DSO ENTITY
DSOs FOR EUROPE

Report on Distributed Flexibility Practices

Markets for Local Services / February 2026

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Acknowledgements

This report has been prepared by the DSO Entity Expert Group on Distributed Flexibility (EG DF) with contributions from its members and participating DSOs across the involved countries.

Participating Countries and National Experts

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Executive Summary

This report provides an overview of current Distribution System Operators' (DSO) practices in the use of distributed flexibility, while stressing the importance of standardising key enabling processes, such as data exchange and coordination mechanisms between markets and between system operators. Building on existing practices and pilot experiences, the report positions these real-world insights as a critical foundation for knowledge sharing, learning, and preparedness for the transition towards regulated and operational local flexibility markets under the Network Code on Demand Response (NC DR)[1].

The effective implementation of the NC DR will largely depend on the design of National Terms and Conditions (NTCs), which constitute the decisive implementation layer of the NC DR. They will set out how flexibility is accessed, qualified, procured, activated, and validated at the national level. DSOs must therefore prepare now, align nationally, and actively shape NTCs to ensure operational feasibility, efficiency, and proportionality.

Analysing the upcoming challenges, the status, and real-world experiences gained in advanced EU Member States, this report sets out key recommendations[2] for European DSOs to prepare for these upcoming tasks:

R1: Start now and embrace the opportunities and challenges that come with the use of local flexibility services

Time is needed to specify and develop tools and processes, to build knowledge and skills, and to manage change internally and with stakeholders. DSOs should therefore start now, implementing local services and markets well before the entry into force of NTCs, while in the meantime, taking advantage of regulatory sandboxes or national practices to manage the steep ramp-up and to enable progressive development of all required progresses.

R2: Define and publish a transparent roadmap to implement local markets

DSOs should set and update a structured and transparent implementation roadmap to allow all parties to work collaboratively towards progressively closing identified gaps, implementing

[1] EU-wide network code on demand response established by Regulation (EU) 2019/943 Article 59(1)(c). The NC DR will establish a harmonised European framework for enabling demand response, distributed generation, and storage to participate in electricity markets and to provide local services to system operators. For DSOs, the NC DR represents a structural transition from pilot projects and regulatory sandboxes towards the regulated and operational procurement of local services. This transition requires DSOs to integrate flexibility as a reliable system operation tool, embedded in daily grid planning and real-time operation.

[2] For ease of reference, recommendations are coded from R1 to R11, while actions are identified separately and numbered starting from A1, where applicable.

and scaling up flexibility in a coordinated manner, while making best use of test-and-learn approaches. In addition, DSOs should provide service providers with visibility on flexibility service opportunities through their published roadmaps.

R3: Engage stakeholders in the implementation process and jointly manage change

DSOs should engage stakeholders from the outset, including during the development of regulatory sandboxes, national practices, and the definition of NTCs, to ensure the development of efficient and pragmatic solutions. DSOs should engage regularly with SPs to understand their challenges and recommendations, and to provide visibility on the development roadmap of local markets.

R4: Promote opportunities for customers to become flexible to develop the needed liquidity for local markets

Local-for-local mechanisms are a strong driver for prosumers to become flexible, as these mechanisms make the value of flexibility tangible at local level. Local services enable, at any time and location, the participation of different kinds of flexible resources, thereby enabling the development of liquidity that can be mobilised to alleviate local congestion or voltage issues.

R5: Secure the flexibility value from end-to-end

DSOs must seek cost-efficient solutions with minimal entry costs for participants, ensuring that flexibility resources can be integrated without imposing excessive burdens. DSOs should consider all processes from end-to-end, ensuring consistency across all involved processes to deliver an optimal value of flexibility. DSOs and service providers, together with the relevant authorities, must secure end-to-end responsibility and accountability from the service provider to the controllable unit, robust to any role or implementation of Technical Aggregators to ensure a safe and secure network.

A1: Regulate Requirements for Technical Aggregation and strengthen cybersecurity requirements

R6: Procure local services and operate markets where efficient

DSOs should therefore start to develop and operate local markets where efficient – either independently, jointly with other system operators, or through delegation to other DSOs or third parties.

R7: Develop tailored (yet standardised) local flexibility products and markets

To foster liquidity and avoid inefficiencies, DSOs must develop local products tailored to the specific characteristics of the distribution grids and ensure the delivery of flexibility where, when, and in the quantities required, while fostering similarities with other flexibility markets and products, including balancing markets. Similarly, in developing local market rules, tools, and processes, DSOs should consider existing national markets, processes, and balancing mechanisms, reusing similar processes wherever possible, and developing necessary specificities.

R8: Establish Flexibility Information System (FIS) modules by using and developing existing infrastructures

Connecting SOs should develop controllable units modules to register flexible resources to be used for the local markets, leveraging their role of trusted Digital Connecting System Operators at the centre of local energy ecosystems, and building on existing solutions for the purpose of cost and time efficiency.

A2: Enable to register all resources beyond the service validation point as a single CU, in addition to the possibility to register technical resources one by one

R9: Ensure physical delivery of flexibility to the grid

DSOs should develop and implement settlement processes and methods that ensure that the expected service is reflected at the service validation point, thereby deterring potential compensation effects.

A3: Improve the concept of compensation effect under the NC DR framework to ensure efficient activation and delivery of services

A4: Ensure the reliability and safety of the grid and foster the development of distributed flexible resources in a non-discriminative manner while acknowledging these goals pertain to two different paradigms thus independent processes

R10: Establish efficient Transmission System Operator (TSO)–DSO and DSO–DSO coordination mechanisms through jointly defined proposals

DSOs and TSOs shall jointly develop coordination mechanisms between transmission and distribution, as well as among DSOs themselves.

R11: Develop proportional, standardised and interoperable data, ICT and (near-) real-time communication requirements for local flexibility services.

Broader upcoming frameworks must recognise DSOs as key actors in data exchange infrastructure and interoperability. DSOs should ensure proportionality in data, ICT and near-real-time communication requirements. DSOs should leverage near-real-time smart metering data where appropriate, as foreseen under Article 20(a) of Directive (EU) 2019/944.

A5: Define provisions for data exchange standardisation within NC DR framework

Taken together, these recommendations provide a practical and pragmatic DSO-driven roadmap to implement and support market development that translates the NC DR into workable NTCs that reflect distribution grid realities and needs. Timely and coordinated action by DSOs is essential to ensure that local flexibility becomes a reliable, scalable system operation tool, improving the efficiency of the development and operation of DSO grids.

Status Quo

All contributing DSOs use local flexibility markets to procure active power services. Most flexibility use cases focus on managing congestion related to consumption or generation when operational limits are reached or exceeded. Flexibility is also a key enabler for accelerating new customer connections, as grid reinforcements often lag behind electrification-driven demand. In countries with harsh winters (e.g., Sweden and Norway), cold weather is a major driver of peak demand flexibility needs.

Across the board, DSOs combine markets for local services with tariff signals, flexible connection agreements (FCAs), and rules-based mechanisms, demonstrating that “one tool” is insufficient.

Key Opportunities and Implementation Challenges for DSOs

DSOs face accelerating connection demand and bidirectional flows, requiring new operational tools, including flexibility procurement, alongside grid reinforcement and digitalisation. The NC DR shifts distributed flexibility from pilots and sandboxes into mandatory national frameworks. DSOs must institutionalise flexibility processes end-to-end: needs assessment, procurement, activation, measurement, verification, settlement, and compliance. Small and medium-sized DSOs cannot implement TSO-like architectures by default. NTCs must support scalable implementation paths: common shared services, standardised interoperable interfaces, and phased obligations.

The large-scale utilisation of distributed flexibility depends as much on data interoperability as on physical assets. As Europe's electricity system transitions from centralised control to decentralised participation, standardised data exchange becomes a prerequisite for efficiency, security, and fair market access. This is particularly evident in the implementation of the Electricity Balancing Guideline (EB GL)[3] and the emerging NC DR.

Distributed flexibility involves millions of controllable units, connected at high, medium, or low voltage grids, often aggregated and activated dynamically across transmission and distribution levels. Without common data models and message formats, aggregators and system operators cannot scale efficiently and face high integration costs, while markets risk fragmentation. Standardisation enables flexibility to be treated as a system resource rather than a bespoke integration challenge.

It is important to note that the most relevant related data exchange procedures involving final customers and market actors are being addressed in the upcoming Implementing Regulation on interoperability requirements and non-discriminatory and transparent procedures for access to data required for demand response (IR DR)[4].

In addition to these procedures, effective coordination mechanisms in the implementation of flexibility services must address four key dimensions:

- Coordination between markets to ensure efficient resource allocation across local, wholesale, and ancillary service markets.

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[3] Commission Regulation (EU) 2017/2195 of 23 November 2017 establishing a guideline on electricity balancing. Available online here.

[4] The data interoperability implementing regulation is coming from Article 24 of Directive 2019/944. To deliver the obligations in Directive 2019/944, Implementing Regulation (EU) 2023/1162 on metering and consumption data requires ENTSO-E and DSO Entity to support the European Commission in creating Implementing Regulations (IRs) on Data Interoperability including two new IRs, customer switching and demand response.

- Coordination between system operators (SOs) to efficiently manage congestion and voltage issues as well as operational limits across system boundaries.
- Coordination between procurement mechanisms to harmonise activation and avoid conflicting signals, establishing clear coordination protocols and standardised data exchange essential for market functionality and interoperability.
- Coordination must prevent conflicting activations and ensure that actions to solve local issues do not create or aggravate constraints elsewhere, for example by creating unmanageable operational overhead for DSOs.

1. Introduction

As the EU energy system has faced unprecedented challenges, such as the increase in energy prices and the need to accelerate the decarbonisation of energy production and consumption, the European Commission has launched new initiatives such as REPowerEU[5] and the Electricity Market Design reforms[6] (EMDR) that aim to accelerate the transformation of Europe's energy system towards a more electrified, decentralised, and customer-centric system.

This requires DSOs to meet new demands, including the connection of most of Europe's renewable energy capacity, EV charging infrastructure, and heat pumps, which represent millions of distributed assets that will interact mostly directly with the DSO grid. Integrating Distributed Energy Resources (DERs) is not just about technology, and it requires a structural end-to-end shift in how DSOs operate, plan, invest in, and govern their systems. This makes DSOs central to delivering the energy transition. The implementation of flexibility services will increasingly be a critical factor in addressing DSO needs, particularly in integrating DERs, managing congestion, and ensuring the safe operation of DSO grids.

To fully capitalise on its benefits, flexibility should be considered alongside other essential investments, such as infrastructure upgrades, the integration of new technologies such as smart meters, and the development of standardised information exchange. DSOs evaluate all flexibility mechanisms available to them, whether market-based, rules-based, flexible connection agreements, or network tariffs, and select the optimal solution or combination of solutions for safe, reliable, and efficient system operation.

Today, DSOs make use of flexibility under national regulations where such frameworks exist, while most DSOs are carrying out pilot projects or regulatory sandboxes, some of which are informal. The "Report on Distributed Flexibility Practices – Markets for Local Services" provides an overview of DSOs' approaches implemented today across various countries, with a particular emphasis on market-based mechanisms. The report builds on distributed flexibility practices and country experiences collected via DSO Entity knowledge-sharing activities and reframes them into an NC DR implementation plan for NTCs drafting teams.

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5 Launched in May 2022 by the European Commission, the REPowerEU Plan aimed at phasing out Russian fossil fuel imports. See more information online here.
6 New Electricity Market Design Rules entered into force on 16 July 2024: amending Directive EU/2024/1711 and the amending Regulation EU/2024/1747.

2. Background and context

In line with **DSO Entity's Technical Vision**[7], flexibility is becoming increasingly relevant for DSOs:

- It contributes directly to the **Green Deal** and **Energy Union** objectives—resilience, affordability, and decarbonisation.
- It supports the **transition** towards DSOs' evolving system operation roles.
- It helps to **accelerate the connection of new third parties** while completing grid investments.
- It helps **alleviate extreme investment pressures**.

Therefore, flexibility is high on the **EU policy agenda**, and it interacts with all core DSO activities from planning to maintenance to day-to-day grid operation. It is also an area where significant legislative developments are taking place.

Within this scope, DSO Entity established the **Expert Group on Distributed Flexibility (EG DF)** in March 2022 to steer legislative matters related to flexibility in the distribution grid at the EU level, to carry out DSO Entity's legal mandates on this topic, and to facilitate knowledge-sharing activities among EU DSOs.

Today, the EG DF operates with **30 experts from 19 countries, as illustrated in Figure 1.**

[7] EU DSO Entity (2024), EU DSO Entity's Technical Vision. Available at: https://eudsoentity.eu/wp-content/uploads/2025/01/Technical-Vision-2024-Final-report-.pdf

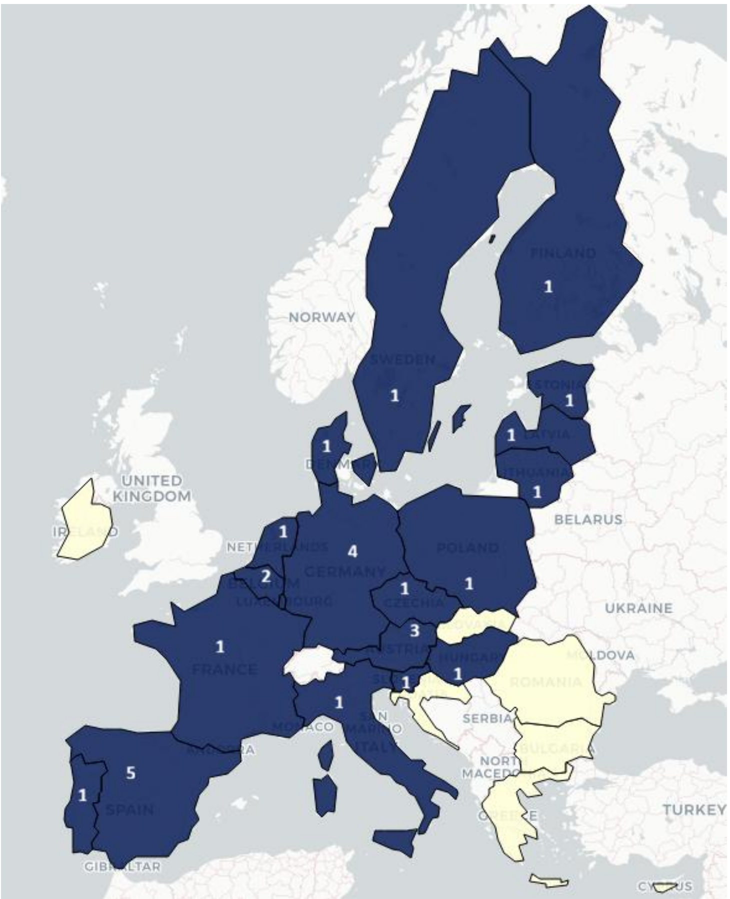

Figure 1 - DSO Entity' EG DF experts by EU Member State

The work of the EG DF is organised around three main work areas, covering:

- the **Network Code on Demand Response**,
- the **Flexibility Needs Assessment Methodology**, and
- **Grid Hosting Capacity Information (Capacitypedia)**.

Through these workstreams, the EG DF delivers on DSO Entity's mandates concerning distributed flexibility. In addition, it aims to support DSOs' practical implementations related to flexibility through knowledge-sharing activities and the exchange of best practices.

In this context, the **"Report on Distributed Flexibility Practices - Market for Local Services"** seeks to facilitate knowledge exchange among DSOs on distributed flexibility.

To support this objective, the EG DF organised a series of internal exchanges in which DSOs shared their experiences with flexibility mechanisms, with particular attention to local flexibility markets. Relevant inputs were collected through dedicated webinars involving DSOs from **France, Italy, the Netherlands, Portugal, Sweden, Norway, and the United Kingdom**.

This report covers participating DSOs from these **five EU Member States** with experience in local flexibility markets, as also illustrated in Figure 2, and includes **two additional non-EU examples**.

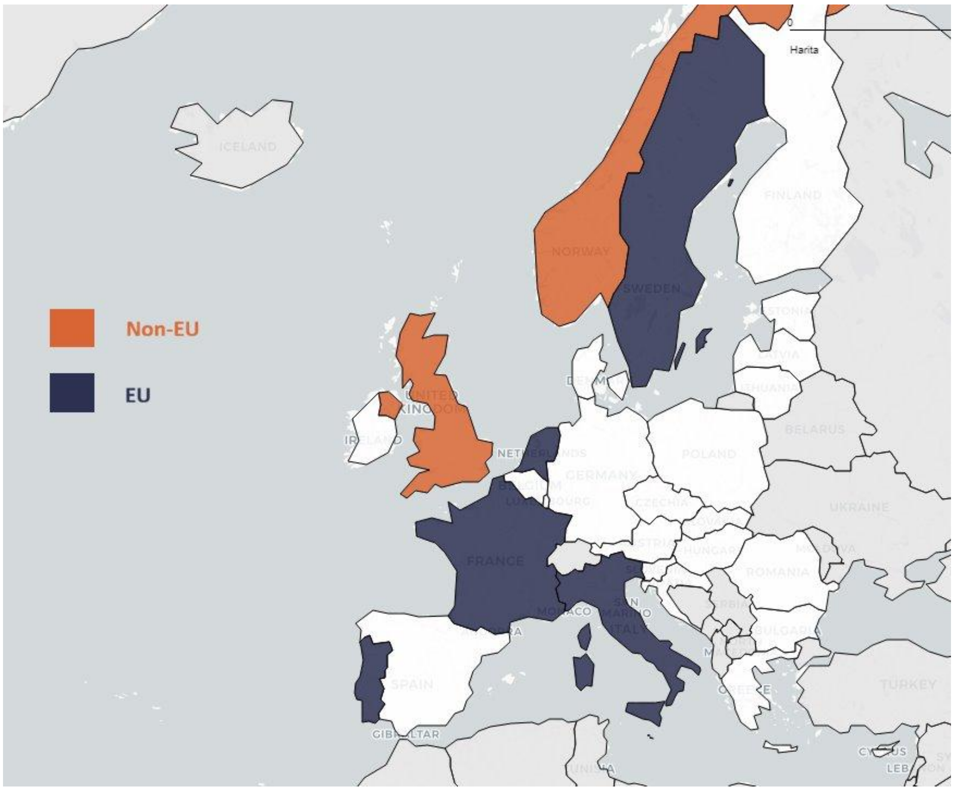

Figure 2 – Webinar series by country

Building on these exchanges, the EG DF carried out country-level deep dives and consolidated the findings in this report to share insights with the wider DSO community. The report focuses exclusively on countries that have established local flexibility markets and are operating them at least at a pilot stage.

Participation in the report was voluntary, and the content reflects the current practices of the contributing DSOs, which are at different stages of implementation under pilots, regulatory sandboxes, or existing national frameworks. Alongside country-specific descriptions, the report also highlights common lessons and insights as well as high-level recommendations & critical regulatory actions derived from these practical DSO experiences.

2.1 Target Vision

The Growing Role of DSOs in Decentralised Power System & Enabling Local Services

The growing role of a DSO is shaped by the shift towards a more dynamic, consumer-centric, and flexible energy system.

With the first Electricity Directive in 1996 (Directive 96/92/EC[8]) the term 'distribution undertakings' was introduced for companies responsible for electricity distribution, reflecting their business-oriented role. Directive 2003/54/EC[9] (second Electricity Directive) marked a shift, introducing the term 'DSO' more consistently across the internal market rules, aligning terminology across Member States. A key step towards the liberalisation of the European energy markets was achieved through the third Electricity Directive (Directive 2009/72/EC[10]) which introduced a formal definition for DSOs in Article 2(6) and legal unbundling requirements with the aim of splitting up the generation, transmission, distribution, and supply activities. This reinforced the DSO's independence from supply and generation activities.

The "Clean Energy for All European Package"[11] finally highlighted in 2019 the central role of DSOs in the EU's energy transition with the Electricity Market Regulation (2019/943/EU) and Electricity Directive (2019/944/EU). The Clean Energy Package (CEP) positioned the DSOs as *active system operators* responsible for enabling flexibility, for example via procuring flexibility services in accordance with transparent, non-discriminatory, and market-based procedures. In addition, EU Regulation 2019/943 foresees the cooperation of DSOs and TSOs in planning and operating their networks, exchanging all necessary information and data, as well as the coordinated use of demand-side flexibility[12].

Transition to a DSO role as active system operators

A DSO is traditionally responsible for building, operating, and maintaining the grid for distributing electricity to final customers and ensuring the reliability, safety, efficiency, and quality of electricity supply. Today, DSOs go beyond grid operation and are increasingly required to manage and coordinate all connected DERs.

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[8] Directive 96/92/EC of the European Parliament and of the Council of 19 December 1996 concerning common rules for the internal market in electricity. Available online here.
[9] Directive 2003/54/EC of the European Parliament and of the Council of 26 June 2003 concerning common rules for the internal market in electricity and repealing Directive 96/92/EC. Available online here.
[10] Directive 2009/72/EC of the European Parliament and of the Council of 13 July 2009 concerning common rules for the internal market in electricity and repealing Directive 2003/54/EC. Available online here.
[11] "Clean Energy Package for all Europeans" refers to a set of rules proposed by the EC in 2016 to respond to the global energy transition. More information available here.
[12] Florence School of Regulation (2019), "Flexibility mechanisms: from the Clean Energy Package to the Network Codes". Available online at: https://fsr.eui.eu/flexibility-mechanisms-what-is-it-about/

The evolving role is primarily driven by the objectives of decarbonisation and electrification, which have led to a rapid increase in the number and diversity of resources connected to the distribution grid. These distributed resources include distributed generation, storage systems, electric vehicles, heat pumps, and a growing number of active customers.

Figures illustrate the scale of this challenge: **600 GW of installed solar PV**, **over 30 million electric vehicles**, and **60 million heat pumps**, as outlined in Figure 3. These figures represent millions of distributed assets that will interact directly with the DSO grid.

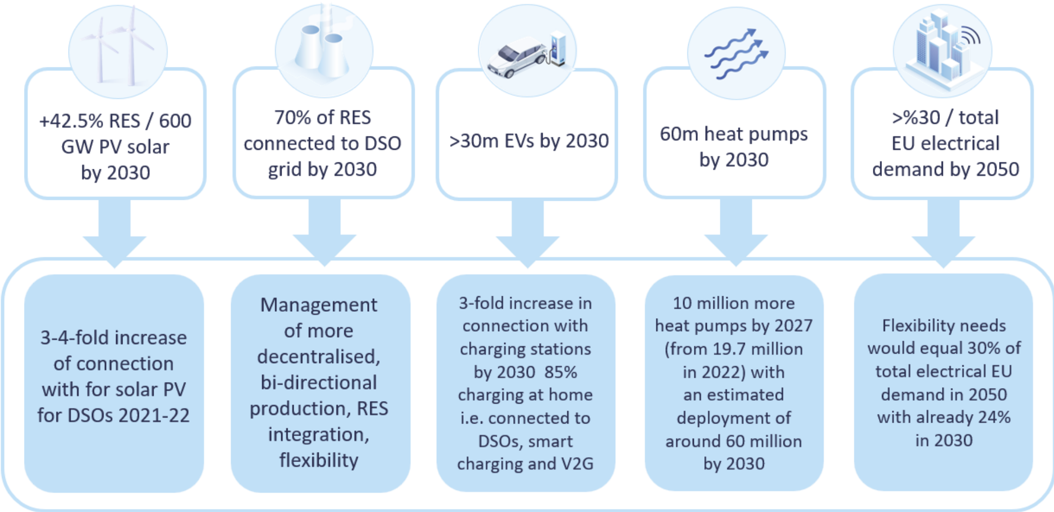

Figure 3 - The role of DSOs in a changing EU energy system

As a result, DSOs are increasingly required to manage greater complexity, more dynamic customer behaviour, and new forms of market participation. This transformation affects multiple dimensions of distribution system operation, ranging from technical grid management to data provision, coordination, and market facilitation.

