



INSTITUT LUXEMBOURGEOIS
DE RÉGULATION

FLEXIBILITY NEEDS ASSESSMENT LUXEMBOURG

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17, rue du Fossé
Adresse postale
L-2922 Luxembourg

T +352 28 228 228
F +352 28 228 229
info@ilr.lu

www.ilr.lu

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1. EXECUTIVE SUMMARY

Article 19e(1) of Regulation (EU) 2019/943 on the internal market for electricity mandates that the regulatory authority or another authority or entity designated by the Member State shall adopt a report on the estimated flexibility needs for a period of at least the next 5 to 10 years at national level. In Luxembourg, the national regulatory authority Institut Luxembourgeois de Regulation (ILR) was assigned to issue this report.

On 25 July 2025, ACER published the Flexibility Needs Assessment Methodology, which serves as basis for the following study, as it defines the various types of flexibility needs and sets out the scope of the assessment. The methodology essentially involves two distinct processes. At the bidding zone level, the transmission system operators (TSOs) shall analyse their system flexibility and network needs. At the distribution network level, the distribution system operators (DSOs) are required to analyse their network flexibility needs. As network flexibility needs on distribution network level could affect system flexibility needs on transmission network level, the process foresees a fine-tuning process of the system flexibility needs results by considering the flexibility needs identified by DSOs.

As Germany and Luxembourg share a joint bidding zone which includes the whole German and Luxembourgish transmission grids, system flexibility needs were assessed in cooperation between the Luxembourgish TSO Creos and the four German TSOs Amprion, TenneT, TransnetBW und 50Hertz. Given the particular situation of Luxembourg, Creos provided the needed data as input from the Luxembourgish side for the assessment of the system flexibility needs.

In terms of temporal, spatial and voltage granularity of DSO input data, it was agreed between the national DSOs (Creos, Sudstroom, Ville de Diekirch, Ville d'Ettelbruck) and ILR that, for the first version of the flexibility needs assessment, the analysis would be limited to the current 65 kV (and future 110 kV) high voltage grid. Flexibility needs were analysed for the target years 2030 and 2035 in a quarter hour resolution. To allow for greater granularity, the study was carried out for six different regions in accordance with the DNDP25: Center, East, North, South-East, South-West and West.

The first iteration of the Luxembourg Flexibility Needs Assessment includes the results of the system flexibility needs determined for the joint DE/LU bidding zone – the interpretation of which can be found in the Flexibility Needs Assessment for Germany – and the results of the network flexibility needs analysis of the high-voltage grid performed by Creos. The analysis was based on four scenarios considering different developments of consumption and RES production for the target years 2030 and 2035, as well as a combined scenario based on the four scenarios to consider all possible developments of consumption and RES production. As input data, historical transformer residual load curves and RES production load curves were projected for both target years based on the Scenario Report 2040 from 2024 and the actual authorized/waitlisted capacity reservation requests from 2025. To assess the network flexibility needs, an analysis on the HV/MV transformers as well as power flow simulations of the high voltage grid were performed to identify congestions.

For both target years, flexibility needs could be identified in both upward and downward directions. These needs will rise sharply in 2035 compared with 2030, with downward needs due to excessive RES production outweighing upward needs. The regions Center and South-West stand out as extremes in terms of upward needs, whilst the North and West regions stand out as extremes in terms of downward needs.

In addition to the identified flexibility needs in terms of energy and the maximum instant power, the regional and national capacity are assessed, which results from the sum of the individual flexibility need peaks within a region. The regional/national capacity serves to determine what amount of installed capacity will be required to meet identified flexibility needs.

The identified energy and maximum instant power for each flexibility direction, as well as the necessary installed capacity in form of the regional capacity is given in Table 1 below for each region and each target year.

Table 1 Summary of identified flexibility needs

Region	2030						2035					
	Energy (MWh)		Power (MW)		Regional Capacity (MW)		Energy (MWh)		Power (MW)		Regional Capacity (MW)	
	Downward	Upward	Downward	Upward	Downward	Upward	Downward	Upward	Downward	Upward	Downward	Upward
Center	0	1053	0	6	0	9	0	5102	0	16	0	27
East	1114	49	23	3	23	3	141	652	28	8	28	9
North	1	112	1	5	1	6	41738	3609	124	14	126	14
South-East	0	1	0	1	0	1	191	902	24	7	24	12
South-West	0	1867	0	9	0	23	0	7089	0	25	0	42
West	40	192	6	3	6	3	29573	11	78	2	78	2

Guiding criteria, in the form of a statistical analysis of the results, characterise the properties of theoretical flexibility services that are needed in the different regions in order to avoid congestions. It highlights the extent to which the identified flexibility needs vary by region in terms of their frequency of activation, duration of activation and energy per activation. Moreover, the analysis of temporal distribution of these needs over daytimes, weekdays and seasons enables an understanding of when the demand for such services would be the highest. In principle, it can be summarised that flexibility needs correlate strongly with consumption patterns and weather conditions. Upward needs are the highest during the dark and cold seasons, as well as on weekdays when consumption is typically higher during midday and the evening. Downward needs emerge mainly during midday of springtime and summer, when PV production is the highest. The highest peaks can be observed when high PV and wind production coincide.

Furthermore, the report examines various aspects of market barriers that hinder the development of non-fossil flexibility solutions based on ACER's Recommendation No 01/2026 of 19 March 2026 on NRAs' reporting on barriers for non-fossil flexibility. On the one hand, the current lack of flexibility options can be explained by the fact that, historically, there have been no congestions. On the other hand, however, several barriers have been identified that are hindering the ramp-up of such flexibility solutions. The unique organisation of the Luxembourgish energy market – comprising a joint bidding zone with Germany, a joint load-frequency control area (LFC-area) with Amprion but separate scheduling areas – presents a particular challenge. For relevant market actors and assets, one of the main issues is the lack of access to all markets within the joint LU/DE bidding zone. Although access to the FCR and FRR has been enabled in recent years, access to markets such as for instantaneous reserve or black start energy remains restricted. In addition, the missing direct access to a NEMO hub prevents Luxembourg based market actors from full market access due to deadline restrictions between scheduling areas. Given the small size of Luxembourg, a lack of attractiveness for potential market actors as well as a lack of innovation and competition can be observed, as the market is quickly saturated. However, establishing a clear and comprehensible regulatory framework can help to promote the development of flexibility options.

The results of the flexibility needs assessment serve several purposes. Where possible, they should be used to initiate measures to eliminate the identified market barriers as far as possible. Furthermore, the findings from the flexibility studies of the distribution network should be considered in the next iteration of the network development plans. Finally, these findings can be used by relevant authorities as guidelines to define support measures for non-fossil flexibility.

2. INTRODUCTION

2.1. PURPOSE AND SCOPE OF THE NATIONAL REPORT

The ongoing transformation of the electricity sector is creating new challenges and opportunities for power systems across Europe. The rapid deployment of renewable energy sources, particularly wind and solar generation, is associated with a structural change of the electricity systems. While these technologies are essential for achieving decarbonisation objectives, their variable and weather-dependent nature introduce greater volatility and uncertainty into electricity systems.

At the same time, the electrification of transport, heating, industry and other sectors is expected to drive a significant increase in electricity demand. This growing demand is expected to place additional pressure on electricity networks, requiring substantial investments in transmission and distribution infrastructure. Peak demand periods and local network constraints are becoming increasingly important considerations for system planning and operation. In this context, flexibility is emerging as a critical resource for maintaining system reliability and ensuring the cost-effective integration of volatile loads and renewable production. Assessing future flexibility needs is essential to avoid potential gaps between the flexibility required by the electricity system and the resources expected to be available and to inform decision-making processes by policymakers, regulators, system operators and market participants, helping to ensure that appropriate market frameworks, infrastructure investments and flexibility solutions are developed in a timely manner.

In accordance with Regulation (EU) 2019/943 of 5 June 2019 on the internal market for electricity (hereinafter ‘Electricity Regulation’), this national flexibility needs assessment (hereinafter ‘FNA’) sets out to estimate the flexibility needed on the national distribution grid level (DSO network needs) as well as on the joint bidding zone level of Germany and Luxembourg (TSO system needs) for the target years 2030 and 2035 as agreed between the involved parties (see 2.3).

2.2. LEGAL AND REGULATORY CONTEXT

Article 19e(1) of the Electricity Regulation mandates that the regulatory authority or another authority or entity designated by a Member State shall adopt a report on the estimated flexibility needs for a period of at least the next 5 to 10 years at national level.

In Luxembourg, as no other authority or entity was designated by the Member State, the regulatory authority (hereinafter ‘ILR’) is charged with adopting the FNA report.

The ACER Decision No 05/2025 of 25 July 2025 on the type and format of data and the methodology for TSOs’ and DSOs’ flexibility needs analysis (hereafter “FNA Methodology”) defines the type and format of data that the TSOs and DSOs are to provide as well as the methodology for the analysis by the TSOs and DSOs of the flexibility needs in each Member state, including guiding criteria on how to assess the capability of the different sources of flexibility to cover the flexibility needs.

Article 1 of the FNA Methodology requires TSOs and DSOs to analyse the following flexibility needs:

- a) system flexibility needs, including:
 - i. RES integration needs pursuant to Article 8 of the FNA Methodology;
 - ii. ramping needs pursuant to Article 9 of the FNA Methodology;
 - iii. short-term flexibility needs pursuant to Article 10 of the FNA Methodology;
- b) distribution network needs pursuant to Article 11 of the FNA Methodology;
- c) transmission network needs pursuant to Article 12 of the Methodology.

The FNA Methodology states that the quantification of system flexibility needs is carried out at bidding zone level and includes needs associated with both the transmission and distribution network without localizing them.

Furthermore, the FNA Methodology provides the main data categories relevant for the evaluation of barriers for flexibility in the market and the contribution of digitalization as well as guiding criteria on how to assess the capability of the different sources of flexibility to cover the flexibility needs.

2.3. GOVERNANCE: DESIGNATED BODIES INVOLVED IN THE FNA REPORT

In accordance with Article 19e(1) of the Electricity Regulation, ILR is charged with adopting the Luxembourgish FNA report.

The framework for the analysis of the network needs was discussed and elaborated in cooperation with the TSO and the four national DSOs¹. In accordance with Article 4(1) of the Electricity Regulation, a national agreement between Creos and ILR was reached on the points listed by said article on 25 November 2025. ILR has decided, that the industrial grid of Sotel Réseau & Cie S.e.c.s. is not considered for the FNA, as they operate neither as a TSO nor as a DSO, and do not have an active connection to the Luxembourg distribution or transmission network.

All the analysis and simulations for the DSO network needs were performed by Creos (DSO)². The data that was agreed upon in the national agreement was supplied to ILR by Creos (DSO) at the end of May 2026.

As the system needs are to be analysed on the bidding zone level, which is common to Germany and Luxembourg (hereafter “DE/LU bidding zone”), the Luxembourgish TSO Creos Luxembourg S.A. (hereinafter ‘Creos (TSO)’) worked together with the German TSO Amprion GmbH (Amprion) to carry out the analysis in coordination with the other German TSOs of the DE/LU bidding zone (TenneT TSO GmbH, 50 Hertz Transmission GmbH and TransnetBW GmbH). Creos (TSO) therefore provided the needed data on the Luxembourgish transmission and distribution network to the German TSOs for the fine-tuning process.

ILR and Creos agreed to consider the TSO network needs, including all subarticles of Article 12, as out of scope for the first FNA iteration to be aligned with the scope applied by the German TSOs.

2.4. DEFINITIONS

According to the FNA methodology, a distinction is made between two main types of flexibility requirements:

- Network flexibility needs
- System flexibility needs

Network flexibility needs are assessed at DSO and TSO level. They reflect the flexibility needed to adjust for grid availability, by means of preventing or solving congestion or voltage issues. System flexibility needs are described by three indicators: RES integration, ramping and short-term. They reflect the flexibility needed to adjust to the variability of generation and consumption. Flexibility needs are categorised as upward needs when more injection into or less demand from the network is required, and as downward needs when less injection or more demand is required.

¹ Creos (DSO), Sudstroum, Ville d’Ettelbruck, Ville de Diekirch

² For the first iteration of the FNA the scope of the analysis is limited at the high voltage (65 kV/110 kV) level. No DSOs other than Creos own assets at these voltage levels, but their related consumption and generation was considered as bottom-up approach

For the purposes of this FNA, the following definitions as well as the definitions in Article 2 of the Electricity Directive, Article 2 of the Electricity Regulation, Article 2 of the ERAA methodology and Article 2 of the FNA Methodology shall apply:

- a) **“downward flexibility needs”** means the needs whose solution requires either decreasing injection into the network or increasing demand from the network;
- b) **“network flexibility needs”** means the flexibility needed to adjust for grid availability, by means of preventing or solving congestion or voltage issues, across relevant timeframe;
- c) **“ramping needs”** refer to needs associated with variations of the residual load assuming perfect forecast conditions;
- d) **“RES curtailment”** means limiting the generation or transmission of renewable power for system operational reasons or grid-capacity reasons;
- e) **“RES integration needs”** refers to the quantity of flexibility required for the Member State to achieve its annual RES integration target;
- f) **“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.
- g) **“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;
- h) **“short-term flexibility needs”** means needs associated with unexpected variations of the residual load such as forced outage of assets during the intra-day or balancing timeframe;
- i) **“system flexibility needs”** means the flexibility needed by the electricity system to adjust to the variability of generation and consumption patterns, across relevant market timeframe;
- j) **“upward flexibility needs”** means needs whose solution requires either increasing injection into the network or decreasing demand from the network.

3. METHODOLOGICAL ASPECTS

3.1. DATA SOURCES

3.1.1. DSO NETWORK NEEDS AND LIMITATIONS

For the purposes of the DSO network needs analysis, multiple data sources were used, with the input data being grouped according to the two main analysis parts of the assessment: Transformer Analysis and Line Analysis.

The transformer analysis refers to the flexibility needs identification at the high voltage/medium voltage (“HV/MV”) transformer station level. Table 2 provides an overview of the input data used by Creos. The main sources for the input data are historical load and generation profiles measured at the relevant transformer stations, as well as preexisting data from the “Scenario Report 2040” from 2024 (SR24) and the “Electricity Distribution Grid Network Development Plan 2025-2035” from 2025 (DNDP25) which are based on the assumptions of the national energy and climate plan from 2024 (NECP).

In order to estimate the additional future generation capacity installed in the relevant target years, the received capacity requests as of December 2025 are used, as these significantly exceed the targets from the NECP. It needs to be noted that the DNDP25 used the capacity requests received up to July 2025, which were significantly lower in absolute numbers compared to the capacity requests received up to December 2025.

Table 2: Transformer analysis - Input data

Input data	Source	Description
Historical transformer load curves	Asset level measurements	Historical 65/20 kV residual transformer load curves from the year 2024, provided with 15-minute time resolution
Regional demand scaling factors	SR24 (DNDP25)	The demand scaling factors are derived for each of the 6 DNDP25 regions from two demand scenarios of the Scenario Report 2040: “high estimate” and “low estimate”.
Representative normalized regional generation profiles	2024 Generation (meter data)	For each of the 6 DNDP25 regions, one representative normalized generation profile is determined per generation type: wind turbine, photovoltaic installation, and biogas. The profiles are normalized with respect to the maximum injected apparent power in the year 2024.
Additional future generation capacity	Capacity Requests (December 2025)	The additional future generation capacity is based on the authorized and waitlisted capacity requests for generation (December 2025).

The Line Analysis refers to the flexibility needs identification at the HV grid level (65 kV/110 kV). Table 3 provides an overview of the input data used by Creos and the respective sources. The main sources for the input data are the results from the transformer analysis as well as preexisting data from the DNDP25.

Table 3: Line Analysis - Input Data

Input data	Source	Description
Projected transformer load curves minus transformer flexibility needs	Transformer analysis (see Table 2)	Projected transformer load curves for the target years 2030 and 2035 minus the flexibility needs at transformer level (see subsection 3.3.1.2)
Creos HV grid	DNDP25	The Creos HV (65 kV and 110 kV) grid model in Powerfactory is used, including the reinforcements planned in the DNDP25.
Additional point loads and generation facilities	Capacity requests (DNDP25)	Additional demand point loads (e.g. datacentres) and generation facilities within the 65 kV (110 kV reinforced) grid that are not directly connected to a 65 kV (110 kV reinforced) / 20 kV Creos transformer in accordance with the modelling approach in the DNDP25.

A more detailed explanation on how the input data from Table 2 and Table 3 was derived and how it was used for the FNA is given in section 3.3.

As the model used to assess future flexibility needs is based on a number of assumptions and simplifications described in the following chapter. Depending on the circumstances, these can lead to an underestimation or overestimation of the need for flexibility identified. The results shown are intended to provide an estimate of how flexibility needs might evolve in line with different rates of growth in supply and demand. In addition to this, the results may vary significantly when compared with other weather years, due to the heavy reliance on renewable energy sources and the weather. They do not represent an exact forecast.

Moreover, the model does not take into account other technical limitations than the analysed HV lines and HV/MV transformers. Network constraints above or under these voltage levels, in particular at 220/380 kV transmission level (including 220 kV / 65 kV (110 kV) substations) are outside the scope of this assessment.

3.1.2. TSO SYSTEM NEEDS AND LIMITATIONS

This chapter gives a short summary on the limitations regarding TSO flexibility results due to the simplifications and assumptions made. For a detailed description and interpretation of the simulations performed on bidding zone level, please refer to the German FNA report.

The analyses for the TSO system needs are based on the results of the 2024 edition of the ERAA. A key methodological limitation is that this study does not consider the grid-side flexibility needs of transmission system operators. The analysis therefore focuses on flexibility needs from an energy economic perspective, without fully accounting for congestion management, grid restrictions, redispatch requirements of TSOs or other grid-operational constraints.

Further modelling simplifications in the ERAA relate to the ideal representation of must-run conditions, control power requirements, the assumption of full controllability of curtailable plants and other operational constraint.

3.2. TARGET YEARS CONSIDERED

All the analysis for this FNA were performed for the target years 2030 and 2035. These target years were chosen mainly for the following reasons:

- To be aligned with the target years used in the ERAA 2024.
- To be aligned with the target years chosen for the German FNA. This simplifies the fine-tuning process of the German Luxembourgish TSO system needs.
- The DNDP25 focuses on the reference years 2030 and 2035.
- The target year 2030 aligns with the last year for which the targets in the NECP are indicated³.

3.3. MODELLING APPROACH

3.3.1. DSO NETWORK NEEDS

For the DSO network needs, a bottom-up approach in two steps was pursued based on the granularities defined in the national agreement. The voltage granularity limits the analysis on the national 65 kV high voltage grid and on the HV/MV (65 kV (110 kV) / 20 kV) substations.

The grid reinforcements which are planned in the DNDP25 and expected to be commissioned before the respective target years (2030 and 2035) are included in the underlying grid assumptions. Consequently, the flexibility needs identified in this assessment represent residual network needs after considering the latest planned DSO grid development. As it is planned to increase the voltage level of the 65 kV grid in the Northern region to 110 kV, parts of said grid will be assumed to be reinforced in the year 2030.

To achieve a higher resolution, the country was split into 6 regions according to the spatial granularity defined in the national agreement and already used in the Scenario Report:

- Center: Includes the capital city, hence a high consumption tendency
- North: Rural region with a high amount of RES (mainly wind) installed
- East: Rural region with a moderate amount of RES installed
- South-East: High density of residential and industrial customers
- South-West: High density of residential and industrial customers
- West: Rural region

For the FNA, as mentioned in section 3.1.1, the analysis was split into two consecutive parts: the transformer analysis and then the line analysis.

3.3.1.1. TRANSFORMER ANALYSIS

As described in section 3.1, the historical transformer load curves as well as production profiles from 2024 served as the main inputs for the transformer analysis. The reason for using data from 2024 was that the relevant data from 2025 was not yet fully available when work on this FNA analysis was started at the end of 2025. In order to generate estimated load curves for the two target years, two separate approaches were used for generation and for demand.

On the demand side, two scaling factors were derived for each of the 6 DNDP25 regions, one based on the “high estimate” and one based on the “low estimate” demand scenario from the SR24. A description of the derivation methodology can be found in chapter 3.4 of the DNDP25. The regional demand scaling factors are only applied to all positive transformer load curve values, which correspond to the net demand at transformer level (assumption A2). In other words, only the demand-dominated periods are scaled, while the generation-dominated periods are not affected. The output of this processing step is a set of transformer load curves where only the demand is scaled. It is important to note that the historical transformer load

³ Some assumptions in the NECP go beyond the horizon of 2035

curves represent residual load curves (net view of demand and generation), i.e. the positive values of the load curve (demand dominated) include the generation of existing installations (commissioned before the beginning of 2025).

On the generation side, the normalized regional profiles are derived by selecting a “state of the art” installation per generation type (photovoltaic, wind turbines, biogas, ...) within each region, whereby a “state of the art” installation is defined as an installation that has a commissioning date after 2020, is one of the largest regional installations of the respective generation type and did not experience any major technical problems during the year 2024. After the installation was selected, the historical generation profile from the year 2024 is extracted and normalized (scaled down) using the authorized apparent power of the installation. After this step, a normalized regional generation profile is derived for each generation type. In order to determine the generation capacity that will be installed in the respective target years in addition to the currently installed capacity, the existing capacity requests (as of December 2025) are used. Depending on the scenario, it is assumed that 100 % (respectively 80 %) of the reserved capacity will be connected to the network by 2030 and additionally, 100 % (respectively 70 %) of the waitlisted capacity by 2035.

The projected transformer load curves for the target years are then equal to the sum of the historical transformer load curve with the scaled demand portion and the sum of products of the normalized regional generation profile and the additional generation capacity:

$$P_{trans\ project}(t) = P_{cons\ scaled}(t) + \sum_i P_{gen\ add,i} * n_{gen\ profile,i}(t)$$

$P_{trans\ project}(t)$:	The projected transformer load curve
$P_{cons\ scaled}(t)$:	The scaled demand curve (demand-dominated periods)
$P_{gen\ add}$:	The additional generation capacity on top of the existing installations (per generation type)
$n_{gen\ profile}(t)$:	The normalized regional generation profile (per generation type)
i :	Generation type

With the projected transformer load curves at hand, the projected station load curves are determined via the sum of the projected transformer load curves being part of the respective station (assumption A7). The projected load curve of the station is then compared to its capacity, and a flexibility need is identified if the load curve exceeds the capacity. Flexibility was only investigated by means to prevent or solve congestions but not in relation to voltage issues.

It needs to be noted that demand and generation are connected to the grid in a different way in regards of security of supply:

- Demand is connected “N-1 safe” in order to guarantee the power supply even in case of an outage. As a result, the positive portion of the projected station load curve is compared to the N-1 capacity of the station. The N-1 capacity of the station is the sum of all transformer capacities minus the capacity of the transformer with the largest capacity.
- Generation is connected “N-0 safe”. Consequently, the negative portion of the projected station load curve is compared to the N-0 capacity of the station. The N-0 capacity of the station is the sum of all the transformer capacities.

Due to the chosen approach to generate the estimated load curves, upward flexibility needs always refer to N-1 demand exceedances, while downward flexibility needs always refer to N-0 generation exceedances. An overall share of 100 % is assumed for the ‘downward flexibility needs pertaining to RES generation

curtailment’ as in general, all downward flexibility needs are most likely due to high generation combined with low demand. Moreover, Luxembourg does not have a significant share of non-RES generation (only 3,5 % of generation in 2025).

The transformer capacity in this context corresponds to the apparent power capacity including active cooling, in other words 100 % capacity of the transformer (assumption A3)⁴. This leads to the conclusion that flexibility needs (exceedances) are expressed in MVA. To comply with the FNA requirements, a simple and transparent one-to-one conversion from apparent power flexibility needs (MVA) to active power needs (MW) is applied (assumption A5).

3.3.1.2. LINE ANALYSIS

The HV/MV transformer results derived from the transformer analysis are used as input for the model of the upstream HV grid. In order to avoid the double counting of flexibility needs between the transformer and line analysis, the transformer flexibility needs are subtracted from the projected transformer (and station) load curves before introducing the latter into the line analysis. These load curves are referred to as “projected and capped transformer load curves” in the following. In other words, the hypothesis is made that first the station level flexibility needs will have to be met, before tackling the upstream regional interconnected HV lines (“bottom-up” approach). The station level flexibility needs can only be met at the lower voltage level of the specific station, thereby justifying the approach chosen. The flexibility needs of the HV lines, on the other hand, may be solved via a multitude of different station flexibility combinations due to the interconnection of the whole regional 65 kV line network.

Based on the input data, consisting of the projected and capped 15-minute transformer load curves, the HV grid model, as well as additional point loads and generation facilities (connected directly to the HV grid), load flow simulations are carried out for the target years based on 15-minute time-series input data covering the entire year. At each time step, the loading of every line and cable within the grid is calculated. Flexibility needs in the N-0 case arise when one or more grid elements exceed their thermal capacity, corresponding to a loading level greater than 100 %. Due to the large number of possible N-1 combinations, — since a different asset could fail every 15 minutes of the year, which is highly unlikely — the line analysis was limited to the N-0 case.

After completing the annual analysis, the flexibility needs of an entire region are determined. This is done by first identifying all lines and cables that experience an overload at least once during the year and then extracting and aggregating the corresponding overload magnitudes, which results in the regional line flexibility needs.

The identified regional line flexibility needs are mapped to upward and downward flexibility needs depending on the needs direction of each quarter hour of the transformer flexibility needs curve within the respective region. If the aggregated transformer load is positive at the moment when an overload occurs on the regional lines and cables, the flexibility need is classified as an upward flexibility need. Conversely, if the aggregated transformer load is negative at the moment of the overload, the identified flexibility need is classified as a downward flexibility need.

Since the line analysis was performed for the N-0 case only, but consumption is connected under N-1 secure conditions and N-1 upward needs are already considered at transformer station level, the line analysis identified downward flexibility needs only.

⁴ The capacities in question are detailed explicitly in the DNDP25

Finally, the regional line and transformer flexibility needs are aggregated to identify the total regional flexibility needs. The national flexibility needs are derived by the combining the individual regional flexibility needs.

3.4. ASSUMPTIONS

Table 4 presents the main modelling assumptions. The objective is to clearly identify which hypotheses influence the results and how they are applied in the computation.

Table 4: Modelling Assumptions

ID	Assumption	Application
A1	Peak scaling factors are applied to timeseries values	The demand scaling factors from the SR24, for each of the FNA selected demand growth scenarios, were intended for peak projections. In the FNA, these factors are applied to an entire timeseries dataset. This provides the correct order of magnitude for projected peak loading situations, but it distorts the historical load curve for medium to lower loadings periods. These periods are not the main focus of the analysis, as flexibility needs are driven by peak injection and demand loadings.
A2	Historical 2024 demand is scaled using regional scaling factors	The demand projection is carried out via a regional multiplication/scaling factor to project the 2024 demand to the target years. The scaling is applied only to the positive values of the historical 2024 transformer residual load curves, which correspond to the net demand at transformer level. Negative values, corresponding to historical net injection, are not impacted (scaled) by the demand scaling factor.
A3	100 % of the transformer capacity with active cooling is considered available	The transformer capacities used in the FNA correspond to the total transformer capacity with active cooling. In other words, 100 % of the transformer capacity is considered available in the simulation. In real operation, grid operations would not necessarily anticipate until 100 % loading before acting (for example by activating flexibility). In the FNA simulation, the flexibility activation is assumed to be immediately available once the 100 % capacity threshold is exceeded.
A4	Target-year generation-capacity assumptions based on the capacity requests up to December 2025	Let X be the percentage of reserved generation capacity and Y the percentage of waitlisted generation capacity assumed to be commissioned. For 2030, the considered additional generation capacity is X % of authorized capacity requests. For 2035, the considered additional generation capacity is X % of authorized capacity requests + Y % of waitlisted capacity requests.
A5	Apparent power flexibility needs	Overloads in terms of apparent power of the grid assets are interpreted as flexibility needs. Furthermore, to comply with ACER's FNA Methodology, active power flexibility needs are required to be reported. Consequently, a one-to-one conversion from apparent to active power is assumed (section 11.1 details the justification of this assumption)
A6	No MV network reconfigurations	The analysis uses the normal operating configuration of the MV network. Possible MV reconfigurations, such as reallocating a feeder load from Station A to Station B even if the feeder is technically connected to both stations, are not considered. No deviation from the normal operating configuration is modelled.
A7	The transformer analysis is performed from a station-level perspective	At HV/MV station level, the analysis uses the net aggregated loading over all transformers from the station. This assumes that the load can be perfectly distributed across the transformers of a station in order to represent the station-level view.

A8	Future generation is modelled using historical normalized generation profiles multiplied by future connection capacity	Future generation time series are generated by multiplying normalized historical 2024 generation profiles by the future generation capacity derived from capacity requests.
A9	One representative regional generation profile	For each region and generation technology, one historical, state-of-the-art 2024 generation profile is selected and used as representative profile.
A10	Only power-related constraints are identified	The FNA focuses on power-related constraints. Voltage constraints are not identified in the analysis.
A11	Share of downward flexibility need pertaining to RES generation curtailment	The ‘share of downward flexibility needs pertaining to RES generation curtailment’ is interpreted as an indicator quantifying the share of downward flexibility needs originating from RES overgeneration (in other words, the downward flexibility which could be solved via RES curtailment). An overall share of 100 % RES generation curtailment for all downward flexibility needs is reported as an overall assumption, in accordance with the national agreement.
A12	Expected contractual means to access flexibility	As agreed between ILR and the DSOs, each high-level flexibility mechanism is indicated for each final network need. Namely, local services, flexible connection agreements, grid tariffs, and RES curtailment (for downward flexibility needs)

4. SCENARIOS AND ASSUMPTIONS DESCRIPTION

4.1. SCENARIOS USED TO ASSESS TSO SYSTEM NEEDS

As explained in subsection 3.1.2, the analyses for the TSO system needs are based on the results of the ERAA 2024. The analyses are focused on the target years 2030 and 2035, as well as on selected weather scenarios (WS14, WS25 and WS28), and do not cover all the years and weather scenarios included in the ERAA. These scenarios are used as a representative selection from the full range of possible weather patterns, as they form the basis of the ERAA's Economic Viability Assessment (EVA).

4.2. SCENARIOS USED TO ASSESS DSO NETWORK NEEDS

To allow for a better understanding of how flexibility needs will evolve depending on different developments of demand or generation, four base scenarios with a corresponding demand and generation estimation were analysed. As the FNA methodology requires for only one final result, a fifth scenario was generated based on the scenarios 1 to 4 by applying the weights as shown in Table 5. These weights reflect the probability of the future evolution of consumption and generation according to the DSO' experience. The main results provided in chapter 5.2.1 stem from this fifth "Combined Scenario".

Table 5 Definition of parameters and scenarios

Scenario	Demand growth	Additional generation capacity	2030 Weight	2035 Weight
S1	Low estimate	High generation estimate	10 %	5 %
S2	Low estimate	Moderate–high generation estimate	40 %	45 %
S3	High estimate	High generation estimate	10 %	5 %
S4	High estimate	Moderate–high generation estimate	40 %	45 %

The demand growth estimates describe the evolution of the national electricity consumption and originates from the Scenario Report 2024 as shown in Figure 1. To explore the worst-case scenario, there was no existent flexibility considered in the evolution of the national demand.

The generation estimates represent the evolution of national renewable energy production. They are derived from Creos' list of authorized and waitlisted capacity request of RES power plants. Capacity requests are waitlisted when no sufficient grid capacity is available and can get set to authorized when the necessary capacity will be available through network reinforcement. In this context, the high generation estimate reflects the situation in which 100 % of authorized capacity is going to be connected to the grid in 2030 and 100 % of authorized and waitlisted capacity in 2035. The moderate-high generation estimate means that 80 % of authorized installations are going to be connected in 2035 and 70 % of authorized and waitlisted installations in 2035. The difference to the 100 % of capacity demands are considered not to be connected before 2035.

