Compass Lexecon Energy

Market design to support a timely development of flexibility in European power systems

Key takeaways from successful case studies

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Contents

Glossary

ACER	EU Agency for the Cooperation of Energy Regulators
BESS	Battery Energy Storage System
BRP	Balance Responsible Party
CfD	Contract for Difference
CHP	Combined Heat and Power
CIS	Capacity Investment Scheme
CRM	Capacity Remuneration Mechanism
DC	Dynamic Containment
DM	Dynamic Moderation
DMP	Declared Market Price
DR	Dynamic Regulation
DSO	Distribution System Operator
DSR	Demand-Side Response
EBGL	Electricity Balancing Guideline
ENTSO-E	European Network of Transmission System Operators for Electricity
EU	European Union
EV	Electric Vehicle
FiP	Feed-in-Premium
FiT	Feed-in-Tariffs
FTR	Financial Transmission Right
GB	Great Britain

IA	Independent Aggregator
ISO	Independent System Operator
IRA	Inflation Reduction Act
LFM	Local Flexibility Market
NEBEF	Block Exchange Notification of Demand Response (*Notification d'Echanges de Blocs d'Effacement*)
NECP	National Energy and Climate Plan
NOVA	Grid optimisation first, before grid strengthening, before grid expansion (*Netz-Optimierung vor Verstärkung vor Ausbau*)
P2H	Power to Hydrogen
RES	Renewable Energy Sources
RES-E	Electricity from Renewable Energy Sources
RIIO	Revenues = Innovation + Incentives + Outputs
RPM	Reliability Pricing Model
RTO	Regional Transmission Organisation
SLA	Service Level Agreement
SNSP	System Non-Synchronous Penetration
ToE	Transfer of Energy
TRL	Technology Readiness Level
TSO	Transmission System Operator
UK	United-Kingdom
VRE	Variable Renewable Electricity
V2G	Vehicle to Grid

1 Executive summary

The challenge: Timely scale-up of flexibility in the power system alongside the growth of low-carbon electricity

As the EU substantially steps up its decarbonisation and renewable deployment targets in order to meet climate change mitigation pledges and alleviate the impact of the energy crisis triggered by Russia's invasion of Ukraine, its electricity sector is undergoing deep structural changes. To integrate an ever-increasing share of variable Electricity from Renewable Energy Sources (RES-E) while phasing out fossil-fuelled thermal power plants that provided baseload electricity, a considerable increase in access to sources of flexibility will be required in upcoming years to maintain security of supply and operate the power system at the lowest cost.

A common definition of flexibility refers to the ability of the relevant power system to adjust supply or demand in response to the evolution of supply and demand, otherwise leading to both anticipated and unforeseen imbalances, in order to continue operating reliably and resiliently. Flexibility needs in the power system therefore refers to supply and demand adjustments that can range from a few hours to several days, as well as the storage (and subsequent discharge) of electricity for periods between a day and a year.

Flexibility needs are estimated to represent around 360 TWh of daily energy transfers by 2030 in the EU, which will be an increase of 140% compared to the 150 TWh available today. This would be equivalent to close to 10% of gross electricity generation in 2030. By 2050, flexibility needs are expected to further triple compared to 2030 levels.

This paper aims to recommend best practices for developing and incentivising flexibility resources needed to help the EU meet its net zero targets while maintaining reliable power system operations. The proposed solutions recognise that while some resources can offer flexibility without substantial constraints (such as battery storage, heat storage, and residential EV charging), others face operational limitations that restrict their flexibility potential (including long-haul EVs, the duty cycles of which limit charging flexibility, critical services like hospitals, and continuous industrial processes such as chemical plants). The recommended incentive-based approaches take these operational constraints into consideration, ensuring a practical and balanced framework that can attract flexible resources while respecting the real-world limitations of different energy consumers and producers. This targeted approach allows for maximising flexibility potential where it exists while acknowledging the need to balance flexibility requirements against operational necessities in other cases.

The solutions: A diverse array of flexible resources is technologically mature

The increasing flexibility needs in the European power system will need to be met, in theory, by a portfolio of different technology options, and the range of low-carbon technologies which are available has substantially increased in recent years.

Different electricity storage options are being developed including various types of batteries – lithium-ion is the most common component but others exist, including compressed air energy, mechanical gravity energy, and flow batteries, all of which have different parameters in terms of duration and runtime. Additionally, there are several types of thermal, mechanical and chemical energy storage, where electrical energy is converted to another form of energy and re-converted back to feed into the grid when needed.

Similarly, active management of electricity demand particularly in residential and commercial buildings, industry, and transportation offers significant flexibility potential as consumption patterns can be adjusted and managed in relation to the electricity system needs, i.e. through the so-called demand-side response provided by distributed or behind-the-metre resources. The most prominent examples include the rise of electric mobility, through which EV batteries could charge and discharge according to the grid needs, the deployment of electric heaters in homes and industrial installations (heat pumps, electric boilers, and furnaces, amongst others) as replacements for fossil-fuelled alternatives, and the rise of solar self-consumption coupled with behind-the-metre batteries.

Enabling the development of such new flexibility sources creates challenges for regulators and system operators who need to ensure an adequate market and regulatory framework.

The critical enablers: The necessary evolutions of the market and regulatory framework to support investment in flexibility

At a European level, the need to adapt the electricity system's governing regulations and market rules to accelerate the roll-out of low-carbon flexibility is paramount and has led to several important regulatory evolutions.

- The Electricity Directive 2019/944 lays out the regulatory basis for all flexibility resources, including storage and demand-side response, to participate in energy markets by mandating that access to all electricity markets should be non-discriminatory.
- The Electricity Market Design reform adopted by the European Parliament and the European Council in 2024 in the aftermath of the energy crisis includes the improvement of flexibility in the power system as one of its key objectives.
- A new network code[1] is being drafted by ENTSO-E and the EU DSO Entity to ensure that demand-side flexibility has access and can participate in all electricity markets, including ancillary services and wholesale markets.

However, both regulatory implementation and the development of flexibility are lagging in many Member States. According to Eurelectric's Power Barometer 2024, the number of hours with zero or negative power prices in at least one EU country went from 150 in 2018 to 820 in 2023. Indeed, the market and regulatory framework for flexibility is unevenly developed across Europe and numerous barriers persist. In several Member States, flexibility deployment – both at a utility-scale and at distributed or behind-the-metre level – lags behind the development of RES-E due to a range of remaining hurdles, which vary according to Member States:

- Access to existing electricity markets can sometimes still be discriminatory for distributed flexibility resources (e.g. DSR and behind-the-metre storage or generation).
- The market design may not adequately reflect all the value associated with flexibility in the power system; in other words, the different benefits that flexible assets can bring are often inadequately rewarded by the current range of markets and products.

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1 Network codes are a range of binding texts defining precise harmonisation rules related to the electricity markets, system operations and access.

- In addition, the high capital intensity of flexibility resources and the significant uncertainties surrounding their future revenue streams due to power price volatility often make investment challenging in the absence of a de-risking contractual or regulatory framework.

In this context, this paper reviews several international case studies to identify key principles and best practices for an electricity market design and regulatory framework that would support the timely development of flexibility. We present a series of examples below of best practice policies to increase the participation and development of a broad range of flexible resources in European power markets, grouped into 3 key "pillars".

Pillar I: Address barriers to the participation of flexible resources in the different markets

The Clean Energy Package ensures the right for final consumers to participate in all electricity markets alongside producers through aggregation, i.e. the management of several consumption points by a single third-party operator. However, in practice, market access for distributed flexibility is still unevenly spread in the EU due to market participation rules hampering third-party aggregation of distributed units. For instance, ACER highlights that only five countries (Germany, Estonia, the Netherlands, Romania, and Slovenia) have fully opened all their balancing services to all types of new distributed energy resources.[2]

Moreover, even in markets where the regulatory framework supports the participation of all flexibility resources, including distributed and aggregated demand-side response, actual participation of these resources can be hindered by the lack and/or the inadequacy of eligibility and technical rules. For instance, in relation to aggregation, the Joint Research Centre of the European Commission points out that "*the secondary legislation and adaptation of market rules, procedures, responsibilities, […] are yet to be drafted in many of [the Member States]*".[3] This affects the participation of distributed flexibility in wholesale energy markets, but also balancing markets, and where applicable, capacity remuneration mechanisms.

Therefore, a key first step to foster the development of flexibility is to allow for third-party aggregation of flexible assets, in particular distributed and behind-the-metre, allow all types of resources to participate across all markets, and to reform existing market eligibility and technical participation rules so that they do not create barriers for small, distributed and energy storage assets. As an example, our report highlights how the French NEBEF[4] mechanism introduced in 2014 played an important role in enabling the development of demand-side response in France by addressing barriers to participation across different markets, providing a regulatory framework for the participation of Independent Aggregators (IAs) in energy markets without suppliers' consent, and streamlining the methodology applied by the relevant TSO for the certification of demand-side response volumes in wholesale markets. Volumes of demand response offered in the mechanism's tenders increased from 850MW in 2018 to nearly 3GW in 2024.

Pillar 2: Ensure that the market design adequately reflects the full value of flexibility for the power system

Another challenge for flexible resources is that the different services they can deliver to the power system may not be explicitly rewarded or monetised given the existing range of products and markets available. In other words, current electricity markets are often incomplete as the range of

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2 ACER (2023), Demand response and other distributed energy resources: what barriers are holding them back?, page 55.

3 Saviuc *et al* (2022) Explicit Demand Response for small end-users and independent aggregators, page 8.

4 Block Exchange Notification of Demand Response (*Notification d'Echanges de Blocs d'Effacement*)

products traded and the services rewarded by system operators may not explicitly remunerate all services that flexible resources can technically provide.

Moreover, flexible resources that can provide multiple services should be able to stack up the various revenue streams. However, the criteria for participation in existing markets can sometimes prevent the provision of other services; for instance, participating in the provision of reserve capacity might mean foregoing the possibility to engage in wholesale market arbitrages.

Therefore, a key principle to foster the development of flexible assets is to ensure that markets and products address the full spectrum of power system needs as well as technical capabilities of flexibility resources, include an efficient stacking up of revenues across markets, and foster active participation to optimise returns.

For instance, most flexible assets can ramp up and down quickly and provide fast ramp-up or balancing energy to system operators. As such, providing granular price signals in electricity markets and ancillary services to adequately reflect the value of fast ramping resources is key. The European harmonisation of the imbalance settlement period towards a 15-minute window should allow flexible assets to benefit from their complementarity with the ramping up and down of solar and wind.

Importantly, flexible resources should be able to monetise their contribution to a range of ancillary services that used to be provided implicitly by conventional power plants, such as fast frequency response, ramping capabilities, voltage control or black-start capabilities. Examples of initiatives to create markets that value those different capabilities include Ireland’s reform of ancillary services and California’s reform of its capacity remuneration mechanism, as detailed further in this report:

- In 2014, Ireland doubled the number of system service products from 7 to 14, to better reflect new services needed when operating the system with high levels of non-synchronous generation. New services include the provision of ramping margins and fast frequency response. Starting from a renewable penetration of 50%, the DS3 Programme achieved a 65% penetration in 2018 and 75% in 2022.
- In 2015, CAISO, the Californian ISO, added a ramping requirement in its existing capacity remuneration mechanism to ensure the system has enough flexible resources available to meet forecasted net load ramps.

Finally, flexible assets can be deployed at specific nodes of the network, including at distribution level, to address local system needs. Based on the review of international case studies in this report, harnessing the potential to locate flexible resources in the areas of the network where they are most needed typically relies on three main approaches:

- First, some countries have started implementing network planning approaches that take commercial flexibility into account as an alternative to traditional network reinforcement and expansion. In the UK, commercial flexibilities are explicitly included in the cost-benefit analysis used by the system operator (NESO) to identify the most advantageous network development solutions. For instance, out of 128 grid solutions suggested by NESO in 2022, the cost-benefit analysis identified eight commercial flexibilities solutions as beneficial. In Germany, the “NOVA”[5] principle applied by the TSOs to identify grid optimisation technologies that can delay reinforcement investments could be generalised as a framework to leverage the value of flexible

[5] Grid optimisation first, before grid strengthening, before grid expansion (*Netz-Optimierung vor Verstärkung vor Ausbau*)

assets as alternatives to grid expansion. This is not yet the case in Germany, could be expanded to allow for this.

- Second, regulatory frameworks for network operators that incentivise the use of local flexibility solutions to alleviate grid constraints are also a way to encourage the development of flexible assets in some specific locations. As an example, the UK's RIIO[6] price control framework includes incentives for DSOs to innovate and use flexible resources as an alternative to grid reinforcements. Similarly, some countries are implementing Local Flexibility Markets (LFMs) used by TSOs or DSOs to procure flexibility to address local issues. Although there are different approaches, a LFM is typically a marketplace where flexibility can be sold or bought at certain network nodes or in a limited geographical area. This allows system operators to use flexibility to solve congestion issues, minimise voltage drops, and defer grid expansion. LFMs have developed in several jurisdictions, including the UK, France, and the Netherlands.
- Third, the local benefits provided by flexible assets can be remunerated through energy market designs that have a locational price signal. There are several potential approaches to achieve this. In the US, many markets rely on nodal pricing by virtue of which both the supply-demand balance and the network congestions set the price of electricity at each node. Another approach could consider further granularity in the bidding zones used for market clearing – a bidding zone split is currently being discussed for different countries in the EU, along with the UK. However, these approaches raise political issues associated with the distributive effects of their associated benefits and costs.

Pillar 3: A de-risking contractual and regulatory framework is needed to support timely investment in flexible resources

Providing non-discriminatory access to existing markets and adequately valuing the various possible services of flexible assets may not be sufficient to foster timely investments in the required flexible resources. Indeed, a typical feature of many flexible assets is their high capital intensity and the large uncertainties surrounding their business case given either the lack of sufficient expected revenues, the volatility and unpredictability of the expected revenues, the need to revenue stack from a range of services/markets/contracts (impacting confidence and bankability), and the lack of information regarding long-term flexibility needs in the system. Finding a business case supporting investment in this context can therefore be challenging. In particular, the volatility and lack of predictability of revenues is perceived to hinder investments in flexible assets in many European markets, in the absence of a de-risking contractual or regulatory mechanism.

Ensuring the long-term predictability of revenues through de-risking market mechanisms is therefore essential to support the timely development of flexibility and meet the rapidly increasing system needs. These mechanisms can be tailored to the specificities of the asset classes they aim to support in terms of support duration, level of additional revenues, technical and operational requirements, in order to avoid a risk of lock-in of technologies that are not optimal for the lowest-cost operation of the power system. This approach is similar to the European support mechanisms for renewable electricity generation capacities that have been developed since the 2010s, or the USA's IRA, which provides direct funding in the form of investment or production tax credits.[7]

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6 Revenues = Innovation + Incentives + Outputs

7 United States Environmental Protection Agency, Summary of Inflation Reduction Act provisions related to renewable energy.

More precisely, mechanisms to support investment in flexible resources typically aim at solving one or several of the following issues:

- A missing money issue**:** The level of revenues that can be captured in electricity and ancillary services markets may be insufficient for asset owners to cover their total costs, although their assets are needed to operate the grid reliably. Market failures such as market concentration, market price or capacity caps might limit revenue opportunities for flexible assets, despite those assets being required for the system's operation.
- Uncertainty regarding future profitability and revenues: When taking investment decisions, investors and lenders seek to balance out the certainty of revenues with the asset risks and costs, in order to evaluate whether the rate of return for the project is acceptable, when balanced against the risks involved. Revenue uncertainties can emerge from different sources, such as volatility in market prices, lack of predictability over future revenue streams, competitive landscape, market design or policy uncertainties.[8]
- Lack of information regarding long-term flexibility needs: To provide appropriate information to investors about the locations, amounts, and periods during which flexibility is needed for a secure power system at the lowest cost, an integrated and co-ordinated planning framework may in some cases be lacking.

To tackle these different issues, several types of contractual and regulatory approaches are possible. These approaches would provide visibility to investors and help them secure revenues while addressing the issues highlighted above. Investment can be supported through the following mechanisms, which have all been deployed in some areas:

- A flexibility contracting scheme, where required investments in flexible capacity are incentivised with a contracting mechanism dedicated to fulfilling flexibility needs. Ireland reformed its ancillary services markets to double the number of contracted products while introducing long-term contracts for capital-intensive flexibility assets.
- A joint optimised contracting mechanism, where the required investments in flexible capacities are incentivised through a single mechanism co-optimising the contracting of flexibility needs as well as firm capacity needs. CAISO's ramping requirements embedded in capacity tenders have successfully attracted investments in flexible resources.
- A simple firm capacity contracting mechanism such as a Capacity Remuneration Mechanism (CRM), although not targeted at flexibility resources, can provide tailored contracts durations to flexible assets, remunerating only the firm capacity they can provide while securing enough additional revenues and predictability to de-risk investments. France's flexibility contracting tenders and Poland's CRM (as well as other CRMs in Europe) have also attracted new projects of flexible assets.

There are several examples of de-risking contracting or regulatory mechanisms that were successful in de-risking the business case for additional flexibility, as outlined in the Appendices. For brevity, we highlight two examples in this summary:

- A simple firm capacity contracting mechanism coupled with a targeted flexibility contracting scheme allowing for premiums: France implemented such a mechanism to remunerate flexible assets with capacity payments in addition to the remuneration of the CRM for their availability in

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8 European Commission (2023) State Aid SA. 104106 (2023/N) – Italy - Support for the development of a centralised electricity storage system in Italy, page 3.

critical periods for the system, including both peak hours or scarcity events. In that sense, France's mechanism is a mixture of a targeted flexibility contracting scheme and a firm capacity contracting scheme. The scheme was initially targeted at DSR resources, which could benefit from single or multi-year contracts of up to 10 years through call for tenders. This mechanism has been a key driver for the development of DSR in France, and resulting contracted volumes have risen over the last years from 1.9 GW in 2022 to 2.9 GW in 2024, which represents approximately 3% of peak demand. The French DSR tenders are in the process of being replaced by a wider mechanism to support low-carbon flexibility sources. From 2025 onwards, participation will be open to wider flexibility technologies beyond DSR, such as storage assets. Selected participants can then offer flexibility across energy markets, from day-ahead to ancillary services.

- CAISO implemented flexible capacity requirements in its capacity mechanism in 2015: In 2006, CAISO implemented a resource adequacy program that requires suppliers ("load serving entities") to ensure system reliability by demonstrating each year that they have sufficient capacity commitments to satisfy their expected peak demand in the forthcoming summer peak season. In 2015, CAISO added a ramping requirement in its existing capacity market to ensure the system has enough flexible resources available to meet forecasted net load ramps. This mechanism was implemented to fulfil an increasing need for flexibility in the Californian system due to the large penetration of intermittent renewables, which could not be addressed via the existing reserves at the time. In terms of capacity procured, sufficient flexibility has been present on the system since the introduction of the mechanism, in that the flexible resources adequacy procurements were sufficient to meet the actual maximum net load ramps for all months in 2022. However, no significant price premium was achieved for assets able to provide both flexibility and firm capacity.

As an overall conclusion, it is important to note that there is no 'one-size-fits-all' market design approach for every European country to foster the development of flexibility resources, but that there are several common principles and best practices which can support the deployment of flexibility in EU power systems. The investment needs and appropriate investment mechanisms for flexible resources vary across countries and regions, reflecting differences in power system needs. As such, the best regulatory and market framework at national or regional level depends on several dimensions, including the current generation mix, the future mix reflecting policy targets, the installed flexible capacity and the type of flexibility needs, the presence of local congestions, and the current and planned interconnections with neighbouring countries.

2 Introduction: Fast-tracking the development of flexibility is key for a successful energy transition in the EU

Flexibility refers to the ability of the power system to adjust supply or demand efficiently in response to evolutions of supply-demand equilibrium or unforeseen imbalances. This concept is essential to maintaining grid stability and is set to become an even more important issue in the future.

The development of intermittent generation in the electricity sector is creating a need for greater flexibility in the grid, and at various timescales – from within a day to within the year. These increasing flexibility needs can be met by several technology options, including storage and distributed flexibility.

However, despite the value flexibility brings to the market and despite growing flexibility needs, the regulatory framework for flexibility is unevenly developed across the EU and different barriers persist.

This section presents:

a. The new challenges associated with the increasing penetration of renewables and the ramping needs for flexibility;

a. The new technology opportunities with which flexibility requirements could be met;

b. The current barriers hindering the development of flexible assets in Europe.