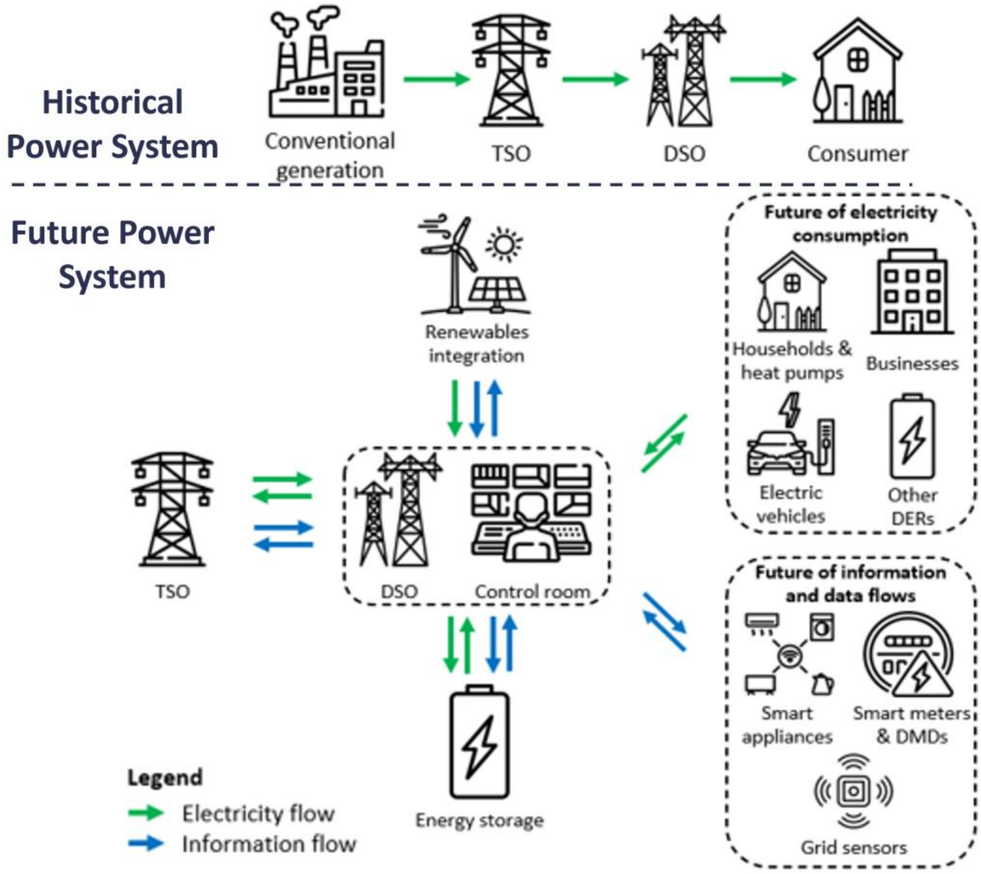

Figure 4 - Historical and future power system comparison

Figure 4 schematically illustrates the shift in the role of DSOs in the traditional power system and the future power system.

The transition towards an active and system-oriented DSO involves several significant changes and advancements across technical, operational, and market dimensions:

1. **Diverse Electricity Flows**: The increase in distributed resources in the form of generation, storage, and new business models (e.g., energy sharing) challenges the distribution system with flows reversing several times a day. Many distribution systems and their protection equipment have been built for electricity flows in one direction and have to adapt to a new reality.

2. **Customers with more dynamic energy behaviour:** New technologies like grid-forming converters and power system electronics, as well as very dynamic behaviour, for example participating in balancing markets or having charging cycles, create challenges for power quality for customers and protection of equipment in the grid.

3. **Smart Technologies and Data Flow Management**: Managing distributed resources requires smarter and more flexible networks supported by reliable and interoperable information flows. This calls for the deployment of advanced digital technologies such as smart metering infrastructure, advanced distribution management systems, data analytics, and digital twins to enable data exchange, enhance system management, and facilitate the role of active customers.

4. **Providing Relevant Information and Data to Stakeholders**: DSOs are responsible for providing relevant information and data to stakeholders, ensuring transparency and informed decision-making to facilitate customers' participation in efficiency programs and flexibility services.

5. **Market Facilitators**: DSOs today play a key role to ensuring fair and non-discriminatory access to the network for all market participants and in identifying and informing their flexibility needs to enable market-based solutions. DSOs facilitate customer participation in markets for local services, balancing markets, energy communities, energy sharing, and supply splitting, etc.

6. **Enhanced coordination**: DSOs are required to establish enhanced coordination mechanisms with other SOs, customers, and between local and other wholesale markets to ensure efficient and reliable electricity distribution.

7. **Development of Enabling EU and National Legal Frameworks**: Through DSO Entity, established to represent DSOs at EU level, DSOs contribute to the development of the EU-level legal framework, including network codes and other necessary regulatory instruments. In addition, DSO Entity serves as a platform for knowledge sharing and the exchange of best practices, supporting the development of NTCs.

DSOs as market facilitators

DSOs have an important role as market facilitators in performing their regulated activities. In addition, DSOs facilitate the participation of distributed connected customers in different products, services, and markets.

Each SO shall choose the most efficient and effective solution or combination of solutions in accordance with the applicable national framework, which can include grid investment, procurement and activation of local services, FCAs, grid tariffs, grid-technical measures, non-costly remedial actions, as well as redispatch, or other tools to solve congestion issues and voltage issues.

DSOs shall use market-based solutions for local services to solve congestion and voltage issues when they are technically applicable, cost-efficient, when there is liquidity, and when they do not distort the electricity markets.

Advancing markets for local services into "business as usual" for DSOs will foster greater market liquidity and play a pivotal role in accelerating the energy transition.

Operationalising the DSO Role as a Market Facilitator

The DSO role as a market facilitator builds on the elements outlined in previous sections, and it is operationalised through a set of key tasks, as illustrated in Figure 5 below. Some of them are addressed in the NC DR[13] framework, and the new EU methodology for TSOs' and DSOs' flexibility needs analysis (FNAM)[14]. A more digitalised DSO benefits from enhanced system visibility and control, while interacting more closely with customers, markets, and other SOs. In this context, DSOs facilitate the development of markets for local services and new business models, enable information, measurement, and data exchange, and ensure the delivery of services in line with the required power quality.

[13] The Network Code Demand Response is currently under development process.
[14] ACER (25 July 2025), "Type and format of data and the methodology for TSOs' and DSOs' flexibility needs analysis" in accordance with Article 19e(4) of Regulation (EU) 2019/943. Available online at this link.

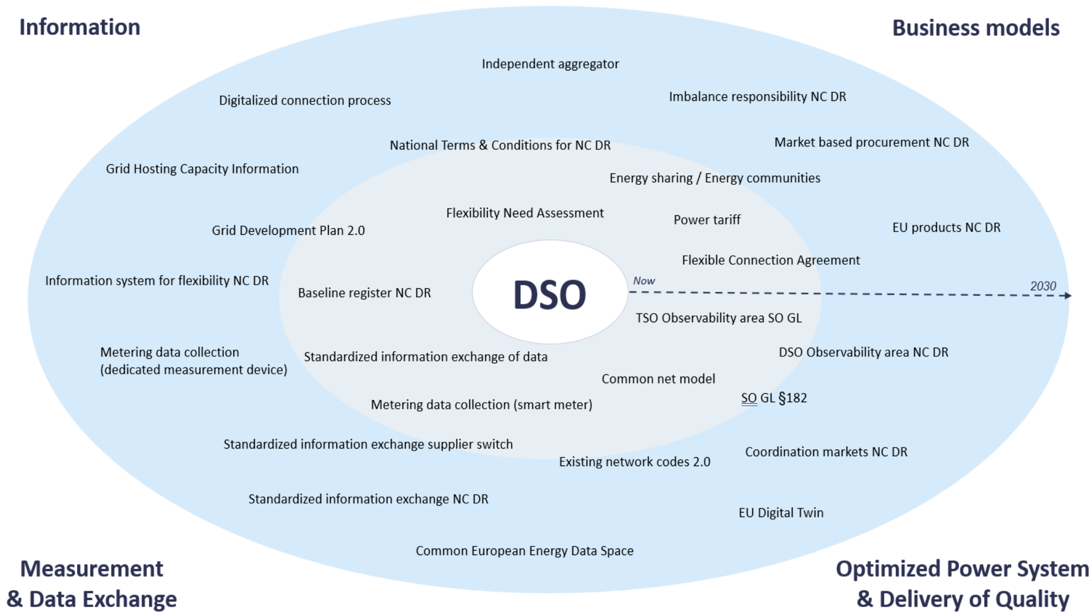

Figure 5 - Overview of DSO Business when using flexibility

A mature NC DR implementation enables DSOs to procure and activate local services as "business as usual", with interoperable processes and data exchange that scale to millions of distributed assets and active customers.

2.2 Flexibility in DSO Entity's Technical Vision

DSO Entity's Technical Vision highlights DSOs' role as market facilitators and the growing role of flexibility in addressing DSOs' needs, such as congestion management, voltage management, and system stability.

Various types of flexibility mechanisms can be used by DSOs in their operations to access flexibility, such as market-based, rules-based, FCAs, and network tariffs, as illustrated in Figure 6.

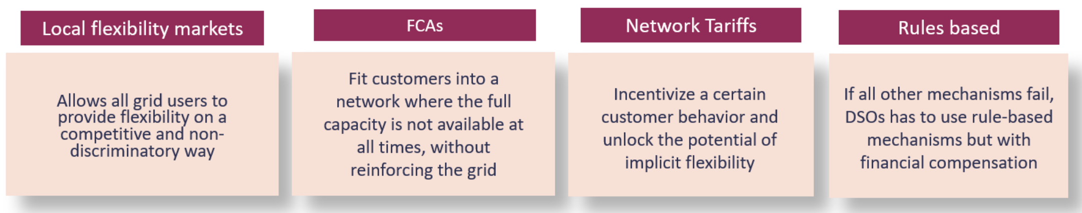

Figure 6 - DSOs incorporate various types of flexibility into their operations

DSOs choose the best solution or best combination of solutions for safe, reliable, and efficient grid development and operation of the grids, considering the specific requirements of their network types. This report contains information on all the options identified within the scope of the country survey, with a particular focus on market-based options.

Empowering customers with flexible, affordable energy solutions

Customer participation in the evolving energy system depends heavily on the effective use of distributed flexibility, and DSOs have a pivotal role in enabling this participation and ensuring that customers can benefit according to their varying needs.

The current and future regulatory framework for the European market, including the NC DR and the IR DR (see Section 1.4 and Appendix A), offers significant potential for harmonisation across DSO areas and countries. DSO Entity highlights in its Technical Vision that a common language, consistency in definitions, products, and processes will ultimately empower customer participation and access to flexible energy services.

In this context, facilitating the use of flexibility will increasingly be among the core tasks for DSOs to empower and increase value for customers. Key areas to support this include multiple dimensions of coordination, the design of flexible products, enabling infrastructure, and data exchange standards that ensure interoperability across the system.

Effective deployment of flexibility requires strong collaboration and coordination across the entire electricity system. This includes structured cooperation among DSOs, as well as seamless coordination between markets, between DSOs themselves, and between DSOs and TSOs. A common list of attributes for flexible products, together with a balanced combination of national and EU-level products, is essential to ensure coherence and interoperability.

Equally important is robust data management by DSOs, enabling transparent, reliable, and efficient processes. Tariffication aspects, including the format and structure of grid tariffs, also play a key role in creating the right signals for system users. In addition, appropriate contracting mechanisms such as FCAs within national frameworks, long-term procurement models (e.g., availability contracts), and well-functioning flexibility markets, are needed to fully unlock and mobilise distributed flexibility.

2.3 Regulatory push implied by the Clean Energy Package

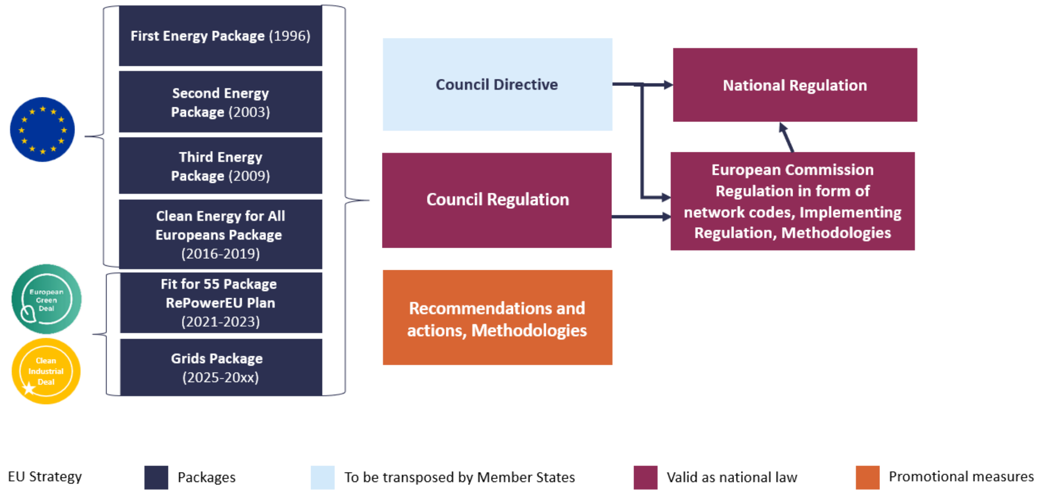

Figure 7 - Overview of EU Regulation

The above-mentioned CEP, adopted in 2019, reforms the EU electricity market by promoting flexible, market-based pricing through Directive (EU) 2019/944 and Regulation (EU) 2019/943, which set out common rules for the internal electricity market.

The CEP outlines the EU's targets up to 2030 and includes its strategic approach to integrating demand response into energy markets. It emphasises the importance of demand response within the broader context of the energy transition and provides the rationale behind its implementation.

Key elements of the CEP related to distributed flexibility include Directive (EU) 2019/944 on common rules for the internal market for electricity and Regulation (EU) 2019/943 on the internal market for electricity.

Figure 8 – Key Steps in the EU Regulatory Framework for distributed flexibility

More details on Directive (EU) 2019/944, Regulation (EU) 2019/943, and other relevant legislative frameworks can be found in Appendix A, including key regulatory developments affecting DSOs, as well as advancements in distributed flexibility, demand response, and the integration of these resources into the distribution systems.

2.4 Evolving legal framework for markets for local services

Network Code on Demand Response (NC DR)

Aligned with the objectives of REPowerEU and the EMDR, the NC DR represents a key building block of the EU regulatory framework supporting the DSOs' transition. It is being developed on the basis of Article 59(1)(e) of the Electricity Regulation (EU) 2019/943, which mandates the establishment of network code rules to implement Article 57 of the same Regulation, together with relevant provisions of Directive (EU) 2019/944. These provisions address demand response in a broad sense (including aggregation, energy storage, and demand curtailment) and clarify key aspects such as cooperation between DSOs and TSOs, the role of DSOs in enabling demand response at the distribution level, and the use of flexibility services in distribution networks.

Based on Article 59(9) of Regulation (EU) 2019/943, the European Commission invited DSO Entity and ENTSO-E to cooperate in developing and submitting the proposal for the NC DR to ACER in accordance with the relevant framework guideline developed by ACER.

The development of the NC DR follows the procedure set out in Article 59 of the Electricity Regulation (EU) 2019/943, as illustrated in Figure 9.

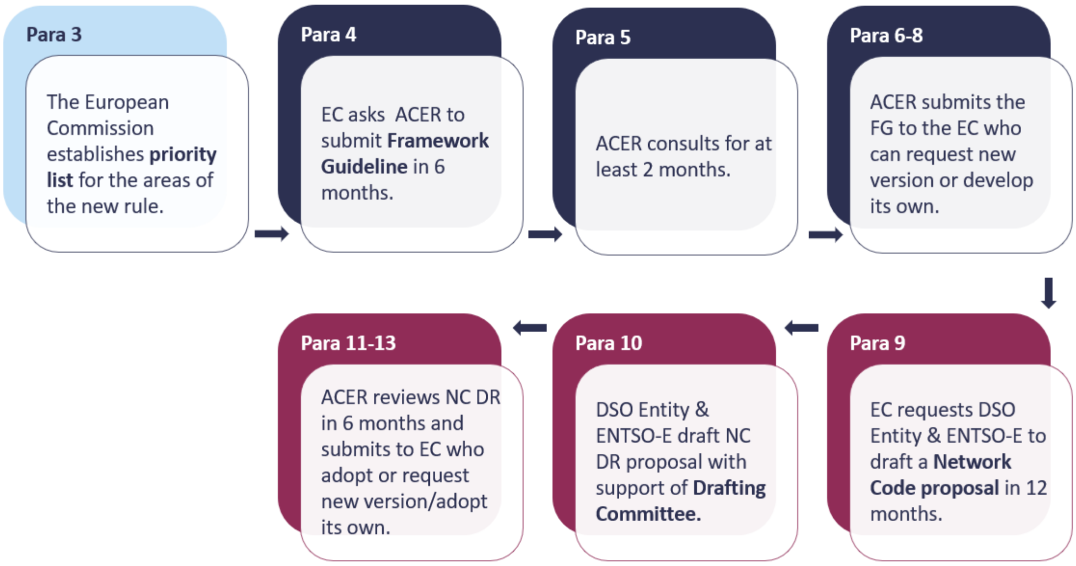

Figure 9 – NC DR Drafting process

In order to support the drafting process, DSO Entity and ENTSO-E jointly convened a Drafting Committee. The Committee played a key role in ensuring transparency, inclusiveness, and technical depth throughout the development of the NC DR. Beyond the Drafting Committee, stakeholder engagement was broader and continuous. This included repeated consultations on relevant draft versions of the Network Code, as well as targeted ad hoc exchanges with stakeholders on specific technical and regulatory topics.

In accordance with this process, the drafting of the NC DR has progressed through several key milestones:

- **8 May 2024**: DSO Entity and ENTSO-E submitted the original NC DR proposal to ACER.
- **7 March 2025**: ACER submitted its revised proposal to the European Commission.

- **15 July 2025**: European Commission launched a public consultation, to which the DSO Entity provided its official response.
- **Q1 2026**: The comitology process led by the European Commission is ongoing.

Following the adoption of the NC DR, the EG DF will implement the mandates and tasks assigned to the DSO Entity within the scope of its framework, supporting its practical implementation at the distribution level.

The NC DR aims to establish a coherent EU-level framework to facilitate the integration of technology-neutral demand-side flexibility into related transmission and distribution system services. By enabling flexibility to be accessed and used where it delivers the highest system value, the NC DR contributes to consumer benefits, system efficiency, and the decarbonisation of the power system.

The NC DR sets out common rules for participation in electricity markets, the provision of services to both TSOs and DSOs, and effective coordination between SOs for network planning and system operation. In doing so, it creates the foundations for the development of markets for local services, while ensuring consistency with wider market arrangements.

More specifically, the NC DR framework addresses the following key areas:

- **General provisions**: Defining the overall framework and principles, and rules to propose, amend and approve NTCs.
- **Market access requirements**: Establishing general criteria for market entry.
- **Qualification process**: Setting the requirements and procedures for qualifying service providers and products.
- **Market-based procurement of local services**: Defining rules for procuring local flexibility services and coordination markets.
- **Energy storage facilities**: Addressing storage ownership and operations by SOs.
- **Distribution network development plans**: Establishing requirements for the planning and development of distribution networks, including information on the need for local services in the medium and long term.
- **Coordination between DSOs and TSOs**: Establishing processes to prevent, detect, and resolve congestion and voltage issues, and to exchange data between SOs.
- **Data exchange**: Defining the data exchange requirements between service providers (SPs) and system users.

For DSOs, the NC DR is particularly relevant as it directly shapes their role as market facilitators at the distribution level. While the Code establishes a common EU framework, many elements, particularly NTCs and the practical organisation of local services markets, will be implemented at national level. This makes the exchange of experiences, challenges, and emerging good practices across Member States essential.

This knowledge-sharing activity therefore provides a timely opportunity for DSOs to reflect on the implications of the NC DR building blocks, discuss practical approaches to market facilitation and coordination, and support the development of national frameworks.

Implementing Regulation on Data Interoperability Requirements for Demand Response (IR DR)

Following the NC DR, the IR DR represents a complementary and equally critical regulatory pillar for the effective facilitation of demand response across the EU.

The IR DR is being developed under the legal mandate of Article 24 of Directive (EU) 2019/944, which requires Member States to ensure the full interoperability of energy services within the Union. In this context, Commission Implementing Regulation (EU) 2023/1162[15] mandates DSO Entity and ENTSO-E to support the European Commission in the development of implementing acts on data interoperability. This mandate reflects the recognition that demand response cannot be effectively deployed without a harmonised, interoperable, and secure data framework.

In line with the Framework Guidelines developed by ACER, the IR DR is expected to enable active consumer participation in the electricity markets. The objective is to continue developing a reference model that facilitates data interoperability among Member States, focusing on the information required to provide demand response, which covers:

- Identification of the different roles associated with the different responsibilities.
- A reference model composed of roles, information flows (procedures) and minimum information requirements (information objects) for providing services.
- An obligation for Member States to map their national models against the included reference model. This information will be published in a public repository maintained by DSO Entity and ENTSO-E.

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

3. Main findings on DSO Perspectives and Conclusions

The following chapter provides high-level recommendations for DSOs to serve as guiding principles for the establishment of frameworks for markets for local services and their practical implementation through NTCs.

These recommendations involve Critical Regulatory Actions, where applicable, needed to remove barriers in existing or foreseen EU regulation or other frameworks to develop local markets, identified based on lessons learnt[16].

For clarity, recommendations are numbered R1 to R11. Where a recommendation requires a critical regulatory action, these actions are listed under the relevant recommendation and numbered starting from A1.

3.1 R1: Start now and embrace the opportunities and challenges that come with the use of local flexibility services

Local services can accelerate decarbonisation through the connection of third parties and improve the efficiency of network development and operations.

Market-based procurement of these services provides many opportunities and comes with the necessity of enabling a participative and inviting environment for both market-sided actors and flexible prosumers.

To allow the development of these markets, a new approach is required to interact with stakeholders more dynamically and in a digital manner.

Hands-on experience and lessons learnt help in drafting the NTCs. **Time is needed to specify and develop tools and processes, to build knowledge and skills, and to manage change internally and with stakeholders. It is advisable to start small, learn fast, adapt when necessary, and scale gradually.**

DSOs should therefore start now, implementing local services and markets well before the entry into force of NTCs, while in the meantime, taking advantage of regulatory sandboxes or national practices to manage the steep ramp-up and to enable progressive development of all required processes.

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[16] For ease of reference, recommendations are coded from R1 to R11, while actions are identified separately and numbered starting from A1, where applicable.

Examples from national practices

All surveyed DSOs started early.

- Liquid local markets take time to develop.
- Early action builds knowledge and trust

3.2 R2: Define and publish a transparent roadmap to implement markets for local services

The implementation of local services requires a realistic and efficient roadmap, acknowledging the progressive development of tools, methods, processes, supporting IT, and rules. DSOs must identify all developments in rules, methods, processes, and IT to embed flexibility in their own activities, which extend well beyond planning and operations.

DSOs, NRAs, and involved stakeholders must develop a shared understanding of existing mechanisms to identify the gaps that need to be addressed. This includes the regulatory framework, coordination with other markets and mechanisms, and coordination between TSOs-DSOs, as well among DSOs. Following the gap analysis, DSOs must establish a realistic engagement plan that provides visibility on the development of local markets and ensures commitment from NRAs and all stakeholders.

The schedule should clearly define responsibilities and milestones, covering key aspects such as development of their own DSO tools and processes, regulatory alignment, technical integration, market design adjustments, coordination between markets, and coordination mechanisms between SOs.

DSOs should set and update a structured and transparent implementation roadmap to allow all parties to work collaboratively towards progressively closing identified gaps, implementing and scaling up flexibility in a coordinated manner, while making best use of test-and-learn approaches. In addition, DSOs should provide SPs with visibility on flexibility service opportunities through their published roadmaps.

Examples from National Practices

Enedis (France) published in February 2020 its “Roadmap for the transformation of network planning methods and the integration of flexibilities”, detailing milestones around use cases such as market-based flexibilities and FCAs.

Göteborg Energi / E.ON (Sweden) provides both short- and long-term visibility to SPs through Network Development Plans and other communication. Upon that, a national webpage is established as an entry point to different markets.[17]

Areti (Italy), in close cooperation with the Italian NRA, ARERA, established a stable and structured local flexibility market path, starting with the ARERA Decision 352/2021 (that is the base for other Italian project such as e-distribuzione, EDGE and Unareti Mindflex) through a real time spot market named 'RomeFlex', and improving it year by year through new Decisions based on growing experiences, increasing volumes, and additional services (step by step with the continuous feedback of SPs). Areti published its "five-year development plan" clearly stating flexibility needs in each period of the plan, and providing a ten-year forecast, thereby giving the market clear signal of stability and confidence for the SP's business plans.

3.3 R3: Engage Stakeholders in the implementation process and jointly manage change

Introducing local markets and flexibility at the DSO level requires extensive change management. Active stakeholder engagement enables the implementation of pragmatic solutions, while balancing the needs and technical capabilities of DSOs and SPs. Moreover, this helps to avoid unintended entry barriers to local markets, which fosters liquidity and enables the inclusion of a diverse range of SPs and flexibility resources.

DSOs should engage stakeholders from the outset, including during the development of regulatory sandboxes, national practices, and the definition of NTCs, to ensure the development of efficient and pragmatic solutions. DSOs should engage regularly with SPs to understand their challenges and recommendations, and to provide visibility on the development roadmap of local markets.

It is more effective to start with simple, practical coordination solutions, and evolve them based on experience rather than developing highly complex coordination mechanisms that would require significant time to design and implement.

DSOs, NRAs, and all stakeholders should acknowledge that not everything can be achieved on day one, whether in regulatory, technical, or economic aspects. Stakeholders must collectively accept the need to overcome these challenges through a shared understanding of the impact of existing gaps, mutual trust, and a common goal supported by a transparent and committed roadmap. This also requires a commitment from NRAs to approve small regulatory adjustments swiftly when gaps are identified.

