Redesigning Poland's Capacity Market and System Flexibility

Part 2

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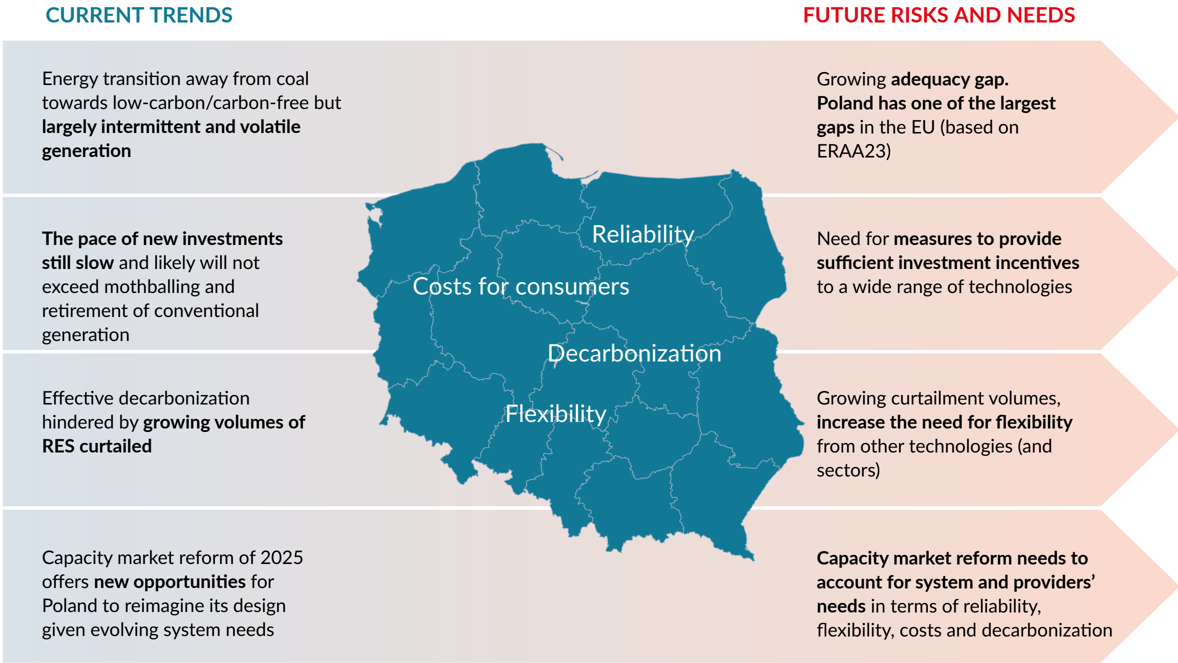
List of abbreviations

ACER	the European Agency for the Cooperation of Energy Regulators
aFRR	automatic frequency restoration reserve
BaU	business-as-usual
BESS	battery energy storage systems
BRP	balance responsible party
BSP	balancing service provider
CCGT	combined cycle gas turbine
CHP	combined heat-and-power
(C)EEAG	Guidelines on State aid for (climate) environmental protection and energy
CACM	Guideline of capacity allocation and congestion management
CONE	cost of new entry
D(S)R	demand (side) response
EB GL	Electricity Balancing Guideline
EENS	expected energy not supplied
EMDR	Electricity Market Design Regulation
ENTSO-E	European Network of Transmission System Operators for Electricity
ERAA	European Resource Adequacy Assessment
EU	European Union
FCR	frequency containment reserve
FNA	flexibility needs assessment
FSP	flexibility service provider
HPP	hydro power plant
ISP	imbalance settlement period
LOLE	loss-of-load expectation
MARI	European platform for the exchange of balancing energy from mFRR
MEC	maximum entry capacity
mFRR	manual frequency restoration reserve
NC DR	Network Code on Demand Response
NRA	national regulatory authority
PICASSO	European platform for the exchange of balancing energy from aFRR
PSE	Polskie Sieci Elektroenergetyczne S.A. (Polish TSO)
RES	renewable energy sources
RCC	regional coordination center
RR	replacement reserve
RS	reliability standard
SOGL	System Operation Guideline
TERRE	European platform for the exchange of balancing energy from RR
VOLL	value of lost load

Executive summary

Poland's capacity market (CM) should undergo a pivotal reform in 2025. At the same time, the national energy mix is evolving. Over the past decade, Poland has significantly increased its share of intermittent renewables, while also new technologies, like battery storage and heat pumps, are gradually entering the market. Meanwhile, coal, though diminishing, still constitutes a large portion of the energy mix, whereas gas-fired power faces price volatility from geopolitical factors. Rising electrification of heating, transportation, and anticipated green hydrogen production is expected to increase peak demand while also opening future opportunities for demand response.