To put these percentages into context: the total of approved and waitlisted capacity requests of RES installations at the MV and HV levels as of December 2025 were as follows:

- Reserved: 1595 MVA
- Waitlisted: 1224 MVA

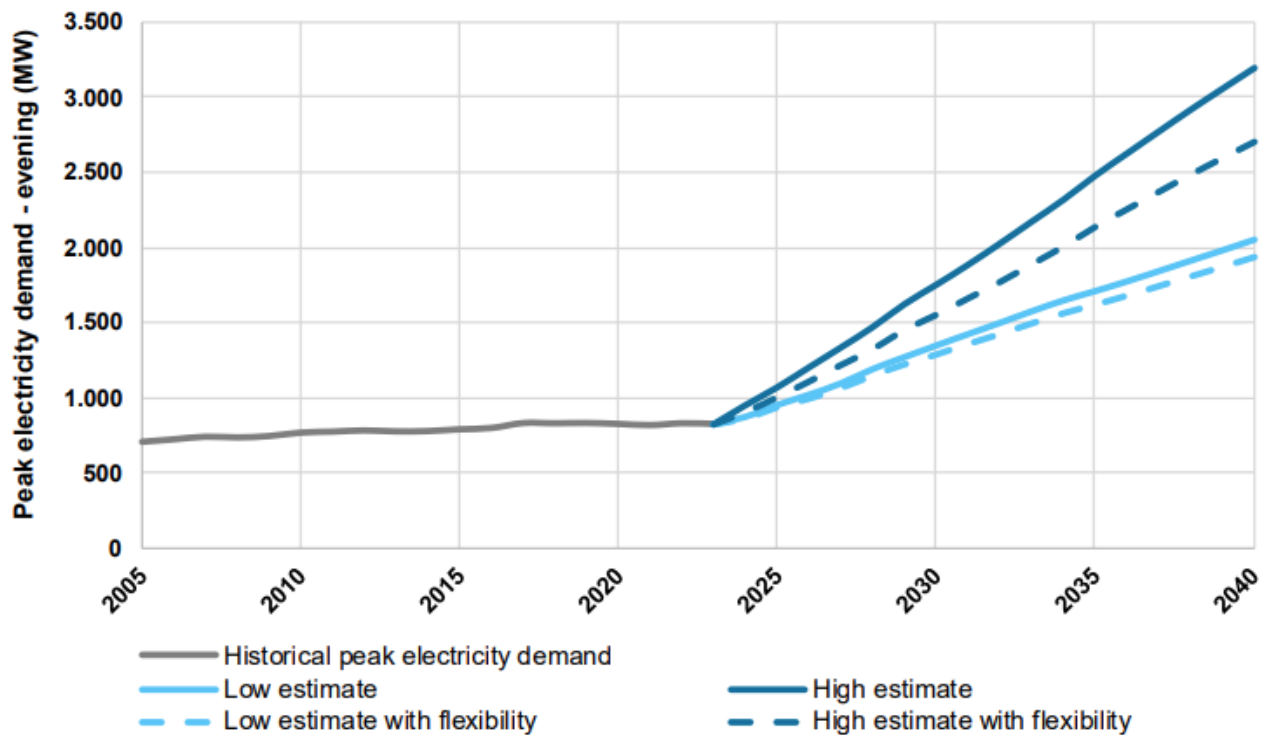


Figure 1 Projected electricity demand during the evening peak of the Scenario Report 2024

4.3. TARGET FOR RES INTEGRATION

To determine the RES integration targets at bidding zone level, the RES development targets from the NECPs of Germany and Luxembourg were used. The aggregated target values result in a volatile renewable energy target of 540 TWh for 2030 and approximately 637 TWh for 2035. These target figures cover only the volatile technologies: PV, onshore wind, offshore wind and run-of-river hydropower. Since no values were available for 2035, these were extrapolated. The results are shown in Figure 2.

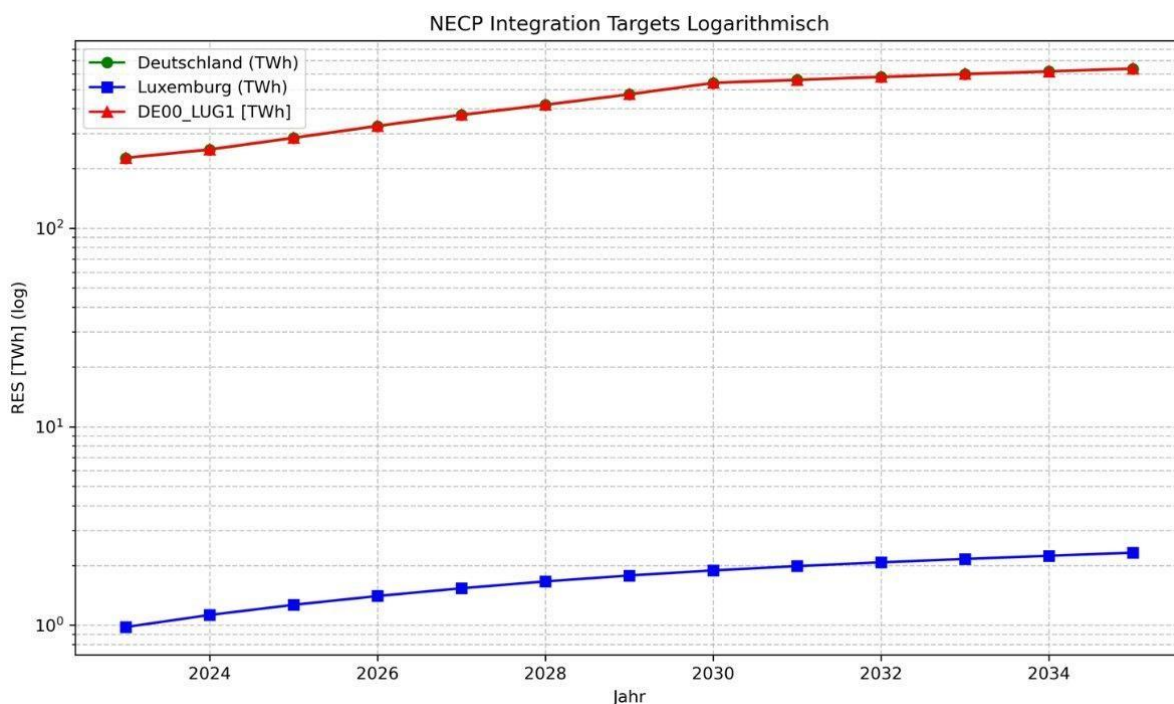


Figure 2 Formulation of the NECP target for the German-Luxembourg bidding zone

Figure 2 above does not take account of the updated NECP LU target values of 2024 but is based on the previous version of 2020:

2020 LU NECP version:

- PV 2035 = 1112 GWh
- Wind 2035 = 674 GWh
- Run-of-river = 100 GWh

2024 LU NECP version:

- PV 2035 = 1112 GWh
- Wind 2035 = 1043 GWh
- Run-of-River = 103 GWh

The volatile renewable energy target in the updated NECP version is 372 GWh higher, which corresponds to a 19,7 % increase. However, in relation to the total volume of the joint DE/LU RES target of 540 TWh in 2030, this only represents a negligible error of 0,07 %.

4.4. PORTFOLIO OF FLEXIBILITY RESOURCES AVAILABLE

4.4.1. DEMAND RESPONSE

4.4.1.1. MOBILITY SECTOR

The transportation sector is shifting toward electrification, driven by technological progress, environmental concerns, and regulatory changes. Electromobility, including electric cars, buses, and trucks, is set to play a key role in sustainable and energy-efficient transportation by 2040. As of June 2026, 65.317 BEVs (excluding non-plugin hybrid vehicles (NPHEV), which are not relevant for the grid) were registered in Luxembourg, amounting to 10,5 % of all registered vehicles.⁵ The share of BEVs in new vehicle registrations is significantly higher with 30,6 % in June 2026⁶. According to the NECP target for 2030, fully electric and hybrid vehicles are expected to dominate new car registrations, with a 49 % electrification rate for passenger cars. Figure 3, taken from the SR24, shows the past and estimated future total cumulated registrations of fully electric and plug-in hybrid cars and vans per year.

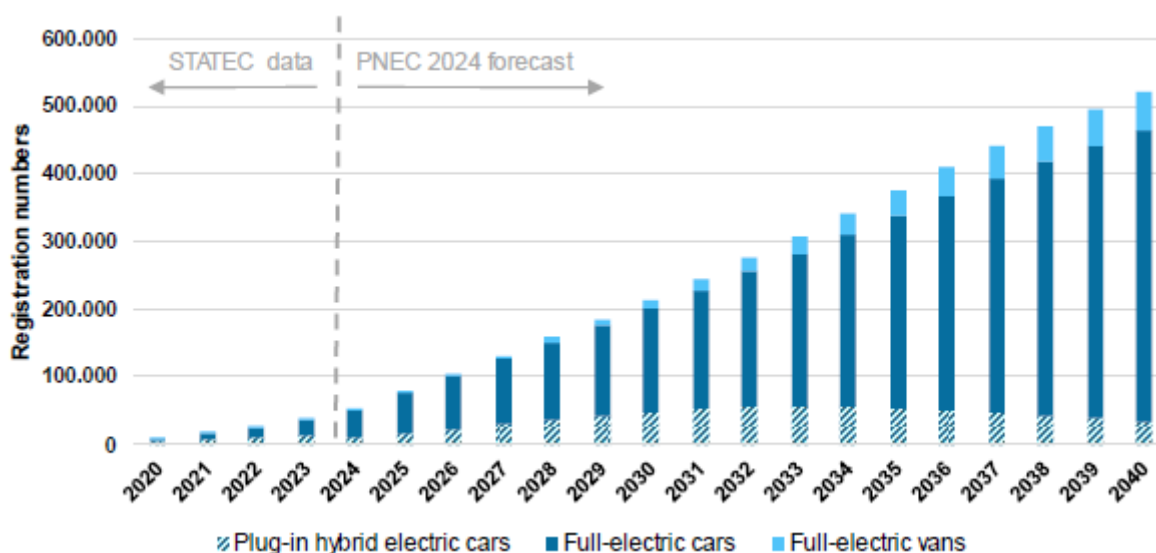


Figure 3: Past and future total cumulated registrations of fully electric and plug-in hybrid cars and vans per year

⁵ [Statec website – total registrations](#)

⁶ [Statec website – new registrations](#)

The electro-mobility sector offers significant potential for flexibility. Although point loads can be very high, they are flexible, meaning that in many use cases they can be waitlisted or flattened, as the vehicle often remains on standby for an extended period of time.

Currently, electric vehicle charger with a nominal power of 7 kW or above must be connected to a relay of the smart meter, offering the possibility for load shedding in critical situations. When the DSOs send a signal, such chargers must reduce their load by at least 30 % for devices with an output of 7 kW or more, by at least 50 % for devices with an output of 11 kW or more, and by at least 75 % for devices with an output of 22 kW or more.

In accordance with Articles 15(3) and 15(4) of the European Union's Alternative Fuels Infrastructure Regulation (AFIR), ILR published a study⁷ assessing the potential contribution of EV charging to the flexibility of the energy system. According to this study, the connected charging power could peak at around 1.700 MW and the discharge power at around 370 MW. In 2030, with an incentivised plug-in behaviour, up to 878 MW of EV charging demand could be shifted from the times of day with the highest EV charging demand to other times of the day. It should be noted that these figures are based on unrealistic assumptions in order to determine the theoretical upper limits of what would be possible. Consequently, the potential for flexibility that could be utilised through the mobility sector will be significantly lower.

4.4.1.2. HEATING

The SR24 projects that the power needs in the tertiary sector due to electric heating will contribute significantly to the evening and midday load peaks of the grid, with between 50 MW and 150 MW for 2035 and between 110 MW and 200 MW for 2040. Air-conditioning systems and cooling processes (refrigeration, cooled warehouses, temperature regulation for server rooms, and process cooling) offer significant potential for demand-side flexibility.

In the residential sector, heating technologies have undergone significant transformation in recent years. According to the SR24, there were 10.230 heat pumps installed in Luxembourg in 2020, expected to grow to nearly 97.500 units in 2040. Flexibility from heat pumps can be utilized in various ways. However, to effectively harness this flexibility, an intelligent control system must be properly implemented to avoid compromising user comfort.

When using heating for flexibility purposes, it is also important to consider rebound effects as for example heat pumps consumption will increase after providing a flexibility service to recover for the deferred head demand.

4.4.1.3. INDUSTRY

The FlexBeAn study, which stands for 'Flexibility Potential and User Behaviour Analysis' suggests a flexibility potential from demand response in the industrial sector ranging from 15,2 MW to 27,4 MW in 2030 and 30,5 MW to 54,8 MW in 2035. The report also states that the flexibility is not necessarily available for a long duration which can limit its use cases.

4.4.2. RENEWABLE GENERATION/CURTAILMENT

According to the national connection requirements, all renewable production units with a nominal power higher than 800 W must be controllable by the DSO. As such, curtailment of generation by the DSO is possible for all production units and is already used in a limited amount. In 2025, such measures were used for a total of 11 times, resulting in a volume of 74,3 MWh of curtailed renewable electricity.

⁷ [Contribution of Electric Vehicle Charge points to the Flexibility of the Luxembourgish Energy System and the Absorption of Renewable Energy](#)

As shown in subsection 5.3.1, curtailment generation during peak hours in combination with the further expansion of renewable generation capacity yields the highest marginal benefits of all flexibility measures required to meet the RES integration targets. Therefore, renewable flexibility resources can offer significant flexibility potential in the form of curtailment.

As shown in Figure 4, both wind and PV have increased significantly in installed capacity over the last 20 years. Between 2020 and 2025, there has been a very strong growth in PV, resulting in the addition of approximately 600 MW of installed power, bringing the total installed capacity to 746 MW. Wind power continues to grow steadily and reached approximately 231 MW of installed power in 2025.

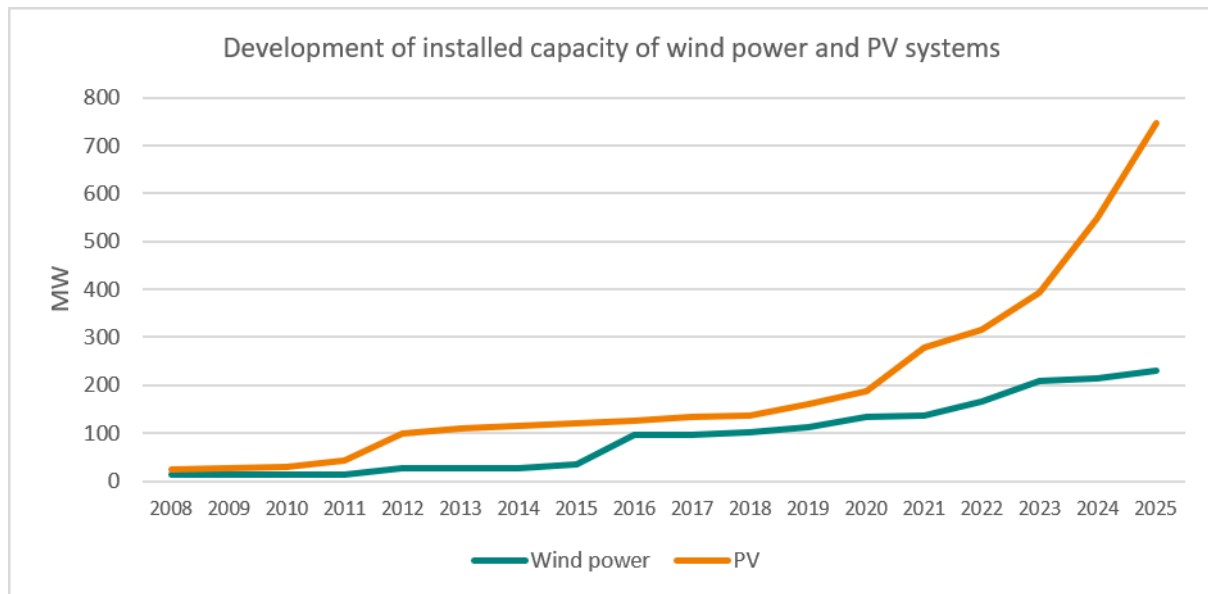


Figure 4 Development of installed capacity of wind power and PV systems in Luxembourg

4.4.3. BATTERIES

Behind-the-meter battery storage systems

In recent years, the Luxembourgish government has promoted the installation of behind-the meter (BTM) battery storage systems in combination with PV. As such, 9.655 batteries with a nominal power of less than 30 kW were installed in December of 2025, accounting for a capacity of 88.850 kWh.

These storage systems primarily benefit clients operating their PV systems in self-consumption mode, helping them optimize their electricity bills. Currently, there are no major incentives to operate the battery in a grid-friendly manner, which leads to them being charged as soon as the PV system generates power. During the summer months, this results in the batteries being fully charged before the midday peak, failing to alleviate peak PV loads on the grid.

Currently, it is not planned for the grid operator to directly control these installations. However, through an adapted tariff structure, local flexibility markets and aggregators these numerous small battery storage systems can become both valuable and essential in the future energy system.

Front-of-the-meter storage systems

Front-of-the-meter storage systems are highly suited for providing system-oriented flexibility in the form of ancillary services, due to their rapid response times, scalability, and versatility allowing them to efficiently absorb and release electricity.

A market-oriented approach to battery deployment is particularly attractive for operators of non-controllable generation installations, like wind farms and large-scale photovoltaic systems, as it allows them to optimize

the economic value of their energy production. These systems store energy during periods of low market demand or reduced profitability and release it back into the grid when market conditions are more favourable.

Unfortunately, no large-scale batteries currently exist in Luxembourg. However, as the DSOs have received multiple capacity reservation requests for such projects, it can be assumed that large-scale battery storage will be available in the coming years. 50 % of the requested BESS capacity would have to be connected at the VHV level and would therefore be unable to cover the flexibility needs of the HV grid examined in the FNA report.

4.4.4. INTERCONNECTION

Within the common Germany/Luxembourg bidding zone, Luxembourg is connected through multiple high voltage lines to the transmission grid of the German TSO Amprion. Creos and Amprion have a contract which ensures the provision of system services from Amprion to Creos for a net-import of Luxembourg up to 980 MVA.

In addition, the Luxembourgish transmission grid is connected to the Belgian transmission grid via a phase shifting transformer (PST) operated by the Belgian TSO Elia. There is no capacity commercialisation on this border, the PST is being used for real-time operation and for ensuring some level of security of supply for Luxembourg.

4.4.5. SHARING

The national framework for energy communities enables grid customers to organise themselves into energy communities at local or national level. Incentives such as the exemption from network tariffs or electricity taxes for shared energy at local level provide financial incentives to shift consumption to the hours when PV production takes place. This could result in an indirect flexibility, as, by its very nature, local consumption can be met by local production, thereby reducing power flows over the grid.

5. RESULTS OF FLEXIBILITY NEEDS ASSESSMENT

5.1. SYSTEM-WIDE FLEXIBILITY NEEDS

The following chapter summarises the findings regarding the flexibility needs identified on bidding zone level. More detailed information on this analysis can be found in the German FNA report.

5.1.1. RES INTEGRATION NEEDS

The following chapter discusses the RES integration needs according to Article 8 of the FNA Methodology. RES integration needs describe the necessary flexibility need to fulfil national NECP targets regarding RES production. The RES integration flexibility need compares the ERAA RES capacity remaining after curtailment due to market oversupply and, after additional DSO grid congestions (fine-tuning, see 11.1), against the NECP target. The resulting flexibility need corresponds to the gap between the NECP target volume and the remaining ERAA RES volume after these curtailments.

5.1.1.1. DISTRIBUTION, DURATION AND TEMPORAL STRUCTURE OF THE CURTAILMENT

For the year 2030, with a renewable energy feed-in of around 540 TWh, energy volumes between 8 and 11 TWh/y will be curtailed, depending on the WS. In 2035, the curtailment will increase to approximately 30 TWh/y. The amount of energy curtailed will thus increase by a factor of approximately three between 2030 and 2035. At the same time, the peak curtailment levels are rising whilst a maximum of 100 – 121 GW will be curtailed in 2030, the peak curtailment levels in 2035 will exceed 180 GW. These very high peaks indicate situations in which the available renewable energy feed-in significantly exceeds the demand during short periods of time.

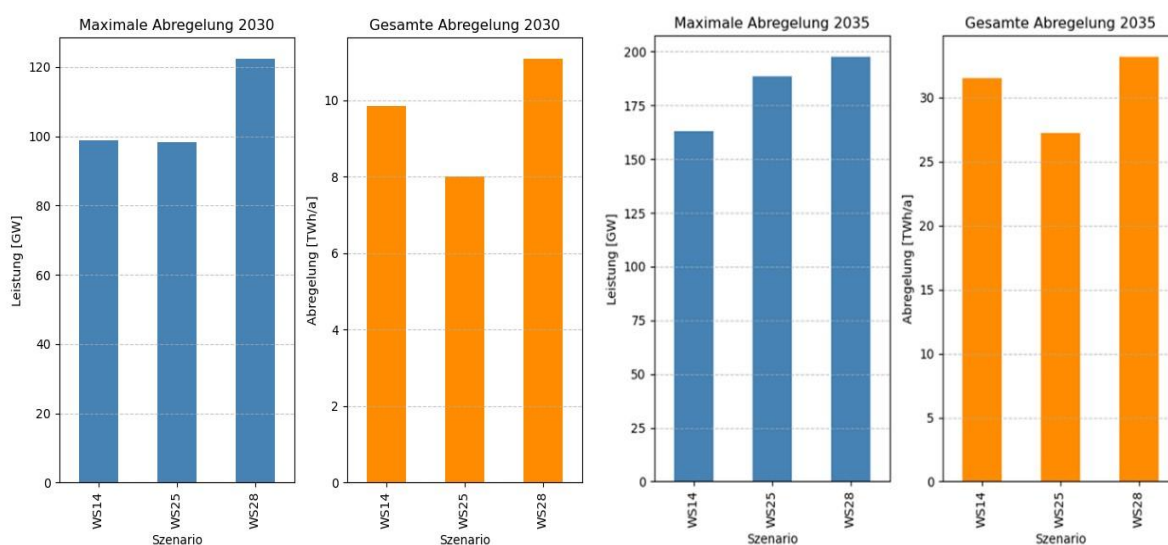


Figure 5 Curtailment of renewable energy in ERAA24 for the weather scenarios used in the FNA for the target years 2030 and 2035

In most cases, curtailment lasts for less than 10 hours at a time. The amount of energy curtailed per event is rather small compared to the range of energy volumes identified. The time interval between events is predominantly less than 250 hours (10 to 11 days), with most curtailments occurring at intervals of no more than 48 hours. It is noteworthy that these fundamental characteristics (duration, energy volumes and intervals between events) do not change significantly between 2030 and 2035, even though the total volume of curtailment increases.

Figure 6 illustrates how the curtailment of renewable energy occurs as a function of the time of day and the calendar day. For the target year 2030, the analysis shows that curtailment events predominantly occur

during the daytime hours. The seasonal peak is the period from late March to July. This suggests a correlation with PV generation and explains the cause of the curtailment durations of significantly less than a day (24 hours). Such curtailments during the day occur in a staggered pattern over consecutive days.

In addition, there are also individual days with curtailment throughout the day. These days can be interpreted as a combination of high wind feed-in and comparatively low demand. In such situations, demand is insufficient to fully absorb the available renewable energy production throughout the entire day. Particularly high curtailment levels are observed during those hours and days when high PV and wind generation coincide with low demand. In these cases, the feed-in peaks from the two volatile technologies accumulate, leading to the highest curtailment peaks. The analysis also shows that curtailment occurs significantly less frequently in winter than in summer.

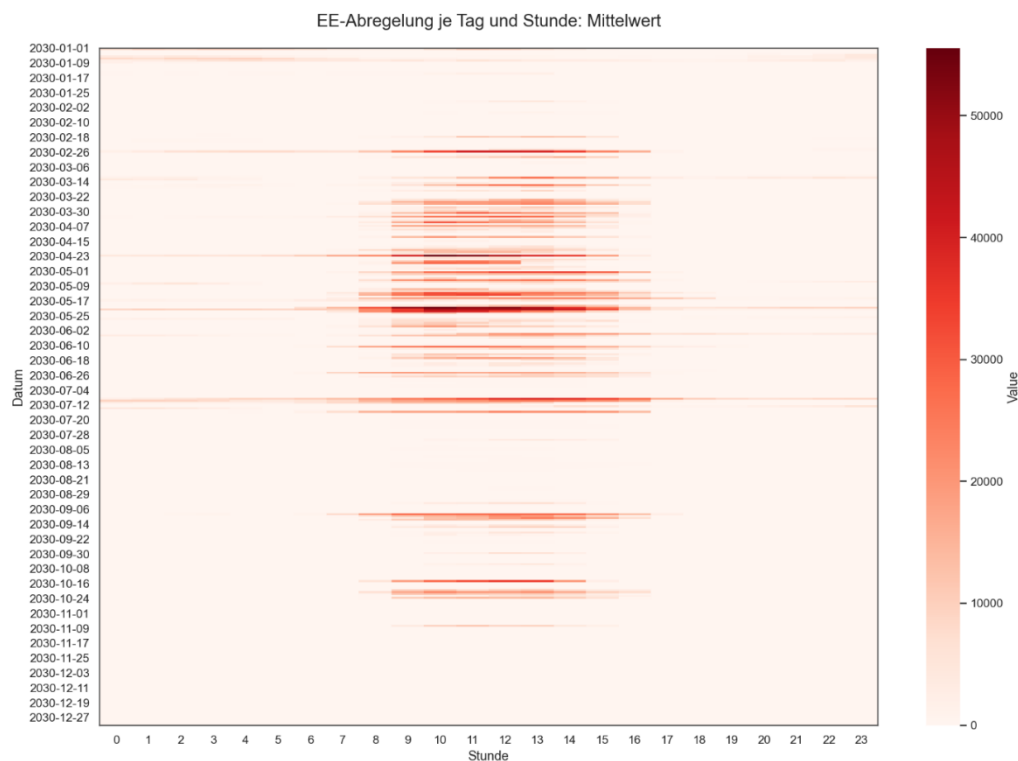


Figure 6 Occurrence of curtailment as a function of day and year. Average for 2030

For the target year 2035, a similar pattern emerges. Compared to 2030, however, both the frequency of curtailment events and their intensity increase. The number of days with all-day curtailment rises, and curtailment also occurs more frequently during the winter months.

In order to understand the cause of curtailment, an analysis was carried out to assess the correlations between renewable energy curtailment and system conditions such as wind and PV feed-in as well as demand. The gradient in Table 6 indicates the average change in curtailment (in MWh) when the respective influencing factor changes by one unit (1 MWh). The results show that the simultaneous injection of wind and PV has not the highest correlation. It becomes stronger when demand is taken into account alongside wind and PV. The negative sign reflects the fact that negative residual loads lead to high curtailment levels.

Table 6 Correlation between wind, PV and load with curtailment in the 2030 weather year.

	Gradient	R ²
PV	0,11	0,01
Wind	0,14	0,05
Load	-0,16	0,3
Wind+PV	0,41	0,22
Load-Wind-PV	-0,618	0,419

Overall, it can be concluded that neither wind nor PV feed-in alone can substantially explain curtailment. Curtailment occurs when there is a high level of both wind and PV feed-in at the same time and demand is not high enough to absorb this generation.

5.1.1.2. Uncovered integration needs

In the following chapter, a comparison of modelled renewable energy feed-in with NECP targets is performed to identify any uncovered integration need for renewable energy. For the target year 2030, following the market-based curtailment of the ERAA, feed-in levels for volatile renewable energy sources range from 532 to 556 TWh, depending on the weather scenario (see Table 7). Compared with the target value of 540 TWh derived from the NECP, this allows the uncovered RES integration target to be determined. This target is negative in two of the three scenarios considered, thus indicating that the RES target for 2030 has been met. Only in the WS14 scenario does an uncovered RES integration target of around 8 TWh arise.

However, for the target year 2035 the uncovered RES integration target shows high negative values for all scenarios, meaning that there is consistently a significant over-achievement in the range of 150 TWh to 188 TWh of the RES target. Consequently, there is no need for additional RES integration regardless of the weather scenario.

Across the three weather scenarios, the signed integration gap has a median of -7,07 TWh and a mean of approximately -5,0 TWh. Therefore, no structural additional RES-integration need is identified for 2030, although WS14 shows a gap of 7,97 TWh."

Table 7 Uncovered renewable energy integration target for system needs in the target year 2030 and 2035

	2030			2035		
	WS14	WS25	WS28	WS14	WS25	WS28
Feed-in of volatile renewable energy (ground-mounted PV, wind, run-of-river) [TWh]	532,34	547,38	556,23	786,91	811,20	824,92
NECP target for volatile renewable energy [TWh]	540,31	540,31	540,31	637,17	637,17	637,17
RES curtailment [TWh]	9,83	8,01	11,07	31,52	27,22	33,18
RES integration target [TWh]	1,87	15,08	26,99	181,26	201,25	220,93
Uncovered RES integration target [TWh]	7,97	0 (-7,07)	0 (-15,92)	0 (-150)	0 (-174)	0 (-188)

5.1.1.3. CHARACTERISATION OF RESIDUAL LOAD TIME SERIES

The analysis of residual load serves to quantify the remaining requirement for flexible generation from the perspective of the overall system. It thus helps to describe, at any given point in time, whether and to what extent flexible controllable generation and consumption resources are required (positive residual load) or whether there is a surplus of renewable energy (negative residual load).

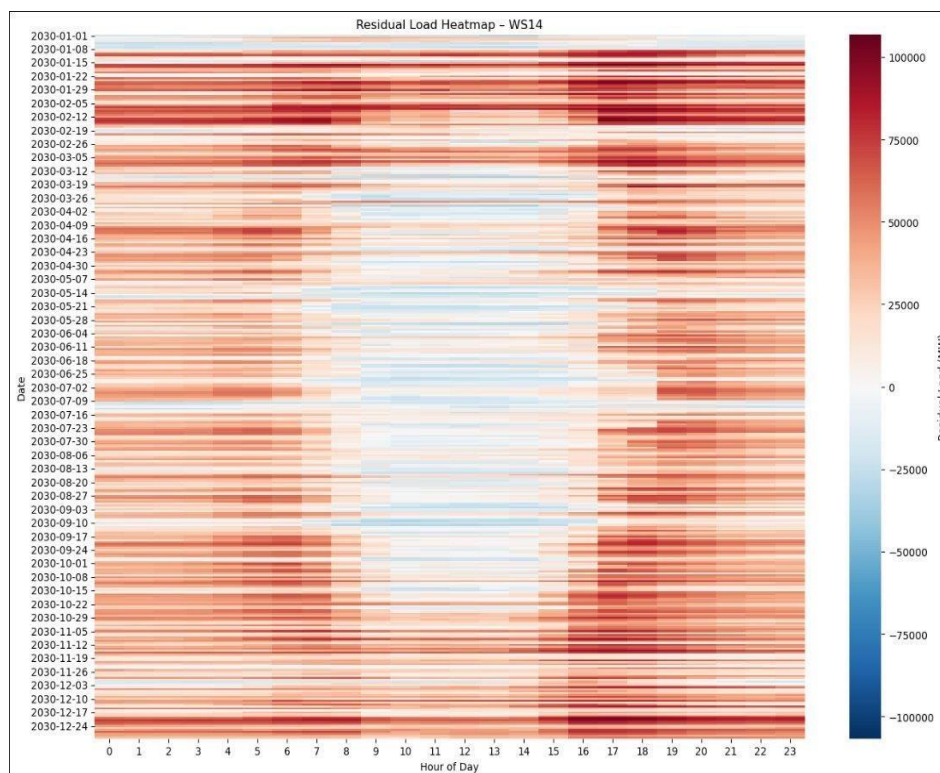


Figure 7 Residual load, based on the example of WS 14 in the target year 2030

For the target year 2030, the analysis of residual load for the WS14 reveals a characteristic pattern of renewable energy surplus and conventional generation demand: Negative residual loads – that is, situations where there is a renewable energy surplus – occur primarily during the day between February and November. During these months and hours, high feed-in from photovoltaic systems regularly results in renewable energy generation exceeding demand. Furthermore, entire days with negative residual load are observed throughout the year, indicating periods with particularly high wind power feed-in coupled with low demand. These days mark situations of continuous renewable energy surplus, in which curtailment is unavoidable without sufficient flexibility or export capacity.