1.2 New challenges: The development of variable generation and the electrification of end-uses increase the need for flexibility

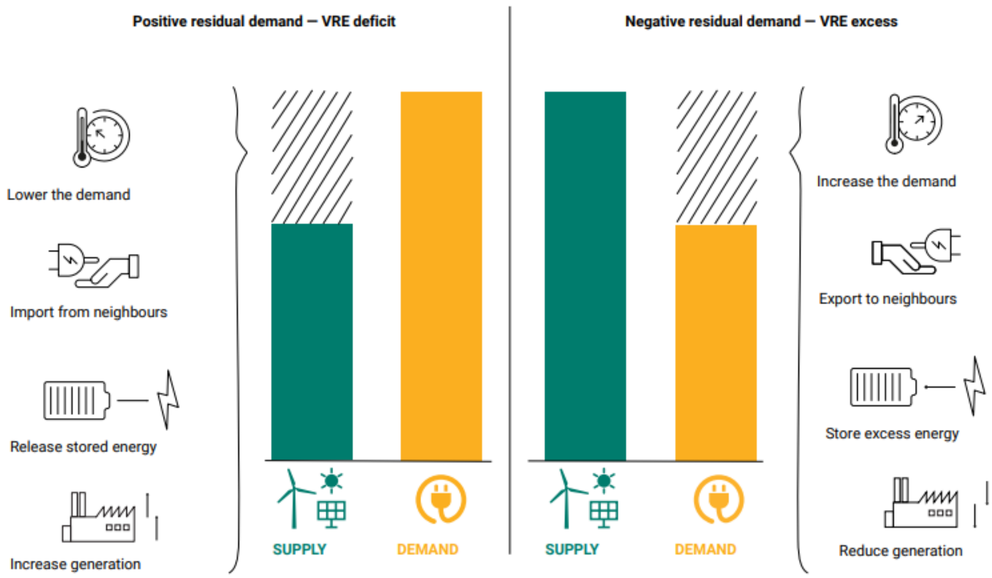
The increasing supply of energy from non-dispatchable renewable sources, like wind and solar power,[9] raises several challenges for the power system's stability and adequacy. New flexibility sources will play a critical role in contributing to the overall balance of supply and demand and in accommodating the increasing penetration of renewables. Key challenges include:

- Residual load dynamics: Renewable generation is characterised by rapid fluctuations with, for instance, daily solar generation patterns, weekly wind generation fluctuations or seasonal weather patterns. Combined with load fluctuations, this creates a need for flexibility at various timescales, from daily to seasonal. During periods of low renewable production, electricity demand needs to be met either by increasing controllable electricity generation, which is primarily gas-fired at this time, reducing demand, importing from other market zones or

9 Dispatchable renewable sources include for instance hydroelectricity, biomass to power, waste to energy. These technologies do not raise flexibility needs.

discharging stored energy to the grid. Conversely, during periods of renewable surplus, excess is managed by decreasing controllable generation, increasing electricity demand, exporting to other market zones or charging storage units from the grid. This can be quantified by assessing the dynamics of the residual load, defined as the difference between electricity demand and renewable supply, as shown in Figure 1.[10]

Figure 1 – Residual Demand Scenarios



Source: EEA & ACER (2023) [Flexibility solutions to support a decarbonised and secure EU electricity system](), page 14.
Note: VRE stands for Variable Renewable Electricity

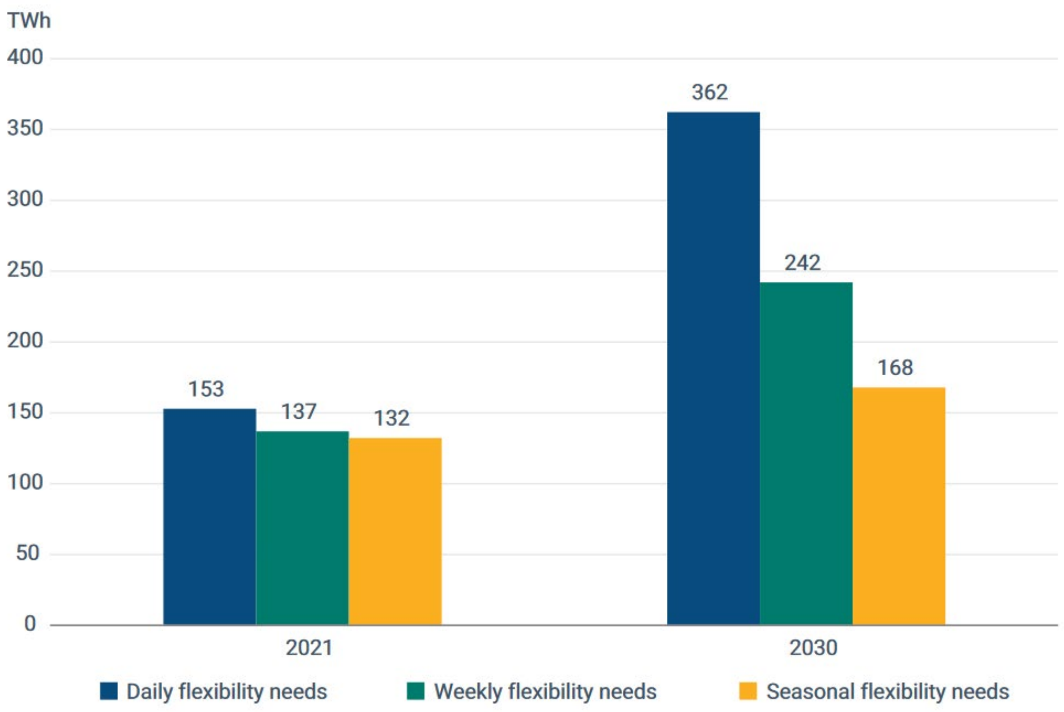
- Imprecision in forecast: The rise in renewable capacity creates uncertainty regarding the actual generation output. This creates risks of imbalance close to real time that need to be offset by some short response time flexibility, of the magnitude of seconds to minutes, and energy capacity of minutes to hours.
- Network congestions: The rise in distributed generation places increasing strain on transmission and distribution networks, particularly at the local level. This issue can be addressed either by reinforcing the network infrastructure or by implementing and/or leveraging localised flexibility sources.
- Power network or generation failure: Failure in the power system assets, whether it is a power line, a generator or substation among others, can induce an imbalance in the supply-demand equilibrium with very little to no notice, requiring a fast response. Traditionally, large centralised thermal and hydro plants had to provide the bulk of the operational flexibility required to secure the power system. The fall in operational hours and progressive phase-out of thermal plants hence makes it necessary to leverage other sources of flexibility, including DSR and behind-the-metre generation or storage.

Overall, by 2030, the electricity system in Europe may need more than twice the current amount of flexibility resources to meet system needs, with flexibility needs expected to increase across

10 Koolen *et al* (2023) Flexibility requirements and the role of storage in future European power systems; EEA & ACER (2023) Flexibility solutions to support a decarbonised and secure EU electricity system

different timescales (e.g., daily, weekly, seasonal). By 2030 for instance, ACER estimates that daily flexibility requirements might increase by a factor of 2.4 compared to 2021, from 153 TWh/year to 362 TWh/year, as shown in Figure 2. This would represent close to 10% of gross electricity generation in 2030.[11] Over the same time horizon, weekly and seasonal flexibility requirements would increase by a factor of 1.8 and 1.3 respectively.

Figure 2 - Daily, Weekly, and Seasonal Flexibility Needs in 2021 and 2030 in Europe



Source: ACER & EEA (2023) Flexibility solutions to support a decarbonised and secure EU electricity system, page 17.

2.2 New opportunities: New technology options can provide flexibility on both the demand (including behind-the-metre) and supply sides

Historically, flexibility has been provided by traditional centralised power generation assets and grid interconnections and has been extended to demand response in electro-intensive industries with large process loads. However, new flexibility options on the demand and supply sides can be leveraged, in particular energy storage and demand-side response.

Energy storage

Energy storage is widely regarded as a key flexible technology for the energy transition, including by the European Commission which refers to it as a key technology to provide the necessary flexibility, stability, and reliability of the whole energy system.[12] Energy storage technologies are diverse and usually well-suited to provide frequency containment and reliability services to the

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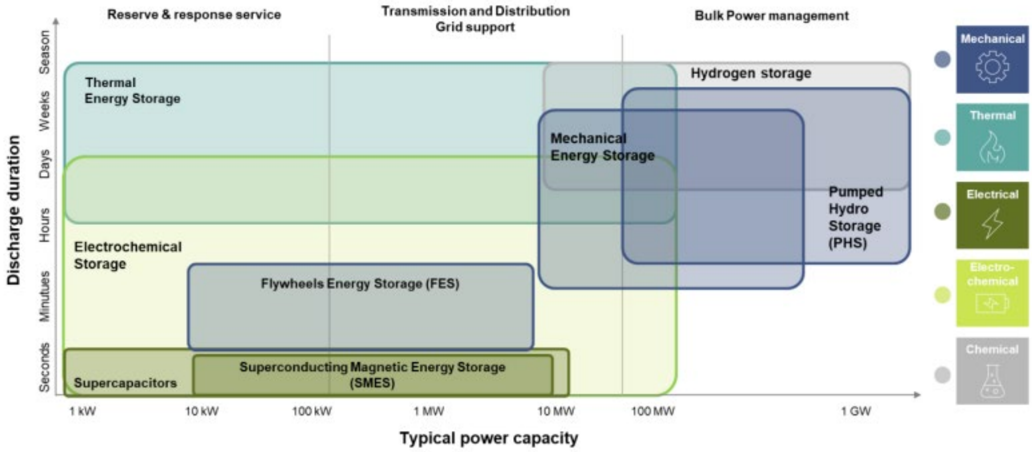
11 Gross electricity generation is forecast at 3362 TWh/y, in European Commission (2024), Commission Staff Working Document - Europe's 2040 climate target and path to climate neutrality by 2050 building a sustainable, just and prosperous society, Table 10.

12 European Commission (2023), Commission Staff Working Document – Energy Storage – Underpinning a decarbonised and secure EU energy system, page 14.

power system while contributing to decarbonisation goals, as illustrated in Figure 3. Energy storage can be developed both at a utility-scale and as behind-the-metre solutions.

Moreover, the maturity and competitiveness of energy storage in terms of costs and capacity is improving worldwide. [13] This is particularly the case for batteries, with for instance an 80% decrease in the price of lithium-ion batteries between 2013 and 2023. [14]

Figure 3 – Power Ranges and Discharge Duration of Different Energy Storage Technologies



Source: EASE (2022) Energy Storage Targets 2030 and 2050: Ensuring Europe's Energy Security in a Renewable Energy System, page 9.

Demand side response

Demand side response, or DSR, describes the adjustment of consumption patterns in response to market signals or system operators' activations. [15] The contribution of DSR to system flexibility in Europe could be substantial: the theoretical DSR potential was estimated at 110 GW in 2016, of which only 21 GW was considered as active in 2019. [16] Moreover, by 2030, the DSR potential is expected to further increase, driven by the electrification of new end-uses in transport, buildings, and industry, and could reach 130 GW to 160 GW according to the European Commission. [17]

In practice, DSR relates to a range of different consumers, with different constraints and costs, and a range of different commercial approaches and business models.

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13 See for instance: BloombergNEF (2024) Lithium-Ion Batteries are set to Face Competition from Novel Tech for Long-Duration Storage: BloombergNEF Research

14 BloombergNEF (2023) Lithium-Ion Battery Prices Hit record Low of $139/kW

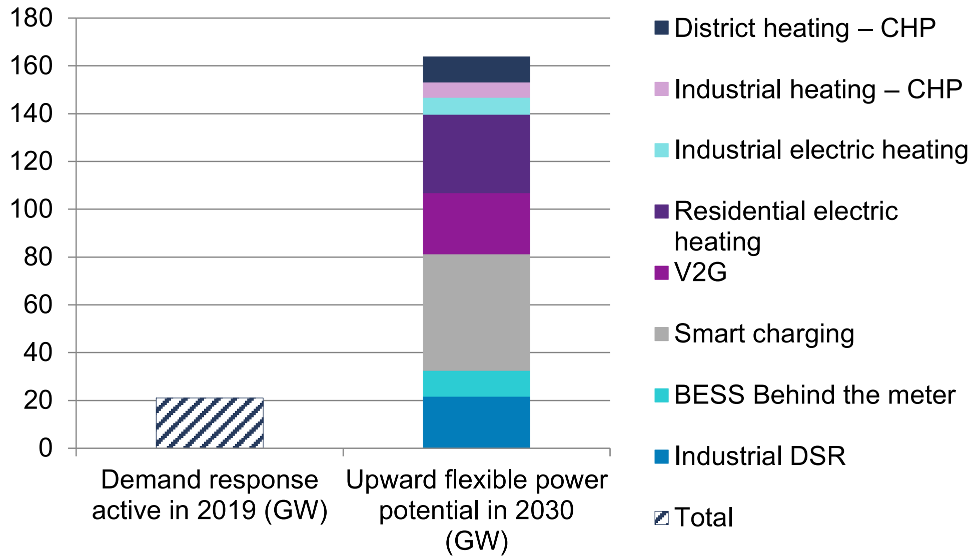
15 Demand response is defined in the Electricity Directive 2019/944 as a "change of electricity load by final customers from their normal or current consumption patterns in response to market signals, including in response to time-variable electricity prices or incentive payments, or in response to the acceptance of the final customer's bid to sell demand reduction or increase at a price in an organised market". Directive (EU) 2019/944 of the European Parliament and of the Council on common rules for the internal market for electricity and amending Directive 2012/27/EU, hereafter Electricity Directive 2019/944/EU, page 16.

16 European Commission (2023) Commission Staff Working Document – Reform of Electricity Market Design, page 59.

17 European Commission (2023) Commission Staff Working Document – Reform of Electricity Market Design, page 58; Smart Energy Demand Coalition (2017) Explicit Demand Response in Europe – Mapping the Markets 2017

First, the large range of different consumers entails various approaches for industrial, residential, or commercial consumers. The ability to provide capacity, both upward and downward, minimum reaction time, and maximum activation duration widely differ across consumer types, creating value in aggregation. Currently, DSR mainly originates from industrial consumers, capable of activating large volumes of flexibility for several hours or more. However, the potential for commercial and residential flexibility remains largely untapped. The flexibility potential of smaller electricity users might increase in conjunction with the electrification of transport and heating through the uptake of electric vehicles and heat pumps respectively as well as the roll-out of smart metres across Europe.[18] Figure 4 illustrates the potential of upward flexibility per DSR technology in 2030 based on smartEn data.[19]

Figure 4 - Current and Projected DSR Capacity in the EU



Source: Compass Lexecon based on smartEn (2022) Demand-side flexibility – Quantification of benefits in the EU, page 17 and European Commission (2023) Commission Staff Working Document – Reform of Electricity Market Design

Note: CHP: Combined Heat and Power, V2G: Vehicle to Grid, BESS: Battery Energy Storage System. The flexible capacity in 2019 streams from multiple sources.

The cost of activating DSR can vary significantly between consumers, depending on the type of underlying consumption patterns and technologies. In the industrial sector for instance, reducing electricity consumption may trigger a reduction in industrial production, and companies may have different opportunity costs associated with momentary loss of production and thus revenues. In the residential sector, acceptable discomfort levels associated with a reduction in electricity consumption may not be the same for all consumers. The amount of revenues that DSR providers would expect before reducing their consumption can hence vary significantly between consumers. In turn, in electricity markets, the market price beyond which DSR would be activated can also vary significantly.

Second, the generic DSR term encompasses a diversity of commercial approaches and business models, which can be broadly partitioned into two categories:

- Implicit DSR can be defined as customers reacting to retail price signals, by shifting their consumption patterns to minimise their bills. Implicit DSR can be triggered for instance by

18 Schittekatte *et al* (2021) The regulatory framework for independent aggregators, page 1.

19 smartEn (2022) Demand-side flexibility – Quantification of benefits in the EU, page 17.

day/night tariffs or critical peak pricing[20] that enable the optimisation of consumption. Since retailers are responsible for the pricing available to clients, they are well-positioned to offer innovative tariff designs that can incentivise implicit DSR. As a result, retail clients, whether industrial, commercial or residential, may believe that their flexibility is sufficiently rewarded through implicit means and may therefore be less inclined to participate in the provision of explicit DSR.[21]

- Explicit DSR refers to a change in electricity consumption following the acceptance of a bid to sell demand reduction or increase in an organised electricity market, like balancing markets, day-ahead or intraday markets. Explicit bidding can be implemented through direct participation or through aggregation. Aggregation is defined in the Electricity Directive as the combination of multiple customer loads or generated electricity for sale, purchase or auction in any electricity market.[22] This role can be fulfilled by aggregators, regardless of whether they are suppliers or IAs.

This diversity of commercial approaches has been supported by the development of IAs – who, as defined by the Electricity Directive, are "*not affiliated to the customer's supplier*"[23] – providing flexibility offers to consumers, in addition to electricity suppliers. Whilst suppliers can also contribute to the development of DSR, they may face a commercial trade-off, as offering DSR services could affect their core energy supply business model by potentially reducing overall consumption.[24]

2.3 Despite the value that flexibility brings to the market, the regulatory framework is unevenly developed across Europe and different barriers persist

At European level, a legal framework has been established to facilitate the participation of all flexible assets in electricity markets. However, its effective implementation at national level remains partial in practice.

Moreover, several barriers to the development of flexible assets persist:

- access to existing electricity markets is still discriminatory for some flexible assets, especially distributed assets;
- the market design may not adequately reflect the real value of flexibility for the power system;
- the investment framework might sometimes be inadequate to ensure sufficient development of flexible assets.

2.3.1 A European legislative framework fosters the participation of all flexible assets in energy markets, although its effective implementation at national level is still incomplete

The Electricity Directive 2019/944 lays the regulatory basis for all flexibility resources, including energy storage and DSR, to participate in energy markets, as access to electricity markets should

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20 Retail electricity prices that very with the availability of supply in the power system and increase when the system is tight, i.e. during peak times.

21 Saviuc *et al* (2022) Explicit demand response for small end-users and independent aggregators, page 8.

22 European Commission (2019) Electricity Directive 2019/944/EU, page 16.

23 Voltalis and EnergyPool are examples of companies participating in electricity markets as IAs.

24 Note that not all DSR result in energy consumption decreases, it can also be displacing consumption. Schittekatte et al. (2021) The regulatory framework for independent aggregators, page 1.

be non-discriminatory.[25] More specifically, for DSR, this means removing barriers so that final customers can participate in explicit as well as implicit demand-side flexibility, sell self-generated electricity, and participate in flexibility schemes, and allowing third parties to manage their installations. Storage is better reflected as well in demand-side flexibility due to behind-the-metre solutions. Member States are expected to transpose this to national law by but both transposition and implementation are not at sufficient levels at this point..

In 2024, a set of measures to reform the electricity market design were adopted by the European Parliament and the Council, with the improvement of flexibility in the power system identified as a key objective. This includes a standardised assessment of flexibility needs, support for flexibility, including storage and DSR, as well as a range of peak-shaving products. The latter refer to products that can be deployed by Member States in case electricity prices become excessively high, and which remunerate consumers for reducing their demand during peak hours. This reform recognises the need to set up an investment framework for flexibility, but the specific provisions (contracts, types of support, etc.) can be defined at national level to attract investors.[26]

A network code is being drafted aiming at ensuring access for demand-side flexibility and other relevant resources to all electricity markets, including ancillary services and wholesale markets. Although the timing of the process remains unclear, the objective is for the final text to be agreed upon through the comitology process and to become binding regulation, following three steps:

- ACER has published a non-binding Framework Guideline on Demand Response which defines objectives, principles, processes, definitions, and high-level requirements of demand response that should guide the drafting of a Network Code.[27]
- On 9 March 2023, the European Commission invited ENTSO-E and the EU DSO Entity to submit a proposal to ACER for a network code specifically addressing demand-side flexibility within 12 months.[28]
- After ACER's opinion on ENTSO-E and EU DSO's proposals**,** the European Commission may submit the resulting text to the comitology procedure.

2.3.2 Despite large potential benefits and recent policy and regulatory developments at EU level, flexible resources still face several barriers

A range of regulatory, market design, and associated business model hurdles may continue to hinder the development of flexibility in Europe as outlined below and detailed in the following Pillars 1, 2, and 3 of this report.

Access to existing electricity markets is still discriminatory in some Member States

This is particularly the case for distributed flexibility resources (e.g. demand-side response and behind-the-metre storage or generation): the access to electricity markets for aggregators and demand-side flexibility providers is still limited in many EU countries. Smaller units and decentralised demand-side flexibility are not always allowed to participate. Not only does the participation of all distributed flexible resources need to be legally allowed in all market segments

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25 Directive (EU) 2019/944 of the European Parliament and of the Council on common rules for the internal market for electricity and amending Directive 2012/27/EU, hereafter Electricity Directive 2019/944

26 European Parliement – Revision of EU electricity market design

27 ACER (2022) Framework Guideline on Demand Response

28 ACER (2022) Press Release

through the transposition of EU law, but adequate technical rules and modalities also need to be introduced to ensure the effective participation of demand-side flexibility.[29]

The market design does often not reflect the full value of flexibility for the power system

The different benefits that flexibility brings to the system are often not rewarded or monetised at their full value. Many countries do not have markets or contracting mechanisms to procure and remunerate the different services that flexible resources can provide to the system.

Moreover, the possibility to stack up flexible services and associated revenues can sometimes be limited. Flexible assets can provide different services to the system and should be able to participate in different markets in parallel. However, even when all flexible assets are allowed to participate in multiple markets, the latter can sometimes be mutually exclusive, which limits the opportunities for stacking revenues and consolidating their business case.[30]

A de-risking contractual and regulatory framework is needed to support investment in flexible resources

The high capital intensity of flexibility assets and the significant uncertainties surrounding their revenues may hamper their development, in the absence of a long-term investment framework to provide targeted support. Designing additional mechanisms to support the development of flexible assets might be required in addition to the two previous sets of suggested regulatory improvements.

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29 See for instance: Saviuc *et al* (2022) Explicit Demand Response for small end-users and independent aggregators, page 3.