Given this landscape, **Poland's energy system urgently requires increased flexibility to integrate renewable sources and transition away from coal**, especially as coal-fired capacity is expected to decline significantly over the next 5 to 10 years. However, **the CM has not yet effectively incentivized low-carbon flexible technologies to meet Poland's projected adequacy gap**, particularly as coal contracts expire after 2028.



Capacity markets have traditionally focused on securing steady, long-duration capacity to be activated in times of scarcity when relatively long start-up times did not seem to pose a critical problem. In contrast, flexibility generally enables rapid adjustments to fluctuations in power output, especially as a response to a greater output volatility in energy systems, with high shares of variable renewables. Thus, **adequacy and flexibility are becoming increasingly interdependent**. First, this overlap can be observed in terms of the duration of relevant services. Second, it is related to the technologies that are capable of providing those services. **In a future, robust system, both adequacy and flexibility need to be considered**, and appropriate incentives **designed to account for both: firm capacity** to ensure steady, long-term (but rather slow) activation **and flexible capacity** that could quickly react to quick changes of power output.

To meet these evolving needs, **Poland's CM reform should embed stronger flexibility incentives**, which may necessitate combining the CM with complementary mechanisms. The EU's 2024 Electricity Regulation amendment emphasizes the importance of flexibility across system reliability dimensions, supporting the need for integrated adequacy and flexibility in market design. By incorporating incentives for more flexible capacity and aligning with EU regulations, Poland can enhance supply security, drive low-carbon investments, and create a resilient energy system capable of balancing both long-term adequacy and the quick-response demands of a renewable-rich system.

There are **several ways in which the synergies between adequacy and flexibility procurement can be leveraged**. We zeroed in on four options, including:

A. An updated capacity market design (based on Part 1 of this report) and a separate support scheme for low-carbon flexibility, as per the updated Electricity Regulation.

B. A two-product solution for the capacity market with separate products (and requirements) for firm and for flexible capacity.

C. A reserve combining strategic and grid reserves.

D. A capabilities market.

Both based on the KPI analysis and expected implementation effort, option B, **a two-product solution with separate products for firm and flexible capacity is recommended as it is expected to have the highest chances of achieving the future system needs while creating incentives for a broad range of technologies**

A two-product CM is expected to better capture a diverse range of firm and flexible technologies in a technology-neutral way, thereby enabling various assets to contribute according to their operational strengths. In this model, two distinct products would address system needs differently: the flexible product would feature shorter activation requirements (15 minutes to 1 hour) and faster startup times, suitable for quick-response technologies such as open-cycle gas turbines (OCGTs), battery storage, heat pumps, and inverter-based renewables (for instance, as part of mixed-technology portfolios). In contrast, the firm capacity product would target assets that provide steady, long-term energy support, with longer activation durations (up to 4 hours) to handle sustained demand. It could be offered by (remaining) coal generation, demand response, co-generation or some gas-fired units.

FLEXIBLE CAPACITY PRODUCT

Flexible capacity is required to respond rapidly to fluctuations during scarcity situations, e.g. caused by a sudden large variation of RES output or unexpected outages.

Capabilities:

- **response time of a few minutes** to ensure ramping capability without significant performance loss
- **short to medium-duration of activation,** i.e. power adjustment over few hours only
- **availability requirements could be adjusted down-wards**, (specific hours of the day rather than 24/7)

Example technologies:

FIRM CAPACITY PRODUCT

Firm capacity is required to provide consistent power during high-demand periods that could last over days.

