltage quality; 3. a positive result of cost-benefit analysis prepared under the European Commission recommendations (CBA must be performed according to recommendation of EC »Guidelines for conducting a cost-benefit analysis of Smart Grid projects«, Report EUR 25246 EN). The NRA publishes standardised identification information about qualified projects on its website and supervises the projects. Two subsets of projects are further incentivised in addition to the previous incentive: 1. Time-limited incentive for whole-systems approach is granted if the project applicant proves that the whole-systems approach (WSA) (benefits in transmission and distribution system) was applied in the planning and implementation of the project. 2. One-time incentive based on KPI for qualified smart grid investments based on by the NRA predescribed output-based KPIs is provided. Also, the NRA provides for <u>qualified investments based on benefit-sharing, an one-time financial incentive</u> in 40% proportion of the cost difference between the use of the conventional investment and a more	

		advanced, innovative, and efficient investment. Within this scheme the NRA qualifies a project for a precisely defined system or network need. The purpose of the incentive is to encourage investment in modern energy systems that enable greater grid flexibility, improved consumption management, integration of renewable energy sources, and long-term reduction of Slovenia's electricity infrastructure development costs. The financial incentive is based on the principle of benefit sharing between the grid users (through lower anticipated network costs) and the TSO/DSO, whereby the latter is granted a share of the difference between the costs of the conventional and the advanced investment solution. Specifically, 40% of the achieved cost difference may be recognized, creating a financial motivation for deploying technologically advanced solutions. To obtain the incentive, the TSO/DSO must submit an application to the NRA after completion of the project. The application must include a description of the system need, a comparison between the conventional and advanced solution, technical characteristics of the project, a cost-benefit analysis, and evidence demonstrating the achieved effects. The project must prove that the advanced solution provides greater efficiency, grid optimization, or other measurable benefits for the electricity system. The NRA assesses the adequacy of the project and verifies whether the conditions for granting the financial incentive are fulfilled. The provision also establishes a supervisory and developmental framework for the introduction of innovative technologies. The NRA maintains a record of supported technologies and classifies them in accordance with international classifications and national strategic documents related to smart grid development. After receiving the incentive, the TSO/DSO is expected to incorporate the acquired experience into future network planning, thereby promoting broader implementation of successful technological solutions. Upon of receipt of this incentive that incentivised type of investment is treated as a standard one and can apply also for the abovementioned project-oriented incentive for smart-grid projects. Also, the NRA provides also a <u>research and innovation (R&I) scheme</u>, which is aimed at:	

		-providing funding for system operators' research and demonstration projects that comply with the referenced Legal act and enable wide potential net societal benefits; -incentivising researching or demonstrating innovative smart grid approaches, sector coupling and ecosystem for deep electrification with the aim to make better use of the existing electricity infrastructure and renewable energy sources, as well as low-carbon and energy-efficient solutions using the open innovation concept; -testing local dynamic network tariffs for energy in the distribution network based on voluntary customer participation, and -sharing the knowledge gained from the implementation of projects to deliver benefits and savings in the use of the network by end-consumers and to ensure more efficient network investments based on the results of the projects. The NRA publishes applications for qualified projects and project reports on its website and supervises the projects. R&I projects are qualified for implementation on the basis of a standardised project application that can be submitted at any time.	
5. If incentives are provided, please explain: a. The type of incentives (e.g. expenditure allowances, TOTEX approach, cost efficiency targets, performance targets, reward/penalty schemes, benefit sharing schemes, etc.) b. The main purpose of the incentives (e.g. establish sandbox or pilot applications, increase system observability and digitalisation, promote efficient system utilisation, increase overall system efficiency, address CAPEX bias, etc.) c. In which year were the incentives introduced?	N/A	a. The smart grid incentives are a financial incentive similar to a WACC adder. The benefit sharing schemes is implemented on a TOTEX decrease principle. The R&I scheme is a pass-through cost scheme. b. The smart grid incentives are aimed at improving digitalisation and introduction of smart grid and novel solutions in the grid in order to increase overall system efficiency, as well as addressing the CAPEX bias. The benefit sharing scheme encourages investments in modern energy systems that enable greater grid flexibility, improved consumption management, integration of renewable energy sources, and long-term reduction of Slovenia's electricity infrastructure development costs. The R&I scheme is established as a sandbox for regulatory pilots in order to promote efficient system utilisation and to promote novel solutions in the grid. c. The smart grid incentive was first introduced in 2015 and revised in 2018 and in 2019. The benefit sharing concept was introduced in 2026. The R&I scheme was introduced in 2018.	No need.

d. How would you assess the results of the incentives so far? e. If there are limited or no positive results, what are the main factors to which you would attribute this?		d. Despite that within the smart grid incentive, the OPEX are considered as pass-through costs, the CAPEX bias is making incentives not stimulating enough. Therefore, the benefit sharing concept was recently introduced. From the uptake point of view, the smart grid incentive seems to be a success respecting the results projects like e.g. SINCRO.GRID (https://www.sincrogrid.eu/en/About-the-Project) and further push from the TSO/DSO combined operator to include also Slovenian distribution companies in the project GreenSwitch (https://www.greenswitchproject.eu/en-us/consortium). The R&I scheme is also a success considering at least a majority uptake in the Slovenian TSO/DSO/distribution companies community. However, the NRA identifies a lack of transition from R&I projects towards larger investments e.g. in the smart grid incentive scheme. For more details please refer to pages 66 thorugh 78 of the following document - https://www.agen-rs.si/documents/10926/38704/Poro%C4%8Dilo-stanju-na-podro%C4%8Dju-energetike-za-leto-2025/86f978f2-3492-48fe-b780-5a055954cb11 e. Not applicable. Positive results are identified but there is always room for improvement as described above.	

5.1.2. Evaluation of the potential of network tariffs to unduly restrict or disincentivize demand response or system users providing flexibility

Network tariff aspects	**Restrictive potential evaluation**	**Justification and/or description of the situation in Slovenia**	**Mitigation measures**
Network tariffs basis	No restrictive potential found in network tariffs basis.	Compliance report on ACER considerations and recommendations with information specific to this aspect (Section 5.2 of ACER 2025 report on network tariff practices): Considerations: - p.116, p.117, p118, p.119: fulfilled, no comments needed.	Monthly monitoring of the tariff reform impact & outcomes based on set of KPIs (in place)

		- p.120: the regulatory principle has been applied onto ToU in order to decrease the complexity to acceptable level. - p.121: power charge ToU is aligned with system network utilisation and cost reflective - p.122: tariff design in Slovenia serves as a complementary instrument for demand response - p.123: average of five maximum power withdrawals in 15 minutes interval is considered - the precision of the signals is preserved - p.124: costs drivers not related to system peak are considered Recommendations: - p.125, p.126, p.127: fulfilled, no comments needed Compliance report on ACER considerations and recommendations with information specific to this aspect (Sections 11.5 and 12.8 of ACER 2023 report on demand response and other distributed energy resources and the barriers that are holding them back). Recommendations: - p.356: ToU power-based network tariffs in place (compliant)	➢ implementation status: completed
Differentiation (or lack of) in network charges between active and non- active customers; and		Compliance report on ACER considerations and recommendations with information specific to this aspect (Sections 11.1 and 12.8 of ACER 2023 report on demand response and other distributed energy resources and the barriers that are holding them back) and the compliance report on ACER considerations and recommendations, and information specific to this aspect (Section 5.5.4 of ACER 2025 report on network tariff practices): - p.179: asymmetric tariff design – active customers (as consumers) pay only for withdrawal. The double-charging is eliminated by tariff design. - p.250, p.348, p.350: fulfilled, no comments needed (study used for tariff reform conducted – differentiation has not been justified)	No need.

Exemptions, discounts, and other differentiated tariff treatments.	Blanked and full-scale exemptions introduced by Slovene Government for storage are distorting the flexibility market (the network costs for active customers are higher than network costs of storage, so the storage is in privileged position when competing on the market).	Compliance report on ACER considerations and recommendations, and information specific to this aspect (Section 5.5 of ACER 2025 report on network tariff practices): - p.180: Slovene legislator introduced blanket exemptions for storage into Energy Law (ZOEE, Article 109.(5) & (6))[39]. The impact of these exemptions could not be assessed yet but negatives outcomes are expected with the further development of flexibility markets. - p.181: tariff discounts are applied for energy communities according to the extent of topological network usage - p. 182: tariff discount is applied to prosumers in net-metering - p. 183: no differentiation in tariffs between the consumers and prosumers applies. Compliance report on ACER considerations and recommendations with information specific to this aspect (Sections 11.4 and 12.8 of ACER 2023 report on demand response and other distributed energy resources and the barriers that are holding them back). - p.351: temporary exemptions in RES levies has been applied by legislator (external to NRA) - p.354: exemptions for active customers providing explicit flexibility, energy communities apply. - p.358: net-metering scheme has not been phased out in timely manner in compliance to the Electricity Directive	The elimination of blanket exemption for storage or as alternative, the introduction of conditional exemptions based on location and operational regime (based on CBA for network). ➢ implementation status: pending When introducing the exemptions, assess the impact of RES levies exemptions onto the distortion of the cost signals to network users or their diminishing impact ➢ implementation status: planned

[39] NRA disagreed and requested elimination or conditional redesign of these exemptions, however, there is no will on the legislator side to perform corrective measures.

5.1.3. Additional barriers relevant to the development of non-fossil flexibility in Slovenia

This list is complementary to the barriers assessed under the main indicators recommended by ACER. It focuses on Slovenian-specific or cross-cutting issues that are not fully captured by the detailed assessment of the main regulatory, market-design, administrative and network-tariff barriers. They address Slovenian-specific or cross-cutting issues that either fall outside the scope of the prescribed indicators or arise from the interaction between market development, digitalisation and the national governance model.

Additional barriers	**Restrictive potential evaluation**	**Justification and/or description of the situation in Slovenia**	**Mitigation measures**
Limited liquidity and predictability of local flexibility markets	Moderate–High	Local flexibility markets in Slovenia remain at an early stage of development. Market-based congestion management has so far been applied only by a limited number of distribution companies, either operationally or through pilot projects. The effectiveness of local procurement may be constrained by the limited number of technically suitable and qualified resources within a specific network area, insufficient aggregation, low frequency of procurement and limited predictability of future revenue streams. The barrier is therefore not solely related to the small size of the Slovenian bidding zone, but primarily to the locational nature of distribution-network needs and the limited number of potential providers at the relevant location and time. Low liquidity may reduce competition, increase procurement costs or make market-based procurement impracticable for specific network constraints.	Publish forward-looking information on expected flexibility needs by location, direction and indicative period; standardise local flexibility products and procurement procedures; facilitate aggregation of small resources; coordinate local procurement with distribution network development plans; assess whether multi-year or periodically repeated procurement products could provide more predictable revenue opportunities. Where effective competition cannot be ensured, apply transparent alternative congestion-management measures and periodically reassess whether market-based procurement has become feasible. <u>Implementation status: under assessment / gradual implementation.</u>
Limited availability and use of locational incentives for distribution-network flexibility	Moderate	Slovenia applies time-differentiated network tariffs and has a regulatory basis for local dynamic network tariffs. However, locational incentives that indicate where flexibility has the highest distribution-network value are not yet widely used. Wholesale and conventional retail price signals primarily indicate the temporal value of electricity, while they generally do not identify local voltage or congestion constraints. Local flexibility markets are still immature and local dynamic network tariffs have not yet been broadly deployed. In addition, dominant static retail products may partly weaken the effect of network tariff signals, particularly where the temporal structure of the retail product is not aligned with network utilisation. Consequently, flexible assets may not be operated or located where they provide the greatest network benefit.	Gradually develop transparent local flexibility procurement mechanisms; pilot and, where justified, introduce local dynamic network tariffs; publish locational information on expected network constraints and flexibility needs; ensure that dominant retail products do not systematically shield customers from relevant network signals; coordinate tariff-based and market-based incentives to avoid conflicting signals or double remuneration. <u>Implementation status: pilots / under assessment.</u>

