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Cost benefit analysis and toolkits

Methodologies for assessing the needed flexibility

Deliverable

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Disclaimer

Preface

The increasing penetration of variable renewable energy sources and the electrification of end-use sectors have brought unprecedented challenges to the operation and planning of power systems. In this context, flexibility has emerged as a critical enabler to maintain the reliability, efficiency, and sustainability of the electricity grid. This discussion paper contributes to the international debate by presenting a comprehensive overview of methodologies for assessing the flexibility required at both system and component levels. The content builds on regulatory developments, such as the EU Flexibility Needs Assessment (FNA), and technical insights from real-world case studies, aiming to support distribution and transmission system operators, policymakers, and market stakeholders in designing and implementing effective flexibility strategies.

Acknowledgments

The authors would like to thank the Italian delegate Antonio Iliceto for his valuable suggestions, which contributed to the drafting of this document.

List of Acronyms

ACER	Agency for the Cooperation of Energy Regulators
aFRR	automatic Frequency Restoration Reserve
CAPEX	Capital Expenditure
DER	Distributed Energy Resources
DSO	Distribution System Operator
EBG	Electricity Balancing Guideline
EENS	Expected Energy Not Served
ENTSO-E	European Network of Transmission System Operators for Electricity
ERAA	European Resource Adequacy Assessment
EU	European Union
EV	Electric Vehicle
FCR	Frequency Containment Reserve
FRR	Frequency Restoration Reserve
FNA	Flexibility Needs Assessment
HVAC	Heating, Ventilation and Air Conditioning
ICT	Information and Communication Technology
IEA	International Energy Agency
LOLE	Loss of Load Expectation
LV	Low Voltage
MAF	Mid-term Adequacy Forecast
mFRR	manual Frequency Restoration Reserve
MV	Medium Voltage
NC RfG	Network Code on Requirements for Generators
OPEX	Operational Expenditure
PV	Photovoltaic
RES	Renewable Energy Sources
SOG	System Operation Guideline

TYNDP	Ten-Year Network Development Plan
TSO	Transmission System Operator
V2G	Vehicle-to-Grid
WP	Work Package

Abstract

This paper presents a structured review of methodologies for assessing the flexibility needs of modern power systems, with a focus on both transmission and distribution levels. Flexibility is analyzed as a system-wide requirement to accommodate the variability and uncertainty introduced by renewable generation, and as a resource-side or grid-side capability enabled by controllable assets. The study introduces conceptual definitions and categories of flexibility, including needed, potential, and feasible flexibility, and explores diverse modeling paradigms ranging from heuristic rules to optimization, data-driven, and physics-based approaches. The paper also discusses recent regulatory frameworks such as the European Flexibility Needs Assessment (FNA) and identifies key criteria for evaluating flexibility requirements across spatial and temporal dimensions. Finally, the report offers a synthesis of emerging practices and highlights the operational, economic, and policy implications of flexibility deployment, supporting informed decision-making in energy system planning and management.

Executive Summary

As the power system undergoes rapid transformation due to the widespread integration of renewable energy sources and electrification of end uses, system operators face increasing challenges in ensuring grid stability and cost-effective operation. Flexibility (defined as the ability of the system or its components to properly respond to changes in generation, load, or network conditions) has become a key solution to these challenges.

This report provides an in-depth analysis of the methodologies available to assess the needed flexibility across different system levels. It begins by framing flexibility within a structured conceptual framework, distinguishing between its potential, feasible, and required components. It then examines both resource-side and grid-side flexibility options, including demand-side management, energy storage, controllable generation, and advanced grid technologies (i.e., dynamic line rating, soft open points, and network reconfiguration).

The document explores a range of modeling and computational approaches used to estimate flexibility potential, including optimization models, scenario-based simulations, and machine learning techniques. These methods are evaluated in terms of data requirements, uncertainty handling, and applicability for planning, operations, and market design. In addition, case studies are provided to describe real-world approaches adopted to quantify flexibility needs at both DSO and TSO levels (Portugal, Denmark, Great Britain, and a TSO-level case study based on ENTSO-E assessments). It subsequently discusses a methodological approach for estimating flexibility needs and implementing local flexibility markets, drawing on four Horizon Europe projects (CoordiNet, EUniversal, OneNet, BeFlexible) as case studies.

A central focus is placed on the European Flexibility Needs Assessment (FNA), recently introduced through Regulation (EU) 2019/943 (as amended), which mandates systematic evaluation of short, medium- and long-term flexibility requirements. The FNA methodology integrates system-level and location-specific assessments and serves as a foundational tool for shaping investment strategies, market mechanisms, and regulatory frameworks.

The report concludes by proposing a WG3 guideline that consolidates the flexibility needs calculation into a step-by-step procedure and identifies the minimum information required to make results traceable and comparable.

Table of Contents

1. Flexibility in the power system

There is no single, universally agreed-upon definition of flexibility. However, a shared conceptual foundation exists, and the definition varies in scope depending on context (system vs. component level), actors (TSO, DSO, aggregator), and applications (operations, planning, markets, regulatory design).

1.1. Definition

1.1.1. Flexibility as a System-Level Concept

From a system-wide standpoint, flexibility refers to the power system's capacity to accommodate the variability and uncertainty introduced, for instance, by renewable generation across multiple time horizons, as well as by other distributed energy resources, such as electric vehicles and heat pumps, whose concurrent operation may lead to increased demand, ranging from seconds and minutes (very short term) to months and years (long term).

When properly integrated into grid planning and operation, flexibility also contributes to guaranteeing system stability and resilience, by supporting the system's ability to withstand disturbances, recover rapidly from disruptive events, and adapt to changing conditions while maintaining secure and reliable operation [1].

This definition is consistently reflected across major international institutions:

"Flexibility is the power system's ability to cope with the variability and uncertainty that renewable generation introduces into the system at different time scales, from the very short term to the long term, minimising the curtailment of renewables and reliably supplying all the demanded energy to customers"
(Irena [2]).

"Flexibility is the EU power system's ability to adjust to the fluctuating generation and consumption of energy"
(ACER, 2023 [3])

"The ability of an electricity system to adjust to the variability of generation and consumption patterns and to grid availability, across relevant market timeframes"
(Regulation (EU) 2024/1747, 2024 [4])

"The ability to adapt the planned development of the power system, quickly and at reasonable cost, to any change, foreseen or not, in the conditions which prevailed at the time it was planned"
(CIGRE Working Group 37.10, 1995 [5])

1.1.2. Flexibility as a Component-Level Capability

In addition to its system-level characterization, flexibility can also be understood as an attribute embedded in or enabled by specific components within the system.

> *"Power system flexibility spans from more flexible generation to stronger transmission and distribution systems, more storage and more flexible demand (IRENA, 2018 [6]).*

In this context, it is possible to distinguish two complementary perspectives.

Component-level flexibility refers to the technical and operational capability of individual resources (such as DERs, controllable loads, and storage systems) to adjust their behavior in response to external signals, including price signals or dispatch instructions.

On the other hand, resource-level flexibility aggregation concerns the collective and coordinated activation of multiple flexible components, enabling the provision of grid services or operational support, which ultimately contributes to the broader system-level flexibility required for a secure and efficient power system operation.

Such flexibility resources can be either third-party owned (for instance, resources managed by aggregators, flexible consumers, or independent storage providers) or owned and operated directly by the DSO and TSO, including infrastructure elements such as switching devices for network reconfiguration, on-load tap-changers (OLTCs) in transformers, or dynamic line rating systems leveraging real-time thermal capacity margins.

Although ownership and operational modalities differ, both third-party and SO-owned flexibility contribute to enhancing the overall adaptability of the distribution and transmission network.

Recent studies [8] have demonstrated that a coordinated activation of both types of resources can effectively maintain network flows within capacity limits, optimize asset utilization, and defer traditional grid reinforcements.

1.1.3. Key Aspects Defining Flexibility

Flexibility in power systems encompasses multiple intrinsic aspects of Distributed Energy Resources (DERs), each describing a different characteristic that influences how a resource can support grid operation under varying conditions. The classification below identifies and defines key dimensions through which flexibility can be understood and characterized.

1.1.3.1. Deviation from Baseline

Flexibility can be defined as the deviation from a predefined reference baseline, typically derived from historical data under normal, unconstrained operating conditions. This baseline represents the expected behavior of the resource (whether distributed or centralized), and deviations from it indicate the resource's capability to respond to external stimuli such as market signals or operational requests. This concept is particularly useful for ex post evaluations of flexibility performance, where the baseline serves to verify the actual flexibility delivered by comparing the measured response with the estimated counterfactual scenario. Defined ex ante, the baseline enables the estimation of expected flexibility prior to activation, supporting market participation, contractual commitments, and settlement processes.

Baseline calculation is not a straightforward task and encompasses several methodologies, including [9]:

- X-of-Y baselines: The average of the highest, middle, or lowest X consumption days within a Y-day set of eligible days;

- Rolling average: A moving average of the past X comparable days, with higher weights assigned to days closer to activation;
- Regression methods: Construction of a baseline function from past data using input parameters such as previous consumption, weather conditions, or operational variables;
- Machine learning techniques: Application of advanced algorithms (e.g., neural networks) to estimate the baseline with improved adaptability and accuracy;
- Meter-Before-Meter-After (MBMA): Use of a meter reading immediately before activation as the baseline reference.

1.1.3.2. Operational Boundaries

Flexibility is inherently constrained by the operational boundaries of the resource (e.g., power ratings, energy storage capacity, and comfort or process constraints). These boundaries define the feasible region of operation and determine the potential flexibility envelope that a resource can offer under specific conditions. Accurately defining these constraints is essential for distinguishing between potential, available, and activated flexibility, respectively, referring to what could be offered, what can be offered at a given moment, and what is actually delivered in response to a control action (see 1.1.4).

1.1.3.3. Temporal Modulation Capability

Temporal flexibility is evaluated by estimating how much energy consumption or production can be shifted over time without compromising service objectives. It reflects the ability to delay or anticipate energy usage in response to external stimuli such as price variations or grid congestion signals. This dimension is particularly relevant for shiftable loads, including electric vehicle charging, HVAC systems, and industrial batch processes. However, temporal modulation must be analyzed together with recovery dynamics, as short-term flexibility may induce rebound or payback effects [11] that offset the initial benefit. In practice, a reduction in load during a flexibility event can be followed by a compensatory increase in consumption, or the activation itself may be deliberately limited to prevent excessive recovery. Therefore, the quantification of temporal flexibility must consider operational boundaries, user preferences, and the potential impact on other system metrics such as peak load and ramping requirements.

1.1.3.4. Representation

While not an intrinsic aspect of flexibility, flexibility representations support comparison, aggregation, and integration into system-level analyses. They focus on representing the flexibility potential of DERs through structured, often visual or numerical, characterizations. Rather than analyzing time series or individual response behaviors, this approach defines multi-dimensional descriptors of the feasible operating region of a resource or an aggregate of resources. Examples include flexibility envelopes (Figure 1-1), which chart the amount of upward and downward reserve a DER can provide over time, and flexibility dimensions, which quantify the responsiveness or availability of a resource under varying grid conditions (Figure 1-2). Together, these representations provide a comprehensive view of flexibility potential across spatial, temporal, and operational dimensions, enabling more effective coordination between system operators and distributed resources.

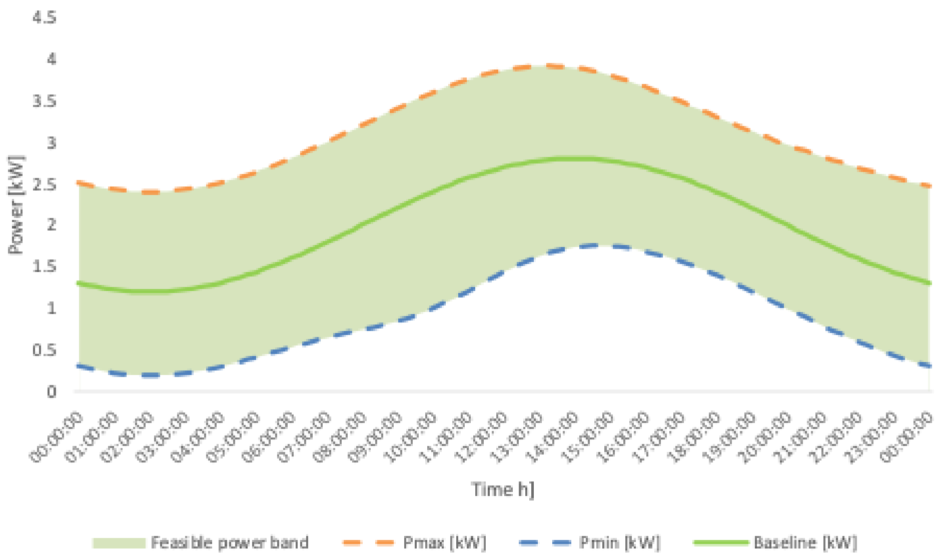


Figure 1-1. Flexibility envelope showing the feasible operating region of a distributed energy resource over time. The shaded area represents the admissible power range between minimum and maximum limits, with the baseline indicating the expected operation.

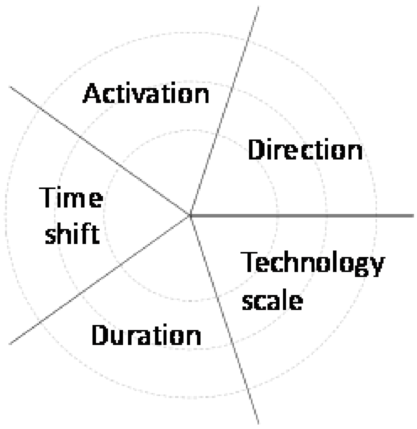


Figure 1-2. Qualitative representation of the flexibility characteristics, considering five dimensions: Activation, Direction, Duration, Time shift, and Technology.

Another relevant representation is the Flexibility Map, which displays, on a geographic basis, the current and potential future flexibility needs across the transmission and distribution network. For instance, in Figure 1-3, the map developed by National Grid shows, for each area where potential demand constraints are identified, an availability window for generation turn-up or demand turn-down services. This spatial and temporal visualization enables both system operators and flexibility providers to identify when and where flexibility is required, supporting network planning, operational decision-making, and market participation.

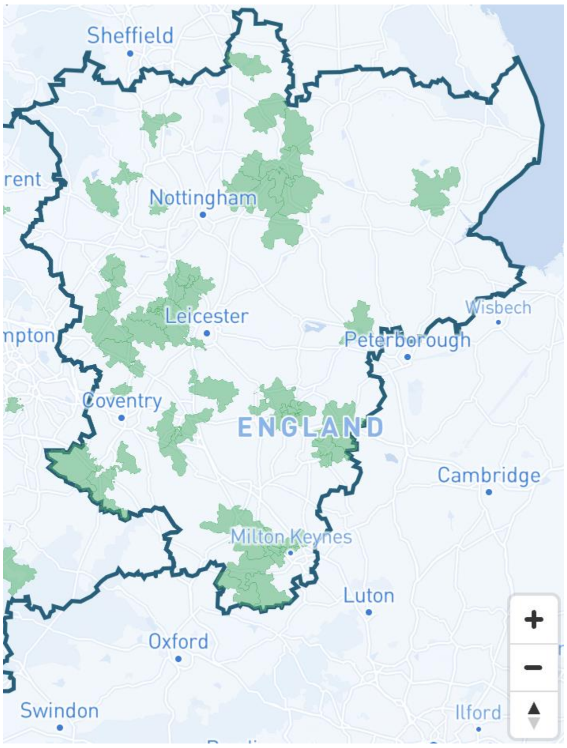


Figure 1-3. National Grid Flexibility Map showing areas across the Midlands and South-East England where potential demand constraints have been identified. The highlighted zones indicate locations with current or future flexibility needs and the corresponding availability windows for generation turn-up or demand turn-down services [10].