Capabilities (similar to the current CM rules):

- **steady, continuous power** to ensure system adequacy over longer periods of time
- resources to operate for **sustained periods of time**, contributing to peak demand coverage and reliability
- **around-the-clock availability**

Example technologies:

These **differentiated requirements would promote diverse participation across technologies while jointly improving Poland's reliability and security of supply**. To avoid over-procurement and control costs for consumers, the study suggests that initial auctions focus primarily on procuring flexible capacity, which would give market participants and the transmission system operator an opportunity to assess price levels and refine the market framework before fully rolling out the two-product system. Additionally, transitional measures such as price caps may be used to manage early price volatility, though caps must be carefully calibrated to ensure they do not inadvertently suppress participation.

The report further emphasizes **encouraging demand response (DR)** to enhance grid adequacy. Implicit DR, which incentivizes consumers to respond to dynamic pricing and grid fees, is recommended to complement explicit DR participation in the CM. The study advocates for capacity-based tariffs, which would distribute CM costs more fairly by assigning a higher cost burden to consumers contributing to peak demand. This approach promotes system reliability by reducing peak strain and ensures DR-investing consumers are not unfairly burdened, fostering a smoother transition toward a resilient and cost-effective energy system.

Similarly to other EU countries, Poland is moving towards a decarbonized future, where carbon-free renewables are playing increasingly prominent roles, while at the same time addressing its long-lived legacy linked to coal-fired generation**. What is clear is that it is not a single technology that is able to deliver the energy transition in Poland while ensuring its security of supply. Instead, a potential from a diversified mix of technologies, including from other energy sectors, like heating, will be needed to fulfill the main needs of the future system, reliability, sustainability and flexibility while keeping the overall costs to consumers in check.**

1. Introduction

1.1. Background

The current period of capacity market functioning in Poland is coming to an end. This is an important moment to look back at its functioning and results as well as draw lessons learned for the future. Over the last ten years, Poland's (and its neighbors') technology mix has evolved to include large and growing shares of intermittent renewable generation while new technologies such as battery storage or heat pumps have also been making headway into the market in the most recent years. In the meantime, the financial support for traditional coal generation both in wholesale markets and in the capacity markets are dwindling while gas-fired generation has been affected by geopolitics-driven price fluctuations.

On the demand side, the consumption profile is also changing in Poland and the rest of the EU. The rising electrification of heating and transportation, and in the future the installation of electrolizers to produce green hydrogen, is increasing overall electricity consumption, especially during peak periods. Also the variability of renewable energy sources, especially the ones behind-the-meter, is creating more dynamic demand patterns, necessitating improved grid management and storage solutions.

These technological shifts and system challenges highlight the need for more flexibility in Poland in order to 1) compensate for inflexible coal-fired generation and 2) enable better integration of renewable production. This need is urgent as the conventional generation is progressively phased out whereas the volumes of RES curtailment are growing (see e.g. Forum Energii, 2024b). These developments also show the continued support for new investments into a broad range of technologies to ensure the country's security of supply.

How did the capacity market (CM) perform in the meantime? Despite its alignment with broader energy goals and market design principles, the existing CM has not effectively driven proactive investments in low-carbon energy. Most changes with regard to participating technologies were driven by the phasing out of coal due to emissions limits mandated by the Electricity Regulation.

What does this mean for the future? Poland's growing adequacy gap, particularly post-2028 as coal generation contracts expire, is expected to still require a capacity market to ensure sufficient support and investment signals for a broad array of technologies (as explained in Part 1 of this report). The application for a new capacity market creates an opportunity for Poland to get "ahead of the curve" and take the recent developments into account to re-design its CM in a way to better incentivize flexible, low-carbon technologies. In addition, in order to enhance the CM's role in Poland's energy transition, the first report recommends:

- introducing a separate product for flexible capacity to better align its requirements with the capabilities of highly flexible technologies,
- tightening conditions for obtaining green bonuses,
- excluding non-green-gasses-ready gas generation,
- and implementing reforms to encourage participation from smaller providers and new entrants.

Complimentary measures to improve demand-side participation, cost allocation through tariffs and keep costs for consumers in check have been proposed.