Insufficient operational observability and automated activation of distributed flexibility at MV/LV level	Moderate–High	Slovenia has achieved a high roll-out of smart meters and broad availability of standard smart-metering functionalities. The remaining barrier is therefore not primarily the absence of metering infrastructure, but insufficient operational observability and integration of near-real-time data into distribution-network operation. Data may not be available with sufficient timeliness, spatial resolution or system integration to identify local voltage and congestion issues, validate the availability of distributed flexibility and support automated activation. Automated monitoring and control of active users, distributed generation, storage, heat pumps and electric vehicle charging remain unevenly developed across distribution areas. This limits the scalable use of flexibility for active network management.	Targeted upgrade of the existing advanced metering infrastructure to enable central access to near-real-time metering data at relevant network nodes and, selectively, at active users' connection points; further deployment and integration of SCADA, ADMS and DER-management functionalities; automated identification of network constraints; automated validation, activation and verification of flexibility services; prioritisation of users and locations where operational data provide demonstrable network value. ➢ Implementation status: ongoing / planned.
Insufficient integration and interoperability of operational, metering and flexibility-related data systems	Moderate	Relevant data are held and processed by ELES, distribution companies, the metering-data infrastructure, market operators, suppliers, aggregators and flexibility providers. Although the legal framework for access to metering and consumption data is largely established, operational use of flexibility requires additional data flows, including information on resource availability, location, network constraints, activation, baseline, verification and settlement. These data flows are not yet fully integrated through harmonised technical interfaces, common semantic models and standard communication protocols. This can make onboarding, validation, activation and settlement more manual, fragmented and difficult to scale.	Define standardised data models, interfaces and communication protocols for flexibility-related data; clarify access rights, responsibilities, data quality requirements and cybersecurity obligations; establish or further develop a common DER/flexibility register where justified; ensure interoperability between metering systems, ADMS, flexibility platforms and market systems; introduce common procedures for activation and settlement data exchange. ➢ Implementation status: under development / planned.
Multi-layered governance and insufficiently integrated coordination for distribution flexibility	Moderate	Slovenia has a specific organisational model in which ELES performs the role of the combined transmission and distribution system operator, while operational distribution activities are carried out by five regional distribution companies under contractual arrangements. This model does not constitute a barrier in itself. However, the multi-layered allocation of tasks may complicate the integration of transmission-level system needs, distribution-network constraints, operational data, investment priorities, network prequalification and flexibility activation. A flexibility activation that is beneficial at system level may be constrained by local MV/LV conditions, while a local activation may affect balancing or transmission-system needs. The barrier therefore concerns the absence of fully integrated	Clearly define responsibilities and decision rights for identifying, validating, procuring and activating flexibility; establish common procedures for network prequalification and constraint validation; develop coordinated TSO–DSO–distribution company data exchange and operational processes; define activation priorities and conflict-resolution rules; align flexibility procurement with network planning and investment decisions; where proportionate, develop common coordination or optimisation tools rather than requiring a single centralised optimisation model. ➢ Implementation status: ongoing / planned.

		coordination procedures rather than the institutional structure itself.	

5.2. Digitalisation

In this chapter the contribution of digitalisation of electricity transmission and distribution networks (as per Electricity Regulation, Article 19e(2)(d)) is evaluated. This section includes the contribution of grid enhancing technologies that improve network management (such as active system management, advanced monitoring and observability, dynamic line rating) to enhance the integration of distributed energy resources and other non-fossil flexibility resources. Besides, some aspects of the technological upgrade of existing advanced metering infrastructure and the development of new data services are evaluated in terms of contribution of Digitalisation of electricity transmission and distribution networks.

Grid digitalisation aspects	Evaluation of contribution to enhance the integration of distributed energy resources and other non-fossil flexibility resources	Justification and/or description of the situation in Slovenia	Mitigation measures
Active system management	There is large potential in the distribution system for contributing to enhancing the integration of distributed energy resources (DER) and other non-fossil flexibility resources (NFFR).	Active system management is merely in the beginning of deployment in the distribution system. Advanced distribution management systems (ADMS) are mostly deployed, but no real operational effect is reported. On the other side, active system management is already present and employed in transmission system operation, and thus there the contribution potential for enhancing integration of DER and other NFFR is largely exhausted.	Since 2025, the NRA provides a general performance incentive for efficient smart grid investments for DSO and TSO, which are linked to monitoring of a series of KPIs (as described above in the incentive section) and among others include all the 3 here described digitalisation aspects (active system management, advanced monitoring and observability, dynamic line rating). Based on the KPIs, an umbrella efficiency KPI is calculated which is directly connected to a financial incentive. For more details please refer to pages 67 thorugh 72 of the following document - https://www.agen-rs.si/documents/10926/38704/Poro%C4%8Dilo-
Advanced monitoring and observability	With wider usage of (near real-time) data and information from sensors, observers, ADMS and weather data, the distribution system can be operated more close to its locational capacity limits and thus more DER can be integrated in the system, as well	Active condition monitoring of asset operability in terms of lifetime management is enabled on many assets, but the exploitation of that information is probably lacking, especially in the distribution system. Thus, there seems to be room for improvement.	

	more renewable energy from PV plants can be injected into the system. Also, NFFR can be controlled more closely to real-time, providing more more room to maneuver in terms alleviating problems with PV injections in particularily problematic locations of the distribution system. The more renewable energy generated by plants connected to the distribution system is consumed close to its generation location, the less of those problematic energy injections are transferred upstream to the transmission grid. The advanced observability would enable the network constraint management in near real-time and promote the use of flexibility by operators.	On the observability side the contribution potential for the transmission system is largely exhausted. The distribution system is getting progressively more observable with additional sensors, meters and observers, so the potential for direct contribution to enhancing the integration of DER and other NFFR is still moderate.	stanju-na-podro%C4%8Dju-energetike-za-leto-2025/86f978f2-3492-48fe-b780-5a055954cb11 ➢ implementation status: completed
Dynamic line rating	Dynamic Line Rating (DLR) and Dynamic Thermal Rating (DTR) increase the usable capacity of transmission lines, distribution feeders and transformers by determining permissible loading from actual or forecast operating and environmental conditions rather than fixed conservative ratings. When thermal capacity is temporarily higher, these technologies can accommodate additional renewable generation, storage charging, demand response or other distributed energy resource activity without immediate curtailment or network reinforcement. By improving real-time network observability and enabling more active operation, DLR/DTR can reduce congestion, release otherwise unused hosting capacity and improve the locational availability of non-	Dynamic line rating (DLR) is currently largely deployed on transmission lines but not on distribution lines. Furthermore, the DSO said that considering economic efficiency there is no or only minimal potential to introduce DLR on distribution lines. On the other hand, dynamic thermal rating (DTR) that includes also transformers has much more potential for immediately contributing to enhancing the integration of DER and other NFFR. DTR is currently largely deployed on transmission transformers but not on distribution transformers. In 2026, the DSO annouced a national DTR deployment on distribution transformers within the benefit sharing scheme previously described in the incentive section. With this national project at least a part of the capacity upgrade of distribution transformers, those that are heavily loaded only a few hours or	

	fossil flexibility resources. They can therefore complement flexibility procurement and active network management: additional network capacity may enable flexible resources to be activated where they are needed, while flexibility can manage periods when dynamically assessed capacity remains insufficient. This coordinated use can reduce renewable curtailment, facilitate new DER connections and defer or optimise conventional network investments. These benefits depend on adequate monitoring, forecasting, communication and operational-control systems, and on the dynamic ratings being incorporated into congestion management, security assessment and TSO–DSO coordination processes.	days per year in favourable ambient conditions, can be omitted or at least postponed.	
Availability of near real time metered data of network users	A targeted upgrade of Slovenia's advanced metering infrastructure could enable central access to near-real-time measurements at selected connection points, particularly for active customers and other users whose consumption, generation or storage can materially affect network operation. This would improve observability at the edge of the distribution network, where increasing penetration of distributed generation, electric vehicles, heat pumps, battery storage and demand response may otherwise remain insufficiently visible to the system operator. More timely measurements would support improved state estimation, congestion and voltage monitoring, forecasting, validation of	The initial smart metering roll-out is finished. In 2026, Slovene NRA conducted the public consultation on the upgrade of AMI in use in order to adress the challenges and new requirements regarding the centralized acceess to near real time metered data for various use-cases. This upgrade is aimed to enable efficient and selective observability in near real time at the edge of the distribution network (the connection points of active users and flexibility resources) – the new communication technologies and (modular) meteres shall be used for such a purpose. The CBA of the foreseen upgrade will be conducted in 2026, whereas the gas smart metereing domain will be included in assesment as well.	CBA analysis for AMI upgrade. ➢ implementation status: project initilization phase

	flexibility availability and verification of flexibility activation. They could therefore enable more targeted and reliable use of distributed non-fossil flexibility, reduce the need for conservative operational limits, facilitate active network management and help defer or optimise conventional reinforcement. A selective approach focused on technically relevant active users would limit costs and data volumes while prioritising network locations where enhanced observability provides the greatest system value. Its effectiveness would depend on appropriate data-access arrangements, interoperability, cybersecurity, data protection and integration of near-real-time measurements into operational and flexibility-management processes		

6. Conclusions

This chapter summarises the principal conclusions of the national Flexibility Needs Assessment. It presents the key findings arising from the assessment, including a consolidated summary of the identified system and network flexibility needs, and outlines the recommended next steps to support the further development of non-fossil flexibility in Slovenia.

6.1. Key findings

- The Slovenian Flexibility Needs Assessment indicates that the Slovenian power system is transitioning from a system primarily concerned with generation adequacy towards one where operational flexibility becomes the dominant challenge. This transition is primarily driven by the increasing penetration of photovoltaic generation and the electrification of transport and heating.
- The identified system-level flexibility needs are predominantly associated with downward flexibility, including uncovered RES integration needs, downward ramping needs and downward short-term flexibility needs. Upward flexibility remains sufficient under the analysed scenarios. The identified uncovered flexibility needs are concentrated in limited seasonal and intraday periods rather than representing persistent year-round inadequacy.
- The dominant driver of future flexibility needs is the increasing occurrence of negative residual load conditions during periods of high photovoltaic generation, resulting in increasing requirements for renewable energy integration and operational flexibility.
- The assessment shows that appropriately dimensioned additional flexibility resources can substantially reduce uncovered RES integration needs. Most of the achievable reduction is obtained with resources having an energy-to-power ratio of approximately eight hours, while longer-duration configurations provide progressively smaller additional benefits.
- No transmission-network flexibility needs were identified under normal operating conditions for the analysed target years. The planned transmission-network development is therefore sufficient to address the assessed transmission constraints within the analysed planning horizon. The identified system-level flexibility needs are primarily driven by the balance between renewable generation and electricity demand rather than by transmission-network constraints.
- At distribution level, flexibility needs are highly location- and voltage-level dependent. Low-voltage networks are predominantly affected by transformer overloading associated with increasing electricity demand, while medium-voltage networks are primarily affected by voltage rise resulting from high penetration of distributed photovoltaic generation.
- Available explicit flexibility is expected to cover only part of the identified distribution-network flexibility needs. The expected availability of explicit flexibility remains relatively limited in both target years, highlighting the continued importance of network development through both long-term network planning and reinforcement as well as near-real time operational optimization, together with further development of contractual means to access flexibility (local flexibility services, flexible connection agreements). The remaining uncovered distribution-network flexibility needs reflect both the limited expected availability of explicit flexibility and the realistic constraints on implementing all technically required network reinforcements within the planning horizon. Consequently, after applying the represented operational measures and the realistically implementable share of network reinforcement, uncovered distribution-network flexibility needs remain in both target years.
- The assessment confirms that future flexibility adequacy requires a combination of flexibility resources employment, planned network development and operational measures to support reliable system operation and renewable energy integration.

6.1.1. Summary of flexibility needs

The flexibility needs assessment identifies the principal system flexibility needs for the target years 2030 and 2035 across RES integration, ramping and short-term flexibility. This section summarises the aforementioned needs along with identified network flexibility needs. Although selected aspects of the fine-tuning approach described in Section 2.3.8 were evaluated during the assessment, no separate fine-tuned results are presented in this report.

The assessment indicates that uncovered downward system flexibility needs constitute the dominant flexibility challenge, while upward flexibility needs are generally covered by the existing and projected flexibility resources.

Potential uncovered RES integration needs are represented by potential RES generation curtailment in accordance with the adopted methodology. These needs are characterised over hourly, daily and seasonal timeframes. Depending on the weather scenario, total potential RES curtailment ranges from 396.3 GWh to 867.8 GWh in 2030 and from 542.5 GWh to 826.4 GWh in 2035. The corresponding average potential curtailment reaches 299–459 MW at the hourly timeframe, 1.73–2.88 GWh/day at the daily timeframe and 33.0–72.3 GWh/month at the seasonal timeframe.