By contrast, positive residual loads without sufficient import capacity indicate a need for flexible generation capacity or demand response. They typically occur between February and November during the hours in the evening, night and early morning hours when PV generation is absent and the contribution from wind energy is insufficient to fully cover the load. During the winter months from November to February, the residual load is often positive throughout the day, as solar feed-in is low and the load may be higher particularly due to heating requirements. Particularly high residual loads are observed between December and February; they frequently occur over extended periods, which can be interpreted as typical ‘Dunkelflaute’ events. From a system perspective, these phases are particularly critical, as a high level of guaranteed power must be maintained over extended periods, whilst at the same time only minimal contributions from wind and PV are available.

Figure 8 evaluates the temporal component of the residual load. The analysis reveals that the variations in hourly values within a single day are the greatest, amounting to around 14 GW. This illustrates that the

residual load is primarily characterised by intraday fluctuations, particularly the transition between day and night hours. The variation in daily averages within a week is around 12 GW and therefore only slightly lower than the hourly variations. It primarily reflects differences between weekdays and weekends, as well as the correlation with changing wind conditions. Although the seasonal variations across the months are the lowest at around 8 GW, they are by no means negligible. It reflects longer-term patterns such as winter peak loads and seasonal variations in renewable energy generation. The same trends are evident for the year 2035. However, the deviations in residual load are higher than those for 2030 due to the higher share of renewable energy.

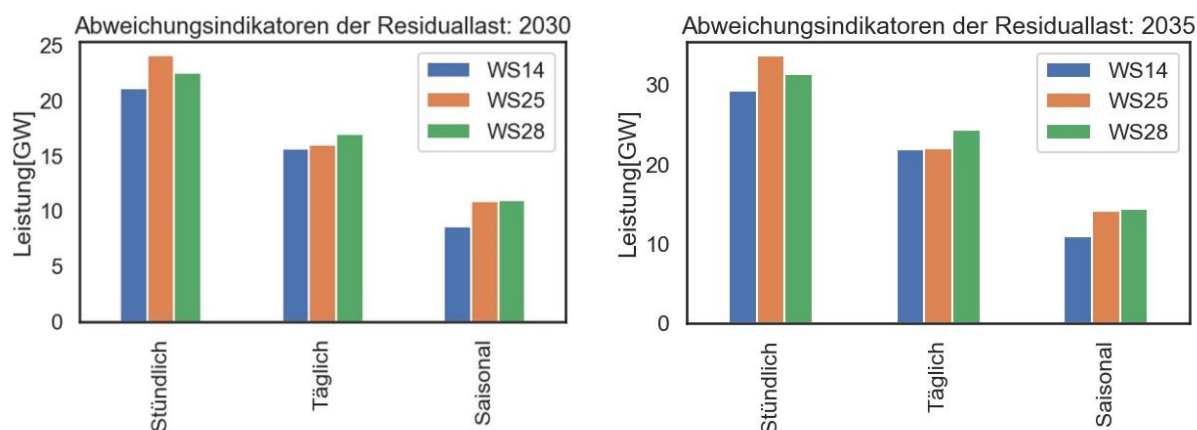


Figure 8 Indicators of deviation from the residual load in 2030 and 2035

5.1.2. RAMPING NEEDS

Ramping needs describe the needed flexibility to cover variations of the residual load on an hourly basis. To assess the ramping needs, in accordance with Article 9 of the FNA methodology, the change in residual load over time is determined at hourly intervals for each target year and each WS. These identified ramping needs must be met by flexibility within the system at every hour. In accordance with the FNA methodology, a residual load ramp is defined as the change in residual load over time from one market time unit to the next. The maximum values of the residual load ramps calculated for the target years under consideration are shown in Table 8 below.

Table 8 Maximum residual load ramps in the positive and negative directions for three weather scenarios in the target years 2030 and 2035

WS	2030		2035	
	Maximum residual load ramp [MW/h]			
	Positive direction	Negative direction	Positive direction	Negative direction
WS14	56.213	-39.744	78.092	-56.570
WS25	59.310	-43.328	81.856	-61.540
WS28	59.032	-45.225	81.472	-62.818
Average	58.185	-42.766	80.473	-60.309

The average hourly maximum residual load ramps in the target year 2030 are approximately 58,2 GW/h in positive direction and -42,8 GW/h in the negative direction. For the target year 2035 the average increases to approximately 80,5 GW/h and -60,3 GW/h respectively.

Figure 9 shows the probability distribution of residual load ramps in the target year 2030 for the three weather scenarios under consideration. For 2035, the distribution is similar.

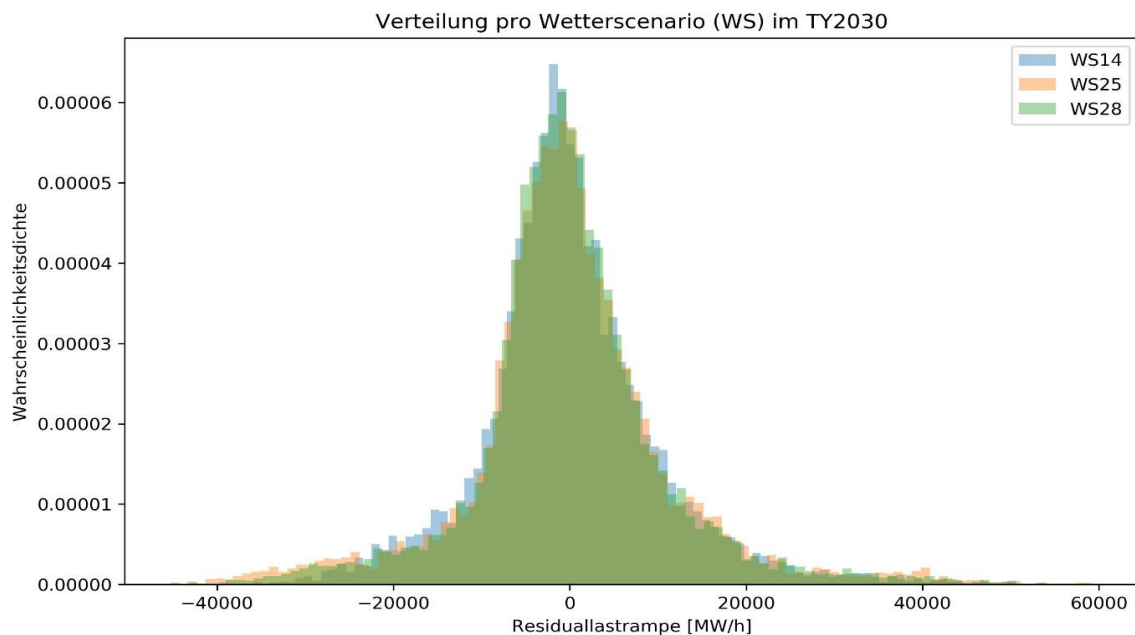


Figure 9 Probability density distribution of residual load ramps for the three weather scenarios (WS) in 2030

Furthermore, the temporal distribution of residual load ramps is discussed in the following. Figure 10 shows the statistical temporal distribution of the residual load ramps over the course of the day for the target year 2030. The distribution for 2035 shows a similar pattern but with higher/lower maximum and minimum values.

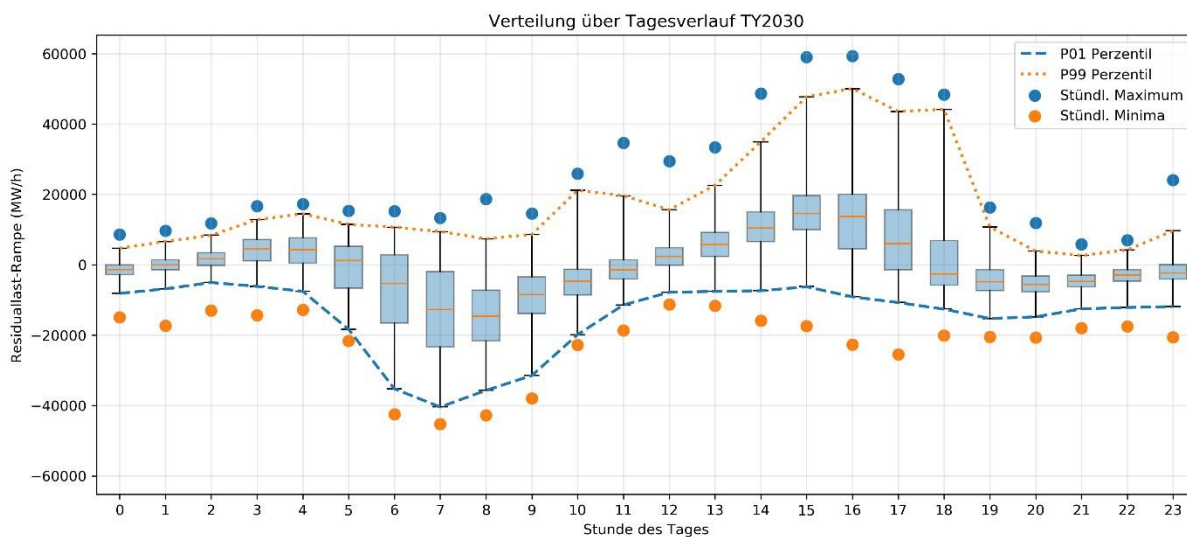


Figure 10 Distribution of residual load ramps throughout the day for the target year 2030

The largest residual load ramps occur both in the morning and in the early evening and are largely determined by PV feed-in. The maximum residual load ramp in the positive direction occurs at 4 pm due to the rapid reduction in PV output, combined with a sharp rise in load. At the same time, the box plot shows that there is a very wide variation in the possible residual load ramps during these hours of the day. The largest negative residual load ramps are observed in the morning hours.

An analysis of the distribution of ramps across the days of the week is shown in Figure 11 for the year 2030.

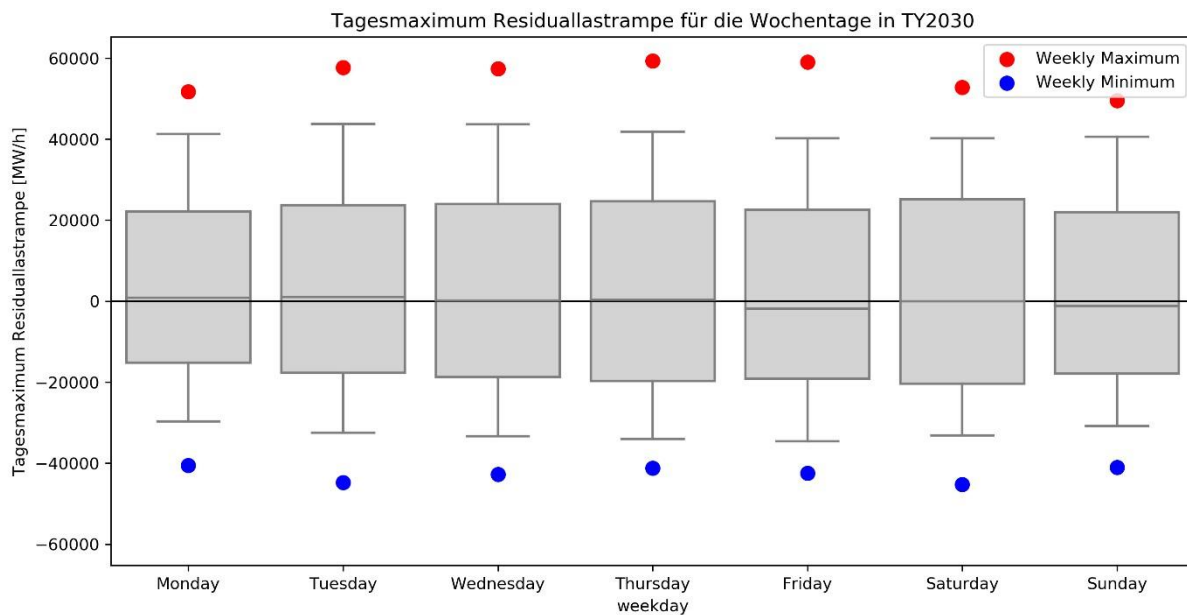


Figure 11 Distribution of ramps across the days of the week in the target year 2030

The seasonality of the residual load ramps is illustrated in Figure 12, based on the monthly maximum ramps in both directions for the two target years 2030. The highest positive ramps occur in February and November for both target years. In the summer months, by contrast, the maximum residual load ramps are less pronounced. One reason for this is that renewable energy feed-in, following market-based curtailment, was used to determine the residual load.

For both target years, the distribution over the year is similar. However, the ramps in 2035 are significantly larger than in 2030 due to the increased installed renewable energy capacities.

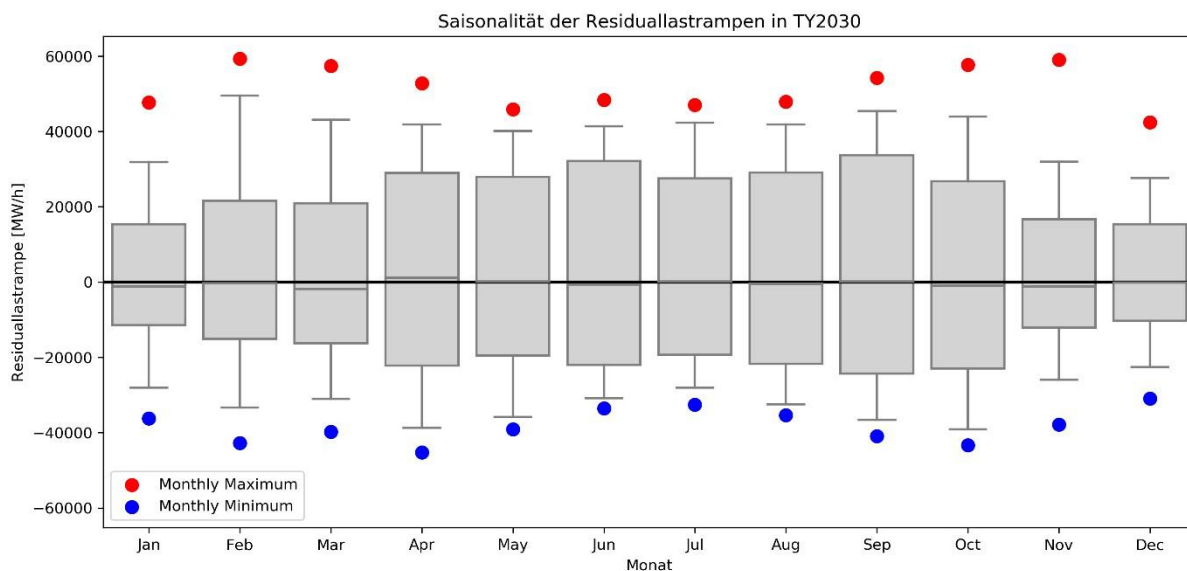


Figure 12 Seasonal variation in residual load ramps in 2030

Furthermore, the correlation between residual load ramps and system conditions was analysed. The results of this analysis showed that changes in PV feed-in correlate strongly with residual load ramps. Changes in wind feed-in, by contrast, show only a comparatively weak correlation with the temporal changes in residual load. A similar picture regarding correlations with system conditions is also evident for the target year 2035.

5.1.2.1. UNCOVERED RAMPING NEEDS

Table 9 shows the results regarding remaining ramp margins for each of the three weather scenarios. The number of hours summarises the frequency of occurrence of uncovered ramps. Furthermore, the minimum margins of the remaining ramping capacity in the system are shown, broken down by weather scenario.

Table 9 Frequency of uncovered ramping needs in the target year 2030

Target year	Weather scenario	Positive direction		Negative direction	
		Frequency of uncovered ramping needs	Minimum remaining margin (MW/h)	Frequency of uncovered ramping needs	Minimum remaining margin (MW/h)
2030	WS14	0	2427	0	-36
	WS25	0	1266	0	-21
	WS28	0	4061	0	-22
2035	WS14	0	2079	0	-358
	WS25	1	0	0	-2122
	WS28	0	5851	0	-1785

By 2030, residual load ramps can be met in every hour of the year across all WS. This shows that all hourly ramps can be covered by the available controllable generation units in both positive and negative directions, indicating that there is no need for additional flexible generation units. In 2035, an uncovered ramping need is identified for WS25 during a single hour, when the system is experiencing a loss of load. Consequently, this can be attributed to a resource adequacy problem and therefore does not indicate a need for flexibility. The adequacy problem has already been analysed in detail in the ERAA24 report⁸ and is therefore not discussed further in this FNA.

5.1.3. SHORT-TERM FLEXIBILITY NEEDS

Short term flexibility needs describe the necessary flexibility to cover unexpected differences between the forecast and the actual residual load. By using historical forecast deviations, an hourly time series is produced that represents short-term flexibility needs for each year and each weather scenario in accordance with Article 10 of the FNA methodology. A positive value indicates a lower actual residual load than expected; consequently, demand must be increased and/or generation reduced. On the contrary, a negative value indicates lower renewable energy generation and/or higher electricity demand, that must be tackled by ramping up further generation or by load reduction.

The upward flexibility needs (shown in blue in the graph below) for 2030 average around 20 GW across the three WS considered, whilst the downward flexibility needs (shown in purple in the graph below) average around 17 GW. By 2035, these needs will rise to almost 29 GW and 23 GW respectively, due to the rise in installed renewable energy capacity and consumer demand by then, which leads to greater forecast deviations in both the positive and negative directions.

⁸ <https://www.entsoe.eu/eraa/2024/reports&results/>

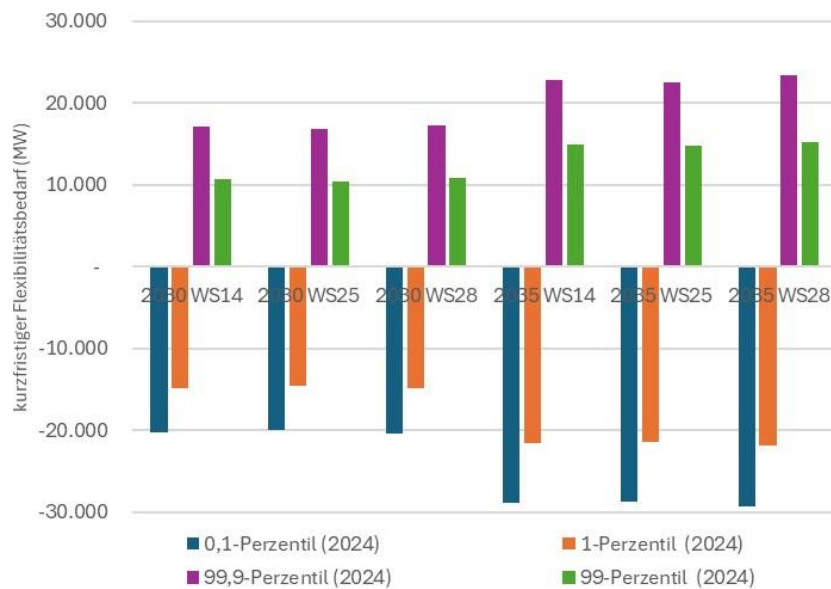


Figure 13 The short-term flexibility needs for the target years and weather scenarios analysed.

5.1.3.1. UNCOVERED SHORT-TERM FLEXIBILITY NEEDS

The hourly uncovered short-term flexibility needs are calculated as the difference between the short-term flexibility needs and the available remaining flexibility options for each target year and weather scenario.

In general, it can be stated that there are no uncovered downward needs in any of the target years and WS considered. This statement is based on the theoretical assumption that wind and PV generation can be curtailed sufficiently at any time should electricity generation exceed demand. Furthermore, it can be said that there is an uncovered upward need mainly during periods of high load and low renewable energy generation. The characteristics of events in which a forecast deviation cannot be covered are shown in Figure 14, based on the 0,1 percentile of each hour.

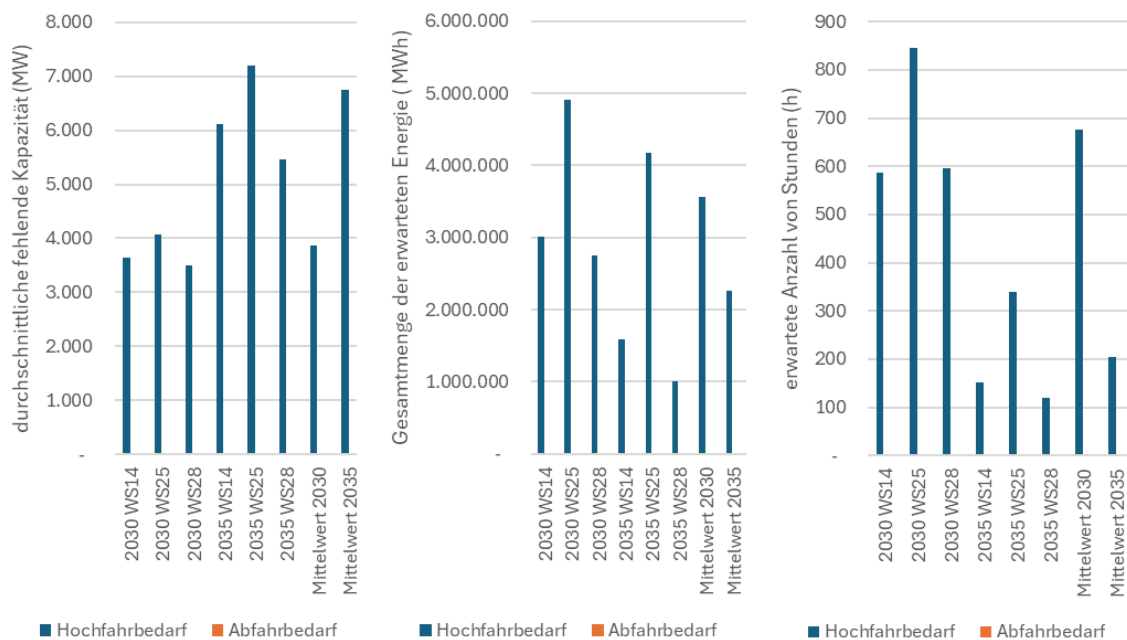


Figure 14 Average capacity required, the absolute amount of energy and the number of hours during which the start-up demand (based on the 0,1-percentile) cannot be met in 2030 and 2035.

In both cases, even the 3 GW of balancing energy specified and reserved under the ERAA is insufficient to meet the expected upward needs. Capacity shortfalls occur more frequently in 2030 than in 2035. However, in 2035, larger amounts of capacity are lacking per event: 7 GW compared with around 4 GW in 2030. This situation is reflected in the energy volumes and the number of hours, which decrease in 2035. Uncovered short-term flexibility need frequently occurs during hours when there is little or no PV feed-in, i.e. in the mornings, evenings and at night.

5.2. NETWORK FLEXIBILITY NEEDS

5.2.1. DSO NETWORK NEEDS

In the following chapter, the identified flexibility needs for the Combined Scenario will be discussed in detail, based on the times series, guiding criteria and indicators provided by Creos in accordance with Article 11 of the FNA methodology. Displayed data as well as more detailed view on individual regions and the other four scenarios can be found in chapter 11.2.

It should also be noted once again that, when comparing the identified flexibility needs in the following chapter, it is important to bear in mind that the downward needs were examined for the N-0 case and the upward needs for transformers for the N-1 case. These are therefore not associated with the same type of operational risk and impact. Downward flexibility needs are analysed based on a N-0 approach and are therefore needed at the very moment to prevent grid congestions, while upwards needs only occur when the network is in an active N-1 condition. In this report, flexibility needs always refer to measures to prevent or resolve congestions, as agreed between ILR and Creos for the scope of the first FNA.

The analysis revealed that downward as well as upward flexibility needs could be identified for both target years in the HV grid and that these are increasing between 2030 and 2035. The identified needs correspond to the sum of flexibility needs of transformers and lines of the HV grid per region and are visualised based on a 15 min resolution for each day and each target year in the following figures.

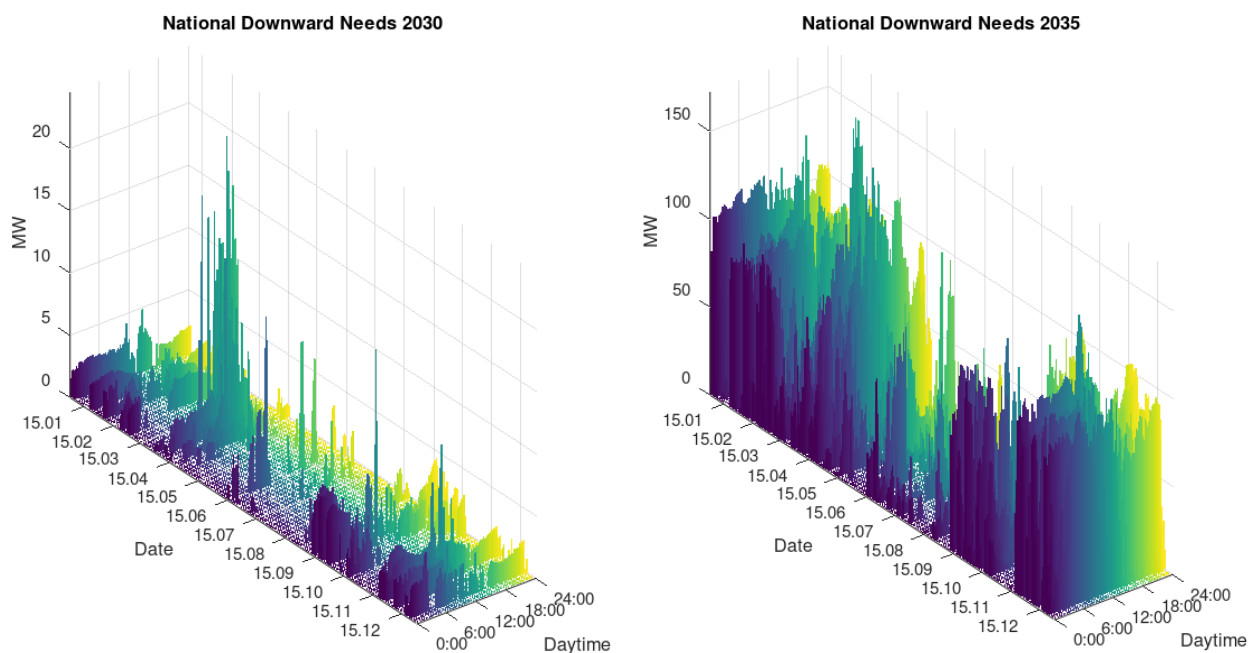


Figure 15 Temporal distribution of national flexibility downward needs in 2030 and 2035

The temporal distribution in Figure 15 shows that downward flexibility needs can occur at any time of a day and can often persist over 24 hours. The highest peak was identified during springtime due to a “Hellbrise⁹” phenomenon encountered in the reference climate year 2024. Overall, lower downward flexibility needs can be observed during the summer months. This is not necessarily always true, but it is the case for this particular analysis, as only a single climatic year was studied with low wind production during these months.

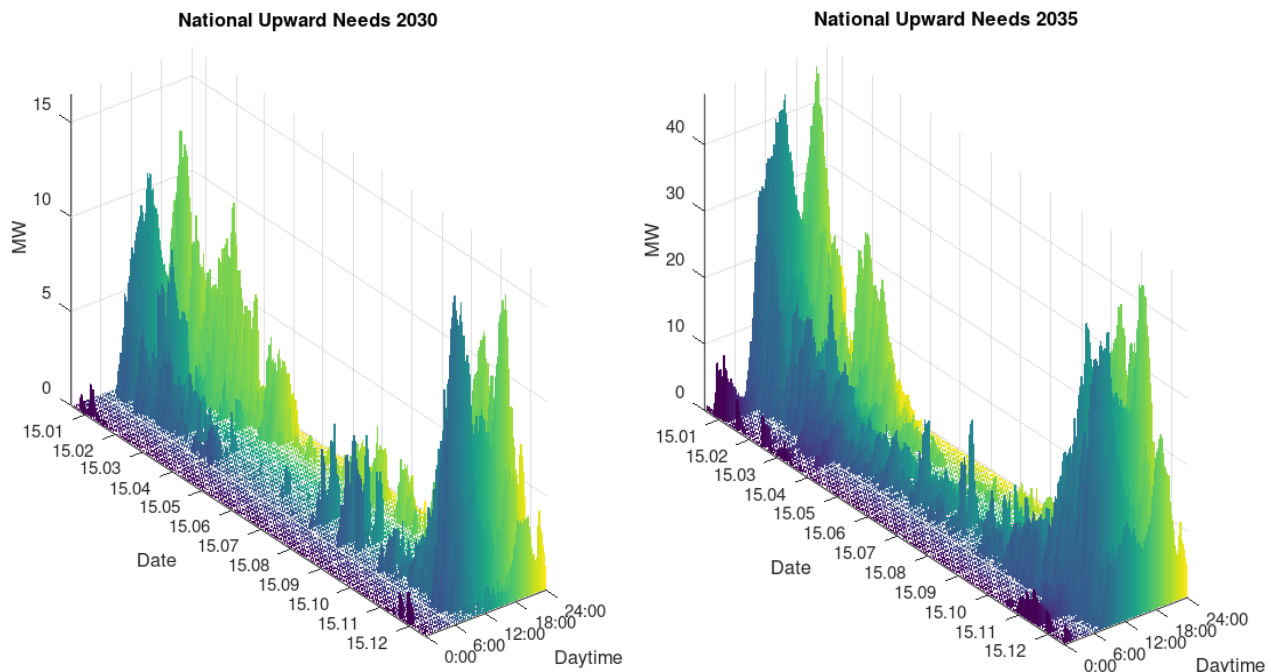


Figure 16 Temporal distribution of national flexibility upward needs in 2030 and 2035

Given the nature of upwards flexibility needs, they arise primarily during the traditional peak consumption periods, namely around midday and in the evenings during winter as shown on Figure 16. Only a few quarter hour periods of upward needs were identified during nighttime.

As Figure 15 and Figure 16 suggest, the highest energy demand emerges from downward flexibility needs in 2035 with a total amount of 71.640,7 MWh. For the same year, upward flexibility amounts to just 17.361,4 MWh on national level. However, both figures represent a massive relative increase compared to the target year of 2030 with 1.153,5 MWh respectively 3.271,9 MWh. In absolute terms, however, the identified flexibility energy volumes are relatively small and manageable. The maximum value of 71,6 GWh in downward direction for 2035 corresponds to roughly 4 % of Luxembourg’s total energy production in 2025 (1.826 GWh).

While in 2030, the volume for upward flexibility need is higher than for the downward direction, this changes in 2035. In the future, the overall volume of flexibility needs will most likely be dominated primarily by downward needs due to high RES generation.

The statistical interpretation of time series of identified national flexibility needs is performed in form of a box chart in Figure 17. It is noticeable, that for each case the 1st (25 % of data falls below and 75 % of data lies above), 2nd (red line, median value where 50 % of data falls below and 50 % of data lies above) and 3rd (75 % of data falls below and 25 % of data lies above) quartiles (lower, middle and upper edge of the box) are close to each other and in general situated in the lower range of encountered flexibility needs. Further, the maximum value (whiskers) is in each case quite far from the 3rd quartile, which indicates that high peaks

⁹ describes a power grid condition with high wind and solar generation paired with low electricity demand. It is the exact opposite of a “Dunkelflaute”

based on the 15 min resolution are quite rare and most of the identified needs are situated close in a lower range.