1.1.4. Operational Differentiation: Needed, Potential, and Feasible Flexibility

From an operational standpoint, flexibility can be further distinguished into three categories:

- **Needed Flexibility:**

This refers to the quantity of flexibility specifically needed to address a particular technical issue in the distribution network. For instance, in [12], at DSO level the needed flexibility is the minimum corrective flexibility required when day-ahead DER forecasts exceed the admissible operating region identified through hosting-capacity optimisation (i.e., when forecasted injections would lead to constraint violations such as voltage or thermal limits). In the same document, at TSO level the needed flexibility is quantified as the reserve capacity required to preserve system balance and frequency quality in the presence of forecast errors and real-time disturbances.

- **Potential Flexibility:**

This is the theoretical maximum amount of flexibility that a Distributed Energy Resource (DER) could provide under ideal conditions. It focuses purely on the technical capabilities of the DER (e.g., the full charge/discharge power range of a battery), without considering any operational, economic, or regulatory constraints.

- **Feasible (or Residual) Flexibility:**

This represents the portion of the potential flexibility that can be safely and effectively utilized without introducing new issues elsewhere in the network. For instance, while curtailing generation at the low-voltage (LV) level might solve a higher-level network problem, it could also lead to local voltage drops and undervoltage conditions. The feasible flexibility is thus the amount of flexibility that can be extracted and used while still maintaining stable and acceptable operating conditions throughout the entire system.

Figure 1-4 illustrates different categories of flexibility within a low-voltage (LV) distribution network considering a summer day. The light blue and light yellow shaded areas represent the potential downward (DW) and upward (UP) flexibility, respectively. However, not all of this potential can be fully utilized by MV networks. The solid blue and yellow bars show the feasible downward and upward flexibility, respectively. Finally, the orange bars represent the portion of flexibility that is used internally by the LV network itself, rather than being made available to higher-level grids too. This internally utilized flexibility is not available to be offered to higher-level networks, as it remains necessary for resolving LV-level criticalities (i.e., overcurrents and overvoltage due to the high production from generators). The **needed flexibility**, while not explicitly depicted in the figure, can be understood as the amount of flexibility required by the LV network to address a particular operational challenge.

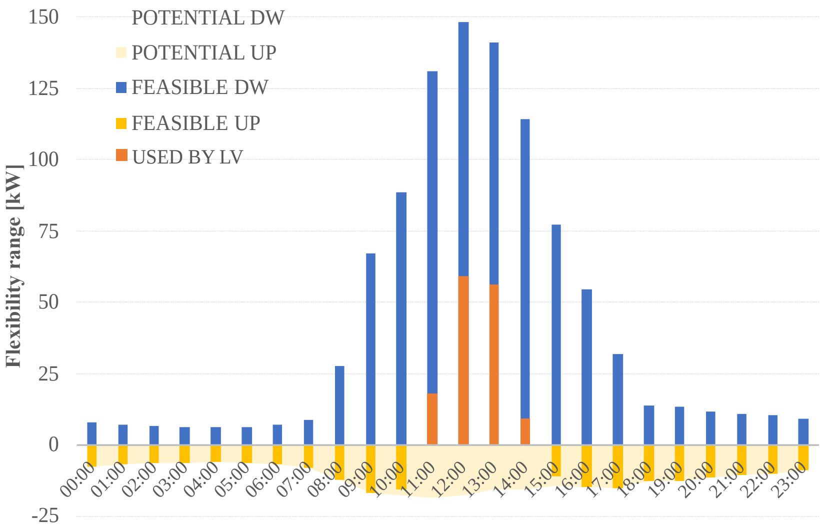


Figure 1-4. Potential, feasible, and used flexibility within an LV distribution network [13].

1.2. Flexibility Procurement

Flexibility procurement refers to the process through which system operators, Transmission System Operators (TSOs) and Distribution System Operators (DSOs), acquire the capability to modify generation, demand, or storage behavior in order to maintain the safe, efficient, and reliable operation of the electrical grid [14]-[16].

To acquire or obtain flexibility from the network customers, both TSOs and DSOs may utilize a variety of mechanisms, that allow to define the possibility of requiring the network customers to adapt their electricity profile to satisfy specific SOs needs:

- flexible connection and access agreements,
- dynamic network tariffs,
- local flexibility markets[1],
- system-wide markets managed by TSO and energy markets,
- other regulated options when liquidity is limited which may be adopted either when market liquidity is limited or when cost–benefit analysis demonstrates their effectiveness, as in the cases of Germany and France..

[1] Examples of local flexibility initiatives include the Italian DSO's Piclo-based market platform, launched in 2023 to procure and dispatch local flexibility services; the Portuguese DSO's first flexibility auction held via the same platform; and the Dutch GOPACS platform, jointly developed by TenneT and four DSOs for coordinated congestion management. Comparable rule-based schemes, such as Redispatch 2.0 in Germany and technical flexibility services adopted by Fluvius in Belgium, also illustrate different regulatory approaches to the acquisition of flexibility.

These mechanisms can be tailored based on several factors, including the nature of the services and products being traded, and the specific circumstances of the market environment, like the voltage level of connected resources, frequency of demand, contractual timeframes, issue volume, network structure, as well as the temporal and locational resolution of the traded services. The size and type of SPs also play a significant role in determining the design of these mechanisms. Furthermore, it is essential to consider customer engagement when designing these flexibility acquisition methods to ensure that customer needs and preferences are appropriately addressed.

The procurement of flexibility involves the definition of standardized products, the establishment of eligibility criteria, and the design of acquisition mechanisms, which may include bilateral agreements, rule-based activations, or competitive market-based schemes [14] Flexibility is increasingly recognized as a cost-effective alternative o complement to traditional grid reinforcement, especially in systems with high penetration of variable renewable energy sources and electrified demand sectors [14].

While both TSOs and DSOs rely on flexibility to address operational challenges, the nature of their needs, timescales, geographical scope, and procurement frameworks differ significantly [14],[16].

- TSOs procure flexibility primarily to maintain the overall system balance, ensure frequency stability, and manage congestion on the transmission network. Their focus is on large-scale, often time-critical services such as Frequency Containment Reserve (FCR), automatic Frequency Restoration Reserve (aFRR), and manual Frequency Restoration Reserve (mFRR). These services are typically procured through national or European platforms governed by harmonized network codes, such as the SOGL (System Operation Guidelines) and the EBGL (Electricity Balancing Guidelines) [14]. Participation requires rigorous technical prequalification, including the ability to provide reliable and fast-acting responses.
- DSOs, on the other hand, procure flexibility to manage local network constraints, optimize voltage profiles, and defer or avoid network reinforcements at the medium and low voltage levels. Their procurement processes are more localized, tailored to specific grid areas or nodes, and encompass a broader variety of mechanisms ,ranging from flexible connection agreements to rule-based services and competitive local market-based tenders [16].

Table 1. Comparison TSO- DSO flexibility

Aspect	TSO	DSO
Service Objective	System balancing, frequency stability, large-scale congestion management	Local congestion management, voltage control, network reinforcement deferral
Activation Timeframes	Very short (seconds to minutes)	Variable (minutes to hours)
Geographical Scope	Supra-regional or national	Local, at medium and low voltage levels
Regulatory Frameworks	European network codes (SOGL, EBGL, NC RfG)	National regulations, local flexibility market frameworks
Market Design	Centralized, harmonized (national or European platforms)	Decentralized, local market mechanisms or bilateral agreements
Procured Services Examples	FCR, aFRR, mFRR	Congestion management, voltage support, hosting capacity enhancement

Although both TSO and DSO flexibility procurement are based on the concept of standardized products (defined in terms of capacity, duration, response time, and location), the purpose, activation conditions, and procurement procedures are distinct. Coordination between TSO and DSO activities is becoming increasingly critical [14],[16] to ensure that the activation of flexibility resources does not create conflicts between system levels and to enable more efficient use of distributed energy resources across the grid.

1.2.1. Flexibility Product Parameters

Flexibility is generally characterized by a set of parameters that describe how, when, and to what extent a resource can deviate from its default operating pattern to support the grid. Key parameters often include:

- Magnitude (Capacity):

The amount of power (in kW or MW) or energy (in kWh or MWh) that can be adjusted up or down from the baseline. This quantifies the sheer volume of flexibility a resource can provide.

- Directionality (Upward/Downward):

Some flexible resources can increase their generation or reduce their load (upward flexibility), others can decrease their generation or increase their load (downward flexibility), and some can do both.

- Response Time (Speed):

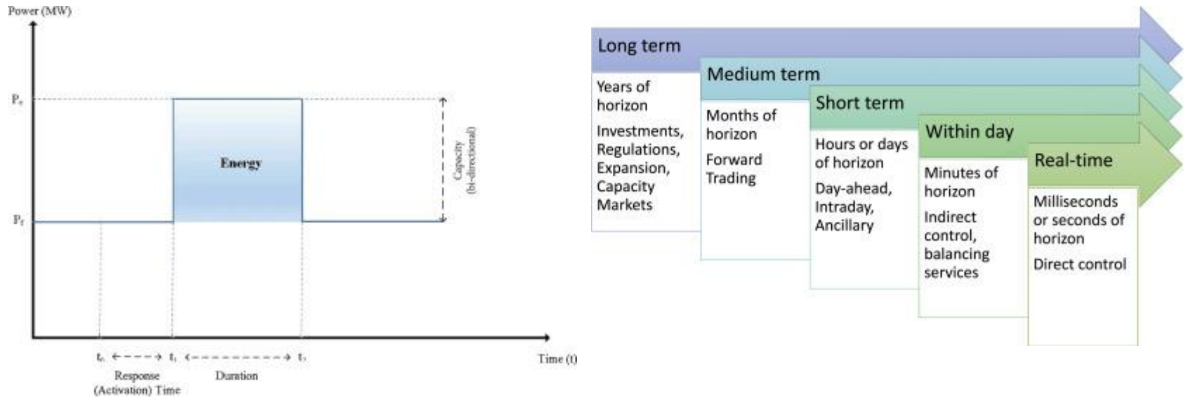
How quickly a resource can ramp up or down to provide the requested flexibility. For instance, certain loads or batteries can respond within seconds, while others might need minutes to adjust their output.

- Timescale:

The need for flexibility in power systems arises at different timescales, from real-time response in milliseconds to long-term investment planning over years. These flexibility timescales are driven by specific system needs and operational procedures, and vary in both temporal and spatial dimensions, as illustrated in Figure 1-5 b):

- Real-time (milliseconds to seconds): Flexibility is needed to maintain frequency stability through inertial response or fast primary frequency control following sudden imbalances (e.g., generator trips).
- Minutes: Voltage regulation actions are triggered by progressive or sudden changes in power flows, often with local impact.
- Minutes to hours: Redispatch of generation or activation of demand response is required to manage power flows and ensure supply-demand balance in the presence of forecast errors or variability.
- Daily: Unit commitment decisions ensure that the right mix of resources is scheduled to meet hourly demand and reserve requirements.
- Long-term (months to years): Flexibility supports seasonal balancing and planning of investments in generation and storage infrastructure.

The term *flexibility timescale* generally refers to the *system-level perspective*, that is, the timeframe over which flexibility is needed to ensure secure and efficient grid operation. In contrast, *duration and availability window* describe the *resource-level perspective*, referring to how long a given asset can provide flexibility (duration) and during which periods it is actually available for activation (availability window).



a) b)

Figure 1-5. a) Characteristics of flexibility in system-wide scale [17]; b) Flexibility trading horizons and markets.

These system needs are summarized in Table 2, linking each timescale to operational actions, main drivers, spatial scope, and typical applications.

Table 2. Flexibility needs across time and spatial scales [18]

Time scale	Type of action/operational procedure	Driver	Spatial scale	Application requiring flexibility
Seconds (including subsecond)	• Inertial response • Primary frequency control	Loss of large generator or interconnector	System-wide (entire synchronous area)	Maintaining frequency stability
Minutes	Voltage regulation	Increase in power flow in a certain direction: • Progressive: driven by change of demand or supply • Sudden: driven by loss of branch or generator	Local	Keeping voltages within acceptable limits
Minutes to hourly	Power flow control (by means of redispatch or active power flow devices)		Mostly local, action should have impact on branch under question	Avoiding thermal overloading of branches
Minutes to hourly	• Redispatch of generation and storage units • Demand side management	• Variability of demand and intermittent generation • Forecast errors	Wide-area (country or part of country, crosscountry exchange can also be used)	Power balancing
Daily	• Decision of which generation units are on per hourly slot • Commitment of flexibility providers to be available	• Expected residual demand per hour • Ensuring that enough reserve is available to counteract contingencies	Wide-area (typically, several countries via market clearing) In future, might be relevant also to local	Unit commitment, Scheduling availability of flexibility resources

		and forecast errors		
Long-term	• Seasonal scheduling of hydro reservoirs and long-term storage, such as thermal, natural gas and hydrogen storage (if any) • Ensuring investments in adequate generation and storage capacities	• Seasonal pattern of energy demand (e.g., winter or summer peaks) and availability of energy supply (hydro, wind, solar) • Long-term expected evolution of energy demand	Typically happening at country level, considering the neighboring countries	Adequacy of power & energy supply

- Frequency of Activation:

How often a resource can be called upon to provide flexibility over a given time frame. This considers whether repeated activation (e.g., multiple times per day or week) is feasible.

- Location (Grid Node Specificity):

The geographical and electrical location of the flexible resource on the network matters. Providing flexibility at or near congestion points or critical nodes in the distribution system can be more valuable than providing it elsewhere. Figure 1-6 illustrates the different spatial granularities at which a flexibility product can be defined, from the individual unit to system (country) level."

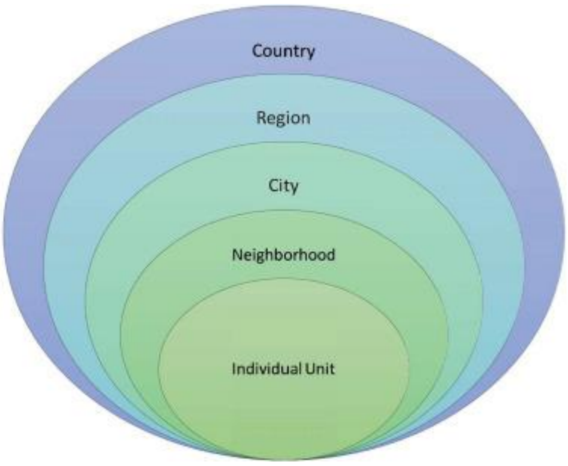


Figure 1-6. Interrelation of flexibility in perspectives of space (local/regional to system level) [17].

1.3. Flexibility Resources

Flexibility provided by third parties and that originating from DSO-owned resources differ in both nature and cost structure. In the case of third-party flexibility, a significant initial CAPEX is required to deploy ICT systems and advanced grid management infrastructure. Once these enablers are in place, the main expenditure becomes OPEX, related to the operational procurement of flexibility services from external providers.

Conversely, DSO-owned flexibility resources entail a combination of CAPEX and OPEX. For instance, investing in transformers equipped with On-Load Tap Changers (OLTCs) represents an increase in CAPEX compared to standard units, while the operational use of these assets (such as the active management of network switches for reconfiguration) contributes to OPEX [14].