For ramping needs, the assessment shows that upward ramping needs are fully covered in all analysed scenarios for 2030, while only limited uncovered upward needs appear in several weather scenarios for 2035. In contrast, uncovered downward ramping needs are identified in all analysed scenarios and increase towards 2035. The average uncovered downward ramping need ranges from 134 MW to 185 MW in 2030 and from 166 MW to 304 MW in 2035, while the corresponding equivalent uncovered energy increases from 36 GWh to 63 GWh in 2030 and from 54 GWh to 131 GWh in 2035.

The assessment of short-term flexibility needs similarly indicates that no uncovered upward short-term flexibility needs are identified in any analysed scenario. However, uncovered downward short-term flexibility needs are present in all scenarios and increase significantly between 2030 and 2035. The uncovered downward short-term flexibility needs range from 347 MW to 420 MW in 2030 and from 578 MW to 645 MW in 2035. The associated expected uncovered energy increases from 5.2 GWh to 7.0 GWh in 2030 and from 14.7 GWh to 22.9 GWh in 2035, while the annual duration of uncovered events increases from approximately 47–61 hours to 80–113 hours.

Regarding transmission network flexibility needs, no flexibility needs were identified under N conditions for any analysed weather scenario in either 2030 or 2035. Under N-1 conditions, flexibility needs are limited and arise only under contingency situations, indicating that transmission network flexibility is primarily required to support system security following network outages.

Regarding distribution network flexibility needs, the results indicate that flexibility needs differ between voltage levels. At the LV level, they are predominantly driven by increasing electricity demand resulting from the electrification of heating and transport, whereas at the MV level they are primarily driven by distributed renewable generation. The limited availability of explicit flexibility means that part of the identified network constraints cannot be resolved through non-wire solutions alone and therefore require network reinforcement.

Overall, the assessment indicates that downward system flexibility requirements dominate the identified system flexibility needs, while upward flexibility requirements remain largely covered throughout the analysed scenarios. In parallel, transmission and distribution network flexibility needs are identified to support secure network operation under the analysed future scenarios. Together, the reported system, transmission network and distribution network flexibility needs constitute a comprehensive overview of the identified flexibility needs within the assessment.

6.2. Next steps

Actions to address the identified flexibility needs

The results of the analysis indicate that future flexibility adequacy will increasingly depend on the deployment and effective utilisation of flexibility resources capable of providing:

- downward flexibility capability,
- fast short-term response,
- intraday energy shifting,
- (local) congestion management support.

Furthermore, addressing the identified flexibility needs will require a combination of:

- deployment of energy storage systems,
- wider participation of demand response,
- increased utilization of flexible operation of renewable generation,
- deployment of other non-fossil, technology-neutral flexibility resources,
- continued transmission and distribution network development,
- further development of contractual mechanisms enabling access to flexibility, including local flexibility markets and flexible connection agreements, where applicable.

From a system perspective, storage technologies with fast-response capability may contribute to:

- improved utilisation of RES generation,
- mitigation of downward ramping deficits.

Demand response may additionally contribute to:

- shifting demand towards periods of high RES generation,
- reduction of residual load volatility,
- local congestion management.

Transmission-level flexibility contributions will remain particularly important for:

- system balancing,
- cross-border exchanges,
- large-scale RES integration.

Distribution-level flexibility contributions will remain particularly important for:

- alleviating local congestions in the distribution system,
- facilitating the integration of both distributed renewable generation and increasing electricity demand associated with the electrification of heating and transport.

Overall, the results of the analysis confirm that future flexibility adequacy cannot rely on a single technology or operational measure. A diversified portfolio of flexibility resources, combined with continued network development and coordinated system operation, will be required to support secure and efficient RES integration under the analysed operating conditions.

In Slovenia, investment aids in the form of direct non-repayable grants can be awarded to natural persons and legal entities for battery storage systems and other flexibility resources as part of the support centre's activities carried out by Borzen. Also, the applied network-tariff design in Slovenia does not hinder the participation of active customers on flexibility markets. Moreover, in the applied regulatory framework, the NRA provides also incentives for the TSO/DSO to employ flexibility in their business processes. Further actions relevant to development of non-fossil flexibility include:

- Facilitation of overcoming or mitigating of already identified barriers for non-fossil flexibility in section 5 of this report via the already planned actions or possible new actions that become relevant in future.
- Preparation of a national barrier mitigation roadmap. The roadmap should link identified barriers to concrete actions: short-term regulatory changes, mid-term digital and market-platform upgrades, and long-term transition toward active network management and flexibility-based planning.
- Facilitation of improvement of "TSO/DSO – distribution companies" coordination, where conflicts and complementarities between balancing, redispatch, RES integration, local congestion management and network planning, including activation priority, data exchange and settlement are holistically reviewed, along with appropriate definition of resource double-use rules.

Indicative national objective for non-fossil flexibility

Indicative national objective for non-fossil flexibility has not yet been set. Pursuant to Article 44.a of the Electricity Supply Act (ZOEE), the government must adopt a national framework target to ensure flexibility without fossil fuels, based on the NRA's assessment of flexibility needs. Until the NRA's report on estimated flexibility needs is adopted, the government may, at the proposal of the TSO, adopt provisional indicative national targets for ensuring flexibility without fossil fuels, which must be approved by the NRA Board. This proposal has not yet been drafted.

Consideration of the FNA results in transmission and distribution network development planning

The Flexibility Needs Assessment has been developed in close alignment with national transmission and distribution network planning activities.

For the transmission system, the assessment is based on the current network topology and incorporates planned transmission grid investments expected to be commissioned by the target years in accordance with the Slovenian Transmission System Development Plan 2025–2034. This ensures that the assessment of transmission-level flexibility needs is performed consistently with the planned network development.

For the distribution system, the baseline assumptions of the FNA are fully aligned with the forthcoming Distribution Network Development Plan (DNDP) 2027–2036. Furthermore, updated datasets prepared for the new DNDP have been incorporated into the FNA, ensuring consistency between both processes.

Planned improvements/changes for the next edition of the FNA report

Further improvements for the next edition of the FNA report are going to include:

- Definition of a mandatory minimum core data structure for collecting, integrating, and exchanging the data required for the national flexibility needs assessment, drawing on experience from the first FNA preparation cycle and the datasets expected to be available to TSO/DSO for the next FNA report.
- Full alignment of forthcoming NDPs with flexibility assessment based on experience gained in the first FNA preparation cycle.

7. References

This chapter presents the literature and source materials used in the preparation of the Flexibility Needs Assessment for the Slovenian Power System [33]. Not all references are explicitly cited throughout the report; however, all listed sources were considered and used in the development of the methodology, analyses, assumptions, and supporting background for this report.

[1] ENTSO-E, ‘ERAA 2024 Edition’. [Online]. Available: https://www.entsoe.eu/eraa/2024/

[2] ENTSO-E, ‘ERAA 2025 Edition’. [Online]. Available: https://www.entsoe.eu/eraa/2025/

[3] ‘Portal Energetika - Nacionalni energetski in podnebni načrt’. Accessed: Apr. 21, 2026. [Online]. Available: https://www.energetika-portal.si/dokumenti/strateski-razvojni-dokumenti/nacionalni-energetski-in-podnebni-nacrt-2024/

[4] ELES, ‘Razvojni načrt prenosnega sistema Republike Slovenije za obdobje 2025-2034’. [Online]. Available: https://www.eles.si/Portals/0/ELES_RNPS-digital_spreads_1.pdf

[5] ‘Portal Energetika - Razvojni načrti operaterjev sistema’. Accessed: Apr. 21, 2026. [Online]. Available: https://www.energetika-portal.si/fileadmin/dokumenti/publikacije/razvojni_nacrti/eles_rn_ds_2025-2034.pdf

[6] ENTSO-E, ‘Transparency platform’. [Online]. Available: https://transparency.entsoe.eu/

[7] ENTSO-E, ‘ERAA 2025 Modelling data’.

[8] Ministry of the environment, climate and energy and SLOVENIAN ENVIRONMENTAL AGENCY, ‘National meteorological service’. [Online]. Available: https://meteo.arso.gov.si/

[9] ‘Javno posvetovanje o 10-letnem razvojnem načrtu distribucijskega sistema električne energije v RS za obdobje 2027-2036’, ELES, d.o.o., sistemski operater prenosnega elektroenergetskega omrežja. Accessed: Apr. 21, 2026. [Online]. Available: https://www.eles.si/novice/ArticleID/22609/Javno-posvetovanje-o-10-letnem-razvojnem-načrtu-distribucijskega-sistema-električne-energije-v-RS-za-obdobje-2027-2036

[10] ‘Osebni avtomobili, avtobusi, miniavtobusi in tovorna vozila konec leta (31. 12.) ter prve registracije teh vozil po: LETO, VRSTA VOZILA, VRSTA POGONA IN GORIVA, MERITVE’, PxWeb. Accessed: Apr. 21, 2026. [Online]. Available: https://pxweb.stat.si:443/SiStatDataSiStatData/pxweb/sl/Data/-/2222109S.px/

[11] PODNEBNI NAČRT REPUBLIKE SLOVENIJE’. Dec. 18, 2024. [Online]. Available: https://www.energetika-portal.si/fileadmin/dokumenti/publikacije/nepn/dokumenti/nepn2024_final_dec2024.pdf

[12] European Union Agency for the Cooperation of Energy Regulators (ACER), ‘ACER Decision on the FNA methodology: Annex I Type and format of data and the methodology for TSOs’ and DSOs’ flexibility needs analysis’. Jul. 25, 2025.

[13] ‘PyPSA User Guide – Optimization overview’. [Online]. Available: https://docs.pypsa.org/latest/user-guide/optimization/overview/

[14] A. J. Wood, B. F. Wollenberg in G. B. Sheblé, Power Generation, Operation, and Control, 3rd Edition. 2013.

[15] ‘The PyPSA Handbook (ScienceDirect)’. [Online]. Available: https://www.sciencedirect.com/book/monograph/9780443266317/the-pypsa-handbook

[16] European Union (EU), ‘REGULATION (EU) 2019/943 OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL of 5 June 2019 on the internal market for electricity’. [Online]. Available: https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX%3A32019R0943&qid=1772580637393

[17] European Commision (EU), ‘COMMISSION REGULATION (EU) 2017/2195 of 23 November 2017 establishing a guideline on electricity balancing’. [Online]. Available: https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX%3A32017R2195&qid=1772580637393

[18] D. Reynolds, ‘Gaussian Mixture Models’, in Encyclopedia of Biometrics, Springer, Boston, MA, 2009, pp. 659–663. doi: 10.1007/978-0-387-73003-5_196.

[19] ‘Akt o metodologiji za obračunavanje omrežnine za elektrooperaterje’, Uradni list RS, 146/22 161/22, 50/23, 71/23, 117/23, 5/24, 30/24, 49/24, 107/24, 27/25, 76/25, 753/26. Available: http://pisrs.si/Pis.web/pregledPredpisa?id=AKT_1266

[20] J. Enrich, R. Li, A. Mizrahi, and M. Reguant, ‘Measuring the impact of time-of-use pricing on electricity consumption: Evidence from Spain’, Journal of Environmental Economics and Management, vol. 123, p. 102901, Jan. 2024, doi: 10.1016/j.jeem.2023.102901.

[21] G. Martin, ‘Overview of the Electricity Smart Metering Customer Behaviour Trial & Cost-Benefit Analysis in Ireland’, E-Control. Accessed: Apr. 13, 2026. [Online]. Available: https://www.e-control.at/marktteilnehmer/infos/veranstaltungen/veranstaltungen-2012/smart-metering-energieeffizienz

[22] A. Faruqui and S. Sergici, ‘Household Response to Dynamic Pricing of Electricity—A Survey of the Experimental Evidence’, Feb. 2009.

[23] J. Schofield, R. Carmichael, S. Tindemans, M. Woolf, M. Bilton, and G. Strbac, ‘Experimental validation of residential consumer responsiveness to dynamic time-of-use pricing’, Jun. 2015, Accessed: Apr. 13, 2026. [Online]. Available: http://hdl.handle.net/10044/1/33925

[24] ‘IEE Project TABULA’. Accessed: Apr. 13, 2026. [Online]. Available: https://episcope.eu/iee-project/tabula/

[25] ‘Tipologija stavb | Episcope in Tabula’. Accessed: Apr. 13, 2026. [Online]. Available: https://www.gi-zrmk.eu/tabula/?page_id=7

[26] K. Golli, ‘Vpliv elektrifikacije ogrevanja gospodinjstev na distribucijsko omrežje’, thesis, Univerza v Ljubljani, Fakulteta za elektrotehniko, 2021. Accessed: Apr. 13, 2026. [Online]. Available: https://repozitorij.uni-lj.si/IzpisGradiva.php?id=124793

[27] ‘Razvoj profilov električnih vozil za testiranje iz | COBISS Plus’. Accessed: Apr. 13, 2026. [Online]. Available: https://plus.cobiss.net/cobiss/si/sl/data/cobib/209716739

[28] Å. L. Sørensen, K. B. Lindberg, I. Sartori, and I. Andresen, ‘Residential electric vehicle charging datasets from apartment buildings’, Data in Brief, vol. 36, p. 107105, Jun. 2021, doi: 10.1016/j.dib.2021.107105.