It is worth noting that, regarding downward needs, the peak value of 172,5 MW in 2035 is almost 7 times higher than in 2030 with 24,5 MW. In 2035, 75 % of identified downward needs on a 15 min basis are lower than 44,2 MW and 50 % of them are lower than 12,3 MW. Regarding upwards flexibility, the peak value of 16,5 MW in 2030 has almost tripled to 47,6 MW by 2035. In 2035, 75 % of upward needs are lower than 7,4 MW and 50 % of them are lower than 2,8 MW.

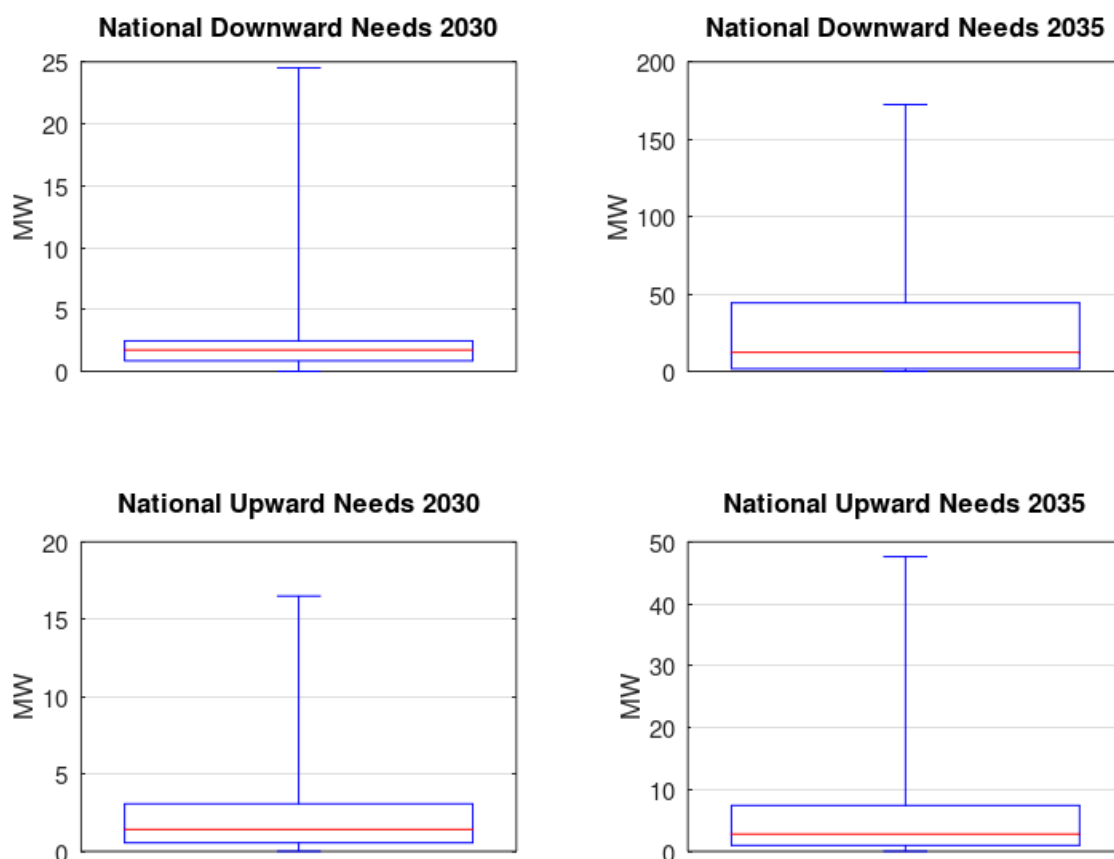


Figure 17 Statistical interpretation of flexibility needs on national level

Figure 18 and Figure 19 provide the breakdown over time of the identified national flexibility needs for both target years and for each region. In order to be able to represent both directions over time in one figure, downwards needs are represented as negative values, while upwards needs are positive values. The regional breakdown quickly reveals the regions where significant congestions will occur, highlighting the corresponding need for flexibility. Whilst in 2030 it is primarily the East region that will determine the national demand for downward flexibility, by 2035 this will be the North and West regions, with a maximum demand of up to 110 MW. In terms of upward flexibility, the situation remains similar in both target years. These are primarily the regions with high consumption – Centre and South-West – that show a higher demand throughout the year, with the peak value doubling from 2030 to 2035.

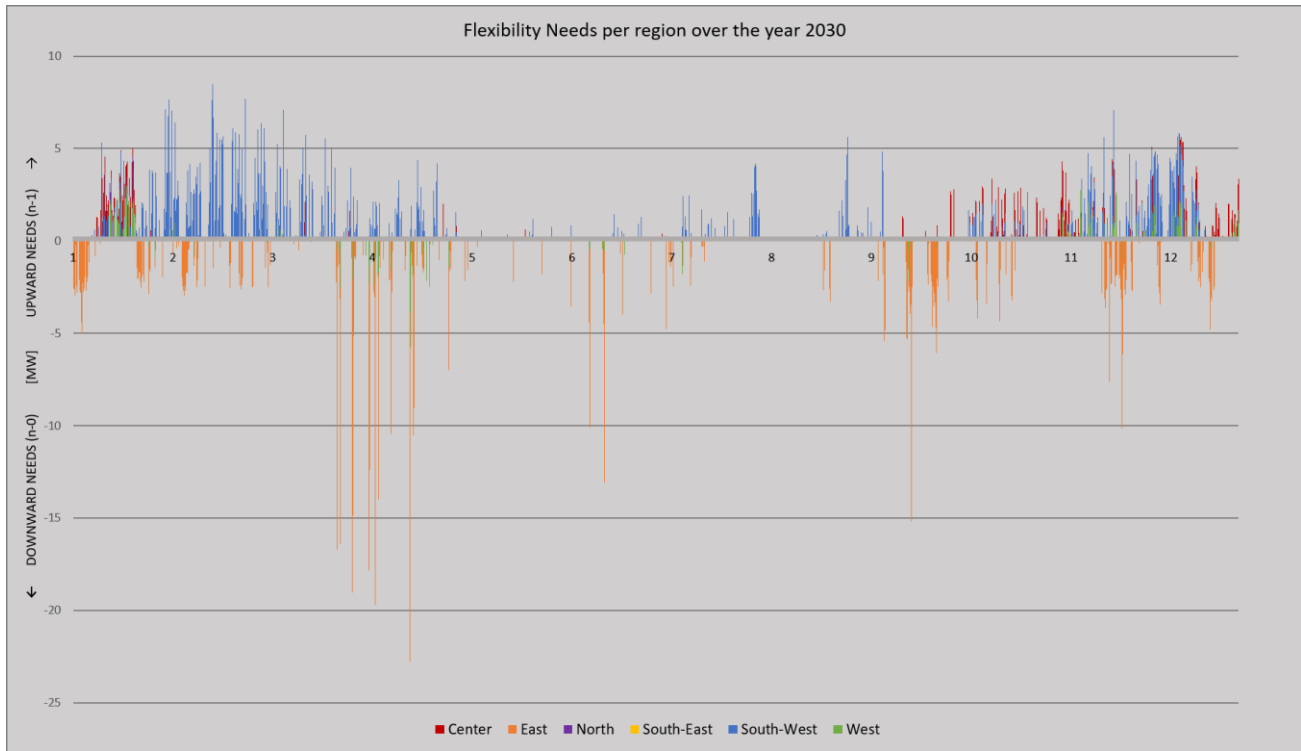


Figure 18 Flexibility needs per region over the year 2030 – Combined Scenario

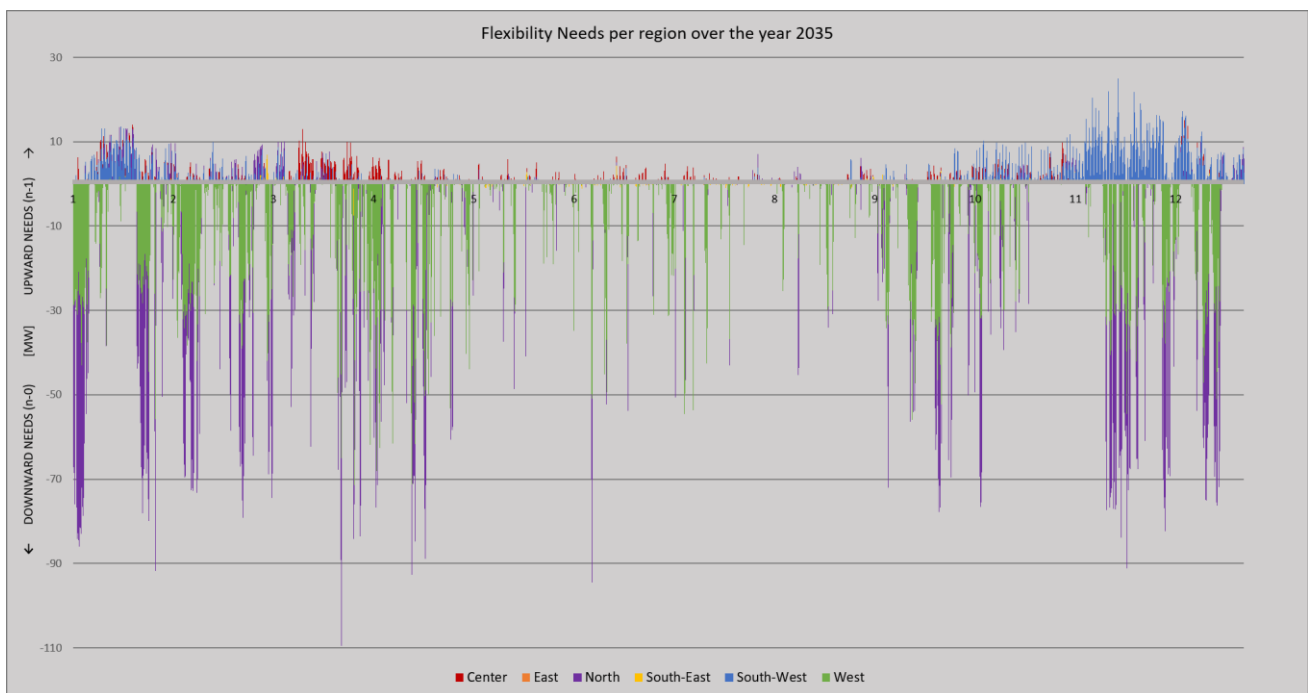


Figure 19 Flexibility Needs per region over the year 2035 – Combined scenario

In order to provide a more detailed description of the flexibility needs of the individual regions, the results for total energy (Figure 20) and maximum instant power (Figure 21) were broken down by region. The total energy corresponds to the sum of identified energy volumes of each 15 min period of the regional flexibility needs time series, which consist of the sum of flexibility needs time series of regional transformers and lines. The maximum instant power represents the maximum value of the regional flexibility needs timeseries.

Regarding total energy and maximum power, the Center and South-West regions show identical patterns. No downward needs were identified in either of these regions characterised by high consumption. However, from a national perspective, both regions show the greatest demand for upward flexibility in terms of energy and power, with an upward trend between the target years. The South-West region has the greatest overall demand for upward flexibility. In 2035, the Center region will account for 29 % and the South-West region for 40 % of the total upward flexibility required in terms of energy.

The region East presents an interesting pattern in terms of downward flexibility. Although the required flexibility in terms of power will rise between 2030 and 2035, the energy required will decrease significantly. This can be explained by the fact that this region is already experiencing congestions (due to high levels of decentralised feed-in) which will be alleviated by grid reinforcements after 2030. The relatively high power combined with a low energy volume indicates that there are very few congestion events occurring. Due to rising consumption, the need for upward flexibility between the target years is increasing.

The North region shows almost no demand for flexibility in terms of energy and only a low demand for flexibility in terms of power by 2030. This is primarily because preparatory work is already being carried out ahead of 2030 to increase the grid voltage from 65 kV to 110 kV, which will already result in higher available transformer capacities even before raising the voltage to 110 kV. By 2035, despite the grid expansion measures, this region will have the highest demand for downward flexibility in terms of power and energy (41,7 GWh), due to the rapid expansion of RES units up to 2035. At first glance, this may seem significant, but in relation to the RES production of 2025, the downward flexibility needs amount to just 2 %. Despite the high demand for downward flexibility due to excessive RES feed-in, there will also be a demand for upward flexibility in 2035.

The South-East region shows no need for downward flexibility in 2030. This changes in 2035, with relatively low demand in terms of energy but high demand in terms of power. The upward flexibility needs increase between the target years.

The West region is projected to have the lowest demand for flexibility in terms of energy out of all regions in 2030. In 2035, however, this demand rises sharply in the downward direction, leading to this region having the second-highest demand for downward flexibility. Together with the Northern region, they account for 99 % of the total downwards energy needs identified for 2035. The behaviour of this region in terms of downward needs is similar to that of the region North, except that the demand for upward flexibility will not increase at the same rate.

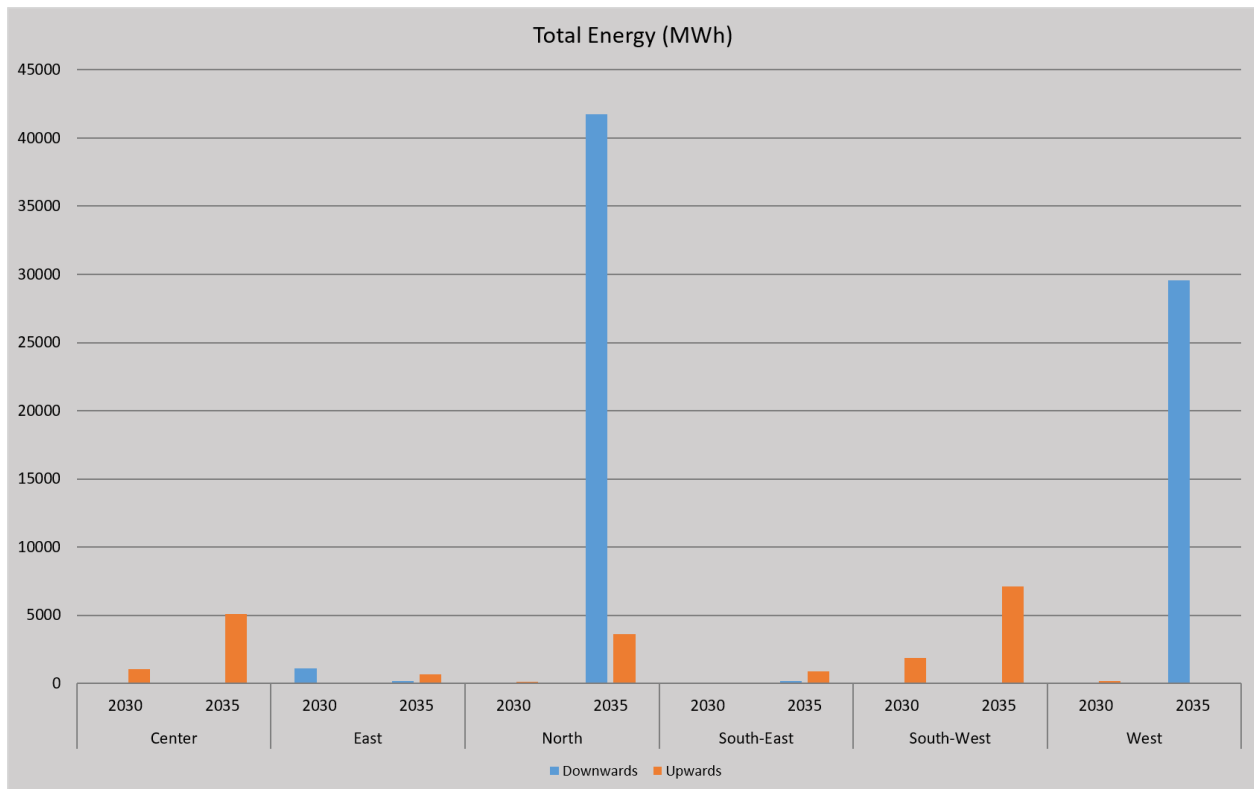


Figure 20 Results of the Combined Scenario – Total Energy per region and year

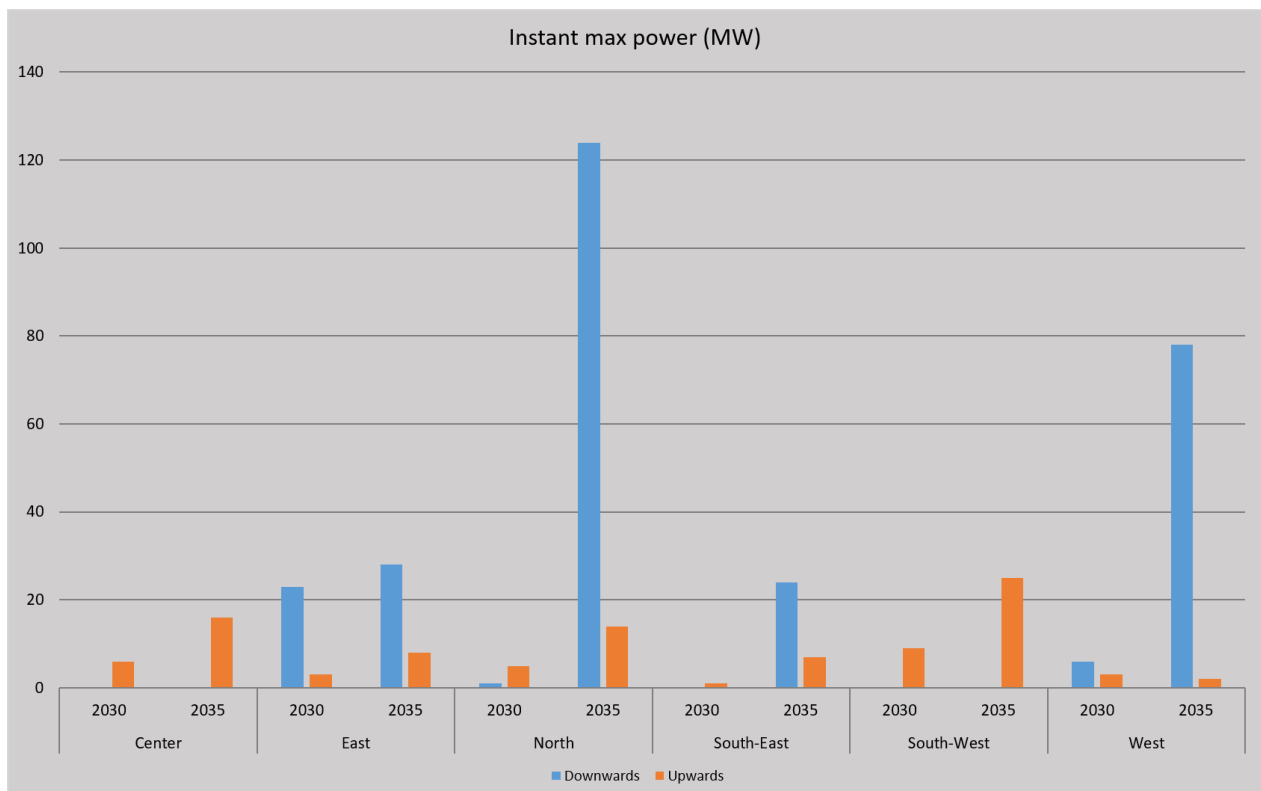


Figure 21 Results of the Combined Scenario – Maximum instant power per region and target year

When comparing the figures above for energy and power, it can be concluded that the specific durations and frequencies of identified flexibility needs must vary considerably between regions. This point is discussed in more detail in the Guiding Criteria in chapter 5.3.2.

Figure 22 and Figure 23 compare the national/regional capacities (the sum of identified power peaks of all assets at regional level) to the instant max power. The regional or national capacity describe the necessary amount of installed capacity on regional/national level to cover the identified flexibility needs while the max instant power describes the maximum peak of the aggregated flexibility needs on regional/national level. A difference between the national/regional capacity and the total max instant power indicates that the individual peaks do not occur at the same time. On national level, regarding downward needs, a total of approximately of 29 MW in 2030 and 255 MW in 2035 of installed capacity would be necessary to meet the identified flexibility needs. In terms of upward needs, the necessary installed capacity amounts to 42 MW in 2030 and 105 MW in 2035. It should be noted that the installed capacity shown must be distributed appropriately across the grid so that congestions can be managed. One single device would not be able to meet the identified needs.

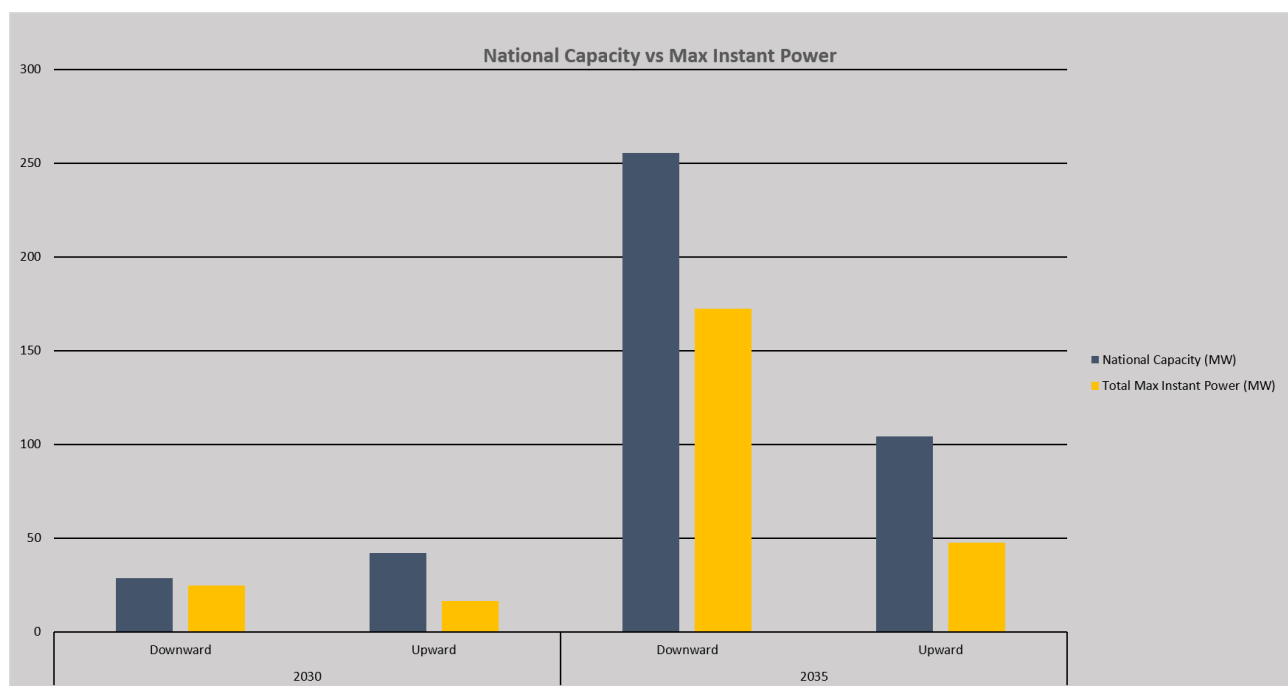


Figure 22 Comparison of national capacity and the max instant power

In Figure 23, the national capacity is broken down to the regional level and compared to the instant max power of the individual region. Here, the observation can be made that in regions, where downward needs were identified, the regional capacity and instant max power are almost the same. This let's conclude that congestions, respectively, the flexibility needs, occur almost at the same time. The region North has the highest need on installed capacity with 126 MW in 2035. This picture is different for upward needs. Larger differences between regional capacity and instant max power can be made, which leads to the conclusion that individual peaks occur at different times. The region South-West shows the highest regional capacity in 2035 with 42 MW. Here, too, the installed capacity must be distributed appropriately across the region and the network in order to solve the congestion problems. It therefore describes the theoretical minimum level of capacity required to meet the identified flexibility needs.

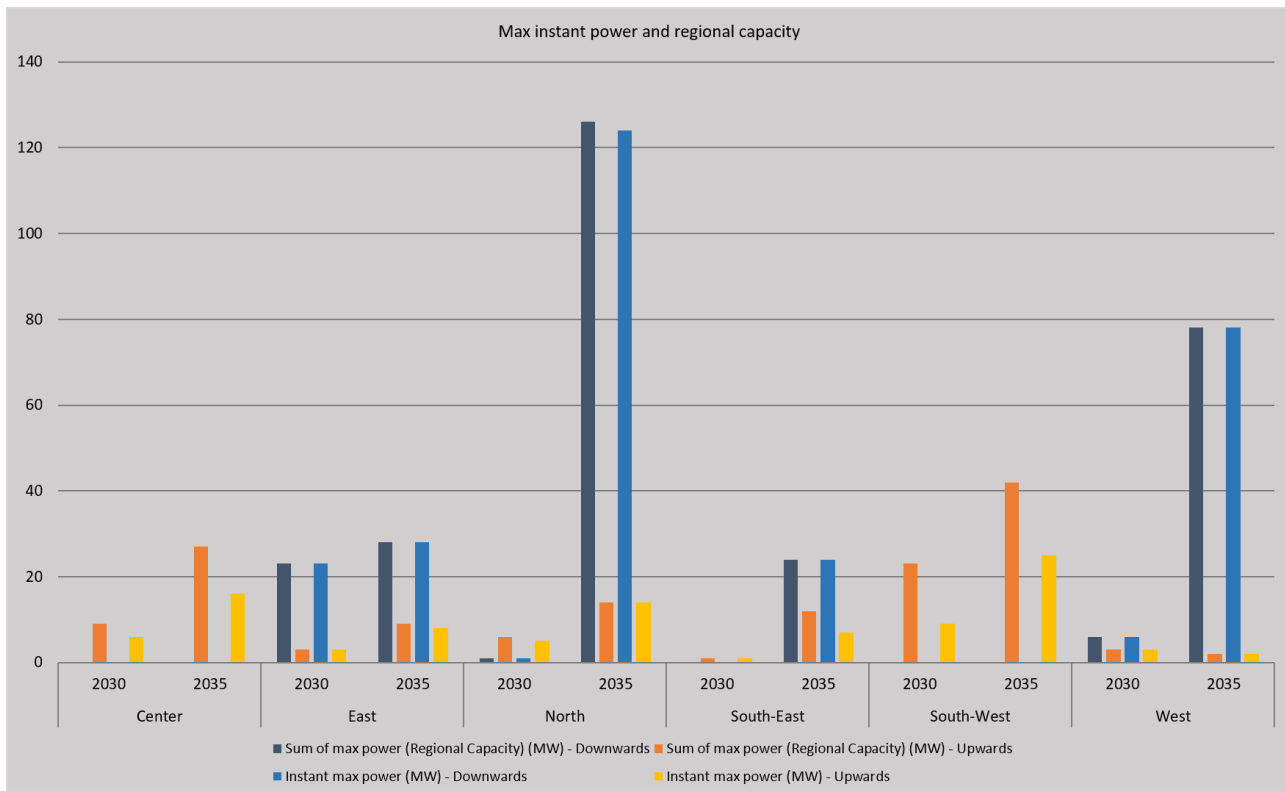


Figure 23 Regional capacity and regional maximum instant power

In order to assess which grid elements are affected the most by congestions and therefore play a key role as drivers of flexibility needs, the transformers share regarding the national capacity and overall flexibility need volume were analysed in Figure 24. When the remaining transformer share is below 100 %, the complement to 100 % can be attributed to the network lines share. For both target years, flexibility upward needs arise exclusively from substations due to the applied methodology, which excludes N-1 upward needs on power lines by design. According to the modelling approach, flexibility needs identified on substation level must be tackled in the subordinate grids to prevent exceeding power flow limits through the substation. Congestions identified on lines could also be resolved through services deployed directly in the HV grid by changing the power flow through the network.

In 2030, the transformer share on the national capacity in downwards direction is 96,17 %, cables and lines only accounting for 3,29 %. Regarding the share on downward flexibility volume, shares are 99,2 % for transformers and 0,08 % for lines. This ratio indicates short periods of congestion on the lines. In 2035, this ratio changes to 37,65 % (transformers) and 62,35 % (lines) in terms of energy and 61,27 % (transformers) and 38,73 % (lines) in terms of the national capacity. The decline in the share of transformers regarding flexibility needs can be explained by the consistent grid reinforcements, in accordance with the DNDP25. The increase in congestion of the HV grid is the result of higher power flows caused by an increasing RES generation and higher individual loads.

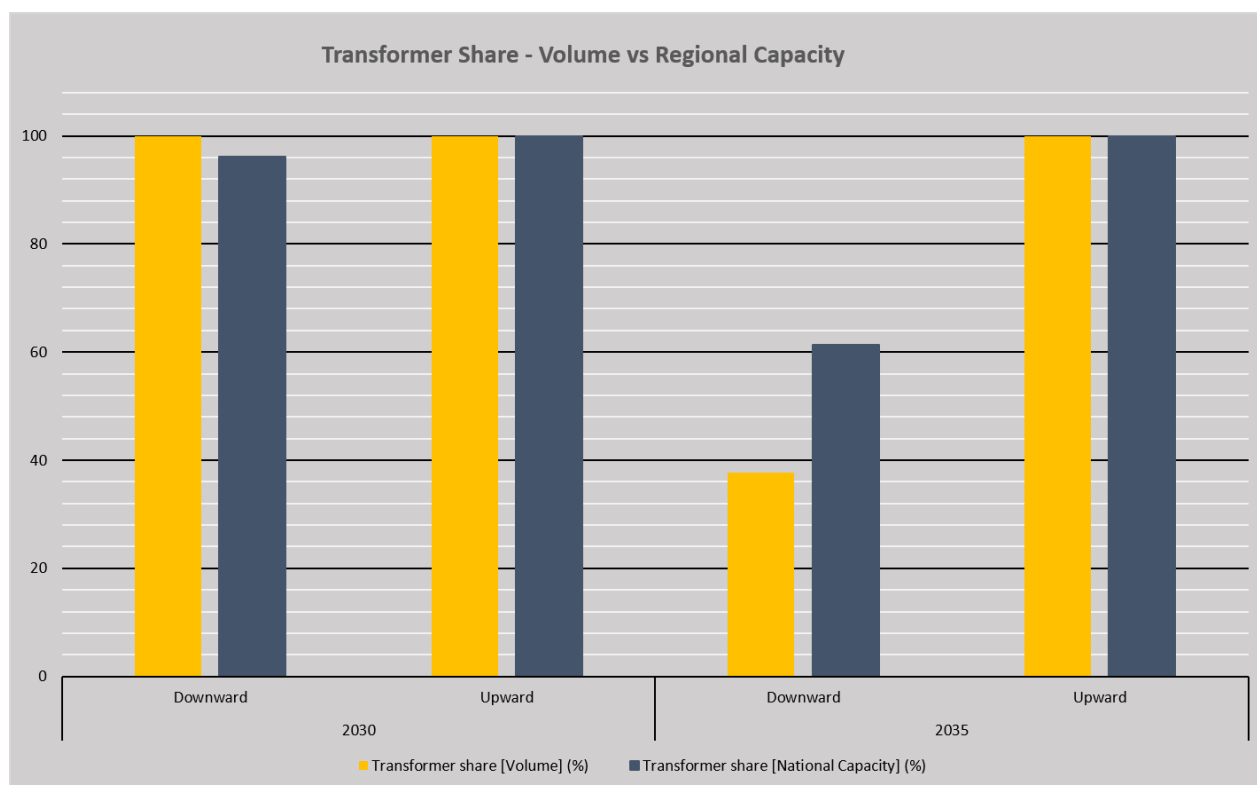


Figure 24 Transformer share on flexibility needs related to the regional capacity and volume

For the target year 2030 and the Combined Scenario, the Eastern region is the only region for which a flexibility need was identified for the network lines, amounting to approximately 1 MW peak. In 2035, the curtailments will extend further along the network lines, resulting in a need for flexibility on HV the lines in the regions East, North and West. The individual shares of lines and transformers in flexibility need per region are shown in Figure 25.