30 European Commission (2023) Commission Staff Working Document – Energy Storage – Underpinning a decarbonised and secure EU energy system

3 Pillar I: Addressing barriers to the participation of flexible resources in different markets

According to Electricity Regulation 2019/943, EU Member States must ensure non-discriminatory access for all market actors in all wholesale electricity markets.[31] This principle of non-discrimination covers different aspects. Markets must be open to all technologies, including DSR and energy storage, and to existing and new assets, individually or through aggregation, regardless of their location on the network, i.e. whether assets are connected to the transmission or distribution networks. Given the diversity of technical solutions and business case associated with flexibility, ensuring non-discriminatory access to all electricity markets is hence a key principle to foster the development of flexible assets.

Utility-scale and distributed flexibility resources are characterised by very different features, for instance in terms of typical asset size, need for aggregation, and technical constraints. These assets may face distinct discriminatory barriers. Market access for utility-scale flexibility resources, including battery storage, has largely improved over the past decades in Europe overall, although some countries have less installed capacity due to a lack of immediate need. However, market access for distributed demand-side resources is uneven across the EU, and the next Pillars mostly focus on the barriers encountered by this type of assets.

Pillar I first outlines the key legal barriers for the development of flexibility and highlights the lack of adequate technical rules and modalities to ensure the effective participation of flexible assets, before presenting some best practices implemented in several countries where these legal and regulatory barriers have been successfully removed.

3.1 The participation of all flexible resources needs to be allowed in all market segments, either directly or through aggregation

Despite the fact that the Clean Energy Package ensures the right for final consumers to participate in all electricity markets alongside producers through aggregation, market access for distributed flexibility is still uneven in the EU. This is due to two main factors: a lack of legal eligibility of certain types of distributed assets to participate and a lack of regulatory framework or legal eligibility for third-party aggregation of distributed units.

3.1.1 Some flexible resources are still not allowed to participate in several electricity markets

For instance, in the day-ahead and intraday markets, ACER points out that the legal eligibility to participate is still limited for some assets, especially in the Czech Republic, Hungary, and Slovakia, as shown in Figure 5.

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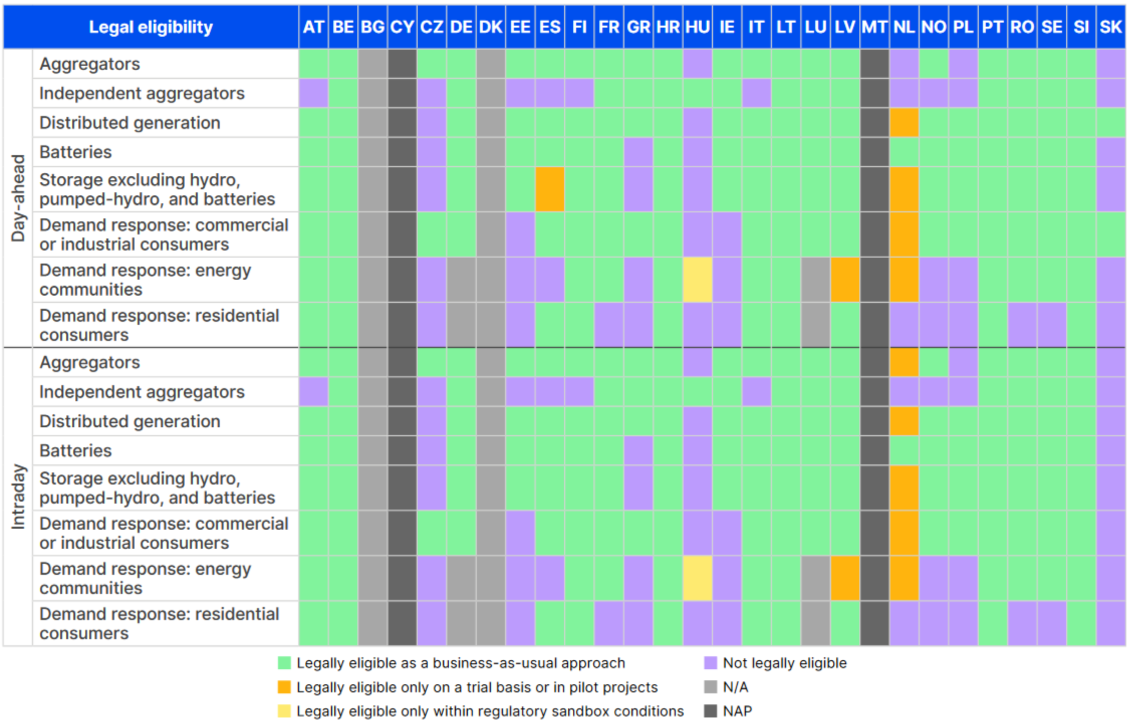
31 Article 6 and 7 of the Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity

Figure 5 – Legal Eligibility of Different Distributed Energy Resources and New Actors to Access Day-ahead and Intraday as of 31 December 2022



Source: ACER (2023) Demand response and other distributed energy resources: what barriers are holding them back?, page 25.

Similarly, ACER highlights that only five countries (Germany, Estonia, the Netherlands, Romania, and Slovenia)[32] have fully opened all their balancing services to all types of new actors and distributed energy resources.[33]

3.1.2 The lack of a framework for the participation of aggregated resources is a key hurdle for the development of distributed flexibility

Most distributed energy resources are not expected to directly participate, they will rather offer their flexibility through independent aggregators, hence the importance of allowing these new actors to operate consumption sites and participate in the market. However, some EU countries are still lagging in the introduction of aggregation models and legal eligibility for aggregation to participate in electricity markets, resulting in a market entry barrier for distributed flexibility resources. For instance, as of 31 December 2022, aggregators could not participate in wholesale markets in four

32 ACER (2023) Demand response and other distributed energy resources: what barriers are holding them back?, page 25.

33 Moreover, some countries do not procure some balancing services using a market-based approach, which may close de-facto these services to some flexible assets. For instance, in Spain, Croatia, Italy, Portugal and Romania, a sub-sets of generation units are obliged to provide FCR. The legal eligibility per Member State of different distributed energy resources and new actors to access balancing products and to provide congestion management services for TSOs and DSOs is also described here: ACER (2023) Demand response and other distributed energy resources: what barriers are holding them back?, page 8.

Member States,[34] and IA in ten of them.[35] In some jurisdictions, the participation of IAs to electricity markets is still conditional to an agreement being reached with the supplier of the consumer (or its Balance Responsible Party (BRP)). Prior consent by suppliers is still necessary in a number of countries, including Germany, Greece, Ireland, and Spain for the participation of DSR in the day-ahead and intraday markets.[36] However, reaching an agreement with the suppliers can hinder the ability of IAs to access the flexibility of end users. Indeed, as highlighted by the French competition authority in 2012,[37] suppliers and aggregators are potential competitors in the wholesale and balancing electricity markets, and for the provision of demand management services to consumers. Suppliers therefore have no incentive for such agreements to be reached.

3.2 Adequate technical rules and modalities need to be introduced to ensure the effective participation of flexible assets

Even in markets where it is legally allowed, the actual participation of all flexibility assets may be hindered by the lack or the inadequacy of eligibility and technical rules. For instance for aggregation, the Joint Research Centre of the European Commission points out that "*the secondary legislation and adaptation of market rules, procedures, responsibilities, […] are yet to be drafted in many of [the Member States]*".[38] Similarly, smartEN, the European association representing the flexible demand management industry, noted in 2024 that "*inadequate rules prevent [decentralised energy resources including energy storage and demand response] from fully participating in key electricity markets and mechanisms*".[39] This affects the participation of distributed flexibility in wholesale energy markets, but also balancing markets, and where applicable, CRMs. Adequate technical modalities need to be implemented, for instance to specify:

- Accessible and technology-neutral prequalification requirements and reliability criteria, including asset size, constraints on number and duration of activations, possibility of aggregation, including through third parties;
- Standardised and public calculation rules of the baseline consumption used as benchmark to assess volumes actually delivered and certify activation.

However, progress needs to be made across Europe, for instance in CRMs and in balancing markets:

- In CRMs, ACER finds that all capacity mechanisms in operation in 2022 had some constraining or unachievable requirements for most distributed energy resources. Although all capacity mechanisms are designed to be technology-neutral in principle, some eligibility requirements might in practice exclude smaller assets. For instance, the minimum capacity that must be offered in the Irish CRM auctions reaches 10 MW. Moreover, some resources may struggle to be available and provide capacity over long periods, and a limited availability period for the

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34 Hungary, Poland, Slovakia and the Netherlands

35 Austria, Czech Republic, Estonia, Spain, Finland, Italy, the Netherlands, Norway, Poland, and Slovakia. ACER (2023) Demand response and other distributed energy resources: what barriers are holding them back?, page 24.

36 smarten (2022) The implementation of the electricity market design to drive demand-side flexibility – smarten monitoring report, page 27.

37 Autorité de la Concurrence (2012) Avis n° 12-A-19 du 26 juillet 2012 concernant l'effacement de consommation dans le secteur de l'électricité, page 9.

38 Saviuc *et al* (2022) Explicit Demand Response for small end-users and independent aggregators, page 8.

39 SmartEn (2024) Implementing EU Laws – A guide to activate demand-side flexibility in the EU 27 Member States, page 37.

duration of the contract may facilitate their participation. However, in Belgium, Finland, Ireland, Italy, and Poland, CRMs do not include a time-limited availability period, and capacity resources must remain available all year.[40]

- In balancing markets, although most Member States allowed different technologies to be aggregated in the same balancing unit in 2022, some restrictions regarding the nature of technologies that can be grouped together could still be observed in some countries, for instance in Denmark, Sweden, and Spain. Moreover, the minimum bid size was still higher than 1 MW in some markets.

Beyond legal and regulatory barriers, market access for distributed assets may also be hindered by the lack of awareness and engagement of end consumers with regards to flexibility opportunities

The development of distributed flexibility is based on the simultaneous participation of a large number of distinct consumers, who choose to modify their consumption patterns to meet the system needs, either by contracting to a third party or by reacting to retail price signals.

This poses an additional challenge compared to utility-scale flexibility or industrial DSR: ensuring that a large number of small consumers are simultaneously involved in a flexibility approach. In this respect, the development of distributed flexibility may be hindered by the lack of information or awareness, a perception of complexity, and lack of engagement of households with regards to their power consumption patterns and flexibility opportunities.[41, 42]

Moreover, beyond the issues of awareness and access to information, participation in flexibility provisions might also be challenging for some households for socio-economic reasons. Flexible assets (for instance, EVs, heat pumps, or smart appliances) tend to be more expensive compared to non-flexible and fossil-fuelled alternatives, and may not be accessible to lower-income households.[43]

3.3 Some countries have successfully created technology-neutral markets that have contributed to the development of flexibility, including from distributed resources

For instance, France has implemented a regulatory framework enabling demand response participation in most markets, including wholesale markets, through the NEBEF rules. The regulatory framework for DSR was implemented in 2014 and has been further developed since, making it one of the most advanced in Europe.[44] DSR can now participate in the day-ahead, intraday, balancing, and capacity markets, as well as in TSO and DSO congestion management services, albeit the latter is still at an experimental stage.

40 ACER (2023) Demand response and other distributed energy resources: what barriers are holding them back?, page 79.

41 *Ibid*

42 Regulatory Assistance Project (2022) The Joy of flex – Embracing household demand-side flexibility as a power system resource for Europe

43 Regulatory Assistance Project (2024) Flex-ability for all: pursuing socially inclusive demand-side flexibility in Europe, page 5.

44 See for instance: Chondrogiannis (2022) Local electricity flexibility markets in Europe.

The NEBEF mechanism has played an important role to enable DSR development in France, by defining the roles of the different players, by providing a regulatory framework for the participation of independent aggregators in energy markets without suppliers' consent, and by streamlining the methodology applied by the TSO for the certification of DSR volumes in wholesale markets. More details about the NEBEF mechanism are provided in Appendix A.1.

4 Pillar 2: Ensure that the market design adequately reflects the full value of flexibility for the power system

Beyond existing markets, some services provided by flexible assets may not yet be explicitly valued or monetised. To attract more flexible assets to the market, it is essential for markets and products to more accurately reflect the needs of the power system that can ideally be met by flexible resources. Currently, however, the different benefits that flexible assets bring are not rewarded or monetised at their full value by the system in some EU countries. Moreover, existing and new markets and products should not be mutually exclusive as long as flexible assets meet the reliability and technical requirements necessary to meet system needs – this would allow to maximise revenue-stacking opportunities for flexible resources.

In Pillar 2, we present:

a. The different services flexible assets can provide to the system, and market tools to adequately monetise these services;

b. The importance of ensuring revenue stacking opportunities for flexible assets across the different markets.

4.2 Filling the gaps: Markets and products need to reflect the different system needs

Flexibility assets can provide different services to the energy system. They can quickly react to system needs and be located in specific parts of the network to alleviate congestions and voltage drops locally.[45] It is essential that all those services are monetised and offer revenue streams for flexible assets. However, not all services are properly valued and monetised yet.

Mechanisms to remunerate benefits related to the fast reaction time of flexible assets

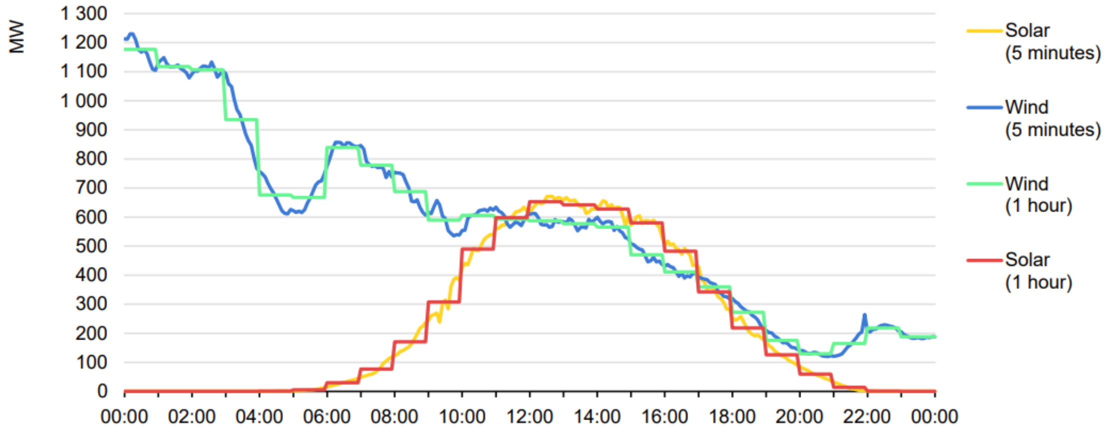
Although diverse, a key capability shared by most flexible assets is to ramp up and down extremely fast.

As such, providing price signals in electricity markets that allow to better reflect the value of fast ramping is key. In this respect, increasing the temporal granularity of price signals may allow important value to be unlocked.[46] This can be seen through generation profiles of wind and solar and how they vary significantly within an hour, as illustrated in Figure 6, resulting in imbalances within the imbalance settlement period. Reducing the time resolution of energy markets can hence reduce the volume of energy imbalances that need to be settled, and adequately remunerate market

45 For instance for storage: IEA (2022) Steering electricity markets towards a rapid decarbonisation, page 14-15.
46 IEA (2022) Steering electricity markets towards a rapid decarbonisation, page 24.

actors that provide short-term flexibility and adjust to changing renewable generation pattern.[47] In this respect, the EU imbalance settlement period change towards a 15-minute step, to be implemented in March 2025, would allow to better reflect the value of flexible assets. More details are provided in Appendix B.2.

Figure 6 - Average Generation of Wind and Solar Energy at 5-minute and 1-hour Resolutions in MW in DK1[48], 13 July 2021



Source: IEA (2022) Steering Electricity Markets Towards a Rapid Decarbonisation, page 25.

In addition, for system services, flexible assets have the ability to provide fast frequency response, ramping capabilities, voltage control, and black start.[49] Historically, those services have been implicitly provided by conventional power plants. The value of such services was not apparent because there was no scarcity in their provisions. However, as conventional thermal plants are gradually being replaced by other technologies that cannot all provide such services, scarcity may appear and price signals need to emerge to drive the development of such capacities.

Several jurisdictions have already made attempts at providing opportunities to value the ramping capabilities of flexibility assets:

- Ireland has for instance reformed its ancillary service market (DS3) to account for the needs of new services associated with the increasing penetration of renewables in the Irish power system. Ireland doubled the number of system service products from 7 to 14 to better reflect new services needed when operating the system with high levels of non-synchronous generation. New services include for instance the provision of ramping margins, or fast frequency response. Starting from a renewable penetration of 50%, the DS3 Programme achieved a 65% penetration in 2018 and 75% in 2022. More details are provided in Appendix C.3.

- In California, there is a decentralised capacity market, through which suppliers ('load serving entities') must ensure system reliability by demonstrating that they have sufficient capacity

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47 Additionally, demand-side flexibility, and particularly distributed flexibility, is characterised by technical constraints that may prevent them from being activated for as long as an hour consistently. A market resolution time step of one hour might thus act as a barrier for the participation of distributed flexibility in electricity markets, in addition to not adequately representing system needs.

48 Bidding zone 1 in Denmark.

49 European Commission (2023) Commission Staff Working Document – Energy Storage – Underpinning a decarbonised and secure EU energy system, page 26.

commitments to satisfy their peak demand. In addition, in 2015, CAISO added a ramping requirement in its existing capacity market to ensure the system has enough flexible resources available to meet forecasted net load ramps. More details are provided in Appendix C.3.

Remunerating benefits related to the location of flexible assets

Flexible assets can be located and leveraged in specific areas of the network to answer local needs. Flexible resources can for instance provide services to network system operators for congestion management and defer or avoid investment in additional network capacity. This is becoming increasingly relevant given the rise in congestion costs in many countries in Europe and the significant need for investments in electricity grids which are required for the energy transition.[50] While long-term solutions to grid constraints may involve traditional grid expansion, such projects often take up to a decade to complete on the transmission system level. Leveraging distributed flexibility offers a faster path to address growing electricity demand and increasing renewable penetration, at least while network reinforcements are pending. Moreover, flexible resources can improve local network reliability. Harnessing this potential relies on four main approaches.

First, some countries have started implementing network planning principles that take into account commercial flexibility as an alternative to traditional network reinforcement and expansion.

- In the UK, commercial flexibility is explicitly included in the cost-benefit analysis used by NESO to identify the most advantageous network development solutions. For instance, out of 128 grid solutions suggested by NESO in 2022, the cost-benefit analysis determined that eight commercial flexibility solutions were more economical that network expansion.[51]
- In Germany, the NOVA principle applied by the TSOs to identify grid technologies that can delay reinforcement investments could be generalised as a framework to leverage the value of flexible assets as alternatives to grid expansion, which is not yet the case in Germany. Under the NOVA principle, when grid constraints are identified, grid optimisation must be considered by TSOs over grid reinforcement.[52] While the use of commercial flexibility is limited to redispatch or grid reserves in Germany, the value of commercial flexible assets in response to network constraints could be assessed before conventional grid reinforcements.

Second, some countries are implementing markets for flexibility to be used in local areas of the network through Local Flexibility Markets (LFMs). LFMs can play a key role in reflecting the value of flexibility at a local level. A LFM corresponds to a marketplace where flexibility can be sold or bought at the distribution network level or in a limited geographical area. This allows distribution and transmission system operators to use flexibility, to solve congestion issues, minimise power outages, and, potentially in some cases, delay or avoid grid expansion investments.

- In Europe, the development of local flexibility markets is relatively limited, and varies widely amongst countries, as illustrated in Figure 7. Only a handful of countries have implemented LFMs, and most of them are still at a pilot stage. Nonetheless, LFMs have reached a business state in several jurisdictions, including the UK, France, and the Netherlands.

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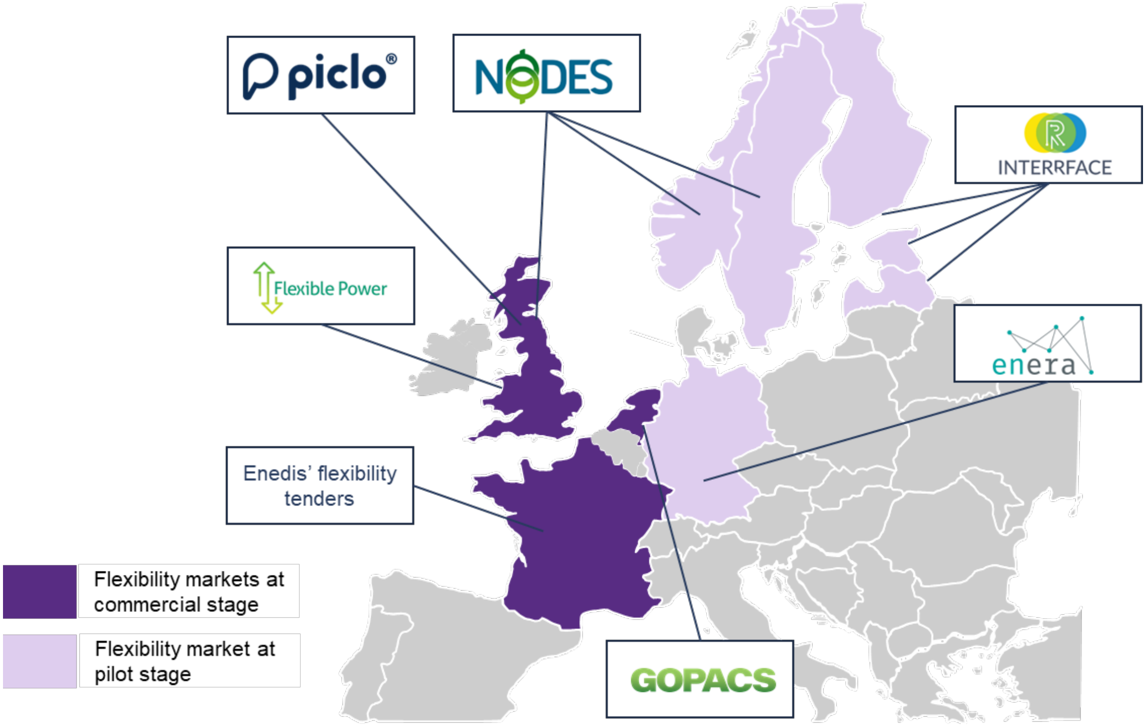
50 See for instance: Compass Lexecon (2024) Prospects for Innovative Grid Technologies, page 35.
51 NGESO (2022) Network Options Assessment 2021/22 Refresh, page 11.
52 See for instance: Compass Lexecon (2024) Prospects for innovative grid technologies, page 108.