[29] ‘NGED’s Electric Nation | EA Technology’. Accessed: Apr. 13, 2026. [Online]. Available: https://eatechnology.com/resources/projects/nged-s-electric-nation/

[30] C. Ziras, M. Thingvad, T. Fog, G. Yousefi, and T. Weckesser, ‘An empirical analysis of electric vehicle charging behavior based on real Danish residential charging data’, Electric Power Systems Research, vol. 234, p. 110556, Sep. 2024, doi: 10.1016/j.epsr.2024.110556.

[31] ‘Dynamic Pricing Outperforms Time-of-Use in California EV Charging Pilot with 98% Energy Delivered Off-Peak’. Accessed: Apr. 13, 2026. [Online]. Available: https://www.ev.energy/en-us/blog/dynamic-pricing-outperforms-time-of-use-in-california-ev-charging-pilot-with-98-energy-delivered-off-peak

[32] ‘Veljavni dokumenti SONDSEE | SODO | Sistemski operater distribucijskega omrežja z električno energijo’. Accessed: May 13, 2026. [Online]. Available: https://www.sodo.si/sl/kdo-smo/zakonodaja/sondsee/veljavni-dokumenti-sondsee

[33] Univerza v Ljubljani, Fakulteta za elektrotehniko, and Elektroinštitut Milan Vidmar, *Flexibility Needs Assessment for the Slovenian Power System*. Technical study prepared for ELES d.o.o., Ljubljana, Slovenia, May 2026. Not publicly available.

[34] Zakon o oskrbi z električno energijo (ZOEE) Uradni list RS, 172/21, 47/25, Available: https://pisrs.si/pregledPredpisa?id=ZAKO8141

Use of AI-assisted drafting tools

OpenAI's ChatGPT was used as a drafting support tool for translation, language editing, source-consistency checks, and editorial assistance. All AI-assisted outputs were reviewed and verified by the report authors.

ANNEX 1 – Deep dive on flexibility needs results

System needs – RES integration results tables

Table 33: System needs - RES integration - Target year 2030, Base scenario

Type[40]	Flexibility need	Indicator	Subindicator		Value	Unit	Target year	WS
System needs	RES integration (as per FNA Methodology, Article 8)	RES integration target	-		4,909	GWh	2030	Base
		RES generation curtailment	RES generation curtailment	Total	396.3	GWh		
			Hourly timeframe	Average	298.6	MW		
				Maximum	1010			
				Minimum	0.1			
			Daily timeframe	Average	1.73	GWh/day		
				Maximum	6.7			
				Minimum	0			
			Seasonal timeframe	Average	33	GWh/month		
				Maximum	63.4			
				Minimum	9.4			
		Residual load variations[41]	Hourly timeframe		3,016,183	MW		
			Daily timeframe		49,434	MW		
			Seasonal timeframe		1,041	MW		

[40] The reported values represent negative residual load as a proxy for RES integration needs under a zero-curtailment assumption. Explicit RES generation curtailment was not quantified, and the additional RES curtailment referred to in Article 8(3) was not included in accordance with the derogation applicable to the first FNA.

[41] As per FNA Methodology, Article 8(5) - Residual load variation indicators are reported as the sum of absolute residual load deviations.

Table 34: System needs - RES integration - Target year 2030, WS23

Type	Flexibility need	Indicator	Subindicator		Value	Unit	Target year	WS
System needs	RES integration (as per FNA Methodology, Article 8)	RES integration target	-		4,909	GWh	2030	WS23
		RES generation curtailment	RES generation curtailment	Total	666.5	GWh		
			Hourly timeframe	Average	390.7	MW		
				Maximum	1010			
				Minimum	0.4			
			Daily timeframe	Average	2.36	GWh/day		
				Maximum	7.42			
				Minimum	0.01			
			Seasonal timeframe	Average	55.5	GWh/month		
				Maximum	88.2			
				Minimum	30			
		Residual load variations	Hourly timeframe		3,961,511	MW		
			Daily timeframe		55,941	MW		
			Seasonal timeframe		682	MW		

Table 35: System needs - RES integration - Target year 2030, WS25

Type	Flexibility need	Indicator	Subindicator		Value	Unit	Target year	WS
System needs	RES integration (as per FNA Methodology, Article 8)	RES integration target	-		4,909	GWh	2030	WS25
		RES generation curtailment	RES generation curtailment	Total	867.8	GWh		
			Hourly timeframe	Average	458.9	MW		
				Maximum	1010			
				Minimum	1.8			
			Daily timeframe	Average	2.88	GWh/day		
				Maximum	8.17			
				Minimum	0			
			Seasonal timeframe	Average	72.3	GWh/month		
				Maximum	114.1			
				Minimum	29.7			
		Residual load variations	Hourly timeframe		4,562,405	MW		
			Daily timeframe		53,172	MW		
			Seasonal timeframe		708	MW		

Table 36: System needs - RES integration - Target year 2030, WS18

Type	Flexibility need	Indicator	Subindicator		Value	Unit	Target year	WS
System needs	RES integration (as per FNA Methodology, Article 8)	RES integration target	-		4,909	GWh	2030	WS18
		RES generation curtailment	RES generation curtailment	Total	688.3	GWh		
			Hourly timeframe	Average	392.2	MW		
				Maximum	1010			
				Minimum	0.5			
			Daily timeframe	Average	2.35	GWh/day		
				Maximum	8.25			
				Minimum	0			
			Seasonal timeframe	Average	57.4	GWh/month		
				Maximum	86.9			
				Minimum	29.7			
		Residual load variations	Hourly timeframe		4,111,865	MW		
			Daily timeframe		56,836	MW		
			Seasonal timeframe		637	MW		

Table 37: System needs - RES integration - Target year 2030, WS27

Type	Flexibility need	Indicator	Subindicator		Value	Unit	Target year	WS
System needs	RES integration (as per FNA Methodology, Article 8)	RES integration target	-		4,909	GWh	2030	WS27
		RES generation curtailment	RES generation curtailment	Total	755.9	GWh		
			Hourly timeframe	Average	430	MW		
				Maximum	1010			
				Minimum	1.6			
			Daily timeframe	Average	2.7	GWh/day		
				Maximum	7.96			
				Minimum	0.07			
			Seasonal timeframe	Average	63	GWh/month		
				Maximum	89.3			
				Minimum	28.1			
		Residual load variations	Hourly timeframe		4,152,397	MW		
			Daily timeframe		57,698	MW		
			Seasonal timeframe		577.2	MW		

Table 38: System needs - RES integration - Target year 2030, WS35

Type	Flexibility need	Indicator	Subindicator		Value	Unit	Target year	WS
System needs	RES integration (as per FNA Methodology, Article 8)	RES integration target	-		4,909	GWh	2030	WS35
		RES generation curtailment	RES generation curtailment	Total	718.6	GWh		
			Hourly timeframe	Average	438.4	MW		
				Maximum	1010			
				Minimum	1			
			Daily timeframe	Average	2.72	GWh/day		
				Maximum	6.93			
				Minimum	0.02			
			Seasonal timeframe	Average	59.9	GWh/month		
				Maximum	86.5			
				Minimum	33.8			
		Residual load variations	Hourly timeframe		3,973,432	MW		
			Daily timeframe		56,832	MW		
			Seasonal timeframe		586.4	MW		

Table 39: System needs - RES integration - Target year 2035, Base scenario

Type	Flexibility need	Indicator	Subindicator		Value	Unit	Target year	WS
System needs	RES integration (as per FNA Methodology, Article 8)	RES integration target	-		7,931	GWh	2035	Base
		RES generation curtailment	RES generation curtailment	Total	542.5	GWh		
			Hourly timeframe	Average	342.5	MW		
				Maximum	513			
				Minimum	0.4			
			Daily timeframe	Average	2.42	GWh/day		
				Maximum	4.14			
				Minimum	0.03			
			Seasonal timeframe	Average	45.2	GWh/month		
				Maximum	79.2			
				Minimum	17			
		Residual load variations[42]	Hourly timeframe		4,035,438	MW		
			Daily timeframe		72,422	MW		
			Seasonal timeframe		2,166	MW		

[42] As per FNA Methodology, Article 8(5) - Residual load variation indicators are reported as the sum of absolute residual load deviations.

Table 40: System needs - RES integration - Target year 2035, WS23

Type	Flexibility need	Indicator	Subindicator		Value	Unit	Target year	WS
System needs	RES integration (as per FNA Methodology, Article 8)	RES integration target	-		7,931	GWh	2035	WS23
		RES generation curtailment	RES generation curtailment	Total	712.3	GWh		
			Hourly timeframe	Average	374.1	MW		
				Maximum	513			
				Minimum	0.7			
			Daily timeframe	Average	2.55	GWh/day		
				Maximum	4.17			
				Minimum	0.07			
			Seasonal timeframe	Average	59.4	GWh/month		
				Maximum	79.6			
				Minimum	25.2			
		Residual load variations	Hourly timeframe		5,267,271	MW		
			Daily timeframe		73,556	MW		
			Seasonal timeframe		1,667	MW		

Table 41: System needs - RES integration - Target year 2035, WS25

Type	Flexibility need	Indicator	Subindicator		Value	Unit	Target year	WS
System needs	RES integration (as per FNA Methodology, Article 8)	RES integration target	-		7,931	GWh	2035	WS25
		RES generation curtailment	RES generation curtailment	Total	826.4	GWh		
			Hourly timeframe	Average	389.5	MW		
				Maximum	513			
				Minimum	0.6			
			Daily timeframe	Average	2.74	GWh/day		
				Maximum	4.68			
				Minimum	0.02			
			Seasonal timeframe	Average	68.9	GWh/month		
				Maximum	89.5			
				Minimum	26.3			
		Residual load variations	Hourly timeframe		5,945,803	MW		
			Daily timeframe		67,687	MW		
			Seasonal timeframe		1,404	MW		

Table 42: System needs - RES integration - Target year 2035, WS18

Type	Flexibility need	Indicator	Subindicator		Value	Unit	Target year	WS
System needs	RES integration (as per FNA Methodology, Article 8)	RES integration target	-		7,931	GWh	2035	WS18
		RES generation curtailment	RES generation curtailment	Total	737.3	GWh		
			Hourly timeframe	Average	372	MW		
				Maximum	513			
				Minimum	1.2			
			Daily timeframe	Average	2.51	GWh/day		
				Maximum	4.18			
				Minimum	0.03			
			Seasonal timeframe	Average	61.4	GWh/month		
				Maximum	80.2			
				Minimum	27.2			
		Residual load variations	Hourly timeframe		5,469,514	MW		
			Daily timeframe		72,179	MW		
			Seasonal timeframe		1,671	MW		

Table 43: System needs - RES integration - Target year 2035, WS27

Type	Flexibility need	Indicator	Subindicator		Value	Unit	Target year	WS
System needs	RES integration (as per FNA Methodology, Article 8)	RES integration target	-		7,931	GWh	2035	WS27
		RES generation curtailment	RES generation curtailment	Total	753.8	GWh		
			Hourly timeframe	Average	381.3	MW		
				Maximum	513			
				Minimum	1.1			
			Daily timeframe	Average	2.66	GWh/day		
				Maximum	4.77			
				Minimum	0.08			
			Seasonal timeframe	Average	62.8	GWh/month		
				Maximum	82.3			
				Minimum	27.9			
		Residual load variations	Hourly timeframe		5,433,851	MW		
			Daily timeframe		74,938	MW		
			Seasonal timeframe		1,604	MW		