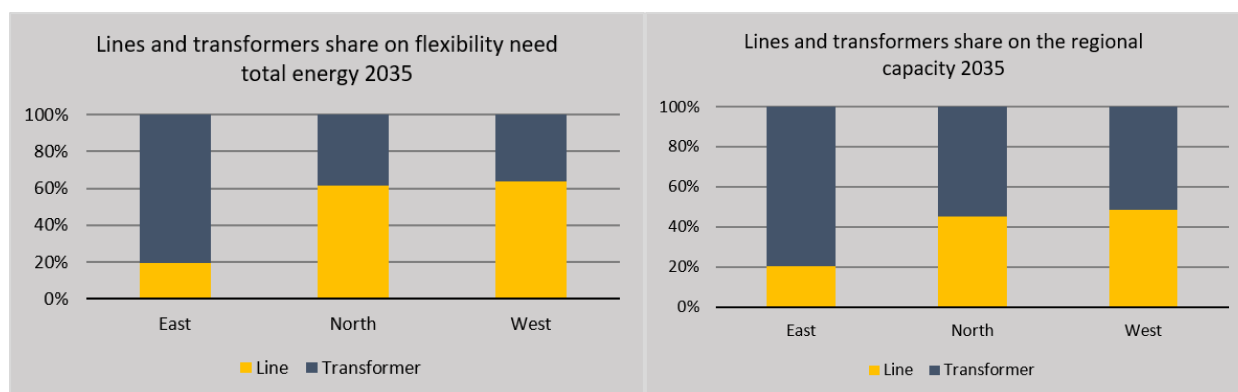


Figure 25 Lines and transformers share on the regional capacity and the total energy

Compared with the North and West regions, congestions in the region East are concentrated primarily at transformer stations with power lines contributing only for a share of 20 % in terms of energy or the regional capacity. In the other two regions, power lines account for the highest share in terms of total energy (60 %) or the regional capacity (50 %).

5.2.2. CONTRACTUAL MEANS FOR ACCESSING FLEXIBILITY

As the model is based on the current DNDP25 scenarios excluding any flexibility, the identified needs reflect the amount of flexibility to be procured for both target years in order to avoid congestions. The procurement of flexibility services can be divided in four categories according to CEER¹⁰:

1. Market-based procurement; e.g. local flexibility services
2. Alternative connection agreements; e.g. flexible connection agreements (FCA)
3. Network tariffs
4. Rules-based approaches

Given the free market economy, a market-based solution should be preferred, as it generally yields the most cost-effective outcome. With this in mind, local flexibility services should be prioritised to tackle congestions in affected grid regions, for example using energy storage or demand response. The advantage of this would not only be the economic aspect, but it could also increase the integration of renewable energy, as, unlike in the case of curtailment, generation could continue. Although this aspect was not considered in this version of the FNA, some assets like storages would also be a suitable approach for addressing voltage issues.

Flexible connection agreements are a form of alternative connection agreements, and they are the ideal tool for avoiding increased upward flexibility needs arising from new industrial or large consumers that are to be connected to the grid – provided that their production processes allow them to be flexible. As well as helping to avoid congestions, they can also help to accelerate the connection of new grid users, as they can already be connected before the grid is reinforced. They are therefore also a valuable tool for integrating the complementary nature of PV and wind energy into the grid, as simultaneous peak generation from both technologies occurs only during limited periods. An FCA could be used to manage these simultaneous peaks whilst enabling the connection of a higher overall share of renewable energy. The framework for flexible connection agreements is currently being developed by ILR in accordance with art 5bis of the Electricity Law.

Network tariff structures constitute an indirect contractual mean to unlock implicit flexibility on a larger scale. Providing tariff signals (e.g. through a time-of-use component) to flexible grid users can incentivise efficient grid usage and lead to a grid friendly behaviour. This can help to flatten out peaks in demand or injection and thus reduce or prevent congestion.

Curtailment of generation from renewable energy sources is a last resort solution used by the DSO for tackling congestions caused by high feed-in volumes. Currently, the DSO can, in accordance with the connection agreement, send instructions to generation units to limit their injection. These actions are not financially compensated nor are they procured as a market product. In 2025, such measures were used 11 times, resulting in a volume of 74,3 MWh of curtailed wind generation (218 MWh in 2024). As explained in the TSO section of the analysis, curtailment is not necessarily a negative process that must be avoided at all costs. Given the foreseeable surplus of renewable capacity relative to demand, curtailment can in some cases prove to be the economically most efficient measure.

5.3. GUIDING CRITERIA

5.3.1. TSO GUIDING CRITERIA

As previously explained, the analysis of the system needs on the bidding zone level was performed by the German TSOs. Creos (TSO) provided the needed data on the Luxemburgish transmission network to the

¹⁰ <https://www.ceer.eu/publication/ceer-conclusions-paper-on-flexibility-use-at-distribution-level/>

German TSOs for the fine-tuning process. This section will therefore give an overview of the guiding criteria which are elaborated in more detail in the German FNA report.

5.3.1.1. RES INTEGRATION

This section describes the flexibility measures required to meet the RES integration targets. The analyses are based on the results of the fine-tuning (see chapter 11.1), showing that the RES integration target 2030 will not be fully met in all the weather scenarios considered. In one of the three weather scenarios (WS14), there is a shortfall amounting to 13,77 TWh. By contrast, the target year 2035 shows a significant over-fulfilment of the RES integration target, with an integration surplus of well over 145 TWh. The process of meeting the shortfall in the specific scenario in the target year 2030 is discussed below. The TSO Guiding Criteria assesses how this identified need, which is triggered in one weather scenario, could be covered. Different expansion paths based on different RES technologies and BESS are compared to determine how the RES Integration Need could be fulfilled, while disregarding economic and geographical limitations.

In accordance with Article 16(6) of the FNA Methodology, the TSOs shall assess the technical capability of the different sources of flexibility to meet uncovered downward needs as included in the RES integration needs. In particular, the TSOs:

- identified for each flexibility resource the marginal contribution to RES integration via the reduction of RES curtailment; and
- derived for each flexibility resource the curve representing the contribution to RES integration via the avoided RES curtailment as a function of the increasing capacity of the resource; and
- compared the resulting curves to establish a hierarchy among the flexibility resources that can facilitate the attainment of the RES integration target.

Table 10 shows the additional unit of capacity until the RES integration target for 2030 is reached as well as the marginal contribution to RES integration of the different flexibility resources. Each line in Table 10 represents one possible expansion path to close the RES integration gap completely. These options are alternatives and not complementary. The analysis shows that run-of-river plants offer the highest marginal benefits, with an expansion of this technology however not being feasible due to geographical limitations. Among scalable renewable energy sources, wind energy technologies offer high marginal benefits, with offshore wind achieving higher marginal benefits than onshore wind and requiring less additional capacity. PV has lower marginal benefit values and requires a greater increase in capacity.

Table 10: Additional capacity & marginal contribution – Bidding zone

	Additional capacity [GW]	Marginal benefit (MWh/MW)
DE00 Run-of-river plants	4,2	3276
LUG1 Run-of-river plants	5,5	2486
DE00 Offshore wind	5,7	2424
LUG1 Onshore wind	9,3	1487
DE00 Onshore wind	10,8	1272
DE00 PV	21,2	650
LUG1 PV	22	625
Battery storage (E/P>8)	25	981-432 (decreasing)

According to the FNA's methodology, a requirement of 5,7 GW of offshore wind is to be reported for WS14 in the target year 2030. However, it is not possible to determine the best expansion pathway based solely on the FNA's analyses as it disregards all economic effects. Similarly, synergies between storage systems and different renewable energy generation profiles, as well as location-specific effects, are overlooked. The results suggest that a combination of the technologies under consideration is systemically more robust than a single-technology expansion pathway. In general, when integrating renewable energy, it must be borne in mind that the analyses neglect important real-world effects. Further expansion of renewable energy is only possible if the grid is expanded in a corresponding manner. This is especially true for offshore wind.

It is interesting to see that, even though at the start of the expansion path, storage can contribute substantially to reducing curtailment and integrating renewable energy, the expansion of renewable generation with curtailment continues to yield significantly higher marginal benefits.

As the results displayed in Table 10 apply to the entire bidding zone, a split is needed for the national results (DE and LU). The split is done based on the land area shares for RES and electricity demand for storage. The results are shown in Table 11 and are subject to the same limitations as those discussed above.

Table 11: Additional capacity 2030– National split

	Germany [GW]	Luxembourg [GW]
Offshore wind	5,7	-
Onshore wind	10,7	0,08
PV	21	0,16
Battery storage (E/P>8)	24,99	0,01

5.3.1.2. RAMPING NEEDS

The results of the FNA analysis indicate that there are no ramping needs and consequently, no need for the discussion required under Article 16 (as is the case with the other two needs). It should be noted once again at this point that ramping needs in the FNA are calculated on an hourly basis using the ERAA and therefore do not consider sub-hourly patterns. The sub-hourly analysis would reveal further ramping needs which are not assessed within the scope of the FNA.

5.3.1.3. SHORT-TERM FLEXIBILITY NEEDS

This subsection analyses short-term flexibility needs in accordance with Article 16(7) & 16(8) of the FNA Methodology. First and foremost, forecast deviations are absorbed by the electricity market, driven by price signals in the day-ahead and intraday markets. For this FNA, it can be assumed that existing available capacity in the market will, for the most part, meet the demand for short-term flexibility. In the ERAA, for example, the load from electrolyzers and large-scale heat pumps is regarded as price-sensitive, but electric vehicles and heat pumps can also shift their load to a certain extent.

Any remaining, unmet short-term flexibility needs must be solved at short notice by using balancing products (FCR, aFRR and mFRR). If the deviations persist, redispatch and/or adjustments on the electricity market become necessary. The ERAA 2024 considers approximately 3 GW of balancing capacity in Germany for both 2030 and 2035. This capacity corresponds roughly to current levels and is held in reserve.

As FNA analyses indicate that a shortage event caused by forecast deviations will last on average around 4 hours in 2030 and around 5 hours in 2035, it is necessary to consider whether there is sufficient energy in the system to absorb such prolonged deviations. Batteries, with a storage capacity of around 2 – 4 hours – as typically assumed in the ERAA – are well-equipped to handle many such events. Demand response can

also help to compensate for short-term deviations, as some loads could react very quickly. There is also the theoretical potential to shift or reduce load. However, availability is a major issue.

In 2030, even the 3 GW of balancing capacity specified and reserved under the ERAA will be insufficient to meet the expected (start-up) demand, given the unmet short-term flexibility requirement, which averages almost 4 GW across the weather scenarios. The same applies to 2035, where the demand for flexibility is even higher, averaging almost 7 GW. To meet the outstanding demand, more suppliers would need to be able to operate flexibly on the electricity market, either through the entry of additional new suppliers and/or by simplifying procurement from existing capacities.

Although favoured for closing the RES-integration gap, additional RES capacity would hardly contribute to covering uncovered upward short-term flexibility needs and could even increase these needs through additional forecast deviations.

Batteries are a flexible technology that will already have a stronger presence on the German/Luxembourgish market by 2030 than assumed in the ERAA 2024 (on which this FNA is based). The ERAA 2024 assumed a battery capacity of 9 GW in 2030 and 19,5 GW in 2035, which has already risen in the ERAA 2025 to 48 GW in 2030 and almost 76 GW in 2035. The potential for demand response is also rising significantly: whilst the ERAA 24 assumed that 5-7 GW of capacity would be added, the ERAA 2025 already projects 10-27 GW. Furthermore, additional flexible capacity could be procured for 2035 via the capacity market for which the first tenders will take place from 2026 onwards.

Simplified market access is a prerequisite for the use of flexibility measures. In recent years, much has already been done to make the electricity market not only more liquid but also more conducive to system stability, for example through the further development of the balancing energy markets or the introduction of Redispatch 2.0 in Germany, which is also intended to encourage greater flexibility. To further expand market access in future, aggregators could, for example, bundle smaller capacities.

The removal of existing market barriers for flexibility is essential in order to meet the demand.

5.3.2. DSO GUIDING CRITERIA

In the following section, the guiding criteria data provided by Creos will be examined. This data enables a more detailed view on how the flexibility need is split between the different regions and it provides a statistical analysis of the national flexibility needs results through the lens of theoretical flexibility services which need to be deployed to prevent congestions. In accordance with Article 16(4) of the FNA Methodology, Creos (DSO) calculated the following criteria for the Combined Scenario and the identified HV network flexibility needs for the relevant target years:

- a) the location of the flexibility need in terms of geographical and voltage level;
- b) the direction of the flexibility needs (upwards or downwards);
- c) the timeframe in which the resource shall be available to solve the flexibility need, including:
 - I. the duration of a continuous need
 - II. the cumulated duration of discontinuous needs
 - III. the frequency of activation
 - IV. the cumulated energy per time block
- d) the local maximum power required during the activation.

The duration of continuous need, as shown in Figure 26 directly relates to the mean statistical duration of each activation block per region as shown in Figure 28Figure 27. The duration of continuous need of the 95th

and the 98th percentile were also examined and can be found in Annex 1. Region West shows the highest mean duration of continuous need in downward direction, followed by the region North, both for the year 2035. In general, upward needs tend to last longer than downward needs with a duration per activation block of 5,6 hours. For the Central and South-West region, no downward needs were identified for any of the target years, therefore no duration is shown. For the South-East region no downward flexibility need was identified for the target year 2030. Durations tend to increase between the target years except for the region East where the duration for an activation in downward direction decreases (see chapter 5.2.1). Overall, the mean duration of continuous needs can range between 1 h and 5,6 h depending on region and direction.

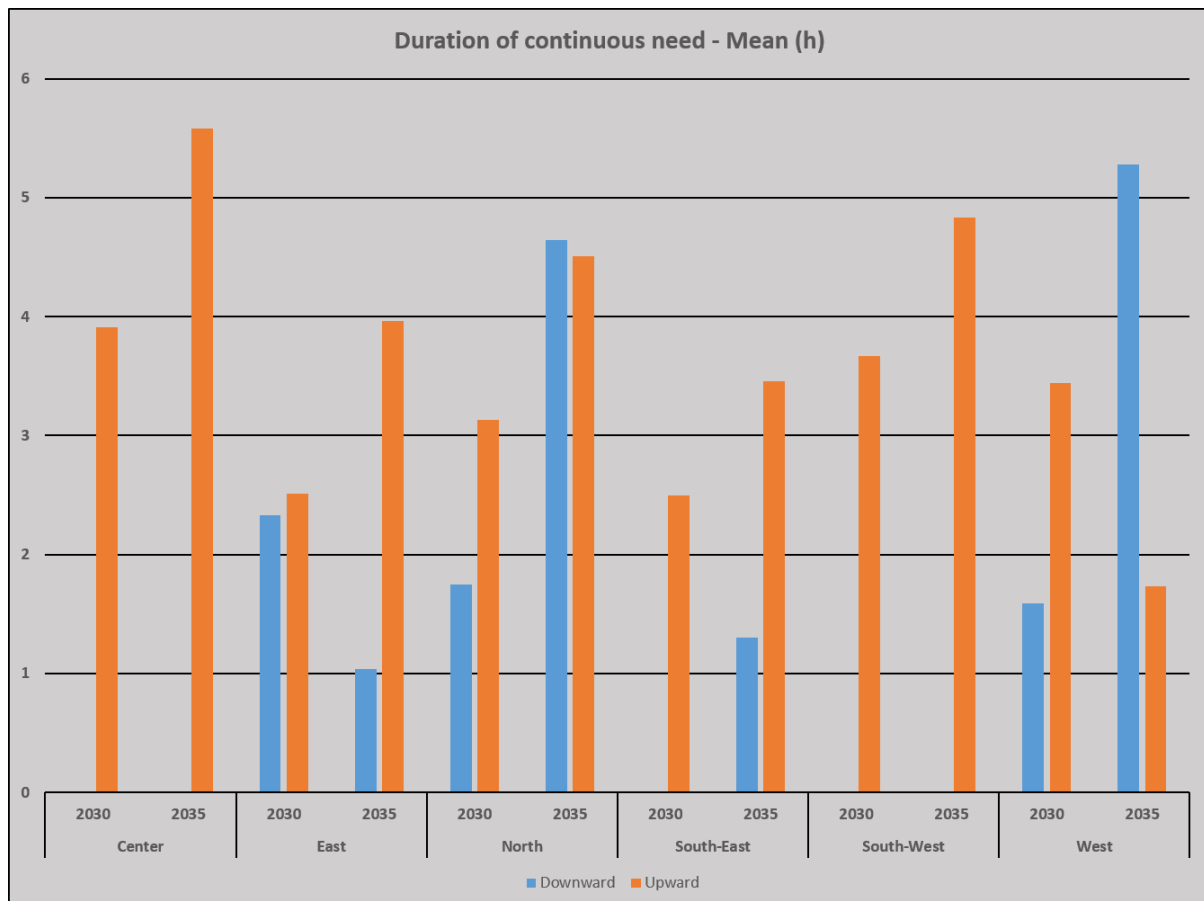


Figure 26 Guiding Criteria – Duration of continuous need – mean value

In Figure 27, the frequency of activation blocks per year for the various regions is displayed. An activation block is defined as a continuous sequence during which flexibility is required, with short non-activation gaps being merged into the same block using a tolerance of one hour. The highest frequency of activation overall with 328 activations per year occurs in the region West followed only then by the region North with 234 activations per year, both in downwards direction. The highest frequency of activation in upwards direction occurs in the regions Center and South-West for the target year 2035 with an almost identical number of yearly activations of 202 respectively 203.

Another important information is the mean value of necessary energy per activation block as shown in Figure 28. It quickly becomes apparent that an activation in the northern region is associated with by far the highest energy volume of almost 180 MWh, followed by the western region with 90 MWh. Most energy volumes per activation block are below 20 MWh.

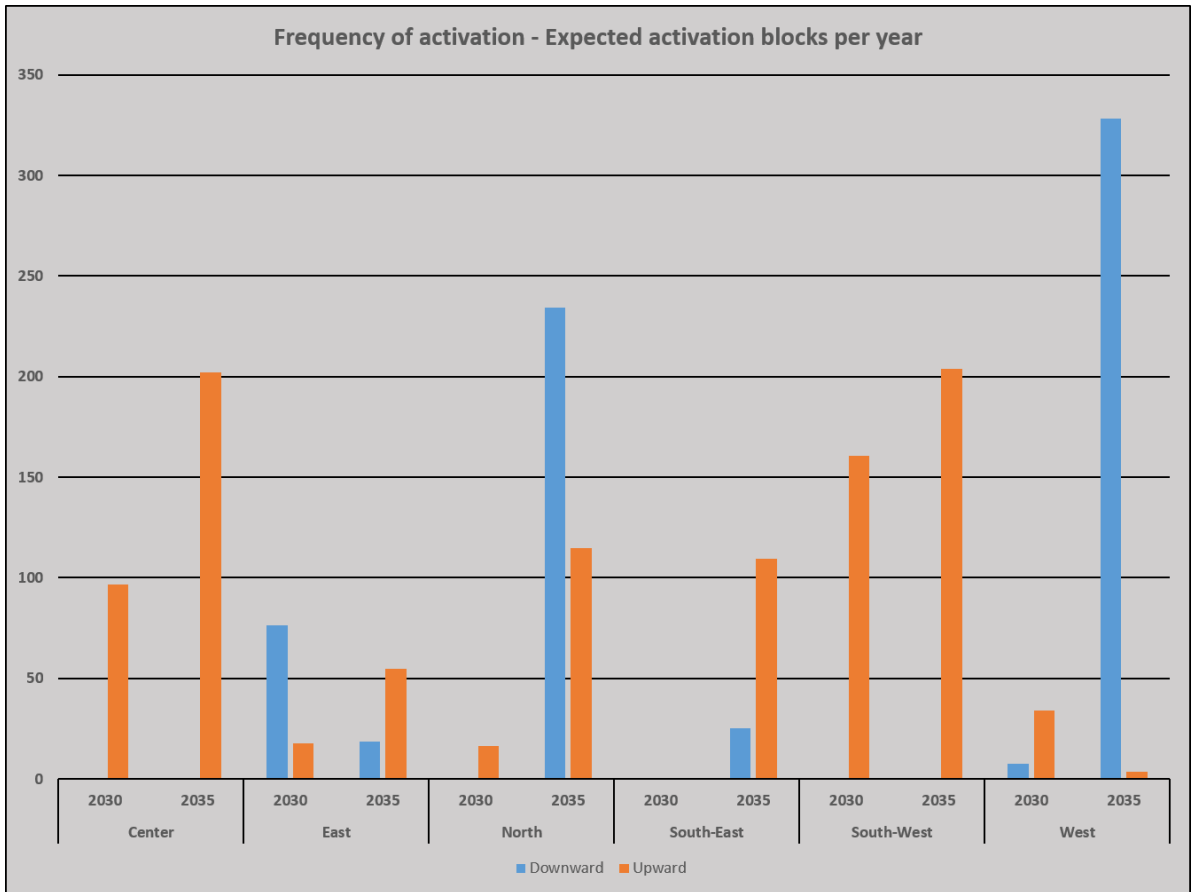


Figure 27 Guiding Criteria – Frequency of activation

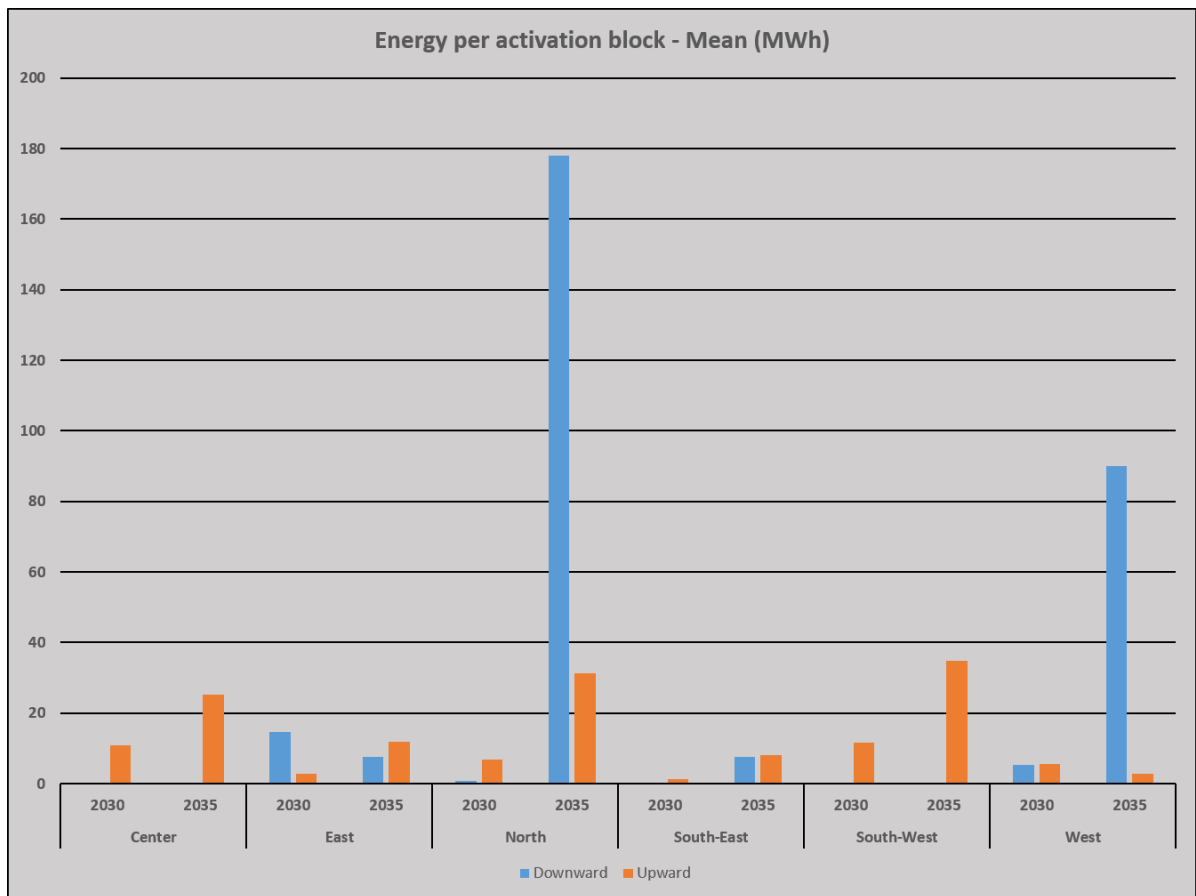


Figure 28 Guiding Criteria – Energy per activation block – mean value

When comparing Figure 26, Figure 27 and Figure 28, it can be concluded that in general upward needs are activated more frequently with higher durations per activation, but lower energy volumes compared to downward needs.

By analysing the flexibility need in terms of power and energy presented in Chapter 5.2.1, the guiding criteria can be used to highlight the different behaviour of flexibility needs in the individual regions. As explained in the previous chapter, the regions North and West have shown a similar level of downward flexibility in terms of power and energy between the target years. However, the emergence of the need for flexibility is determined by the fact that, in contrast to the region North, in the region West the required activations occur statistically much more frequently and last longer, but the energy per activation is only half as much.

Figure 29 shows the cumulative duration of discontinuous need, representing the expected hours per year for which the statistical flexibility services described above need to be activated per region. For most regions, the upwards direction dominates the expected active hours of flexibility. Only the northern and western region are defined by a high amount of expected active hours of downward flexibility in 2035. Some bars are not visible as the value of expected active hours is very low in comparison to the ones of other regions. The cumulative duration per year varies widely and ranges from 0,3 h/y to over 1.500 y/h across the regions and between the directions. Due to the high frequency of activation combined with the longest duration per activation, the region West consequently has the highest number of expected active hours.

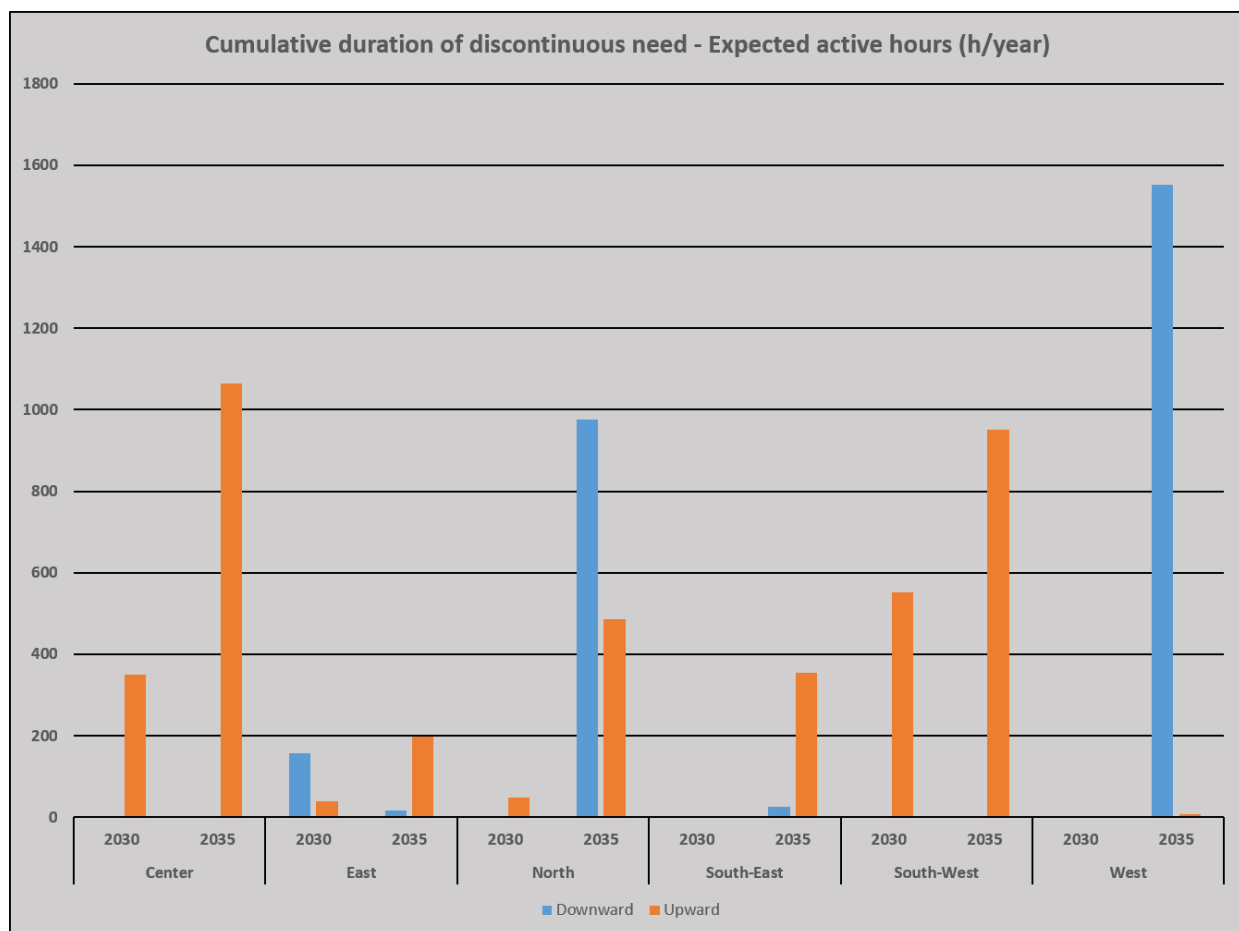


Figure 29 Guiding Criteria – Cumulative duration of discontinuous need – Expected active hours per year

The following section describes the temporal distribution of identified flexibility per region over the day, the week and the year. Figure 30 shows the share of annual active hours throughout the day. It confirms the observations made in Figure 15 and Figure 16, namely that upward needs mainly arise during periods of high consumption. Consequently, the distribution over daytime is determined primarily by the morning, midday and evening hours. Regarding the emergence of downward flexibility need, it is most likely to occur when all

renewable energy sources are generating electricity at the same time. This is particularly the case around midday, as reflected in the figure.

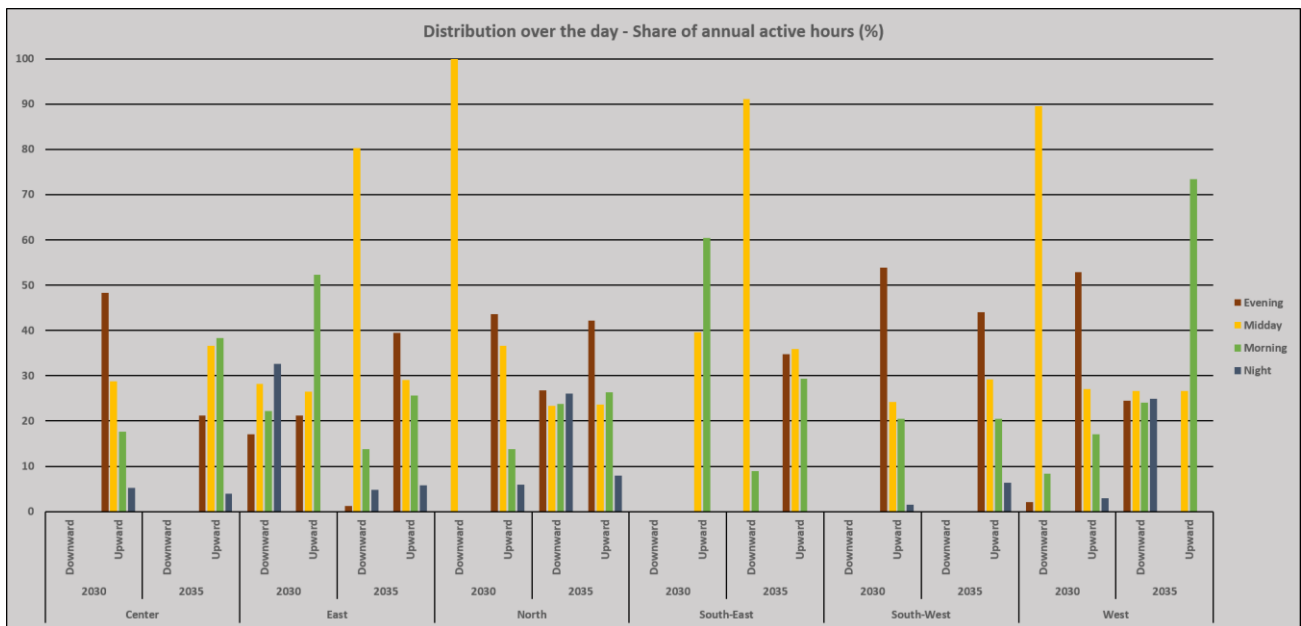


Figure 30 Guiding Criteria – Distribution over the day

When observing the occurrence of flexibility needs over the different weekdays, it stands to reason that upward needs were identified mainly on workdays when grid load tends to be higher due to active industry. Values of 100 % indicate that flexibility needs in the given direction were identified only on one weekday. For downward needs, there is no specific behaviour observable as RES production depends mainly on the used climate year and the fact that only a single year was used.