Figure 7 - Key Local Flexibility Markets Introduced in European Countries



Source: Compass Lexecon based on Chondrogiannis *et al* (2022) Local electricity flexibility markets in Europe, page 20.

Third, countries have implemented innovative regulatory frameworks incentivising the use of local flexibility by TSOs and DSOs. The British RIIO[53] price control framework includes incentives for DSOs to innovate and use flexible resources as an alternative to grid reinforcements. This regulatory framework has successfully stimulated the development of local flexibility to relieve congestions on the distribution network. The first tenders for the provision of flexibility services to DSOs took place in 2018, and an increasing volume of flexibility has been procured each year, reaching a total capacity of around 4 GW in 2024/2025. The development of local flexibility contracting has been enabled by the emergence of flexibility platforms. Flexibility service providers can participate in local flexibility tenders via two main market platforms: Flexible Power,[54] developed by DSOs, or Piclo Flex.[55] These platforms can be used for a range of features, such as the advertisement of flexibility needs, gathering flexibility bids and offers, automated settlement and dispatch, and granting of long-term contracts. More details are provided in Appendix B.1

Fourth, the local benefits that flexible assets can bring could be better remunerated through more granular energy markets that provide locational price signals. Several approaches are possible to do so. In the US, most markets rely on nodal pricing by virtue of which both the supply-demand balance and the network congestions set the price of electricity at each node. Another approach could consider further granularity in the bidding zones used for market clearing, for instance a bidding zone split is being discussed currently for the UK. These approaches raise important political issues associated with the distribution of benefits and costs.

53 The 'RIIO' price control framework stands for Revenues = Innovation + Incentives + Outputs.

54 Joint initiative by Western Power Distribution, Northern Powergrid, Scottish and Southern Electricity Networks, SP Energy Networks and Electricity Northwest.

55 See website. Independent trading platform used by Electricity Northwest, NIE Networks, SP Energy Networks and UK Power Networks (in 2021).

Other benefits

The benefits of flexible assets also include the contribution to system adequacy through the provision of firm capacity for peak demand. However, the contribution of some flexible assets, e.g. DSR, to system adequacy is not fully reflected in all countries in the absence of CRMs or of adequate participation rules.

4.3 Moreover, flexible resources need to be able to stack up revenues from participation in different markets/products

Value stacking refers to the practice of maximising the value derived from an asset or a portfolio of assets by participating in multiple markets and proving multiple services simultaneously. For storage assets for instance, the European Commission notes that "*revenue stacking (i.e. securing a flow of revenues from many different services) increases the return on investment and the attractiveness to investors of projects*".[56]

However, value-stacking for flexible assets is sometimes limited in some European countries and the technical requirements for flexible assets to participate in various markets may make it difficult in practice. Revenue stacking requires policies beyond the general scope under which the EU regulates flexible assets, and typically needs to be implemented through technical regulation at a national level. Revenue stacking opportunities are hindered by several barriers, including the difficulty for flexibility providers to comply with evolving specific rules across multiple markets.[57]

To enable flexibility providers to stack value across multiple markets, the barriers to entering markets should be lowered. This entails mirroring the requirements for participation in one market as closely as possible in other markets, to the extent feasible, while also ensuring that contractual clauses do not unduly impede participation in multiple markets.[58] Moreover, revenue stacking also needs to be enabled between products procured at the transmission and at the distribution levels.[59] For instance, ancillary services products for transmission should not preclude participation in congestion services at the distribution level, provided rules are in place to co-optimise activations and avoid contradicting orders being sent form two network operators. In other words, effective TSO-DSO coordination must be furthered to make it possible while ensuring the grid's reliable operation.

56 European Commission (2023) Commission Staff Working Document – Energy Storage – Underpinning a decarbonised and secure EU energy system, page 25.

57 As of June 2022, I. Varela Soares et al. (2023) Considerations for benefit stacking policies in the EU electricity storage market, page 7.

58 European Smart Grids Task Force – Expert Group 3 (2019) Final report: Demand Side Flexibility – Perceived barriers and proposed recommendations, page 17.

59 See for instance: CEDEC, E.DSO, ENSTO-E, Eurelectric, GEODE (2019) TSO-DSO report – An integrated approach to active system management, with a focus on TSO-DSO coordination in congestion management and balancing, page 5.

5 Pillar 3: A de-risking contractual and regulatory framework is needed to support timely investment in flexible resources

Another distinctive feature of flexible assets is their high capital intensity, which creates a challenging business case for investment, taking into account their often volatile and unpredictable revenues. Flexible resources often require a large upfront investment, while their revenues are uncertain and potentially insufficient to reward investment. From a financing and investment perspective, this makes investing in and operating flexible assets challenging in the absence of specific de-risking contractual or regulatory mechanisms. Thus, providing non-discriminatory access to existing markets (c.f. Pillar I: Addressing barriers to the participation of flexible resources in different markets), and adequately monetising the various services flexible assets bring to the system (c.f. Pillar 2: Ensure that the market design adequately reflects the full value of flexibility for the power system) may not be enough to foster timely investments to successfully reach Europe's climate targets.

Providing for long-term predictability of revenues through a contractual and/or regulatory investment framework is often a cost-efficient way to support the timely development of flexible resources to meet system needs.

Pillar 3 outlines:

a. The need for an investment framework as part of the market design to ensure that flexibility needs are met in a timely manner,

b. The different types of investment frameworks which can be developed.

5.2 A complementary investment framework is often needed to ensure that flexibility system needs are met in a timely way

Massive investments are needed to meet European decarbonisation objectives while addressing identified flexibility needs. For instance, the REPowerEU plan would require €300bn of investments by 2030, in addition to the Fit-for-55 investments.[60] Moreover, regarding flexible assets, the International Energy Agency highlighted in 2024 that at the global level, investments in battery projects would need to grow by 25% every year in order to triple installed renewables capacity by 2030, as agreed by parties at the COP28.[61]

This requires a framework allowing these investments to be made, to ensure that the necessary flexibility is delivered to the system on time and at the right location. In this context, the financing

60 European Commission (2022) Commission Staff Working Document - Implementing the repower eu action plan: investment needs, hydrogen accelerator and achieving the bio-methane targets, page 5.

61 IEA (2024) World Energy Investment 2024, page 83.

capability is a highly relevant concern to face this investment challenge, and private capital and debt financing will be key to deliver the needed system flexibility.[62, 63]

New capacities able to provide flexibility, whether utility-sized, such as large-scale battery storage, gas plants, pumped-hydro, or distributed, such as demand-side response, require upfront capital investments. This could be either from the consumer side, to acquire an electric vehicle able to provide services to the grid, or the installation of large batteries for instance.

However, the market design may sometimes be insufficient for flexible assets to be profitable:

- Some technologies may be facing a missing money issue, as market revenues are insufficient to cover costs,
- The level of risks to which projects are exposed may be too high to allow for investments in flexible assets, or at high costs to consumers, and
- It might not provide a coordinated approach to attract timely investments in line with the evolution of system needs.

As a result, an investment framework providing long-term predictability could be necessary to complement market signals and attract investments in flexible capacities to the extent required by the energy transition and in a timely manner.[64] In order to be cost-efficient, the creation of a long-term investment framework, its duration and the level of additional revenues it provides, should be conditional on, or account for, the level of capital intensity and uncertainties faced by a given technology.[65]

Generally, the need for investment mechanisms for flexible assets has already been acknowledged by the recent Electricity Market Design reform. The agreement in 2023 between the Council and the European Parliament opened the door to the introduction of "*support schemes […] for the available capacity of non-fossil flexibility*" if they are needed to achieve flexibility development targets, for instance through capacity mechanisms in countries where such schemes have been introduced.[66] In essence, the challenge of flexibility development is akin to the history of renewables development in the European electricity system which depended on the use of support mechanisms such as feed-in-tariffs or the trading of green certificates (see Appendix C.6).

5.2.1 The need for investment mechanisms: Missing money

First, some technologies may be facing a missing money issue, despite the fact that their timely development is necessary to meet system flexibility needs. Despite revenue stacking opportunities across different markets, the level of revenues that can be captured in electricity and ancillary services markets may be insufficient for asset owners to cover their fixed costs.

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62 For instance, IRENA highlights that most of the investment needed for renewables must come from the private sector (IRENA (2016) Unlocking renewable energy investment: the role of risk mitigation and structured finance), page 37 and a similar conclusion can be made for flexible assets.

63 European Commission (2023) Commission Staff Working Document – Energy Storage – Underpinning a decarbonised and secure EU energy system, page 24.

64 Compass Lexecon (2022) A market fit for net-zero power system – Eurelectric's flagship study, page 8.

65 The price of lithium-ion batteries has for instance decrease by 80% between 2013 and 2023; BloombergNEF (2023) Lithium-Ion Battery Prices Hit record Low of $139/kW

66 Regulation 2023/0077 amending Regulations (EU) 2019/942 and (EU) 2019/943 as regards improving the Union's electricity market design, page 32.

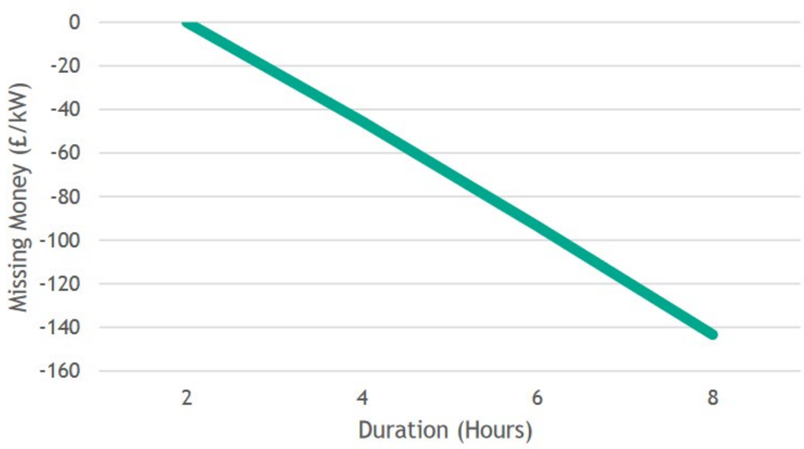
Several market failures in the current market design might limit revenue opportunities for flexible assets.[67] This may lead to a misalignment between the value flexible assets can bring to the system and the remuneration received, which could warrant a policy intervention with an investment mechanism.

As highlighted previously in this report in Pillar I: Addressing barriers to the participation of flexible resources in different markets and Pillar 2: Ensure that the market design adequately reflects the full value of flexibility for the power system, revenue stacking opportunities for flexible assets might be limited by the discriminatory nature of existing electricity markets, as some services that flexible assets bring to the system may not be explicitly monetised, and technical requirements for flexible assets to participate in various markets may make it difficult in practice.

Moreover, short-term price signals might not adequately reflect system needs and reward assets. In particular, policy interventions or price caps in spot markets tend to induce distortions and reduce revenues for flexible assets.[68] On one hand, flexible assets such as storage earn revenues with the volatility of prices on the spot market, while policymakers have shown their desire to reduce such volatility for consumers, as illustrated during the energy crisis.

Missing money can be observed for relatively mature technologies, like batteries. For instance, in Ireland, the TSOs EirGrid and SONI identified an issue of missing money for batteries, which tends to increase depending on the storage duration capability and size of the asset.[69]

Figure 8 – Storage Duration and Missing Money in Ireland



Source: SONI & EirGrid (2023) A call for Evidence on the Market procurement options for long duration energy storage (LDES), page 31.

However, the missing money problem is particularly acute for less mature technologies. Their above average costs, both CAPEX and OPEX, does not allow them to be economically viable when competing against incumbent production plants. However, triggering their maturity and the associated cost reductions rely on providing innovators and first movers with the required revenues to structure the industry. In other words, even if these technologies are not the most competitive in

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67 Most frequent market failures in EU power system include participants' risk aversions, imperfect competition, existence of price caps and inability for prices to reflect the value of loss load. See for instance, France Stratégie (2014), The Crisis of the European Electricity System, box 2.

68 See for instance: ACER (2023) Demand response and other distributed energy resources: what barriers are holding them back, page 91.

69 SONI & EirGrid (2023) A call for Evidence on the Market procurement options for long duration energy storage (LDES), page 31.

the short term, their development could be beneficial to diversify the flexibility portfolio in the system, and to ensure the presence of the range of necessary flexibility capabilities in the long term.

As a result, public intervention could be necessary to ensure revenue stacking opportunities by making existing markets non-discriminatory and monetising all system services, as well as ensure that the market framework is suitable for sufficient and timely investments in flexibility. In addition to correcting the market failures identified, complementing market signals with additional investment incentives might be necessary in some cases to compensate for the missing money problem and unlock investments.

5.2.2 The need for investment mechanisms: de-risking investments

Flexibility projects such as battery projects are characterised by a high degree of uncertainty regarding future profitability and revenues. When taking investment decisions, investors and lenders seek to balance out the certainty of revenues with the asset's risks and costs in order to evaluate whether the rate of return for the project is acceptable when considering the risks involved.[70]

Revenue uncertainties can emerge from different sources, such as volatility in market prices, lack of predictability over future revenue streams, competitive landscape, market design or policy uncertainties for instance.[71] These uncertainties over the future profitability of the asset tend to significantly restrict access of flexible assets to finance, and hence increase the cost of capital of flexible assets and hinder investment opportunities.

Investors may fear that future revenues would not be sufficient to cover their fixed costs and ensure a satisfactory return on investments. This is particularly the case for flexibility assets with long asset lifetime, long development lead times, and high share of capital expenditure. On this point, the European Commission noted in 2023 for energy storage projects that:

> "The availability of finance and access to capital is still a highly relevant concern, particularly for fully 'merchant' projects (i.e. projects without state subsidies) and first-of-their-kind technologies. Equity financing is the main source of financing for utility-scale energy-storage projects nowadays. This is because most energy-storage projects are not attractive for risk-averse investors due to the uncertainty of their economic and administrative assumptions. However, debt financing has an important role to play in financing energy-storage projects efficiently."[72]

Long-term contracts play a critical role in supporting large-scale investment in flexible technologies which are capital-intensive, as they offer long-term revenue certainty for investors. This reduces investment risks, making financing more accessible and lowering the cost of capital, ultimately benefiting consumers through reduced overall costs. As a result, long-term contracts can serve as the anchor of an investment framework, enabling efficient risk allocation.

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70 Riverswan energy advisory (2021) Filling the flexibility gap Realising the benefits of long duration electricity storage, page 11.

71 European Commission (2023) State Aid SA. 104106 (2023/N) – Italy - Support for the development of a centralised electricity storage system in Italy, page 3.

72 European Commission (2023) Commission Staff Working Document – Energy Storage – Underpinning a decarbonised and secure EU energy system, page 24.

In addition to market revenue risks, some flexible assets may face other types of risks, such as technology risks for early-stage innovative technologies.[73] At their early development stage, flexibility technologies may face uncertainties over their technical capabilities, as well as their ability to answer system needs at scale. In this case, public intervention can also be necessary to take on these risks. For instance, upfront public funding could be necessary to help innovative technologies develop at the speed required to reach net zero targets.

5.2.3 The need for investment mechanisms: investment coordination

The scale of the flexibility needs requires a coordinated approach to ensure that investments are timely, in suitable locations, and at levels that meet system needs. To identify the most appropriate and cost-effective options for a secure power system, an integrated and coordinated planning framework is needed, one that simultaneously addresses generation, flexibility, transmission and distribution networks, demand-side management, and electrification of other sectors.[74]

Indeed, the timely development of sources of flexibility and firm power is needed alongside the growth of renewables. At the same time, new opportunities will emerge both on the supply side with new storage technologies and on the demand side with new flexible loads from the electrification of the transport, industry, and buildings sectors.

As a result, there is a need to coordinate investments across industry segments, demand side, and sectors as they develop. This need was recognised in Italy, for instance. When facing significant need for energy storage to integrate a volume of renewable capacity in line with the ambitions stated in the National Energy and Climate Plan (NECP), the Italian authorities acknowledged that "*energy-only markets do not promote coordinated development of generation, transmission, and storage capacity due to an information asymmetry between different players in the electricity sector and a lack of coordination between investors in RES generation capacity and storage systems*".[75]

In this regard, a long-term contracting mechanism can be a useful instrument to ensure that investments in flexibility assets are made in a timely manner in line with the planning framework. Contracting for certain system needs over the long term sends investment signals ahead of market signals, which is necessary to ensure a timely deployment of necessary assets..

73 In this context, early-stage innovative flexible technologies refer to flexibility technology that have not yet reached a level of technology maturity . The level of technology maturity can be quantified with the Technology Readiness Level (TRL) scale. For instance, the IEA provides a list of clean energy technologies ranked by TRLs, ranging from 1 to 11 (IEA (2024) ETP Clean Energy Technology guide). As of 2024, flexibility technologies that are at a stage of commercial demonstration in final conditions, but still not commercially available (with a TRL equal to or below 8) include for instance solid-state batteries, liquid air energy storage, or gravity-based storage.

74 The 2024 TYNDP framework that required both the power and gas transmission operators' associations (ENTSOE and ENTSOG) to work on common long-term scenarios for the EU energy system is one step in that direction. But national initiatives in that sense are lacking.

75 European Commission (2023) State Aid SA. 104106 (2023/N) – Italy - Support for the development of a centralised electricity storage system in Italy, page 3.

5.3 Different types of contractual and regulatory investment schemes can be implemented depending on the specific needs of each power system

5.3.1 Different contracting and regulatory mechanisms can foster investment in flexible resources

An energy-only market design can be appropriate when the current market design of a given country already provides adequate price signals and sufficient incentives to drive investment in flexibility. Where this is not the case, market design combined with regulatory reforms could also prove sufficient to meet system needs, by removing barriers to investments and enhancing flexibility price signals. However, when markets signals alone do not deliver the required system flexibility, a complementary investment mechanism is needed.

There are different types of market design archetypes that can be implemented for flexibility providers to receive long-term contracts, which allow visibility, and to secure revenues for investors. Investment can be incentivised with:

- Flexibility contracting scheme, where required investments in flexible capacity are incentivised with a contracting mechanism dedicated to fulfilling flexibility needs, or
- Joint optimised contracting mechanism, where the required investments in flexible capacities are incentivised through a single mechanism co-optimising the contracting of flexibility needs as well as firm capacity needs, or
- A simple firm capacity contracting mechanism, such as a capacity remuneration mechanism, which although not targeted at flexibility resources can provide tailored contract durations to flexible assets remunerating only the firm capacity they can provide while securing enough additional revenues and predictability to de-risk investments.

The design of a flexibility contracting scheme should be based on actual needs rather than the willingness to support certain technologies. System needs then drive the types of products to be contracted. Designing such schemes relies on a range of options and raises a number of issues, including:

- How to remunerate flexible capacities**?** Remuneration can be granted based on the contracted capacity, for instance with a direct grant during the construction phase, or with capacity payments during the operational phase. In the latter case, the remuneration could take the form of a premium on top of the remuneration perceived in a market-wide CRM. Remuneration can also be based on the amount of energy produced, for instance with a Contract for Difference (CfD) scheme (cf. box “Zooming in on CfDs”), although the design of CfD for flexibility assets needs to be carefully crafted as it is of utmost importance to maintain efficient dispatch incentives.
- How to procure contracted capacities? Contracting schemes can involve auctions to allocate contracts competitively. This mechanism provides market players with an incentive to declare the ‘true’ level of support they require, and thus acts as an information-revealing mechanism.[76] Contracts can also be granted based on a set of criteria, for instance for projects meeting a minimum technical requirement.
- How long should flexible capacity be contracted? The contract duration could range from one to several years, depending on the need for capacities to secure revenues over a long period of

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76 Compass Lexecon (2022) A market fit for net-zero power system – Eurelectric’s flagship study

time. While revenue certainty is higher for investors with longer contract durations, the risk taken on by the contract counterparty is also greater.

- Which assets should be eligible? Should the investment scheme target specific technologies or be designed as technology neutral? This topic is covered in depth in Pillar 3: Investment mechanisms for flexibility can target specific technologies, or be designed as technology-neutral.