Table 44: System needs - RES integration - Target year 2035, WS35

Type	Flexibility need	Indicator	Subindicator		Value	Unit	Target year	WS
System needs	RES integration (as per FNA Methodology, Article 8)	RES integration target	-		7,931	GWh	2035	WS35
		RES generation curtailment	RES generation curtailment	Total	724.7	GWh		
			Hourly timeframe	Average	380.2	MW		
				Maximum	513			
				Minimum	0.5			
			Daily timeframe	Average	2.61	GWh/day		
				Maximum	4.52			
				Minimum	0.01			
			Seasonal timeframe	Average	60.4	GWh/month		
				Maximum	91.7			
				Minimum	30.9			
		Residual load variations	Hourly timeframe		5,217,731	MW		
			Daily timeframe		76,394	MW		
			Seasonal timeframe		1,507	MW		

System needs – ramping needs results table

Table 45: System needs - ramping needs - Target year 2030, Base scenario

Type	Flexibility need	Indicator	Subindicator	Value	Unit	Scenario	Target year	Comments (i.e. up/downward, covered/uncovered, etc.)
System needs	Ramping needs (as per FNA Methodology, Article 9)	Residual load ramping need	Average	121.6	MW	Base	2030	Absolute hourly residual load variation
			Maximum	786.8	MW			Maximum absolute hourly residual load variation
			Minimum	0	MW			Minimum absolute hourly residual load variation
			Relevant percentile of upward ramp	344.8	MW			P95
		Upward uncovered ramping needs	Upward uncovered ramping needs - average	0	MW			Uncovered upward needs only
			Relevant percentile of uncovered upward need	0	MW			P95 of positive uncovered upward needs
			Equivalent total uncovered energy - upward	0	MW			Sum of uncovered upward ramping needs
		Downward uncovered ramping needs	Downward uncovered ramping needs - average	133.8	MW			Uncovered downward needs only
			Relevant percentile of uncovered downward need	333.4	MW			P95 of positive uncovered downward needs
			Equivalent total uncovered energy – downward	36,134	MWh			Sum of uncovered downward ramping needs

Table 46: System needs - ramping needs - Target year 2030, WS23

Type	Flexibility need	Indicator	Subindicator	Value	Unit	Scenario	Target year	**Comments** (i.e. up/downward, covered/uncovered, etc.)
System needs	Ramping needs (as per FNA Methodology, Article 9)	Residual load ramping need	Average	151.7	MW	WS23	2030	Absolute hourly residual load variation
			Maximum	842.7	MW			Maximum absolute hourly residual load variation
			Minimum	0	MW			Minimum absolute hourly residual load variation
			Relevant percentile of upward ramp	422.2	MW			P95
		Upward uncovered ramping needs	Upward uncovered ramping needs - average	0	MW			Uncovered upward needs only
			Relevant percentile of uncovered upward need	0	MW			P95 of positive uncovered upward needs
			Equivalent total uncovered energy - upward	0	MW			Sum of uncovered upward ramping needs
		Downward uncovered ramping needs	Downward uncovered ramping needs - average	148.7	MW			Uncovered downward needs only
			Relevant percentile of uncovered downward need	358.6	MW			P95 of positive uncovered downward needs
			Equivalent total uncovered energy – downward	45,489	MWh			Sum of uncovered downward ramping needs

Table 47: System needs - ramping needs - Target year 2030, WS25

Type	Flexibility need	Indicator	Subindicator	Value	Unit	Scenario	Target year	**Comments** (i.e. up/downward, covered/uncovered, etc.)
System needs	Ramping needs (as per FNA Methodology, Article 9)	Residual load ramping need	Average	165	MW	WS25	2030	Absolute hourly residual load variation
			Maximum	867.6	MW			Maximum absolute hourly residual load variation
			Minimum	0	MW			Minimum absolute hourly residual load variation
			Relevant percentile of upward ramp	492.2	MW			P95
		Upward uncovered ramping needs	Upward uncovered ramping needs - average	0	MW			Uncovered upward needs only
			Relevant percentile of uncovered upward need	0	MW			P95 of positive uncovered upward needs
			Equivalent total uncovered energy - upward	0	MW			Sum of uncovered upward ramping needs
		Downward uncovered ramping needs	Downward uncovered ramping needs - average	178.5	MW			Uncovered downward needs only
			Relevant percentile of uncovered downward need	386.7	MW			P95 of positive uncovered downward needs
			Equivalent total uncovered energy – downward	63,365	MWh			Sum of uncovered downward ramping needs

Table 48: System needs - ramping needs - Target year 2030, WS18

Type	Flexibility need	Indicator	Subindicator	Value	Unit	Scenario	Target year	**Comments** (i.e. up/downward, covered/uncovered, etc.)
System needs	Ramping needs (as per FNA Methodology, Article 9)	Residual load ramping need	Average	155.5	MW	WS18	2030	Absolute hourly residual load variation
			Maximum	850.2	MW			Maximum absolute hourly residual load variation
			Minimum	0	MW			Minimum absolute hourly residual load variation
			Relevant percentile of upward ramp	445.9	MW			P95
		Upward uncovered ramping needs	Upward uncovered ramping needs - average	0	MW			Uncovered upward needs only
			Relevant percentile of uncovered upward need	0	MW			P95 of positive uncovered upward needs
			Equivalent total uncovered energy - upward	0	MW			Sum of uncovered upward ramping needs
		Downward uncovered ramping needs	Downward uncovered ramping needs - average	157.5	MW			Uncovered downward needs only
			Relevant percentile of uncovered downward need	356	MW			P95 of positive uncovered downward needs
			Equivalent total uncovered energy – downward	52,909	MWh			Sum of uncovered downward ramping needs

Table 49: System needs - ramping needs - Target year 2030, WS27

Type	Flexibility need	Indicator	Subindicator	Value	Unit	Scenario	Target year	**Comments** (i.e. up/downward, covered/uncovered, etc.)
System needs	Ramping needs (as per FNA Methodology, Article 9)	Residual load ramping need	Average	155.3	MW	WS27	2030	Absolute hourly residual load variation
			Maximum	855.9	MW			Maximum absolute hourly residual load variation
			Minimum	0	MW			Minimum absolute hourly residual load variation
			Relevant percentile of upward ramp	471.7	MW			P95
		Upward uncovered ramping needs	Upward uncovered ramping needs - average	0	MW			Uncovered upward needs only
			Relevant percentile of uncovered upward need	0	MW			P95 of positive uncovered upward needs
			Equivalent total uncovered energy - upward	0	MW			Sum of uncovered upward ramping needs
		Downward uncovered ramping needs	Downward uncovered ramping needs - average	180.6	MW			Uncovered downward needs only
			Relevant percentile of uncovered downward need	378.4	MW			P95 of positive uncovered downward needs
			Equivalent total uncovered energy – downward	60,145	MWh			Sum of uncovered downward ramping needs

Table 50: System needs - ramping needs - Target year 2030, WS35

Type	Flexibility need	Indicator	Subindicator	Value	Unit	Scenario	Target year	**Comments** (i.e. up/downward, covered/uncovered, etc.)
System needs	Ramping needs (as per FNA Methodology, Article 9)	Residual load ramping need	Average	149.9	MW	WS35	2030	Absolute hourly residual load variation
			Maximum	859.3	MW			Maximum absolute hourly residual load variation
			Minimum	0	MW			Minimum absolute hourly residual load variation
			Relevant percentile of upward ramp	442.5	MW			P95
		Upward uncovered ramping needs	Upward uncovered ramping needs - average	0	MW			Uncovered upward needs only
			Relevant percentile of uncovered upward need	0	MW			P95 of positive uncovered upward needs
			Equivalent total uncovered energy - upward	0	MW			Sum of uncovered upward ramping needs
		Downward uncovered ramping needs	Downward uncovered ramping needs - average	185.1	MW			Uncovered downward needs only
			Relevant percentile of uncovered downward need	422.5	MW			P95 of positive uncovered downward needs
			Equivalent total uncovered energy – downward	59,034	MWh			Sum of uncovered downward ramping needs

Table 51: System needs - ramping needs - Target year 2035, Base scenario

Type	Flexibility need	Indicator	Subindicator	Value	Unit	Scenario	Target year	**Comments** (i.e. up/downward, covered/uncovered, etc.)
System needs	Ramping needs (as per FNA Methodology, Article 9)	Residual load ramping need	Average	144.8	MW	Base	2035	Absolute hourly residual load variation
			Maximum	1,198.8	MW			Maximum absolute hourly residual load variation
			Minimum	0	MW			Minimum absolute hourly residual load variation
			Relevant percentile of upward ramp	475.8	MW			P95
		Upward uncovered ramping needs	Upward uncovered ramping needs - average	0	MW			Uncovered upward needs only
			Relevant percentile of uncovered upward need	0	MW			P95 of positive uncovered upward needs
			Equivalent total uncovered energy - upward	0	MWh			Sum of uncovered upward ramping needs
		Downward uncovered ramping needs	Downward uncovered ramping needs - average	166.2	MW			Uncovered downward needs only
			Relevant percentile of uncovered downward need	419.1	MW			P95 of positive uncovered downward needs
			Equivalent total uncovered energy – downward	54,168	MWh			Sum of uncovered downward ramping needs

Table 52: System needs - ramping needs - Target year 2035, WS23

<table>
<tr><th>Type</th><th>Flexibility need</th><th>Indicator</th><th>Subindicator</th><th>Value</th><th>Unit</th><th>Scenario</th><th>Target year</th><th>Comments (i.e. up/downward, covered/uncovered, etc.)</th></tr>
<tr><td rowspan="10">System needs</td><td rowspan="10">Ramping needs (as per FNA Methodology, Article 9)</td><td rowspan="4">Residual load ramping need</td><td>Average</td><td>194.2</td><td>MW</td><td rowspan="10">WS23</td><td rowspan="10">2035</td><td>Absolute hourly residual load variation</td></tr>
<tr><td>Maximum</td><td>1,264.2</td><td>MW</td><td>Maximum absolute hourly residual load variation</td></tr>
<tr><td>Minimum</td><td>0</td><td>MW</td><td>Minimum absolute hourly residual load variation</td></tr>
<tr><td>Relevant percentile of upward ramp</td><td>587.3</td><td>MW</td><td>P95</td></tr>
<tr><td rowspan="3">Upward uncovered ramping needs</td><td>Upward uncovered ramping needs - average</td><td>38</td><td>MW</td><td>Uncovered upward needs only</td></tr>
<tr><td>Relevant percentile of uncovered upward need</td><td>38</td><td>MW</td><td>P95 of positive uncovered upward needs</td></tr>
<tr><td>Equivalent total uncovered energy - upward</td><td>38</td><td>MWh</td><td>Sum of uncovered upward ramping needs</td></tr>
<tr><td rowspan="3">Downward uncovered ramping needs</td><td>Downward uncovered ramping needs - average</td><td>207.4</td><td>MW</td><td>Uncovered downward needs only</td></tr>
<tr><td>Relevant percentile of uncovered downward need</td><td>558.5</td><td>MW</td><td>P95 of positive uncovered downward needs</td></tr>
<tr><td>Equivalent total uncovered energy – downward</td><td>83,993</td><td>MWh</td><td>Sum of uncovered downward ramping needs</td></tr>
</table>

Table 53: System needs - ramping needs - Target year 2035, WS25

Type	Flexibility need	Indicator	Subindicator	Value	Unit	Scenario	Target year	**Comments** (i.e. up/downward, covered/uncovered, etc.)
System needs	Ramping needs (as per FNA Methodology, Article 9)	Residual load ramping need	Average	206.6	MW	WS25	2035	Absolute hourly residual load variation
			Maximum	1,360	MW			Maximum absolute hourly residual load variation
			Minimum	0	MW			Minimum absolute hourly residual load variation
			Relevant percentile of upward ramp	690.1	MW			P95
		Upward uncovered ramping needs	Upward uncovered ramping needs - average	40.7	MW			Uncovered upward needs only
			Relevant percentile of uncovered upward need	64.3	MW			P95 of positive uncovered upward needs
			Equivalent total uncovered energy - upward	122.1	MWh			Sum of uncovered upward ramping needs
		Downward uncovered ramping needs	Downward uncovered ramping needs - average	303.5	MW			Uncovered downward needs only
			Relevant percentile of uncovered downward need	764.4	MW			P95 of positive uncovered downward needs
			Equivalent total uncovered energy – downward	131,396	MWh			Sum of uncovered downward ramping needs