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[17] More information online at the following link: [Lokala flexibilitetsmarknader i Sverige - Energiföretagen Sverige]

Examples from National Practices

Enedis (France) has engaged from the outset through structured and periodic interactions with stakeholders, for example via reports focused on strategy, value, roadmaps, targeted consultations and workshops on contractual and technical focus on local services, numerous webinars and presentations, and annual tenders offering increasing opportunities and improved frameworks. Enedis also conducts training tests to support both its internal teams (operations, or back-office) and SPs, enhancing their capability to deliver reliable local services.

Alliander (The Netherlands). The **Grid Operators Platform for Congestion Solutions (GOPACS)** platform design involved iterative input from DSOs, TSO, power exchanges, and market participants.

Areti (Italy), as required by ARERA for pilot projects, publishes a detailed report every six months on the results of the RomeFlex market, providing feedback to stakeholders on technology improvements, the resolution of operational issues, and the implementation of SPs and NRA indications on the direction of the activities. Starting from January 2026, a "KPI Report" pilot project will be published every 12 months by ARERA, outlining key market figures and comparing against predefined objectives.

E-REDES (Portugal) promotes local flexibility markets by focusing on customer engagement initiatives to increase liquidity. This is achieved by creating dedicated channels through which SPs can contact the DSO for questions and suggestions, as well as by organising multiple open webinars and in-person workshops.

3.4 R4: Promote opportunities for customers to become flexible to develop the needed liquidity for local markets

Customers have many reasons to become flexible, whether to optimise their energy bill, monetise the opportunity to deliver services for balancing or local services, engage in local energy sharing communities and/or for other purposes. The effectiveness of local markets depends critically on liquidity, which is essential to avoid procurement processes remaining thin, volatile, or economically inefficient.

Local-for-local mechanisms are a strong driver for prosumers to become flexible, as these mechanisms make the value of flexibility tangible at local level.
Local services enable, at any time and location, the participation of different kind of flexible resources, thereby enabling the development of liquidity that can be mobilised to alleviate local congestion or voltage issues.

Examples from National Practices

Enedis (France) together with RTE (French TSO), Think Smartgrids (the French association promoting smart technologies) and GIMELEC (the association of French electric equipment manufacturers) develops the 'Flex Ready' framework to foster flexibility from public and commercial buildings. This enables building managers to develop and stack the value of flexibility of their buildings across multiple opportunities.

Alliander (The Netherlands) - Created GOPACS, a platform that integrates multiple power exchanges and service providers, giving visibility and access to different actor types.

E-REDES (**Portugal**) offers multiple service windows and allows participation with planned assets to increase participation.

Areti (**Italy**) allows small customers (even 300 W) to participate via a complete set of free platforms for SPs and customer's appliances, enabling rapid readiness for flexibility and ensuring broad market engagement by removing barriers to entry. Additionally, the RomeFlex marketplace is the GME (the Governative Market Place for energy), the same used by the TSO, allowing SPs to have a seamless and common approach to flexibility across both TSOs and DSOs.

3.5 R5: Secure the flexibility value from end-to-end

Local services can accelerate decarbonisation through the connection of third parties and improve the efficiency of network development and operations. Introducing subsidies may foster the initial development of flexibility liquidity, but they can affect the rationale of collective welfare improvement. Long-term business models should be viable without such subsidies.

Securing the business case of flexibility encompasses the entire DSO lifecycle: grid planning, congestion, identification of opportunities, and definition of products with attributes reflecting system needs, procurement, prequalification criteria to guarantee technical and operational readiness, dispatch, settlement, and verification to ensure that robust validation criteria enable the verification of the actual delivery of services, ensuring alignment with contractual and regulatory expectations.

DSOs should therefore consider all processes from end-to-end, ensuring consistency across all involved processes to deliver an optimal value of flexibility.

Engaging in flexibility also represents an investment for system users and SPs. Consumers and SPs must be able to perceive the value of flexibility accurately and effectively in order to participate.

DSOs must seek cost-efficient solutions with minimal entry costs for participants, ensuring that flexibility resources can be integrated without imposing excessive burdens.

Technical Aggregators (e.g., DER Operators) may play a significant role. They could support system users in securing the value of participating in flexibility. Technical Aggregators may operate between the SP and the final flexible customer, helping SPs to access and activate flexible resources.

DSOs and SPs, together with the relevant authorities, must secure end-to-end responsibility and accountability from the SP to the controllable unit (CU), robust to any role or implementation of Technical Aggregators to ensure a safe and secure network.

Examples from National Practices

Enedis (**France**) published its first report on value of flexibility (propensity to pay) and related methods in 2017. These methods were detailed in greater details in 2023 within the preliminary Network Development Plan. Enedis builds processes for local services as close as possible to the process for balancing and national mechanisms to minimise costs for SPs.

Alliander (The Netherlands) - GOPACS connects market and grid planning through a coordinated platform that handles procurement, dispatch, and partial validation - representing an end-to-end example.

Areti (Italy) integrates DSO planning, balancing service provider (BSP) activation, and real-time monitoring through central platforms (BSP Platform, FIS – Flexibility Register, and Market Interface Platform) as well as customer appliances (PGUI, Power Grid User Interface, i.e. a standard interface between Set Points coming from DSO and flexible resources). This provides, free of charge to SPs, an 'end-to-end', turnkey flexibility environment.

Glitre Nett (Norway) uses a grid optimisation tool and NODES platform to connect planning, operations, and market activation.

E-REDES (Portugal) publishes flexibility alternatives in its Network Development Plan. For investment solutions where flexibility might be a cost-effective alternative, E-REDES provides detailed information on such options.

A1: Regulate Requirements for Technical Aggregation and strengthen cybersecurity requirements

Technical Aggregators and/or any other cloud-hosted technology and control structures that enable communication with technical resources may play a significant role in flexibility markets. These intermediate actors can create a legal void if end-to end responsibility and accountability are not properly addressed in the NC DR.

Considering that many of these infrastructures are currently operated from regions outside the EU, often also by personnel not located within the EU, the absence of appropriate requirements could allow CUs to be switched off or manipulated from such environments. This would create a significant systemic risk and dependencies.

The NC DR should therefore ensure that end-to-end responsibility and accountability are secured, regardless of the implementation and division of operational roles between SPs, technical aggregators and/or other actors.

When developing NTCs for SPs, it is important to ensure that at least all control structures (for both CUs and SPs), staff, etc., are located within the European Economic Area, and that investing in improving the cybersecurity aspects: Network Code on Cybersecurity[18], NIS 2 Directive[19], etc. would not be sufficient on its own.

3.6 R6: Procure local services and operate markers efficient

The NC DR establishes local congestion management and voltage control services as legitimate tools for DSOs to improve the efficiency of network development and operations and the right for each DSO to operate local markets to procure the services required, in coordination with other local and balancing markets.

DSOs should therefore start to develop and operate local markets where efficient – either independently, jointly with other system operators, or through delegation to other DSOs or third parties.

DSOs should use real use cases to support the development of local markets. DSOs could start with use cases such as planned maintenance or moderate congestion, avoiding critical grid issues during early testing phases, in order to reduce operational risk and to get people onboard in the organisation. Where no real need exists, DSOs should perform tests to train both SPs and DSOs for future real situations.

Examples from National Practices

Enedis (**France**) performs all necessary procurement processes and in particular develops a market information platform on the website[20]. Enedis is currently undertaking a joint project with the French TSO to build a joint procurement and market coordination platform.

Alliander/ (The Netherlands) - GOPACS is the Dutch coordination platform enabling SOs to buy flexibility from consumers via the connected power exchanges (currently EPEX SPOT and ETPA). GOPACS is neither a power exchange nor a market platform. It was developed by TenneT and all DSOs to create a unified flexibility market in the Netherlands.

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[18] Commission Delegated Regulation (EU) 2024/1366 of 11 March 2024 supplementing Regulation (EU) 2019/943 of the European Parliament and of the Council by establishing a network code on sector-specific rules for cybersecurity aspects of cross-border electricity flows

[19] Directive (EU) 2022/2555 of the European Parliament and of the Council of 14 December 2022 on measures for a high common level of cybersecurity across the Union, amending Regulation (EU) No 910/2014 and Directive (EU) 2018/1972, and repealing Directive (EU) 2016/1148 (NIS 2 Directive)

[20] More information online at: http://www.flexibilites-enedis.fr/

Areti (Italy) operates the local flexibility market in Rome, providing, through the GME platform, the opportunity for all the other Italian DSOs to reuse the entire RomeFlex environment in their territories. As a result, a DSO is able to start running flexibility in an average of six months.

E-REDES (Portugal) - Operating since 2023, a local flexibility market in Portugal using Piclo as a technological partner for procurement. The use cases that were tendered to date include flexibility to support planned maintenance, restore the grid in case of sporadic constraints (grid failures) and manage demand at peak consumption.

3.7 R7: Develop tailored (yet standardised) local flexibility products, markets rules and processes

Distribution grid constraints are inherently local and therefore require solutions tailored to meet local technical requirements. Such constraints cannot be efficiently addressed solely through balancing products designed for system-wide needs. While balancing products may act as initial market makers, they lack the locational granularity and, in many cases, also the activation mechanism and technical attributes required to manage congestion and voltage issues at distribution level.

To foster liquidity and avoid inefficiencies, DSOs must be able to develop local products tailored to the specific characteristics of the distribution grids and ensure the delivery of flexibility where, when, and in the quantities required, while fostering similarities with other flexibility markets and products, including balancing markets.

Similarly, in developing local market rules, tools, and processes, DSOs should consider existing national markets, processes, and balancing mechanisms, reusing similar processes wherever possible, and developing necessary specificities.

Examples from National Practices

Enedis (**France**) develops products that are as simple as possible (currently mainly 30 min 500 kW) and aligns rules as closely as possible with balancing products and mechanisms. Enedis ensures that differences with balancing and national mechanisms are strictly necessary and well communicated to market participants.

Alliander (The Netherlands) uses congestion management products such as:

- **Capacity Limiting Contracts** between the SO and the customer or SP, mostly managed and activated through GOPACS, procured in advance and activated in the day-ahead market when congestion is anticipated.
- **Market-based redispatch**, procured via the GOPACS intraday market when congestion occurs. SPs submit their flexibility bids through one of the connected

power exchanges (ETPA or EPEX SPOT) for a specific congestion problem and GOPACS' algorithm calculates the most efficient, cost effective, and balanced solution for the congestion problem.

E-REDES (Portugal) designs tailored products in local flexibility markets, such as **Dynamic, Secure and Restore**., based on UK-defined products in order to simplify rules and processes and address specific grid needs including maintenance support, peak demand management, emergency grid failures and mobile substation deployment. They define clear availability windows and activation times (from one-week to at least 15-minutes' notice).

Areti (Italy) reused all the experiences from the Italian TSO (GME marketplace, procedures, taxonomy etc.) and synchronised its market with the TSO market to enable seamless participation by SP across local and balancing markets.

Göteborg Energi / E.ON / Vattenfall Distribution / Jämtkraft (Sweden) has developed their first **national standardised products** in dialogue with stakeholders and TSO, approved by the Swedish NRA in December 2025. These co-exist with products under development.[21]

3.8 R8: Establish Flexibility Information System (FIS) modules by building on existing infrastructures

The infrastructures and processes to be built for the local services will need to integrate into the broader landscape of national energy market environments. The operation of, and data managed within a CU module, are closely linked to the tasks and databases of connecting system operators, which manage their customer relations.

Connecting SOs should develop CU modules to register flexible resources to be used for the local markets, leveraging their role of trusted SOs providing the digital infrastructure at the centre of local energy ecosystems - Digital Connecting SOs- and building on existing solutions for the purpose of cost and time efficiency.

Examples from National Practices

Enedis (France) operates the CU module and part of the SP module - for Service Providing Unit/Service Providing Group (SPU/SPG) registration - for national mechanisms, balancing services, and local services. Enedis' CU module currently manages more than 700,000 flexible sites, doubling each year over the last three years. Each connected site is registered as a single CU, facilitating onboarding without interfering with the know-how of technical aggregators and SPs. Enedis performs many baselining and settlement processes for DSOs-connected assets in France for both balancing and local services. The specification for processes and tools

[21] More information online at the following link: Lokala flexibilitetsmarknader i Sverige - Energiföretagen Sverige

for local and balancing services is optimised to be identical, or as similar as possible, significantly improving IT development and reducing costs (one single tool to develop).

Establishing new data platforms instead of using existing infrastructures, combined with standardised data exchange and interoperability, is generally more expensive[22].

In **Austria**, “Connecting System Operators” empower their connection management and customer care structures to cope with the administration of CU modules in a de-centralised way. For the market participant - facing structures of the SP module - they cooperate with APG (the Austrian TSO) to develop a common SP module.

Areti (Italy) implemented from 2022, a unique Flexibility Register segmented for different Italian DSOs and the TSO, accessible to all Italian SPs through secure credentials (userid/pwd) where they can find all their resources’ state, measures and rolling baseline updated in real time (15 minutes). The platform has been continuously updated according to the evolution of the NC DR, being now compliant with the current definition of Flexibility Information System as the unique entry point for all flexibility markets and stakeholders.

A2: Enable to register all resources beyond the service validation point as a single CU, in addition to the possibility to register technical resources one by one

Treating an entire site as a single ‘CU’ offers multiple benefits in many settings.

This approach aligns with incentives for customers or DER operators to respond to external signals and monetise the overall flexibility of their site. Likewise, the know-hoof technical aggregators lies in combining the capabilities of many different technical resources into reliable flexibility solutions.

The NC DR should therefore enable the registration as a single CU of a whole site, such as behind a service validation point, in addition to allowing the registration of devices one by one.

A clear distinction should be made between:

- ***the physical technical resource[23], and***
- ***the CU which relates to a logical concept to deliver the overall usable flexibility, involving the technical resources together with command and control, telecommunications, and local and/or remote energy management system:*** *definition of CU as a single or an*

[22] For example, comparing the model in Austria/France/Netherlands with Denmark/Finland.
[23] Power-generating module and/or demand unit pursuant to Article 2(5) of the draft amendments to the network code on requirements for grid connection of generators (RfG 2.0) and Article 2(4) of draft amendments to the network code on demand connection (DCC 2.0).

ensemble of technical resources of a single system user, that are jointly/commonly command-controlled is required.

3.9 R9: Ensure physical delivery of flexibility to the grid

The needed activated flexibility must be efficiently delivered to the grid. This is essential not only for settlement and payment for a procured service, but above all to ensure network safety, reliability, and value of flexibility.

DSOs should develop and implement settlement processes and methods that ensure that the expected service is reflected at the **service validation point**, thereby deterring potential compensation effects.

To this end, DSOs should define, for each customer, the service validation point, as foreseen in the draft IR DR.

DSOs should also ensure that baselines and settlement methods are available to assess delivery of services and enable participation of any flexible resource.

Examples from National Practices

Across all implemented markets and projects, careful assessment of the location and meters used to assess the service have been made, taking into account differences that may occur between connection points, connection agreement points, or multiple delivery points for the same site. The contract types of connection differ among countries as well as in a single country depending on the SOs' practice, voltage level or customer type. The generic concept of 'service validation point', to be defined by the connecting SO, is therefore essential.

A3: Improve the concept of compensation effect to ensure efficient activation and delivery of services

The provision of flexibility should efficiently resolve congestion and voltage issues to maximise the value of flexibility in the power system. Draft Articles 12 to 15 of the ACER Recommendation for the NC DR[24] *are intended to quantify and validate flexibility services. However, the relevant provisions, as currently drafted, leave room for interpretation. In particular, the proposed definition of the "compensation effect" may raise concerns at EU level.*

Under the ACER Recommendation for the NC DR, compensation effects are currently foreseen to stem only from other non-activated CUs behind the same grid connection point. Based on practical experience, however, compensation effects may also arise from other technical

[24] ACER Proposal for a new EU-wide network code on demand response (7 March 2025) – Available online here.

resources and from the default behaviour of consumers or building energy management systems.

Extension of 'compensation effects' to the effect of all demand unit/RfG modules (i.e. all technical resources) behind the same service validation point, regardless of whether they are or not registered in the flexibility information system, and which are not activated by a SP to deliver a given product. What matters is whether services are reflected at the service validation point(s).

Hence, any NTCs for Local (and Balancing) Services should provide a strong set of rules to detect such deviations, ideally including measurements from smart meters, whether validated historical metering data or measurements from the standardised interface for non-validated near real-time data.

A4: Ensure the reliability and safety of the grid and foster the development of distributed flexible resources in a non-discriminative manner while acknowledging these goals pertain to two different paradigms thus independent processes

Ensuring the delivery of reliable services for a safe electric system and fostering the value and development of flexibility, require non-discriminatory provisions to qualify products, independently of factors such as the history or the size of the flexible assets.

Fostering the development of distributed flexible resources in a non-discriminative manner can be efficiently achieved by facilitating the participation of aggregators and of any flexible resources through aggregation across all markets and should be the central objective of a demand-side flexibility framework.

The NC DR could further support the onboarding of newcomers and the development of their capabilities by acknowledging the possibility of training tests in representative conditions, rather than lowering requirements for qualification of SPs and products that threaten the safety and reliability of the grid, undermine the value of flexibility and affect fair competition between SPs. Any flexible resources can also participate through aggregators in markets.

The NC DR could further strengthen its impact by 1) addressing objectives such as proportionate prequalification requirements at product level, access to relevant data; 2) ensuring that demand-side flexibility processes are aligned with the established EU market framework, and 3) focusing on portfolio development of SPs rather than rotation of such portfolio between SPs. Facilitating aggregator participation in markets would avoid reducing the minimum bid size of standard balancing products from 1 MW to 0,1 MW, thereby avoiding significantly increasing complexity and operating costs in European balancing platforms.

3.10 R10: Establish efficient TSO–DSO and DSO–DSO coordination mechanisms through jointly defined proposals

Networks operated by different SOs are highly interconnected, meaning that actions taken to resolve congestion, voltage, or balancing issues in one network may create unintended congestions or voltage issues in another. Coordination between SOs therefore spans the full temporal scope: from grid prequalification and temporary limits (to ensure that activation of services does not compromise the safety of the grid) to actions to prevent or solve congestion or voltage issues during operational time to secure operational limits. Efficient coordination requires that NC DR focuses on the objectives to be achieved and leaves possibility to tailor implementation to the capabilities of each SO.

DSOs and TSOs shall jointly develop coordination mechanisms between transmission and distribution, as well as among DSOs themselves.

Examples from National Practices

E.ON / Vattenfall Distribution / Ellevio (Sweden) - In CoordiNet, the TSO and DSO markets were coordinated (market design and IT solutions) in several aspects, including subscription TSO/DSO and forwarding of bids from DSO market to mFRR market. This coordination made markets more efficient for SPs and provided a more efficient valuation of DSO flexibility needs. This coordination was discontinued after CoordiNet despite DSOs and SPs' support

Alliander (The Netherlands) exemplifies strong TSO-DSO collaboration through shared procurement and counterbid matching, and strong DSO-DSO collaboration via shared congestion information and coordinated flexibility activation.

Enedis (France) started local services with a common understanding with RTE that minimal coordination (e.g., phone call) was sufficient for the first Enedis activations (few MW or MWh occasionally). In the meantime, Enedis and RTE designed, through joint workshops of operations and market teams, a comprehensive coordination mechanism, under implementation, to optimise coordination of all solutions (grid measures, market-based, rules-based, FCAs). It is based on using operational limits at the interface between TSO and DSO to both strengthen and simplify coordination mechanisms. Coordinated and optimised criteria to select the best solution or combination of solutions, secure the value of flexibility in operations in a consistent manner with the value anticipated at the time of network development.

Areti & Terna (Italy) - DSO priority access to available resources with TSO market alignment, stronger TSO-DSO coordination: the sandbox of this coordination has been the EU Beflexible Project deployed with Terna and e-distribuzione, and the results will be implemented in Regulation by ARERA by 2027 in the review of TIDE (Testo Integrato Dispacciamento Elettrico).

Glitre Nett & Statnett (Norway) - Sequential coordination: DSOs activate flexibility first, then TSO can access non-activated flexibility, showing one way of partial coordination.

E-REDES (Portugal) is coordinating rules and procedures with the TSO, establishing a 'procedures manual'.

3.11 R11: Develop proportional, standardised and interoperable data, ICT and (near-)real-time communication requirements for local flexibility services

Flexibility processes involve significant data exchange and the lowest possible market barriers, which are best implemented through standardised and interoperable solutions.

The IR DR framework defines harmonised interoperability requirements and standardised procedures for data access and exchange. It specifies the roles, information objects, and end-to-end processes to register, qualify, activate, and validate demand response resources through the FIS, including the SP and CU modules. The NTCs will mandate interoperable standardised data exchange based on European and international standards, including ETSI–CEN–CENELEC deliverables and IEC standards such as IEC 62325-x and IEC 62746-4 (both aligned with the Common Information Model for Electricity), to enable scalable digital interaction between DSOs, market actors and CUs.

Broader upcoming frameworks must recognise DSOs as key actors in data exchange infrastructure and interoperability. DSOs should ensure proportionality in data, ICT and near-real-time communication requirements. DSOs should leverage near-real-time smart metering data where appropriate, as foreseen under Article 20(a) of Directive (EU) 2019/944.

A5: Define provisions for data exchange standardisation within NC DR framework

Data exchange standardisation is not prescribed in the existing EU Regulation, which may produce market fragmentation and vendor lock-in. DSOs need fit-for-purpose, and common standards to be available by the time digital platforms are established.

The NC DR provisions should include requirements about data exchange standardisation. Meanwhile, DSOs and stakeholders should contribute to the improvement of available standards (e.g., Common Information Model IEC 62325-x, IEC 62746-4), and actively and continuously engage with Standards Defining Organisations.

Where needed, NRAs and DSOs should consult DSO Entity & ENTSO-E, and leverage near-real-time smart metering data in line with Article 20(a) of Directive (EU) 2019/944.

3.12 Conclusions

The analysis presented in this report demonstrates that distributed flexibility and markets for local services are no longer emerging concepts but are proven-in-use core instruments for distribution system operation in a rapidly electrifying and decentralised energy system. Across Member States, **DSOs are already using flexibility, often in combination with grid reinforcement, tariffs, FCAs and rules-based measures to manage congestion, maintain voltage quality, and accelerate customer connections.** The NC DR builds on these developments and marks a decisive shift from fragmented pilots towards a harmonised European framework for operational flexibility. DSOs have implemented different solutions throughout Europe. These solutions work and are efficient because they leverage national specificities and already existing markets and mechanisms, have been defined through close involvement of all stakeholders, and have been tailored to the specificities and capabilities of system operators.

A central conclusion of this report is that local grid challenges are fundamentally different from system-wide balancing needs. Distribution-level constraints are highly locational, time-specific and closely linked to the physical characteristics of individual networks. As a result, the effective use of flexibility at distribution level requires tailored products, proportionate qualification and data requirements, and activation processes that reflect distribution grid realities. Relying solely on balancing products or transmission-level concepts may result in inefficiencies, reduced participation, and increased operational complexity for DSOs.

The report further confirms that the success of markets for local services depends on liquidity, trust and operational simplicity.

Evidence from advanced Member States shows that liquidity cannot be created instantaneously; it must be built over time through predictable procurement, transparent rules, and active engagement with SPs and customers. Local-for-local mechanisms, energy communities, and energy-sharing arrangements demonstrate a strong activating effect on prosumers by making the value of flexibility tangible at local level. These approaches should be seen not as deviations from market principles, but as effective enablers of participation and scalability.

Digitalisation emerges as a decisive enabler throughout the report. The large-scale integration of distributed flexibility requires standardised, interoperable and increasingly near-real-time data exchange between SOs, SPs, and CUs.

In this context, DSOs are evolving towards a role as Digital Connecting System Operators, operating scalable digital interfaces while safeguarding system security and data protection. The NC DR framework, together with the upcoming IR DR, provides the regulatory basis for this transition, but its success will depend on proportionate national implementation choices. Coordination is another recurring conclusion. Effective flexibility deployment requires structured coordination between markets, between DSOs and TSOs, and between neighbouring DSOs, in order to avoid conflicting activations and unintended network effects.

Furthermore, coordination frameworks must remain operationally workable and avoid excessive administrative burden. Clear roles, transparent data exchange and pragmatic governance arrangements are essential to ensure that coordination enhances, rather than hinders, the use of flexibility.

Finally, **the report underlines that NTCs are the decisive implementation lever for translating the NC DR into practical outcomes.** The design choices made at national level will determine whether flexibility becomes a reliable, scalable and cost-efficient system operation tool, or remains underused due to complexity, misaligned incentives or disproportionate requirements. DSOs therefore need to engage early, align nationally and actively shape NTCs, drawing on existing practices and the lessons highlighted in this report.

In conclusion, both distributed flexibility and markets for local services represent an opportunity for DSOs. When implemented pragmatically and proportionately, they can reduce grid reinforcement needs, improve operational resilience, and strengthen the role of DSOs at the centre of local energy ecosystems. Timely and coordinated action is essential to ensure that the NC DR delivers on its objectives and supports a secure, efficient and customer-centric European electricity system.


Local markets

Section A: Concepts for Local Markets

4. What is a market for local services?

Markets for local services are used to procure flexibility services and resolve congestion or voltage issues in transmission or distribution networks.