Going forward, the picture would be incomplete without highlighting the growing system need for flexibility. More specifically, this means that the future system needs to ensure that there is both sufficient firm capacity to offset large generation shortages (or low demand response) ensuring long-term resource adequacy and flexible capacity, especially able to react to quick residual-load fluctuations due to the increase (or decrease) in variable renewable energy production. It has recently been widely acknowledged that securing sufficient *flexible* capacity would unlikely be achieved through an energy-only markets alone. This also seems to be the updated stance of the EU: the latest amendment of the Electricity Regulation paves the way for availability payments for investments in non-fossil flexibility – including through adapting existing capacity mechanisms.

This second report thus intends to achieve several goals:

1. Build a bridge between adequacy and flexibility, as defined in Sections 1.2 and 1.3, and clarify their meaning and interrelation based on the currently applicable legal framework.
2. Based on the existing use cases for flexibility, propose and analyze ways of flexibility procurement within the framework of a capacity market and beyond.
3. Recommend an approach and its design for a more robust and flexible energy system in Poland.

1.2. What is flexibility?

Key messages:

- Flexibility has been only recently defined in the amended Electricity Regulation.
- For the first time, flexibility is interpreted in broad terms, including long-term flexibility, able to offset fluctuations of variable renewables.
- Flexibility spans multiple system needs and multiple timeframes. It thereby translates in use cases which have to be further assessed to understand and quantify the future needs and availability of flexibility.

With the EU's Electricity Market Design Regulation (EMDR), which updated the Electricity Regulation in mid-2024, flexibility has for the first time been formally defined as "*the ability of an electricity system to adjust to the variability of generation and consumption patterns and to grid availability, across relevant market timeframes*" (Art. 2(97)). This rather broad definition generally links flexibility with the objective of being able to handle variations of generation or load, an aspect becoming more and more important as the energy system transitions towards more RES, while considering grid availability. It further refers to *"relevant market timeframes"* without specifying the markets in question.

Following the definition above, such *ability* of the system requires different kinds of services, both on demand and supply side, depending on the set goals and the system's needs. These needs may vary along several dimensions, such as technical requirements, geographical scope or need owners, leading to different use cases for flexibility.

Generally speaking, this definition alone tells us little about the timeframes flexibility might be used in. And indeed, especially in the past, it has been more common to use a narrow definition of flexibility that is predominantly used to ensure (short-term) system stability, that is, frequency or voltage stability (Art. 2, System Operation Guideline (SOGL)). In addition, short-term flexibility may include applications for congestion management (e.g. ENTSO-E, 2023). However, the amended Electricity Regulation has conceptualized flexibility in a much broader sense making an explicit reference to long-term flexibility. Further regulatory aspects will be discussed in Section 1.4.

Looking at flexibility from the other side of the coin, namely its potential, this is constrained by several aspects:

- the general resource potential,
- grid availability,
- economic or market-related considerations of providers, and
- technical requirements placed on the providing resources (Tolstrup K. et al., 2024).

The latter again points towards the different use cases that set the basic boundaries for the flexibility potential. Ultimately, a market or a mechanism is as good as the incentives it provides to participate in it while technical restrictions placed on prospective participants may exclude certain technologies altogether.

Therefore, it is useful and necessary to assess flexibility along the different use cases and their technical characteristics as their sum defines the system's needs for flexibility but also the potential for its provision. In this report, we primarily address the former while focusing on ways flexibility could be secured in the future Polish energy system with the help of the capacity market and beyond.

1.3. What is the link between adequacy and flexibility?

Key messages:

- An adequacy concern is the formal ground for an application for a capacity market.
- It is getting more and more complex to draw a clear line between the concepts of flexibility and adequacy – both are part of the process to ensure power system reliability.
- The Electricity Regulation amended in 2024 establishes a link between adequacy and flexibility. Also, flexibility is no longer associated with short-term measures alone and covers both energy (activation) and capacity (availability) aspects.