Table 54: System needs - ramping needs - Target year 2035, WS18

Type	Flexibility need	Indicator	Subindicator	Value	Unit	Scenario	Target year	**Comments** (i.e. up/downward, covered/uncovered, etc.)
System needs	Ramping needs (as per FNA Methodology, Article 9)	Residual load ramping need	Average	200.1	MW	WS18	2035	Absolute hourly residual load variation
			Maximum	1,344.5	MW			Maximum absolute hourly residual load variation
			Minimum	0	MW			Minimum absolute hourly residual load variation
			Relevant percentile of upward ramp	608	MW			P95
		Upward uncovered ramping needs	Upward uncovered ramping needs - average	40.6	MW			Uncovered upward needs only
			Relevant percentile of uncovered upward need	40.6	MW			P95 of positive uncovered upward needs
			Equivalent total uncovered energy - upward	40.6	MWh			Sum of uncovered upward ramping needs
		Downward uncovered ramping needs	Downward uncovered ramping needs - average	227.9	MW			Uncovered downward needs only
			Relevant percentile of uncovered downward need	602.9	MW			P95 of positive uncovered downward needs
			Equivalent total uncovered energy – downward	103,679	MWh			Sum of uncovered downward ramping needs

Table 55: System needs - ramping needs - Target year 2035, WS27

Type	Flexibility need	Indicator	Subindicator	Value	Unit	Scenario	Target year	**Comments** (i.e. up/downward, covered/uncovered, etc.)
System needs	Ramping needs (as per FNA Methodology, Article 9)	Residual load ramping need	Average	195.8	MW	WS27	2035	Absolute hourly residual load variation
			Maximum	1,359.9	MW			Maximum absolute hourly residual load variation
			Minimum	0	MW			Minimum absolute hourly residual load variation
			Relevant percentile of upward ramp	632.2	MW			P95
		Upward uncovered ramping needs	Upward uncovered ramping needs - average	74.7	MW			Uncovered upward needs only
			Relevant percentile of uncovered upward need	74.7	MW			P95 of positive uncovered upward needs
			Equivalent total uncovered energy - upward	74.7	MWh			Sum of uncovered upward ramping needs
		Downward uncovered ramping needs	Downward uncovered ramping needs - average	267.2	MW			Uncovered downward needs only
			Relevant percentile of uncovered downward need	691.6	MW			P95 of positive uncovered downward needs
			Equivalent total uncovered energy – downward	115,444	MWh			Sum of uncovered downward ramping needs

Table 56: System needs - ramping needs - Target year 2035, WS35

Type	Flexibility need	Indicator	Subindicator	Value	Unit	Scenario	Target year	**Comments** (i.e. up/downward, covered/uncovered, etc.)
System needs	Ramping needs (as per FNA Methodology, Article 9)	Residual load ramping need	Average	189.7	MW	WS35	2035	Absolute hourly residual load variation
			Maximum	1,345.8	MW			Maximum absolute hourly residual load variation
			Minimum	0	MW			Minimum absolute hourly residual load variation
			Relevant percentile of upward ramp	579.4	MW			P95
		Upward uncovered ramping needs	Upward uncovered ramping needs - average	0	MW			Uncovered upward needs only
			Relevant percentile of uncovered upward need	0	MW			P95 of positive uncovered upward needs
			Equivalent total uncovered energy - upward	0	MWh			Sum of uncovered upward ramping needs
		Downward uncovered ramping needs	Downward uncovered ramping needs - average	298	MW			Uncovered downward needs only
			Relevant percentile of uncovered downward need	868.1	MW			P95 of positive uncovered downward needs
			Equivalent total uncovered energy – downward	107,585	MWh			Sum of uncovered downward ramping needs

System needs – short-term needs results table

Table 57: System needs - short-term needs - Target year 2030, Base scenario

Type	Flexibility needs	Indicator	Subindicator	Value		Unit	Scenario	Target year	**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	Slow[43] (1h – D-1) timeframe	515.4	MW	Base	2030	
		Downward residual load forecast errors	Relevant percentile of the forecast error	Slow (1h – D-1) timeframe	512.3	MW			
		Uncovered short-term flexibility needs	Upward uncovered short-term needs	Slow (1h – D-1) timeframe	0	MW			
			Downward uncovered short-term needs	Slow (1h – D-1) timeframe	346.7	MW			
			Average capacity per uncovered short-term flexibility need event	112.2		MW			
			Total expected energy from uncovered upward	0		MWh			

[43]Only the slow timeframe (1 h–D-1) was assessed, as historical forecast error data were available only for the day-ahead forecasting horizon.

Type	Flexibility needs	Indicator	Subindicator	Value	Unit	Scenario	Target year	**Comments** (i.e. up/downward, covered/uncovered, etc.)
			short-term flexibility needs events					
			Total expected energy from uncovered downward short-term flexibility needs events	5,814	MWh			
			Number of hours with uncovered short-term flexibility need event	51.8	h			

Table 58: System needs - short-term needs - Target year 2030, WS23

Type	Flexibility needs	Indicator	Subindicator	Value		Unit	Scenario	Target year	**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	Slow (1h – D-1) timeframe	499.6	MW	WS23	2030	
		Downward residual load forecast errors	Relevant percentile of the forecast error	Slow (1h – D-1) timeframe	533.7	MW			
		Uncovered short-term flexibility needs	Upward uncovered short-term needs	Slow (1h – D-1) timeframe	0	MW			
			Downward uncovered short-term needs	Slow (1h – D-1) timeframe	385.7	MW			
			Average capacity per uncovered short-term flexibility need event	113.1		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	5,940	MWh			
			Number of hours with uncovered short-term flexibility need event	52.5	h			

Table 59: System needs - short-term needs - Target year 2030, WS25

Type	Flexibility needs	Indicator	Subindicator	Value		Unit	Scenario	Target year	**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	Slow (1h – D-1) timeframe	563.4	MW	WS25	2030	
		Downward residual load forecast errors	Relevant percentile of the forecast error	Slow (1h – D-1) timeframe	585.9	MW			
		Uncovered short-term flexibility needs	Upward uncovered short-term needs	Slow (1h – D-1) timeframe	0	MW			
			Downward uncovered short-term needs	Slow (1h – D-1) timeframe	419.5	MW			
			Average capacity per uncovered short-term flexibility need event	118.2		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	6,996		MWh			
			Number of hours with uncovered short-term flexibility need event	59.2		h			

Table 60: System needs - short-term needs - Target year 2030, WS18

Type	Flexibility needs	Indicator	Subindicator	Value		Unit	Scenario	Target year	**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	Slow (1h – D-1) timeframe	512.3	MW	WS18	2030	
		Downward residual load forecast errors	Relevant percentile of the forecast error	Slow (1h – D-1) timeframe	539.1	MW			
		Uncovered short-term flexibility needs	Upward uncovered short-term needs	Slow (1h – D-1) timeframe	0	MW			
			Downward uncovered short-term needs	Slow (1h – D-1) timeframe	384.6	MW			
			Average capacity per uncovered short-term flexibility need event	111.7		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	6,803	MWh			
			Number of hours with uncovered short-term flexibility need event	60.9	h			

Table 61: System needs - short-term needs - Target year 2030, WS27

Type	Flexibility needs	Indicator	Subindicator	Value		Unit	Scenario	Target year	**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	Slow (1h – D-1) timeframe	532.2	MW	WS27	2030	
		Downward residual load forecast errors	Relevant percentile of the forecast error	Slow (1h – D-1) timeframe	537.9	MW			
		Uncovered short-term flexibility needs	Upward uncovered short-term needs	Slow (1h – D-1) timeframe	0	MW			
			Downward uncovered short-term needs	Slow (1h – D-1) timeframe	383.1	MW			
			Average capacity per uncovered short-term flexibility need event	107		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	6,089	MWh			
			Number of hours with uncovered short-term flexibility need event	56.9	h			

Table 62: System needs - short-term needs - Target year 2030, WS35

Type	Flexibility needs	Indicator	Subindicator	Value		Unit	Scenario	Target year	**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	Slow (1h – D-1) timeframe	523.2	MW	WS35	2030	
		Downward residual load forecast errors	Relevant percentile of the forecast error	Slow (1h – D-1) timeframe	564.9	MW			
		Uncovered short-term flexibility needs	Upward uncovered short-term needs	Slow (1h – D-1) timeframe	0	MW			
			Downward uncovered short-term needs	Slow (1h – D-1) timeframe	406.1	MW			
			Average capacity per uncovered short-term flexibility need event	112.6		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	5,237	MWh			
			Number of hours with uncovered short-term flexibility need event	46.5	h			

Table 63: System needs - short-term needs - Target year 2035, Base scenario

Type	Flexibility needs	Indicator	Subindicator	Value		Unit	Scenario	Target year	**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	Slow (1h – D-1) timeframe	858.5	MW	Base	2035	
		Downward residual load forecast errors	Relevant percentile of the forecast error	Slow (1h – D-1) timeframe	861.5	MW			
		Uncovered short-term flexibility needs	Upward uncovered short-term needs	Slow (1h – D-1) timeframe	0	MW			
			Downward uncovered short-term needs	Slow (1h – D-1) timeframe	589.6	MW			
			Average capacity per uncovered short-term flexibility need event		182.9	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		14,690	MWh			
			Number of hours with uncovered short-term flexibility need event		80.3	h			

Table 64: System needs - short-term needs - Target year 2035, WS23

Type	Flexibility needs	Indicator	Subindicator	Value		Unit	Scenario	Target year	**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	Slow (1h – D-1) timeframe	820.4	MW	WS23	2035	
		Downward residual load forecast errors	Relevant percentile of the forecast error	Slow (1h – D-1) timeframe	872.1	MW			
		Uncovered short-term flexibility needs	Upward uncovered short-term needs	Slow (1h – D-1) timeframe	0	MW			
			Downward uncovered short-term needs	Slow (1h – D-1) timeframe	644.5	MW			
			Average capacity per uncovered short-term flexibility need event		182	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		14,812	MWh			
			Number of hours with uncovered short-term flexibility need event		81.4	h			

Table 65: System needs - short-term needs - Target year 2035, WS25

Type	Flexibility needs	Indicator	Subindicator	Value		Unit	Scenario	Target year	**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	Slow[44] (1h – D-1) timeframe	940.6	MW	WS25	2035	
		Downward residual load forecast errors	Relevant percentile of the forecast error	Slow (1h – D-1) timeframe	964.9	MW			
		Uncovered short-term flexibility needs	Upward uncovered short-term needs	Slow (1h – D-1) timeframe	0	MW			
			Downward uncovered short-term needs	Slow (1h – D-1) timeframe	631.7	MW			
			Average capacity per uncovered short-term flexibility need event		201.5	MW			
			Total expected energy from uncovered upward short-term flexibility needs events		0	MWh			
			Total expected energy from uncovered		22,854	MWh			

[44]Only the slow timeframe (1 h–D-1) was assessed, as historical forecast error data were available only for the day-ahead forecasting horizon.

			downward short-term flexibility needs events					
			Number of hours with uncovered short-term flexibility need event	113.4	h			

Table 66: System needs - short-term needs - Target year 2035, WS18

Type	Flexibility needs	Indicator	Subindicator	Value		Unit	Scenario	Target year	**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	Slow[45] (1h – D-1) timeframe	838.7	MW	WS18	2035	
		Downward residual load forecast errors	Relevant percentile of the forecast error	Slow (1h – D-1) timeframe	893	MW			
		Uncovered short-term flexibility needs	Upward uncovered short-term needs	Slow (1h – D-1) timeframe	0	MW			
			Downward uncovered short-term needs	Slow (1h – D-1) timeframe	577.8	MW			
			Average capacity per uncovered short-term flexibility need event		184.3	MW			
			Total expected energy from uncovered upward short-term flexibility needs events		0	MWh			
			Total expected energy from uncovered downward		18,426	MWh			

[45] Only the slow timeframe (1 h–D-1) was assessed, as historical forecast error data were available only for the day-ahead forecasting horizon.

			short-term flexibility needs events					
			Number of hours with uncovered short-term flexibility need event	100	h			

Table 67: System needs - short-term needs - Target year 2035, WS27

Type	Flexibility needs	Indicator	Subindicator	Value		Unit	Scenario	Target year	**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	Slow (1h – D-1) timeframe	884.8	MW	WS27	2035	
		Downward residual load forecast errors	Relevant percentile of the forecast error	Slow (1h – D-1) timeframe	895.4	MW			
		Uncovered short-term flexibility needs	Upward uncovered short-term needs	Slow (1h – D-1) timeframe	0	MW			
			Downward uncovered short-term needs	Slow (1h – D-1) timeframe	581.8	MW			
			Average capacity per uncovered short-term flexibility need event		186.9	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		19,547	MWh			

			Number of hours with uncovered short-term flexibility need event	104.6	h			

Table 68: System needs - short-term needs - Target year 2035, WS35

Type	Flexibility needs	Indicator	Subindicator	Value		Unit	Scenario	Target year	**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	Slow (1h – D-1) timeframe	865	MW	WS35	2035	
		Downward residual load forecast errors	Relevant percentile of the forecast error	Slow (1h – D-1) timeframe	921.9	MW			
		Uncovered short-term flexibility needs	Upward uncovered short-term needs	Slow (1h – D-1) timeframe	0	MW			
			Downward uncovered short-term needs	Slow (1h – D-1) timeframe	596.3	MW			
			Average capacity per uncovered short-term flexibility need event		187.7	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		15,974	MWh			

			Number of hours with uncovered short-term flexibility need event	85.1	h			

ANNEX 2 - Approach to DSO data treatment

In Slovenia, the transmission and distribution system operator functions are performed by a single combined system operator. Therefore, The DSO component of the assessment was based on common planning data, scenarios and methodologies. Additional parameters related to network reinforcement measures were provided for each distribution network operator (DNO) area, reflecting DNO-specific engineering judgement and planning practices.