Flexibility can be sourced from a wide range of resources, each with distinct characteristics in terms of how quickly they can respond, how long they can maintain that response, and whether they can provide upward or downward adjustments in power flow. Because different resources excel under different conditions and constraints, combining multiple types of flexibility providers is often necessary to ensure a robust, reliable, and resilient flexibility capability.

This section delineates the diverse range of assets and operational strategies that contribute to power system flexibility. These can broadly be categorized into two primary groups: resource-side flexibility, involving units that directly adjust power injection or consumption, and grid-side flexibility solutions, which optimize the utilization or configuration of network infrastructure. The interplay between these categories is fundamental for achieving an efficient, reliable, and decarbonized power system.

1.3.1. Resource-Side Flexibility

1.3.1.1. Flexible Load

These are demand-side resources whose consumption patterns can be altered to offer flexibility services.

- **Controllable Load (Shifting in Time):**

Loads such as electric heating/cooling systems, washing machines, dishwashers, or certain industrial processes can be scheduled or delayed to off-peak periods, effectively shifting demand from one time interval to another without significantly affecting the end-use service. This time-shifting capability helps smooth the load curve, reduce peak demand, and accommodate variable renewable generation.

- **Switchable Load (Curtailment or Increase):**

Some loads can be fully or partially disconnected (curtailed) during times of grid stress. Conversely, loads can be strategically increased to absorb excess generation.

1.3.1.2. Flexible Generation

Generation sources can also provide flexibility by adjusting their output in response to grid conditions.

- ***Curtailment:***
  Variable renewable energy sources (e.g., wind or solar) can be curtailed when there is an oversupply or to manage local congestion. Although this reduces the utilization of renewable energy, it enhances stability and helps prevent network overloads.
- **Shifting in Time:**

  Certain types of generation, especially conventional plants or combined heat and power units, can alter their production schedules. When coupled with storage of fuels or by leveraging sector coupling (e.g., tapping into heat or gas networks), these generators can run when needed most, effectively storing flexibility in other energy vectors (like thermal energy) and releasing it as electricity at more opportune times.

1.3.1.3. Storage (Energy Storage Systems or Electric Vehicles)

Storage solutions bridge the gap between supply and demand by acting either as a flexible load or a source of generation, depending on their operational mode.

- **Flexible Load Mode:**

When charging, battery storage or Electric Vehicles (EVs) consume electricity, potentially absorbing surplus renewable energy during low-demand periods. By doing so, they prevent wasteful curtailments and help maintain stable system operation.

- **Flexible Generation Mode:**

When discharging, these same storage systems feed electricity back into the grid, providing upward flexibility. In the case of electric vehicles, this bidirectional interaction, known as *Vehicle-to-Grid (V2G)*, enables aggregated EV fleets to operate as distributed energy resources, supporting grid balancing, reducing peak demand, and providing ancillary services such as frequency regulation.

This ability to rapidly inject power helps counteract short-term supply deficits, reduce peak demand, or provide valuable ancillary services such as frequency regulation.

Figure 1-7 shows an overview of the characteristics (activation, flow direction, technology scale, duration and time speed) of different flexibility providers types.

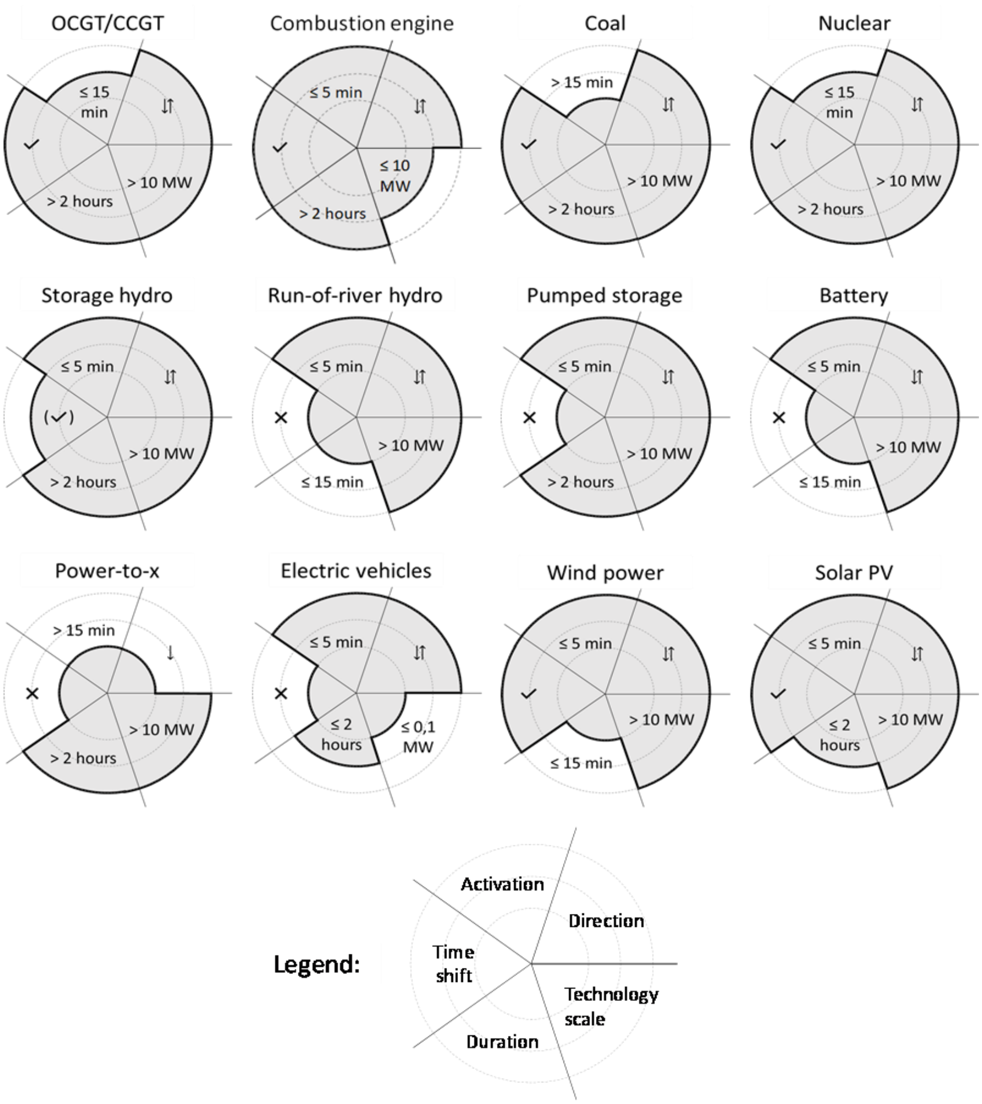


Figure 1-7. Overview of DERs' flexibility characteristics [7].

1.3.1.4. Small Resources Aggregation

All the resources installed in the network, including those characterised by small size, can contribute to system flexibility. Aggregation offers the opportunity for smaller residential and commercial customers to exploit their flexibility potential by pooling their capabilities. It is a commercial function that groups decentralized generation, storage, and flexible consumption to provide energy and system services.

Aggregators can be retailers, grid operators, or independent third parties. They act as intermediaries between customers who offer flexibility (both on the demand and generation side) and the markets or system operators that procure it. Aggregators identify, coordinate, and manage the participation of multiple distributed resources, enabling their joint contribution to flexibility markets or system operations.

A relevant example of this model is represented by energy communities, where groups of prosumers (including households, small businesses, and public entities) collectively manage local generation, storage, and flexible loads. Within such communities, aggregation mechanisms can be employed to optimize collective self-consumption, participate in flexibility markets, or provide grid support services, thus enhancing both local energy autonomy and overall system efficiency [19].

1.3.1.5. Sector Coupling

In the context of flexibility, **sector coupling** plays a key enabling role by connecting the electricity sector with other energy vectors (such as heating, cooling, gas, and mobility) to unlock new flexibility potentials across multiple time and spatial scales. The aim of sector coupling is to exploit synergies among different energy sectors with the ultimate goal of achieving deep decarbonization of the overall energy system [18], [20].

Sector coupling refers to the integration of the electricity sector with other energy sectors (such as heating, cooling, gas, transport, and industry) in order to enhance system flexibility. By enabling the conversion, storage, and utilization of electricity across these sectors, sector coupling unlocks additional flexibility resources and provides new options for balancing supply and demand.

Examples include:

- Power-to-Heat: Excess electricity (e.g., from renewables) can be used to produce heat via electric boilers or heat pumps, which can be stored in thermal buffers or building structures, allowing a temporal shift between electricity generation and final energy use.
- Power-to-Gas: Surplus electricity can be converted into hydrogen or synthetic methane via electrolysis and methanation, providing long-term storage and flexibility across seasonal timescales.
- Power-to-Mobility: Electric vehicles (already discussed under storage) act as both consumers and potential suppliers of electricity. Sector coupling emphasizes their role within the broader transport sector, enabling system services like peak shaving or frequency control through smart charging.

By coupling sectors with different load patterns and storage characteristics, the energy system becomes more resilient to variability, allowing a higher penetration of renewable energy sources while reducing reliance on purely electrical balancing mechanisms.

1.3.2. Grid-Side Flexibility Solutions

Grid-side flexibility solutions focus on enhancing the capacity, reliability, and efficiency of the existing transmission and distribution infrastructure. Unlike resource-side flexibility, these solutions do not necessarily involve direct power injection or consumption from a generation or load unit but rather optimize the utilization or configuration of the network itself through advanced technologies and operational strategies [21],[22].

1.3.2.1. Dynamic Line Rating (DLR)

A technology that determines the real-time thermal capacity of overhead power lines by continuously monitoring and forecasting actual weather conditions (e.g., ambient temperature, wind speed, solar radiation) and line parameters. This allows for a more accurate and often higher operating limit compared to conservative static ratings, enabling grid operators to safely increase line utilization during favorable conditions. DLR thus provides a flexible and dynamic increase in transmission capacity to manage fluctuating power flows and alleviate congestion.

1.3.2.2. Soft Open Point (SOP)

A power electronic device based on semiconductor converters installed installed to replace traditional mechanical tie switches (normally open points) with voltage source converters connected in a back-to-back configuration. Unlike passive switches, SOPs allow for active power flow control between different feeders or network sections, enabling dynamic management of power flows, reduction of losses, voltage support, and congestion relief. By providing continuous and flexible control, SOPs enhance the operational flexibility and controllability of distribution networks, contributing to improved grid efficiency and the integration of distributed energy resources [24].

1.3.2.3. Network Reconfiguration

Involves the strategic alteration of the topological state of a power network by opening or closing switches and circuit breakers. This process can be performed manually by operators or automatically via advanced distribution management systems (ADMS). Network reconfiguration allows for the re-routing of power flows to alleviate congestion, improve voltage profiles, reduce technical losses, or expedite service restoration following outages. This provides operational flexibility to adapt the grid's configuration to manage varying load patterns, distributed generation output, and unexpected grid events.

1.3.3. Flexibility Value

Beyond its technical attributes, flexibility in power systems inherently possesses significant economic value, which is increasingly crucial for Grid Operators in an evolving energy landscape. This value stems from its ability to enhance system efficiency, reliability, and cost-effectiveness by adapting to the variability of renewable energy sources and dynamic load patterns, thus increasing the network hosting capacity [49].

The economic benefits of flexibility can be broadly categorized into distinct, yet interconnected, value streams [16]:

- **Investment Deferral and Mitigation:** Flexibility, particularly from DERs at the distribution level, can significantly postpone and mitigate the need for costly conventional grid reinforcements (e.g., new lines, transformers, substations). By proactively managing local congestion and voltage deviations, flexibility solutions offer a cost-efficient alternative to traditional infrastructure upgrades, leading to substantial reductions in Capital Expenditure (CAPEX). It is important to note that the utilities can rely on flexibilities for infrastructure planning only if there are mechanisms (e.g., bilateral contracts) to “ensure” that the offered flexibilities are reliably provided. Otherwise, the utility planning engineers cannot rely on the “potential availability” of such resources. This aspect is currently a challenge for the utilities, especially for distributed small-scale DERs. It is also noted that in majority of the grid planning analyses performed to assess the benefits of the flexibilities, the ICT costs to monitor and interact with the flexibility provider are not taken into account, which is another important aspect.
- **Operational Optimization:** Flexible resources contribute to operational expenditure (OPEX) savings by mitigating congestion, reducing technical losses, improving power quality and voltage profiles, and minimizing the need for expensive redispatch or curtailment of renewable generation. Furthermore, aggregated DER flexibility can provide essential ancillary services (e.g., frequency regulation, voltage support, black start capability) to the broader power system, enhancing overall operational efficiency and grid stability.
- **Market Efficiency and System Resilience:** By enabling the shifting of demand or supply, flexibility helps to reduce price volatility in wholesale electricity markets, especially during peak demand or low renewable output periods. This fosters more efficient market operation and facilitates the integration of higher shares of intermittent

renewables, contributing to a more robust, secure, and cost-efficient energy transition and enhancing energy independence.

Quantifying this multifaceted value is paramount for DSOs to make informed investment and operational decisions, allowing for direct comparison between flexibility solutions and traditional infrastructure upgrades. While the exact valuation methodologies can be complex, involving the aggregation of multiple value streams, considerations of specific market designs, and the inherent uncertainties of future system evolution, the overarching objective remains to identify the most cost-efficient pathways to meet evolving system needs. Methodologies are needed to identify this cost-efficient level of flexibility, thereby facilitating optimal planning and resource allocation across the power system.

2. Modeling Paradigms and Computational Approaches for Flexibility Needs Assessment

The transition toward active distribution networks with high shares of DERs requires SOs to identify and quantify their flexibility needs (i.e., the amount and location of active or reactive power adjustments required to maintain secure operation under variable and uncertain conditions). Flexibility assessment is a key prerequisite for planning and operation, supporting both preventive grid reinforcement and the procurement of market-based flexibility services as encouraged by EU Directive 2019/944 and Regulation 2019/943.

Existing methodologies for assessing flexibility needs can be classified according to three main conceptual approaches (rule-based, optimization-based, and data-driven) each relying on different assumptions about data availability, network observability, and uncertainty representation [25]. These categories are not mutually exclusive but often combined in hybrid frameworks

2.1. Modeling Paradigms for Flexibility Needs Estimation

2.1.1. Rule-Based or Heuristic Models

Rule-based methods rely on predefined engineering criteria derived from operational experience and network physics. They use direct relationships between observable variables (e.g., voltages, line loadings, or nodal injections) and the flexibility required to restore normal conditions. Sensitivity coefficients are computed to quantify how small variations in nodal active or reactive power injections affect key electrical quantities such as bus voltages and branch currents. Derived from the Jacobian matrix of the power flow equations, these coefficients represent the linearized response of the system around a specific operating point and allow identifying the nodes whose power adjustments have the most significant influence on network constraints.

For instance, in [26], buses are grouped into zones based on their normalized active-power sensitivities to voltage and current magnitudes. This allows DSOs to express flexibility needs at a zonal level without requiring full OPF optimization. Rule-based methods are transparent and computationally efficient, making them suitable for quick assessments or low-observability networks. However, they lack optimality and cannot explicitly manage uncertainty or temporal correlations.

Rule-based approaches also include capacity-driven methodologies that estimate flexibility requirements from the exceedance of network limits rather than from detailed electrical simulations. A notable example is the Common Evaluation Methodology (CEM) developed by Baringa for the UK Energy Networks Association [27]. The model determines the flexibility needed to offset forecasted load exceedance over asset capacity and compares its cost against conventional reinforcement through a cost–benefit framework. Although primarily designed as an economic evaluation tool, the underlying estimation of flexibility volumes follows a rule-based logic derived from capacity thresholds and predefined assumptions on network growth.