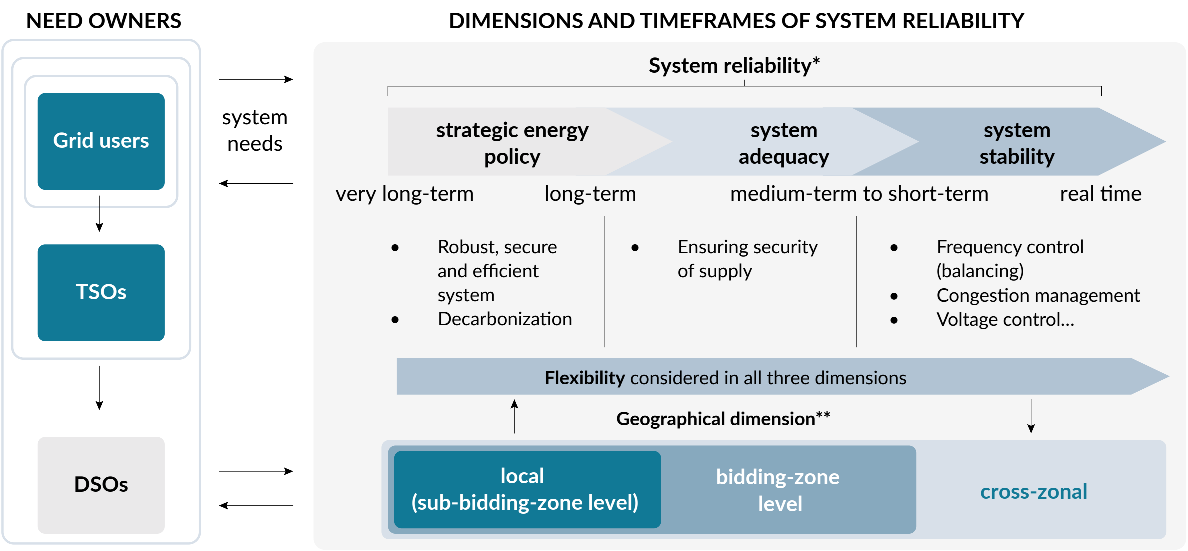
As a reminder, an adequacy concern constitutes legal grounds for applying for a capacity market and is hence highly relevant for this discussion. Read in conjunction with European Resource Adequacy Reports (ERAA) reports, adequacy's general goal is linked to "*securing enough capacity available to minimize loss of load during a scarcity event*" (Tolstrup K. et al., 2024).

Flexibility and adequacy are two dimensions contributing to ensuring overall power system reliability

As illustrated in Figure 1 (top-right box), system reliability spans measures from (very) long term, using strategic energy policy, to medium, short-term and near-real-time measures to ensure system adequacy and stability. Together flexibility and adequacy address numerous related system needs, such as ensuring security of supply, frequency control or congestion management. As such, these measures have different planning horizons: compare, for instance, investment or infrastructure planning and operational measures such as frequency regulation as a result of forecast errors where limited information is available in advance.

Over time, what is understood under the term "flexibility" has evolved. Its definition was finally introduced in the amended text of the Electricity Regulation in 2024. It became clear that flexibility is no longer associated with system stability, i.e. short-term measures, alone. Instead, it is considered in all three dimensions, shown in top right part of Figure 1 – in contrast, adequacy covers one of them. Moreover, the Regulation now requires Member States to define indicative national flexibility targets (link to the first dimension) and specifically refers to measures to ensure *availability* of more non-fossil flexibility (link to the second dimension) as further outlined in Section 1.4.

Figure 1. From adequacy to flexibility – Dimensions of reliability (note that the areas in dark grey are visualized for the sake of completeness, yet are out of the focus of this report)



* Definition of reliability based on Pérez-Arriaga I. (2007).
** Geographical dimension refers to whether a given system need is local or spans a broader area.

The vertical dimension of reliability (Figure 1, on the left) is linked to its need owners, grid users and system operators, both TSOs and DSOs depending on the required location and type of measures involved. Similarly, reliability can be ensured on the asset (consumption or generation), distribution and transmission levels. Grid users, that is, consumers and producers, require flexibility mostly in order to reduce costs or generate additional revenues. The measures they can refer to range from investing in own flexible assets to implicitly reacting to price signals or direct market participation. TSOs and DSOs require flexibility to address system needs depicted to the right of Figure 1. Especially now that the volumes of small-scale generation and flexible demand connected to the distribution network level are growing, the link between TSO and DSO needs and the measures they recur to is growing stronger. Yet, in this report, we predominantly focus on TSO-level needs and use cases.