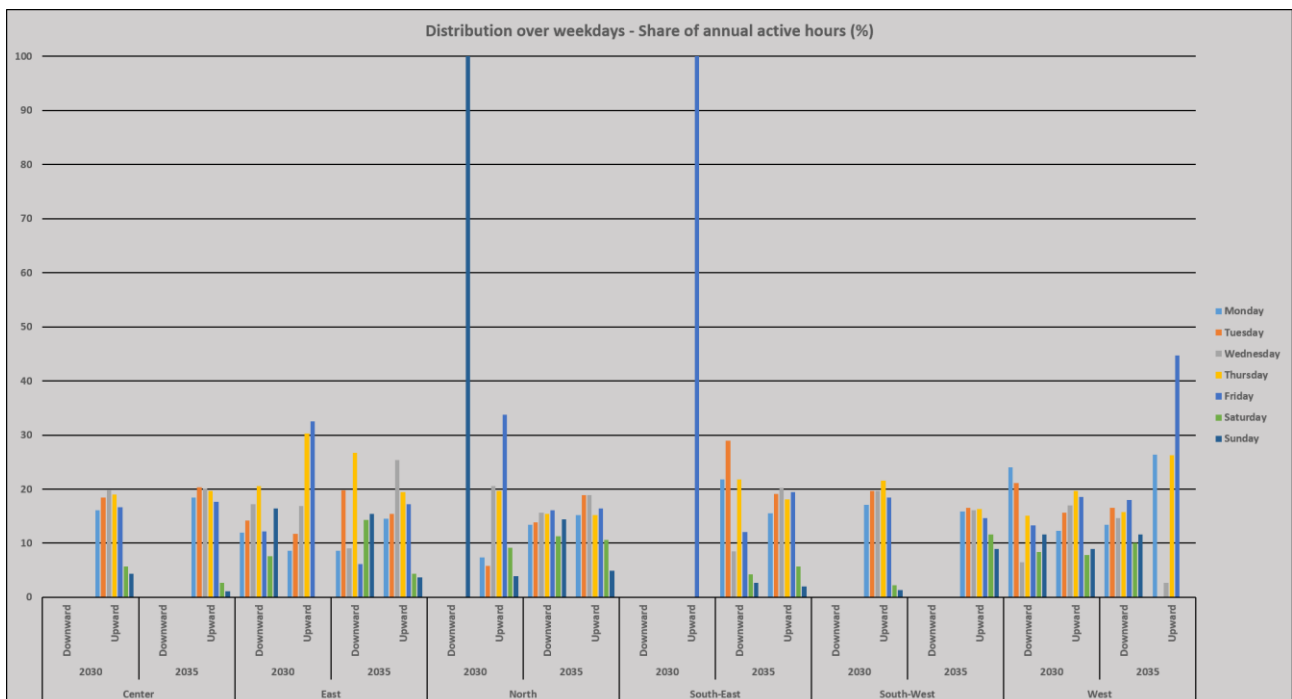


Figure 31 Guiding Criteria – Distribution over weekdays

This becomes clear once again when looking at the distribution across the seasons. As mentioned before, the chosen climate year 2024 for the model contains a period of simultaneously high wind and PV production during springtime, which is directly reflected in Figure 32. Notably, the regions North and West show for 2035

the highest share during winter regarding downward flexibility needs. This suggests that, given the time of year, wind power is the main cause. As could already be seen from Figure 16, upward needs occur mainly during autumn and winter, when consumption is high and RES production typically low. From 2035 onwards, however, an increase in upward needs during the summer months can be observed.

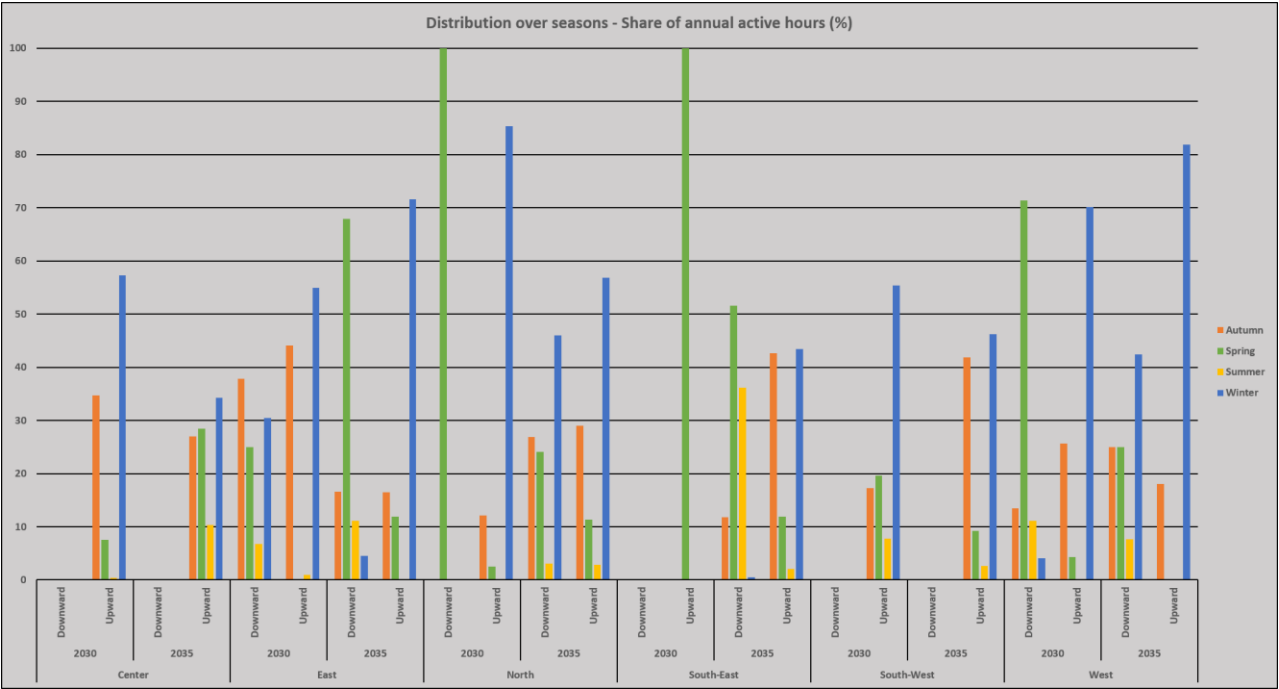


Figure 32 Guiding Criteria – Distribution over seasons

6. BARRIERS FOR FLEXIBILITY AND CONTRIBUTION OF DIGITALISATION

To evaluate barriers to flexibility in the market and the contribution of digitalisation to the Flexibility Needs Assessment Report pursuant to Article 19e(2), points (c) and (d) of the Electricity Regulation and Article 15 of the FNA Methodology, the following potential barriers will be analysed:

1. Lack of proper legal framework for market access to new entrants and small actors
2. Lack of enablers and incentives to provide flexibility
3. Restrictive requirements to provide balancing services
4. Restrictive requirements to provide congestion management
5. Complex, lengthy, and discriminatory administrative requirements
6. Lack of regulatory incentives to system operators to consider non-wire alternatives.

While sections 6.2 to 6.7 will go into further detail, answering to the questions set out in the Annex, section 2 of the ACER Recommendation No. 1/2026¹¹ (hereinafter 'ACER Recommendation'), section 6.1 provides an overview of the barriers that were identified by the questionnaire as well as by the experience of ILR.

For sections 6.2 to 6.7 it is recommended to read the information provided in parallel to the questions set out in the ACER Recommendation. Due to the volume of the questions, these were not included in this report.

6.1. SUMMARY OF IDENTIFIED BARRIERS

Aggregation Models

Even though the Luxembourgish Electricity Law states that all end customers, including those who actively participate in demand response through aggregation, may participate on a non-discriminatory basis in all electricity markets, a clear regulatory framework for aggregation has yet to be defined. Article 8sexies (3) of the Electricity Law tasks ILR with developing rules governing demand response through aggregation, which shall include at least the following elements:

- a) non-discriminatory and transparent rules that clearly assign roles and responsibilities to all electricity undertakings and customers;
- b) non-discriminatory and transparent rules and procedures for the exchange of data between market participants engaged in aggregation and other electricity undertakings that ensure easy access to data on equal and non-discriminatory terms while fully protecting commercially sensitive information and customers' personal data;
- c) a conflict resolution mechanism between market participants engaged in aggregation and other market participants, including responsibility for imbalances;
- d) procedures for allocating responsible parties and other relevant parties the quantities of electrical energy resulting from demand response measures and, where warranted, a method for financial compensation.

Even though it is technically possible for independent aggregators to participate in the Day-ahead, Intraday, FCR and FRR markets (no congestion management in Luxembourg), the current lack of a clear rules most likely represent a barrier for aggregators to become active in Luxembourg.

¹¹ <https://www.acer.europa.eu/sites/default/files/documents/Recommendations/ACER-Recommendation-01-2026-NRAs-reporting-barriers-to-flexibility.pdf>

Restrictions to Market Access

Even though the indicator from the ACER Recommendation only enquires about access to day-ahead and intraday markets, some restrictions apply to other markets as well.

As explained previously, Luxembourg has a quite unique market situation as it is sharing a common bidding zone with Germany and a common LFC area with the German TSO Amprion via the connection to the transmission grid of Amprion. However, Creos TSO and Amprion operate two separate scheduling areas, which adds a certain level of complexity for market actors situated in Luxembourg.

This results in market participants based in Luxembourg not having the same trading opportunities as the ones in Germany, making it less attractive for assets to be located in Luxembourg and thus posing a significant barrier to the development of flexibility services at the national level. While access to the FCR and FRR markets has been enabled in 2020, respectively 2025, market actors are still unable to participate in some of the German ancillary services, as for example redispatch or capacity reserves as well as the markets for instantaneous reserves or for the provision of black-start energy. Until now, no power plants connected to the national grid provide this type of services.

As explained in subsection 6.4.2, pooling of flexible units across border (LU-DE) is not allowed for FRR services, which severely limits the number of units available (e.g. for an aggregator) in a pool and increases the likeliness of the minimum bid size being a barrier for market access.

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

As shown in subsection 6.3.2, only a limited number of retail electricity contracts with time differentiation or dynamic electricity prices are available. The uptake in dynamic contracts for residential customers being as low as 0,012 %.

The very low uptake of dynamic price contracts might be explained by multiple reasons:

- High margins added by suppliers to the wholesale price, making these products unattractive compared to other offers. These margins were however lowered in 2025 compared to 2024 and might continue to decrease;
- Higher complexity of such offers, requiring residential customers to adopt their behaviour and to have some degree of understanding of the electricity markets;
- Higher risks associated with dynamic electricity price contracts;
- Unawareness of residential customers that such products exist;
- Low incentives to switch suppliers or contracts due to limited competition and rather small price differences;
- Comparatively low share of energy cost in the total budget of a household, which does not favour consumers becoming active on the retail market;
- Lack of service providers offering appropriate technical solutions enabling customers to harvest their full flexibility potential.

Lack of network tariffs with time differentiation

As explained in subsection 6.3.2, no network tariffs with time differentiation currently exist. However, it is planned to introduce time-of-use components for all voltage levels in the coming years.

Lack of market-based congestion management

As explained in section 6.5, the use of non-market-based congestion management is mainly due to the very low frequency of congestions as well as the small market size of Luxembourg. With very limited activation volumes as well as only very few flexibility service providers (demand response or generation facilities) in Luxembourg, it is likely that a market-based approach would either not be available at all, or competition would be insufficient and lead to an economically less efficient solution.

Small market size of Luxembourg

With only about 288.697 residential, 66.042 professional and 188 industrial customers in the Luxembourgish electricity grid, the number of potential clients for market actors is limited. This reduces the attractiveness of the Luxembourgish market and therefore the likelihood of new market actors like aggregators or suppliers (offering time differentiated or dynamic electricity price contracts) entering.

6.2. LACK OF PROPER LEGAL FRAMEWORK FOR MARKET ACCESS TO NEW ENTRANTS AND SMALL ACTORS

6.2.1. MAIN ROLES AND RESPONSIBILITIES OF NEW ACTORS NOT DEFINED

Active customers

The Electricity Law transposed the related provisions of the Electricity Directive, ensuring that final customers are entitled to act as active customers and exercise the rights listed in the questions a) to d) of the ACER Recommendation. The following table indicates the relevant articles of the Electricity Law.

Art. 8bis, Art. 1 (31ter)	Every end customer has the right to act as an active customer and thereby has the right to act as a self-consumer and participate in energy sharing. According to the definition of energy sharing, renewable electricity which is generated or stored off-site is included in energy sharing.
Art. 8 bis	Every active client is authorised to carry out its activities either directly or through aggregation.
/	There is no provision directly concerning power purchase agreements. Currently, for active customers to sell self-generated electricity through power purchase agreements, they would need to be granted a supply authorization in accordance with Article 46 of the Electricity Law.
Art. 8quinquies	An active customer who owns an energy storage facility shall be connected to the grid by the relevant system operator within a reasonable period, not exceeding ninety days, following their application, provided that all the necessary conditions, such as responsibility for balancing and the provision of suitable meters, are met.

Aggregation

The activity of “aggregation” and the market actors “aggregator” and “independent aggregator” are defined in the same way as in the Electricity Directive.

Article of the Electricity Law	Definition
Art. 1 ^{er} (1terdecies)	Aggregator
Art. 1 ^{er} (1quaterdecies)	Independent Aggregator
Art. 1 ^{er} (1quindecies)	Aggregation

The Electricity Law transposed the related provisions of the Electricity Directive, ensuring that final customers have the rights listed in question 3 a) to c) of the ACER Recommendation. The following table indicates the relevant articles of the Electricity Law as well as short responses to the mentioned questions.

Art. 8sexies	All end customers, including those who actively participate in demand response through aggregation, may participate on a non-discriminatory basis, alongside electricity generators, in all electricity markets. In particular, they are permitted to enter into an aggregation contract without the consent of the other electricity suppliers with whom they have a contract. Every aggregator has the right to enter the electricity markets without the consent of other market participants.
Art. 8sexies	End customers who have a contract with independent aggregators must not be subject to unfair charges, penalties or other unfair contractual restrictions imposed by their suppliers.
Art. 19 (8)	Final customers are not subject to discriminatory technical and administrative requirements, procedures or charges by their supplier on the basis of whether they have a contract with a market participant engaged in aggregation.

Energy communities

All the necessary legislation is in force. The following table indicates the relevant articles of the Electricity Law as well as short responses to points 4 and 5.

Art. 8quater (1) a) & c)	An energy community can generate, consume, store and sell electricity, including electricity from renewable sources, produced by the 'facilities' owned by it or its members or shareholders, or for which they hold a lease agreement, including through power purchase agreements. An energy community can provide energy efficiency services, electric vehicle charging services or other energy services to its members or shareholders.
Art. 8quater (1) b)	An energy community can access all electricity markets directly or through aggregation in a non-discriminatory manner.
Art. 8quater (2)	Energy communities are treated in a non-discriminatory and proportionate manner with regard to their activities, rights and obligations as final customers, producers, suppliers, distribution system operators or market participants engaged in aggregation.

Energy storage behind-the-meter

Energy storage facilities are allowed to be connected to the same grid access point and combined with all of the facilities listed in question 6 (facilities producing renewable energy, electric vehicle recharging points, final customers' demand facilities).

Aggregation models

As mentioned above, Article 8sexies states that all end customers, including those who actively participate in demand response through aggregation may participate on a non-discriminatory basis in all electricity markets. While the current rules for balancing service providers (BSPs)¹² and balancing responsible parties (BRPs)¹³ foresee that aggregation of technical units situated in Luxembourg is allowed, a clear regulatory

¹² https://www.creos-net.lu/fileadmin/dokumente/news/241213_Creos_Modalit%C3%A9s_BSP_FRR.pdf?t=1753078460247

¹³ https://www.ilr.lu/wp-content/uploads/cadre-legal/ILR_ELC_pub_2026_03_11_Creos_Terms-and-conditions_BRP.pdf

framework for aggregation has yet to be defined. Even though multiple independent aggregation models are technically possible, roles and responsibilities of the different market actors, procedures for the exchange of data and procedures for allocating BRPs the quantities of electrical energy resulting from demand response measures and, where warranted, a method for financial transfer or compensation are either not defined at all or not clear framework exists.

The current lack of a clear regulatory framework most likely represents a barrier for the entry of aggregators into the Luxemburgish market. Therefore, as foreseen by Article 8sexies of the Electricity Law, ILR will establish rules for demand side response through aggregation in close consultation with system operators and relevant market participants.

6.2.2. MARKET ACCESS RESTRICTED DUE TO LACK OF LEGAL ELIGIBILITY

Aggregation & Direct participation

There are no legal restrictions for market participants to participate in wholesale markets and system operation services/products. However, it needs to be noted that, unlike for the FCR, pooling of units for FRR across borders (LU-DE) is not allowed, severely limiting the number of units available (e.g. for an aggregator) in a pool and increasing the likeliness of the minimum bid size being a barrier for market access.

6.2.3. UNCLEAR FRAMEWORK FOR ACCESS TO FINAL CUSTOMER DATA

Luxembourg implements the reference model for metering and consumption data access primarily through the national data platform LENEDA¹⁴.

The roles and responsibilities set out in Table I of the Annex (ELEX:32023R1162) to regulation¹⁵ (EU) 2023/1162 on interoperability requirements and non-discriminatory and transparent procedures for access to metering and consumption data, are reflected in the national market organisation; the parties acting as metered data administrator, metering point administrator, data access provider and permission administrator (Articles 5–8 of the aforementioned regulation) are identified within the LENEDA framework.

Information on the national market organisation and on the relevant roles is made available to eligible parties and final customers, notably through the market's operating and communication rules (LENEDA Market Rules). National practices regarding interoperability and data access procedures are in line with the (EU) regulations. The LENEDA platform and the corresponding market rules will continue to evolve and mature in order to best adapt to market needs and future European Union regulations, in particular those relating to the implementation of the Network Code on Demand Response, which is currently under formal review by the European Commission following the official recommendation submitted by the Agency for the Cooperation of Energy Regulators (ACER) on 7 March 2025. Finally, it is worth mentioning that there are no charges imposed by regulated entities providing data services to eligible parties for access to data.

6.2.4. OWNERSHIP RESTRICTIONS FOR ENERGY STORAGE AND ELECTRO-MOBILITY

Storage

In accordance with Article 36(2) of the Electricity Directive, the Electricity Law (Article 28ter) states that the regulator may allow system operators (DSO or TSO) to own, develop, manage or operate energy storage

¹⁴ <https://leneda.eu/en/>

¹⁵ https://eur-lex.europa.eu/eli/reg_impl/2023/1162/oj/eng

facilities when these are fully integrated network components or where the conditions listed in Article 28ter of the Electricity Law are met. However, no derogation is currently in place.

Electro-mobility

Article 27(13) of the Electricity Law prohibits DSOs from owning, developing, managing or operating recharging points for electric vehicles except where DSOs own private recharging points solely for their own use.

6.2.5. RESTRICTIONS ON TRADE IN DAY-AHEAD AND INTRADAY MARKETS

Germany and Luxembourg constitute a common bidding zone. The scheduling areas of Creos and Amprion are separate, but there is no NEMOs hub in the Creos scheduling area. As such, market participants aiming at delivering electricity in Luxembourg need to nominate on the NEMO hubs active in the Amprion's area.

The smallest minimum bid size of products for trading in the day-ahead and intraday markets is 0,1 MW. The imbalance settlement period is 15 minutes and NEMOs enable market participants to trade in energy in time intervals equal to the imbalance settlement period for the day-ahead and intraday markets.

As market participants active in Luxembourgish have no direct NEMO access, nominations are always subject to a 15-minute deadline to allow exchange between Creos and Amprion. In continuous intraday trading, the lead time is as short as five minutes if the trade takes place within the same control area. Assets based in Luxembourg can't profit of this timeline, due to the separate scheduling areas and the 15-minute nomination deadline to Amprion. This represents a market barrier for Luxembourg based market actors trying to perform short term trading.

Even though this indicator from the ACER Recommendation only enquires about access to day-ahead markets and intraday markets, some remarks on access to other markets shall be made in this subsection. As Germany and Luxembourg share a common market area, market actors should be able to participate on all markets regardless of whether they are situated in Luxembourg or Germany. However, technical units situated in Luxembourg are still unable to participate in some of the German ancillary services, as for example redispatch or capacity reserves as well as the markets for instantaneous reserves or for the provision of black-start energy.

6.3. LACK OF ENABLERS AND INCENTIVES TO PROVIDE FLEXIBILITY

6.3.1. LACK OF ADEQUATE METERING SYSTEMS

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

Near to 100 % of household and non-household final customers are equipped with smart meters.

Currently no sub-meters nor dedicated measurement devices are used by TSOs, DSOs and market participants, as such devices have not been needed at this point in time. The already installed smart meters cover the current metering needs. However, it needs to be said that no aggregators nor balancing service providers are currently active in Luxembourg. If this changes, the need for such devices may arise. Furthermore, discussions about the participation of energy storage in energy sharing are currently ongoing and may raise the need for additional metering devices.

Lack of smart meters with minimum functionalities & other functionalities and services enabling flexibility and demand response

All the minimum functionalities of smart metering systems listed in the ACER Recommendation are available for 100 % of household and non-household final customers equipped with smart meters.

Final customers can have access to their consumption either via the portal of their supplier or via the LENEDA platform that is being deployed, thanks to the information transferred by the smart meters.

Smart meters register the generation/consumption data every ¼ hour, which is also the time resolution for imbalance settlement.

6.3.2. ABSENCE OF PRICE SIGNALS

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

Article 47(5) of the Electricity Law foresees that suppliers with more than 15.000 end customers shall offer final customers with smart meters the option to conclude a dynamic electricity price contract. The different types of retail electricity contracts available at the end of 2025, and the related uptake of household customers, is indicated in the table below. This data is not available for non-household customers.

Type of contract	Availability for households (quantitative)	Uptake of household customer in %
Fixed-price, fixed-term	2	4,4
Time-of-use fixed-price, fixed-term	2	
Variable price contracts with one single price that varies between quarters / months / days	-	-
Variable price contracts with time-of-use pricing that varies between quarters / months / days	2	NA ¹⁶
Dynamic price contracts	3	< 0,1
Hybrid contracts	-	-
Other	6	95,6

“Other” represents the “fixed price, non-fixed term” contracts traditionally offered in Luxembourg. These contracts allow the supplier to adjust its prices at any time, provided that the consumer is notified at least 30 days before the change takes effect. Generally, these prices adjustments occur only once a year. During this period, the consumer may terminate their contract free of charge without the new price taking effect.

Article 19 of the Electricity Law states that all customers are free to purchase electricity from the supplier of their choice and to have more than one electricity supply contract at a time, provided that the necessary connection and metering points are in place.

Lack of consideration of network tariffs with time differentiation

Currently no network tariffs with time-of-use (static or dynamic) elements are applied. However, it is considered to introduce time-of-use components for all voltage levels before 2030.

In 2025 a new tariff structure for the low voltage level was introduced, incentivising network users to “flatten the curve” and reduce network peaks by limiting simultaneous use of household appliances and, where possible, to spread their use out over time. As the new tariff structure already introduced a certain level of

¹⁶ This contract offer was released very recently. No data is available at the time of writing this report.

complexity compared to the previous one (especially for household customers), time-of-use elements were not yet included. It is however considered to introduce a time-of-use component by expanding the existing structure. Equally for the MV, HV and VHV levels, it is planned to introduce a new tariff structure before 2030, which will most likely include a time-of-use component.

6.4. RESTRICTIVE REQUIREMENTS TO PROVIDE BALANCING SERVICES

6.4.1. NON-MARKET-BASED BALANCING PRODUCTS

Given that the Creos control area does not have the necessary reserves to cover its own balance between electricity supply and demand, Creos TSO has established with the German TSO Amprion GmbH, in accordance with Article 120 of Regulation (EU) 2017/1485 of 2 August 2017 establishing a guideline for the operation of the electricity transmission system a common load-frequency control area (LFC area), where Amprion is responsible for the procurement of balancing services. As such, Creos doesn't directly procure any balancing capacity nor balancing energy.

6.4.2. RESTRICTIONS IN THE PREQUALIFICATION OF RESERVE PROVIDING GROUPS (RPGS)

The prerequisite for BSPs based in Luxembourg to participate in the German balancing market is a successful prequalification. The prequalification process for technical units (TU) connected to the Luxembourgish grid operated by Creos Luxembourg is done by the German transmission system operator (TSO) Amprion¹⁷. The German rules for participation in the balancing market¹⁸ uniformly regulate market access from qualification to settlement for all market participants. A BSP requires a framework agreement with Amprion, which takes on the role of the connecting TSO, as well as a successful prequalification procedure for the respective TU in Luxembourg.

No combinations of generation, demand or storage are explicitly prohibited for FCR, aFRR, or mFRR. All combinations are allowed in reserve providing groups, subject to meeting technical and prequalification requirements.

Prequalification is required per balancing product (FCR, aFRR, mFRR), but not separately for balancing capacity and balancing energy, as both are assessed together within the same process.

6.4.3. LARGE MINIMUM ELIGIBLE CAPACITY

The prequalification process itself does not set a strict minimum MW threshold.

6.4.4. UNREGULATED DURATION OR LONG PREQUALIFICATION PROCESS

First time prequalification

Eight weeks are available to the reserve connecting TSO to evaluate the completeness of a prequalification application, four weeks for the reserve provider to submit additional information from receipt of a request by the TSO for additional information and three months for the TSO to confirm to the reserve provider if the reserve providing unit/group has been prequalified.

Re-prequalification

No re-prequalification process is defined.

Product design and market architecture

¹⁷ [Creos website – Balancing capacity](#)

¹⁸ [Modalitäten für Regelreserveanbieter](#)

ILR is not aware of any specific/local products that could be used by Amprion and serve the purpose of balancing the common Creos/Amprion LFC area.

6.4.5. TOO SHORT PREDEFINED MINIMUM DURATION BETWEEN CONSECUTIVE ACTIVATIONS

For both aFRR and mFRR, the minimum time between deactivation and subsequent activation is not fixed, with no defined maximum, as activations are driven by real-time system needs rather than predefined intervals.

6.4.6. LONG PROCUREMENT LEAD TIME AND LONG DURATION OF BALANCING CAPACITY CONTRACTS

Given the particular situation of Luxembourg, balancing capacity is procured by Amprion for the common Creos/Amprion LFC area.

6.5. RESTRICTIVE REQUIREMENTS TO PROVIDE CONGESTION MANAGEMENT

6.5.1. UNJUSTIFIED LACK OF MARKET-BASED TSO CONGESTION MANAGEMENT

There are currently no congestions on the Luxembourgish transmission system. Creos TSO does not use any redispatch measures as there are currently no substantial congestions problems. Remedial actions are currently only applied in emergency situations (force majeure). These actions are not financially compensated nor are they procured as a market product. Under the connection or use-of-system agreement, connection users are required to comply with the instructions issued by the system operator.

6.5.2. UNJUSTIFIED LACK OF MARKET-BASED DSO CONGESTION MANAGEMENT

It is important to note that the Luxembourgish electricity grid currently does not show any significant congestions with the only congestions occurring being due to high generation of renewables. In order to solve these congestions, the DSO can, in accordance with the connection agreement, send instructions to generation units to limit their injection. These actions are not financially compensated nor are they procured as a market product. In 2025, such measures were used 11 times, resulting in a volume of 74,3 MWh of curtailed renewable electricity (from wind generation).

The use of such a non-market-based congestion management is mainly due to the very low frequency of congestions at the moment, as well as the small size of Luxembourg.

Non-market-based congestion management was only applied to solve physical congestions in specific grid areas or voltage levels. When protection limits in substations are reached, dispatching identifies potential installations which can solve the congestion and sends out the information to reduce the injection.

If the congestion becomes more frequent or occur in wider zones, the use of non-market-based congestion management will be reassessed. For the future we see a tendency for market-based tenders by the system operators in order to procure capacity congestion management.

6.5.3. CONSTRAINTS IN LOCAL MARKETS FOR TSO/DSO CONGESTION MANAGEMENT

No local markets for TSO/DSO congestion management are operational in Luxembourg.

6.6. COMPLEX, LENGTHY, AND DISCRIMINATORY ADMINISTRATIVE REQUIREMENTS

6.6.1. INEFFICIENT GRID CONNECTION PROCEDURES

All the relevant information on procedures to obtain a grid connection permit for renewables self-consumers, energy storage facilities and installation of heat pumps can be found on the websites of the system operators. A step-by-step connection procedure can be done online, parallel to other required authorisations. Deadlines for all steps of the procedures are clearly defined by Article 5 of the Electricity Law (capacity requests) or in the respective documents on the DSOs websites (e.g. capacity requests).

Article 5 of the Electricity Law states that TSOs and DSOs shall establish standardised and simplified procedures to facilitate the connection to the grid of decentralised producers of electricity from renewable energy sources or through high-efficiency cogeneration, and shall provide the complete and necessary information required, including:

- a) a comprehensive and detailed estimate of the costs associated with the connection;
- b) a reasonable and detailed timetable for the receipt and processing of the application;
- c) an indicative timetable for any proposed connection to the grid.

The same article states that installations or aggregated generation units belonging to self-consumers of renewable energy, and demonstration projects with an electrical capacity of 30 kW or less – or the equivalent for connections other than three-phase connections – must be connected to the grid following a simple application to the DSO. If the DSO does not reject the request within one month (for security reasons only), the installation or aggregated generation unit may be connected.

In accordance with Article 50(4a) of the Electricity Regulation and Article 31(3) of the Electricity Directive a capacity map for generation for the all the voltage levels higher or equal to 20 kV has been published in July 2026. A similar map for demand is currently being established and will be published in the future.

Connection queues in Luxembourg are currently quite long, with 821 MVA of wind and 422 MVA of solar generation being waitlisted as of 31 December 2025. Given this long waiting list, one might question whether the “first come, first served” principle currently applied represents an efficient solution. Discussions about alternative options are however still in the early stages.

6.6.2. DISPROPORTIONATE PROCEDURES AND REQUIREMENTS FOR MARKET ACCESS

We have not identified or been made aware of any potentially unjustified differences in procedures and requirements to access wholesale electricity markets and local markets for congestion management 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).