Local flexibility markets focus on congestion management at local level, and it is essential that their processes do not unduly distort the functioning of current wholesale markets. DSOs are responsible for procuring local services using locational information to address congestion issues within the grid. The diagram in Figure 10 highlights how the interaction between wholesale and markets for local services, along with the role of system operators, ensures effective congestion management and grid stability.

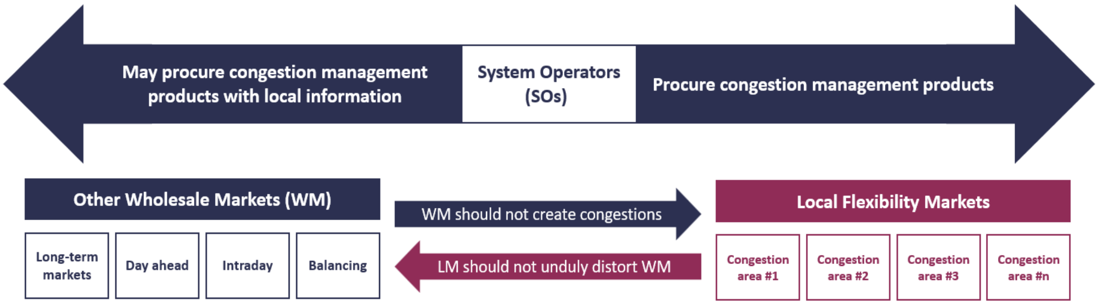

Figure 10 – Interaction between wholesale and market for local services

Market-based procurement for solving congestion and voltage issues can take different forms such as continuous markets and/or tenders.

When a product is defined in the local market, all requirements and rules are established in advance, enabling SPs to participate in an open, transparent and non-discriminatory manner.

4.1 ABC for markets for local services

This section sets out the definitions used in relation to existing DSO practices for markets for local services. As highlighted in the previous sections of the report, upcoming EU regulatory developments are expected to introduce formal definitions for these concepts. However, at the time of drafting this report, these regulatory frameworks have not yet been fully adopted.

The definitions presented in this section are therefore based on the **current regulatory frameworks and/or the practical experiences** of the DSOs covered in the report. They reflect how key concepts are understood and applied in existing national contexts, pilot projects and operational local flexibility markets.

Providing clear and common definitions ensures a **shared understanding** of the concepts used throughout the report. This supports readability, avoids ambiguity and allows readers from different regulatory and market backgrounds to interpret the findings consistently, facilitating effective knowledge sharing and comparison of practices across countries.

- **Flexibility resource:** Technical resources participating in electricity markets, referred to as Controllable Units (CU), Service Providing Group (SPG) and Service Providing Unit (SPU).
- **Local markets**: Markets to procure local services aimed at solving congestion issues or voltage issues in the transmission or distribution network within the same bidding zone.
- **Continuous market:** Bids are **selected** as soon as SPs offer, and a buyer's **needs** align.
- **Sequential market**: A market that involves one or more gate closures, after which a single auction clears the market to determine the price. Different pricing mechanisms can be applied.
- **Local services:** Energy and/or capacity provided by a service provider to a SO to solve congestion or voltage issues in their systems.
- **CU:** A single power-generating module and/or demand unit pursuant to Article 2(5) of [RfG NC 2.0] and Article 2(4) of [DCC 2.0]; a single technical resource or an ensemble of technical resources behind the same single accounting point, if these technical resources are commonly controlled.
- **SPG**: A pool of CUs connected to more than one connection point within the same scheduling area. SPG is defined by the SP to provide local services.
- **SPU:** A SPU means a single CU or an ensemble of CUs connected to a single connection point. SPU is defined by the SP to provide local services.
- **Part of SPG:** While delivery, settlement and validation are assessed over the entirety of an SPG, 'parts of SPG' enable SP and SOs to exchange data on a finer scale (such as split per transformer or per feeder) and finetune the assessment of the effect of activation of local services. This supports improved grid prequalification and temporary limits, limit adverse effects on liquidity, adjust forecasts and finetune the analysis of observations versus forecasts.
- **Aggregation Zone**: A geographic area, grid elements, or a list of connection agreement points where CUs must be connected to fulfil the locational requirements of a product. An aggregation zone is defined or updated by procuring **SOs** in coordination with connecting and impacted system operators.

- **Flexibility Information System (FIS):** A system to register customers and SPs participating in markets for local services, and to exchange data for necessary processes.
- **Procurement:** The process by which SPs place their offers and SOs procure their flexibility needs.
- **Selecting and activation**: The process through which SOs select and activate flexibility through matching or choosing the best option or best combination of solutions.
- **Availability contract procurement**: Some DSOs procure availability contracts in their markets for local services, which can take place before a season or continuously.
- **Temporary limits:** Limits identified by the relevant SO to ensure in the operational planning and operations that the delivery of the balancing or local services does not compromise the safe operation of the transmission and distribution systems.
- **Delivery**: The act by which flexibility providers deliver the called flexibility.
- **Service validation**: The process by which measurement data from meters is compared with a baseline.
- **Service validation point:** The point defined by the connecting system operator at which the delivered service is considered to be reflected on the grid, allowing for the use of multiple methods and criteria to assess such reflection depending on network configurations and service types.
- **Compensation effect**: An alteration of injection or withdrawal by any technical resource different from the concerned CU of the activated SPU or SPG, during the activation period of a local service, which counteracts the effects of the activation at the service validation point.
- **Settlement:** The financial consequences in the form of remuneration, penalties or other.
- **Imbalance management**: The handling of imbalances, depending on the aggregation model and applicable regulation.

4.2 The main roles & new models of local flexibility markets

This section outlines the key roles of parties in markets for local services, together with the enabling models and frameworks shaping their participation.

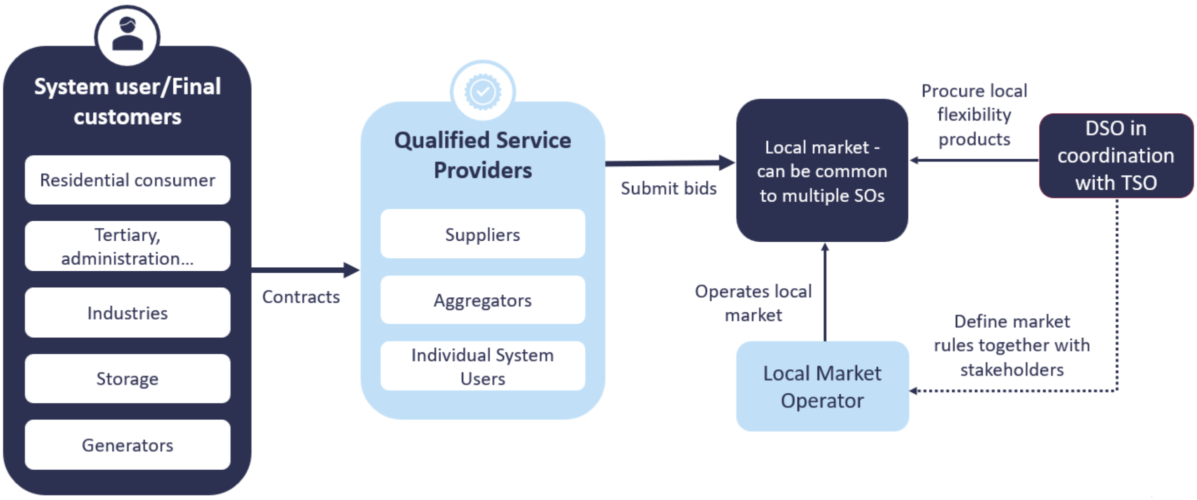

Figure 11 – Key roles of parties in markets for local services

4.2.1 The Service Provider

The SP forecasts and controls flexibility resources by reducing or increasing consumption, production, or charging and discharging storage when needed. By managing these resources, the obtained flexibility becomes a commodity that can be valued. Demand response covers distributed production, consumption, and storage.

To become a qualified SP, an SP must meet specific requirements, such as financial or ICT-related criteria.

Products must also comply with the defined product requirements, which are assessed through a distinct process.

4.2.2 The Aggregation

Aggregation refers to the coordinated command and control of one or several distributed flexibility resources to collectively deliver a service. Aggregation refers to two points of view. The commercial aggregator manages the market process, while the technical aggregator provides the technical solution for delivering reliable and aggregated overall flexibility from several resources.

In the context of NC DR[25], "service provider" covers both commercial aggregator and technical aggregator.

Whatever the implementation and split of tasks between technical and commercial aggregator that are altogether rules in NCDR, responsibility and accountability must be ensured from end to end which implies clear definition.

The service provider can be independent from retailers and/or Balancing Responsible Parties.

> Technical aggregators can help actors to achieve technical connectivity with CUs. Technical aggregators are crucial to bring small resources that are lower than the minimum bid to the market by making them easily available to *Commercial Aggregators/SPs*.

4.2.3 The Procuring System Operator

The procuring SOs is responsible for procuring, selecting bids, writing contracts with SPs, monitoring compliance with market rules, validating performance and billing. The procuring SO can delegate these tasks.

The SO is procuring local services through products (bidding or tenders).

4.2.4 The Balancing Responsible Party

A balancing responsible party (BRP) is a market participant, or its designated representative, responsible for its imbalances in the electricity market.

The BRP has obligations towards SOs and reports forecasts of the production and consumption data.

The rules governing imbalance management differ across Member States.

4.2.5 The Electricity Retailer

The electricity retailer is an entity that purchases electricity from producers or wholesalers and sells it to end customers. The retailer is responsible for offering competitive prices and services to its customers, as well as managing customer relationships and billing. The electricity retailer can act as a SP.

[25] ACER Proposal for a new EU-wide network code on demand response (7 March 2025) – Available online here.

5. Key processes of the markets for local services

5.1 Coordination

Effective coordination mechanisms in the implementation of flexibility services must address three key dimensions: **Coordination Between Markets**, **Coordination Between SOs**, and **Coordination Between Procurement Mechanisms**.

Figure 12 visually summarises the three key dimensions of effective coordination mechanisms in the operation of markets for local services.

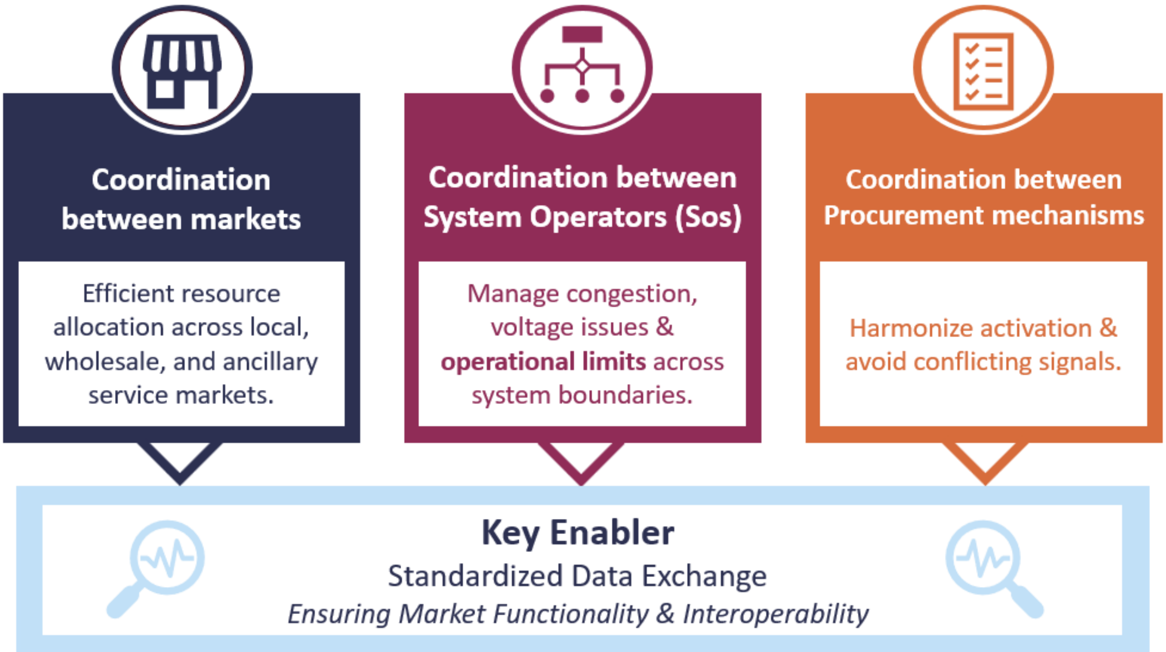

Figure 12 - Three main areas of coordination for markets for local services

Market coordination aims to ensure efficient resource allocation across local, wholesale, and ancillary service markets; SOs coordination focuses on effectively managing congestion, voltage issues, and operational limits across system boundaries; and procurement coordination seeks to harmonise activation processes and prevent conflicting signals.

Establishing clear coordination protocols and standardised data exchange is essential for market functionality and interoperability.

5.2 Qualification of service providers, product prequalification, product verification and grid prequalification

Qualification refers to the process by which SPGs, or SPUs are assessed to verify their technical and operational capability to deliver the required products reliably. Its primary objective is to ensure system security and the safe operation of the grid by confirming that only technically capable resources participate, while keeping administrative requirements proportionate, non-discriminatory, and limited to what is strictly necessary. Well-designed qualification processes aim to minimise unnecessary complexity, avoid duplication, and facilitate market access through simple, transparent, and digitally enabled procedures.

Figure 13 illustrates the qualification processes for SPUs/SPGs and their key objectives.

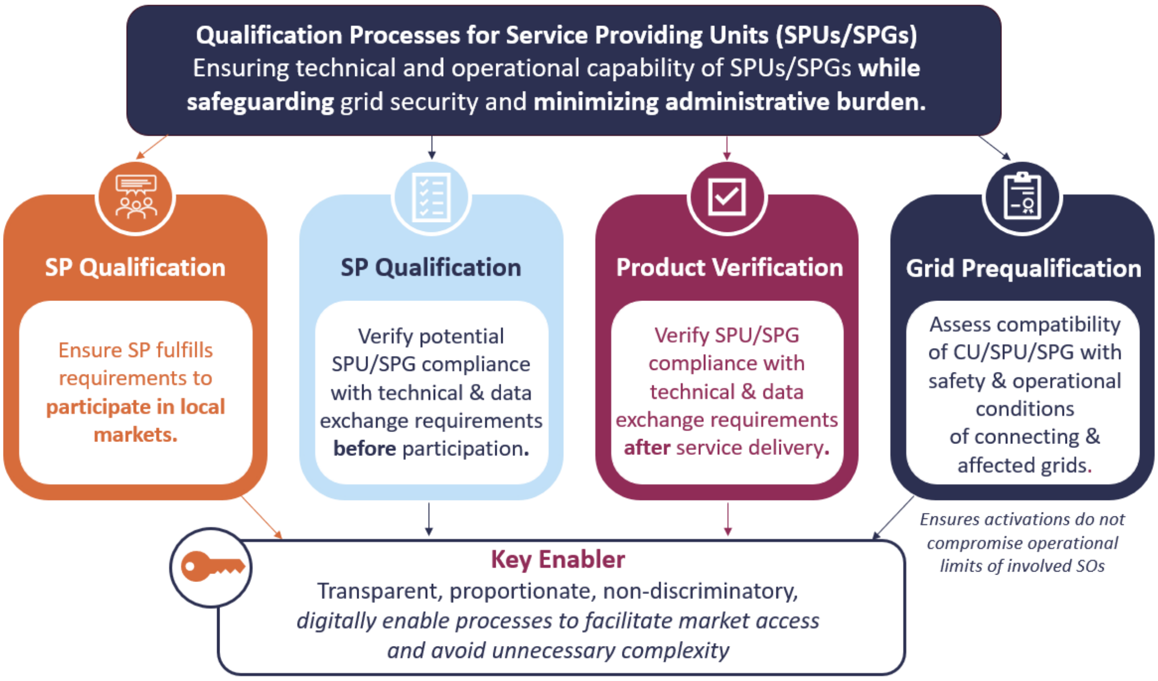

Figure 13 - Qualification processes for service providing units (SPUs/SPGs)

The qualification processes are divided into four main areas:

- **SP Qualification** verifies the market participant's capability to deliver a local service, fulfilling the necessary criteria for market access, thereby becoming an authorised SP.
- **Product Prequalification** refers to the procedure to verify the compliance of a potential SPU or SPG with the technical and data exchange requirements, prior to participation, to provide products for local services.

- **Product Verification** represents the process, carried out after service delivery, used to verify the compliance of an SPU or SPG with the technical and data exchange requirements.
- **Grid Prequalification** describes the procedure by which the connecting and affected system operators assess the compatibility of a CU, SPU, or SPG with the safety and operational conditions of the connecting and affected grids, ensuring that activations of these SPUs/SPGs do not compromise the operational limits of all the involved SOs.

5.3 Baselining

All SPs participating in markets for local services are required to apply an effective validation method to ensure that the committed service is delivered to the grid as requested. Validation is carried out against a baseline, which represents a counterfactual reference of the electrical quantities that would have been withdrawn or injected in the absence of any activation of local services, or no activation of demand response in other wholesale market.

There are different methods to estimate the baseline. The following provides a non-exhaustive overview of commonly applied baseline estimation approaches, distinguishing between methods where the baseline is determined before delivery and those assessed after delivery.

Baselines that are determined up-front: These baseline methods (BMs) are predictions or a set-point such as:

- **Declarative BMs**: The baseline forecast is provided by the SPs themselves. Various methods can be used to develop the forecast.
- **Historical BMs**:
  - **Historical baseline without same day adjustment (SDA):** Certain data from days before activation is selected according to predetermined rules, after which a baseline is created for the delivery day based on either an average or a median for each time point.
  - **Historical baseline with SDA**: The method combines a historical baseline with adjustments to take advantage of data from the delivery day.
  - **Regression-based BMs:** A regression model to predict what the production or consumption would have been on the delivery day using historical data and external parameters.
  - **Maximum baseload BMs**: Historical metered data to generate a flat level of electricity demand or capacity that the system user is rewarded for remaining at or below.
  - **Zero baseline BMs**: Baseline set to zero; any output is treated as ‘flexibility’.

Baselines that are determined after the delivery of the service: These baselines methods are based on measurements, control signals or others such as:

- **Meter before meter after (MBMA):** The measurement(s) of production or consumption just before activation are used as a reference for comparison during the activation period.
- **Window before BMs**: Meter readings during the activation period are compared against meter readings prior to the activation period.
- **Window before and after BMs**: Similar to window before, but the window after is also considered to compensate for rebound effects.
- **Control group BMs**: Statistical sampling to create a counterfactual for a portfolio of similar system users who are not providing flexibility.
- **Fixed BMs**: A static withdrawal/injection profile (usually technology-specific) to which the metered output is compared.

Calculation-based BMs: The baseline is calculated using external parameters, such as weather conditions, usually without relying on historical data. The calculation is done in real-time or retrospectively using real-time data from the delivery period.[26]

The most appropriate baselining method primarily depends on the type of product and flexibility resource, with these two factors influencing the SO's choice of baseline:

- **The type of product** for which the baseline is used, e.g. the duration when the resource is called for; and
- **The resources** that participate, e.g. reserve power is only used at outage and when called for by the local market.

Baseline for DSO products is still an area of learning for all actors. Controls can be performed to evaluate the accuracy and reliability of the baselines.

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[26] Energiforsk (April 2022), "Baselinemetoder för flexibilitetsprodukter - Rapport 2021:826". Available online at: https://energiforsk.se/media/31177/baselinemetoder-for-flexibilitetsprodukter-energiforskrapport-2021-826.pdf

5.4 Data management and standardisation of data exchange

The large-scale utilisation of distributed flexibility depends as much on data interoperability as on physical assets. As Europe's electricity system transitions from centralised control to decentralised participation, standardised data exchange becomes a prerequisite for efficiency, security, and fair market access. This is particularly evident in the implementation of the emerging NC DR.

Distributed flexibility involves millions of small CUs, often aggregated and activated dynamically across transmission and distribution levels. Without common data models and message formats, aggregators cannot scale efficiently, SOs face high integration costs, and markets risk fragmentation. Standardisation enables flexibility to be treated as a system resource rather than a bespoke integration challenge.

5.5 Assessment of flexibility needs

As defined in Article 19e of the Electricity Regulation, Member States shall adopt a report on the estimated flexibility needs for a period of at least the next five to ten years at national level, in view of the need to cost effectively achieve security and reliability of supply and decarbonise the electricity system.

This report shall evaluate the types of flexibility needs, consider the potential of non-fossil flexibility resources, evaluate barriers to flexibility in the market, evaluate the contribution of digitalisation of distribution networks, and take into account sources of flexibility that are expected to be available in other Member States.

National reports will offer valuable insight to customers, policymakers, and stakeholders, helping ensure that flexible resources will be available when forecasted system needs emerge.

Distribution Network Development Plans serve as the primary source for DSOs to determine flexibility needs, providing medium to long-term visibility on forecasted flexibility needs.


Local markets

Section B: Country Survey

DSOs having (i) implemented or (ii) demonstrated large-scale flexibility markets with open market-based calls where the DSO is purchasing flexibility services for DSO needs that are described in this report are[27]: Alliander (Netherlands), UK Power Networks (UK), E.ON Energy Networks and Göteborg Energy Nät (Sweden), E-REDES (Portugal), Glitre Nett (Norway), Areti (Italy) and Enedis (France).

Some flexibility markets are a cooperation between DSO(s) and TSO(s), and some are only DSO local flexibility markets. The report only refers to the SOs that have been participating voluntarily in DSO Entity work and knowledge-sharing.

This report focuses on the DSOs which have implemented a local market. Planned DSO flexibility markets, TSO markets and rules-based redispatch models to manage congestion and voltage issues are not taken into account.

This Section B introduces detailed information on the different DSOs, while Appendix B titled 'Detailed Comparison of Local Market Aspects' provides a general overview of the DSOs, their challenges, and includes **comparison tables** showing how they have set up their markets.

B.1 Alliander - Netherlands use case

Introduction

National context

The Dutch electricity system is structured with TenneT, being the TSO managing the 110 kV to 380 kV grid, while DSOs handle the High Voltage (50 – 110 kV) (HV), Medium Voltage (400 V – 50 kV) (MV) and Low Voltage (400 V) (LV) grids, ensuring local electricity distribution and congestion management.

The TSO grid is mostly meshed, and the DSO grid is mostly radial.

SO Challenges

The SOs in the Netherlands face multiple challenges such as:

- Rising electricity demand from the electrification of transport, heating, and industrial sectors.
- Decentralised energy production from DER, including solar and wind power, leading to bidirectional power flows.

[27] These companies have participated in DSO Entity's knowledge-sharing through webinars and written input and are not a complete list of all existing flexibility markets.

- Limited grid expansion due to long planning and construction timelines, requiring alternative congestion solutions.
- Ensuring system reliability while integrating market-based flexibility mechanisms.
- Network transport capacity constraints and voltage issues.

Types of congestion

There are different types for congestions in the Netherlands, in rural and urban areas such as:

- Consumption congestion: Peaks during winter due to increased electricity use for heating and industrial operations.
- Production congestion: Happens in summer due to excess generation from solar and wind power.
- Voltage level congestion: Primarily affecting HV and MV levels, but LV networks are increasingly impacted due to higher decentralised generation and electrification trends.

Driving Forces behind Flexibility Solutions

- Societal demand for grid access and additional capacity: Customers expect timely connections, and grid operators aim to reduce outages while maintaining grid reliability.
- Regulatory push for market-based solutions: The Dutch government and regulators advocate for the use of flexibility markets to optimise grid operations.

Evolution of congestion management in the Netherlands

Historical Development and Pilot Projects

- **2017**: TenneT and Stedin launch a pilot for the **Grid Operators Platform for Congestion Solutions** (GOPACS) as a congestion management platform.
- **2019**: National rollout of GOPACS with all DSOs joining.
- **2021**: Integration with EPEX SPOT for improved market liquidity.
- **2023**: Expansion to additional trading platforms.

Congestion management, market-based flexibility, and GOPACS

Network Design Principles and Integration of Flexibility

- **N-1 Principle**: Grid operators apply the N-1 principle for both consumption and generation, ensuring that the grid can withstand the failure of a single component without affecting the system's stability.

- **Overbooking Strategy**: The regulatory authority has set a technical and a financial limit for the activation of congestion management services. The technical limit allows grid operators to overbook secondary substations from 110% up to **150% of their nominal capacity** as an administrative measure. However, in practice, they must manage any load beyond **110%** through flexibility mechanisms since the substations cannot technically exceed **80-100% of their physical limits**. This overbooking can only be applied to **specific customers with loads exceeding 1 MVA**. These customers are required to have **congestion protection**, which is activated if no flexibility can be procured via the flexibility market.

- The **financial limit** is set by regulatory authority and indicates the amount of euros a grid operator has to spent on congestion management services in a defined congestion area. The annual financial limit is calculated by the following formula: Available transport capacity (MW) x hours congestion period (hour)[28] x 1,02 €/MWh.

- Grid operators must balance technical constraints with financial limitations when managing congestion. If the technical or financial limits are reached, the grid operators are allowed to turn down customers for a new connection or additional capacity. If the limit is not reached, the grid operator has to apply congestion management services in order to facilitate the requests for a new connection or additional capacity.