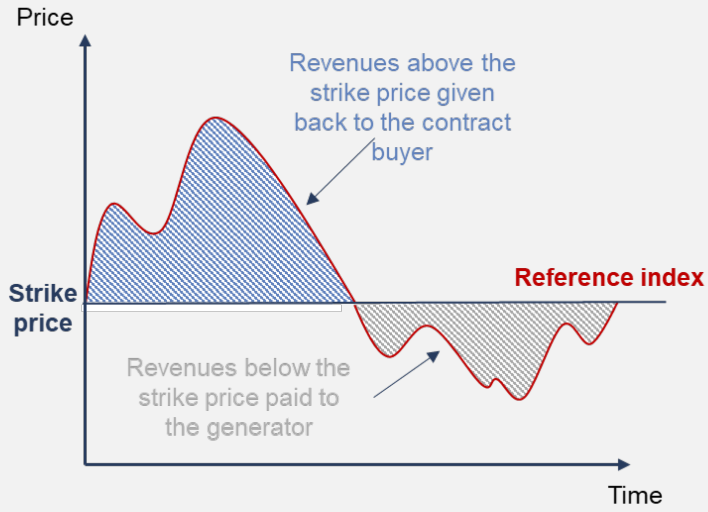
For instance, France implemented a mechanism to remunerate specific flexibility technologies with capacity payments received on top of the remuneration perceived in the CRM. The scheme was initially targeted towards DSR providers, which could benefit from single or multi-year contracts of up to 10 years through calls for tenders. This mechanism has been a key driver of the development of DSR capacities in France, and contracted volumes through the mechanism have risen over the last years, from 1.9 GW in 2022 to 2.9 GW in 2024. The French DSR tenders are in the process of being replaced by a wider mechanism to support low-carbon flexibility sources. From 2025 onwards, participation will be open to a wider range of flexibility technologies beyond DSR, such as storage assets, although this mechanism will not be designed as a fully technology-neutral scheme to reach flexibility needs. More details are provided in Appendix C.2.

Moreover, Australia is implementing a technology-neutral capacity investment scheme incorporating flexible assets, namely the Capacity Investment Scheme (CIS). The CIS functions with competitive tenders held approximately every six months. Selected projects are offered long-term agreements with the Australian government on an agreed revenue floor and ceiling. The length of the contracts offered are bid-dependent but may go up to 15 years. The CIS is designed to be technology-neutral among clean technologies, encompassing flexible capacities such as storage, other zero-emissions technologies, as well as virtual power plants. More details are provided in Appendix C.1

Zooming in on CfDs – Compared with non-dispatchable renewable assets, designing efficient CfDs for storage and flexible assets raises additional complexities

CfDs are contracts with electricity generators which stabilise market revenues according to a set strike price. More precisely, a CfD is a contract where the buyer (e.g. the state) pays the contractual ‘strike’ price to the seller for the contracted volume, and the seller (e.g. the generator) pays the reference index to the buyer. Therefore, in times where the strike price exceeds the market price, the generator receives a premium and in times where the strike price is below market price, the difference is retroceded to the buyer to reach the strike price. Such schemes are typically used to support renewable assets. The CfD mechanism is illustrated in **Figure 9** below.

Figure 9 - Illustration of a Two-sided CfD Mechanism



Source: Compass Lexecon

While traditional CfDs have been instrumental in the development of renewable capacities so far in Europe, designing efficient CfDs for storage and flexible assets raises additional complexities. Indeed, a two-way CfD settled on the real output of an asset would smoothen revenues over time by guaranteeing the strike price when the asset is producing, thus eliminating the flexibility signals to produce at a particular time. This stems from several characteristics of flexibility assets which differ from renewable assets for which CfDs initially emerged:

- While generation units are unidirectional (i.e., only generating), the operation of storage assets requires the management of bi-directional energy flows (i.e., charging and discharging to generate), energy reservoir, and other technical constraints.

- Flexibility assets face intertemporal decisions. They optimise when to charge and when to generate electricity. This can be on a short term (i.e., during a day) or on a longer term (i.e., storing the energy over several months). Dispatch incentives are central to their efficient use and should not be distorted by investment schemes, more crucially than for variable generation.

- Flexibility assets also have multi-market opportunities which complicates the possibility of designing an optimal de-risking scheme. Given technical properties, flexible assets can participate in the day-ahead and intraday markets but are also crucial in ancillary services markets.

Flexibility could also be jointly contracted with another service through joint procurement schemes. For instance, firm and flexible capacity could be procured jointly within a single investment mechanism, with two main implementation options:

- A single product could be defined based on the contribution of each technology towards the security of supply target, taking into account both firm and flexible system requirements. A single derating factor would jointly take into account the contribution of each technology to these two system needs. This product would be procured through a single auction clearing price.
- Two products, for firm and flexible capacity, could also be defined separately in a single mechanism. Distinct derating factors would be associated to each technology class depending on their firm and flexible capabilities. The demand for each product would be calculated separately, and products could be procured through separate or joint auctions, taking into account the substitutability and complementarity between the two products.

If the need for a contracting mechanism for both firm and flexible capacity materialises, the relevant implementation option would depend on the overlap between the group of resources which can provide firm capacity, and the group of resources which can provide flexible capacity.

In theory, if there is no overlap across resources, two separate mechanisms to contract firm and flexible capacities could be appropriate. However, in practice, the resources delivering firmness and flexibility overlap: the assets that can provide firm capacity may also be able to provide flexibility. Therefore, having a separate or stepwise mechanism could lead to inefficiencies, such as risks of double-remuneration for the same capacities or risks of locking-in of less efficient capacities.

In the latter case, one mechanism could either procure one product (e.g. a CRM for firm capacity), assuming other required characteristics would come along “naturally”, or procure both firm and flexible capacity to overcome previously mentioned issues at potentially higher implementation costs (for instance, a joint optimised firm/flexible capacity mechanism).

For instance, CAISO implemented flexible capacity requirements in its capacity mechanism in 2015. In 2006, CAISO implemented a resource adequacy program that requires suppliers (‘load serving entities’) to ensure system reliability each year by demonstrating that they have sufficient capacity commitments to satisfy their expected peak demand in the forthcoming summer peak season. In 2015, CAISO added a ramping requirement in its existing capacity market to ensure the system has enough flexible resources available to meet forecasted net load ramps. This mechanism was implemented to fulfil an increasing need for flexibility in the Californian system due to the large penetration of intermittent renewables, which could not be addressed via the existing reserves at the time. In terms of capacity procured, enough flexibility has been present on the system since the introduction of the mechanism. The flexible resources adequacy procurements were sufficient to meet the actual maximum net load ramps for all months in 2022. However, no significant price premium was achieved for assets able to provide both flexibility and firm capacity. More details are provided in Appendix C.3.

Flexibility investments can also be incentivised indirectly through RES-E schemes, when they incentivise co-location with batteries for instance. For instance, in the UK, co-located storage can participate to CfD auctions for renewable capacity.[77] Spain also introduced targeted tenders for energy storage to be collocated with existing renewable assets, with 880MW/1,809MWh of capacity being contracted during the first auction in 2023.[78]

5.3.2 Investment mechanisms for flexibility can target specific technologies, or be designed as technology-neutral

Contracting mechanisms for flexible assets can either target specific technologies or be designed as technology-neutral, implying that all technologies capable of answering system needs are considered eligible. Technology-neutral and targeted mechanisms provide different outcomes in terms of costs and technology development.

- Targeted mechanisms may be well suited to stimulate the development of nascent technologies and encourage innovation.[79] This can be relevant to develop flexible technologies that are not yet fully mature and cost-competitive compared to other flexible assets, but have technical

77 See for instance: ModoEnergy (2022) CfD Batteries – co-location of storage in the Contract for Difference scheme

78 See for instance: Energy Storage News (2023) Spain awards contracts to 1.9GWh energy storage in first PERTE tender

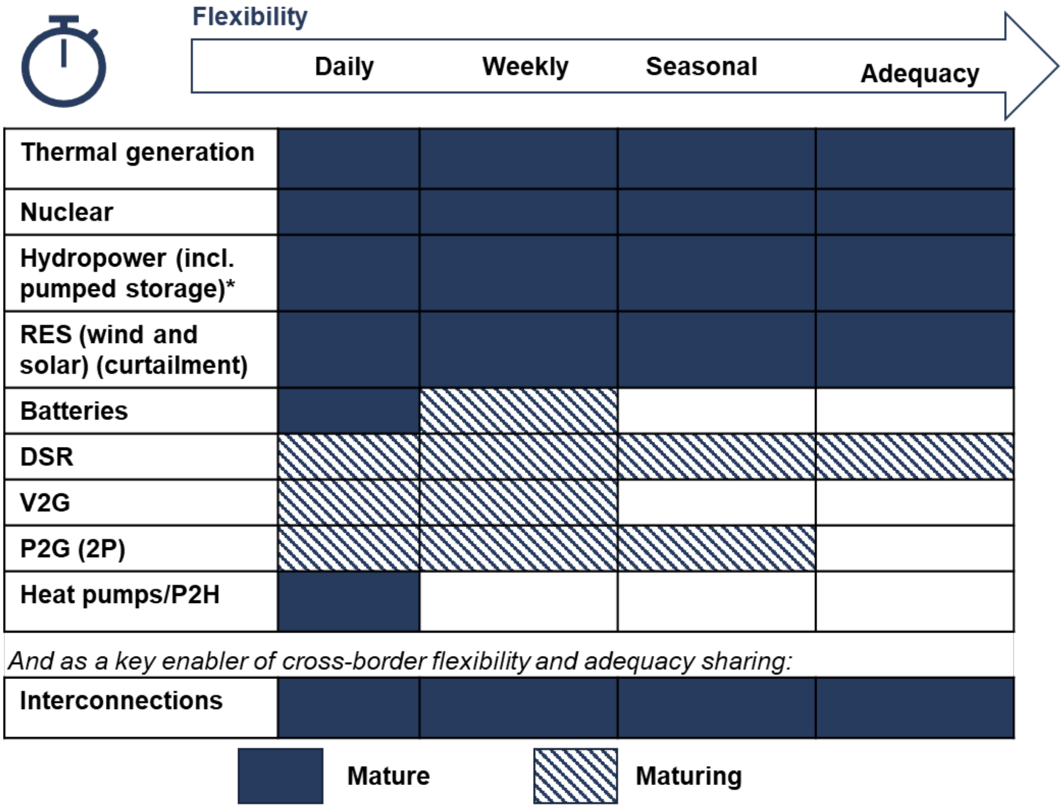
79 IEA (2022) Steering Electricity Markets Towards a Rapid Decarbonisation, page 42.

characteristics that can contribute to meeting upcoming system needs (e.g. in terms of flexibility timescale, ramping rates, reaction time, etc). A targeted mechanism can also be relevant when there are specific flexibility needs which can only be met with specific technologies, for which more complex contracting mechanisms may not be necessary.

- With technology-neutral schemes, the different technologies able to answer system needs compete with each other. System needs can therefore be met at a lower cost, at least in the short-term, as mature technologies are likely to win the auctions.[80] Moreover, the pool of eligible capacities is larger than with targeted mechanisms: neutral mechanisms hence typically hold a greater certainty of reaching security of supply objectives.

Thus, suitable eligibility rules depend on the nature of system needs and on the level of maturity of the different flexible technologies. Each technology type presents specific characteristics (dispatchability, energy-limits, ramping rate) that allow it to answer to different system needs, as shown in Figure 10. In countries where seasonal flexibility needs are increasing, and the potential for nuclear and hydropower is limited, targeted mechanisms may be required to meet system needs given that the level of maturity of alternative seasonal flexibility solutions may be limited. In countries with daily flexibility needs, the pool of mature flexibility technologies may be large enough to leverage cross-technology competition, for instance with battery storage competing with Power-to-Hydrogen (P2H).

Figure 10 – Level of Maturity for Different Types of Flexibility



Source: Compass Lexecon

80 *Ibid*

Moreover, other considerations may also be taken into account in the design of eligibility rules.

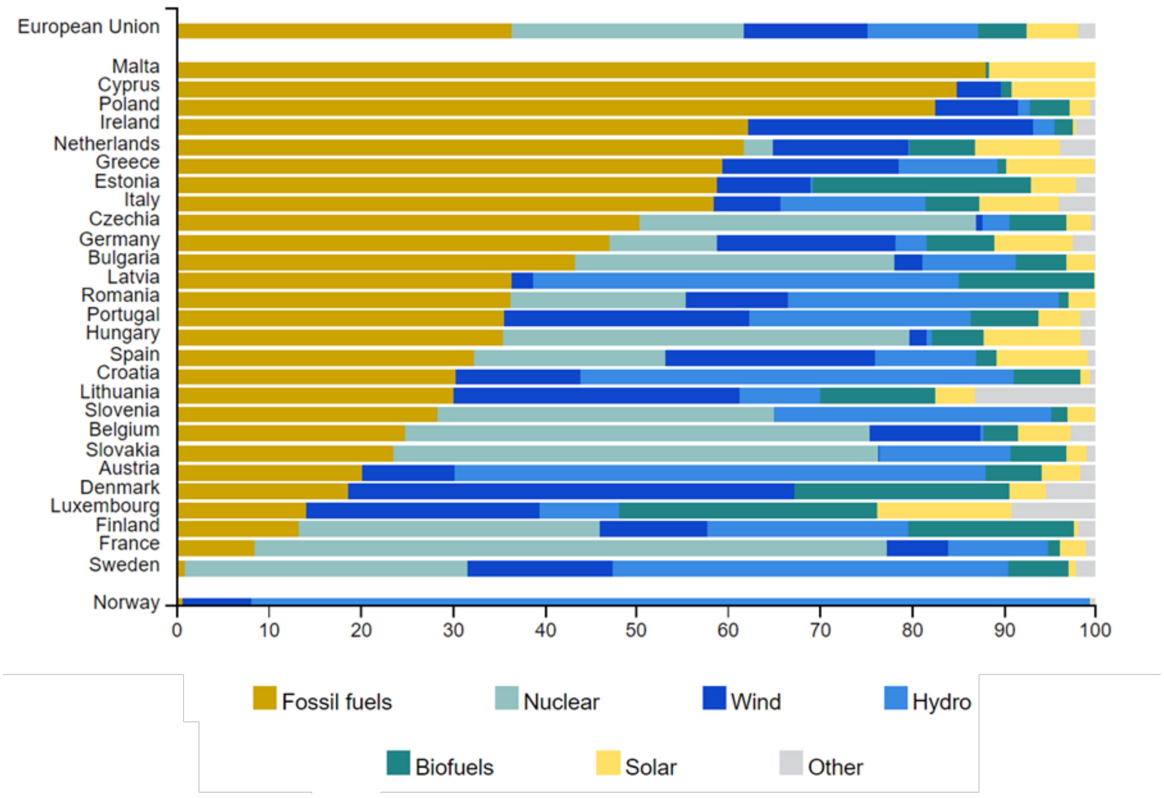
- Targeted mechanisms may be easier to define and implement than technology-neutral mechanisms. With technology-neutral schemes, more attention may be required to ensure that participation requirements and products are non-discriminatory compared to targeted mechanisms.
- Other important factors to consider include the diversification of technologies to improve resilience, supply chain dependencies, construction lead times, and asset lifetimes.

5.3.3 There is no ‘one-size-fits-all’ approach for investment mechanisms for flexible resources in Europe

There is no ‘one-size-fits-all’ market design approach for every European country to foster the development of flexibility resources. The investment needs and appropriate investment mechanisms vary across countries and regions, as Member States can vary in terms of market design in place, depth of market, duration since and degree of liberalisation and unbundling in the domestic market, etc.

More precisely, the choice of market design at national or regional level depends on several dimensions. This includes the current generation mix, shown on Figure 11 below for EU countries, the future mix, the installed flexible capacity and the type of flexibility needs, the presence of local congestions, interconnections with neighbouring countries, or existing market arrangements for instance.

Figure 11 - Production of Electricity by Source in the EU 2021 (%)



Source: Eurostat (2023) Shedding light on energy in the EU.

Moreover, investment mechanisms should account for the current national regulatory framework and pre-existing market instruments. New investment schemes should be designed in such a way to avoid any under- or over-procurement of flexible capacity through uncoordinated instruments, and to avoid overcompensating contracted assets.

However, even though there is no ‘one-size-fits-all’ approach for every European country, a degree of harmonisation across the EU is desirable to avoid cross-border distortions and a patchwork of approaches. Coordination and harmonisation should be ensured to a certain extent to stimulate cross-border competition and provide a level-playing field in the internal energy market.

A Appendix 1 – Case studies for Pillar I: Addressing barriers the participation of flexible resources in different markets

A.1 Case study: France's NEBEF

France introduced the NEBEF mechanism to facilitate DSR participation in the wholesale market.

DSR has been able to participate in the French balancing market since its early stages, but participation was initially limited to larger consumers and conditional to an agreement with the supplier and/or its BRP to define the detailed modalities of control and compensation.

In its 2012 opinion,[81] the French Competition Authority considered that the obligation for independent aggregators to sign an agreement with the BRPs of the consumer sites was a barrier to the development of DSR, limiting the potential competition on the DSR market. As a result, RTE, the French TSO, and CRE, the French regulator, had to revise the market rules to overcome this barrier. In this context, they developed the Block Exchange Notification of Demand Response (NEBEF) mechanism.[82]

The NEBEF mechanism allows to sell DSR as generation capacity without the prior consent of the balancing responsible party.

The NEBEF mechanism[83] allows DSR operators to sell blocks of DSR in the intraday and day-ahead markets without prior consent from the supplier's BRP. These blocks of DSR correspond to the volume of energy not consumed by flexible consumers during activation periods. In wholesale markets, from the buyer's point of view, buying a block of DSR operators is strictly equivalent to buying a block of energy produced by a generating unit.

The NEBEF mechanism has played an important role in enabling DSR development in France, by defining the roles of the different players, providing a regulatory framework for the participation of independent aggregators in energy markets without suppliers' consent, and streamlining the methodology applied by the TSO for the certification of DSR volumes in wholesale markets. Figure 12 below summarises the steps of the NEBEF mechanism.

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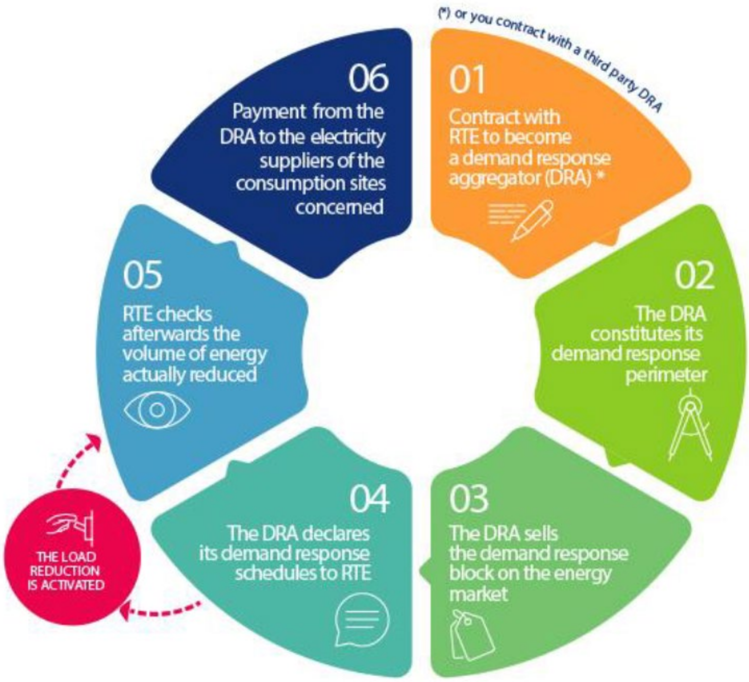
81 Autorité de la Concurrence (2012), Avis n° 12-A-19 du 26 juillet 2012 concernant l'effacement de consommation dans le secteur de l'électricité, page 7.

82 RTE (2023) Règles pour la valorisation des effacements de consommation sur les marchés de l'énergie – NEBEF 3.5.

83 *Ibid*

Figure 12 – The NEBEF Process



Source: RTE

While the NEBEF mechanism favoured the development of DSR, the activated volumes represent a small share of total load.

The NEBEF mechanism, alongside the different schemes to enable DSR participation in France and DSR tenders in particular, has enabled DSR participation in wholesale markets up to 440MW in 2022, corresponding to about 0.5% of the peak load.[84] Over the years, the consecutive adjustments of the NEBEF rules and increasing volatility on wholesale markets, have led to an increase in the number of participants as well as volumes traded.[85]

However, activated volumes are still relatively low compared to the total load. Even in 2022, activated volumes only corresponded to 0.1% of the total load, while daily flexibility needs are expected to significantly increase in the French electricity system. According to RTE, daily flexibility needs are expected to increase two to seven times between now and 2050, depending on the scenario.[86]

A.2 Case study: Belgium's Transfer of Energy and CRM rules

Belgium introduced the Transfer of Energy (ToE) framework to foster the development of distributed flexibility through independent aggregation.

84 Compass Lexecon analysis, based on data from RTE.
85 Enefirst (2020) Report on international experiences with E1st, page 44.
86 RTE (2050) Futurs Energétiques 2050 – Chapitre 7 : La sécurité d'approvisionnement

The ToE mechanism in Belgium allows grid users to value their flexibility in the day-ahead and intraday electricity markets by themselves or via an intermediary of their own choice, a so-called Flexibility Service Provider (FSP) which is independent from their supplier.[87]

In practice, this involves:

- Neutralising the impact of the activation of flexibility on the calculation of the imbalance of the BRP of the supplier.
- Providing the necessary data to the FSP and the supplier to enable them to correctly adjust the financial impact of the activation on the supplier.