2.1.2. Optimisation Algorithms

Optimization-based approaches formulate flexibility needs assessment as a constrained optimization problem, typically derived from Optimal Power Flow (OPF) formulations. The goal is to identify the minimum amount of flexibility required to ensure that operational limits on voltage and current are respected, while accounting for the physical constraints of the distribution grid.

Depending on how uncertainty is represented, different formulations can be adopted. Deterministic OPF models compute baseline flexibility requirements under nominal forecast conditions. Scenario-based and stochastic formulations extend the analysis to multiple realizations of load and renewable generation, often using Monte Carlo sampling techniques [28]. Robust and chance-constrained formulations introduce confidence levels to balance over- and under-procurement risks [29], while multi-period approaches include intertemporal constraints of distributed resources and generate time-dependent flexibility envelopes [30]. Deterministic OPF, based on single forecasted conditions, provides a baseline flexibility requirement.

In [12], the quantification of the DSO's needed flexibility is operationalised through a day-ahead hosting capacity (HC) assessment, used as a proxy for the maximum DER injection that can be accommodated without corrective actions. The method relies on optimisation-based nodal and total hosting-capacity estimation. Specifically, the DSO solves a constrained maximisation problem that maximises the sum of nodal DER injections, subject to distribution-network constraints expressed through piecewise linearised power-flow equations, including active/reactive power balance, voltage bounds, and feeder current limits. To translate HC into "needed flexibility" at the day-ahead time scale, day-ahead RES forecasts at each node are compared against the estimated nodal HC. Three operational cases are defined: (i) forecasts ≤ HC everywhere (no action), (ii) forecasts exceed HC at some nodes (the DSO updates nodal targets and re-runs the optimisation to obtain revised, non-violating HCs; if infeasible, flexibility is procured/activated through local mechanisms), and (iii) forecasts exceed HC broadly (local security compromised, requiring FER activation via local markets and/or dynamic tariffs).

Advanced formulations also include probabilistic and risk-oriented optimization models, where flexibility is represented as a controllable decision variable to mitigate the probability of network constraint violations under uncertain load and generation conditions [23]

Sensitivity coefficients are frequently embedded within these formulations to linearize the network response or to aggregate buses into electrically homogeneous zones, improving computational efficiency. These optimization-based frameworks are rigorous and interpretable but can become computationally demanding for large networks or extensive scenario sets.

2.1.3. Data-driven Approaches

Data-driven methodologies estimate flexibility needs directly from historical data and real-time measurements, leveraging statistical learning rather than explicit physical models. Techniques such as regression, clustering, and neural networks can forecast the flexibility required to maintain secure operation given system states and exogenous variables (e.g., temperature, PV generation).

In the EUniversal German demonstration [28], aggregated measurement data were used to derive flexibility estimates under partial observability, integrated with reduced-order network models. These hybrid approaches combine the predictive capacity of machine learning with the physical consistency of OPF-based optimization. Data-driven methods are scalable and adaptive, making them suitable for near-real-time applications. Their limitations include dependence on data quality, limited interpretability, and potential extrapolation errors when operating conditions deviate from historical data.

Table 3 summarizes the main characteristics of the methodological families.

Each approach is described in terms of its data requirements, ability to represent uncertainty, underlying mathematical formulation, and main strengths and limitations.

Rule-based methods rely on a limited set of network parameters and sensitivity coefficients. They are fully deterministic and transparent, offering fast computation but limited accuracy under uncertain conditions.

Optimization-based formulations require complete network and forecast data. They can incorporate deterministic, stochastic, or robust representations of uncertainty, ensuring technically consistent and optimal results at the cost of higher computational effort.

Data-driven approaches depend primarily on historical and real-time measurements and use statistical or machine learning techniques. Their main advantage lies in adaptability and scalability, although their performance depends heavily on data quality and model interpretability.

Table 3. Comparison of different methodologies

Approach	Input Requirements	Uncertainty Representation	Mathematical Nature	Advantages	Limitations
Rule-based	Network parameters, sensitivities, operating limits	Implicit / none	Deterministic	Transparent, fast, low data needs	Non-optimal, cannot handle uncertainty
Optimization-based	Full network model, DER characteristics, forecasts	Deterministic, stochastic, or robust	Deterministic or probabilistic	Rigorous, physically consistent, extendable to markets	Computationally intensive
Data-driven	Historical and real-time measurements	Implicitly probabilistic	Statistical / ML-based	Adaptive, scalable, suitable for real-time	Requires large datasets, limited interpretability

2.2. Computational Techniques

Computational techniques play a crucial role in making flexibility needs assessment (FNA) tractable for large-scale systems. They can be grouped into two main categories according to the type of complexity they address.

Temporal uncertainty representation focuses on the variability of demand and renewable generation. Scenario-based techniques generate multiple realizations of load and PV profiles to represent forecast uncertainty, while clustering methods are used for scenario reduction by grouping similar time series into typical days or representative operating conditions. This approach allows capturing the annual variability with reduced computational effort. Monte Carlo simulations further extend this concept by statistically sampling a large number of realizations to approximate the probability distribution of flexibility needs [20], whereas worst-case analysis ensures that the estimated flexibility covers the most adverse but still feasible operating conditions [30].

Spatial complexity reduction deals with the dimensionality of the network model. Network clustering or grid segmentation techniques aggregate nodes that exhibit similar electrical sensitivities, thereby enabling the definition of zonal flexibility needs and a substantial reduction of the optimization problem size [26], [28].

Temporal and spatial clustering are complementary: the former reduces the number of operating scenarios, while the latter reduces the number of network variables. Combined, they make stochastic and probabilistic flexibility assessments computationally feasible even for large and highly meshed distribution systems.

2.3. Mathematical Model: Probabilistic Versus Deterministic Approaches

A long-standing debate in distribution network planning concerns the adequacy of **deterministic versus probabilistic approaches** in dealing with increasing uncertainty from distributed generation, electrification, and flexible demand. Traditionally, planning has relied on the so-called *fit-and-forget* paradigm, a deterministic method in which networks are designed to withstand extreme worst-case conditions (typically assuming maximum demand and minimum generation, or vice versa) through permanent infrastructure upgrades. While this approach offers simplicity and robust margins, it neglects the actual probability of such scenarios and leads to systematic overinvestment and underutilization of existing assets.

In contrast, **probabilistic approaches** embrace uncertainty by modelling generation and demand variability through statistical distributions, typically using probabilistic load flow and risk assessment techniques. Rather than eliminating all risk, these methods aim to keep the expected number of technical violations within an acceptable threshold, allowing for more flexible and cost-efficient planning.

The choice between these paradigms has a profound impact on both hosting capacity (HC) estimation and the value attributed to flexibility. In the real-scale case study analyzed [23], the deterministic method led to a projected upgrade of 43% of MV lines by 2050, with 36% of interventions anticipated in the first decade (2023–2030). By contrast, adopting a probabilistic risk-based methodology reduced the upgrade needs to 17% in the first decade and 31% across the entire period. This difference reflects a potential 30% reduction in CAPEX, as probabilistic planning allows for deferring investments while maintaining system reliability. Furthermore, the value of flexibility emerges only within a probabilistic framework: deterministic models overestimate the activation requirements, making flexibility economically unviable. Probabilistic simulations, on the other hand, show that flexibility is primarily needed during low-probability, high-impact events, with a yearly activation below 200 hours and required power adjustments never exceeding 300 kW, according to the results of the real MV case study presented in [23]. These findings confirm that risk-oriented probabilistic models are essential to unlock the full potential of flexibility, enabling SOs to support the energy transition while optimizing infrastructure deployment.

3. Case Studies

This chapter presents selected case studies illustrating how flexibility needs are assessed and translated into planning or procurement decisions at distribution and transmission levels. Several European countries are progressively integrating flexibility into network development planning. For example, in France, Enedis evaluates flexibility, including storage and market-based local flexibility services, as an alternative or complement to conventional grid reinforcement, particularly for medium-voltage reinforcements aimed at solving congestion. Since 2021, this assessment has been embedded in cost–benefit analyses for relevant reinforcement projects, although conventional reinforcement often remains the most competitive solution depending on local conditions. Similarly, in Lithuania, the Distribution Network Development Plan estimates that the deployment of flexibility could defer grid investments by approximately EUR 39–50 million over the 2024–2033 period.

However, these examples are mentioned here only to contextualise the broader European landscape. The case studies analysed in detail in the following sections were selected because they provide publicly available methodologies, quantitative outputs, or planning instruments that are directly relevant to flexibility needs assessment. The chapter therefore focuses on Portugal, Denmark, Great Britain, and the ENTSO-E pan-European case, covering both distribution-level and system-level perspectives.

3.1. Flexibility in the Portuguese Distribution Network Development Plan

The Portuguese Distribution Network Development and Investment Plan (Plano de Desenvolvimento e Investimento da Rede de Distribuição de Eletricidade, PDIRD-E 2024), prepared by E-REDES, introduces a systematic methodology for integrating flexibility as a structural element in network planning.

3.1.1. Flexibility as an Alternative to Conventional Investments

The Plano de Desenvolvimento e Investimento da Rede de Distribuição de Eletricidade (PDIRD-E 2024) represents the main regulatory instrument defining the development of the Portuguese electricity distribution network for the period 2026–2030 [31]. It was elaborated by E-REDES, the national Distribution System Operator (DSO), under the supervision of the Entidade Reguladora dos Serviços Energéticos (ERSE) and in alignment with the national energy policy objectives set by the Plano Nacional de Energia e Clima 2030.

The 2024 edition formally introduces flexibility as a planning resource, , which establishes the legal framework for the integration of distributed resources, energy communities, and flexibility markets in the Portuguese power system. Flexibility is recognised not as an ancillary option, but as a structural element within distribution network development planning, enabling a more adaptive, efficient, and economically sustainable grid.

3.1.2. Methodology for Quantifying Flexibility Requirements

According to the PDIRD-E 2024, flexibility is integrated into network planning as a non-wires alternative (NWA) to conventional grid reinforcement [31]. E-REDES identifies flexibility as a mechanism to reduce or defer investments while ensuring system reliability and operational security.

Flexibility services can be procured from:

- Demand response (temporary load reduction or shifting);
- Distributed generation (including renewable resources);
- Energy storage systems, both stationary and aggregated.

E-REDES adopts a probabilistic network dimensioning criterion, under which the grid is planned to operate safely for 95 % of annual hours using its physical infrastructure. The remaining 5 % (corresponding to extreme peak conditions) is managed through contracted flexibility services. This principle avoids over-dimensioning and ensures that investment decisions account for real network utilisation profiles rather than deterministic peak conditions.

This planning approach has allowed E-REDES to defer or avoid seven reinforcement projects originally foreseen in the 2024 plan, including the postponement of the Valença primary substation renewal from 2026 to 2029 [31].

The quantitative definition of flexibility requirements follows a probabilistic and data-driven process, developed within the framework of the FIRMe Project (Flexibility Integration into Regional Medium Voltage Networks) [32]

The methodology employs synthetic load and generation diagrams derived from smart-grid data, allowing E-REDES to represent network conditions under realistic temporal and stochastic variations. Using these diagrams, probabilistic simulations identify the operational constraints (such as voltage deviations or line overloads) that may occur under peak scenarios.

For each identified constraint, E-REDES determines the following parameters:

- The maximum flexible power required to remove the constraint;
- The temporal activation windows during which flexibility is needed;
- The network zones and voltage levels where flexibility can be effectively deployed.

These parameters form the technical specifications for market-based procurement of flexibility services, enabling the DSO to contract targeted and measurable actions directly linked to network needs [31].

3.1.3. Economic Valuation and Reserve Price Determination

E-REDES introduces an economic assessment model to compare flexibility against traditional network investments. The approach is based on determining a reserve price, i.e., the maximum price that can be paid for flexibility services while maintaining cost-effectiveness compared to conventional reinforcement.

The reserve price is defined by equation (1) :

$$P_{\text{reserve}} = B_{\text{flexibility}} - B_{\text{lost}} \tag{1}$$

where $B_{\text{flexibility}}$ represents the specific benefits of flexibility (e.g., deferred investment and higher residual asset value), and B_{lost} denotes the benefits that would be obtained only through physical grid expansion (e.g., technical loss reduction).

The trade-off between the two alternatives, and the resulting reservation price, is illustrated in Figure 3-1.

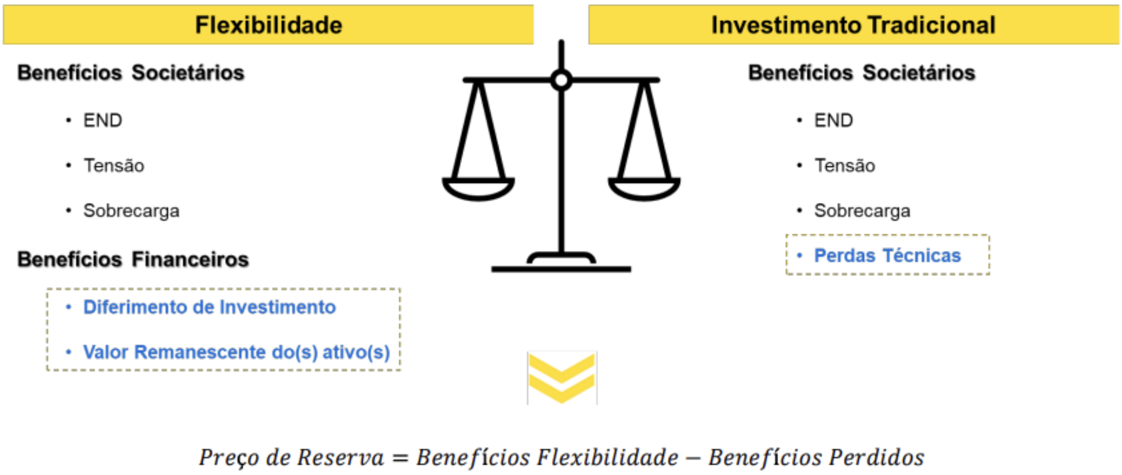


Figure 3-1. Common and exclusive benefits of the investment alternative and the flexibility alternative, and calculation of the reservation price for grid development projects. [31].

In several analysed cases, the reserve price resulted negative, indicating that conventional investments may remain economically preferable when their systemic benefits, such as loss reduction and reliability improvement, outweigh the advantages of flexibility.

3.1.4. Integration of Flexibility Requirements

The Annex C.4 of the plan provides the detailed flexibility requirements for tenders planned for 2026-2027, where a non-wires alternative has been considered [33]. Each project includes:

- The maximum power requirement (in MW) to eliminate the network constraint;
- The activation period (hours or months) associated with the flexibility service;
- The specific substations, feeders, and voltage levels concerned.

These requirements are directly derived from the probabilistic analysis described above and serve as the technical baseline for flexibility market procurement. Among six projects justified by supply-security needs four were considered potentially feasible through flexibility and were provisionally deferred, subject to confirmation through the outcomes of the flexibility procurement tenders (including the savings reported in C.2).

This systematic inclusion of flexibility parameters into the annexes of the PDIRD-E ensures that flexibility is not treated as an ad-hoc option but as a formally recognised planning instrument subject to regulatory oversight by ERSE.

3.2. Flexibility in the Danish Distribution Network Development Plan

An example of a needed flexibility assessment procedure is proposed in the network development plan of Radius Elnet (Denmark), where flexibility is treated as a planning option to mitigate anticipated capacity constraints and defer conventional grid reinforcements [34].