6.7. LACK OF REGULATORY INCENTIVES TO SYSTEM OPERATORS TO CONSIDER NON-WIRE ALTERNATIVES

The Luxembourgish regulatory framework does ensure that both TSOs and DSOs can procure flexibility services as needed for efficient and secure system operation. Article 27(7) of the Electricity Law states that the rules adopted by network operators for procuring technical flexibility services shall be objective, transparent and non-discriminatory, and shall be drawn up through a transparent and participatory process involving all relevant electricity companies and market participants, including those offering energy

generated from renewable sources, those engaged in active demand response, operators of energy storage facilities and aggregators.

Concerning the requirement for TSOs and DSOs to assess the procurement of flexibility services as an alternative to grid expansion, the electricity law states that the network development plans drawn up for high-, medium-, and low-voltage networks provide transparency regarding the technical flexibility services needed in the medium and long term, and set out the investments planned for the next five to ten years, with particular emphasis on the key infrastructure required to connect new generation capacity and new loads, including electric vehicle charging points. These network development plans also include the use of active demand participation, energy efficiency, energy storage facilities, and other resources that network operators must use as alternatives to expanding their networks.

The regulatory framework allows recovery of justified and efficient CAPEX and OPEX costs through the allowed revenue as defined in the tariff methodology which can include costs related to flexibility and digitalisation.

The regulatory framework does not provide explicit incentives for TSOs or DSOs to procure flexibility, however DSOs receive a specific financial incentive for the deployment of smart stations. This incentive is structured as a performance-based mechanisms and is mainly aimed at improving network observability, digitalisation and enhancing system monitoring. More broadly, the regulatory framework supports efficient network operation, the integration of renewables and flexibility, and allows for experimental projects or regulatory sandboxes to test innovative solutions.

So far, the incentives (applicable starting 2025) have shown limited effectiveness and may lead to overinvestment or could even promote deployment beyond what is technically necessary or economically optimal.

6.8. OTHER BARRIERS

Given the fundamental organisation of the electricity market between Germany and Luxembourg, the fact that there are different grid tariffs within the respective Amprion and Creos networks could be interpreted as a barrier. An asset planning to participate in the DE/LU electricity market will opt for the cheaper grid in accordance with the applicable grid tariff. This does not pose a problem with regard to system flexibility needs, as these apply at the bidding zone level and both grids would therefore benefit accordingly. The situation is different when it comes to distribution network flexibility needs, as these must be dealt with locally. The geographical preference for other networks consequently leads to a shortage of actors and options.

The volume-based part of the current network tariff for electricity consumption represents a further financial barrier to storage, as these charges also apply to the volume of electricity that is merely stored and later reinjected, rather than just to the volume used for own consumption.

7. CONCLUSIONS

7.1. KEY FINDINGS

7.1.1. FLEXIBILITY NEEDS

The analysis and interpretation of the System Flexibility Needs results on bidding zone level regarding:

- RES integration needs - to meet combined national targets regarding RES production;
- Ramping needs - the necessary flexibility to cover variations of the residual load on an hourly basis;
- Short term flexibility needs – the necessary flexibility to cover unexpected differences between the forecast and the residual load

can be summarised as follows:

- RES Integration: no structural integration need across the different WS was identified, although WS14 shows an isolated gap;
- Ramping needs: Hourly ramps are covered under ERAA assumptions, but sub-hourly needs are excluded from the analysis;
- Short-term flexibility needs: uncovered upward needs exist.

A detailed interpretation of the identified System Flexibility Needs can be found in the German FNA report released by the Bundesnetzagentur.

Simulations and analysis performed by Creos on the Network Flexibility Needs enabled an insight on the future evolution of flexibility needed on the HV-grid level to prevent grid congestions. As described in 3.1.1, the analysis is based on production and residual load curves from the year 2024. The lack of additional weather scenarios has the disadvantage that the impact of different weather conditions – which have a significant influence on RES – cannot be fully accounted for in the identified flexibility. Furthermore, several assumptions and methodological aspects made, as described in 3.3 and 3.4, to simplify the analysis could result in the identified needs being underestimated or overestimated. In addition, any flexibility needs to respect the 980 MVA net-import limit on the interconnectors to the German grid are not considered in the analysis. Therefore, the results should be interpreted with due caution as they focus solely on the high-voltage grid and transformer stations and do not necessarily take into account the technical and contractual limits applicable to other voltage levels or cross-border connections.

The temporal distribution over the day and year of identified upward network flexibility needs correspond to the typical behaviour of consumers. High upwards needs were observed in the middays and evenings or during cold weather seasons. Temporal distribution of downward needs is influenced by RES production patterns, e.g. high simultaneously injection during midday due to PV and wind, result in high downward needs. Comparing the total volumes by direction for the year 2030, upwards needs will slightly outweigh downward needs, with both volumes being quite small with 1,2 GWh and 3,3 GWh over the whole year. In a relative view, flexibility needs will increase drastically in 2035 with downwards needs now exceeding that for upwards needs. In absolute terms, however, the volumes remain with 71,6 GWh and 17,4 GWh at a level where they could still be tackled by corresponding flexibility services.

The investigations at regional level highlight four regions in particular. Regarding identified upwards needs, the Center and South-West regions show the greatest demand in terms of energy and power. Even though the volume required is well below that of downward needs, these cases present the greater challenge, as upward needs are more difficult to counteract. Unlike downward needs – where the possibility of curtailment means that the problem can, in fact, be part of the solution – for upwards needs this inherent flexibility is lacking among consumers and loads. Although the upward needs were analysed for the N-1 scenario –

meaning that the identified needs only arise in case of a N-1 event – the results indicate a need for consideration, as these loads may not be supplied reliably in the future and could indicate a structural problem. Upward needs observed in the ‘combined scenario’ are triggered exclusively by scenarios based on the high demand estimate.

As regards downward needs, the North and West regions by far have the highest demand in the long term. Notably, the region North has a high need for flexibility even though this is where the most extensive grid expansion measures are being implemented in the long term. This is caused by the relatively high number of renewable energy installations resulting from the chosen scenario and assumptions.

In general, a need for downward flexibility on the high-voltage grid lines was identified in only three regions East, North and West. In these regions, lines do account for a significant proportion of the identified flexibility power, regional capacity and energy. It is only in these cases that flexibility services could also be activated in the HV grid as a countermeasure to alleviate the power flow accordingly. In the other cases where a need has been identified at transformer/substation level, the activation must take place in the subordinate networks directly at the root cause. Otherwise, the power flow through the transformer cannot be influenced and the congestion prevented. Regarding upward needs, no clear conclusion in this regard can be drawn as the methodology did not consider the N-1 case for Upward Needs on HV lines.

A deep dive on the flexibility needs results depending on the scenario in chapter 11.2.1 enabled an insight on how national needs could change based on the individual development of consumption and RES generation. If both continue to develop in line with the low estimate for consumption and medium-high for generation, a significant amount of downward or upwards needs will not arise until 2035. In general, the low estimate for consumption results for both target years in limited upward flexibility needs for the corresponding scenarios. Only the worst case “high demand estimate” triggers upward needs. However, even the medium-high estimate for generation produces relatively high downward flexibility needs in 2035. In the long term, downwards needs will outweigh upward needs. The comparison shows that the scenario with higher consumption also indicates a greater need for downward flexibility due to higher power flows within the high-voltage grid. Therefore, it can be concluded that higher consumption does not necessarily mitigate excessive RES production. However, in all scenarios, the power flow does not simply disappear. The excess energy is fed into the overlaying 220 kV transmission grid via the EHV/HV substations, which was not studied in the analysis because they were considered as out of scope.

7.1.2. BARRIERS FOR FLEXIBILITY

The evaluation identified multiple barriers for flexibility providers located in Luxembourg. Whilst assets located in Luxembourg can participate in the FCR and FRR markets, they are still unable to access some of the German ancillary services, as for example redispatch or capacity reserves, as well as the markets for instantaneous reserves or for the provision of black-start energy. Given that storage facilities are ideally suited to providing such services in the future, this may mean that the financial prospects for such assets are more attractive in the other scheduling area within the same bidding zone. This, as well as the fact that there are different network tariffs with different approaches within the same market area could lead such assets to locate in the grid which offers the best conditions for them. This, in turn, could hinder the emergence of a local flexibility market in consequence of a lack of market actors and assets.

At the same time, the small size of the Luxembourgish market inevitably leads to a lack of innovation, as margins are low compared with other markets and potential is quickly exhausted.

Another barrier arising from the fundamental organisation of the market is the lack of a NEMO hub for direct market access in Luxembourg, which would eliminate the need for nominations to be routed via Amprion. This would enable market participants to take part in shorter-term trading – which is currently blocked by the 15-minute nomination deadline between the scheduling areas of Amprion and Creos – and allow for a

broader market access. As these barriers stem from the fundamental structure of the Luxembourg electricity market, they are not easy to address. Any changes would quickly have far-reaching technical and financial consequences for the current market organisation.

Historically, there has been only minimal need for flexibility, as congestions occur very rarely. However, this could change in the future in view of the results. Flexible connection agreements, for which the regulatory framework is about to come into force soon, will be able to help tackle upcoming upward needs.

Although the completion of the smart meter roll-out in principle gives every user the opportunity to benefit from dynamic electricity products, demand for such is currently low. However, smart meters also make it possible to set up energy communities, which are becoming increasingly common. These provide their members with a financial incentive – in the form of exempting them from network tariffs or electricity taxes – to time their consumption to coincide with periods of high PV production. This could result in an indirect form of flexibility that cannot be specifically triggered, but which serves to mitigate high feed-in volumes at a local level and, by shifting the load over time, to smooth out subsequent consumption peaks.

The analysis carried out by the German TSOs for the transmission network and by Creos for the HV distribution network in the first edition of the Flexibility Needs Assessment report was able to highlight already several interesting trends for the near future in regards of the national and cross-border flexibility needs according to the assumptions made. The results should by no means be interpreted as definitive predictions, but rather as indicators of how the situation regarding flexibility in the distribution network might develop in line with the assumptions made. It remains to be seen how Luxembourg's energy landscape will develop.

7.2. NEXT STEPS

The results of the flexibility assessment now serve three main purposes. Firstly, they provide important insights for the network development plans and are therefore to be incorporated into the next iterations. Secondly, the results can serve as a guideline for the government in developing non-fossil flexibility support schemes. This is closely linked to the final point, namely the removal of identified market barriers in order to expand the portfolio of non-fossil flexibility options. Even though some barriers can be removed in the short to medium term, e.g. providing a clear and comprehensive regulatory framework for flexibility service providers. It should be noted that some of the barriers are due to the fundamental structure of the Luxembourg electricity market, which are difficult to remove and would require considerable technical and financial effort.

The next iteration of the Flexibility Needs Assessment, which is due in two years' time, shall be further improved by applying the lessons learned, by utilising refined assumptions and performing a further detailed analysis. The improvements for the next version should include, amongst others:

- Consideration of the latest NECP version targets for the calculation of combined DE/LU targets on bidding zone level.
- Consideration of multiple climate years, as they can have a significant impact on the results due to the heavy reliance of renewable energy on weather conditions. Care should be taken to ensure that the climate years used in the analysis of system and network needs are the same, to ensure the consistency of the results regarding the fine-tuning process.
- Investigation of voltage problems.
- Extension of the voltage granularity to include other network levels.
- Assessment of network flexibility needs of the transmission grid, EHV/HV transformer stations and interconnectors.

8. ABBREVIATIONS

Abbreviation	Description
Amprion	Amprion GmbH
BNetzA	Bundesnetzagentur
DNDP25	Distribution Network Development Plan 2025
DSO	Distribution System Operator
ERAA	European Resource Adequacy Assessment
EVA	Economic Viability Assessment
FNA	Flexibility Needs Assessment
HV	High Voltage (110 kV and 65 kV)
ILR	Institut Luxembourgeois de Régulation
LFC Area	Load Frequency Control Area
MV	Medium Voltage (20 kV)
NECP	National Energy and Climate Plan
NEMO	Nominated Electricity Market Operator
RES	Renewable Energy Source
SR24	Scenario Report 2024
TSO	Transmission System Operator
WS	Weather Scenario

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11. ANNEX 1 – DEEP DIVE ON FLEXIBILITY NEEDS RESULTS

11.1. RESULTS AFTER FINE-TUNING

11.1.1. RES CURTAILMENT

As part of the fine-tuning process, in addition to the purely market-based curtailment measures within the framework of this FNA, the renewable energy curtailment measures implemented by the distribution system operators are also taken into account. This section discusses the changes to the curtailment measures resulting from DSO notifications.

Table 12 Changes to curtailment between System Need (market-based) and Fine-Tuning (overall output control)

Weather scenario	Target year	Market curtailment [TWh]	DSO curtailment [TWh]	Total curtailment [TWh]	Additional DSO curtailment [TWh]
WS14	2030	9,8	12	15,6	5,8
	2035	31,5	16,9	36,3	4,7
WS25	2030	8	12	13,5	5,5
	2035	27,2	16,9	31,4	4,2
WS28	2030	11,1	12	15,6	4,5
	2035	33,2	16,9	37,2	4,1

For the target years 2030 and 2035, the diagram shows that the volumes of curtailed renewable feed-in at distribution network level will reach a substantial level and make an independent contribution to overall curtailment. A key factor here is the reported additional distribution network operator curtailment, which quantifies the proportion of curtailment directly attributable to constraints in the distribution networks.

In the target year 2030, market curtailment ranges between 8,0 TWh and 11,1 TWh depending on the weather scenario, whilst a constant 12 TWh is reported for the distribution network level. The resulting total curtailment ranges between 13,5 TWh and 15,6 TWh. The additional curtailment caused exclusively by distribution network constraints amounts to between 4,5 TWh and 5,8 TWh, thus representing a quantitatively significant proportion of the total curtailment.

Curtailment results for the different weather scenarios and target years after the fine-tuning process are shown in Figure 33 in analogy to chapter 5.1.1.1.

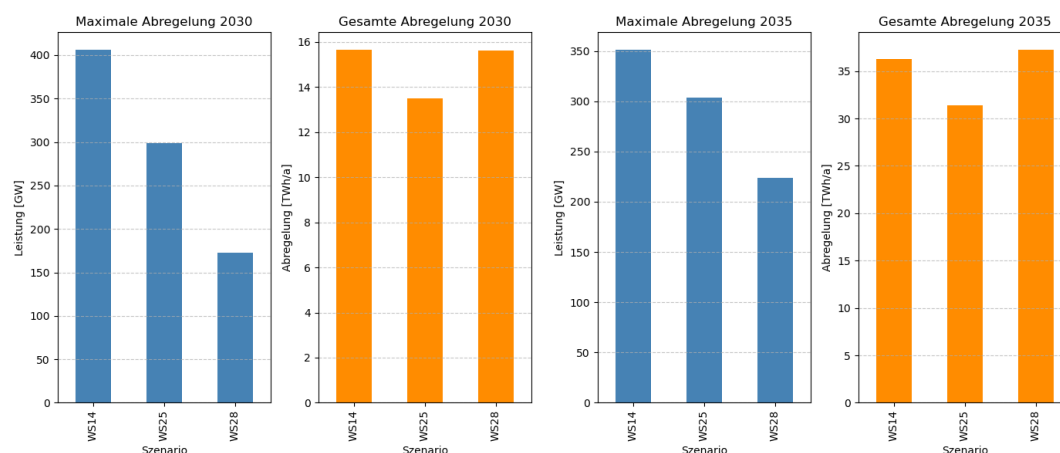


Figure 33 Fine-tuned results: Curtailment of renewable energy in ERAA 24 for the weather scenarios used in the FNA for the target years 2030 and 2035

11.1.2. DERIVING MARGINAL BENEFIT

In accordance with the FNA methodology, for all scenarios in which a renewable energy integration target has not been met, the measures potentially required to close the gap are assessed. This is the case for the target year 2030 in WS 14. The methodological approach is essentially the same as that was used to derive the marginal benefit of system needs. In this approach, however, the curtailment under consideration of the feed-in profiles of the distribution system operators is also taken into account. Furthermore, the gap to be closed in the renewable energy integration target increases from an initial figure of around 8 TWh to 13,77 TWh.

Compared with time series derived purely from market data, this scenario shows an increased marginal benefit of storage technologies at the beginning. This is due to the inclusion of the distribution system operators' curtailment time series, which are more spread out over time than the market-based curtailment signals. The spatially and temporally diversified feed-in at distribution network level results in more frequent and longer-lasting periods of surplus, which enable more efficient use of storage, particularly in the early stages of development. Accordingly, at the start of the development path, storage can contribute more to reducing curtailment and integrating renewable energy than in a market-based comparison. However, the marginal benefit progressively diminishes with more capacity being installed and the potential for curtailment therefore reducing.

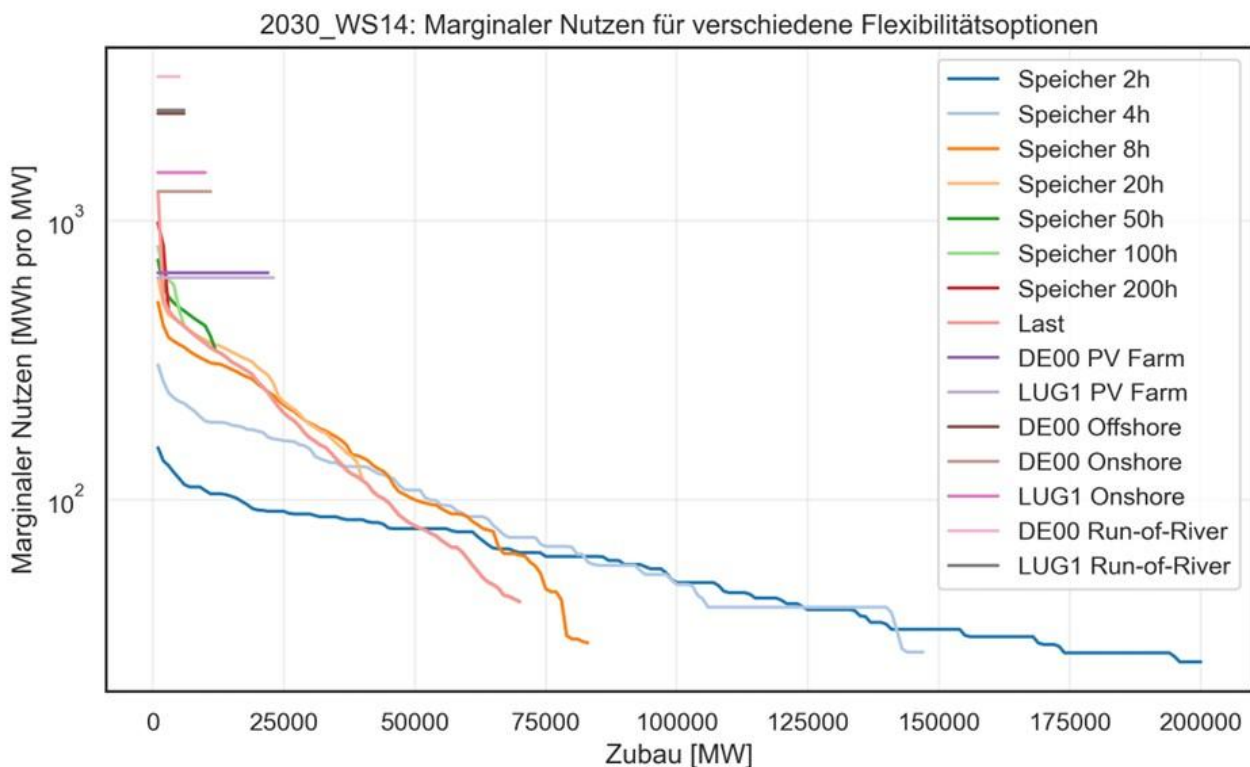


Figure 34 Marginal benefits of the various flexibility options considered for bridging the gap between renewable energy integration targets in the target year 2030, WS 14 (fine-tuning)

Regardless of the specific characteristics of each scenario, the fundamental findings regarding the assessment of marginal benefit remain valid. The development of renewable generation capacity including curtailment continues to yield significantly higher marginal benefit values than storage technologies, as additional renewable energy capacity, with its respective full-utilisation hours, contributes directly to increasing the quantities of energy that can be integrated. Storage systems, by contrast, make a complementary contribution to renewable energy integration, which is determined in particular by the temporal shifting of feed-in that would otherwise be curtailed. Within storage technologies, systems with

high energy-to-power ratios ($E/P > 8$ h) consistently show higher marginal benefits than short-term storage systems, whilst at very high E/P ratios there are hardly any further differences. The basic ranking of the technology options considered remains consistent across the scenarios. No economic costs were considered for deriving the marginal benefit curves.

11.1.3. ADDITIONAL FLEXIBILITY TO MEET RES INTEGRATION TARGETS

The additional curtailment at distribution network level reduces renewable energy feed-in. Consequently, the uncovered renewable energy integration target in the fine-tuning phase shifts for each scenario. In 2030, there is still only a need for renewable energy integration in WS14 amounting to 13,77 TWh (5,8 TWh more compared to the system needs).

Table 13 Fine-tuned uncovered RES integration target for the year 2030

	WS14	WS25	WS28
Feed-in of volatile renewable energy (ground-mounted PV, wind, run-of-river) [TWh]	526,53	541,89	551,69
NECP target for volatile renewable energy [TWh]	540,31	540,31	540,31
RES curtailment [TWh]	15,64	13,49	15,61
RES integration target [TWh]	1,87	15,08	26,99
Uncovered RES integration target [TWh]	13,77	0 (-1,59)	0 (-11,39)

For 2035, all weather scenarios considered show negative values, indicating that the underlying integration target is systematically exceeded. Consequently, no additional flexibility requirement is identified; the median being 0 TWh.

Table 14 Fine-tuned uncovered RES target for the year 2035

	WS14	WS25	WS28
Feed-in of volatile renewable energy (ground-mounted PV, wind, run-of-river) [TWh]	782,18	807,02	820,86
NECP target for volatile renewable energy [TWh]	637,17	637,17	637,17
RES curtailment [TWh]	36,25	31,40	37,24
RES integration target [TWh]	181,26	201,25	220,93
Uncovered RES integration target [TWh]	0 (-145)	0 (-170)	0 (-184)

11.2. DEEP DIVE ON DSO FLEXIBILITY NEEDS RESULTS

11.2.1. RESULTS OF BASE SCENARIOS S1-S4

In the following, as an addition to chapter 5.2.1 on national flexibility needs based on the combined scenario, the results for the four baseline scenarios S1 to S4 are examined in greater detail. As each scenario is based on individual assumptions regarding the development of the national energy consumption and generation, comparing these scenarios makes it possible to forecast trends in flexibility needs (e.g. in the event of more rapid development of renewable energy sources).

Figure 35 shows the total flexibility energy volume identified for each scenario. In both target years, scenarios S1 (0,29 MWh for 2030 and 103,55 MWh for 2035) and S2 (0,77 MWh for 2030 and 114,65 MWh for 2035) indicate almost no flexibility need in upward direction in terms of volume in 2030 due to the low demand estimate, with S1 indicating even slightly less volume because of the higher RES generation assumption. S3 and S4, which are based on the high demand estimate, show for 2035 a significantly higher amount of flexibility needs in the upward direction in terms of energy compared to the combined scenario. Again, the scenario involving higher RES production (S4) shows the slightly lower flexibility needs.

Regarding 2035, the very high energy volume needed to meet downward flexibility needs of 210 GWh for S1 and 222 GWh for S3 is particularly striking (scenarios in which 100 % of the authorized and waitlisted capacity requests are assumed to be connected). It is also interesting to note that the highest downwards needs in terms of volume were identified for S3, the scenario with a higher consumption assumption compared to S1. This can be explained by the fact that the high demand estimate in S3 creates higher power flows across the HV grid than the scenario with the low demand estimate, which result in congestions on HV lines. According to the methodology pursued by Creos, identified flexibility needs are classified according to the predominant flexibility need direction emerging from the region, in this case this is the downwards direction. In accordance with the principles of load flow, the excess energy will flow into the 220 kV level. However, constraints coming from the EHV/HV were considered as out of scope for this FNA iteration.

If we consider scenario S2, which assumes the slowest growth in consumption and production, there are still flexibility needs for both target years. However, these are only significant in downward direction in 2035.

Regarding the identified flexibility needs of the network lines, these remain limited to the regions East, North and West only, regardless of the scenario for 2035. For the target year 2030, the scenarios based on the highest RES generation assumption (S1 and S3) indicate a flexibility need on network lines, just as it was the case for the Combined Scenario. The identified needs on HV lines were always in downward direction.

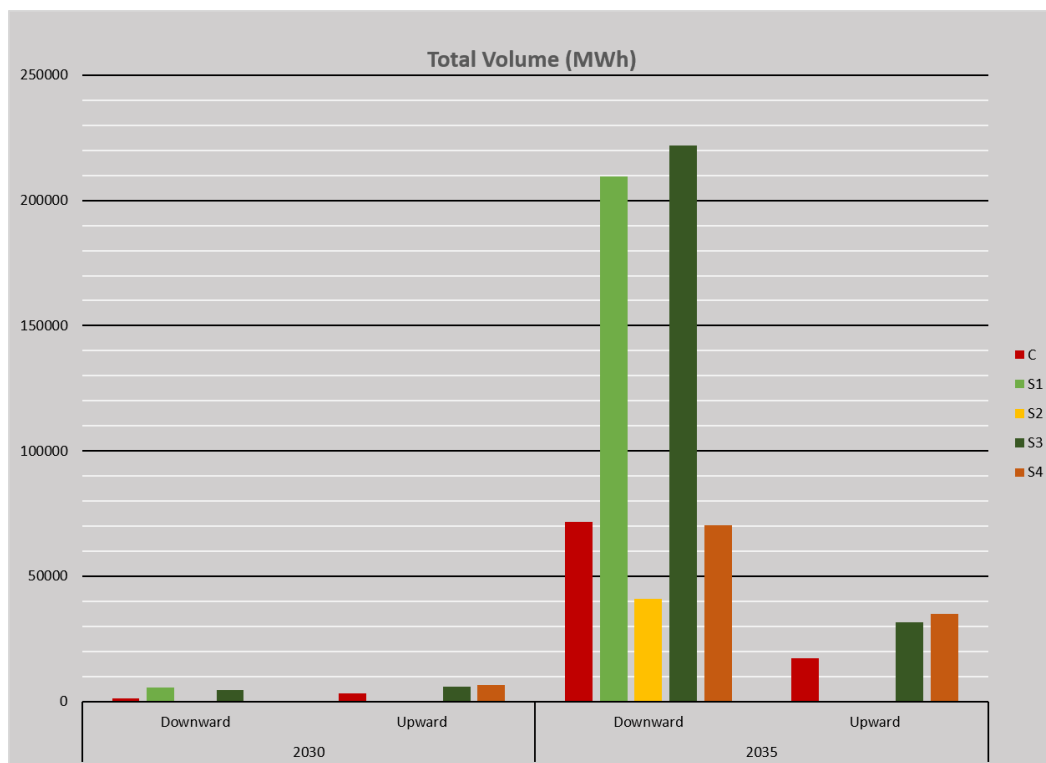


Figure 35 Total energy volume per scenario

Regarding the max instant Power, Figure 36 shows mainly the same trends as discussed for the total energy volume. For upward and downward needs, the maximum instant power is double the amount as identified for the combined scenario.

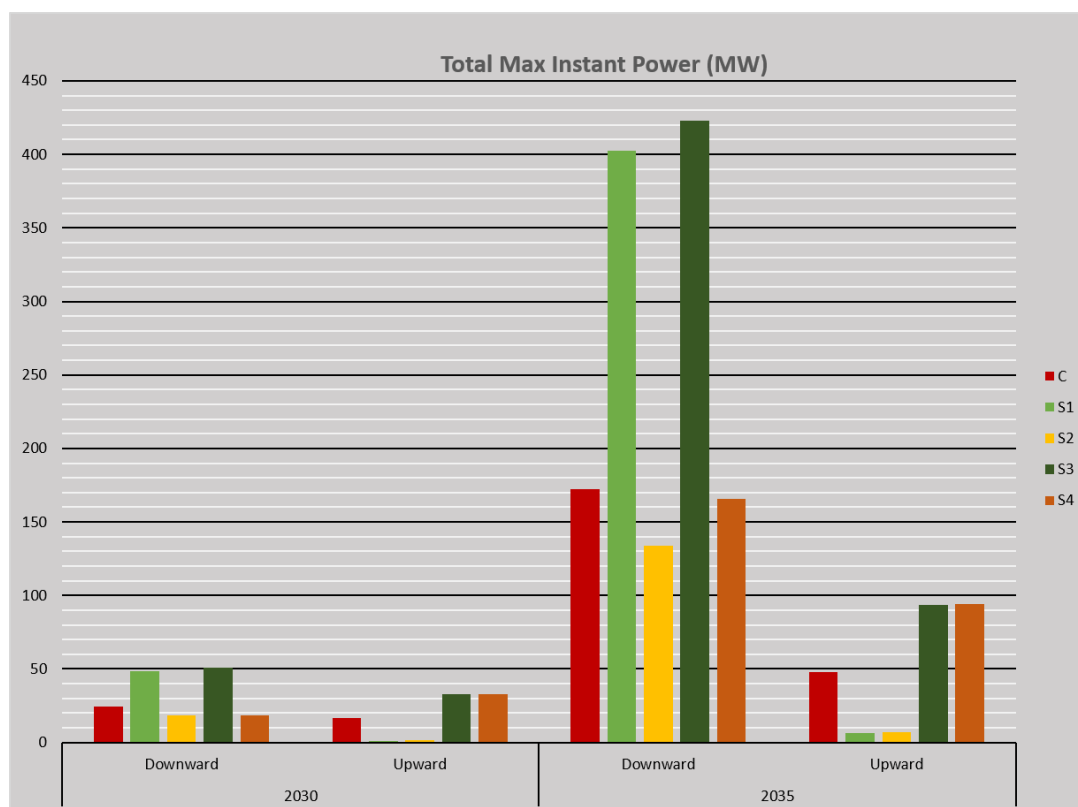


Figure 36 Total max power per scenario

To supplement the previous figure, the regional capacity for each scenario is shown below; in other words, the installed capacity required to meet the identified flexibility needs. Here, too, the trends between the individual scenarios remain the same.