Finally, **different system needs in the context of reliability have different geographical resolutions, that is, different areas where a reliability case could occur**, from local areas (e.g. a single distribution network) to regional (e.g. a single bidding zone) or cross-zonal, which would require international, multi-stakeholder coordination. For instance, a voltage issue may occur in a single distribution grid due to a simultaneous in-feed of electricity from rooftop photovoltaics. A congestion issue can occur on any of the three levels with different parties involved. Finally, large market cooperation projects, such as balancing energy platforms, span multiple bidding zones, have harmonized approaches and integrated price formation.

Consequently, **as system and market actors' needs are evolving, adequacy and flexibility are becoming harder to disentangle while their interdependencies get more obvious. In a future, robust system both adequacy and flexibility need to be considered, and appropriate incentives designed.**

1.4. Regulatory dimension

Key message:

The amended Electricity Regulation includes new provisions to ensure the coverage of (future) flexibility needs in the power system. Based on a to-be-developed methodology, Member States shall assess flexibility needs, translate the outcomes into national flexibility targets and, if needed, may introduce flexibility support schemes.

Both flexibility and adequacy are now explicitly part of the EU's legal framework, i.e. part of the Electricity Regulation and its latest amendment based on the EMDR. While the regulatory dimension of adequacy was already presented in part 1, this section covers flexibility being newly added to the legal framework as of July 2024. Furthermore, regulatory provisions with regards to congestion management and balancing services, needed to ensure system stability and a flexible system, are outlined. As flexibility and DR are also addressed by the still to be adopted Network Code on Demand Response (NC DR), the related discussions and their status-quo are also presented.

The consolidated text of the amended Electricity Regulation of 2024 does not only define the term flexibility for the first time (cf. Section 1.2). It also provides new requirements and provisions to ensure the coverage of (future) flexibility needs in the power system. This includes the development of a dedicated methodology to assess flexibility needs, translating the outcomes of the assessments into national flexibility targets and, if needed, introducing flexibility support schemes – albeit restricted to non-fossil flexibility.

Its Article 19e(6) requires ENTSO-E and EU DSO Entity to develop a **flexibility needs assessment (FNA) methodology** by April 2025, which is to be approved or amended by ACER within three months, i.e. by July 2025. The first draft to be prepared by ENTSO-E and EU DSO Entity was expected end of October 2024.

No later than one year after its approval and every two years thereafter, national regulatory authorities (NRAs) are expected to publish dedicated biannual **reports on the estimated flexibility needs** for a period of 5 to 10 years each (Art. 19e(1)).

Furthermore, Art. 19e(2) provides the framework for the **FNA report** itself by stipulating (summarized):

- evaluate the different types of flexibility needs, at least on a seasonal, daily and hourly basis and different assumptions in respect to electricity market prices, generation and demand,
- consider the potential of non-fossil flexibility resources to fulfil the flexibility needs, both at transmission and distribution levels,
- evaluate the barriers for flexibility in the market and propose relevant mitigation measures and incentives,
- evaluate the contribution of digitalization of networks,
- account for flexibility available across borders.

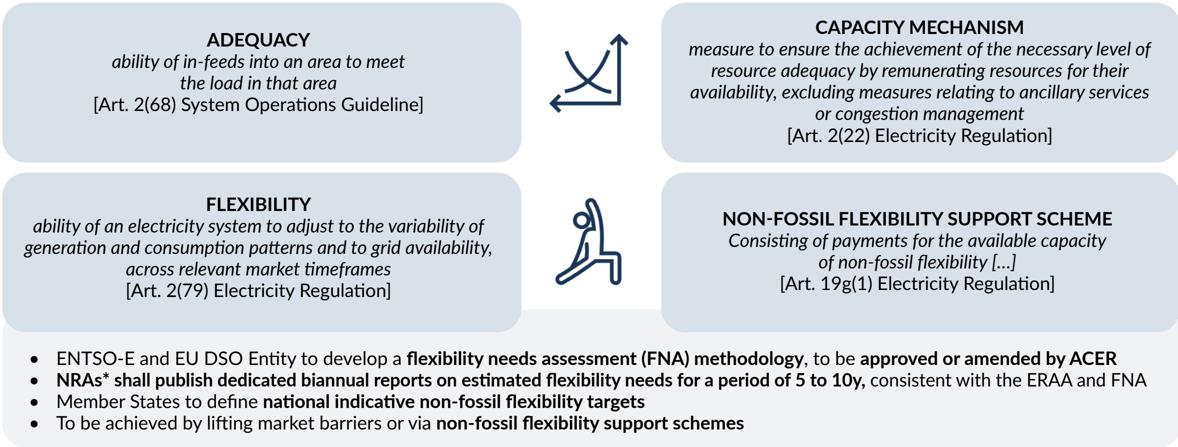
Based on the reports and no later than six months after their approval, Member States shall define **national indicative non-fossil flexibility targets**, including the specific contributions of DR and BESS (Art. 19f). According to Art. 19f and Art. 19g, these targets may be achieved by lifting overall market barriers or via so-called **non-fossil flexibility support schemes**, if existing investments are expected not to be sufficient. Importantly, such flexibility support schemes refer to **payments for available capacity**, i.e. kW-based remuneration, rather than produced energy (Art. 19g). The implication of the principle is that this support scheme cannot take the form of a one-off investment support payment but would be more akin to a capacity payment based e.g. on the outcome of an auction. A standardized bilateral contract between a provider of non-fossil flexibility and the TSO would then also include minimum availability requirements.