The methodology is grounded in a 10-year demand projection based on the Danish Energy Agency's general analysis assumptions, complemented by Radius' own planning assumptions. A baseline forecast of "classical" electricity consumption is first established and then expanded to reflect electrification trends associated with the green transition, explicitly including electric vehicles and individual heat pumps, as well as known large upcoming consumers (while acknowledging that additional, currently unknown large connections are not represented).

A central step is the translation of projected annual energy into a dimensioning maximum power indicator. This conversion is carried out at netstation level (10/0.4 kV transformer substations) by constructing an annual hourly load profile (kWh/h) and adopting the 99th percentile (99% fractile) as the planning-relevant "maximum effect." The profile itself is derived from template-based consumption shapes for classical demand and template EV-charging profiles, so the dimensioning value reflects a high-percentile operating condition rather than the absolute annual maximum.

Within this framework, flexibility is treated as a resource that must materially reduce the upper tail of the load duration curve (i.e., “take the top off” the curve) to be system-relevant, since peak shaving can avoid or defer conventional grid reinforcements. The plan distinguishes between implicit flexibility (e.g., time-differentiated tariffs and demand charges that incentivise off-peak consumption) and explicit flexibility (contractual products or arrangements that enable direct regulation of consumption/production under predefined conditions, targeted at peak reduction).

Finally, Radius reports the resulting expected flexibility needs as aggregated power values (MW) over the planning horizons 0–2 years, 3–5 years, and 6–10 years (60 MW, 94 MW, and 186 MW, respectively), and provides a zone-based geographical allocation over the longer-term interval. The document also highlights that these figures are aggregated and sensitive to broader societal developments, and that parts of the planning (particularly the projection of needs on the 0.4 kV and 10 kV levels) rely on a generic modelling approach due to uncertainty in the future localisation and intensity of electrification across areas.

3.3. Flexibility in the British Distribution Network Planning Framework

In Great Britain, the Open Networks programme of the UK Energy Networks Association (ENA) has developed the Common Evaluation Methodology (CEM) and the associated CBA Excel-based tool, which provide a standardised framework for assessing flexibility as an alternative to traditional reinforcement [35].

Figure 3-2 and Figure 3-3 show the main page of the tool and the Sheet Flex volume and cost inputs page.

CEM is a capacity-driven, rule-based methodology: for each constrained asset, it compares projected loading with the firm capacity and derives the required flexibility as the amount of load reduction or generation curtailment needed to eliminate the forecast exceedance over time (typically expressed in MW/MVA and hours per year).

In the CEM, flexibility requirements are not defined by the DSO and entered as annual volumes (or via days/hours and average hourly requirements) for each year and scenario. For reinforcement deferral, the tool deterministically computes asset exceedance by comparing scenario peak-load forecasts against available capacity, and then performs the economic comparison between flexibility and conventional reinforcement across scenarios.

This “needed flexibility” profile is then fed into a discounted cash-flow model that compares the net present value of procuring flexibility services against network reinforcement across multiple load-growth scenarios, and derives indicators such as the economically efficient volume of flexibility, the optimal deferral period, and the ceiling price that a DSO can pay while remaining cost-neutral. In this way, CEM links a simplified, capacity-based flexibility needs assessment to planning and procurement decisions that are directly actionable for distribution network operators.

The tool is publicly available together with a user guide on the ENA website. The methodology is now embedded in GB Distribution Network Options Assessment (DNOA) processes as the industry-standard CBA for flexibility.

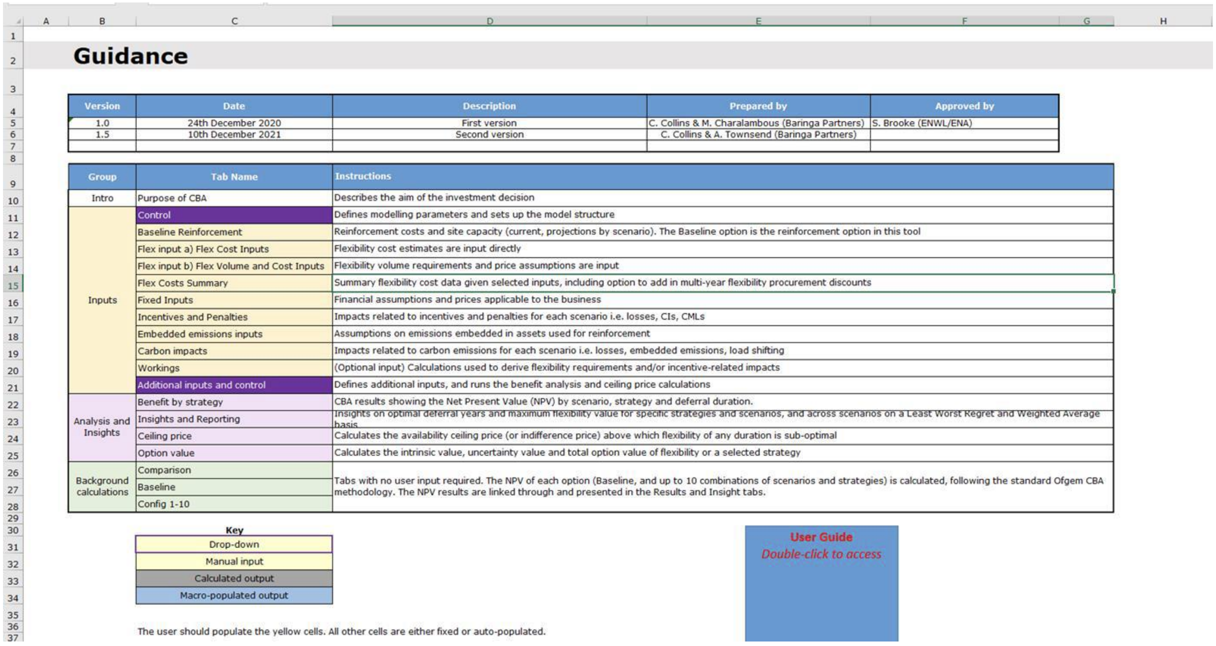


Figure 3-2. View of the CBA Excel-based tool.

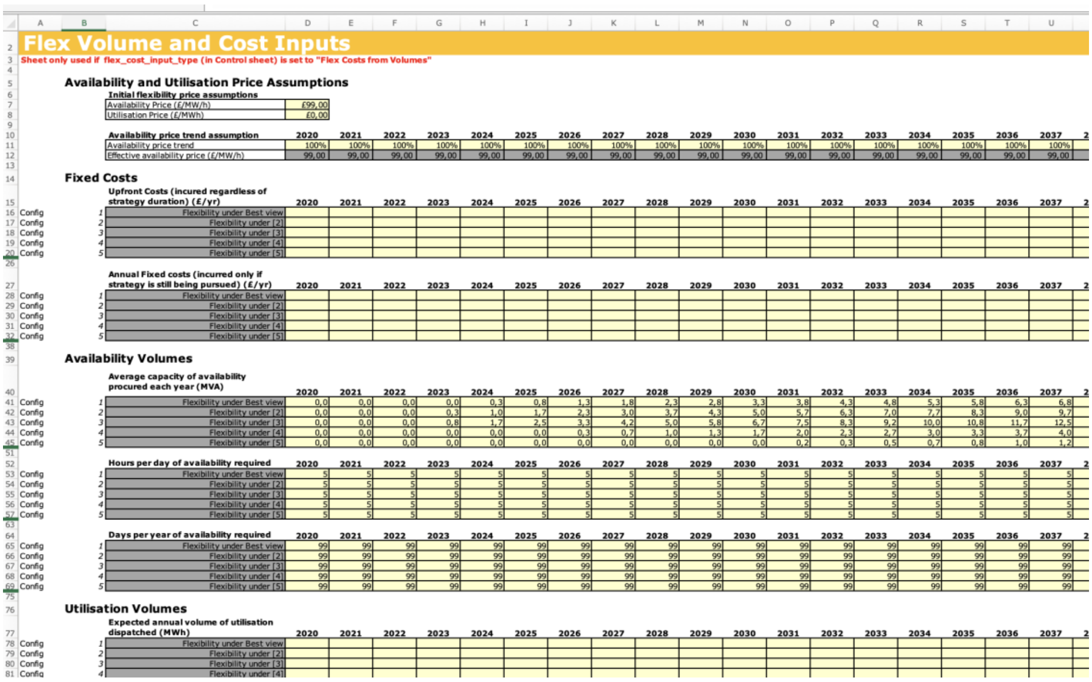


Figure 3-3. Sheet Flex volume and cost inputs.

3.4. ENTSO-E (Pan-European)

ENTSO-E proposes a system-level procedure to quantify future flexibility needs in the day-ahead adequacy timeframe by deriving indicator-based metrics from the hourly outputs of chronological probabilistic adequacy studies used within MAF (Mid-term Adequacy Forecast), ERAA (European Resource Adequacy Assessment), and TYNDP (Ten-Year Network Development Plan) processes [50]. The approach is intended to complement adequacy simulations by highlighting variability-driven stress conditions that may require additional flexibility, without replacing the underlying probabilistic assessments [50].

The methodology targets two day-ahead challenges. The first addresses ramping needs, quantified through residual-load ramps over 1 h, 3 h, and 8 h horizons and normalised to the market zone's derated dispatchable capacity [50]. To relate ramping stress to adequacy relevance, the procedure evaluates the shares of LOLE (Loss of Load Expectation) and EENS (Expected Energy Not Served) occurring during the 5% highest ramp periods, and it also considers curtailed renewable surplus energy where available (reported in the ENTSO-E document as curtailed surplus energy) [50].

The second challenge addresses scarcity periods, quantified through the annual maximum of a 120-hour (5-day) rolling average of residual load, including system reserve requirements such as FCR (Frequency Containment Reserve) and FRR (Frequency Restoration Reserve), and normalised to derated dispatchable capacity [50]. In parallel, the shares of LOLE and EENS occurring within the identified scarcity window are used to assess whether adequacy concerns concentrate in extended multi-day stress conditions (e.g., windless winter weeks), which may be less compatible with short-duration flexibility resources alone [50]

ENTSO-E illustrates the application of these indicators on a national example (Germany) using outputs from MAF 2020 for 2025 and 2030 . The paper notes that residual-load plots are not intended to represent cross-border exchanges explicitly and that the dispatchable capacity used for normalisation is derated for forced outages and can include demand response assumptions. In the scarcity example, the maximum 120-hour average residual load (including FCR+FRR) reaches 96% of dispatchable capacity in 2025 and 102% in 2030, indicating that extended stress periods may approach or exceed the available dispatchable portfolio and increase reliance on cross-border support and other flexibility sources [50].

A subsequent ENTSO-E system study broadens the analysis by adopting flexibility needs indicators across timeframes and by providing a quantitative pan-European outlook based on ERAA 2023 datasets as primary input [51]. The study considers (i) multi-day variable renewable shortage events affecting multiple countries, (ii) residual-load variability up to the day-ahead timeframe (including ramping effects), and (iii) short-duration needs driven by forecast errors in variable renewable generation and demand in the intraday timeframe. These results provide an updated quantitative reference supporting the assessment that system-level flexibility needs are increasing rapidly and complement the indicator-based ramping and scarcity metrics proposed in the earlier ENTSO-E contribution.

3.5. Methodological Approach for Estimating Flexibility Needs and Implementing Local Flexibility Markets in Horizon Europe projects

3.5.1. Introduction to EU Projects

The estimation of flexibility needs is a prerequisite for implementing flexibility markets (FMs), because system operators must first identify where, when, and how much flexibility is required before procuring services from flexibility service providers (SPs). The European project experience analysed in this section shows a common methodological pattern: demonstrator or pilot data are used to build representative grid case studies; power-flow simulations are applied to detect operational constraints; these constraints are translated into flexibility needs; and a local market-clearing model is simulated to assess whether available flexibility can remove the identified network issues.

Among European-funded projects, considering their activities related to estimating flexibility needs, CoordiNet focuses on the scalability and replicability of market platforms and standardised products, including congestion management, balancing, and voltage control under different TSO-DSO coordination schemes [36]. EUniversal extends this scope by analysing local flexibility markets for congestion management, voltage control, and combined congestion-management and voltage-control services in Germany, Poland, and Portugal [37]. OneNet, in its Western Cluster SRA, assesses the scalability and replicability potential of demonstrator solutions by combining qualitative analysis of non-technical boundary conditions with a quantitative, simulation-based techno-economic assessment of local congestion-management markets in the Spanish Murcia and Alcalá de Henares case studies [38].

BeFlexible extends the use of flexibility-need assessment to the coordinated design of several mechanisms for acquiring DSO services (network tariffs, local flexibility markets and flexible or connection agreements) [39].

Within this scope, the methodological question is how flexibility needs can be estimated from demo or pilot data and then translated into market inputs for local flexibility procurement. The core methodological framework is: a co-simulation that links network-operation studies, flexibility-need estimation, sensitivity-based market clearing, ex-post power-flow validation, and techno-economic key performance indicator (KPI) calculation. This framework is consistent with the simulation-based approaches reported in OneNet, CoordiNet, EUniversal, and BeFlexible where case studies are derived from pilots or demonstrators and then modified through scenario parameters such as demand growth, distributed generation growth, SP availability, SP location, product type, voltage limits, and coordination scheme [36]–[39].

3.5.2. Methodological Approach

The methodological approach followed in the reviewd projects consists of a closed market-network assessment loop. Its purpose is to transform network operating problems into market inputs and then verify whether the market outcome is technically effective. The method can be decomposed into seven sequential blocks, as depicted in Figure 3-4.

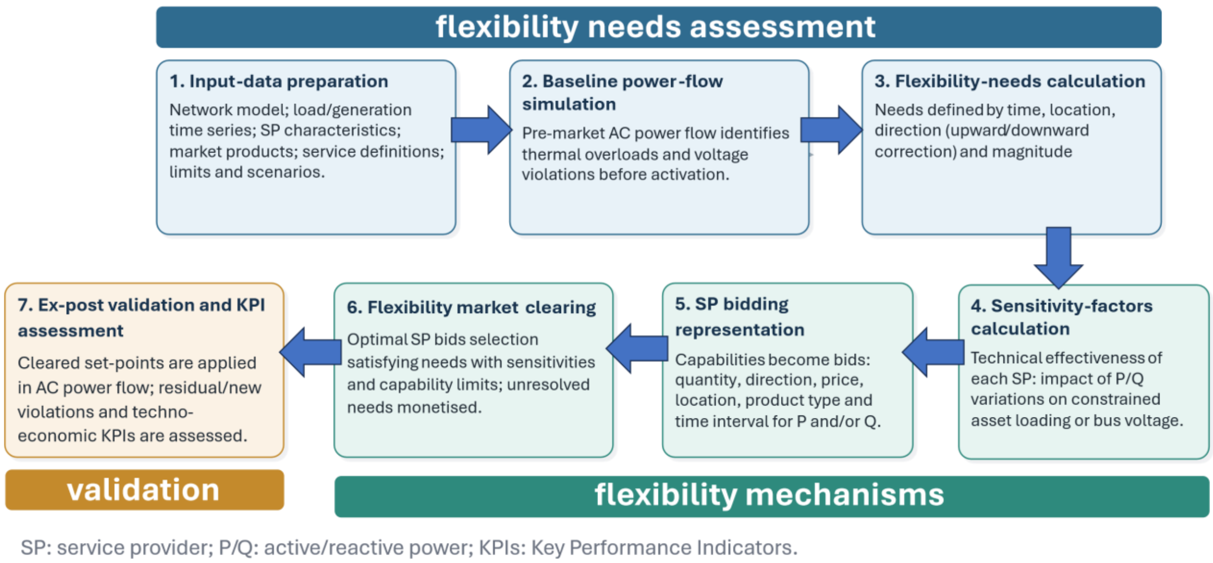


Figure 3-4. Methodological workflow of the flexibility assessment loop adopted in the reviewd European projects.