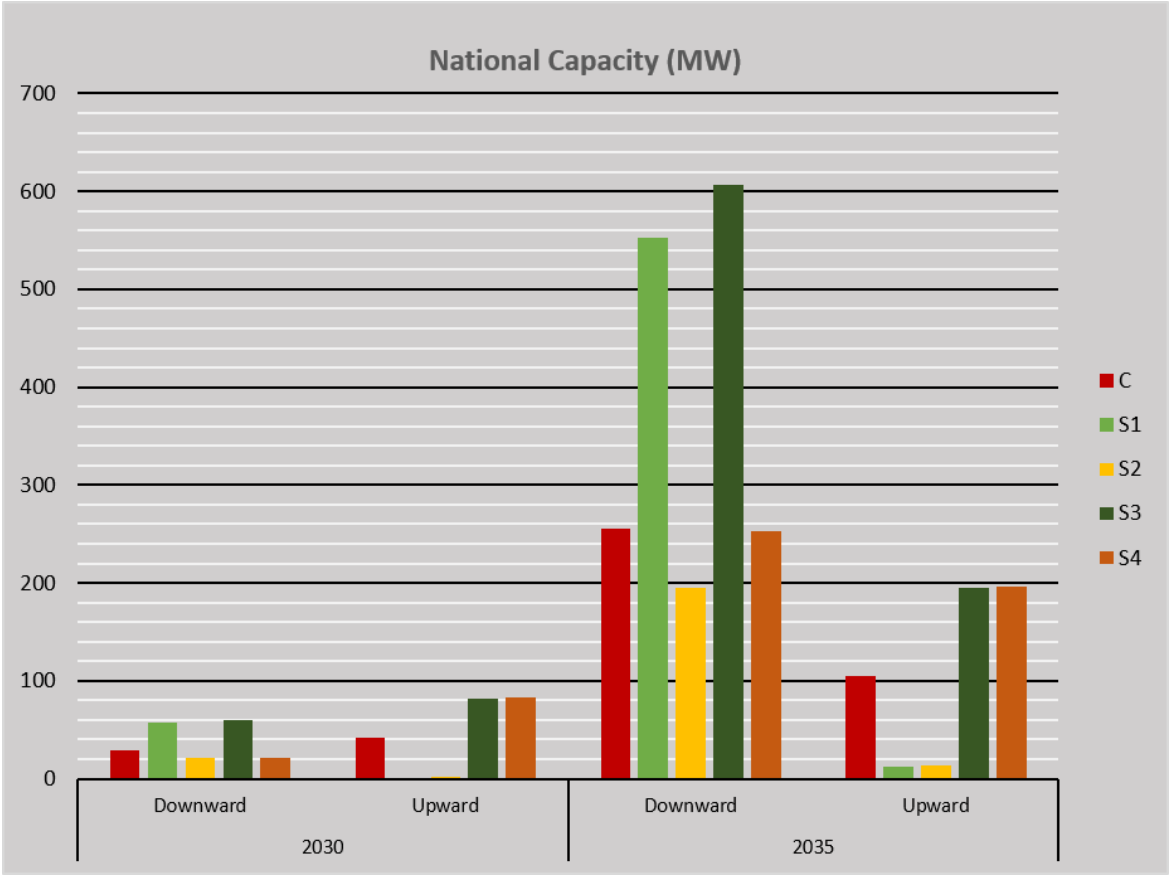


Figure 37 National capacity per scenario

Figure 38, Figure 39 and Figure 40 give a more detailed view on the energy, maximum instant power as well as the regional capacity required to meet flexibility needs per region, scenario and target year.

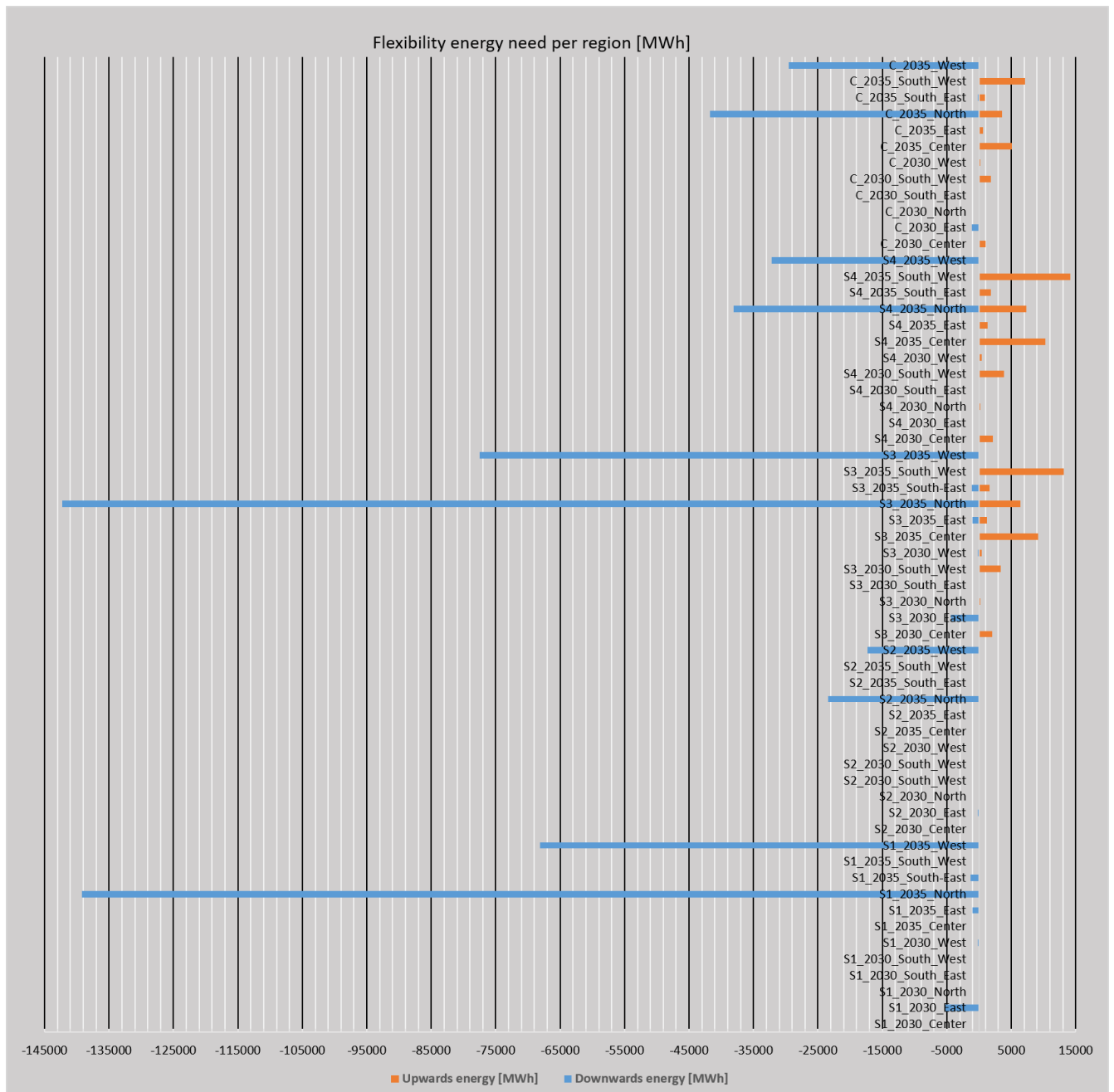


Figure 38 Total energy per scenario, region and target year

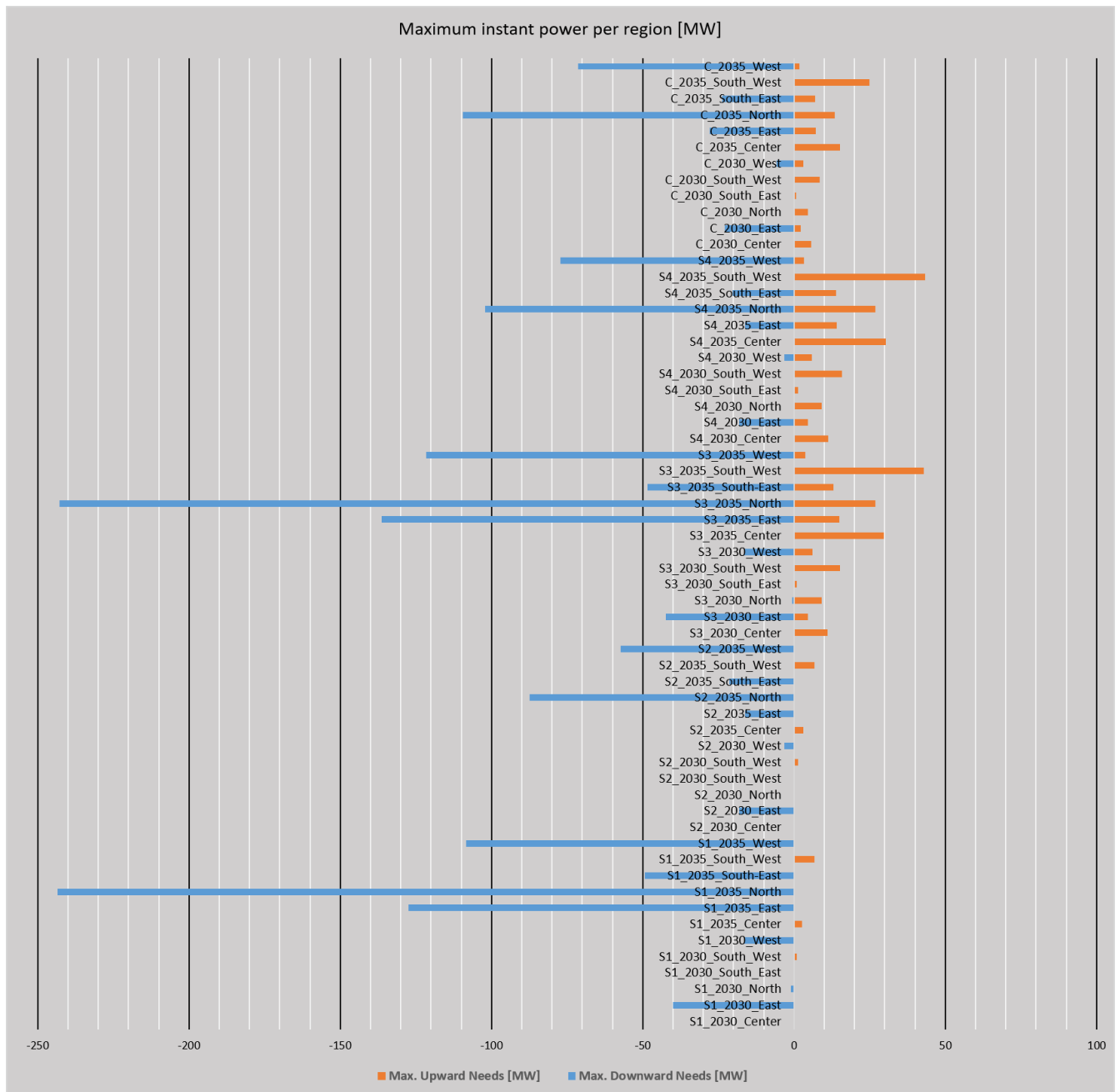


Figure 39 Max power per scenario, region and target year

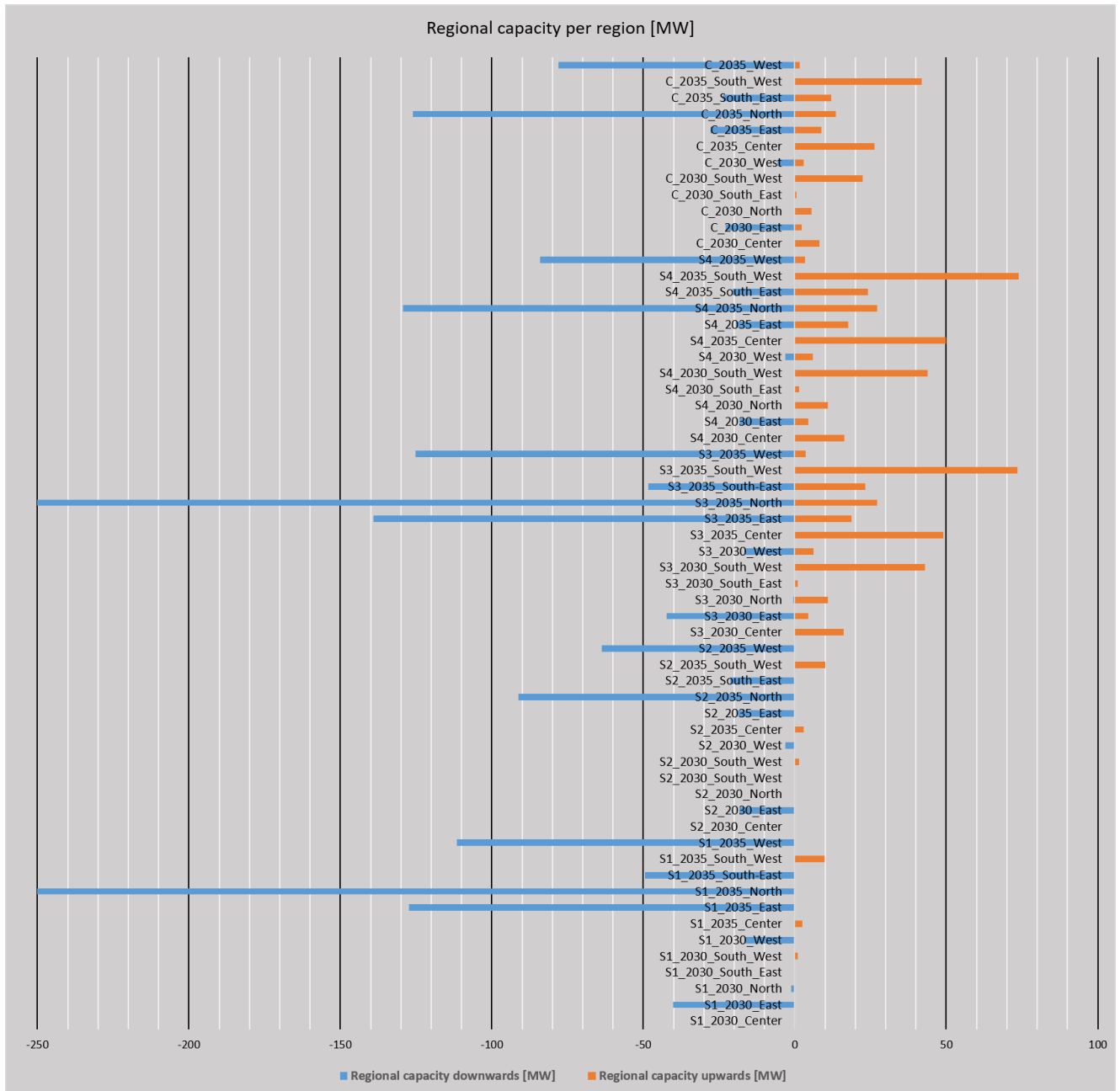


Figure 40 Regional capacity per scenario, region and target year

11.2.2. NATIONAL INDICATORS

National Indicators					
	Combined scenario	Scenario 1	Scenario 2	Scenario 3	Scenario 4
2030					
National Capacity (MW)					
Downward	28,7	57,5	21,3	59,3	21,3
Upward	42,0	0,9	1,4	81,8	82,9
Total Max Instant Power (MW)					
Downward	24,5	48,6	18,2	50,9	18,2
Upward	16,5	0,9	1,4	33,0	33,0
Total Volume (MWh)					
Downward	1153,5	5530,4	206,2	4595,7	146,0
Upward	3271,9	0,3	0,8	6052,7	6665,8
Transformer share [Capacity] (%)					
Downward	96,2	92,4	100,0	88,8	100,0
Upward	100,0	100,0	100,0	100,0	100,0
Transformer share [Max Power] (%)					
Downward	95,5	91,0	100,0	86,9	100,0
Upward	100,0	100,0	100,0	100,0	100,0
Transformer share [Volume] (%)					
Downward	99,9	99,9	100,0	99,9	100,0
Upward	100,0	100,0	100,0	100,0	100,0
2035					
National Capacity (MW)					
Downward	255,6	553,0	195,0	606,3	253,2
Upward	104,3	12,5	13,0	195,1	196,0
Total Max Instant Power (MW)					
Downward	172,5	402,7	133,9	423,0	165,7
Upward	47,6	6,7	6,8	93,3	94,2
Total Volume (MWh)					
Downward	71640,7	209602,6	40868,5	221831,4	70396,0
Upward	17361,4	103,6	114,7	31646,4	34938,5
Transformer share [Capacity] (%)					
Downward	61,3	68,7	68,1	62,3	51,7
Upward	100,0	100,0	100,0	100,0	100,0
Transformer share [Max Power] (%)					
Downward	58,8	65,5	62,7	61,5	50,0
Upward	100,0	100,0	100,0	100,0	100,0
Transformer share [Volume] (%)					
Downward	37,7	62,7	45,7	54,1	19,0
Upward	100,0	100,0	100,0	100,0	100,0

11.2.3. GUIDING CRITERIA

Table 15 Guiding Criteria – Cumulative duration of discontinuous need

Cumulative duration of discontinuous need - Expected active hours (h/year)						
	Center	East	North	South-East	South-West	West
Downward						
2030	0,0	155,9	0,3	0,0	0,0	0,0
2035	0,0	15,5	976,3	25,7	0,0	1553,1
Upward						
2030	350,1	38,9	49,1	1,2	551,8	0,0
2035	1064,9	198,3	486,8	355,0	952,0	6,2

Table 16 Guiding Criteria – Distribution over day

Distribution over day						
	Center	East	North	South-East	South-West	West
Downward						
2030						
Share of annual active hours (%)						
Evening	0,0	17,0	0,0	0,0	0,0	2,2
Midday	0,0	28,3	100,0	0,0	0,0	89,5
Morning	0,0	22,2	0,0	0,0	0,0	8,4
Night	0,0	32,6	0,0	0,0	0,0	0,0
Weighted active hours (h/year)						
Evening	0,0	26,5	0,0	0,0	0,0	0,2
Midday	0,0	44,1	0,3	0,0	0,0	8,3
Morning	0,0	34,6	0,0	0,0	0,0	0,8
Night	0,0	50,8	0,0	0,0	0,0	0,0
2035						
Share of annual active hours (%)						
Evening	0,0	1,3	26,8	0,0	0,0	24,5
Midday	0,0	80,2	23,3	91,1	0,0	26,6
Morning	0,0	13,7	23,8	8,9	0,0	24,0
Night	0,0	4,8	26,1	0,0	0,0	24,9
Weighted active hours (h/year)						
Evening	0,0	0,2	261,5	0,0	0,0	380,4
Midday	0,0	12,4	227,8	23,4	0,0	412,5
Morning	0,0	2,1	232,5	2,3	0,0	373,1
Night	0,0	0,7	254,5	0,0	0,0	387,1
Upward						
2030						
Share of annual active hours (%)						
Evening	48,3	21,2	43,6	0,0	53,8	52,9
Midday	28,8	26,5	36,7	39,6	24,2	27,1
Morning	17,6	52,3	13,7	60,4	20,5	17,1
Night	5,3	0,0	6,0	0,0	1,5	3,0

Weighted active hours (h/year)						
Evening	169,3	8,2	21,4	0,0	297,0	57,8
Midday	100,7	10,3	18,0	0,5	133,5	29,6
Morning	61,7	20,4	6,8	0,7	113,1	18,7
Night	18,5	0,0	3,0	0,0	8,3	3,3
2035						
Share of annual active hours (%)						
Evening	21,2	39,5	42,1	34,8	44,0	0,0
Midday	36,6	29,1	23,6	35,9	29,2	26,6
Morning	38,3	25,6	26,3	29,3	20,5	73,4
Night	3,9	5,9	8,0	0,0	6,3	0,0
Weighted active hours (h/year)						
Evening	225,3	78,3	205,2	123,5	419,1	0,0
Midday	389,9	57,6	114,8	127,3	277,9	1,6
Morning	408,0	50,8	127,9	104,0	194,7	4,5
Night	41,8	11,6	39,0	0,1	60,3	0,0

Table 17 Guiding Criteria – Distribution over weekday

Distribution over weekday						
	Center	East	North	South-East	South-West	West
Downward						
2030						
Share of annual active hours (%)						
Monday	0,0	11,9	0,0	0,0	0,0	24,1
Tuesday	0,0	14,2	0,0	0,0	0,0	21,1
Wednesday	0,0	17,3	0,0	0,0	0,0	6,5
Thursday	0,0	20,5	0,0	0,0	0,0	15,1
Friday	0,0	12,2	0,0	0,0	0,0	13,2
Saturday	0,0	7,6	0,0	0,0	0,0	8,4
Sunday	0,0	16,4	100,0	0,0	0,0	11,6
Weighted active hours (h/year)						
Monday	0,0	18,6	0,0	0,0	0,0	2,2
Tuesday	0,0	22,2	0,0	0,0	0,0	2,0
Wednesday	0,0	26,9	0,0	0,0	0,0	0,6
Thursday	0,0	32,0	0,0	0,0	0,0	1,4
Friday	0,0	19,0	0,0	0,0	0,0	1,2
Saturday	0,0	11,8	0,0	0,0	0,0	0,8
Sunday	0,0	25,5	0,3	0,0	0,0	1,1
2035						
Share of annual active hours (%)						
Monday	0,0	8,6	13,4	21,7	0,0	13,5
Tuesday	0,0	19,8	13,8	29,0	0,0	16,5
Wednesday	0,0	9,0	15,6	8,5	0,0	14,6
Thursday	0,0	26,7	15,4	21,8	0,0	15,8

Friday	0,0	6,1	16,0	12,1	0,0	18,0
Saturday	0,0	14,3	11,3	4,2	0,0	10,1
Sunday	0,0	15,4	14,4	2,6	0,0	11,6
Weighted active hours (h/year)						
Monday	0,0	1,3	131,1	5,6	0,0	209,1
Tuesday	0,0	3,1	135,1	7,5	0,0	256,2
Wednesday	0,0	1,4	152,3	2,2	0,0	227,2
Thursday	0,0	4,1	150,0	5,6	0,0	244,8
Friday	0,0	1,0	156,6	3,1	0,0	279,6
Saturday	0,0	2,2	110,2	1,1	0,0	156,3
Sunday	0,0	2,4	141,0	0,7	0,0	179,9
Upward						
2030						
Share of annual active hours (%)						
Monday	16,1	8,6	7,3	0,0	17,1	12,3
Tuesday	18,4	11,7	5,8	0,0	19,7	15,6
Wednesday	19,7	16,9	20,5	0,0	19,7	17,0
Thursday	19,0	30,3	19,7	0,0	21,6	19,7
Friday	16,7	32,5	33,7	100,0	18,4	18,5
Saturday	5,7	0,0	9,1	0,0	2,3	7,9
Sunday	4,4	0,0	3,9	0,0	1,3	9,0
Weighted active hours (h/year)						
Monday	56,2	3,4	3,6	0,0	94,2	13,5
Tuesday	64,5	4,6	2,9	0,0	108,6	17,1
Wednesday	69,1	6,6	10,1	0,0	108,7	18,6
Thursday	66,6	11,8	9,7	0,0	118,9	21,5
Friday	58,4	12,6	16,6	1,2	101,6	20,3
Saturday	20,1	0,0	4,5	0,0	12,5	8,6
Sunday	15,3	0,0	1,9	0,0	7,4	9,8
2035						
Share of annual active hours (%)						
Monday	18,4	14,5	15,1	15,5	15,9	26,4
Tuesday	20,4	15,4	18,9	19,1	16,5	0,0
Wednesday	20,1	25,4	18,9	20,2	16,1	2,6
Thursday	19,6	19,4	15,2	18,1	16,3	26,2
Friday	17,6	17,2	16,4	19,4	14,7	44,7
Saturday	2,7	4,3	10,6	5,6	11,6	0,0
Sunday	1,2	3,7	4,9	2,0	9,0	0,0
Weighted active hours (h/year)						
Monday	196,1	28,8	73,7	55,1	150,9	1,6
Tuesday	217,1	30,6	92,2	67,7	157,2	0,0
Wednesday	213,9	50,4	91,9	71,7	152,9	0,2
Thursday	209,1	38,5	74,1	64,1	155,6	1,6
Friday	187,8	34,1	79,8	69,0	139,7	2,8
Saturday	28,6	8,6	51,4	20,0	110,2	0,0
Sunday	12,4	7,4	23,8	7,3	85,5	0,0

Table 18 Guiding Criteria – Distribution over season

Distribution over season						
	Center	East	North	South-East	South-West	West
Downward						
2030						
Share of annual active hours (%)						
Autumn	0,0	37,8	0,0	0,0	0,0	13,5
Spring	0,0	25,0	100,0	0,0	0,0	71,4
Summer	0,0	6,8	0,0	0,0	0,0	11,1
Winter	0,0	30,4	0,0	0,0	0,0	4,1
Weighted active hours (h/year)						
Autumn	0,0	58,9	0,0	0,0	0,0	13,5
Spring	0,0	39,0	0,3	0,0	0,0	71,4
Summer	0,0	10,6	0,0	0,0	0,0	11,1
Winter	0,0	47,4	0,0	0,0	0,0	4,1
2035						
Share of annual active hours (%)						
Autumn	0,0	16,6	26,9	11,8	0,0	24,9
Spring	0,0	67,9	24,1	51,6	0,0	25,0
Summer	0,0	11,1	3,1	36,1	0,0	7,7
Winter	0,0	4,5	46,0	0,5	0,0	42,5
Weighted active hours (h/year)						
Autumn	0,0	2,6	262,3	3,0	0,0	387,1
Spring	0,0	10,5	235,2	13,3	0,0	387,7
Summer	0,0	1,7	29,9	9,3	0,0	118,9
Winter	0,0	0,7	448,9	0,1	0,0	659,4
Upward						
2030						
Share of annual active hours (%)						
Autumn	34,7	44,1	12,1	0,0	17,3	25,6
Spring	7,6	0,0	2,5	100,0	19,6	4,3
Summer	0,4	0,9	0,0	0,0	7,7	0,0
Winter	57,3	55,0	85,4	0,0	55,4	70,1
Weighted active hours (h/year)						
Autumn	121,5	17,2	6,0	0,0	95,4	25,6
Spring	26,6	0,0	1,2	1,2	108,0	4,3
Summer	1,5	0,4	0,0	0,0	42,6	0,0
Winter	200,6	21,4	41,9	0,0	305,8	70,1
2035						
Share of annual active hours (%)						
Autumn	27,0	16,4	29,0	42,6	41,9	18,1
Spring	28,4	11,9	11,4	11,9	9,2	0,0
Summer	10,4	0,1	2,8	2,1	2,6	0,0
Winter	34,2	71,6	56,8	43,5	46,3	81,9

Weighted active hours (h/year)						
Autumn	287,7	32,6	141,2	151,2	398,9	1,1
Spring	302,4	23,6	55,3	42,1	87,9	0,0
Summer	110,6	0,3	13,8	7,4	24,7	0,0
Winter	364,3	141,9	276,5	154,3	440,5	5,0

Table 19 Guiding Criteria – Frequency of activation – Expected Activation blocks per year

Expected activation blocks per year						
Row Labels	Center	East	North	South-East	South-West	West
Downward						
2030	0	76,4	0,2	0	0	7,6
2035	0	18,4	234,4	25,2	0	328,4
Upward						
2030	96,6	17,7	16,6	0,5	160,7	34,1
2035	202,2	54,9	115,0	109,6	203,8	3,6

Table 20 Guiding Criteria – Duration of continuous need – mean value, 98th and 95th percentile

Duration of continuous need						
	Center	East	North	South-East	South-West	West
Downward						
2030						
Mean (h)	0,0	2,3	1,8	0,0	0,0	1,6
P95 (h)	0,0	9,6	2,0	0,0	0,0	4,4
P98 (h)	0,0	14,4	2,0	0,0	0,0	5,0
2035						
Mean (h)	0,0	1,0	4,6	1,3	0,0	5,3
P95 (h)	0,0	3,8	20,4	4,0	0,0	21,8
P98 (h)	0,0	5,5	32,3	5,2	0,0	36,1
Upward						
2030						
Mean (h)	3,9	2,5	3,1	2,5	3,7	3,4
P95 (h)	16,3	7,0	12,8	2,5	14,4	12,1
P98 (h)	17,3	7,8	14,4	2,5	16,8	15,3
2035						
Mean (h)	5,6	4,0	4,5	3,5	4,8	1,7
P95 (h)	16,8	15,8	17,1	13,0	18,5	3,4
P98 (h)	19,3	18,5	19,3	14,7	21,2	3,5

Table 21 Guiding Criteria – Energy per activation block – mean value, 95th and 98th percentile

Energy per activation block						
	Center	East	North	South-East	South-West	West
Downward						
2030						
Mean (MWh)	0,0	14,6	0,8	0,0	0,0	5,2
P95 (MWh)	0,0	85,4	1,2	0,0	0,0	22,9
P98 (MWh)	0,0	148,5	1,2	0,0	0,0	35,7
2035						
Mean (MWh)	0,0	7,6	178,1	7,6	0,0	90,0
P95 (MWh)	0,0	35,0	1024,9	34,3	0,0	456,7
P98 (MWh)	0,0	74,3	1704,3	63,6	0,0	850,0
Upward						
2030						
Mean (MWh)	10,9	2,7	6,7	1,2	11,6	5,6
P95 (MWh)	68,5	10,7	35,9	1,3	51,4	25,8
P98 (MWh)	81,1	14,4	37,2	1,3	87,9	32,3
2035						
Mean (MWh)	25,2	11,9	31,4	8,2	34,8	2,9
P95 (MWh)	129,0	67,8	147,4	47,4	215,9	7,5
P98 (MWh)	189,4	101,3	255,5	61,1	318,4	7,8

11.2.4. TABLE TO REPORT DSO'S NETWORK FLEXIBILITY NEEDS

Direction	Target Year	Need	Type of value	Spatial Granularity
Downwards	2030	0	Total Energy (MWh)	Center
		0	Sum of max power (Regional Capacity) (MW)	Center
		0	Instant max power (MW)	Center
		1114	Total Energy (MWh)	East
		23	Sum of max power (Regional Capacity) (MW)	East
		23	Instant max power (MW)	East
		1	Total Energy (MWh)	North
		1	Sum of max power (Regional Capacity) (MW)	North
		1	Instant max power (MW)	North
		0	Total Energy (MWh)	South-East
		0	Sum of max power (Regional Capacity) (MW)	South-East
		0	Instant max power (MW)	South-East
		0	Total Energy (MWh)	South-West
		0	Sum of max power (Regional Capacity) (MW)	South-West
		0	Instant max power (MW)	South-West
		40	Total Energy (MWh)	West
		6	Sum of max power (Regional Capacity) (MW)	West
		6	Instant max power (MW)	West
	2035	0	Total Energy (MWh)	Center
		0	Sum of max power (Regional Capacity) (MW)	Center
		0	Instant max power (MW)	Center
		141	Total Energy (MWh)	East
		28	Sum of max power (Regional Capacity) (MW)	East
		28	Instant max power (MW)	East
		41738	Total Energy (MWh)	North
		126	Sum of max power (Regional Capacity) (MW)	North
		124	Instant max power (MW)	North
		191	Total Energy (MWh)	South-East
		24	Sum of max power (Regional Capacity) (MW)	South-East
		24	Instant max power (MW)	South-East
		0	Total Energy (MWh)	South-West

Upwards		0	Sum of max power (Regional Capacity) (MW)	South-West
		0	Instant max power (MW)	South-West
		29573	Total Energy (MWh)	West
		78	Sum of max power (Regional Capacity) (MW)	West
		78	Instant max power (MW)	West
	2030	1053	Total Energy (MWh)	Center
		9	Sum of max power (Regional Capacity) (MW)	Center
		6	Instant max power (MW)	Center
		49	Total Energy (MWh)	East
		3	Sum of max power (Regional Capacity) (MW)	East
		3	Instant max power (MW)	East
		112	Total Energy (MWh)	North
		6	Sum of max power (Regional Capacity) (MW)	North
		5	Instant max power (MW)	North
		1	Total Energy (MWh)	South-East
		1	Sum of max power (Regional Capacity) (MW)	South-East
		1	Instant max power (MW)	South-East
		1867	Total Energy (MWh)	South-West
		23	Sum of max power (Regional Capacity) (MW)	South-West
		9	Instant max power (MW)	South-West
		192	Total Energy (MWh)	West
		3	Sum of max power (Regional Capacity) (MW)	West
		3	Instant max power (MW)	West
	2035	5102	Total Energy (MWh)	Center
		27	Sum of max power (Regional Capacity) (MW)	Center
		16	Instant max power (MW)	Center
		652	Total Energy (MWh)	East
		9	Sum of max power (Regional Capacity) (MW)	East
		8	Instant max power (MW)	East
		3609	Total Energy (MWh)	North
		14	Sum of max power (Regional Capacity) (MW)	North
		14	Instant max power (MW)	North
		902	Total Energy (MWh)	South-East

		12	Sum of max power (Regional Capacity) (MW)	South-East
		7	Instant max power (MW)	South-East
		7089	Total Energy (MWh)	South-West
		42	Sum of max power (Regional Capacity) (MW)	South-West
		25	Instant max power (MW)	South-West
		11	Total Energy (MWh)	West
		2	Sum of max power (Regional Capacity) (MW)	West
		2	Instant max power (MW)	West