Moreover, some arrangements have been introduced in the Belgian CRM for distributed flexibility, and the attractiveness of the CRM for this type of assets will be assessed in forthcoming Y-1 auctions.

For instance, market participants can tailor their capacity obligation to some technical constraints. Market participants can choose a service level agreement (SLA), i.e. an availability duration obligation (1h to unlimited) in line with their technical constraints. The obligated capacity equals their non-de-rated capacity for hours within their energy constraints, and to zero for any other hour in the same day.

Figure 13 – Choice of Service Level Agreement in the Belgian CRM

Category	2028-29/Y-4 Derating Factor [%]
SLA-1h	19
SLA-2h	35
SLA-3h	48
SLA-4h	57
SLA-5h	65
SLA-6h	71
SLA-7h	76
SLA-8h	81
SLA-9h	86
SLA-10h	89
SLA-11h	93
SLA-12h	95
SLA unlimited	100

Source: Elia (2024) Capacity Remuneration Mechanism, page 36.

The Belgian CRM is built with a reliability option, implying that producers are obliged to return money received from the capacity contracts if the hourly power prices exceed a strike price in case of unforeseen price peaks that decrease the need for capacity revenues. DSR players can adapt their reliability option to their specific opportunity costs. In principle, the revenues that contracted capacity units derive from their participation in the energy market in scarcity periods have to be paid back when the market price is above a given strike price. However, capacities without daily schedules, for instance DSR, can switch from using one single strike price to using multiple declared market prices (DMPs) associated with volume thresholds. These DMPs can be higher than the strike price and represent the prices above which these CMUs declare to deliver energy in the energy market, with associated volumes. This makes it possible to take into account the specific opportunity costs of DSR assets. This principle is further illustrated in Figure 14.

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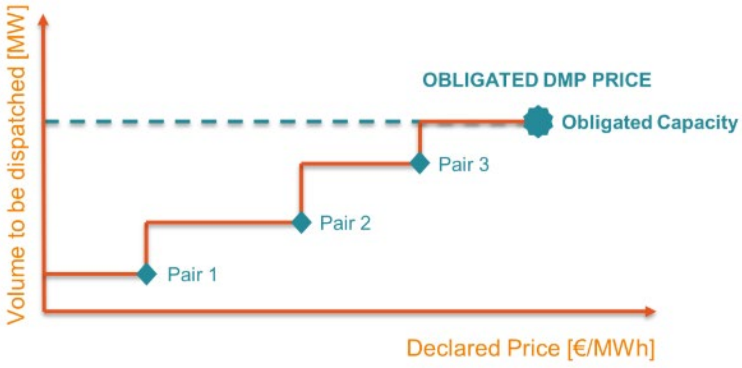
87 Elia (2020) Design note: Transfer of Energy in DA and ID markets

Figure 14 – Illustration of DMP Price-volume Pairs in the Belgian CRM



Source: Elia (2019) CRM Design Note: Availability Obligations and Penalties, page 30.

However, criticism has been voiced by DSR providers regarding the applicability of reliability options for DSR assets, who emphasise that DSR capacities should be exempt from the obligation to pay back price peaks under reliability options when the market price exceeds the strike price.

The behaviour of players in the forthcoming DY-2 and DY-1 auctions, the timing of which is supposed to be more appropriate than for DY-4 in relation to delivery, will nevertheless give a clearer indication of the attractiveness of the CRM for DSR capacity.

A.3 Case study: PJM Interconnection's Demand Response programme

The organisation of electricity systems in the US is different than in Europe.

While some areas are characterised by vertically integrated monopolies, responsible for generating, transmitting, and distributing electricity to end customers, typically, in the South and West, two-thirds of customers in the US live in a region where electricity markets are deregulated. In these seven regions, ISOs or Regional Transmission Organisations (RTOs) organise competitive power markets between suppliers and generators, manage the rules for the dispatch of generators, and operate portions of the electric transmission system. [88] The specific market features vary from one region to the other, although US markets are generally organised with central dispatch,[89] and transmission constraints are integrated in market prices through nodal pricing.[90]

PJM Interconnection LLC has enabled DSR players to participate in the wholesale and capacity markets.

Right from its implementation, the PJM capacity market, called the Reliability Pricing Model, was open to DSR participation and effectively enabled its development in the late 2000s. For instance,

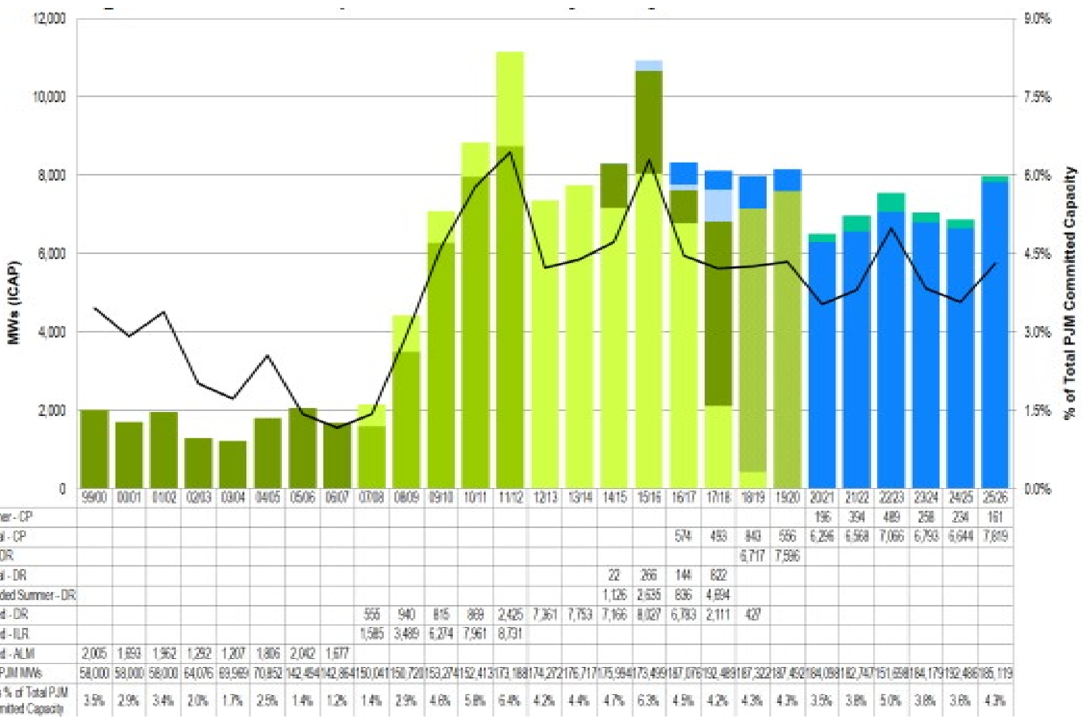
88 EPA (2023) Power market structure

89 Central dispatch refers to a scheduling and dispatching model where the generation schedules and consumption schedules as well as dispatching of power generating facilities and demand facilities, are determined by a TSO within the integrated scheduling process. In such systems, balancing, congestion management and reserve procurement are performed simultaneously in an integrated process.

90 Nodal pricing refers to a price formation mechanism where every node in the electricity grid is a separate biding zone. Transmission constraints are accounted for in the market clearing algorithm, and the price at each node represents the locational value of energy, which includes the cost of the energy and the cost of delivering it.

as shown in the Figure 15 below the DSR capacity available in the market rose from less than 2GW in 2006/07 to more than 11GW in 2011/12, following the implementation of the capacity mechanism (the Reliability Pricing Model, or RPM) in 2007, reaching more than 6% of the committed capacity.[91] Since the peak in 2011/12, DSR participation has remained high, although it fluctuates due to more restrictive technical constraints.

Figure 15 – PJM Demand Response Committed MWs by Delivery Year



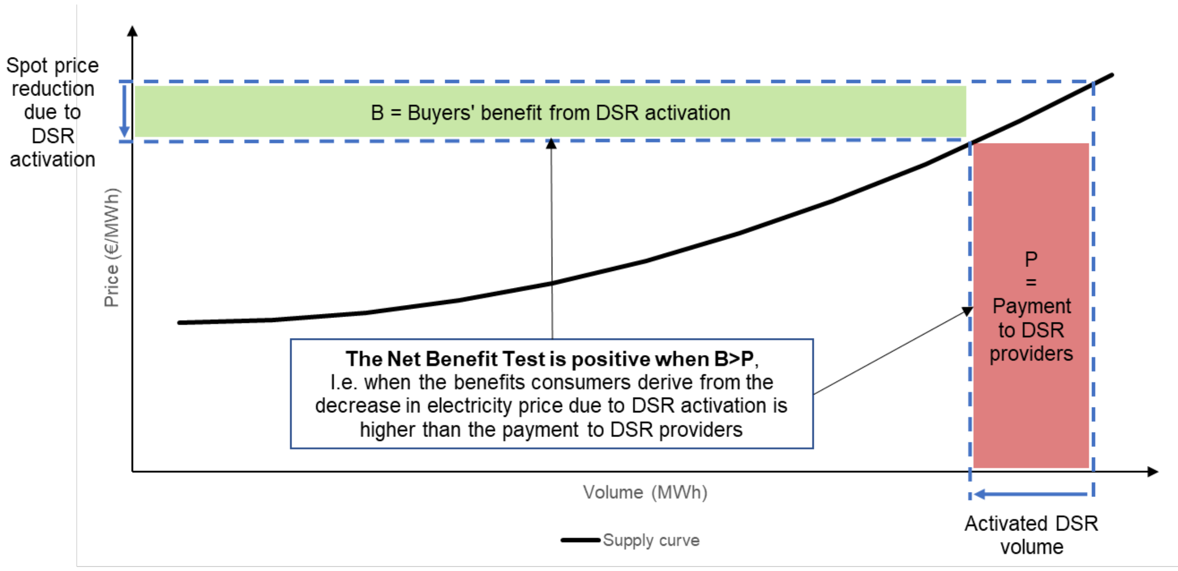
Source: PJM (2024) [2024 Demand Response Operations Markets Activity Report: December 2024](), page 5.

Moreover, DSR players can participate to the wholesale market through PJM's Economic Demand Response Program. When the activation of DSR in the wholesale market is perceived as beneficial for all consumers, DSR resources can be dispatched in wholesale markets and receive the full market price like generators. More precisely, consumers can reduce their load in the energy market when the wholesale price is higher than PJM's published monthly Net Benefit Price. The Net Benefit Price represents the price in PJM's wholesale markets at which the benefits of reducing wholesale prices through economic demand response exceed the costs of paying for economic demand response.[92] This principle is illustrated in Figure 16.

91 PJM stands for Pennsylvania, New Jersey, Maryland.

92 PJM – Retail electricity consumer opportunities for Demand Response in PJM's Wholesale markets, page 2-3.

Figure 16 – Illustration of the Net Benefit Test Principle



Source: Compass Lexecon

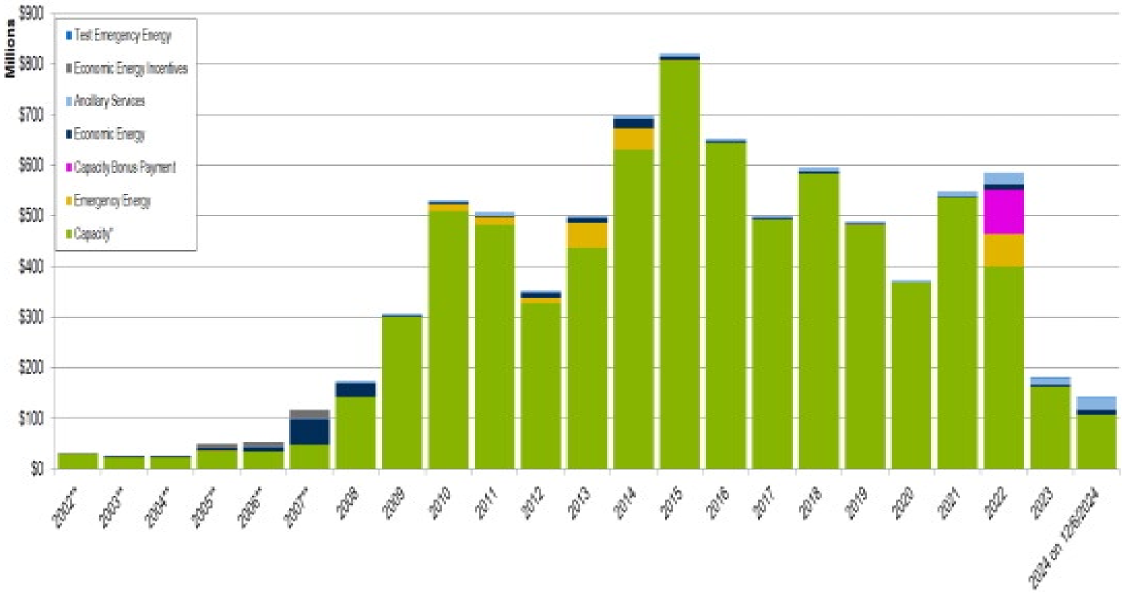
DSR players can also participate in ancillary services, including the Synchronised Reserves, the Day-Ahead Scheduling Reserves Market, and Regulation.[93]

DSR deployment is correlated to the implementation of capacity mechanisms

Overall, PJM indicates that the earnings of DSR resources from wholesale markets still constitute a small portion of their total income. The business case of DSR is indeed still largely driven by capacity remuneration, as indicated in Figure 17.[94] For instance, in 2021, 95% of DSR revenues were coming from capacity markets participation.

93 PJM – Retail electricity consumer opportunities for Demand Response in PJM's Wholesale markets, page 3.
94 PJM (2022) 2021 Demand Response Operations – Markets Activity Report: March 2022, page 4.

Figure 17 – PJM Estimated Revenue for Economic and Load Management DR by Wholesale Markets



Source: PJM (2024) 2024 Demand Response Operations Markets Activity Report: December 2024, page 4.

B Appendix 2 – Case studies for Pillar II: Ensure that the market design adequately reflects the full value of flexibility for the power system

B.1 Local Case study: UK's RIIO framework for grid operators has incentivised the development of local flexibility

Flexibility needs in the UK are expected to increase by 2030, driven by ramping congestion issues and increasing RES-E penetration.

Flexibility needs in the UK are expected to increase by 2030, driven by rising congestion issues and increasing renewable generation penetration, including on the distribution network. In this context, public authorities expect DSR, batteries, and other sources of flexibility to bring significant savings by reducing the required generation and network capacity, or postponing investments.

Through recent years, the capacity market as well as the framework for contracting capacity for ancillary services played a significant role in the development of flexibility in the UK.

An innovative regulatory framework has been introduced to incentivise system operators to resort to consumer flexibilities as an alternative to grid investments.

In the UK, the RIIO-1[95] framework price control for network companies introduced for the period 2015-2023 integrates capital and operational expenses through a TOTEX approach. This encourages network operators including DSOs to consider holistic solutions for grid management, reducing the "CAPEX bias" associated with traditional regulatory frameworks that remunerate network operators based on their regulated asset base.[96]

The RIIO framework also included incentives for DSOs to innovate and use flexible resources as an alternative to grid reinforcements. The RIIO-ED2 price control period 2023-2028 included incentives on DSOs' performance in using flexible distributed resources. Depending on their performance related to outturn performance metrics, covering flexibility reinforcement deferral, secondary network visibility and curtailment efficiency,[97] network companies could earn up to +0.4% of RoRE[98] per year, and be penalised up to -0.2%.[99]

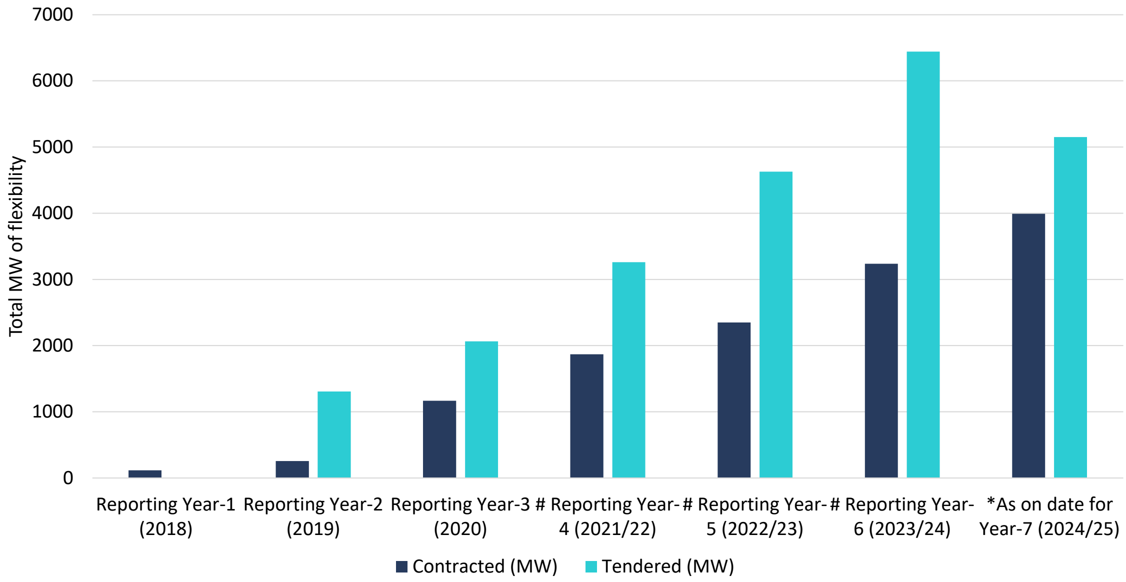
95 The 'RIIO' price control framework stands for Revenues = Innovation + Incentives + Outputs.
96 CEER (2024) Report on Regulatory Frameworks for European Energy Networks 2023.
97 Ofgem (2024) RIIO-ED2 Distribution System Operation Incentive metrics consultation.
98 Return on Regulatory Equity
99 Ofgem (2022) RIIO-ED2 Final Determinations Overview document, page 23.

Additionally, to develop flexibility at scale, Ofgem, also decided in 2023 to allow DSR participation in wholesale electricity markets, including via aggregators and without prior consent from suppliers. Moreover, suppliers' compensation costs are mutualised amongst suppliers rather than borne by independent aggregators. Ofgem explained that such approach would lead to greater volumes of flexibility deployment, and therefore "*greater welfare benefits*" compared to a solution where independent aggregators would bear these costs.[100]

In the UK, a framework to capture the different types of benefits associated with flexibility and fostering flexibilities for network operations has been developed.

The UK regulatory framework has successfully stimulated the development of local flexibility to relieve congestions on the distribution network. The first tenders for the provision of flexibility services to DSOs took place in 2018, and an increasing volume of flexibility has been procured each year, reaching a total capacity of around 4 GW in 2024/2025, as shown on Figure 18 below.[101] However, the contracted capacity is still markedly below the tendered flexibility capacity for DSOs, indicating that an important share of the need is not fulfilled every year. This capacity is contracted across a range of technologies. DSR accounts for approximately 13% of contracted capacity in 2023/2024, storage amounts to 29% of capacity, while another 31% are provided by wind and solar resources.[102]

Figure 18 - Tendered and Contracted Local Flexibility Services for Delivery in the Reporting Year in the UK



Source: Energy Network Association (2024) Open Networks - 2024 Flexibility Figures.
Note: 2024/2025 data point is as of August 2024.

The development of local flexibility contracting has been enabled by the emergence of flexibility platforms in the UK. Flexibility service providers can participate in local flexibility tenders via two

100 Ofgem (2023) Balancing and Settlement Code (BSC) P415: Facilitating access to wholesale markets for flexibility dispatched by Virtual Lead Parties (P415)
101 Energy Network Association (2024) Open Networks - 2024 Flexibility Figures.
102 Energy Network Association (2024) Open Networks - 2024 Flexibility Figures.

main market platforms: Flexible Power,[103] developed by DSOs, or Piclo Flex.[104] These platforms can be used for a range of features, such as the advertisement of flexibility needs, gathering flexibility bids and offers, automated settlement, and dispatch. While these platforms are key enablers of local flexibility contracting at distribution level, there is a need for greater collaboration across DSO and TSO levels for the optimisation of flexibility use.

Last, the introduction of specific incentives for the development of flexibility has been an innovative feature of the UK regulatory framework. However, the implementation of the regulatory framework has been challenging, with Ofgem deciding in April 2024 to cancel the application of financial rewards or penalties until the next price control from 2029.[105] This is because issues such as data quality, insufficient historical data, methodological challenges, and the risk of unintended consequences proved challenging to build a robust performance incentive framework for DSO flexibility so far.[106]

B.2 Case study: EU's 15-minute imbalance settlement period

Under the electricity balancing guidelines published by European Commission in 2017, the imbalance settlement period must be harmonised to 15 minutes in each European country.

Commission Regulation (EU) 2017/2195 of 23 November 2017 establishing a Guideline on Electricity Balancing (EBGL) lays down detailed rules for the integration of balancing markets in the EU. It lays down a balancing market target model for each EU country, with the aim of promoting effective competition, non-discrimination, transparency and integration in electricity balancing markets. The aim is to increase the efficiency of the European balancing system and security of supply.[107]

In particular, the guideline requires all TSOs to harmonise the imbalance settlement period to 15 minutes by 2025 at the latest. The imbalance settlement is a financial settlement mechanism aimed at charging or paying BRPs for their imbalances for each imbalance settlement period. Historically, EU countries have applied imbalance settlement period of 60, 30, and 15 minutes.[108]

The harmonisation of the imbalance settlement period to 15 minutes across the EU presents several benefits, including wider access to balancing markets for all flexible assets.