3.5.2.1. Input-Data Preparation

The first block defines the input layer of the study. This includes the network model, load and generation time series, SP characteristics, market products, service definitions, operational limits, and scenario assumptions. Network data describe the topology, voltage levels, electrical assets, and connection points of loads, generation units, storage units, and SPs. Time series define the active- and reactive-power injections or consumptions over the analysed horizon. SP data specify the technology type, nodal location, upward and downward flexibility capability, active- and reactive-power limits, and activation cost assumptions [36]–[39].

An essential requirement is that the network model, SP model, and market model exchange are consistent. This modularity is necessary because demonstrator studies often combine real data, anonymised network models, synthetic grids, and scenario-based assumptions [36]–[39].

3.5.2.2. Baseline Power-Flow Simulation

The second block performs the pre-market network assessment. A power-flow simulation is run for the selected operating horizon using the baseline load and generation profiles. The purpose is to identify operational limit violations before any market activation. Thermal issues are detected from line and transformer loading values above their admissible limits. Voltage issues are detected from bus-voltage magnitudes outside the adopted voltage band [36]–[39].

The baseline simulation can cover a full year, representative days, selected critical hours, or stress-test scenarios. The choice depends on the available data and the project objective. A yearly simulation is useful to estimate the frequency and duration of constraints, while representative days reduce computational burden and allow focused comparison between market designs [36]–[39].

3.5.2.3. Flexibility-Needs Calculation

The third block converts network violations into flexibility needs. For congestion management, the flexibility need is associated with the overloaded line or transformer, the time interval in which the overload occurs, and the amount of apparent-power relief required. For voltage control, the flexibility need is associated with the bus where the voltage violation occurs, the time interval, the direction of correction, and the required voltage support [36]–[39].

Direction of correction refers to the provision of upward or downward correction trough flexibility service, consistently with the upward/downward balancing direction convention used in the EU Electricity Balancing Guideline [40]. An upward correction means an increase in net active-power injection into the grid, achieved either by increasing generation/export or reducing demand/import, whereas a downward correction means a decrease in net active-power injection, achieved either by reducing generation/export or increasing demand/import.

Each flexibility need should therefore be characterised by four attributes: time, location, direction, and magnitude. This is essential because local flexibility is not a homogeneous system-wide commodity. The same volume of flexibility can have very different technical value depending on where it is connected and whether it acts in the required direction [36]–[39].

In BeFlexible, the flexibility-need assessment follows this same logic but also integrates an additional layer in which flexible resources first optimise their consumption in response to global tariff signals to generate a baseline profile to identify contingency-management needs. These needs are then used for LFM clearing and to define corrective ex-post local tariffs and to analyse flexible connection agreements [39].

3.5.2.4. Sensitivity-Factor Calculation

The fourth block estimates the technical effectiveness of each SP with respect to each flexibility need. Sensitivity factors are used to include network information in the market-clearing problem without embedding a complete alternating-current optimal power flow in the market model. For congestion management, sensitivities approximate the impact of active- and reactive-power variations at FSP nodes on the loading of congested lines or transformers. For voltage control, sensitivities approximate the impact of active- and reactive-power variations on bus-voltage magnitudes [36]–[39], [41].

At a high level, congestion-management sensitivity factors describe how a change in the active or reactive power provided by each flexibility service provider affects the apparent-power flow of a constrained network element, such as an overloaded line or transformer, at a given time. In this way, the methodology estimates how effective each provider is in reducing the loading of the constrained asset. The total expected relief on the constrained element is obtained by combining the active- and reactive-power contributions of all available providers, weighted by their respective thermal sensitivity factors [36]–[39], [41].

Similarly, voltage-control sensitivity factors describe how changes in the active or reactive power provided by each flexibility service provider affect the voltage magnitude at a given network bus and time. These factors indicate whether a provider can effectively contribute to correcting an overvoltage or undervoltage problem. The expected voltage correction at each bus is therefore estimated by combining the active- and reactive-power contributions of all relevant providers, weighted by their corresponding voltage sensitivity factors [36]–[39], [41].

3.5.2.5. SP Bidding Representation

The fifth block converts SP capability into market bids. Bids include quantity, direction, price, location, product type, and time interval. Active-power bids may represent load reduction, load increase, generation increase, or generation decrease. Reactive-power bids represent the capacity of resources to absorb or inject reactive power according to their technical capability curves and operating point [36]–[39], [41].

In the reviewed projects bid prices are derived from cost assumptions, flexibility-market data, or project-specific assumptions. This is adequate for comparing technical and techno-economic behaviour across scenarios, but it should not be interpreted as a forecast of actual strategic bidding in future markets [36]–[39], [41]..

3.5.2.6. Flexibility Market Clearing

The sixth block clears the local flexibility market. The market-clearing problem selects the optimal set of SP bids that mimised the flexibility procurement costs, satisfies the calculated flexibility needs considering the network-sensitivities, and subject to SP capability limits. When flexibility is insufficient or technically ineffective, non-supplied flexibility or unresolved network needs is represented and accounted in monetary terms; hence representing the economic value assigned to non-supplied service and ensure that the model prioritises solving network constraints whenever technically and economically feasible [36]–[39], [41].

Depending on the flexibility market design, the clearing model can represent congestion management only, voltage control only, or joint congestion management and voltage control. It can also consider active-power-only products, reactive-power-only products, or combined active-reactive products [36]–[39], [41].

In BeFlexible, the flexibility-need assessment is used to evaluate and coordinate DSO service acquisition mechanisms that complement flexibility makets, including network tariffs, ex-post local tariffs, and flexible connection agreements [41].

3.5.2.7. Ex-post Validation and KPI Assessment

The final block validates the cleared market solution through an ex-post power-flow simulation. Cleared bids are translated into active- and reactive-power set-points and applied to the network model. The post-market power flow verifies whether the original overloads and voltage violations are removed and whether new violations appear [36]–[39], [41].

This validation step is required because the market-clearing problem uses a linearised network representation without embedding network constraints (i.e., the problem solved is not a linearized optimal power flow). The linearised network representation provides a practical approximation for quantifying the impact of each SP on network operational contingencies and incorporating this information into the market-clearing algorithm. However, the resulting solution must still be validated through an ex-post AC power-flow analysis, as the linearised formulation does not guarantee full AC feasibility. Therefore, technical success must be measured after applying the cleared set-points to the full network model [36]–[39], [41].

The main KPIs include total system cost, flexibility procurement cost, avoided restrictions, residual violations, activated flexibility, cost of non-supplied flexibility, number and volume of transactions, and, where applicable, hosting-capacity and environmental indicators [36]–[39], [41].

3.5.3. Case Studies

3.5.3.1. CoordiNet

CoordiNet implements in the demonstrators' scalability and replicability analysis the flexibility need assessment and flexibility market simulations through three modelling workstreams. In the three workstreams, the workflow follows the general sequence described in section 3.5.2: power-flow analysis, identification of congested lines or transformers, calculation of DSO flexibility needs, computation of sensitivity factors, local market clearing, and post-evaluation [36]. The first workstream analyses TSO-DSO coordination for balancing and congestion management, using an economic-dispatch model with DC power-flow equations. It is applied to Spanish and Swedish case studies and compares coordination schemes such as common, central, and multi-level procurement, including joint and separate procurement of balancing and congestion-management services [36].

The second workstream focuses on local congestion management in medium-voltage distribution grids. It is applied to the Spanish Malaga and Murcia demo sites and to the Greek Argostoli/Kefalonia demo site. The model uses a PTDF-linearised local market.

The third workstream analyses market-based procurement of voltage-control services. It uses sensitivity-factor-based local market models, considering Spanish and Greek networks. The analysed coordination schemes include common, multi-level, fragmented, and local market models. The SPs considered for voltage control are mainly distributed generators interfaced with power electronics, providing reactive-power support [36].

CoordiNet's case-study implementation is important for three reasons. First, it explicitly separates services and coordination schemes, allowing to assess how market performance changes under different TSO-DSO arrangements. Second, it shows how PTDFs and voltage sensitivities can be used as practical network representations in market clearing. Third, it demonstrates that flexibility procurement may not fully solve all criticalities when SPs are insufficient, poorly located, or constrained by technology-specific capabilities [36].

3.5.3.2. EUniversal

EUniversal implements as a multi-country comparison of local flexibility market models the demonstrators' scalability and replicability analysis the flexibility need assessment and flexibility market simulations. The project considers demonstrators in Germany, Poland, and Portugal and tests market configurations that combine three service specifications: congestion management, voltage control, and joint congestion management and voltage control. These services are combined with active-power-only, reactive-power-only, and joint active-reactive product configurations [37].

The Polish case, uses a synthetic medium-voltage grid built with equivalent characteristics to the real demo network using the Reference Network Model [43]. It consists of 22 buses, 20 lines, two HV/MV transformers, eight aggregated load points, seven distributed generators, and one storage unit. Six SPs are considered, including generation and storage. Representative 24 h profiles are used for maximum- and minimum-demand days, and the scenarios create both congestion and voltage-control needs [37].

The German cases, use MV/LV networks provided by the demonstrator partners, with focuson low-voltage constraints. One of the two studied networks includes 1885 buses, 1586 lines, nine 20/0.4 kV transformers, 633 load points, and 60 distributed generators, mostly photovoltaic units. While the other network includes 2431 buses, 1952 lines, 24 transformers, 831 load points, and 32 photovoltaic generators. In both cases, annual profiles with 8760 hourly operating points are used [37].

The Portuguese case, uses an MV/LV feeder supplied by a 60/15 kV substation. It includes 1602 buses, 800 lines, 38 secondary substations, 326 load points, 18 photovoltaic generators, and four batteries. The case is particularly relevant because it contains both medium-voltage and low-voltage flexibility needs and several SP technologies, including loads, photovoltaic generation, and storage [37].

EUniversal applies the same four-step quantitative process to each demonstrator: input-data collection, scenario definition, LFM modelling, and KPI calculation. The LFM modelling step is further decomposed into flexibility-need calculation, sensitivity-factor calculation, SP bid generation, market clearing, and post-evaluation. Flexibility needs are calculated through time-series power flows. Sensitivity factors are then calculated for each SP relative to each flexibility need, linearised sensitivity factors are used to quantify how active- and reactive-power variations from each FSP affect the apparent-power flow of congested lines or transformers. Bids are generated according to technology capability and cost assumptions. The market is cleared by minimising the cost of satisfying the calculated needs. Finally, an ex-post validation checks that cleared bids do not violate DSO operational limits [37].

3.5.3.3. OneNet

OneNet implements the flexibility need assessment and flexibility market simulations as a part of the quantitative scalability and replicability analysisis of the Western Cluster through a simulation-based techno-economic assessment of local congestion-management markets in the Spanish demonstrator. The analysis focuses on Murcia and Alcalá de Henares. Unlike EUniversal, the OneNet market model is restricted to active-power products for congestion management, because this is the relevant scope of the Spanish demonstrator case study [38].

The Murcia case uses a synthetic distribution grid built using the Reference Network Model [43] with 7373 buses, 7084 lines, and 303 transformers. To reduce computational complexity and focus on the electrically relevant area, an equivalent network is built with 322 buses, 309 lines, and 12 transformers. The stress scenario studied considers additional electric-vehicle charging loads. The market horizon is one year, with hourly power-flow simulations over 8760 hours [38].

In the first Murcia scenario, one service provider is considered. This provider is a load that offers upward active-power flexibility through demand reduction. Five cases with a progressive increase of the volume of flexibility offered to the market are considered. The pre-market simulation detects approximately 420 congestion occurrences. The local market progressively reduces these congestions as the available flexibility increases, reaching 100% avoided congestions in the highest-flexibility cases [38]. A second Murcia scenario introduces more service providers in the area. These additional providers are located downstream of congested elements. The results show that the additional providers improve techno-economic performance because better-located resources reduce the amount of active power that must be procured to achieve the same technical effect [38].

The Alcalá de Henares case also uses a synthetic network built with the Reference Network Model [43] with 5288 buses, 5020 lines, and 304 transformers. The equivalent network used has 333 buses, 314 lines, and 19 transformers. Five service providers are considered: four loads and one biogas generator. Electric-vehicle charging loads are added to create congestion-management needs, and the market horizon is one year with hourly simulations [38]. In Alcalá de Henares, the pre-market simulation detects 222 h with congestion, corresponding to 232 congestion occurrences. The market performance improves as the offered flexibility increases, but the effect saturates. The avoided congestion percentage rises from 3.9% to 27.2% as the flexibility volume available from SPs increases, and then saturates reaching 44%. Even with the highest flexibility volume, 56% of congestion occurrences remain unresolved. This shows that additional flexibility volume at the existing nodes is not sufficient; new providers must be connected at more effective locations [38].

3.5.3.4. BeFlexible

The BeFlexible case-study structure is organised around mechanism interactions, using flexibility-need assessment as a common analytical basis to evaluate how flexibility needs change in different scenarios and how efficiently different DSO service acquisition mechanisms address them. Cases 1–3 analyse the interaction between tariff-based signals and LFMs under different tariff designs, temperature conditions and regulated-charge assumptions. Case 1 compares time-block, flatter and volumetric tariff designs; Case 2 introduces country-specific temperature profiles; and Case 3 analyses the effect of modifying regulated charge components in the Spanish tariff. Case 4 extends the analysis to flexible connection agreements, using the Swedish volumetric tariff and temperature profile as the reference condition and testing reductions in EV maximum charging power combined with subsequent LFM activation [39],[42].

3.5.4. Discussion on the Results From the Case Studies

The results from CoordiNet, EUniversal, OneNet, and BeFlexible show that local flexibility market performance depends on the interaction between network topology, SP location, product definition, flexibility availability, and market design.

First, all projects confirm that flexibility location is decisive. CoordiNet shows that SPs with low or zero sensitivity to a congested element cannot solve the corresponding contingency, even if they provide flexibility at low cost [36]. EUniversal reaches the same conclusion through its sensitivity-based comparison of active and reactive products across Polish, German, and Portuguese networks [37]. OneNet provides a quantitative evidence in the Alcalá case, where increasing the flexibility volume of existing providers does not remove all congestions because the remaining needs require providers at different network locations [38].

Second, the BeFlexible results show that tariff design can be a dominant driver of flexibility needs because predictable global tariff signals may synchronise price-responsive resources, especially EVs, and create congestion. LFMs and ex-post local tariffs improve congestion-management outcomes by introducing market-based activation and locational corrective signals, but their effectiveness depends on available flexibility volumes and on whether the signals remain sufficiently coordinated [39],[42].

Third, the projects show that flexibility volume alone is not an adequate measure of market liquidity. In CoordiNet, some congestion scenarios remain unresolved even after procuring the maximum available flexibility [36]. In EUniversal, flexibility is explicitly described as a multidimensional issue as it must be available in the required quantity, location, direction, product type, and time interval [37].