The DSO network needs assessment was based on the Distribution Network Development Plan (DNDP) 2025–2034 [5] and the updated National Energy and Climate Plan (NECP, 2024) [3], in accordance with Article 6(6) of the FNA Methodology. No additional data or analyses pursuant to Article 4(1)(i) of the FNA Methodology were provided beyond those described under the updates implemented in accordance with Article 6(7), which are described in Sections 2.3.7.2 and 3.1.2.1 of this report

The assessment considered both medium- and low-voltage distribution networks using representative reference network models. Each reference network represents a cluster of distribution networks with similar structural and operational characteristics. Network simulations were performed on the representative reference networks, after which the results were generalised from individual reference networks to representative network groups, aggregated to the distribution network operator (DNO) area level and subsequently generalised to the Slovenian distribution system.

The generalisation methodology differs according to the assessed parameter. Explicit flexibility requirements are generalised based on the availability of controllable technologies within each network cluster. Transformer loading is generalised using measured peak loading distributions together with the simulated relative increase in transformer loading, while voltage-related reinforcement needs are generalised using statistical indicators describing the electrical characteristics of networks within each cluster. Network reinforcement requirements and associated investment costs are subsequently derived from the generalised results using DNO-specific planning assumptions. These parameters reflect local engineering practice and asset characteristics and influence the selection and cost of reinforcement measures, but do not affect the identified flexibility needs.

Finally, no data on the temporary unavailability of flexibility resources, including unavailability resulting from grid prequalification constraints as referred to in Article 13(1) of the FNA Methodology, were provided by the DSO. Consequently, the DSO assessment did not explicitly account for the temporary unavailability of flexibility resources.

ANNEX 3 - Approach to guiding criteria

A3.1 Objective and scope

This annex describes the approach used to assess the capability of different sources of flexibility and other relevant solutions to cover the system and network flexibility needs identified for the 2030 and 2035 target years. The approach applies the guiding criteria under Article 16 of the FNA Methodology by characterising the location, voltage level, direction, timing, recurrence, power, energy and duration of flexibility needs to the extent that these indicators were available.

The purpose of the criteria is not to redefine the amount of the needs, but to describe their technical form and to support an assessment of which resources or alternative measures could technically address them. The approach distinguishes between:

- system flexibility needs assessed at bidding-zone level;
- transmission-network flexibility needs;
- distribution-network flexibility needs, which are local and voltage-level specific.

The criteria were applied to the needs retained following the fine-tuning relevance assessment. Where no material adjustment resulted from fine-tuning, the retained need was equal to the need quantified before fine-tuning. This was the case for the system needs because the assessed transmission-network constraints did not materially change uncovered RES integration needs. Distribution-network needs retained their local character and were assessed on the basis of the network-driven results.

A3.2 Distribution-network flexibility needs

A3.2.1 Assessment basis and available indicators

Distribution-network flexibility needs were assessed at 15-minute resolution for the target years 2030 and 2035. The available results were aggregated and reported by DNO area and, where applicable, by voltage level and relevant time block.

The available guiding-criteria indicators include:

Indicator	Application in the distribution assessment
Geographical location	DNO area
Network location	Voltage level at which the thermal constraint or voltage issue occurs
Direction	Upward or downward flexibility
Timeframe	Relevant time block and seasonal or daily occurrence pattern
Energy	Energy associated with the need over the relevant time block and over the year
Power	Local maximum power required during activation and an aggregated sum of local maximum values
Uncovered part	Share of identified flexibility needs reported as uncovered
RES curtailment	Share of downward flexibility needs associated with RES generation curtailment
Access arrangement	Expected contractual or operational means of accessing flexibility

The reported sum of local maximum power values is an aggregation of maxima identified at different network locations. It should not be interpreted as a coincident national maximum. The technically relevant criterion for the capability of a local resource remains the maximum power required at the affected location.

The identified time blocks, associated energy values and local maximum power provide the principal available temporal and quantitative characterisation of the distribution-network needs. The duration of individual continuous activation events, the cumulative duration of discontinuous activations and a separate indicator of activation frequency were not consolidated in the reported results and are therefore not assessed separately in this annex.

Applicable economic criteria were not determined for individual local needs. Consequently, the distribution assessment characterises the technical capability required from resources but does not provide a local cost-effectiveness threshold or clearing-price criterion.

A3.2.2 Direction, location and timing of the needs

Low-voltage networks

At LV level, the dominant need is for upward flexibility. It arises mainly from thermal constraints associated with MV/LV transformer overloading. Overloading is most pronounced during winter but also occurs in other seasons.

The highest loading generally occurs during the evening period, approximately between 19:00 and 24:00, primarily due to electricity consumption by heat pumps and electric vehicles. The representation of implicit flexibility through the shifting of EV charging to off-peak tariff periods also results in a new night-time demand peak.

The LV results therefore indicate a requirement for locally available upward flexibility during periods of high demand. Such a need may technically be addressed by:

- reducing demand in the affected network area;
- shifting demand to another period;
- increasing local injection;
- using storage to discharge at the affected location; or
- reinforcing the relevant transformer or network element.

The use of a dynamic network tariff as a complementary network-energy tariff intended to mitigate the new night-time peak was not simulated. The reported needs therefore do not include any additional mitigation that such a tariff might provide.

Medium-voltage networks

At MV level, the predominant need is for downward flexibility. It arises mainly from voltage rise resulting from high penetration of photovoltaic generation.

The relevant voltage constraints occur mainly outside the winter season during daylight hours. Their exact timing depends on solar irradiance and on the presence, capacity and operational pattern of battery storage, which affects the net power injected into the network.

The MV results therefore indicate a requirement for locally available downward flexibility during periods of high distributed generation. Such a need may technically be addressed by:

- reducing local injection;
- curtailing photovoltaic generation;
- increasing local demand;
- charging storage;
- applying reactive-power or voltage-control measures;
- using a flexible connection arrangement; or

- reinforcing the affected network.

A3.2.3 Development between target years and availability of flexibility

Distribution-network flexibility needs increase between 2030 and 2035. At the same time, the expected and simulated volume of available explicit flexibility remains relatively limited in both target years.

The increase in identified needs should not be interpreted as evidence that all such needs must be covered by new flexibility resources. Depending on location and timing, individual needs may be addressed by a combination of available flexibility, operational measures, non-wire solutions and network reinforcement.

A3.2.4 Technology-specific representation

As a general modelling assumption, explicit flexibility was considered separately for each technology category. Flexibility available from a particular resource type was primarily used to mitigate network constraints associated with that resource type.

This assumption reflects the expectation that, within the analysed planning horizon, local flexibility markets will not yet have reached sufficient maturity and liquidity to enable fully technology-neutral procurement across all resource categories. Accordingly, substitution between different types of resources was not comprehensively modelled.

Electric vehicles

Electric-vehicle flexibility was represented through adjustments to charging schedules and was primarily used to manage demand-related constraints. EV charging can be shifted with limited impact on mobility requirements where suitable smart-charging equipment, communication and control arrangements are available.

However, shifting charging to off-peak tariff periods may concentrate charging and create a new night-time peak. The potential contribution of an additional dynamic network tariff to mitigating this effect was not assessed.

EV flexibility was not assumed to be available in sufficient volumes to mitigate voltage rise caused by high photovoltaic generation. This is a modelling and expected-market-availability assumption rather than an inherent technical inability of EV charging to absorb electricity.

Heat pumps

Heat pumps contribute significantly to winter peak demand and can provide upward flexibility through a temporary reduction in electricity consumption.

The technically usable flexibility depends on:

- the thermal performance and inertia of the building;
- the outdoor temperature;
- the heating system;
- the permissible duration and depth of consumption reduction; and
- the effect on occupant comfort.

Better-performing buildings can generally tolerate longer or deeper temporary demand reductions without materially affecting indoor comfort. Building energy efficiency therefore influences the effective flexibility capability of heat pumps.

Photovoltaic generation

Photovoltaic generation provides downward flexibility through active-power curtailment during relevant network constraints under flexible connection arrangements.

Under the assessed arrangement, curtailment is automatically triggered by predefined network conditions. It is therefore treated as a rule-based operational measure consistent with implicit flexibility.

PV curtailment would constitute explicit flexibility only where it is offered, procured and directly activated to provide a specified network service.

Battery energy storage systems

Battery storage affects net demand and injection through autonomous operation based on predefined control strategies. Its contribution was therefore represented as implicit flexibility rather than as available explicit flexibility.

Battery storage can technically contribute to both:

- upward flexibility by discharging or reducing charging; and
- downward flexibility by charging or reducing discharge.

Its contribution as an explicitly procured flexibility service was not assessed. Such participation would require suitable metering, communication, market-access, contractual and control arrangements.

Scope of downward flexibility

Within the applied distribution framework, downward flexibility was represented exclusively through:

- curtailment of photovoltaic generation under flexible connection arrangements; and
- operation of battery energy storage systems.

Other potential downward flexibility resources were not modelled. The reported capability assessment should therefore not be interpreted as an exhaustive assessment of all resources that could technically increase consumption or reduce injection.

A3.2.5 Flexible connection arrangements

Flexible connection arrangements facilitate the integration of distributed generation, demand and energy storage while increasing the utilisation of existing network infrastructure. Under such an arrangement, generation or consumption is limited only when network congestion or another relevant operating constraint occurs.

In the assessed framework, the limitation is activated automatically according to predefined network conditions and is therefore treated as a rule-based operational measure.

As the share of connections subject to flexible arrangements increases, the expected volume of generation curtailment may also increase, particularly during periods of high renewable generation and limited network capacity.

Flexible connection arrangements are consequently treated as a transitional measure supporting the connection of distributed resources until:

- the necessary network reinforcement is implemented;
- technology-neutral local procurement becomes sufficiently mature; or
- other operational solutions become available.

A3.2.6 Covered and uncovered distribution needs

Available explicit flexibility and the represented non-wire solutions were first applied to mitigate identified thermal constraints and voltage-limit violations.

Where the represented measures were insufficient, the technically required network reinforcement was identified. However, only the share of reinforcement measures expected to be realistically implemented within the planning horizon was included in the final scenario.

Not all technically required reinforcement measures are expected to be implemented by the target year due to:

- financial limitations;
- investment-planning cycles;
- permitting constraints; and
- investment prioritisation.

The part of the network in which constraints cannot be resolved through assumed available explicit flexibility, represented operational measures or realistically implemented reinforcement is reported as uncovered flexibility needs.

The uncovered share therefore reflects the combined effect of:

1. relatively limited expected availability of explicit flexibility;
2. the technical effectiveness of the represented non-wire and operational measures; and
3. the assumed realistic implementation of network reinforcement.

The classification of a residual constraint as an uncovered flexibility need does not demonstrate that procurement of an additional flexibility resource is necessarily the least-cost solution. It indicates that the constraint remains unresolved under the specific assumptions regarding available flexibility, represented measures and implementable reinforcement.

A3.2.7 Technology neutrality and limitations

The assessment does not quantify the extent to which flexibility from one technology category could substitute for flexibility from another and does not establish a technology-neutral ranking of the represented distribution resources.

No separate technology-neutral optimisation was performed to determine a cost-optimal combination of:

- additional flexibility resources;
- non-wire alternatives;
- operational measures; and
- network reinforcement.

Consequently, the assessment does not identify a preferred additional technology for each individual uncovered local need. Such a comparison would require the technical and economic characteristics of additional resources to be matched with:

- geographical and network location;
- voltage level;
- direction;
- duration;
- recurrence;

- required power;
- required energy; and
- applicable economic criteria.