- **Peak Assumptions**: Operators assume that **individual peaks do not occur simultaneously**, which allows to integrate more customers into the existing grid and reduces the need for immediate grid reinforcements.

Flexibility Mechanisms and Procurement

The Netherlands employs a structured congestion management approach, prioritising market-based mechanisms while maintaining rules-based interventions as a fallback. There are currently three main congestion management products:

1. **Capacity Limiting Contracts (CLC)**

    - **Procurement and Activation**: Contracts are signed between the grid operator and the customer or SP and mostly **managed and activated through GOPACS**. They are procured in advance and activated in the **day-ahead** market when congestion is anticipated.

[28] Congestion period is defined as the moment of 'pre-announcing congestion and starting the congestion investigation' until the area no longer has structural congestion. There is not necessarily congestion at the start of the congestion period.

- **How it works**: Customers agree to temporarily reduce their connection capacity to a predefined level upon request. Grid operators are developing different varieties of the CLC, such as a group CLC (one contract for a group of connection points) and capacity steering contracts (asking for increase in connection capacity). These contracts are currently under development.
- **Compensation**: Customers receive a fixed monthly **availability fee** and an **activation payment** when their capacity is restricted. The prices are defined by the grid operator based on formulas.

2. **Market-Based Redispatch**

- **Procurement and Activation**: Procured in the **GOPACS intraday market** when congestion occurs.
- **How it works**: Flexibility providers submit their flexibility bids through one of the connected power exchanges (ETPA or EPEX SPOT) for a specific congestion problem and GOPACS algorithm calculates the most efficient, cost effective and balanced solution for the congestion problem. Activation of congestion management services cannot disturb the balance on national level as GOPACS always ensures for a counter bid in the opposite direction outside the congestion area (e.g., 10 MW upward flexibility in congestion area - buy order - is always matched with 10 MW downward flexibility outside the congestion area - sell order). The flexibility bids can be either to reduce/increase consumption or reduce/increase generation.
- **Compensation**: Participants are paid based on a **pay-as-bid** system, ensuring competitive pricing (no availability compensation). No price indication by the grid operator.

3. **Flexible Connection Agreements**

- **Procurement and Activation**: The FCA is signed between the grid operator and the customer. There are different types of FCA under development with different activation timelines, but the latest activation is in day-ahead timeframe.
- **How it works**: Customers agree to an FCA, and the grid operator communicates (for TSO customers via GOPACS) the activation of the FCA.
- **Compensation**: Customers receive a reduction on their tariff.

4. Non-Market-Based Redispatch (Rules-Based Mechanism)

- **Procurement and Activation**: Non-marked based congestion management (NMCM) can only be applied under strict circumstances, such as no market-based solution found or not enough competition in a certain congestion area.
- **How it works**: In case NMCM regime is activated, customers are obliged to submit a flexibility bid to GOPACS with a cost-based price (instead of a voluntarily bid with a price determined by the customer itself).
- **Compensation**: Cost-based price. Customer determines his price based on a defined methodology[29].

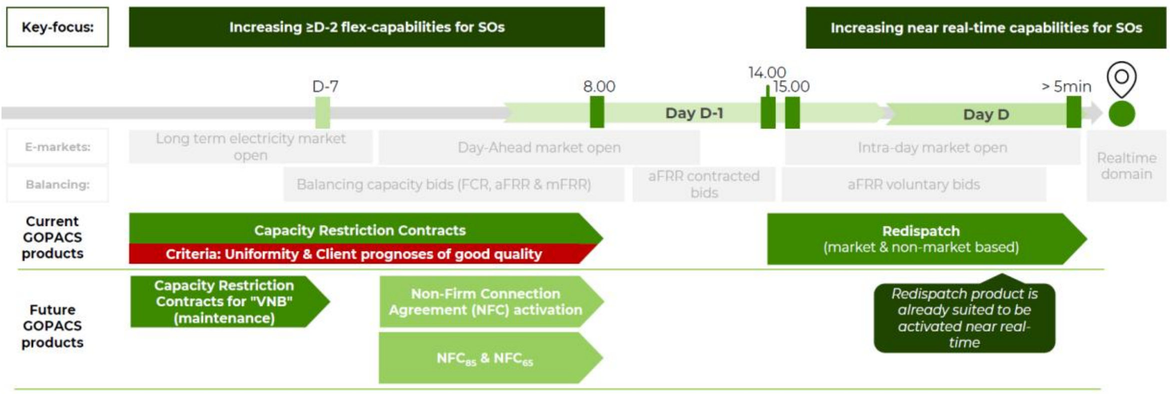

Figure 14: Timeline for different flexibility products in the Netherlands

Source: Internal resource from webinar conducted with Alliander and GOPACS.

Currently, the minimal bid size is 100 kW and 15 minutes. The grid operators and the market parties (e.g., supplier, BRP) are in the process of developing the market rules for aggregation. If the flexibility is not delivered, grid operators can apply penalties based on a defined formula. Grid operators however tend to first contact the SP and investigate why flexibility has not been delivered, before applying penalties.

GOPACS: the Market Operator for Congestion Management

GOPACS is the Dutch coordination platform which allows system operators to buy flexibility from consumers via the connected Power Exchanges (currently EPEX SPOT and ETPA). GOPACS is therefore not a power exchange nor a market platform. It was developed by **TenneT and all DSOs** to create a unified flexibility market in the Netherlands.

[29] Methodology to determine compensation for non-market based redispatch available at: Vergoedingstabel Niet-marktgebaseerd congestiemanagement (NMCM) juli 2025

- **Market-Based flexibility platform**: GOPACS connects grid operators with flexibility providers via power exchanges (PX) like **EPEX SPOT and ETPA**. The basis of the platform is to provide a level playing field for PXs to connect to GOPACS and sell their flexibility to the grid operators.
- **TSO-DSO coordination**: GOPACS facilitates **coordinated flexibility procurement** across voltage levels, enabling:
    - Vertical access to flexibility for both TSO and DSOs (which allows the SOs to call on each other's contracts).
    - TSO-DSO coordination ensuring the solving of congestion problems in one grid does not lead to additional congestion in the other grid operator's grid.
    - Supporting TSO and DSOs with validation of services and publication of information.
- **Bid and counterbid matching**: When congestion is identified, GOPACS allows the **TSO and DSOs to communicate flexibility needs and procure flexibility** by matching bids from flexibility providers with counterbids from participants in non-congested areas for the redispatch product. This ensures that the national balance of the grid is maintained. Counterbid matching is not necessary for the activation of CLCs in DA as the nominations can still be updated.
- **Flexibility activation:** GOPACS sends activation signals out to the SPs, either directly (CLC) or via the power exchange platform (market-based redispatch).
- **Validation of activation:** GOPACS performs the validation of the flexibility but not (yet) the financial settlement. This is still done by the grid operators. A support of the financial settlement via GOPACS is under investigation.
- **Qualification of service providers**: The SP first needs to be prequalified by TenneT (also if the SP wants to provide services in the DSO grid) and registered in the central data registers of the grid operators. Once acknowledged, the SP can register themselves on the GOPACS platform which is also the start of the prequalification procedure of the asset performed by the connecting grid operator. A streamlined, easier and more accessible process is currently under investigation.
- **Data publication**: GOPACS currently publishes data on redispatch such as:
    - Total expenses per month per SO.
    - Total activated volumes per month per SO.

- Total spread price per month per SO.
- Activated volume per announcement, including requested capacity and requesting SO.

GOPACS does not communicate individual prices & bids. In the nearby future GOPACS will also publish the activated CLCs on its website.

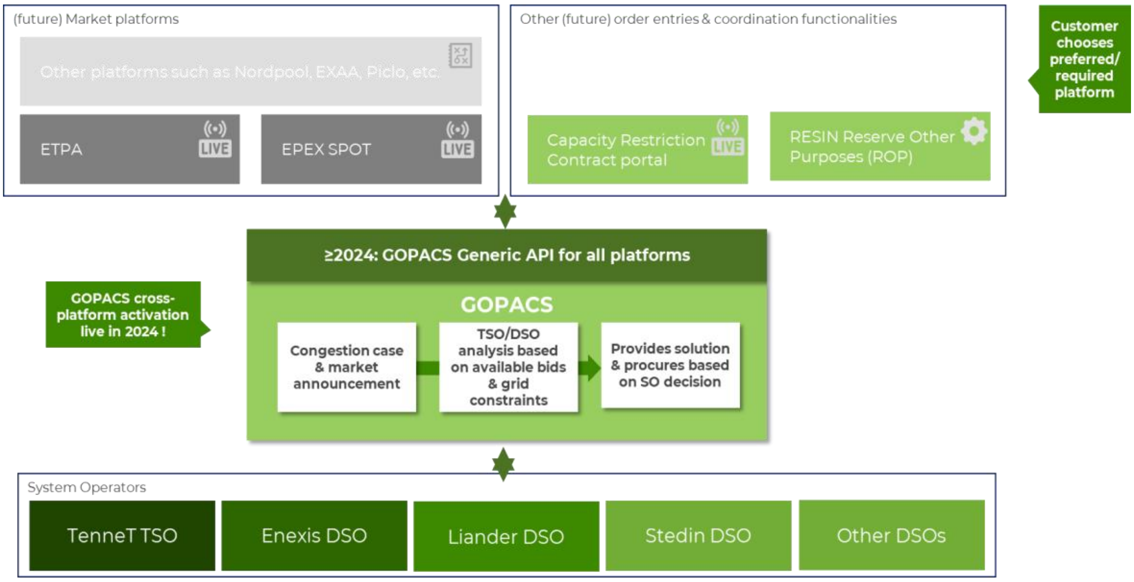

Figure 15: Interaction of different platforms

Source: Internal resource from webinar conducted with Alliander and GOPACS.

Added Value for Stakeholders

Market-based congestion management provides value to different stakeholders involved in the electricity system:

- **Grid Operators (TSOs and DSOs):** By leveraging flexibility markets, grid operators can optimise grid use and enhance system reliability. For the Dutch grid operators, it is essential to perform congestion management as they are obliged to connect new customers or provide existing customers with additional transport capacity on short term.
- **Service providers (SPs):** These providers benefit from an additional revenue stream by offering local services to the grid operators on behalf of customers.
- **End Customers:** Businesses and industries participating in flexibility programs receive financial compensation while contributing to a more stable and efficient energy system.

In addition, it also allows for customers waiting for a new connection/additional capacity to be connected sooner.

- **Regulators and Policymakers:** A transparent and market-driven congestion management approach supports regulatory goals for a fair and efficient electricity market.

Operational Capabilities for Flexibility Management

Alliander has set up **a systems operations team**. It is composed of agile teams developing and maintaining technical capabilities for congestion management. They collaborate within the **Linux Foundation**, ensuring **open-source** developments that can be adopted by other grid operators. They work on various tools such as:

- **Advanced forecasting tools**: Predict congestion patterns and optimise flexibility procurement.
- **Automated dispatch systems**: Enable real-time flexibility activation.
- **AI-driven optimisation tools**: Improve grid stability and efficiency.

Data Exchange Requirements

All data exchange is done via GOPACS API. The grid operator communicates the congestion areas and the flexibility activation whereas the flexible customers need to provide the baseline as well as the metering data per connection point. The baseline is submitted to the grid operator (not GOPACS), and the metering data is handled through the central metering data register of the grid operators (maintained by EDSN, the organisation owned by grid operators which supports several central data registers and process for the grid operators). GOPACS is connected to the relevant EDSN register to receive the metering data.

Current challenges and Future Outlook

- **Development of Standardised Contracts and Products**: Grid operators are working towards standardising contracts and flexibility products across the sector to replace fragmented, individual solutions and create a more efficient and liquid market. It allows for solving congestion jointly and being able to use the flexibility available in each other's grids.
- **Scalability of Market-Based Flexibility**: Currently, there is a lack of liquidity in the day-ahead and intraday markets, making it challenging to secure enough flexibility.
- **Technological Integration**: Advancing forecasting tools and digital twins to improve grid resilience. However, concerns remain about the **low quality of customer forecasts and**

baseline data, which can impact the effectiveness of flexibility activation and congestion management decisions.

- **Customer experience**: There is a lack of automation, experience and knowledge from the customer side.

B.2 Enedis - France use case

Introduction

National Context

France's electricity system consists of a **TSO**, **Réseau de Transport d'Électricité (RTE)**, and **DSOs**, including **Enedis**, the largest DSO, covering 95% of France with about 40 million system users.

- The **TSO (RTE)** manages the **HV network** (**63 kV and above)** in a meshed way.
- The **DSOs (Enedis and about 140 other DSOs)** manage MV (mainly **20 kV) and 400 V** radial networks.

Challenges of DSOs

Grid operators face multiple challenges due to the growing share of DERs, electrification of end-use sectors, and increasing energy demand. Enedis has issues with renewables mainly in rural areas and with consumption mainly in urban areas. For Enedis, most issues currently materialise:

- on the HV/MV primary substation, where Enedis will permanently embed flexibility on network design and increase CAPEX efficiency by about 30% by connecting more renewable than under no flexibility design and relying on flexibility when needed: the 'ReFlex' project.
- on the connection to the TSO grid, which requires coordination with RTE in real time when activation of Enedis connected resources is necessary to efficiently solve congestion on RTE and Enedis, and which increasingly requires to connect renewables through temporary FCAs.

The main use case for Enedis for flexibility is to foster renewable connection. Enedis also uses market-based flexibility to handle issues related to demand congestions to optimise both network design and operations (investment deferral and support for operations and works planning).

Due to the use of time of use tariffs[30] during decades, EV charging can be shifted during off-peak. This enables cheaper charging while alleviating reinforcement.

Evolution of Congestion Management Over the Last Years

Timeline of the Evolution Towards the Current Model

- **2017:** Enedis conducted an **economic assessment of smart grid solutions[31]**, including assessment of flexibility and publication of propensity to pay local services.
- **2018-2019:** Stakeholder consultations.
- **2020:** Enedis launched its first call for tenders, signing contracts for local services.
- **2021:** Pilot project 'ReFlex' (see below) started with **10 HV/MV primary substations**, adding **210 MW of additional connection capacity for renewables**.
- **From 2020 and each year after:** Tender for local services, with increasing results. The 2024 flexibility tenders awarding **46 MW for support to operations and works planning**.
- **2025-2027**: First phase generalisation of ReFlex on about 100 HV/MV additional primary transformers, adding several hundred MW connection capacity, on transformers where ReFlex provides the most value and where ReFlex is technically possible from a command-and-control standpoint.
- **From 2028**: Second phase generalisation of ReFlex, rolling out ReFlex wherever it provides most value, while Enedis second generation DERMS will enable to roll-out ReFlex on any primary HV/MV substation.

Throughout all these years, Enedis consulted stakeholders as part of its annual work plan to foster local services, with request for contributions, workshops and bilateral feedback after each tender.

Congestion Management and Market-Based Flexibility

Network Design Principles

The design of the electricity network plays a crucial role in ensuring reliable power distribution while integrating increasing amounts of DERs and optimising investment strategies. Enedis follows specific network design principles to manage congestions and optimise grid operation effectively.

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[30] Time of use tariffs are well understood and widely chosen by customers and followed by suppliers in their tariffs.
[31] Available at online here

- **Radial Network Structure for Distribution:** Unlike the meshed HV transmission network managed by RTE, the MV and LV distribution network operated by Enedis is radial, meaning that power flows from substations to end-users in a structured manner.

- **Optimised Hosting Capacity for Renewables (S3REnR):** The network design considers future renewable energy integration by systematic surveying potential projects on medium-long term (which includes projects that have not yet applied for connection), ensuring that grid reinforcements align with projected growth in decentralised production. This is done in coordination with the TSO.

- **Reinforcement vs. Flexibility Trade-Offs:** Investment deferral strategies are evaluated through cost-benefit analysis[32] to determine whether network upgrades or flexibility solutions provide the best economic and operational outcomes.

Flexibility Mechanisms

Enedis uses all four contractual means to access flexibility: time-of-use network tariffs, rules-based flexibility, permanent FCA, temporary FCAs and local services. Enedis prioritises market-based flexibility as the primary solution and resorts to rules-based mechanisms as a backup when market-based options are insufficient or unavailable. The Distributed Energy Resource Management System (DERMS) of Enedis forecasts and solves congestion and voltage issues and selects the best solution or combination of solutions among available means.

- **Incentives on subscribed capacity**: Network tariff includes a significant share related to subscribed capacity. Customers are incentivised to 'flatten' their load curve, by shifting consumption at other time of the day. For LV customers less than 36 kVA, this incentive is further enhanced by a breaker that trips off if a customer consumes more than its subscribed capacity (whereas larger customer can consume beyond the subscribed capacity without any breaker enforcing subscribed capacity, with a higher tariff beyond the subscribed capacity).

- **Time-of-use tariffs** help shift consumption patterns in a reproducible and overall reliable manner. The time periods are by taking into consideration balancing as well as network issues. The time periods have been historically set to shift load (hot water tanks) at night to reduce the needed modulation of the nuclear production. In the 2025-2029 network tariff period, Enedis will undertake a major overhaul of the time periods of time-of-use

[32] More information available at:
- Section 6 in Enedis "Distribution Network Development Plan" for comprehensive methods to assess and value flexibility. Available online here
- Section 7 in "Economic Assessment Of Smart Grids Solutions". Available online here.

network tariffs, whereby at least three hours off-peak will be set April-October at daylight (and five minimum hours off-peak still at night time), to help better synchronise with PV generation, while off-peak will be mainly set at nighttime in November-March. In addition, the Linky Smart meter is equipped with one physical on-off switch and seven virtual switches (accessible via the real-time smartmeter interface) whose on/off states are defined for each one/two hours of the year by the supplier. Suppliers mainly mimic the network tariff timetable for the setting of the hard switch, which is turned on during off-peak. Customers can link on a voluntary basis their appliances (such as hot water tanks or EV charging) to the hard switch. This enables customers to benefit from off-peak tariffs automatically, without any further burden. Customers can at any time manually override and charge their EV or heat their water tank if they see the need (yet pay peak-time tariff).

- **Permanent FCAs** are available for renewable producers (more than 250 kW) as a choice between: 1) paying for a needed reinforcement of MV feeder, or 2) accepting curtailment (without compensation) and avoiding the cost induced by needed reinforcement works. The permanent FCA results to be attractive from an economic point of view to a limited fraction of connection applications: small production sites (otherwise a new feeder would be necessary to avoid high curtailment) located far from the transformer (otherwise a new feeder is cheaper than curtailment). The savings for the relevant MV DER connections are estimated to be on average around **90 k€/MW** in the 2017 report on economic assessment of smart grid solutions**.**

- **Temporary FCAs** are already allowed and contracted, until reinforcement work is completed, both for producers and consumers. Limitations can be static (predetermined depending on the time) or in certain cases dynamic (adjusted in real time). Dynamic limitations are only relevant where the build and run cost of command and control and back-office for contract management are lower than the benefits, as assessed by a cost benefit analysis, and where the system user has a permanent interest in the temporary FCA. LV producers connected with temporary FCA will not be curtailed. Instead, they pay a lumpsum of 5.4 €/kW at the time of connection that finances the flexibility that will be provided by other means (market-based or rules-based curtailment of HV or MV producers). This avoids disproportionate to build and run costs to command and control and FCA contract management of LV producers, decreases uncertainty on their business plan and ensure fairness as it is quite impossible to split fairly in real-time the curtailment induced by optimal design from the amount induced by overbooking (early connection), while avoiding loopholes (such as malfunction of the command and control in LV producers).

- **Market-based flexibility** can be used for **investment deferral, maintenance support, or as an alternative to RES curtailment**:
  - Since 2021, Enedis performs a **cost-benefit analysis for every MV reinforcement** intended to solely solve demand congestion, whether for primary substation or feeder, N or N-1 scheme, capacity or voltage issues. However, most often, reinforcement results to be more competitive than ideal flexibility (namely flexibility provided at zero cost without any limitation on power or duration, always and immediately available, located in the proper location). The savings for investment deferral could typically range from **0 to 24 k€/MW/year**, depending on the local situation and needed reinforcement works[33].
  - For maintenance support, Enedis has identified in 2024 **50 opportunities** and **contracted 46 MW**, where flexibility value is assessed versus the **cost of an alternate traditional solution** that would otherwise be used to solve congestion, such as dispatch of mobile generators, increased works forces, etc.
  - The **ReFlex project** consisted in permanently embedding flexibility into network design and increasing CAPEX efficiency of reinforcements. Instead of curtailing production (e.g., rules-based mechanism), Enedis procures and activates market-based local services. These services are likely provided by other flexible resources. The use of market-based flexibility as an alternative to **RES curtailment** is considered the most promising use case. Due to the kinematics of project developments and connection in the pilot area, even if the new connection scheme was enabled in 2021, the first flexibility need occurred in 2025.
- **Rules-based mechanism**: This mechanism **is mandatory for MV producers and allows RES curtailment** under predefined conditions. The producer is usually compensated (on a no gain no loss basis and the activation is neutralized for BRP) unless it is a planned maintenance. For example, there is **no compensation** up to **360 hours over three years for TSO maintenance** and **816 hours over four years for DSO maintenance**. For the Reflex connection scheme (flexibility embed in the design of HV/MV transformers), Enedis has evaluated that they can achieve **30% CAPEX savings of primary substations with less than 0.06% energy curtailment** through optimised curtailment strategies. Under Reflex,

[33]More information available at:
- Section 6 in Enedis "Distribution Network Development Plan" for comprehensive methods to assess and value flexibility. Available online here.
- Section 7 in "Economic Assessment of Smart Grids Solutions". Available online here.

curtailed producers are compensated for each kWh of curtailed energy (no gain no loss basis) and their BRP is neutralized.

Market-based procurement

As highlighted in the previous chapter, Enedis uses market-based procurement for three different use cases: reinforcement deferral, maintenance support and renewable energy integration. For this, it has two different products:

- **Capacity reservation**: Tender to reserve flexible capacity. The SP has to provide a price €/MW for the reservation and €/MWh for the activation. The activation price is automatically forwarded to the energy products. After the award of the tender for capacity reservation, the SP shall recruit the assets according to predefined milestones (tender is awarded based on a commitment to recruit the needed flexible sites in due time for the first expected congestion/voltage issue to solve, not based on the flexible assets actually in the portfolio of the SP at the time of the tender) and qualify for the products. If the SP does not meet a milestone, the SP faces a penalty and/or disqualification. This product is mostly used for investment deferral. Capacities are currently procured twice in a year, but Enedis is planning to increase this frequency.
- **Energy products**: Only assets which have passed product prequalification can participate in this market, and there are thus no penalties if SP fails to qualify for products without capacity reservation. Offers from capacity reservation are automatically forwarded, but other offers can also participate, and Enedis activates the most economical one. Products with capacity reservation is used to activate the flexibility required for investment deferral or to schedule maintenance or construction works (planned unavailability of grid elements), while products without capacity are mainly used as an alternative to RES curtailment or as an alternative for operational means (where outages do not justify reinforcement). Energy products are procured once the congestion materialises in the day-ahead (for example for congestions due to low temperatures) or near-real-time (for example for RES).

Enedis has developed **standardised products of 500 kW (aggregated) with a one/two-hour duration** and is working on **reducing the individual flexible capacity to 100 kW**. This reduction will be implemented once real-time observability of local services is in place, as foreseen in the upcoming NC DR. Aggregation models are part of the market design and rules since the first tender, allowing any asset regardless its size or voltage level to participate (provided they are connected on the proper location). In addition, assets which are not yet registered or connected can participate to the tender, provided the products are qualified at a predefined deadline, consistent with the potential first activation need.

Enedis procurement rules require activation tests to qualify SPs and products. The qualification rules allow up to two failed communication tests before a required passed communication test and up to two failed activation tests before a required passed activation test for the first product prequalification.

TSO-DSO Coordination

Effective coordination between RTE and Enedis is crucial to ensure grid stability and optimise the use of flexibility resources. RTE only sees what comes in and out of the HV/MV transformers and has no view on the radial network from Enedis and how it is configured. Thus, the concept of operational limits set at the interface between RTE and Enedis is both efficient and simple. Whenever RTE has a congestion, the following coordination process would apply:

- RTE informs Enedis of a possible congestion, possibly requiring activation of resources on Enedis network.
- Enedis informs RTE on the possible solutions and their related costs.
- RTE runs their simulations based on the costs and solutions provided by Enedis and sets the relevant operational limits at TSO/DSO interface (HV/MV transformers).
- Enedis activates the most cost-efficient solution or combination of solutions to comply with the operational limits set by RTE and congestion on Enedis network, which can be grid reconfiguration, market-based flexibility or RES curtailment.

The **RTE-Enedis optimised coordination process**, set to be fully deployed by 2028, will enhance real-time cooperation and streamline flexibility activation across the transmission and distribution networks. Defining this coordination based on operational limits, related data exchange process and ICT represents a several year project. It involves joint workshops of Enedis and RTE operations, market and IT teams, designing together the best coordination mechanisms, while economists assess the relevant criteria to define the best solution or combination of solutions.

Besides the operational coordination, Enedis and RTE collaborate on **regional DER hosting scheme** to optimise grid planning and investment strategies.