ENTSO-E notes that possible benefits of a shorter settlement period of 15 minutes include wider access to balancing markets: "*shorter period between gate closure and delivery may allow less controllable generation and loads to participate in the balancing market where they could not with a longer period*". Moreover, with a shorter settlement period, the system can potentially benefit from reduced imbalance.[109]

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103 See website. Joint initiative by Western Power Distribution, Northern Powergrid, Scottish and Southern Electricity Networks, SP Energy Networks and Electricity North West.

104 See website. Independent trading platform used by Electricity North West, NIE Networks, SP Energy Networks and UK Power Networks (in 2021).

105 Ofgem (2024) RIIO-ED2 Distribution System Operation Incentive metrics decision, page 2.

106 *Ibid,* page 2.

107 ENTSOE (2018) Electricity balancing in Europe – An overview of the European balancing market and electricity balancing guideline, page 3.

108 *Ibid*, page 12-13.

109 ENTSO-E (2015) Cost benefit analysis for electricity balancing – ISP harmonisation methodology, page 22.

However, the benefits of switching to an imbalance settlement period of 15 minutes cannot be easily quantified and important implementation costs may need to be taken into account.

CRE notes that "*ensuing benefits from switching to a 15-minute imbalance settlement period, likely to result in a more efficient mobilisation of balancing resources in the […] electricity system, cannot be easily quantified*."[110] The cost-benefit analysis mandated by ENTSO-E concludes that assessing the net impact of a change in ISP is "*clearly a complex and uncertain undertaking*."

B.3 Case study: UK Ancillary services reform – Introduction of fast frequency response

NESO introduced fast frequency response services in 2020 to meet the new flexibility requirements of the electricity system.

NESO has implemented a reform of the UK ancillary services since 2019 and introduced three types of dynamic services to provide fast frequency response. These fast-acting frequency response products have been deemed necessary by the system operators since keeping frequency at the required 50Hz is becoming increasingly challenging. The inertia of the UK electricity system is decreasing due to the introduction of intermittent renewables and the phase-out of conventional thermal power stations. This tends to exacerbate frequency drops in case of sudden demand or generation loss.[111]

- Dynamic Containment (DC) is particularly suited to act in the event of a sudden demand or generation loss. DC is a fast-acting, post-fault service designed to arrest frequency in large-loss, low inertia scenarios. The DC Low Frequency product was launched in October 2020, followed by the launch of the DC High Frequency service in October 2021.
- Dynamic Moderation (DM) and Dynamic Regulation (DR) provide a constant power response across a ±0.015 Hz to 0.2 Hz range. DM and DR are pre-fault services: providers make automatic adjustments in generation or demand. DR provides a constant power response across the operational frequency range, reaching full delivery at a ±0.2 Hz frequency deviation. DM responds between ±0.1 Hz and ±0.2 Hz, providing additional power to stabilise frequency as it moves closer to operational limits. DM and DR went live in March 2022.[112]

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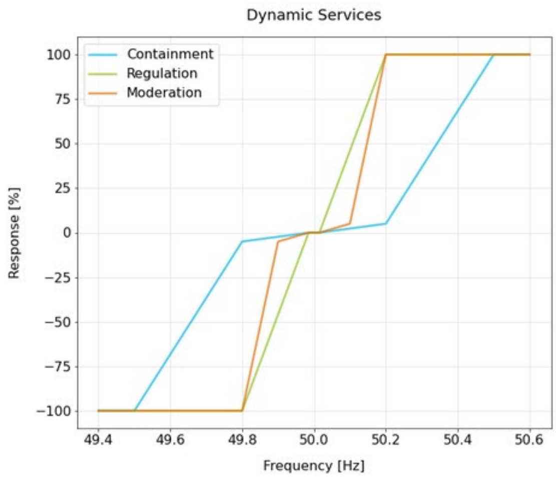
110 CRE (2018) Deliberation of the French Energy Regulatory Commission of 14 November 2018 on the decision to grant a derogation until 1 January 2025 to switch to a 15 minute imbalance settlement period in France, page 3.

111 National Grid ESO (2019) Response and Reserve Roadmap

112 ESO (2024) New Dynamic Response Services – Provider Guidance v.8

Figure 19 - Dynamic Services Delivery Requirements Curves (left) and Service Specifications (right)



Service specification	Description	DC	DM	DR
Initiation time	The maximum time between a change in frequency and change in the delivery of response	0.5s	0.5s	2s
Max time to full delivery	The maximum time between frequency deviation occurring and delivery of the saturation quantity	1s	1s	10s
Delivery duration	Time that an energy limited provider must be capable of sustained delivery	15 minutes	30 minutes	60 minutes

Source: Open Energi (2024) A new frontier in dynamic frequency. Does it stack up (left); ESO (2024) New Dynamic Response Services – Provider Guidance v.8, page 7 (right).

The introduction of new services successfully led to the development of new flexibility assets.

Since their introduction in the UK, batteries have been the main provider of fast frequency response services. Batteries can provide a near-instantaneous response in both up and down directions, which makes it a key technology to provide these services.

Some observers note that the provision of these services has been a key source of revenue for the UK battery fleet, with stable, high prices and low cycle rates.[113] In turn, this reform of the UK ancillary services has been a key driver of the development of new battery projects: it has attracted many battery projects given the profitability that could derived from the procurement of these services.[114]

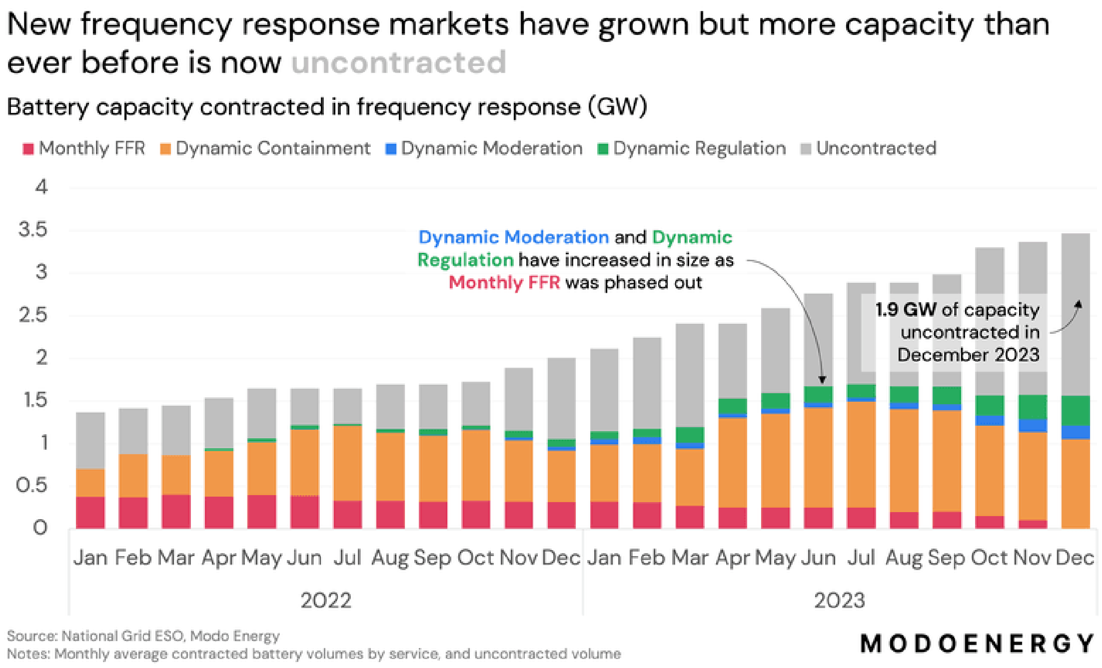
However, dynamic services reserve is reaching saturation, and the business case of battery project may need to transition from dynamic service procurement to energy arbitrage

Dynamic reserves have rapidly reached saturation, with evidence as early as Q4 2022.[115] The revenue stack of batteries in the UK may need to progressively transition from ancillary services procurement to energy arbitrage.

This shift is already underway, as total operating battery capacity is growing in the UK, although the contracted volumes of frequency response have remained stable, as shown in Figure 20. This means that more capacity than ever is uncontracted and operating in wholesale markets.

113 See for instance: ModoEnergy (2021) Symmetric DC participation – how much can you stack?
114 See for instance: Timera Energy (2022) GB batteries confront ancillary saturation
115 Ibid

Figure 20 – Total Operating Battery Capacity in frequency response in the UK between 2022 and 2023



Source: ModoEnergy (2024) The top ten battery energy storage headlines from Q4 2023

B.4 Case study: USA's nodal pricing

In several regions of the United States, wholesale market prices express the local value of energy through marginal locational pricing.

In the zonal system used by most EU Member States, market prices are determined on a country-by-country basis. Grid operators handle internal congestion within their national grids through redispatch measures, with the associated costs passed on to grid users via network tariffs. Likewise, network operators cover power losses by purchasing energy from the market, and these costs are also transferred to network users. Consequently, generators have no incentive to adjust their production schedules to minimise grid losses.[116]

By contrast, all US jurisdictions where power systems are liberalised use nodal pricing (also called Locational Marginal Pricing – LMP), a method whereby market clearing prices are calculated for a number of locations on the transmission grid (nodes). The nodes represent a physical location on the transmission system aggregating local generators and loads. Hence, the clearing price at each node expresses the locational value of energy: the cost of the energy and the cost of delivering (losses and congestion). This signals local scarcity to generators and loads, and helps alleviating congestions.

The use of nodal pricing can bring several benefits to the system, for example in relation to the location of flexible assets.

116 FTI Compass Lexecon Energy (2018) Nodal pricing systems: the US experience and outlook for Europe, page 4.

Using a nodal wholesale market price, based on the marginal cost of using the network in a given geographical location, can guide producers' choices in terms of where to locate their investments. Flexible assets can be located where their value would be maximised, depending on the signal given by nodal prices.

While the hourly nodal price may be considered too volatile to provide a reliable investment signal on its own, derivatives exist to provide market participants with a hedge against this volatility:

- Futures markets provide a hedge against the temporal volatility of prices at regional level. Such markets generally do not distinguish between different network nodes but define a forward product for the delivery of electricity to a regional hub.

- Products to hedge congestion risk**,** i.e. the geographical volatility of nodal prices, are created in the nodal markets in order to deal with the risk of congestion between the various nodes in the system in the daily market. These products take the form of Financial Transmission Rights (FTRs), which entitle the holder to receive the difference in nodal prices between the point of withdrawal and the point of injection.

A flexible capacity holding a long-term contract for electricity on its regional hub and a FTR between its node and the regional hub can hedge itself in part against temporal and geographical price volatility. Moreover, the price at which the flexible asset buys the FTR varies according to the nodes in the network and therefore represents a long-term location price signal. [117]

However, the nodal approach raises several questions and implementation issues, and cannot easily be transposed to European countries.

Transitioning to a nodal system at the European level would require an evolution of the target model and associated regulations, fundamentally transforming the market architecture.

Moreover, from a more operational point of view, numerous questions would arise:

- While in Europe, market participants are currently primarily responsible for optimising the scheduling of their assets within their portfolio and balancing their injections and withdrawals, in a nodal system, the responsibility for scheduling would shift to the grid operator. This would represent a move from a decentralised scheduling model to a centralised one, with a change in the responsibilities of the stakeholders.

- To allow market participants to hedge against price variation **risks** at different network nodes, a market for CfDs (similar to financial transmission rights in U.S. markets) would need to be established.

- Furthermore, transitioning to a nodal pricing system would require closer alignment between the activities of grid operators and energy exchanges for short-term markets.

B.5 Case study: Germany's NOVA principle for grid expansion

The German TSOs follow a network development policy that favours firstly optimising and strengthening the existing network, and then extending the network.

In Germany, the energy transition requires major investment in the transmission network. The development of onshore and offshore wind generation in the north and east of the country is far outstripping regional demand. Furthermore, the strong demand in the south and west of the country,

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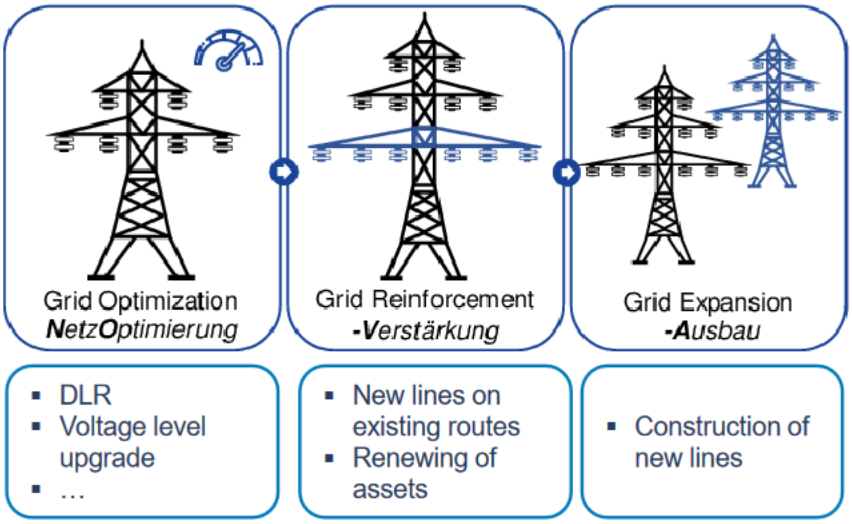
117 Ibid, page 4.

particularly from industrial sites, cannot be met by local production in the future. As a result, there is a need to transport electricity from the north to the south of the country, resulting in major infrastructure expansion needs.[118] However, the development of the network is facing major problems of social acceptance.[119]

As a result, German TSOs developed a methodology to steer investments into solutions other than expansion to manage grid constraints in order to improve social acceptance levels towards grid infrastructure projects overall. All German TSOs apply the so-called NOVA principle when expanding the transmission grid and implementing related construction projects: only if optimisation and reinforcement of the existing network can no longer ensure the necessary transmission capacity is the feasibility of an expansion examined. This principle is summarised in Figure 21.

Figure 21 – NOVA Grid Planning Principle Applied by German TSOs



Source: Compass Lexecon, adapted from Wagner (2020) Grid planning principle "NOVA", page 2.

While the use of commercial flexibility is still limited in Germany, the NOVA principle could be used to maximise the use of commercial flexible assets to answer network constraints.

The NOVA principle applied by the TSOs could provide an interesting framework to leverage the value of flexible assets as network expansion alternatives. The use of commercial flexibility could for instance be incorporated within this framework as an optimisation measure. Whenever a network constraint is identified, the use of commercial flexibilities could be considered before any reinforcement or expansion work in order to limit infrastructure work.

118 German TSOs (2024) Network Development Plan 2037/2045 (2025)

119 See for instance: Flachsbarth *et al* (2021) Addressing the effect of social acceptance on the distribution of wind energy plants and the transmission grid in Germany

C Appendix 3 – Case study for Pillar III: An investment framework for flexible resources

C.1 Case study: Australia's capacity investment scheme

Australia is implementing a new Capacity Investment Scheme

To face the challenges posed by the energy transition, Australia recently implemented a new Capacity Investment Scheme (CIS) which aims to deliver an additional 32 GW of generation capacity by 2030 and deliver the Australian government's target of 82% renewable electricity by 2030.

Currently and traditionally, the Australian market has relied on an energy-only market approach with several light design elements containing electricity prices, such as market price caps. However, growing concerns for adequacy in the NEM have led to the introduction of a first mechanism in 2019, called the Retailer Reliability Obligation, to be replaced with the CIS from 2025.

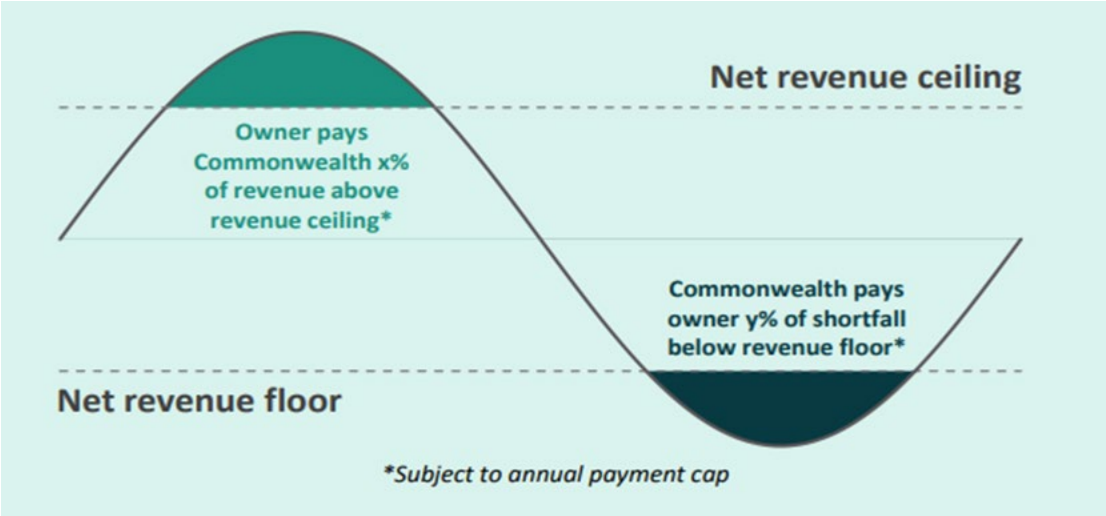
The CIS covers low-carbon flexibility assets, and acts as a revenue cap and floor mechanism.

The CIS functions with competitive tenders, held approximately every six months. Selected projects are offered long-term agreements with the Australian government on an agreed revenue floor and ceiling. The length of the contracts offered are bid-dependent but may go up to 15 years.

The CIS is designed to be technology neutral among clean technologies. It encompasses flexible capacities such as storage, other zero-emissions technologies, as well as virtual power plants which are eligible to the CIS. With regards to storage projects, the duration of storage is considered as part of the tender merit criteria for the selection of contracted projects.

If a selected project's earnings exceed the net revenue ceiling in the duration of the contract, the owner will pay the government an agreed percentage of revenue above the ceiling. In the opposite scenario, the government will cover a portion of the difference between the revenue floor and zero revenue.

Figure 22: The CIS Revenue Mechanism



Source: Source: DCCEEW (2024) Capacity Investment Scheme, page 16.

The introduction of CIS acknowledges limitations in market signals to incentivise investments, and acts as a de-risking instrument for flexibility revenues.

The introduction of the investment mechanism in Australia recognises the risks of leaving all signals up to the market to respond to the needs of a system in transition, where the need for coordinated investments is important. With issues linked to the acceptability of price spikes and associated interventions, the Australian case showed the limits for markets to deliver the necessary signals for adequacy or flexibility.

The underwriting mechanism settings in the CIS are designed to preserve a level of price exposure for project proponents and are available for hedging in the contracts market. As a result, it contributes to de-risking investments, including for low-carbon flexibility assets covered by the mechanism.

However, as the mechanism has just been introduced, it is not clear whether the proposed reforms will be sufficient to incentivise new investments in assets with the specific capabilities needed by the TSO.

C.2 Case study: France’s flexibility contracting tender

France implemented a complementary mechanism to remunerate specific flexibility technologies interlinked with the CRM.[120]

In France, the DSR call for tenders is a system to support the development of electricity consumption demand response, which was approved by the European Commission in 2018 and extended in 2023. This mechanism was developed to support DSR capacity specifically to reach national objectives, rather than based on technology-neutral pre-identified flexibility needs.

120 Commission Européenne (2018) SA.48490 (2017/N) – France Soutien de l'effacement en France par appel d'offres.

The measure aimed to ensure the emergence of the DSR sector and its competitiveness on the market, in addition to the market-wide CRM, to reach 6 GW of DSR, including implicit DSR, in 2023 .

The DSR mechanism provides contracts up to 10 years, and links revenues to the CRM.[121]

The mechanism consists of annual tenders open to DSR capacities, awarding a feed-in-premium on the capacity price to winners in exchange for an obligation to make their capacity available in different market segments, during specific days identified by the TSO and consistent with the capacity market availability obligation. This ensures that the supported DSR is made available on the days of greatest tension on the electrical system.

The feed-in-premium relies on the principle of CfDs, i.e. calculated against the revenue that can be perceived in the capacity market, to avoid any windfall profits for DSR units, and therefore contributing to the proportionality of the measure. The mechanism takes the form of single or multi-year contracts of up to 10 years for certain categories, depending on RTE's needs. It is worth noting that only 'green' DSR is eligible, i.e. corresponding to an actual decrease in consumption (e.g. load shedding by starting up a generator is not eligible).

The DSR mechanism is replaced from 2025 onwards by the decarbonised flexibility mechanism.[122]

Capacity remuneration through dedicated tenders and the CRM has been the key driver of the development of DSR capacities in France and accounts for about 95% of total DSR revenues.[123] DSR participation in wholesale markets reached up to 440MW in 2022, corresponding to about 0.5% of the peak load.[124] Contracted volumes through the mechanism have risen over the last years, from 1.9 GW in 2022 to 2.9 GW in 2024, as shown on Figure 23.[125] Even then, the procured volumes fall short of political objectives: the French targets for DSR were 4.5 GW in 2023, towards 6.5 GW in 2028.[126]

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121 RTE (2023) Cahier des charges de l'appel d'offres de crise portant sur le développement de capacités d'effacement de consommation d'électricité pour le T4 2023 et l'année 2024, page 6.