Forth, active-power and reactive-power products have different technical roles. CoordiNet treats active power mainly in the context of balancing and congestion management, while reactive power is used for voltage-control procurement [36]. EUniversal provides a direct comparison of active-only, reactive-only, and combined active-reactive products. Its results show that combined active-reactive procurement generally reduces costs and solves the same or more constraints than single-product alternatives, while active-power-only markets are generally more effective than reactive-power-only markets for solving network criticalities in the analysed MV and LV grids [37].

Fifth, multi-service markets can improve technical and economic performance, but they increase implementation complexity. CoordiNet separates congestion-management and voltage-control workstreams, which makes the service-specific effects easier to analyse [36]. EUniversal explicitly compares congestion-management-only, voltage-control-only, and joint congestion-management and voltage-control markets. Its results show that multi-service markets are generally more effective and efficient, but also more complex to implement [37]. BeFlexible results also show that congestion-oriented mechanisms based on active power do not fully address voltage problems, confirming the need for complementary voltage-control services [39],[42].

Sixth, validation is essential. CoordiNet applies post-evaluation to verify that the PTDF-linearised market-clearing solution does not create new congestion problems [36]. EUniversal emphasises that post-evaluation is required because the LFM model uses incomplete grid modelling and sensitivity factors rather than full AC optimal power flow [37]. The flexibility procurement framework must close the loop with post-market AC power-flow validation and residual-violation detection [41]. Therefore, the market-clearing result should be technically validated with ex-post network simulations or by complying with some ex-ante security envelops.

3.5.5. Gaps to Further Improve the Methodology Adopted by the Horizon Europe Projects

The first methodological gap concerns data governance for flexibility-need assessment. CoordiNet, EUniversal, OneNet and BeFlexible show that this process is highly data-intensive, since it requires information on network topology, operational limits, asset characteristics, resource availability, user behaviour, flexibility baselines and activation performance. Much of this information is sensitive and may be subject to security, privacy, commercial-confidentiality or market-strategy constraints. Therefore, detailed input data and granular assessment results cannot always be shared publicly or exchanged without restrictions. Future applications should define dedicated data-governance frameworks that enable flexibility-need assessment while limiting the exposure of critical network, asset, resource and user data. This requires clear rules for data access, aggregation, anonymisation, role-based permissions, cybersecurity protection and publication of results, so that the assessment can support DSO service acquisition without creating vulnerabilities through excessive data disclosure.

The second gap concerns FSP bid modelling. The reviewed studies generally use cost-based or assumed marginal bid prices rather than strategic market bids. This is adequate for techno-economic comparison under controlled assumptions, but it does not represent how SPs may bid under pay-as-bid, marginal pricing, portfolio aggregation, or strategic behaviour. Future methodologies should include behavioural bidding models, aggregator portfolio constraints, uncertainty in availability, and settlement-related incentives.

The third gap concerns the integration of flexibility-need assessment with DSO-controlled operational measures. Methodologies should co-optimise market-based flexibility with DSO-owned actions, such as network reconfiguration, on-load tap changer control, voltage-control devices or other operational measures. CoordiNet, EUniversal, OneNet and BeFlexible indicate that unresolved criticalities are often linked to the location, timing or technical effectiveness of available SPs. Therefore, flexibility-need assessment should evolve towards an integrated operational-planning framework that minimises total system cost by jointly considering SO-controlled measures, market-based procurement and, where relevant, reinforcement alternatives [44].

The fifth gap concerns the approximation introduced by sensitivity-based market clearing. Sensitivity factors reduce computational complexity and protect network-data confidentiality, but they cannot fully replace AC feasibility assessment. This is why ex-post validation is required. Future work should improve sensitivity updating, grid prequalification, bid filtering, traffic-light constraints, and hybrid formulations that retain tractability while reducing infeasible or counterproductive market outcomes.

The sixth gap concerns regulatory and implementation readiness. CoordiNet identifies that congestion management and voltage control market-oriented definitions and procedures remain insufficiently harmonised across countries. Furthermore, BeFlexible highlights that flexibility-need assessment should be expanded from isolated market simulation to coordinated mechanism design. Poorly coordinated signals may shift congestion to adjacent hours or different network elements making the results of the flexibility need assessment not reflective of the acutal network conditions. Flexibility need assessment methodologies should therefore assess temporal and spatial coordination between tariffs, LFMs, flexible connections and voltage-control services.

3.5.6. Conclusions From the Review of European Project Practices

The reviewed European project experience supports a common simulation-based methodology for estimating flexibility needs and assessing local flexibility markets. The methodology starts from demonstrator or pilot data, runs baseline power-flow simulations, identifies congestion and voltage violations, converts them into flexibility needs, calculates network sensitivity factors, generates FSP bids, clears a local market, validates the outcome through ex-post power flow, and calculates technical and economic KPIs.

CoordiNet demonstrates this logic across TSO-DSO coordination, local congestion management, and voltage-control workstreams. EUniversal generalises the approach across several countries, networks, services, and active-reactive product combinations. OneNet applies a focused version of the methodology to active-power congestion-management markets in the Spanish Western Cluster case studies. BeFlexible complements CoordiNet, EUniversal and OneNet by showing that flexibility-need assessment have to be addressed considering a common analytical layer that consider all flexibility mechanisms in place.

The main finding is that local flexibility markets can be effective, but flexibility must be available at the correct location, in the correct direction, during the relevant time interval, and through a product that is technically suited to the network problem. The case studies also show that increasing flexibility volume is not sufficient when SPs are poorly located or technically unable to affect the constraint. Therefore, flexibility needs must be assessed through location, sensitivity, timing, product type, and technology capability, rather than only through aggregate MW or MVAr volumes.

Future methodological development should prioritise better calibration of demo-based simulations, richer FSP and bid models, intertemporal constraints, uncertainty treatment, coordination with SO-owned operational measures, and regulatory implementation frameworks that make flexibility procurement comparable with traditional grid solutions.

4. Standards and Emerging Guidelines for Flexibility Assessment

Recognising the strategic importance of flexibility in avoiding RES curtailement, the European Union has introduced specific regulatory provisions aimed at fostering its development and integration. In particular, the revised Electricity Market Design Regulation (Regulation (EU) 2019/943, as amended by Regulation (EU) 2024/1747), establishes the obligation to perform periodic Flexibility Needs Assessments (FNAs) at national level. These assessments are intended to provide a structured and standardised framework for collecting, organising, and reporting information on flexibility needs over short-, medium-, and long-term horizons, ensuring consistency across Member States and alignment with broader energy policy objectives.

4.1. The Flexibility Needs Assessment Methodology

The FNA is a new regulatory instrument introduced under Article 19e of the Electricity Regulation, aimed at estimating flexibility needs at national level over a five- to ten-year horizon based on data provided by TSOs and DSOs. It is developed jointly by the European Network of Transmission System Operators for Electricity (ENTSO-E) and the EU Distribution System Operators Entity (EU DSO Entity), who are responsible for drafting a harmonised methodology that integrates system-wide and network-specific analyses [45]. The official methodology was issued on July 2025 by the Agency for the Cooperation of Energy Regulators (ACER) and must be implemented by Member States through a nationally coordinated process (see Section 4.1.4).

Unlike traditional Resource Adequacy Assessments (RAAs), which focus primarily on capacity sufficiency under peak load conditions, the FNA quantifies the ability of the electricity system to manage variability, forecast uncertainty, and network constraints on multiple timeframes (intra-day, daily, seasonal). By capturing both system-level balancing requirements and location-specific grid limitations, the FNA provides a structured foundation for defining non-fossil flexibility targets, planning investments, and adapting regulatory frameworks.

4.1.1. Purpose and Scope

The core objective of the FNA is to determine the cost-efficient volume and type of flexibility needed to ensure that decarbonised electricity supply can meet demand across all timescales, while minimising unnecessary investments in conventional generation or grid expansion [45].

In particular, the FNA serves two complementary purposes:

- **To maximise the efficient use of low-carbon electricity** by quantifying the flexibility needed to reduce renewable energy curtailment, align generation with demand, and decrease reliance on fossil-based generation.
- **To supplement RAAs** by capturing operational aspects of system adequacy not reflected in capacity-based assessments. This includes the ability to respond to intra-day deviations, rapid ramps, and forecast errors that influence short-term system stability.

The outcome of national FNA reports informs the formulation of indicative targets for non-fossil flexibility resources, to be integrated into the Member States' National Energy and Climate Plans (NECPs).

4.1.2. Categories of Flexibility Needs and Indicators

The FNA methodology distinguishes between system-level flexibility needs, which affect the power system as a whole, and network-level needs, which arise from localised grid constraints. This dual structure reflects the different temporal, spatial, and operational characteristics of flexibility requirements.

System-level needs are assessed independently by TSO and classified into three categories

- *RES integration needs* emerge when the system is unable to absorb surplus renewable electricity during periods of low demand and high generation. These needs are quantified through analysis of RES curtailment time series and residual load variability across multiple timeframes, under the constraint of national RES integration targets (article 9).
- *Ramping needs* are associated with the system's ability to manage forecasted variations in residual load, typically on an hourly basis. They reflect the technical capability of dispatchable resources to accommodate steep load changes due to variations in vRES and demand, and are assessed by comparing residual load ramps with available ramping margins from flexible assets (article 10).
- *Short-term flexibility needs* capture the system's capacity to respond to unpredicted events such as forecast errors in demand or generation, or forced outages. These are evaluated using probabilistic analysis of historical prediction errors and outage statistics, and translated into upward and downward flexibility requirements over multiple sub-hourly timeframes (e.g., 5–15 min, 15–60 min, 1–5 h) [46].

Network-level flexibility needs are assessed independently by TSOs and DSOs. They reflect local conditions where system-level adequacy may not ensure deliverability due to congestion or voltage issues. Quantification is based on outcomes of Distribution Network Development Plans (DNDPs) and includes location-specific indicators of power and energy needs under representative scenarios.

This layered structure ensures that both macro-scale and locally constrained flexibility requirements are addressed, avoiding underestimation or double-counting.

4.1.3. Methodological Framework

The FNA methodology supports both transmission- and distribution-level assessments, allowing adaptation to national contexts while maintaining European consistency.

4.1.3.1. System Level

At the transmission level, TSOs may choose between two modelling approaches:

- **Post-processing of ERAA/NRAA outputs**: Existing dispatch simulations are used to derive flexibility needs by analysing residual load, RES curtailment, and available margins under technical constraints.
- **Dedicated economic dispatch simulations**: These include enhanced modelling of flexibility-related constraints (e.g. ramp limits, start-up/shut-down dynamics) and allow for higher-resolution assessment of short-term dynamics. Though more resource-intensive, this approach improves accuracy, particularly for ramping and reserve needs.

For each **system-level** flexibility category:

- RES integration is evaluated by introducing a virtual technology-neutral flexibility asset (e.g. storage-like unit) into the simulation, optimised to reduce curtailment across multiple timeframes.
- Ramping needs are assessed by comparing expected residual load gradients with actual ramping capabilities of available resources.
- Short-term needs are estimated using probabilistic models based on forecast errors and outage statistics, producing sub-hourly capacity requirements.

4.1.3.2. Network Level

TSOs should quantify downward **network-level** needs resulting in RES generation curtailment due to transmission network constraints, even including it in simulation for system needs assessment (focusing on cases where the system is not experiencing high RES generation curtailment as a result of economic dispatch, but local RES generation curtailment due to local constraints).

At the distribution level, DSOs are required to use their DNDPs as the primary source of input data to estimate **local network-level** flexibility needs. These include both upward and downward needs and are typically provided as aggregate indicators of peak power and total energy required to resolve congestion under representative scenarios.

Integration of flexibility needs assessment in DNDPs is currently very limited in the EU. DNDPs (in most cases) cannot yet be used as a source of data for the FNAM.

Where DNDPs are unavailable or insufficient, DSO(s) cannot provide the quantitative information; qualitative information may be provided for the purpose of the first FNA report supplementing their assessments with additional studies (provided these follow DNDP-consistent scenarios and methodologies).

4.1.3.3. Fine-Tuning

The methodology includes a “fine-tuning” phase to adjust system-level results based on downward transmission and distribution network-level needs resulting in RES curtailment and potential unavailability of flexibility resources due to grid prequalification or temporary operational limits. These adjustments ensure that RES integration needs, ramping and short-term needs reflect real-world constraints beyond the copper-plate assumption adopted in TSO simulations. Figure 4-1: Layered architecture of the Flexibility Needs Assessment Methodology, showing the integration of system needs, network needs, and fine-tuning

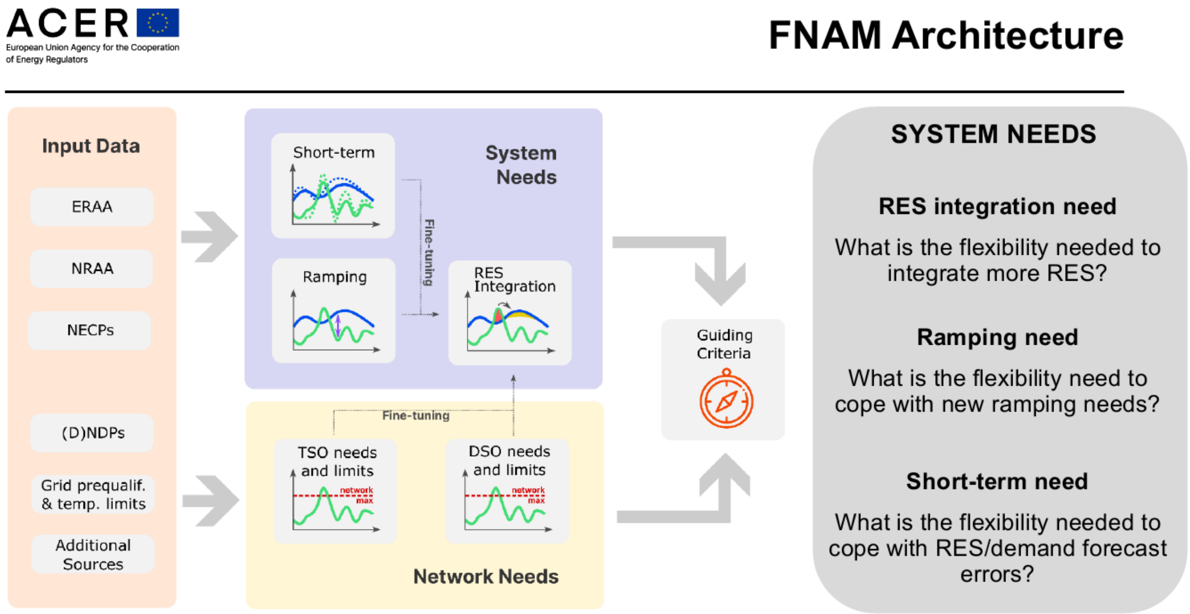


Figure 4-1. FNAM Architecture

4.1.4. Standardisation and National Implementation

Following the approval of the FNA methodology by the Agency for the Cooperation of Energy Regulators (ACER), each Member State is required to implement it through a nationally coordinated process. To this end, a designated authority or entity (appointed by the national government) is responsible for coordinating the application of the methodology, consolidating the necessary input data, and adopting the final national FNA report.

This process involves the structured submission of data and indicators from both transmission and distribution system operators (TSOs and DSOs). TSOs provide system-level outputs derived from economic dispatch simulations, while DSOs contribute location-specific flexibility needs based on their Distribution Network Development Plans (DNDPs) or, if necessary, complementary studies. The assessment also includes information on the temporary unavailability of flexibility resources, such as those not yet prequalified or subject to operational limits.

To ensure consistency and comparability across Member States, the methodology establishes a minimum set of requirements regarding spatial, temporal, and voltage-level granularity, as well as common target years. In countries where multiple DSOs operate, coordination is essential to harmonise methodologies and aggregate local assessments into a coherent national picture.