Enedis Market Platform

Enedis has developed its own dedicated **local market platform**[34]. This platform allows Enedis to communicate its local flexibility tenders, and the service providers to submit their bids.

Some key features of the platform include:

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[34] Available online here

- **Identification of Flexibility Needs:** The platform maps congestion zones and publishes flexibility requirements.
- **Eligibility Verification:** Participants can check the relevance of system users to provide a service based on the meter identification.

Future developments expected include:

- **Automated Bidding Process:** SPs can submit bids based on predefined flexibility products.
- **Integration with DERMS:** The platform is designed to work with Enedis' DERMS for activation.

Currently Enedis does **periodic tenders to award contracts** but is planning to move to a continuous market allowing real-time procurement of local services.

Operational Capabilities for Flexibility Management

The successful operation of local services requires a combination of **technological, operational, and market-oriented capabilities**. Enedis and other stakeholders involved in flexibility markets must develop and maintain the following capabilities:

- **Advanced IT and Digital Infrastructure:**
    - **Real-time monitoring of the grid** with increased locational granularity.
    - **Data exchange** with other SOs, SPs and system users for the observability of activation of local or balancing services.
    - Deployment of **second-generation DERMS** to manage real-time flexibility activation and seamlessly use all possible solutions to efficiently forecast, prevent and solve congestion.
    - Integration with **market platforms** for efficient procurement and settlement.
- **Operational Expertise:**
    - Network operators must be trained in **using flexibility to solve congestions**.
    - Coordination of markets.
- **Stakeholder Coordination:**
    - Close collaboration between **TSOs and DSOs** to optimise flexibility activation and avoid conflicting signals.

- Engagement with **aggregators and SPs** to enhance participation and liquidity in markets for local services.

Key Lessons Learned

- **Permanently embedding flexibility in network design significantly increases the CAPEX efficiency of reinforcements**, enabling to connect renewables faster and in greater amount.
- **Market-based flexibility can be viable**, but investments are often more cost-efficient even when compared to ideal flexibility (price zero, no limit on power or duration, always available and located on the right side of the congestion). It is a case-by-case analysis. The increasing needs of flexibility for the system induces a significant development of flexible resources on the grid, which also increases the availability of resources relevant for local services. This is a win-win situation.
- **Permanent FCA is valuable, yet on a narrow scope.** First, many customers can be connected without reinforcements. Second, FCAs require a positive cost-benefit. Build and run cost of back-office (reporting, customer management, and in particular claim management) can represent a significant share of the overall cost benefit analysis, which can be the main barrier to enable use cases. Obviously, build and run costs of command-and-control is important. Finally, regulatory criteria and the framework for FCAs, such as ensuring 70% guaranteed capacity and limiting average curtailment to 5% for producers can be detrimental, as they inherently limit the possible scope, but more importantly they can require an expensive back-office (cost to report and manage claims could be significantly higher than the cost of curtailed energy).
- **No one fits all solution**. A combination of time-of-use tariffs, market-based procurement, FCAs, and rules-based mechanisms is required.

Challenges and Outlook

Current Challenges

- **Limited liquidity** in markets for local services. However, there is currently a significant increase in the flexible sites in the flexible register, for national mechanisms. Such sites can participate for local services.
- **Administrative complexity** of FCAs, in particular for small LV PV customers: the cost for command and control and back-office (and management of possible claims) would be disproportionate to the value of flexibility.

- Need for **improved TSO-DSO coordination**, and development of a second generation DERMS**.**

Future Plans (2025-2028)

- **Expansion of continuous flexibility markets.**
- **Development of second-generation DERMS** and **RTE-Enedis optimised coordination process.**
- **Refinement of regulatory frameworks** to enhance market participation.
- **Further integration of local flexibility** into national balancing markets (cf NCDR and coordination between markets).

B.3 E-REDES - Portugal use case

Introduction

Structure of the Electric System

Portugal's electricity grid is divided into transmission and distribution networks:

- The **TSO** manages the very high-voltage (VHV, 400 KV, 220 kV and 150 kV) grid.
- The **DSO, E-REDES**, operates the high voltage (HV, 60 kV), **medium voltage (MV, 10 kV, 15 kV and 30 kV) and low voltage (LV, 230 V and 400 V) networks**, covering **99.9% of mainland Portugal** and ensuring the reliable distribution of electricity to consumers.

Challenges of Grid Operators

- The **increase in distributed generation** has created pressure on the grid and is projected to double in the coming years.
- **EV adoption** is growing rapidly, requiring additional infrastructure.
- **Self-consumption systems** have increased significantly.
- The TSO level is currently **fully saturated**, meaning that no additional capacity for new generation can be connected.
- The **DSO grid has limited congestion** but is experiencing increasing challenges due to the energy transition.
- There are **financial and resource limitations** in implementing infrastructure upgrades.

- Grid operators must increase the investment in the grid to cope with these challenges, while in punctual situations can integrate **flexibility** solutions to complement that investment, while ensuring network stability.

Evolution of Congestion Management Over the Last Years

Timeline of Evolution

- **2019**: EU Directive 2019/944 establishes the framework for markets for local services.
- **2022**: Portugal transposes the directive into national legislation.
- **2023**: New regulatory requirements mandate the consideration of flexibility in the **Network Development Plan**, and **E-REDES had six months to submit a pilot proposal on markets for local services to the NRA.**
- **2023**: The **FIRMe pilot project** is launched. The project goal is to test and promote market liquidity and to gain experience in market procurement and flexibility management. First set of tenders took place in the summer of 2023.
- **2024:** First flexibility contracts were signed at the beginning of the year, with the agents who submitted competitive bids, and have the deadline of December 2025.
- **2025 and beyond**: New tenders and market expansions have been opened from September 2025 to October 2025 to procure flexibility for years 2026 and 2027.

Congestion Management and Market-Based Flexibility

Network Design Principles

E-REDES conducts a **cost-benefit analysis** for every grid reinforcement with special focus at high and medium voltage levels (60 kV- 10 kV). Traditional grid investments are valued by two criteria: reduction of network losses and the value of lost load (VOLL). When comparing flexibility to grid reinforcement, only the VOLL reduction can be used as a benefit. For this reason, the grid investment is the better solution in the majority of the cases and the number of flexibility use cases for deferral of grid reinforcements is small.

E-REDES applies N-1 rule to consumption only. E-REDES aims at using flexibility products (e.g., Restore product) for the unlikely situations in which a failure occurs, and the N-1 reserve may not be enough to supply all the loads. For these use cases, the counterfactual to flexibility is the decrease in quality of service due to unlikely grid failures.

Congestion Management via flexibility

E-REDES has different flexibility mechanisms implemented:

- **Time-of-Use tariffs** are defined by the regulator, but they are not dynamic and not for locational congestion management.
- E-REDES is currently developing a pilot project for **FCAs**.
- E-REDES uses **markets** for local services to handle issues on 60 kV, 30 kV, 15 kV and 10 kV grid. All downstream installations (also LV) can provide local services, as longs as their connection is in the congested area.

Flexibility Products in Place

- **Pricing**: E-REDES indicates price signals (reserve price in €/MW for capacity and €/MWh for activation), the total power requested, and the expected usage times per year. The SP is free to choose which price they offer for availability and which price for energy. The evaluation of the offers by E-REDES will be based on the total annual cost, calculated using the availability price and the energy price multiplied by the expected usage time. The expected usage time is not a maximum nor a minimum activation duration, but an indication by E-REDES of what they expect. In the first tender, all competitive offers that were lower than the reserve price (calculated based on capacity and energy price and the expected usage time) were selected. E-REDES decided to disclose the activation and capacity price signals to stimulate the market.

- Flex services can be provided in **multiple service windows** (defined by E-REDES) that can cover the total period of the contracts, or just some periods. Depending on the situation, E-REDES can publish one service window or multiple service windows, split into seasons, day of the week or time of the day.

- Products are bought **long-term** (currently two years from the signature as the project is a regulatory sandbox for two years). For E-REDES, this long-term procurement reflects better the reality of a grid operator who mainly uses flexibility as a complement to grid reinforcement, which is planned many years in advance.

- **Product prequalification**: E-REDES has set up a simple product prequalification, after which customers can offer bids. In this process, E-REDES checks that the customer is connected to the right voltage level, that the flexibility goes in the right direction (up or down), that the customer is located inside the required grid area (identification via customer ID) and that the asset has at least the minimum size. On the first set of tenders, customers could do the prequalification also with assets which are not yet installed.

- **Grid prequalification**: As E-REDES is the only DSO, there are no connecting or impacted DSO. E-REDES validates if the bids and activations are within the maximum technical characteristics of the connection point and that the customer has a smart meter.

- The **minimum bid size** is 10 kW.
- E-REDES does an **activation test** with the customers which have been selected based on their bids. This test is done after the tender but before signing the contract and requires also that the flexible asset is installed.
- The **Baseline** depends on the assets, and in particular:
  - For consumption units, it is based on historical measurement data from the Smart Meter of the connection point. The flexibility must thus be visible on this connection point:
    - Working days: Average of the most representative eight days out of the last 10 with same day two hours adjustment factor[35].
    - Weekends: Average of the most representative two days out of the last four weekend days (two weekends) with same day two hours adjustment factor.
  - For solar / wind / hydric generation, the baseline is given by the neighbours' behaviour
  - For storage, the baseline is zero
- There are **no penalties** applied yet. However, in the first tenders the service was only remunerated when the customer delivers at least 85% of the promised service. Customers are paid up to 115% of service delivery for the energy part. On the second wave of tenders, these thresholds were changed from 85% to 60% and from 115% to 140%:
  - < 85 % service delivery: no payment
  - > 85 % and <115 % service delivery: payment according to the energy delivered (when customer delivers 105 % of service, he is paid 105 % of his offer)
  - > 115 % service delivery: payment of 115 % of his offer
  - These thresholds were changed in the second tenders to a minimum of 60% and a maximum of 140%.

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[35] If an activation order is set to start at 8am, E-REDES looks at the consumption it had between 6am-8am and shifts the baseline load curve to start at the average of the consumption of those two hours. The historical measurement only gives the behaviour for the baseline afterwards.

- There is currently no **balancing correction** as the volumes and activations are very low for the moment and the majority of SPs are the owners of the assets.

- Product table

Product	Purpose	Benefits	Activation Timing	Counterfactual
Dynamic	Maintenance support	Cost decrease Emissions decrease	Availabilities requested with one week notice Activation within 15- minute notice	Mobile substation deployment
Secure	Peak demand management	Investment deferral Faster connection for customers	Availability defined in product windows At least 15-minute activation notice	Grid reinforcement
Restore	Emergency grid failures	Reduction of the value of lost load in case of failure	Availability defined in product windows At least 15-minute activation notice	Additional customer disruption (Value of lost load)

In the first tender, E-REDES:

- Requested 56 MW in eight different competitions for three different products
- Was offered 36 MW by SPs.
- Contracted 7 MW
- Activated 0,9 MW in the first year of operation

E-REDES was particularly successful in procuring flexibility for the **Dynamic product** due to several key factors:

- **Longer Activation Notice**: The one week notice before activation allowed flexibility providers (SPs) to plan their participation in advance, making it more feasible for them to commit.

- **Lower Operational Risk for SPs**: Since the Dynamic product was used for scheduled maintenance, it provided predictability for SPs, reducing uncertainty compared to emergency-based activations.
- **Cost-Effective Alternative to Mobile Substations**: The Dynamic product replaces mobile substation deployment, which is expensive and logistically complex, making flexibility a more attractive option compared to traditional grid solutions.

TSO-DSO coordination

There is only one DSO in mainland Portugal, so no DSO-DSO coordination is required. The TSO is informed when activation orders are sent. As the local market and ancillary markets are very different, there is currently no aim to harmonise products. E-REDES believes that too much harmonisation between local market and ancillary markets will reduce liquidity, as the SPs participating in the local market are smaller and cannot fulfil very demanding requirements such as automation for instance. There are nevertheless talks and regulatory obligations to harmonise to some degree the prequalification process.

The SP can participate in multiple markets. It is however important to guarantee that the LFM has priority over other markets, since it is more local and has less liquidity than system wide markets.

Market operation

The local market is operated by Piclo platform. E-REDES does periodic tenders (e.g. once per year):

- Competition disclosure until opening of the tenders: three months. In this phase, E-REDES publishes the following information: technical requirements, procuring capacity, periods, probability of activation, average energy utilisation, price signals, rules of the tender, contract template and grid locations.
- Tender phase: One – one and half months.
- Market outcome: One month after tender closure.

The platform details all the accepted and rejected bids, including the prices and volumes.

Figure 16: Map disclosing tenders

Source: Plico Platform. Available online here.

Operational Capabilities

To effectively implement and manage market-based flexibility, E-REDES currently operates with the following capabilities:

- **Grid Monitoring and Forecasting**: While real-time monitoring systems are in place, forecasting tools are still being improved to better anticipate congestion and flexibility needs. Currently E-REDES does not require any real-time data form the flexible customers and does not verify in real-time the activation of the flexibility service. E-REDES only monitors the grid situation in real-time.
- **Market Integration**: The Piclo platform is used solely for flexibility procurement, and no further integration with grid management systems has been implemented.
- **Manual Dispatch Systems**: Flexibility activations are currently handled manually via phone and email, with plans to introduce automation in the future. Although many SPs appreciate manual activations given the fact that they don't have any automation installed and also do not wish to spend money to do it, aggregators can also easily establish automation via API on top of the e-mail activation orders.
- **Customer and Stakeholder Engagement**: E-REDES has customer key account managers who contacted potential customers to participate in the flexibility market.

- **Settlement and Verification**: Flexibility verification is based on smart meter data and done by E-REDES billing teams within 20 working days of the month after activation.

Data Exchange Requirements

To ensure efficient operation of the flexibility market, E-REDES has established the following data exchange requirements:

- **Prequalification Data**: Participants must provide smart meter IDs, asset location details, and proof of minimum capacity requirements.
- **Settlement Data:** After activation, smart meter readings are used to verify local service delivery, ensuring accurate compensation.
- **Communication Protocols**: Currently, communication between E-REDES and participants is handled manually via email and phone, with plans for future automation.

Challenges and Future Outlook

- **Market Liquidity**: While E-REDES successfully procured flexibility for the Dynamic product, participation in Secure and Restore products was lower, indicating a need to expand provider engagement. For Secure product, E-REDES is considering moving the activation to the day-ahead.

- **Counter activations**: for market liquidity reasons, counter activations should be avoided. It is hard enough already to find value and liquidity for flexibility. If counter activations are required, this doubles the flexibility needs.

- **Penalties** need to be implemented in the future, but they will reduce the liquidity. For this reason, E-REDES is currently reluctant to implement them has not implemented this yet but foresees it for the future.

- **Product harmonisation** can increase the market liquidity, but E-REDES wants to continue experimenting with the designs of products to innovate and learn. Product harmonisation can also decrease market liquidity if there are heavy requirements for the SPs.

    - **Scaling Up Market Integration**: While Piclo is currently used only for procurement, future efforts may include integrating additional functionalities.

B.4 Glitre Nett - Norway use case

Introduction

Structure of the Electric System

- **Transmission grid:** TSO operates the meshed transmission grid at 420 and 132 kV and owns the 420/300-132 kV transformers (transmission system connection points).
- **Regional distribution grid**: DSOs own the meshed regional distribution grid from 50 kV to 132 kV, but TSOs operate it.
- **Local distribution grid:** DSOs operate the local distribution grid, which is below 22 kV. The grid is radial operated but build in a meshed structure to reconfigure due to maintenance and faults.

Challenges for Grid Operators

Grid operators face several challenges, including:

- **Capacity limitations** in their own grid and in the transmission system.
- **Rising electricity demand** from new customers and industries.
- **Changing consumption behaviours** among existing customers.

Types of Congestions and Related Use Cases for Flexibility

Although standard consumption for a normal household has been historically around 20.000 kWh, Norway faces currently issues with peak consumption during cold winters and maintenance periods. The congestions can be for a few hours only, but up to several days, and happen in both rural and urban areas.

Evolution of Congestion Management Over the Last Years

Timeline of Congestion Management Evolution

- **2016:** The first flexibility pilot project was launched at **Engene substation**, for which Glitre Nett had a DERMS solution. The initial driver was to use the existing grid capacity while engaging with customers.
- **2019-2022: Norflex project** between Agder Energi, Glitre Energi, NODES, and Statnett. In this project, the Nodes local market platform was developed, and aggregated flexibility was forwarded from the Nodes platform to the mFRR market from Statnett.

- **2024:** Implementation of the **Euroflex project** across eight DSOs, covering two-thirds of Norway's population.

Congestion Management and Market-Based Flexibility

Network Design Principles

- Glitre Nett does not do cost benefit analysis to compare flexibility to grid reinforcement yet, because flexibility is only used in operations.
- Glitre Nett **overbooks grid capacity by 20%** with higher risk. For demand, Glitre Nett respects n-1 capacity whereas for generation, n capacity is taken into account. 20% to 100% of overbooking is done via flexibility (market-based if available and rules-based mechanisms).
- Glitre Nett applies **N-1 principles** for consumption (80% average max loads, meaning 98% in time duration period) and **N-0 principles** for production.

Flexibility Mechanisms

As the TSO operates the 132-50 kV distribution grid, Glitre Nett uses the following flexibility mechanisms only for 22 and 11 kV grid:

- **Market-based solutions:** Seasonal and weekly capacity products with a continuous gate closure. For energy products, the gate closure is one hour before operating.
- **Tariffs:** Flexible capacity tariffs for voluntary load curtailment. This was used by a lot of customers, but when Glitre Nett started calling the load curtailment, customers switched to fixed capacity tariffs.
- **Rules-based mechanism**: DSOs offer connections with a rules-based mechanism when not enough capacity is available to connect the customer.
- **Grid reconfiguration:** Used for short term planning and in operations.

Flexibility Products

In the Euroflex project, Glitre Nett is currently testing and using three different products:

- **LongFlex products:** Open six months in advance and closes the day of activation, although in practice the market is not open this close to operating hour. Glitre Nett indicates the capacity and volume which they require, and the maximum prices they are willing to provide. SP have to provide a capacity price, an activation price and volume. Glitre Nett selects the best offers, and the SP are remunerated for their availability according to the capacity price (pay-as-bid). The activation offer and price are automatically forwarded to the ShortFlex market.

- **ShortFlex products:** Market opens seven days in advance and closes one hour before activation. Market consists in activating required flexibility in operations. It includes flexibility selected in the LongFlex market, but also other offers. Only activated flexibility is renumerated (pay-as-bid).
- **MaxUsage:** This is the newest product which is tested. Customers commit to a maximum consumption per hour. The product is not used much for the moment, because of the uncertainty of the amount Glitre Nett is willing to pay.

Minimum order size in the Euroflex project is 1kW. The minimum durations for the offers are one hour, whereas the settlement is done per 15 minutes. For the baseline, the SP can choose to provide its own baseline or chose a baseline method from the market platform. These baselines are based on measurements (e.g. hour before and hour after activation).

TSO – DSO Coordination

In the Norflex project, Agder Energi, Glitre Energi, NODES, and Statnett have tested integrations between local market and balancing market. This integration is currently done in a **sequential coordination:** DSOs activate flexibility first, then the TSO can access the non-activated flexibility. This model is favoured for the moment because it is easier for the calculation of imbalance and costs compared to a simultaneous coordination in which DSO and TSO would be able to access flexibility in parallel. As the traded volumes are low for the moment, the TSO does not retrieve the information on the procured and activated products (information is however available) and does not do a balancing correction yet.

It is also important that flexible assets can participate in different markets. Assets are not all the time required by one market, and value stacking via different markets increases market liquidity for all grid operators.

Market Operation

The local market in Norway is operated by Nodes. The Nodes platform was developed in the Norflex project. It includes the following capabilities:

- **Display of flexibility needs**: an open portal displays the open tenders for capacity and market data such as reserved capacity, activations and associated prices)[36].
- **SP qualification**: economic requirements of SPs are checked.

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[36] Nodes Platform. Available at Dashboard | NODES.

- **CU registration**: all Cu are registered with predefined required properties like EAN/MeterPointID (MPID), capacity, BRP, type, longitude and latitude. It is the DSO that assign the CUs to the correct trade area (called grid node in NODES) by retrieving the CU with its MPID through an API from the market platform, analysing using a grid model and then sending back that information through the API to the market platform.
- **Offer selection**: SPs are informed on the selected, rejected or not traded bids through the API.
- **Verification and settlement**: market platform includes the verification and quantification of the flexibility as well as the financial settlement and invoicing.

Data Exchange and Capability Requirements

- **Data used for congestion management:** Market data, grid time series, weather data, grid model, operational data.
- **Data required from flexible customers**: Load predictions (time series)
- **Data made available by Glitre Nett**: Volume, max price, location and time for flexibility need via market platform.
- **Platforms used:** GridTools platform for decision support and integration with NODES Market Platform.
- **Organisational requirements**: More coordination between grid planning and grid operations is required. Flexibility usage needs to be better integrated into grid planning process.
- **Forecasting and real-time capabilities**: Forecasting capabilities are important to have a view on what is happening in the next days, and to start activating flexibility. However, not all congestions can be identified the day before (e.g. faults). Therefore, it is also important to have real-time capabilities to manage these issues via flexibility.

Challenges and Outlook

Main Current Challenges

- **Regulatory barriers:** CAPEX-centric incentives hinder flexibility market adoption.
- **TSO-DSO conflicts:** Disagreements over resource ownership and activation.
- **Market liquidity issues:** Need for higher customer engagement and incentive structures.

Future Plans and Developments

- **Expansion of Flexibility Markets:** More DSOs joining markets for local services.
- **Introduction of New Flexibility Products:** Further trials for **MaxUsage**.
- **Improved Coordination Models:** Exploring simultaneous activation between TSOs and DSOs.
- **Regulatory Reforms:** Push towards **TOTEX-based regulation** to reward flexibility utilisation.
- **Integrate flexibility into grid planning:** Flexibility is currently only used in operations but should also be used in grid planning in the future.

B.5 E.ON Energy Networks and Göteborg Energi Nät - Sweden Use Case

Introduction

Structure of the Electric System

Sweden's electricity system consists of four electricity trading areas, that are connected with each other and interconnected with its neighbouring countries. The Swedish TSO Svenska Kraftnät maintains balancing energy markets together with the other Nordic TSOs. The system is structured as follows:

- The TSO manages **transmission grid** at 400 kV, 230 kV and 120 kV.
- The five Regional DSOs manage the **regional transmission grid** at voltage levels of 130 kV and 70 kV.
- 165 Local DSOs and the five regional DSOs handle **lower voltage levels** for distribution to consumers.

Challenges of Grid Operators

- **Rising electricity demand** due to electrification, industrial expansion, and new large energy consumers such as battery factories and data centers.
- **Aging infrastructure**, requiring reinvestment and grid upgrades. Big parts of the grid are more than 50 years old.
- **Congestion within trading areas**, which was historically managed through trade zones but is now a growing issue. These congestions come because of changing electricity flows due to new cross-border power dynamics affecting capacity.

Types of Congestion and Use Cases for Flexibility

Most congestions from DSOs are due to a **limitation of the subscribed capacity at TSO connection point**. The TSO imposes limits on DSO subscription increases, restricting the ability to connect new customers:

- **Operational congestion**: Seasonal demand variations, particularly in winter (November to March). A 10-year winter in Sweden results in a capacity increase of 30%.
- **Maintenance-related congestion**: Temporary constraints during grid upgrades or reinforcements.

Generation driven congestions are rather a new phenomenon in Sweden but will of course also develop over the next years.

Driving Forces Behind Congestion and the Use of Flexibility

- The growth of **high-demand industrial sectors** and the need for **faster customer connections**.
- A desire to use the existing grid more efficiently and to **reduce grid expansion costs**.
- Regulatory pressure to develop **market-based congestion management** as an alternative to infrastructure investments.

Evolution of Congestion Management Over the Last Years

Timeline of Evolution

- **2019-2023**: The **CoordiNet project** (EU-funded Horizon 2020) introduced structured flexibility markets. Participating SOs: DSOs Vattenfall Distribution, E.ON ENERGY NETWORKS, Ellevio and the TSO Svenska kraftnät.
- **2021-2024**: The **sthlmflex** market launched in Stockholm, using an independent marketplace (Nodes). Participating SOs: DSOs Vattenfall Distribution, Ellevio and the TSO Svenska kraftnät.
- **2023-2024**: Further expansions with Vattenfall Distributions **Uppsala Flexmarket,** E.ON ENERGY NETWORKS: **Flexmarket,** Göteborg Energis **Effekthandel Väst and** Jämtkrafts **Jämtflex**.
- **2025**: Existing in flexibility markets in Sweden: E.ON Energy Networks' **Flexmarket,** Göteborg Energis **Effekthandel Väst,** demonstrations of procurement.

Congestion Management and Market-Based Flexibility

Network Design Principles

Göteborg Energi Nät has a meshed network but which is operated radially. It applies N-1 principle for consumption on HV and MV (with some exceptions), and N-0 for generation (or hybrid solution N-0,5 if not connected to meshed network). Göteborg Energi also applies overbooking rules based on expected aggregated load contribution, which is based on measured values and not on contracted capacities. Götebork Energi does not apply a CBA systematically on all grid reinforcements and therefore there are no strict rules on when investments should be made.