Future development of technology-neutral procurement could enable flexibility from different categories to address a wider range of constraints than assumed in the current assessment. Relevant developments include:

- smart charging of electric vehicles;
- improvements in building energy efficiency;
- arrangements allowing battery storage to provide explicit flexibility services; and
- progressive development of technology-neutral local flexibility procurement.

These future developments were not included as additional available flexibility unless they were already reflected in the assumptions for the relevant target year.

A3.3 System flexibility needs

A3.3.1 Assessment basis

System flexibility needs were assessed at bidding-zone level and include:

- RES integration needs;
- ramping needs; and
- short-term flexibility needs.

The guiding-criteria assessment complements the results quantified under Articles 8, 9 and 10 by:

1. characterising the technical form of uncovered needs; and
2. assessing the contribution of additional generic flexibility configurations to reducing uncovered RES integration needs.

A3.3.2 Technical characterisation of uncovered events

Continuous flexibility-needs events were identified as consecutive MTUs with uncovered needs. For each identified event, the following were determined:

- event duration;
- maximum power requirement during the event; and
- energy volume.

The analysis comprised uncovered RES integration, ramping and short-term flexibility events and was presented for WS25, which demonstrated the highest needs in the analysed scenarios.

The event representation provides information on the combinations of duration and maximum power that potential resources would need to provide. It also illustrates that different categories of system need have different technical profiles.

The underlying results include the number of MTUs with uncovered needs for relevant need categories. However, the interval between uncovered events and a consolidated presentation of all Article 16(5) indicators across hourly, daily and seasonal timeframes were not separately reported for each category.

Summary of Article 16(5) indicators

Required sub-indicator	RES integration	Ramping	Short-term
Number of MTUs with uncovered need	Available in underlying results	Available in underlying results	Available in underlying results
Interval between uncovered needs	Not separately consolidated	Not separately consolidated	Not separately consolidated
Duration of uncovered needs	Event-based analysis available	Event-based analysis available	Event-based analysis available
Energy volume	Available	Available	Available
Power volume / maximum event power	Available	Available	Available
Hourly, daily and seasonal consolidation	Partially available in preceding result sections	Partially available	Partially available

The absence of a separately consolidated interval-between-events indicator limits the ability to assess recovery time, recharging opportunity and repeated-use requirements for energy-limited resources.

A3.3.3 Direction of system needs

The identified uncovered system needs are predominantly downward. Increasing photovoltaic generation is associated with:

- periods of negative residual load and uncovered RES integration needs;
- more demanding downward ramps; and
- higher downward short-term flexibility requirements.

No uncovered upward short-term flexibility needs were identified in the analysed scenarios.

Where uncovered upward needs are zero, an additional comparison of resources for covering those needs is not applicable. This should be distinguished from the existence of gross upward flexibility requirements, which may be fully covered by the available capability.

A3.3.4 Generic-resource capability assessment

The capability of additional resources to reduce uncovered RES integration needs was assessed using a technology-neutral generic flexibility resource.

The generic resource was characterised by:

- installed power;
- energy capacity;
- energy-to-power ratio;
- availability; and
- representative round-trip efficiency.

The same general assumptions were used as in the assessment under Article 8(10). Different technical duration characteristics were represented through different energy-to-power ratios.

The generic model was considered conceptually applicable to:

- battery energy storage systems;
- pumped-storage hydropower;
- aggregators;

- prosumers;
- electric vehicles; and
- other demand-side flexibility resources.

The list identifies resource categories to which the generic mathematical representation could conceptually be applied. It does not mean that the individual operational characteristics of all listed resources were separately modelled or validated.

A3.3.5 Contribution curves and marginal contribution

Contribution curves show the remaining uncovered RES integration need as the energy capacity of additional, technology-neutral flexibility increases under different assumed activation duration (i.e. energy-to-power ratios). The slope of each curve represents the marginal contribution of additional flexibility capacity in reducing the uncovered RES integration need.

The contribution curves generally show diminishing marginal reductions in uncovered RES integration needs as the capacity of each generic, technology-neutral flexibility configuration increases. Under the analysed conditions, configurations with shorter energy-to-power ratios achieve a greater reduction per additional GWh of energy capacity.

This result reflects both the predominantly limited duration of the identified events and the metric used for the comparison. At the same energy capacity, a shorter-duration configuration has a higher power rating and is therefore better able to address events with high power requirements. The curves consequently do not demonstrate that shorter-duration resources are generally superior when compared at equal power, on a cost basis or under operating conditions requiring recovery between successive events.

A3.3.6 Limitations of the generic-resource assessment

Within the adopted framework, different flexibility technologies were represented through the same generic mathematical model. Differences in activation costs were not considered because the assessment focused on technical rather than economic performance.

The assessment did not separately model technology-specific differences in:

- temporal availability;
- response time;
- energy-recovery requirements;
- state-of-charge constraints;
- user or comfort constraints;
- rebound effects;
- cycling limits;
- seasonal availability;
- locational accessibility;
- grid prequalification;
- communications and control; or
- activation cost.

The contribution curves therefore provide a comparison of generic technical configurations rather than a complete comparison or hierarchy of individual flexibility-resource categories.

A3.3.7 Short-term needs, reserves and balancing

Short-term flexibility needs were compared with remaining domestic flexibility margins after day-ahead dispatch. Frequency Containment Reserve was excluded to avoid double counting.

Cross-border exchange margins and market-liquidity constraints were not included in the short-term flexibility margin. This may contribute to conservative estimates.

No dedicated assessment was performed to determine how uncovered short-term needs would first be addressed through:

- additional FRR capacity;
- increased participation in balancing;
- changes in balancing-product design; or
- other balancing arrangements.

Reserve requirements were included in the input information, but no direct quantitative mapping was made

A3.4 Transmission-network flexibility needs

A3.4.1 Assessment and result

Transmission-network flexibility needs were assessed using a detailed AC load-flow model of the Slovenian transmission network. The network model incorporated the planned grid investments expected to be commissioned by the target years.

The assessment considered thermal loading and voltage conditions under normal operating conditions and, separately, contingency conditions.

No transmission-network flexibility needs were identified under normal operating conditions for any analysed weather scenario in 2030 or 2035. The reported value is therefore zero for both power and energy under those conditions.

Transmission-network constraints did not materially change the identified uncovered RES integration energy. Their effect remained below the relevance threshold for fine-tuning.

A3.4.2 Application of guiding criteria

Because no non-zero transmission-network flexibility needs were identified under normal operating conditions, additional location, direction, duration, recurrence, power and energy sub-indicators were not required for those reported needs.

The planned transmission-network development incorporated into the model represents the relevant network solution for the assessed normal operating conditions.

Where N-1 results are reported elsewhere, their status should be clearly distinguished from the zero result under normal conditions. If an N-1 result is classified as a formal transmission-network flexibility need under Article 12, its location and technical characteristics should be reported consistently in the relevant transmission-network section

A3.5 Interdependencies between needs

The assessment identifies photovoltaic generation as a common driver of several categories of flexibility need. Higher PV generation contributes to:

- RES integration needs during surplus conditions;
- downward ramping needs during rapid increases in PV output; and
- downward short-term flexibility needs associated with forecast uncertainty.

This demonstrates a qualitative interdependency between the needs assessed under Articles 8, 9 and 10.

A comprehensive quantitative interdependency analysis was not performed. In particular, the assessment does not quantify:

- the temporal overlap of events across categories;
- the extent to which one activation could address more than one need;
- potential competition between system and local network needs;
- the availability of the same resource for simultaneous services;
- interaction between upward and downward requirements; or
- the risk of double counting a resource across different needs.

Consequently, the results should not be added mechanically across categories to define a single required flexibility capacity.

A3.6 Alternatives to new flexibility resources

The assessment represents or identifies the following potential alternatives or complements to new flexibility resources:

Level	Relevant alternative or complementary measure
System	Cross-border exchanges, operational use of existing dispatchable resources, demand response and existing storage
Transmission network	Planned transmission-grid development
Distribution network	Network reinforcement, advanced voltage control, reactive-power control, OLTC transformers, flexible connection arrangements and other non-wire solutions
Demand side	Managed EV charging and temporary heat-pump demand reduction
Generation side	PV active-power curtailment
Storage	Autonomous charging and discharging under predefined strategies

These measures were represented to different levels of detail. Their inclusion in the assessment does not demonstrate that they are mutually substitutable or economically equivalent.

Flexible connection arrangements can support earlier or additional connection of distributed resources but may result in increasing renewable-generation curtailment as their use expands.

Network reinforcement remains relevant where available flexibility and non-wire alternatives are insufficient or where the long-term cost of recurrent flexibility activation would exceed that of reinforcement.

The latter cost comparison was not quantified in the current assessment and should therefore be understood as the decision context rather than as a reported numerical result.

A3.7 Cost-effectiveness assessment

No integrated cost-benefit or cost-effectiveness optimisation was carried out to compare all additional flexibility resources, non-wire alternatives, cross-border solutions and network reinforcement.

The study therefore does not establish:

- a least-cost portfolio;
- a technology-specific merit order;
- a preferred resource for each uncovered local need;
- an economically optimal split between flexibility and reinforcement; or

- a cost threshold for procurement.

The analysis nevertheless supports future cost-effectiveness assessments by identifying several of the required technical dimensions, including direction, timing, duration, power, energy and location.

A complete comparison would additionally require consistent information on:

- investment and operating costs;
- activation costs;
- expected utilisation;
- lifetime;
- efficiency;
- availability;
- network losses;
- curtailment costs;
- reliability and security implications;
- rebound effects;
- implementation lead time; and
- residual or terminal value.

A3.8 Summary of coverage and limitations

Article 16 element	Treatment in the assessment	Limitation
Basis: fine-tuned or non-fine-tuned needs	Applied to needs retained after the fine-tuning relevance assessment	No separate formal agreement is reproduced in this annex
Distribution indicators	Location, voltage level, direction, time block, energy, local maximum power and uncovered share available	Continuous duration, cumulative discontinuous duration, frequency and economic criteria not consolidated
System-event indicators	Duration, maximum power and energy assessed; MTU counts available in results	Event intervals and fully consolidated hourly/daily/seasonal presentation incomplete
RES-integration contribution curves	Produced for generic resource configurations	Not separate technology-specific curves or ranking
Uncovered upward needs	No uncovered upward short-term needs identified	Gross upward requirements still exist but are covered
Short-term needs and balancing	Remaining margins assessed; FCR excluded	No dedicated FRR or further-balancing-participation assessment
Transmission-network needs	Zero under normal operating conditions	N-1 status must remain clearly distinguished
Interdependencies	Common PV driver qualitatively identified	No comprehensive quantitative overlap or competition analysis
Alternatives under Article 16(11)	Relevant technical alternatives identified	No integrated cost-effectiveness optimisation

The guiding-criteria assessment should therefore be interpreted as a structured technical capability assessment based on the information available in the first national FNA cycle. It provides a basis for identifying suitable technical characteristics and relevant categories of measures but does not constitute a complete technology-specific, locational and cost-optimised procurement assessment.

ANNEX 4 – Methodological approach to Economic Dispatch modelling

The Slovenian FNA is based on an own Economic Dispatch (ED) model developed using the PyPSA framework. ED is an optimisation problem that, for given capacities of generation units and storage systems, calculates the time sequence of operational decisions that meet the electricity demand while respecting technical constraints, to minimise total system operating cost.

As the basic building block of the mathematical model for ED, the Python library PSA (Python for Power System Analysis – PyPSA) [13] is used. PyPSA is an open-source software library intended for the simulation and optimisation of advanced power systems. PyPSA is designed to enable simulations and calculations for large-scale power networks and long input data time series.

Within the PyPSA framework, the ED problem is formulated as a core component of broader models, such as optimal power flow or power system investment planning. ED can be interpreted in two complementary ways:

- as a centralised market problem whose objective is the minimisation of total operational cost (e.g., using a rolling horizon approach);
- as a deterministic optimal control problem of a dynamic system, where temporal coupling is of key importance.

In the PyPSA model, ED is formulated as an optimisation problem that minimises total system cost over the selected rolling horizon. This includes minimising operational, maintenance, start-up, and shutdown costs of power plants and other model components (such as storage systems, etc.). PyPSA uses a standard mathematical formulation for ED, which is described in detail in the literature [14], [13], [15].

The core constraint of the ED model is the energy balance for each market time unit (MTU); therefore, the key input is the electricity demand time series.