The designated authority may request additional data or analysis from TSOs and DSOs, provided these requests are justified, proportionate, and consistent with the overall objectives of the FNA. Input data must be submitted within clearly defined deadlines (typically between the third and tenth month after the approval of the methodology) to allow for validation, integration, and adoption of the final report.

To support transparency and cross-country consistency, standardised templates are provided for reporting both input data and assessments of market barriers. The national FNA reports, once completed, serve as input for an EU-wide assessment coordinated by ACER, which includes recommendations on cross-border issues and policy measures to unlock non-fossil flexibility.

This process must be completed within twelve months from the approval of the methodology by ACER and is repeated every two years, in accordance with the regulatory cycle defined in Article 19e. The FNA process is structured into three sequential phases, as illustrated in Figure 4-2. The first phase involves the joint development of the methodology by the EU DSO Entity and ENTSO-E, followed by its review and approval by ACER. The second phase concerns the national implementation, where TSOs and DSOs provide the required data to a designated authority, which consolidates and publishes the national FNA report. In the final phase, ACER conducts an EU-wide assessment based on these national reports, focusing on cross-border relevance and regulatory barriers to flexibility. This timeline ensures coordination across Member States and is repeated every two years in accordance with Article 19e of the Electricity Regulation.

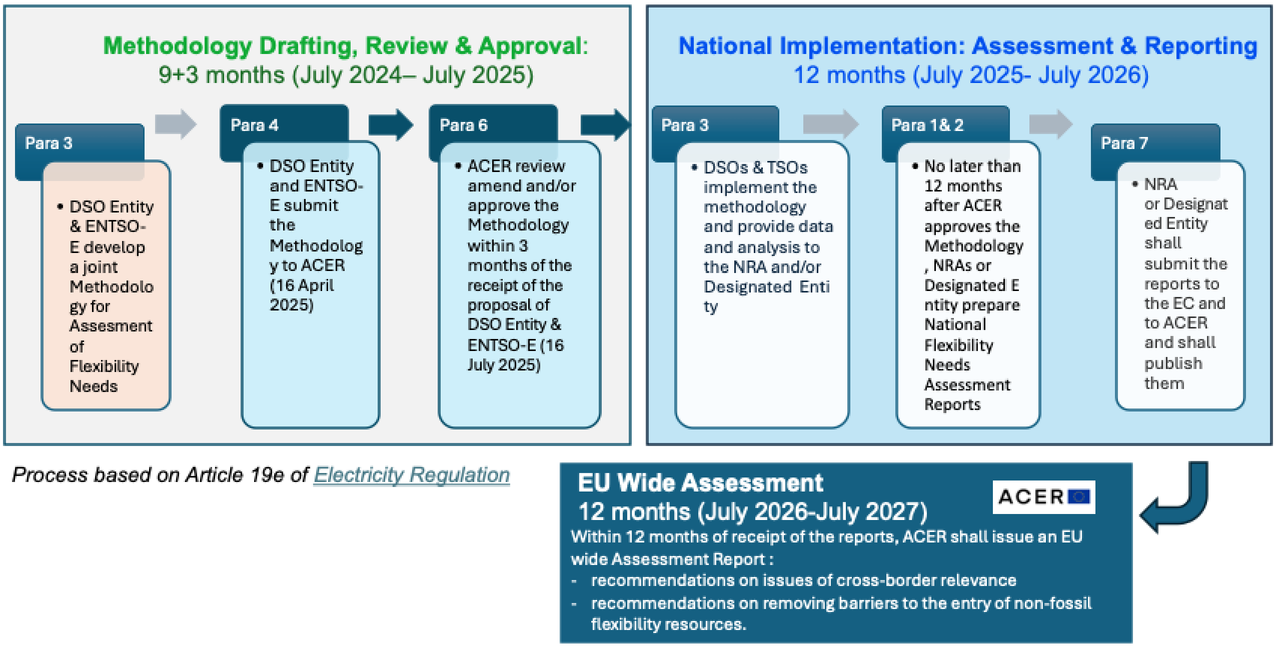


Figure 4-2. Timeline of the Flexibility Needs Assessment (FNA) process, including methodology development, national implementation, and EU-wide assessment, as established by Article 19e of

Regulation (EU) 2019/943, as amended. Paragraph references (e.g., Para 3) correspond to specific clauses within Article 19e [47].

4.1.5. Guiding Criteria for Policymakers

Despite the increasing relevance of flexibility in energy system planning, multiple barriers hinder its effective deployment.

By identifying gaps between the needs and actual capability of the different sources of flexibility to cover flexibility needs, the FNA can inform policy revisions aimed at aligning market incentives with system requirements. It also supports the establishment of national objectives for non-fossil flexibility, thereby reducing investment risk and improving long-term planning certainty for grid operators and market participants [46]

A key strength of the FNA methodology lies in its capacity to provide a coherent set of guiding principles for policy formulation. Rather than prescribing a unique volume of flexibility, the FNA distinguishes between various flexibility needs (e.g., decarbonisation-driven, network-related, adequacy-related) and timescales (e.g., short-term, daily, seasonal), thus encouraging targeted and proportionate responses [46].

These insights can inform the revision of support schemes, the design of new products for flexibility procurement, and the adaptation of network codes and regulatory incentives [46].

Importantly, the FNA also allows the modelling of a “natural” demand curve (i.e., demand levels before the impact of any external flexibility incentive), thereby making explicit the contribution of demand-side flexibility and avoiding its implicit inclusion in an inflexible baseline [49]. Although this approximation is inherently complex, especially as new flexible loads emerge, the transparency of the assumptions involved supports more robust and defensible planning.

5. WG3 guideline for DSO for Flexibility Need Calculation procedure

Based on the review of methodologies and case studies, ISGAN WG3 has identified a set of guiding principles to support System Operators in designing a flexibility assessment procedure.

The starting point of any credible assessment is the definition of a clear reference case. The baseline should represent the network scenario without flexibility activation, incorporating projected demand growth and electrification trends (including electric vehicles, heat pumps, and other emerging loads) rather than reflecting only current operating conditions. Once critical operating conditions are identified against this baseline, the flexibility need is defined as the corrective volume required to resolve them. This ensures that the role of flexibility remains interpretable and that results are not conflated with business-as-usual investment needs. The Portuguese experience described in Section 3.1 provides a concrete example of how probabilistic load and generation diagrams can be used to construct such a baseline and identify constraint exceedances in a reproducible way.

The overall assessment philosophy should move away from worst-case deterministic, fit-and-forget approaches, which tend to over-dimension networks and obscure when flexibility is genuinely needed. Adopting a probabilistic framework, with explicit confidence levels (such as the 95% annual hours criterion used by E-REDES), enables a clearer separation between normal operating conditions and rare but critical events. As discussed in Section 2.3, probabilistic methods have been shown to reduce projected upgrade needs significantly compared to deterministic planning, while also revealing the actual activation profiles of flexibility: limited in annual hours, bounded in required power, and concentrated in specific periods.

The complexity of the method should be matched to the maturity of available data. In networks with limited observability or incomplete metering, rule-based approaches using sensitivity coefficients or capacity exceedance logic (such as those underlying the Common Evaluation Methodology described in Section 3.3) provide a transparent and defensible starting point. As data quality and network visibility improve, a progressive transition toward optimization-based or data-driven techniques becomes both feasible and beneficial, as illustrated by the stochastic OPF approaches reviewed in Section 2.1. A specific challenge arises in networks where historical measurement data are insufficient to populate probabilistic models: in such cases the assessment necessarily relies on synthetic load and generation profiles derived from simulations, which introduces additional uncertainty. DSOs should be explicit about this limitation when reporting results, and should treat simulation-based estimates as a provisional foundation to be progressively replaced as real operational data accumulate.

Once the method is selected, flexibility needs should be quantified with adequate spatial and temporal granularity to be operationally meaningful. Aggregated national volumes or annual averages provide limited value for procurement and planning decisions. Needs should instead be expressed at the level of individual substations or feeders, and associated with specific activation windows, identifying not only how much flexibility is required, but where and when. The Danish case (Section 3.2) and the Portuguese plan (Section 3.1) both illustrate how zone-based and time-windowed specifications translate directly into procurement tender parameters.

A rigorous distinction must also be maintained between the theoretical flexibility potential of DERs and the flexibility that the grid can actually use. As formalized in Section 1.1.4, feasible flexibility accounts for network constraints, internal usage within lower voltage levels, and the operational boundaries of individual resources. Assessing flexibility needs on the basis of feasible, rather than theoretical, potential avoids overestimating what is deliverable and supports more credible sizing of procurement volumes.

However, defining how much flexibility is technically feasible is not sufficient if that flexibility cannot be reliably counted upon. For long-term planning purposes, a DSO must be able to treat contracted flexibility as a dependable resource, comparable in certainty to a conventional grid investment. This requires contractual and regulatory frameworks that guarantee the availability of flexibility over multi-year horizons, including mechanisms to handle provider exit, portfolio changes, and non-performance. At the operational level, the DSO must be able to verify in near real time that the promised flexibility is actually being delivered, which implies the ability to monitor resource behavior before, during, and after each activation event and to compare observed performance against the agreed baseline. Ensuring this level of reliability and verifiability in daily operations depends critically on the underlying ICT infrastructure: advanced metering, communication systems capable of supporting dispatch signals and measurement feedback, and data management platforms able to handle the volume and granularity required. The deployment and maintenance of such infrastructure represents a significant cost component that should be explicitly included in the cost-benefit assessments used to compare flexibility against conventional reinforcement, as omitting it risks underestimating the true cost of a flexibility-based planning strategy.

Finally, the scope of the assessment should reflect interactions among resources and across system layers. Evaluating single resources in isolation may overlook portfolio effects, the rebound dynamics of flexible loads, and the contribution of grid-side options such as dynamic line rating and network reconfiguration. Sector coupling, as discussed in Section 1.3.2, can also expand the effective flexibility envelope across temporal scales. Explicit modelling of load recovery effects (particularly relevant for demand response and electric vehicle charging) is necessary to avoid underestimating post-event rebound peaks.

To ensure that results are traceable and comparable across planning cycles and across Member States (a requirement that the FNA framework described in Section 4.1 is beginning to formalize) DSOs should document at minimum: the spatial granularity of the assessment (voltage level and zone definition), the temporal resolution and activation windows, the scenario assumptions and planning horizon, the baseline construction method and its electrification assumptions, the uncertainty representation approach, whether the reported volumes refer to needed, feasible, or theoretical flexibility, and whether the assessment relies on measured data or simulation-derived profiles. Standardising these elements is a precondition for meaningful benchmarking, regulatory oversight, and the aggregation of DSO inputs into national FNA reports.

These recurring pitfalls, and the corresponding methodological solutions, are summarised in Table 4.

Table 4. Common pitfalls in DSO flexibility needs assessment and recommended methodological solutions

ASPECT	PITFALL	SOLUTION
Assessment Philosophy	Relying on "Worst-Case" (fit-and-forget) deterministic models due to the lack of data to create “statistically reliable” probabilistic frameworks	Adopt Probabilistic frameworks and define acceptable Confidence Levels (e.g., 95%).
Granularity	Providing aggregated national volumes or generic annual averages.	Define needs by Zone (Substation/Feeder) and Time (Critical Windows).
Flexibility Definition	Confusing potential flexibility (theoretical DER capacity) with what the grid can physically utilize.	Identify feasible flexibility by filtering potential resources through network constraints and internal usage.

Transparency & Baselines	Using "black box" baselines where the reference behavior without flexibility is unclear.	Standardize transparent baseline methodologies that account for natural demand growth and electrification trends.
Data	Applying complex optimization models (OPF) to networks with poor data quality or low observability.	Match methodology to data maturity: use rule-based for low observability and transition to data-driven as visibility improves
Resource Scope	Focusing only on single resources (e.g., batteries or generators) ignoring their combination or "rebound effect" of loads.	Include Grid-Side levers (DLR, Reconfiguration) and Sector Coupling; model load recovery dynamics explicitly.
Reliability	The “potential flexibility” that can be provided by the small-scale DER owners are not seen as reliable sources by utilities. DSOs may not have the means to monitor whether the “committed / offered” flexibility is really provided or not. Therefore relying on flexibilities for grid infrastructure planning is an open issue.	Regulation dhould allow DSOs to offer mechanisms to DER owners such that the offered flexibilities are realized and can be monitored in daily operation. ICT infrastructure (including the intra-day accessibility of smart meter data, and increased observability of the grids) should be in place to exploit the full potential of flexibilities.

6. Conclusions

The rapid growth of variable renewable generation and the electrification of end-use sectors are increasing both the variability and the uncertainty of power system operation and development. This evolution is exposing the limits of static fit-and-forget planning, since network constraints and balancing requirements increasingly depend on time, location, and operating conditions. In this context, flexibility (the capability of generation, demand, and storage to adjust power injections or withdrawals in response to system needs) has become a key option to maintain security and cost-efficiency while supporting decarbonisation. Consequently, system operators are required to quantify, in a transparent and defensible manner, how much flexibility is needed, where it is needed, and over which time horizons.

This discussion paper reviewed the main concepts and methodological families used to assess flexibility needs in modern power systems, with specific attention to both system-level requirements and network-level constraints. The analysis framed flexibility as a multi-dimensional concept, spatially and temporally dependent, and distinguished among needed, potential, and feasible flexibility as a basis for consistent interpretation across planning and operational contexts.

A comparative overview of rule-based, optimization-based, and data-driven approaches highlighted that no single method is universally dominant: methodological choices primarily depend on data availability, network observability, computational tractability, and the way uncertainty is represented. In particular, probabilistic and risk-oriented formulations emerged as key enablers to avoid systematic overinvestment and to support credible sizing of flexibility volumes under increasing uncertainty from electrification and variable renewable generation.

While flexibility needs assessment is currently most mature at TSO level, the case studies illustrated how it is increasingly integrated into DSO planning and procurement practices as well. Examples ranged from capacity-driven and standardised evaluation frameworks linking needed flexibility profiles to economic decision metrics, to advanced stochastic and chance-constrained OPF pipelines producing time-windowed and location-specific flexibility envelopes. The Portuguese experience is particularly instructive in this respect: through probabilistic simulation, quantitative requirement definition, and explicit economic valuation, E-REDES has positioned flexibility as a structural planning instrument, capable of reducing investment needs, enhancing operational adaptability, and supporting the transition toward a decarbonised distribution network. Taken together, these experiences confirm that needed flexibility becomes actionable only when it is expressed with adequate temporal granularity, electrical locality, and explicit risk criteria.

At the European level, the Flexibility Needs Assessment framework provides an emerging reference for harmonised reporting and cross-country comparability, combining system-level indicators with network-level inputs and embedding the process in a recurring regulatory cycle. Its progressive implementation will be an important test of whether the methodological advances documented in this paper can be translated into consistent and comparable national assessments.

Within this context, WG3's added value is to emphasise a concise set of points of attention that drive the credibility and usability of flexibility-need results. These include the traceability of assumptions and scenarios, the explicit management of uncertainty to control over- or under-estimation risks, the distinction between theoretical need and deliverable feasible flexibility, and the clarity of outputs for planning decisions, particularly when flexibility is compared against conventional grid reinforcement options. As data quality improves and DSO observability expands, the conditions are progressively maturing to move from rule-based approximations toward more rigorous and location-specific assessments, making the quantification of flexibility needs an increasingly reliable foundation for investment and procurement decisions across the energy transition.

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