E.ON Energy Networks has a radial and meshed grid. It applies N-1 rules for consumption and generation and overbooks its grid up to 130% with FCA and flexibility markets. Before deciding on grid reinforcements, it conducts a cost benefit analysis to decide if flexibility makes sense and evaluate the maximum cost for flexibility.

How Congestions Are Managed

Different types of flexibility solutions are used in the following order

- **Technical solutions**, such as grid planning and grid reconfiguration, are the first solutions activated to solve congestions.
- **Grid tariffs** give the customer a price signal to behave in a grid beneficial way. They are static for the moment, and they have a strong capacity incentive.
- **Markets for local services** allow DSOs to source local services from market participants in case there are congestions which have not been solved with the two former mechanisms.
- **FCAs** are the last resort. Customers who cannot be connected with a fixed capacity to the grid receive the possibility to be connected via a flexible connection agreement. Customers are forced to reduce their consumption in case the grid operator cannot solve the grid congestion by another mechanism listed before.

Flexibility Market operated at Effekthandel Väst

Effekthandel Väst is the flexibility market operated in the Göteborg region. The market platform used is the Nodes platform.

The following products are traded in Effekthandel Väst:

- **LongFlex**: Availability-based contracts over weeks to seasons (November-March). Participants are paid for their availability (€/MW), but they are activated via the ShortFlex products. Price is defined by pay-as-bid, but prices are indicated by DSO in tender requests.

- **ShortFlex**: These are hourly flexibility bids for energy (€/MWh). SPs which have been selected via the LongFlex product have to participate in the ShortFlex market. The selected Service Providers have to activate their flexible energy. Market opens six days before delivery and closes two hours before delivery. Price is defined by pay-as-bid and prices of all sell- and buy-orders are visible for.

- **MaxUsage**: this product is designed for those who want to participate in a simple way with minimal administration. SPs reduce their power consumption to a specified level during certain hours and days. The compensation is paid for as long as the SP stays below the agreed level. Price is defined by pay-as-bid, but prices are indicated by DSO in tender requests.

Minimum bid size for participation on the market is 50 kW and aggregation is allowed. Prices and volumes of tenders are published on NODES platform publicly. Published market data includes reserved and activated volume as well as reservation and activation price.

For baseline, there are different methods available:

- Average of meter data for the corresponding delivery period over the five preceding trading days.

- Average of meter data for the corresponding delivery period over the five preceding trading days with meter value adjusted for activated volumes during that period.

- The meter value the hour before the trade.

- Average of meter data before and meter data after delivery period.

- SP can provide their own baseline including a description/motivation of method used

The compensation for the ShortFlex activation is based on delivery percentage, with a minimum delivery at 75%. For LongTerm Flex, the compensation for availability is reduced based on the delivery. For MaxUsage, customers receive the full compensation if they stay under the agreed limit, and no compensation if they go above the agreed limit.

Flexibility Market operated by E.ON Energy Networks

E.ON Energy Networks is operating a flexibility market in nine regions. E.ON Energy Networks buys the following products usually for the period between November and March via their Switch platform:

- **Season availability**: tenders are submitted before the season, whereas the activation takes place the day before up to two hours before delivery. The SP is remunerated for the availability (€/MW) and for the activation when they are activated (€/MWh).
- **Availability**: for shorter durations (tenders are done seven - two days before delivery), SPs can also offer for availability and activation.
- **Direct orders**: these are energy only products, which are tendered two days up to three hours before delivery.

The availability prices are fixed whereas the activation price is fixed by pay-as-bid. Minimum bid size is 100 kW and aggregation is allowed. The minimum service delivery to receive the compensation is 75%. Max, min and average prices for all past auctions are published.

The SP can provide his own baseline, or the baseline can be based on measurements.

Coordination Between TSO and DSOs

There is not much coordination between the TSO and the DSO. DSOs use the flexibility to manage their TSO subscription limits.

Market Liquidity and Participation

- Liquidity is still developing, with **30 service providers** participating in Effekthandel Väst.
- Strategies to increase liquidity include **long-term contracts and transparency in future market needs**. E.ON Energy Networks, for example, currently buys flexibility until 2029.

Requirements for Operating Flexibility

- **Forecasting capabilities** to predict demand fluctuations.
- **Data exchange requirements** to ensure real-time communication between DSOs and flexibility providers.

Challenges and Outlook

Main current challenges

- **Regulatory uncertainty**: No national framework for FCA.
- **TSO-DSO alignment issues**: Grid congestion is often an administrative problem rather than a physical one.
- **Need for increased participation** to enhance market liquidity.

Future Plans

- **Expansion of flexibility markets** to cover more geographical areas and voltage levels.
- **Improved coordination between TSOs and DSOs** to streamline congestion management.
- **Further integration of new flexibility resources** such as battery storage and EV charging.
- **Ongoing development of digital tools** for automated flexibility procurement.

B.6 UK Power Networks - UK use case

Introduction

National Context

UK Power Networks (UKPN) is the DSO for London, the Southeast, and East of England, serving approximately eight million households and businesses on voltage levels 132 kV and downwards. UKPN has a peak demand of about 14 GW and significant distributed generation (DG), with around 10 GW currently connected and an additional 20 GW already accepted for future connection.

SO Challenges

UKPN's congestion management challenges are driven primarily by thermal constraints, particularly on primary (HV/MV) and secondary (MV/LV) substations, with voltage and fault-level issues being less common. These challenges appear in rural and urban areas outside of London.

Types of Congestion and use cases

Currently, around 4% of primary substations exhibit demand congestion, which is forecasted to rise to 12% by 2030, 30% by 2035, and up to 70% by 2050.

Flexibility is used for both demand and generation curtailment. It plays a central role in:

- Managing thermal constraints.
- Deferring or avoiding capital-intensive reinforcement.
- Enabling earlier and more cost-effective customer connections.
- Supporting planned maintenance works.

Evolution of Congestion Management

UKPN has been active in flexibility for over 10 years, beginning with innovation projects and transitioning to business-as-usual integration in recent years. Its first flexibility auction took place in 2017, with only 1 MW secured from a 20 MW request. Over time, UKPN scaled its operations and has now integrated both long-term and short-term flexibility procurement processes, including transparent publication of results and standardisation of processes.

Congestion Management

Network Design Principles and Integration of Flexibility

UKPN grid is more meshed in London and more radial in rural areas. UKPN applies N-1 planning standards for demand and N-0 for generation. Investment decisions are typically triggered when forecast utilisation reaches 100% in the next three years. The flexibility-first principle ensures that reinforcement is only pursued when flexibility is not cost-effective.

Flexibility Mechanisms

UKPN uses two main types of flexibility mechanisms: **flexibility services** (market-based) and **flexible connections** (rules-based, typically uncompensated). Over the past two years, UKPN has dispatched over 20 GWh of flexibility across approximately 80 high voltage and a few hundred LV substations.

Flexibility Products in Place

Long-Term Auctions

- First tender was in 2017.
- Run twice per year.
- Minimum bid size is 10 kW, which can be aggregated from different assets.
- Used for demand turn down only.
- Based on strategic forecasts of network utilisation.
- Two variants:
  - **Availability + Utilisation**: Providers commit availability; UKPN decides on activation in day-ahead.
  - **Availability + Scheduled Utilisation**: Fixed, pre-agreed dispatch windows (e.g., every weekday 17h–19h in winter).

- Availability is remunerated in £/MW/h and utilisation in £/MWh.
- Targeted at thermal constraints and planned maintenance needs.
- Common across all GB DSOs under a standard product suite.

Day-Ahead Auctions

- In operation for around one year.
- Auction which is run daily at the same time for next-day delivery.
- Utilisation is remunerated in £/MWh.
- Based on automated short-term forecasts with live network/weather data.
- Covers both demand turn-up and turn-down.
- Designed to align with wholesale and TSO market timelines.
- About 50% of UKPN flexibility now dispatched via this method.

Procurement and Remuneration

Remuneration is based on a **cost-benefit analysis**[37] comparing flexibility to network reinforcement. The flexibility budget is capped based on the deferred investment's net present value, with a current price cap of £600/MWh under review. They are however currently considering how to evolve the CBA to appropriately value the acceleration in connections.

For planned maintenance works, UKPN values the flexibility based on reducing the risk of power cuts which has a regulatory value.

Contracts are awarded on a **pay-as-bid** basis. Each auction result is published transparently, showing prices, dispatch decisions, and rejected offers. These numbers are public for the last five to six years, giving market actors valuable insights for their pricing strategy.

LV assets can bid with a minimum threshold of 10 kW, which UKPN aims to lower further. Around 175,000 flexible assets are registered, 90% of which are connected at LV but account for only 25% of the MW capacity.

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[37] CBA methodology. Available to download at: https://www.energynetworks.org/assets/images/common-evaluation-methodology-tool-v3-and-supporting-materials.zip?1735139449

Prequalification

UK Grid Operators have mostly standardised their SP (commercial) and product (technical) prequalification. For some aspects, there are still deviations accepted and they expect to align these in the near future[38].

Baseline and Reliability

Baseline is still a big challenge, and UKPN is thinking in the direction to move to simpler baselines. UKPN has accepted a lot of baselines in the past, including recent history, and is currently thinking to move to standard profiles for domestic customers (e.g., heat pump, EV, etc.) and customer nominates baselines with accuracy checks for commercial and industrial customers.

UKPN does not apply a BRP correction for flexibility services. The review of this approach is however part of the 2026 Market facilitator draft roadmap[39]. Assets must deliver at least 60% of their committed flexibility to receive any payment. Customers are currently not penalised for not delivering their flexibility.

UKPN incorporates a conservative margin in forecasts to mitigate non-delivery risk. Around 75% of the procured flexibility is delivered. This is a high enough number that they can plan around.

TSO-DSO Cooperation

UKPN is part of the national effort to standardise data exchange and ensure interoperability across platforms and regions. Regarding the activation of flexibility, the agreed principle is currently that the DSO has first right.

Platform

Both flexibility products operate through the EPEX Spot Local flex platform, with full API support from registration to settlement.

Operational Capabilities for Flex Management

UKPN's DSO team includes:

- A **dedicated operations team** in the control room, managing dispatch and curtailment.
- A **forecasting and planning team**, running both long-term and automated short-term forecasts.

[38] ENA (March 2024), "Prequalification standardization report". Available online here
[39] Elexon (October 2025), "Market Facilitator Draft Delivery Plan". Available online here

- A **flexibility market team**, engaging and onboarding SPs and managing data validation and settlement

Systems used such as:

- DERMS.
- Localflex platform.
- Short-term forecasts (every 30 minutes for seven-days horizon).
- Long-term forecasts (for all 120,000 substations to 2050).

Added Value for Stakeholders and grid operators

Customers gain faster access and compensation for flexibility. UKPN benefits from a favourable regulatory framework:

- **TOTEX incentives**: DSO keeps 50% of any savings achieved (flexibility vs reinforcement).
- **Innovation funding**: Historically supported flexibility R&D.
- **DSO performance incentives**: Measure satisfaction of SPs and progress against KPIs.

Data Exchange

UKPN publishes:

- Daily needs by 10:00 AM.
- Dispatch and price results.
- All auction outcomes (Five-six years public archive).

SPs interact via APIs:

- Registration.
- Bidding and auction.
- Dispatch signals.
- Half-hour metering data uploads.

Current Challenges and Future Outlook

- Evolving the CBA to reflect the value of faster connections, not just investment deferral.
- Balancing the need for market innovation with harmonisation across GB DSOs and NESO (TSO)[40].
- Reviewing the £600/MWh cap to ensure it still drives optimal outcomes.
- Review and simplification of baseline methodologies.
- Reduction of minimum bid size below 10 kW.

B.7 Areti - Italy use case

Introduction

National Context

Italy is undergoing a major energy transition marked by electrification of heat, mobility, and distributed generation. Areti, the DSO for Rome, anticipates a significant peak demand increase—from 2.1 GW in 2022 to 3.3 GW by 2032. However, such peak levels are only expected to occur for around 1.000 hours per year, making full grid reinforcement an inefficient approach.

[40] More information available online at LCP-Delta-UPKN-Improving-Coordination-in-GB-Markets-2025.pdf

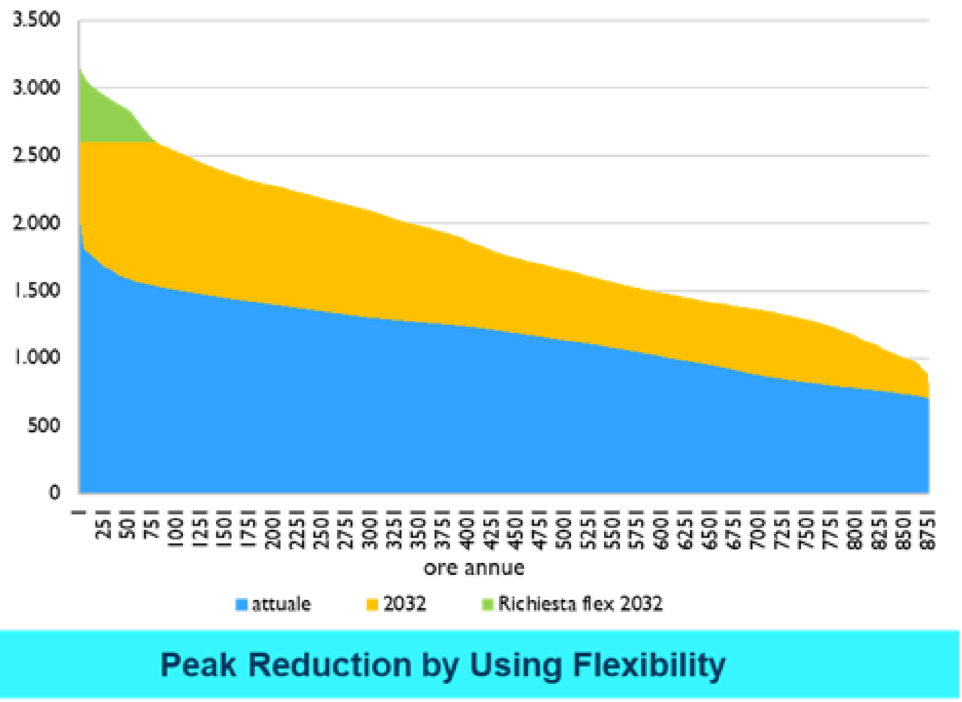

Figure 17: Forecast of peak load

Source: Internal resource from webinar conducted with ARETI

System Operator (SO) Challenges

Areti manages the 20 kV and 400 V grid in Rome and faces challenges in accommodating fast-growing electrification demands while keeping infrastructure investment costs under control. In the urban area, Areti faces consumption congestions whereas in the rural areas, it faces consumption and generation congestions.

With limited CAPEX availability and rising peak loads, Areti must optimise its grid management strategies by leveraging flexibility to defer or avoid costly reinforcements. Areti also faces a lot of reactive power problems because the underground cables are very close to each other.

Types of Congestion

Congestions in Rome are, and will be more and more in the coming years, driven primarily by winter peaks, especially in the evening during winter time (from 18h to 23h) and at midday during summer time (from 12h to 15h) due to widespread use of electric heating (heat pumps), electric cooking, and increasing penetration of EVs. These peaks lead to temporary overloads limited to 1.000 hours per year (above 2,5 GW at the state of today) in the medium and low voltage.

Driving Forces Behind Flexibility Solutions

The flexibility approach is driven by:

- EU funded innovation projects.
- Regulatory push by ARERA (Italian NRA).
- Economic need to avoid oversized, underutilised infrastructure.
- Availability of distributed resources (EVs, PVs, batteries, smart appliances).
- A mature technological architecture enabling market-based flexibility, based on the Platone Horizon project.

Evolution of Congestion Management

Areti’s congestion management strategy has evolved through years of EU-funded innovation projects, culminating in the RomeFlex initiative. Initially based on research pilots, RomeFlex is now for two years a fully operational local market co-developed with GME (Italy’s market operator). The platform has been in full operation for two years and is integrated into Areti's development plan approved by the regulator.

Areti is currently managing 22 MW of flexibility coming from 1.300 customers and 18 SPs, with a constant growth of the market liquidity in the last two years.

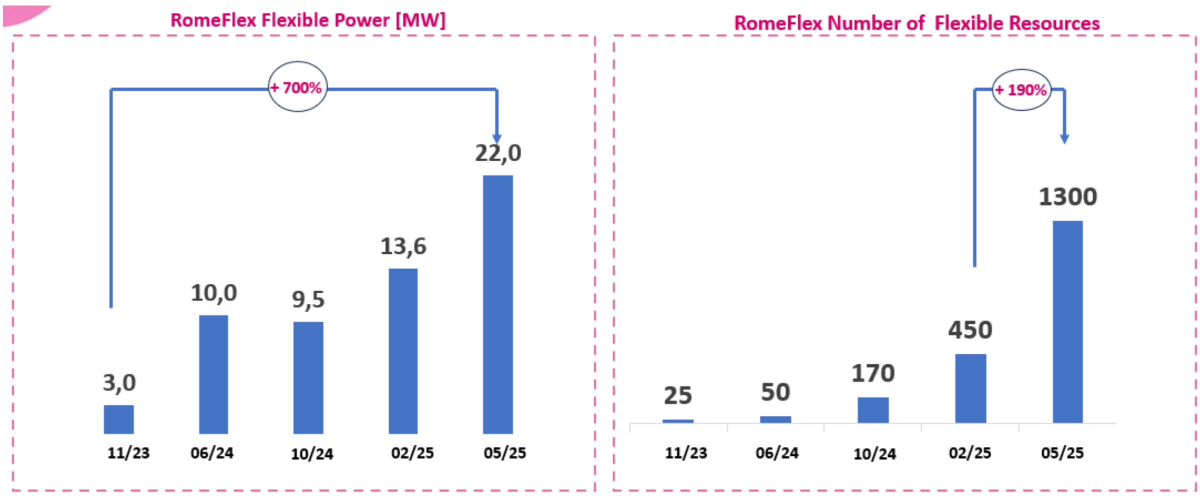

Figure 18: Evolution of flexible power and resources

Source: Internal resource from webinar conducted with ARETI

Congestion Management

Network Design Principles and Integration of Flexibility

Areti plans to reinforce its grid only up to 2.6 GW capacity. The remaining 700 MW of expected peak load will be addressed through flexibility measures, estimated to 250 GWh. Areti estimates that this approach will reduce the total annual expenditures by 45%[41]:

- 1.100 M€ until 2032 for full grid reinforcement scenario without flexibility.
- 480 M€ for grid reinforcement and 130 M€ for flexibility for optimal scenario combining both.

The urban areas are operated in a meshed way, and the rural areas in a radial way.

Flexibility Mechanisms

RomeFlex supports both mechanisms for upward and downward flexibility:

- **Forward market mechanisms**: Long-term capacity reservations (Three – nine months). SPs rewarded in this market have to offer in the daily Spot market, below the activation price which they offered. Capacity is paid based on the bid of the SP.

- **Spot market mechanisms**: Day-ahead activations for the next day's needs. SPs who are not rewarded in the long-term capacity market can participate nevertheless in the Spot market, but they are only paid for activation. Activation is paid based on the bid of the SP.

Participation in the markets is voluntary, and there are no penalties imposed currently in case the offered flexibility is not delivered. SPs must deliver at least 60% of the committed service to receive availability payment for that day. Activation payments are always done based on what is delivered by the SP.

Flexibility Products in Place

RomeFlex offers two core products:

- **Capacity (Availability)**: maximum price fixed at €60,000/MW/year, paid proportionally based on contracted time. A customer who is available for two hours a day for six months receives 2.500 €/MW.

- **Energy (Utilisation)**: Spot activations compensated based on the offer of the SP, at a maximum level up to €400/MWh.

[41] More information available online at Piano di Sviluppo 2025.

Products are granulated to 15 minutes, with minimum flex service size at 300W. This aligns with the resolution of Italy's smart meters. Customers participating need at least 3 kW. Areti can only procure active power services for the moment.

For the moment, imbalances generated via the activation of flexibility are not corrected nor paid to the BRP.

TSO-DSO Cooperation

RomeFlex is a natural extension of Terna's (TSO) market, leveraging the same interface (GME). Coordination is based on priority access for DSOs under the current pilot regulation. SPs can sell to either on TSO or DSO markets, with differentiated pricing rules to avoid double compensation.

Platform

The whole platform has been developed in various EU funded projects, among others the Platone project.

- The **Market Interface Platform (MIP)**, handles requests, clearing, certification (via blockchain), and communication between DSOs, BSPs, and GME. It also allows real-time aggregation of resources and management of local congestion zones.
- The **flexibility register** manages the qualification process for market participants, the registration of DER, the collection of measurement data and the baseline calculation.
- The **BSP platform** can be used by SPs to register and manage their resources, submit their bis and receive and send out activation signals. Small customers such as energy communities and single citizens (via the flexibility app) can rely on the BSP platform to send the activation signals directly to the customer devices via the Power Grid User Interface (PGUI). Big SP have their own platform to activate their assets via the PGUI.
- The **DSO technical platform** allows power grid simulations, weather forecasting and requesting of flexibility services.
- The **PGUI** is a device offered by Areti which is installed by the SP at the customers site, connected to the Smart Meter, and receives instructions and communicates measurement data from the flexibility register and activates the flexible assets. All participants in the flexibility market need this PGUI because it certifies the measurement data, builds up a certified baseline and confirms that the customer received the set point.

Areti does not display grid details when indicating where flexibility is required but sets up a list of resources per SP which can help to solve the grid issues (Dynamic Aggregates). These dynamic aggregates are communicated to the respective SPs.

All measurements are certified via blockchain and verified against baseline data. There have been no complaints until now about the settlement of the service.

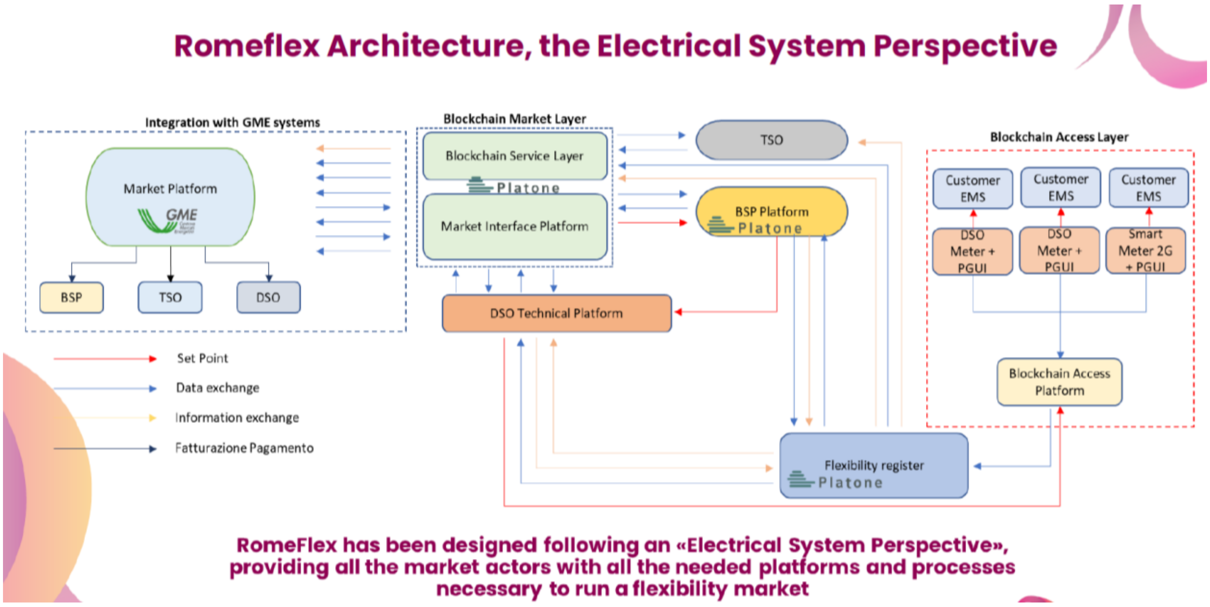

Figure 19: Romeflex Architecture

Source: Internal resource from webinar conducted with ARETI

Added Value for Stakeholders

- **Customers** earn revenue for providing flexibility, even at small scales.
- **Aggregators and BSPs** benefit from a unified market with no entry cost.
- **Areti** achieves a 45% reduction in expenditure compared to full grid reinforcement (objective to be realised).
- **Regulator (ARERA)** supports the model and enables cost recovery through tariff adjustments.

Data Exchange

All transactions—bids, set points, measurements, and settlements—are blockchain-certified. Real-time data is gathered via smart meters and PGUIs. The baseline is defined by the actual measurements of the five preceding days before the flexibility activation for similar hours. The flexibility register consolidates asset data, baseline calculations, and measurements to identify potential assets which can support the requested service and validate services delivered.

Areti does a product prequalification for each resource of each SP before admitting them to the market, and a grid qualification of each asset every 24 hours for the day after.