122 Commission Européenne (2023) Aide d'État SA.107352 (2023/N) – France : mesure de soutien aux flexibilités décarbonées de court terme en France par appels d'offres, page 16.

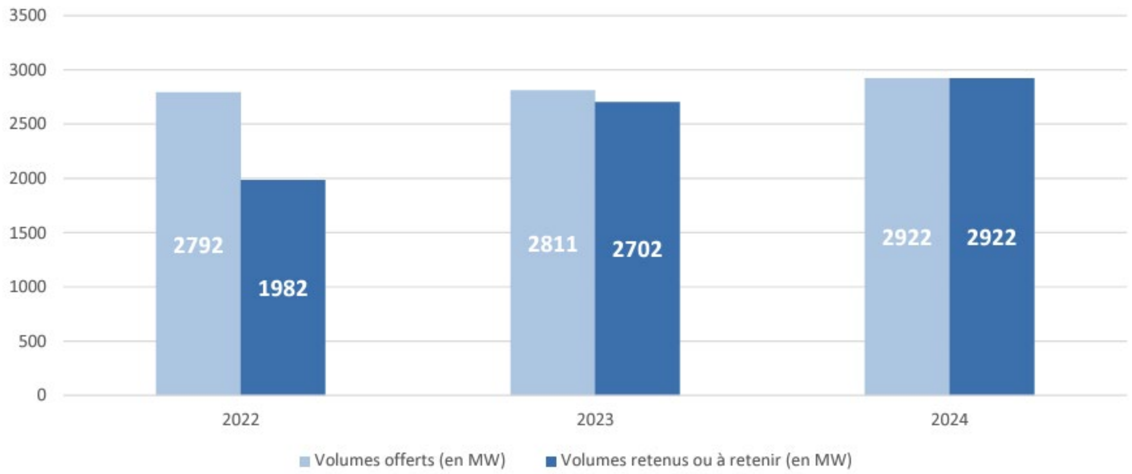
123 French government (2020) Integrated national energy and climate plan for France, page 271.

124 Compass Lexecon analysis, based on data from RTE.

125 In 2018, 850MW were offered in the first tender. RTE (2018), Appel d'offres portant sur le développement de capacités d'effacement de consommation d'électricité pour 2018, page 7.

126 French government (2020) Stratégie française pour l'énergie et le climat – Programmation Pluriannuelle de l'Energie, 2019-2023, 2024-2028, page 188.

Figure 23 - DSR Tender Offered Volumes (light blue) and Contracted (blue) in France, 2022-2024 (MW)



Source: RTE (2023) Résultats de l'AOE 2024, page 3.

The DSR tenders in France are in the process of being replaced by a wider mechanism to support low-carbon flexibility sources. The upcoming decarbonised flexibility mechanism is planned to cover the period 2025-2026. For 2024-2026, €1.3bn have been set to incentivise investment in 13.6 GW of 'decarbonised flexibility' through the new mechanism. The French government argue that there is too much uncertainty about future revenue expectations and the period over which these revenues will be received to allow the development of new low-carbon flexibilities based solely on market revenues, for which the mechanism is needed.

While this new mechanism opens participation to wider flexibility technologies beyond DSR, such as storage assets, it is still not fully technology-neutral to reach flexibility needs. In other words, instead of remunerating a specific product responding to a specific system need, the new mechanism is targeting specific technologies to achieve policy development goals.

C.3 Case study: CAISO's flexible ramping products

CAISO implemented flexible capacity requirements in its capacity mechanism in 2015.

In 2006, CAISO implemented a resource adequacy programme that requires suppliers ('load serving entities') to ensure system reliability each year by demonstrating that they have sufficient capacity commitments to satisfy their expected peak demand in the forthcoming summer peak season. In 2015, CAISO added a ramping requirement in its existing capacity market to ensure the system has enough flexible resources available to meet forecasted net load ramps.

This mechanism was implemented to fulfil an increasing need for flexibility in the Californian system due to the large penetration of intermittent renewables, which could not be addressed via the existing reserves at the time. In 2024 for instance, solar generation represented more than 60% of installed capacity in California.[127]

127 California ISO (2024) Key Statistics, page 3.

CAISO sets the flexibility requirements, but the procurement is mostly decentralised.

CAISO sets system-wide flexible capacity requirements based on demand fluctuations and variations in wind and solar generation. It identifies base, peak, and super peak conditions and assigns capacity levels to load serving entities, who must show they have sufficient resource contracted. If there is a shortfall, CAISO procures backstop capacity as a last resort.

To qualify as flexible capacity, a resource must have a certified capacity and be able to ramp up on a 5-minute dispatch notice and produce for at least three hours. The monthly flexible requirement of load serving entities is set at the forecast maximum consecutive three-hour net load ramp during the month.

The mechanism is successful in planning and procuring the required flexible capacity, but there is no significant premium for flexible capacity.

In terms of capacity procured, enough flexibility has been present on the system since the introduction of the mechanism. The flexible resources adequacy procurements were sufficient to meet the actual maximum net load ramps for all months in 2022.[128] Year-ahead total flexible resource adequacy procurement exceeded total requirements, and the must-offer obligation for procured capacity was sufficient to meet the maximum net load ramp in all months in 2020-2022. In 2022, CAISO converted to nodal pricing and procurement of flexible ramping capacity to address a growing concern about the physical deliverability of procured flexible ramping services.

However, the role of the mechanism itself to drive investment in flexible capacity is unclear. Indeed, current flexibility supply and demand do not result in a significant premium paid for flexible capacity in the capacity mechanism. Over the period 2018-2022, the average price for flexible capacity contracts was $32/kW/year, which is not significantly different from capacity price without flexibility. In 2022, prices for flexible capacity were considerably lower than those for non-flexible system capacity, as shown on Figure 24 below.

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128 California Public Utilities Commission (2024) 2022 RESOURCE ADEQUACY REPORT, page 24.

Figure 24 - Comparison of Flexible and Non-flexible Capacity Price in the California CRM in 2022

	Flexible Capacity	Non-Flexible Capacity
Contracted Capacity (MW)	12,503	23,885
Percentage of Total Capacity in Data Set	34%	65%
Weighted Average Price ($/kW-month)	$6.61	$8.00
Average Price ($/kW-month)	$7.26	$8.66
85% of MW at or below ($/kW-month)	$8.10	$15.00

Source: California Public Utilities Commission (2024) 2022 RESOURCE ADEQUACY REPORT, page 33.
Note: flexibility prices are for capacity located outside of local areas.

This could be explained by the fact that more than 90% of the remunerated technologies are gas-fired capacities. The absence of significant flexibility premium could result from the fact that the current fleet is already flexible or because the demand for flexibility has not yet sufficiently increased.

From a market design perspective, this case study raises the question of the complementarity of the underlying capacities addressing system needs. Indeed, the necessity of introducing complex procurement mechanisms covering both firm and flexibility characteristics can be questioned if the capacities delivering firmness and flexibility overlap. By procuring only one product, for instance firm capacity, flexible capacity would be developed 'naturally' as a by-product.

C.4 Case study: Ireland's long-term ancillary services contracts

As an island, Ireland has important flexibility needs to cater to intermittent and HVDC developments, in particular to ensure adequate inertia in its system.[129]

Due to operational constraints, Ireland has had to curtail wind generation whenever the System Non-Synchronous Penetration (SNSP) exceeds 50%. This limit hinders the achievement of the renewable targets for 2030: 37% of power generation is expected to come from wind, which would require massive wind curtailment of up to 25% per year.

As a result, Ireland introduced the DS3 Programme in 2011, built around three main pillars: system performance, system policies, and system tools. The focus has been on creating the correct technical and commercial mechanisms to incentivise and improve system performance and capability. Part of this programme includes the review of system services.

129 EirGrid. DS3 Information programme, page 9.

To face these challenges, Ireland reformed its ancillary services to double the number of contracted products and introduce long-term contracts for capital-intensive flexibility assets.

Ireland doubled the number of System Service products from 7 to 14, to better reflect new services needed when operating the system with high levels of non-synchronous generation – these revenues are cumulated with energy market revenues and the CRM. New mechanisms were created to generate new revenues stream for capacity and incentivise adequate levels of ancillary service provision to TSOs.

Figure 25 - List of Historical and New System Services Products Introduced as Part of the DS3 Programme in Ireland

Existing

Service name	Description
Primary Operating Reserve	MW delivered between 5 and 15 s
Secondary Operating Reserve	MW delivered between 15 and 90 s
Tertiary Operating Reserve 1	MW delivered between 90 s and 5 min
Tertiary Operating Reserve 2	MW delivered between 5 min and 20 min
Replacement Reserve (De-Synchronised)	MW delivered between 20 min and 1 h
Replacement Reserve (Synchronised)	MW delivered between 20 min and 1 h
Steady-state Reactive Power	MVAr capability * (% of capacity that capability is provided)

New

Service name	Description
Synchronous Inertial Response	(Stored kinetic energy) * (SIR Factor – 15)
Ramping Margin 1 Hour	The increased MW output that can be delivered with a good degree of certainty
Ramping Margin 3 Hour	
Ramping Margin 8 Hour	
Fast Frequency Response	MW delivered between 0.15 and 10 s
Fast Post-Fault Active Power Recovery	Active power >90% within 250 ms of voltage >90%
Dynamic Reactive Response	MVAr capability during large (>30%) voltage dips

Introduced from 1 October 2016
Introduced from 1 October 2018
In the process of being introduced (required only at SNSP levels above 70%)

Source: Compass Lexecon based on Sigrid.

At the same time, Ireland introduced 6-year contracts for flexibility ancillary services, particularly to incentivise assets with high capital costs.

The DS3 programme successfully allowed for greater renewable penetration, but raises questions with respect to market design.

The introduction of new ancillary services has enabled higher wind penetration in Ireland: starting from a SNSP of 50%, DS3 Programme achieved a 65% level in 2018 and 75% in 2022. However, the success of the DS3 scheme comes at a cost, as the DS3 budget significantly increased between 2016 and 2020.

The introduction of long-term contracts provides de-risking to flexibility sources and aims to secure their development. In 2019 for instance, the first auction rewarded three battery projects totalling 110 MW of capacity, at record low costs (-82% compared to the regulated tariff, which would save final consumers around €170m).

However, the cumulation of ancillary services long-term contracts and the CRM mechanism in Ireland may raise the question of the risk of double payment and over-contracting for the concerned flexibility capacity. In addition, while adding new value streams, the multiplication of ancillary services products can add complexity and divide liquidity in these markets, which should be taken into account when considering this market design framework

C.5 Case study: Poland's capacity remuneration mechanism

Market-wide CRMs in Europe offer an investment framework for firm capacity units.

EU power markets have been historically based on the energy-only market design model, but many countries have deemed it necessary to introduce capacity mechanisms to ensure security of supply and sufficient investment in firm capacity.

Figure 26 – CRMs in European Countries

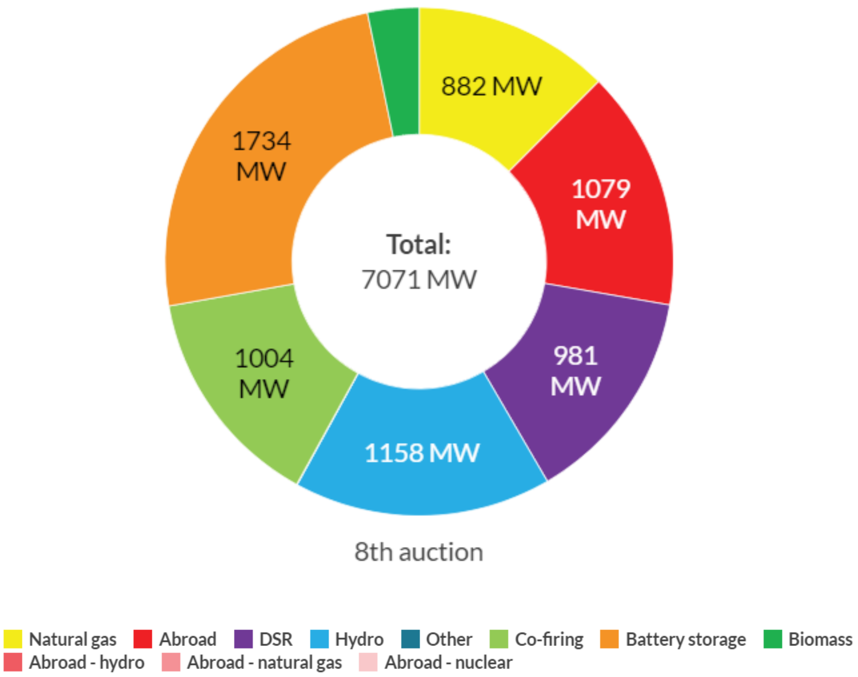
Source: Compass Lexecon

Although CRM products are not dedicated to flexibility, flexible assets have increasingly been contracted in recent CRM auctions, for instance in the Polish CRM.

The Polish CRM has indeed attracted significant amounts of battery storage and demand response in recent auction rounds. For instance for batteries, in the 8th CRM auction held in December 2023 for the provision of capacity in 2028, energy storage attracted the most contracts exceeding 1.7 GW of capacity, which is 10 times more than their first participation in the previous auction held in 2022 for delivery in 2027, when 165 MW of storage capacity was contracted. [130]

[130] Forum Energii (2024) Eighth capacity market auction – High time for the flexibility market

Figure 27 – Contracted Technologies in the Eighth Capacity Auction of the Polish CRM



Source: Forum Energii (2024) Eighth capacity market auction – High time for the flexibility market

This shift in contracted technology compared to earlier CRM auctions has been driven by the introduction of the Emission Performance Standard, which resulted in fewer coal/lignite plants being able to secure CRM contracts. In practice, standard auctions are organised first for power capacities meeting the emissions threshold of 550 kgCO2/MWh. If there is a remaining need for firm capacity after this round of auctions, this remaining need is auctioned allowing the participation of coal plants.

This was not due to any change in the design of the CRM from its original concept. Supporting the development of flexible capacity may require the development of ad-hoc products/mechanisms, as the participation of batteries in the CRM is not necessarily guaranteed in the long run. For example, concerns have been raised for the eighth auction about the choice of de-rating factor for batteries, which could significantly reduce the competitiveness of these assets in the auctions.[131]

C.6 Case study: European wind and solar generation support mechanisms

From the early 2000s, the EU has promoted the increasing use of Renewable Energy Sources (RES) in energy production, and in particular the use of RES in electricity production. The EU's framework for RES development rests on EU-level legislation, with a series of Directives setting targets for the share of RES in energy consumption for the EU as a whole and for Member States individually.

In order to achieve the renewables targets and meet their policy objectives, all EU Member States adopted measures to promote electricity generation from renewable sources.

131 See for instance: PV magazine – Energy storage (2024) Poland's new capacity market auction could hamper BESS

When European countries set their RES targets, the cost of RES electricity production was generally higher than the cost of producing electricity with conventional fossil-fired generation. Therefore, RES electricity technologies needed support to make them economically attractive to investors and promoting RES deployment required the development of RES support schemes.

From an economic point of view, the objectives of the design of a RES-E support scheme are to achieve the required RES-E deployment at a minimum cost by providing:

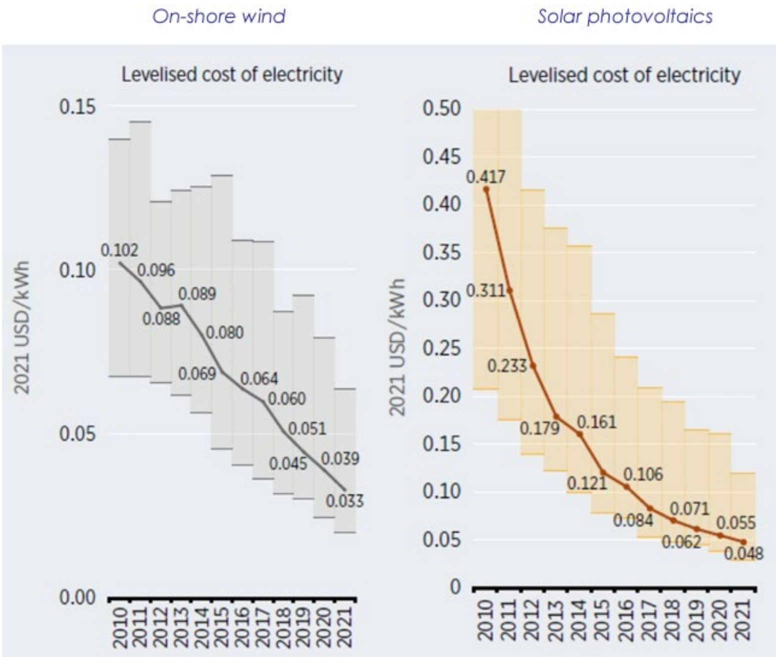
- additional revenues when supported technologies are not yet competitive but are expected to see cost decreases;
- predictability and stability of revenues to ensure the effectiveness of the support scheme in the medium to long term.

The renewable support schemes implemented in Europe aimed at remunerating renewable producers above the electricity market price, which would attract investment and help achieve the RES-E development goals underlying such schemes. However, the nature and design of this remuneration differed across the implemented schemes which implied different risk allocations between the RES-E producers, regulators and governments, and electricity consumers. In broad terms, EU Member States enacted two types of support schemes:

- Feed-in tariffs (“FiTs”) are price-based support schemes protecting the RES producer from the RES production price risk, relying on the government or regulator to fix the price at an efficient level. RES power plants benefit from a predictable stream of revenue ensured by a predictable tariff (the FiT) for their production of electricity which is defined ex ante (at the time the support is granted) and applies over a predetermined period. A variant of the FiT scheme is the feed-in premium (“FiP”) mechanism under which RES-E power plants receive the wholesale market price for electricity plus a premium (the FiP) defined ex ante that guarantees a minimum RES production price. The government or regulator bears the risk of over- or under-achievement of the RES-E policy goal if the FiT or FiP remuneration is not optimally set and leads to too little or too much RES capacity investment.
- Quota obligation schemes with tradeable Green Certificates (GCs) are volume-based support schemes in which the government or regulator does not commit to guaranteeing a RES-E production price but instead ensures a set volume of RES-E consumption over a period (quota) corresponding to the long-term target of the scheme and in line with the broader policy goals of the government or regulator. A trading mechanism determines the price of GCs and ensures that the long-term target of the scheme is achieved. In practice, eligible RES-E power plants receive a remuneration for their production which corresponds to the sum of the electricity market price and the price of the GC. Investors are exposed to electricity and GC price risks but can predict their future likely range of revenues based on key characteristics for supply and demand in the GC market. For governments, GC schemes guarantee the achievement of the RES target through the schemes' self-balancing, but they need to actively monitor and potentially adjust eligibility for new projects to maintain support in line with the evolution of costs.

These early investment frameworks targeting renewable electricity generation installations allowed for a major decrease in production costs, as shown in Figure 28.

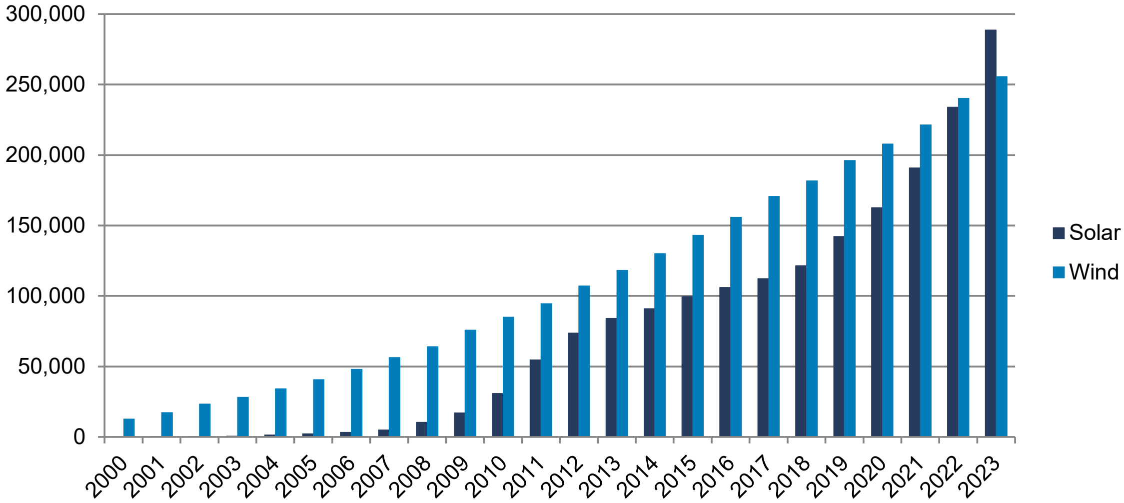
Figure 28: Levelized Cost of Electricity for Solar Photovoltaics and Onshore Wind Over 2010-2021 ($/kWh)



Source: European Commission (2023), The development of Renewable energy in the electricity market, graph 5.1.

Simultaneously, the installed capacity of solar and wind generation units in Europe has grown from 12 GW in 2000 to 550 GW at the end of 2023, as shown in Figure 29.

Figure 29: Cumulated Installed Capacity of Solar and Wind Power 2000-2022 in Europe (GW)



Source: Compass Lexecon analysis based on data from IRENASTAT

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