Current Challenges and Future Outlook

Current Challenges:

- **Limited liquidity** in the spot market.
- Regulatory constraints still limit **inclusion of reactive power** services.
- **Intraday market** not yet activated due to limited BSP participation.
- Need for **ongoing harmonisation** between TSO and DSO flexibility activations.

Future Outlook:

- Expansion of **residential flexibility base** (target: 4,000 households in next tender from currently 450).
- Potential introduction of **penalties** in 2026.
- Full integration of **intraday market** mechanisms.
- **Progressive national rollout** as other DSOs adopt the RomeFlex platform via GME, bringing new opportunities for SPs.
- Procurement of **reactive power services** if validated by the NRA.

Appendices

Appendix A: Advancements in the New EU Regulatory Framework for Demand Response

Directive (EU) 2019/944 on common rules for the internal market for electricity

The Directive establishes the foundational framework for distributed flexibility and demand-side response, identifying "demand side solutions" as a key component of the transition to a cleaner energy system. Historically, electricity consumers acted passively, often purchasing electricity at regulated rates disconnected from market signals.

Moving forward, consumers should be given the opportunity to actively engage in the energy market with the ability to control and optimise their energy usage. As renewable energy continues to expand its share in the energy mix, the future electricity system must use all available flexibility options - particularly demand-side solutions and energy storage - supported by digital technologies and the integration of innovative tools into the grid.

Within the Directive 2019/944, it is important to highlight:

- **Active Customers (Article 15)**
  Final customers have the right to generate, consume, store, or sell self-produced electricity and participate in flexibility or energy efficiency schemes without facing excessive barriers. These rights aim to empower consumers and encourage a decentralised, flexible energy system.

- **Demand Response through Aggregation (Article 17)**
  According to Article 17, Member States must support and enable demand response through aggregation. Final consumers, including those participating via aggregators, should be permitted to engage in all electricity markets alongside producers without discrimination. A significant legislative provision is that consumers may enter aggregation agreements without needing consent from their existing electricity suppliers. Aggregators are thus treated as independent entities, separate from both suppliers and BRPs.

- **Smart Metering Systems (Article 19)**
  To ensure consumers can engage meaningfully and receive the right incentives, EU legislation highlights the need for efficient and near real-time metering systems. Smart meters must be deployed to enable consumer participation in the electricity market. These devices provide real-time consumption data, supporting energy-saving behaviour, dynamic pricing, and energy-sharing schemes. Smart metering is essential for implementing dynamic contracts and integrating renewable energy effectively.

- **Flexibility in Distribution Networks (Article 32)**
  Member States shall incentivise DSOs to use flexibility services like demand response and energy storage to manage congestion and optimise network development. DSOs publish transparent network development plans every two years, considering alternatives to infrastructure expansion and promoting renewables and electrification.

Regulation (EU) 2019/943 on the internal market for electricity

The European Commission provides a clear definition of "demand side solutions", identifying them as responses to price signals within structured market environments.

- **Establishment of the EU DSO Entity (Articles 52-56)**
  The establishment is a significant step in formalising the role of DSOs in the evolving energy market. Article 55 assigns key tasks to DSO Entity that support the energy transition, including the coordination of distribution network planning with the operation and transmission network planning, the integration of renewables and distributed energy resources, and importantly, the facilitation of demand-side flexibility and response. This is consistent with the fact that majority of renewables (70% of as per 2030) and majority of EV charging and heat pumps will be connected to the DSO grid.

- **Charges for access to networks, use of networks and reinforcement (Article 18)**
  Network charges covering access, connection, and reinforcements must be **cost-reflective, transparent**, and designed to support **network security and flexibility**, without including unrelated policy costs. Tariff methodologies must reflect costs and provide **incentives for efficiency, innovation, and flexibility services.**

- **Cooperation between TSOs and DSOs (Article 57)**
  The cooperation foresees the exchange of all necessary data and information between TSOs and DSOs as well as the coordinated use of demand-side flexibility. This emphasises the **shared responsibility** and **mutual role** of TSOs and DSOs in the development and implementation of market-based frameworks within a **decarbonised power system.**

EU Electricity Market Design Reform (EMDR)

EMDR put **demand-side flexibility** and **energy storage** at the core of this strategy. Member States will be required to regularly assess their national flexibility needs and will gain access to funding mechanisms aimed at supporting the deployment of demand response and storage technologies.

Key elements of the reform related to distributed flexibility include:

- **Dedicated Measurement Devices (Regulation (EU) 2019/943 - Article 7b)**
  Where a final customer does not have a smart meter installed or where the smart meter of a final customer does not deliver the necessary data to provide demand response or flexibility services, TSOs and DSOs shall accept the data from a dedicated measurement device (DMD), where available, for the settlement of demand response and flexibility services, and shall not discriminate against that final customer in their procurement of flexibility services. Regulation (EU) 2019/943 **-** Whereas 18 - further clarifies: DMD data should be used for the observability and settlement of flexibility services only in those cases where smart metering systems are not yet installed and in cases where smart metering systems do not provide for the sufficient level of data granularity.

- **Trade on day-ahead and intraday markets (Regulation (EU) 2019/943 - Article 8)**
  Reduction of Minimum Bid Sizes: Lowering bid size thresholds in day-ahead and intraday markets aims to open participation to a broader range of actors, especially smaller flexibility providers.

- **Charges for access to networks, use of networks and reinforcement (Regulation - (EU) 2019/943 - Art. 18)**
  With the new provisions introduced for tariff methodologies, DSOs will need to account for both capital and operational costs in their tariff structures. This can improve the incentive to integrate flexibility services that can reduce operational costs and optimise grid investments.

- **Flexibility Needs Assessments, National Indicative Targets for Flexibility and Flexibility Support Schemes (Regulation (EU) 2019/943 - Articles 19e, 19f & 19g)**
  New provisions on the **Flexibility Needs Assessment** provides a **national outlook on necessary flexibility resources** for secure and efficient operation of future electricity systems. It enables Member States to establish non-fossil flexibility targets that can potentially lead to the implementation of support schemes for non-fossil flexibility when required. If existing capacity mechanisms are insufficient to meet flexibility targets, Member States may introduce additional financial support schemes to encourage non-fossil flexibility sources like storage and demand response.
- **FCAs (Directive (EU) 2019/944 - Article 6a)**
  The new provision introduces a regulatory framework allowing TSOs and DSOs to offer **FCAs** in areas with **limited or no network capacity**. In some cases, **flexible connections may be**

permanent solutions, especially where full grid expansion is not cost-effective. This can be relevant for some of the connections of **renewables**, **energy storage and electromobility.**
For DSOs, FCAs provide a valuable tool to integrate new customers faster and defer or alleviate infrastructure investments. In return, customers accept conditional access to the network, including potential curtailments when grid constraints arise.

New EU Methodology for Flexibility Needs Assessment

- As part of the EMDR, a key new EU methodology for assessing flexibility needs was envisioned through the recast of the Electricity Regulation that introduced the new Article 19e. This creates not just a new responsibility, but also a valuable opportunity for SOs to play a pivotal role in driving the energy transition.
- At the heart of this approach is a multi-step process designed to evaluate flexibility needs at both the national and EU levels.
- The first task handed over to DSO Entity and ENTSO-E was to develop an initial proposal for the methodology. Within nine months following the entry into force of new provisions, DSO Entity and ENTSO-E sent the proposal to ACER by April 2025 and, as of July 2025, it was formally adopted and published, marking the official launch of the flexibility needs analysis process at national level.
- Flexibility is becoming more critical for DSOs to operate and develop the grids cost efficiently to connect renewables and new decentralised loads. At the distribution level, DSO must manage congestion and voltage issues, which are local and must be solved where and when they occur.
- Until now, flexibility needs were assessed at the system level by TSOs, mainly for frequency management through studies such as adequacy assessments. The FNAM is the first initiative to specifically address network needs.
- As of July 2026, Member States will be required to report the flexibility needs of their electricity systems, as well as their transmission and distribution networks, at the national level. This assessment will play a key role in shaping national flexibility targets and, depending on the findings, may lead to the definition of flexibility support mechanisms at the national level.
- The FNAM defines a process that will be repeated every two years. This ongoing evaluation is critical for DSOs to provide visibility to SPs on the future flexibility needs and also to provide insights to policy makers to make flexible resources available in the future when forecasted flexibility needs will arise at DSO grids.

Appendix B: Detailed Comparison of Local Market aspects

The following tables in Appendix B give a general overview of the different DSOs, their challenges, and how they have set up their markets. For more detailed information on the different DSOs, please refer to Section B, in which you can also find links with more detailed information.

Table B1.1 - Comparison of general approach of DSOs

DSO	Grid operation (radial or meshed)	Grid challenges (rural/urban, production/consumption)	Network design principles and overbooking rules	CBA methodology
Alliander	- TSO mostly meshed - DSO mostly radial	- Primarily HV and MV, but LV levels also increasingly impacted - Generation as well as consumption challenges in rural and urban areas	- N-1 principle for consumption and generation - Overbooking strategy up to 150% of nominal capacity, managed via flexibility above 110% of physical flows	- No CBA - Financial limit on flexibility expense per congested area
UK Power Networks	More meshed in London, more radial in rural areas	Consumption and generation issues on primary and secondary substations, in rural and urban areas outside of London	Investment decisions are typically triggered when utilisation forecast reaches 100% in the next years	CBA done systematically for grid reinforcement projects. CBA calculates price cap of flexibility
E.ON Energy Networks and Göteborg Energi Nät	- Göteborg Energi Nät: Meshed network which is operated radially - E.ON Energy networks: radial and meshed	- Consumption issues due to electrification, industrial expansion and data centres in winter (November to March) and during maintenance - Aging infrastructure - Contractual congestions on TSO connections	Göteborg Energi: - N-1-principle used for consumption on HV and MV (with some exceptions). Generation N-0 or hybrid solution N-0,5 if not connected to meshed network - Overbooking based on expected aggregated load	Göteborg Energi: - No CBA conducted to compare with grid reinforcement on a regular basis - Price on flexibility markets mainly depending on price of infeed from regional DSO E.ON

DSO	Grid operation (radial or meshed)	Grid challenges (rural/urban, production/consumption)	Network design principles and overbooking rules	CBA methodology
		- Generation issues only start showing up	contribution in the system (not contract based) - Strict rules on when investments should be made are not implemented, mainly proactive measures with some margin, and mitigating actions if needed. N-1Rto be evaluated E.ON - Mainly N-1 for consumption and generation - Overbooking strategy up to 130% with FCA and flexibility markets	- CBA proactive before starting a new flexibility market - Reinforcements cost sets maximum cost for flexibility
E-REDES	/	- Generation issues today, consumption issues projected - TSO grid fully saturated for generation - DSO has limited congestions, but increasing	- N-1 for consumption and N-0 for generation - Investment deferral strategies are evaluated through CBA	CBA to compare grid reinforcement with flexibility
Glitre Nett	-TSO and DSO regional: meshed -DSO local: build meshed, but operated radial	- Capacity limitations in DSO grid and in the transmission system. - Rising electricity demand from new customers and industries. - Changing consumption behaviours among existing customers	- N-1 for consumption and N-0 for generation, with a 20% overbooking - Overbooking between 20 to 100 % is done via flexibility	No CBA to compare flexibility to grid reinforcement

DSO	Grid operation (radial or meshed)	Grid challenges (rural/urban, production/consumption)	Network design principles and overbooking rules	CBA methodology
Areti	- Urban area: meshed - Rural area: radial	- Consumption issues in urban area - Active and reactive power	/	/
Enedis	- TSO: meshed (HV) - DSO: radial (Enedis operates only MV and LV)	- Congestion issues on TSO HV network (complying with operational limits set by TSO at HV/MV transformers) for generation and possibly demand - Congestions issues on HV/MV primary substation for generation - Congestion issues on MV network or HV/MV transformers for demand	- Design based on CBA, which often results to N-1 for consumption and N-0 for generation - Investment deferral strategies are evaluated through CBA - Main use case (named 'ReFlex') in value and amount of flexibility needed is over-connection of RES on HV/MV transformers leading to about 30 % CAPEX increased efficiency while inducing minimal flexibility needs (less than 0.06 % of producible energy) as per 2019 prospective France wide study (now optimised as business as usual with globally consistent figures). Joint optimisation of HV network and HV/MV transformers between TSO and DSOs to optimise RES hosting capacity	CBA to compare grid reinforcement with flexibility between scenarios with or without flexibility (mainly cost of flexibility, losses, non-injected energy or lost loads, and difference of cost of investment at optimal vs. later date, or of other possible alternatives of technical solutions)

DSO	Grid operation (radial or meshed)	Grid challenges (rural/urban, production/consumption)	Network design principles and overbooking rules	CBA methodology
			(S3RENR framework).	

Table B1.2 - General principles for markets for local services

DSO	Platform used	Imbalance	TSO-DSO coordination
Alliander	GOPACS	No imbalances are created, because there is a bid and counterbid matching	TSO and DSOs coordinate their flexibility purchases via GOPACS, allowing vertical access to flexibility and prevention of congestion issues because of flexibility activations
UK Power Networks	EPEXSpot Localflex	- No balancing correction for the moment - A review of this is planned for 2026	- TSO and DSOs are part of the national effort to standardise data exchange and ensure interoperability between platforms - For activation of flexibility, the DSO has the first right
E.ON ENERGY NETWORKS and Göteborg Energi Nät	Nodes (E.ON ENERGY NETWORKS), Switch (Göteborg Energi Nät)	Not regulated by the market, customer responsibility, not regulated nationally, limited volume of flexibility	- Limited coordination between TSO, regional DSO and local DSO for flexibility - Cooperation exists between TSO and regional DSO on temporary subscriptions (operational limits) SO GL § 182 is under negotiation

DSO	Platform used	Imbalance	TSO-DSO coordination
E-REDES	Piclo	No balancing correction for the moment	- No harmonisation between TSO and DSO markets for the moment - TSO is informed about flexibility activations
Glitre Nett	Nodes	No balancing correction for the moment because of the limited volume of flexibility	- TSO-DSO coordination has been tested in Norflex project via a sequential purchase coordination: - DSO purchases flexibility first, afterwards TSO - TSO does not retrieve activation volumes for the moment because of the low volume
Areti	GME / Platone	No balancing correction for the moment	- Integration of local flex market into TSO market - SP can sell flexibility to TSO and DSO
Enedis	Enedis platform	- BRP neutralization since March 2023 - TSO handles system imbalance created by activation of local services and bills DSO for the imbalance adjustment costs	- DSO activates TSO flexibility needs in DSO grid and complies with operational limits set by TSO at HV/MV transformers while DSO solves in addition its own congestion and voltage issues - Coordination process in improvement and fully deployed by 2028

DSO	SP Qualification / Product Prequalification	Continuous or sequential markets?
Alliander	- SP qualification via TSO - Product prequalification via GOPACS and connecting SO	Sequential

UK Power Networks	National standardisation of SP (commercial) qualification and product (technical) prequalification	Sequential
E.ON ENERGY NETWORKS and Göteborg Energi Nät	Göteborg Energi Nät: - Simple product prequalification (information about SP, asset-ID, downward/upward, min and max bid size, measurement data, baseline information, group or unit) - Activation test before market season E.ON Energy Networks - Simple product prequalification (information about SP, asset ID, downward/upward, min and max bid size, measurement data, baseline information, group or unit) - Communication test for data exchange - Voluntary activation test before market season	Effekthandel Väst and E.ON: Continuous and sequential
Enedis	- Verification of the location of flexible sites + consistency between the sum of subscribed capacity of all registered sites and min bid size. - Activation tests to qualify SP and prequalify products, and train both SP and Enedis control room. Up to two failed communication tests and up to two failed activation tests are allowed for first product prequalification. - Assets do not need to be prequalified when participating in capacity reservation market, but SPU & SPG need to be prequalified in due time. For energy products, assets need to be prequalified before participation in the market.	Currently: Sequential (tender to select and qualify SPs & products according to pre-defined propensity to pay) and continuous (for availability)
E-REDES	- Simple product prequalification (voltage level, downward/upward, location and min size) - Grid prequalification only by E-REDES (only DSO) - Activation test after tender	Sequential
Glitre Nett	SP qualification (economic requirements)	Sequential
Areti	- Product prequalification: asset per SP - Grid prequalification: every asset day-ahead	Sequential

B1.3 - Product Design

All markets which have been reviewed by the EG DF procure their flexibility in advance (procurement of capacity) and activate it only when required day-ahead up to intraday (activation of energy). The procurement in advance makes sure that the flexible capacity is available when required, which is especially important when the flexibility is used as reinforcement deferral. For the activation, the offers in relation to the procured capacity are automatically transferred to the energy product, but additional offers can be submitted there by SPs (see Figure 14 below). The procured capacity is usually paid as a €/MW for making the capacity available (even without activation) whereas the activated energy is only paid when the flexibility is also activated and depending on how much energy is activated compared to the baseline.

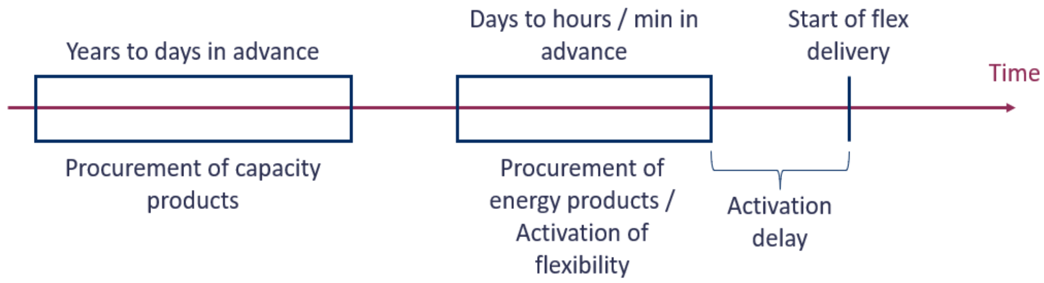

Figure 20: Process of procurement of capacity and energy and activation of flexibility

DSO	When are products procured	When are products activated	Minimum requirements (bid size)
Alliander	<u>Capacity Limiting Contracts</u> Procurement in advance (monthly availability fee) <u>Market-based redispatch</u> Intraday market when congestion appears	<u>Capacity Limiting Contracts</u> Activation day-ahead (activation payment) <u>Market-based redispatch</u> When procured	- 100 kW and 15 minutes - Aggregation rules to reach 100 kW under development
UK Power Networks	<u>Long-term auctions</u> Twice per year (pay-as-bid) <u>Day-ahead auctions</u> Day-ahead (pay-as-bid)	<u>Long term auctions</u> Two variants: utilisation is decided day-ahead, or pre-agreed <u>Day-ahead auctions</u> when procured	- Min bid size 10 kW (can be aggregated) - Min delivery: 60%

DSO	When are products procured	When are products activated	Minimum requirements (bid size)
Sweden (Göteborg Energi Nät)	LongFlex product Procurement in advance. Selected offers are automatically transferred to ShortFlex market Pay-as-bid (€/MW) Procurement is usually done in the beginning of the market season ShortFlex product Hourly activation on the ShortFlex market. Activation can be done starting from when the market opens six days before delivery and until market closure two hours before delivery Max usage product Capped power products of varying durations in the MaxUsage market. Procurement is usually done in the beginning of the market season	LongFlex and ShortFlex: Activation only via ShortFlex product. Pay-as-bid (€/MWh) Hourly activation on the ShortFlex market from market opening (six days before delivery) until market closure (two hours before delivery) MaxUsage: No further activation (activated when procured), the seller will promise to keep the consumption under an agreed limit at certain hours	- Min bid size for participation on the market 50 kW - Aggregation allowed
Sweden (E.ON ENERGY NETWORKS)	Season availability Tenders for availability before the season Availability Seven to two days before delivery Direct orders Two days up to three hours before delivery	Season availability Activation from day-ahead up to two hours before delivery Availability Activation day-ahead Direct orders Activation from day-ahead up to two hours before delivery	- Min bid size 100 kW - Aggregation allowed - Min delivery 75%
E-REDES	For all three products (Dynamic, Secure and Restore)	Dynamic Availability requested one week before	- Min bid size 10 kW - Min delivery: 85%

DSO	When are products procured	When are products activated	Minimum requirements (bid size)
	In advance for two years Pay-as-bid	Activation within a minimum of 15 minutes Secure Availability defined in product windows Activation within a minimum of 15 minutes Restore Availability defined in product windows Activation within a minimum of 15 minutes at failure moment	
Glitre Nett	LongFlex product Six months in advance up to the day of activation. Selected offers are automatically transferred to ShortFlex market Pay-as-bid (€/MW) ShortFlex product Seven days in advance up to one hour before activation	Activation only via ShortFlex product. Activation 1 hour in advance Pay-as-bid (€/MWh)	- Min capacity: 1 kW - Min duration: 1h
Areti	Forward market / Availability Availability procured in advance for three to nine months. Selected offers are automatically transferred to Spot market Spot market mechanism / utilisation Procured and activated day-ahead	Forward market / Availability Activation via Spot market mechanism / utilisation Spot market mechanism / utilisation Procured and activated day-ahead	- Min flex service: 300 W - Min asset size: 3 kW - Min delivery: 60%

DSO	When are products procured	When are products activated	Minimum requirements (bid size)
Enedis	Capacity reservation Tender to reserve capacity. Reservation and activation price submitted by SP. Activation price is Forwarded to energy products market. For capacity products awarded through tenders, penalties if SP fails predefined milestones, to qualify product in time needed Energy products Energy products are procured day-ahead or near real-time.	Capacity reservation no activation of flex via this product. Activation is done via energy products Energy product Energy products are activated when procured. Only activation payment in €/MWh	Min 500[42] kW (aggregated) and ½ hour duration

DSO	How are prices fixed	Is there a price indication	Baseline	Various
Alliander	Capacity Limiting Contracts Based on formula Market-based redispatch Pay-as-bid (only activation payment)	Capacity Limiting Contracts Based on formula Market-based redispatch No	Provided by customer	Penalty (based on formula) in case flexibility is not delivered. Grid operators tend to first contact SP before applying penalties.
UK Power Networks	Pay-as-bid	Max price and data from all past auctions are made publicly available (selected and	Various baselines in the past, incl. historic measurements Future: standard profiles for domestic	Assets must deliver at least 60% of their committed flexibility to receive any payment. There are currently no penalties applied, but around 75% of the

[42] Reduction to 100 kW when real-time observability is in place.

DSO	How are prices fixed	Is there a price indication	Baseline	Various
		non-selected offers)	customers and nominations for commercial and industrial customers	procured flexibility is delivered.
Göteborg Energi Nät	Pay as bid (for availability and activation)	ShortFlex Prices of all sell-orders and buy-orders are visible for market participants. LongFlex and Max Usage Maximum prices are indicated by DSO in tender requests. Prices and volumes of tenders are published on NODES publicly available website. In addition, market data, which includes reserved and activated volume as well as reservation and activation price, is also published on the website. The availability of market data contributes to	Different methods are available: 1. Average of meter data for the corresponding delivery period over the five preceding trading days. 2. Average of meter data for the corresponding delivery period over the five preceding trading days with meter value adjusted for activated volumes during that period. 3. The meter value the hour before the trade. 4. Average of meter data before and after delivery period. 5. SP can provide their own baseline including a description and motivation of method used.	ShortFlex Compensation based on delivery percentage. Delivery < 75 % = 0 compensation. Delivery > 75 % = compensation corresponds to the percentage of delivery, for example 80 % delivered = 80 % compensation. LongFlex Compensation for availability and activation. Compensation for activation is based on the same principle as ShortFlex. The compensation for availability is reduced based on the delivery. Max Usage Compensation for all delivered hours according to contract. Full compensation if below agreed limit and no compensation above the agreed limit.

DSO	How are prices fixed	Is there a price indication	Baseline	Various
		price indication[43].		
E.ON ENERGY NETWORKS	- Availability price is fixed - Activation price Pay-as-bid	Max, min and average price for all past auctions are official	Different methods are available: 1. SP can provide own baseline 2. Baseline based on measure ments in platform 3. 'Zero-principal baseline'	
E-REDES	Pay-as-bid (for availability and activation)	Yes, for availability and activation	<u>Consumption</u> Historic measurements (Eight days out of the last 10 workdays or two out of the last four weekend days) Solar / wind / hydric generation: neighbours' behaviour Storage: 0	<u>Compensation</u> Delivery < 85 % = 0 compensation. Delivery > 85 % and < 115 % = compensation corresponds to the percentage of delivery, delivery > 115% = 115% No <u>penalties</u> for the moment
Glitre Nett	Pay-as-bid (for availability and activation)	Max price they are willing to pay	SP can provide baseline or baseline based on measurements	
Areti	Pay-as-bid	Max price for availability and utilisation is published	Baseline based on measurement data from five preceding days similar hours	

[43] Data available online at : Dashboard | NODES

DSO	How are prices fixed	Is there a price indication	Baseline	Various
Enedis	Pay-as-bid	- No price indication for demand congestions - No publication for the moment, because not enough offers and activation (to not distort the market) - 2017 report of economic assessment of smartgrid solutions[44] provides visibility to the propensity to pay local services	Same baselines allowed as for balancing	

[44] Available online at rapport-valorisation-economique-des-smart-grids.pdf in French (see last 30 pages)