The **design principles** of non-fossil flexibility support schemes are described in Art. 19h and generally echo those for capacity mechanisms and are to be designed by individual Member States (Tolstrup K. et al., 2024). The selection of capacity providers must be open, transparent, and competitive, avoiding any undue market distortions or unnecessary fossil fuel use. Further provisions include, among others, cost-effective processes of procurement (not explicitly market-based), sizing not going beyond what is necessary, possibility of locational incentives, integration into electricity markets as well as avoiding of market distortions. Importantly, one of the provisions requires non-fossil flexibility support schemes to be *limited to new investment in non-fossil flexibility resources such as DR and BESS* (Art. 19h(b)).

Hence, as referred to in Section 1.3 outlining the link between flexibility and adequacy, **the amended Electricity Regulation seems to associate flexibility not only with short-term applications related to system stability but also with longer-term adequacy needs.** Firstly, Member States need to assess “at least” seasonal, daily and hourly flexibility (Art. 19e(2)). Moreover, the amended Electricity Regulation links support schemes for flexibility with capacity mechanisms, being the main tool to address adequacy concerns. Importantly, Member States applying a capacity mechanism shall consider adaptations to its design in order to promote participation of non-fossil flexibility. The wording does not exclude the option to apply both support schemes (Rec. 47, Art. 19g). This wording, however, leaves the question of what kind of use cases or services this flexibility will be made available for open. Note that the definition of capacity mechanisms in Art. 2(22) explicitly excludes measures related to ancillary services and congestion management.

As an overview, Figure 2 presents how flexibility and adequacy are defined and supported in EU regulation.

Figure 2. Overview of how EU regulation addresses flexibility and adequacy



* If e.g. the TSO is designated to adopt the report, the NRA shall approve or amend it.

The recent developments with regard to the capacity market reform and the use cases for flexibility, such as balancing and congestion management, along with their regulation are provided in Annex A of this report.

2. Approaches to flexibility procurement

Key messages:

- Flexibility is relevant for both system adequacy and grid stability and is associated with a broad range of services or use cases while no technology is technically capable of providing all of them.
- The distinction between services remunerated only based on energy (MWh), only based on capacity (MW), or both is to be kept in mind. Both can be procured and remunerated in different ways depending on market design, highlighting the need for careful consideration of how flexibility and adequacy are conceptualized and compensated.

As outlined in the introduction to this report, it is useful to approach flexibility in terms of use cases. Therefore, this chapter focuses on uses cases for flexibility, their overlaps with adequacy and thereby aims at identifying the needs, benefits and consequences of common or separate procurement. Note that each use case is linked to a specific system need, which can be procured by a transmission or a distribution system operator (TSO or DSO). The services for distribution grids are out of scope of this report. Similarly, this report does not cover strategic energy policy or associated tools which are nevertheless mentioned in Figure 3 (left) for the sake of completeness.

2.1. Flexibility as an integral part of system reliability

As mentioned in Section 1.3, flexibility is considered in all dimensions of system reliability, be it by accounting for it in power system planning or defining flexibility targets (cf. Section 1.4) in the long term, including resource adequacy assessments in the medium term or contracting it in the shorter term for multiple system services[1].

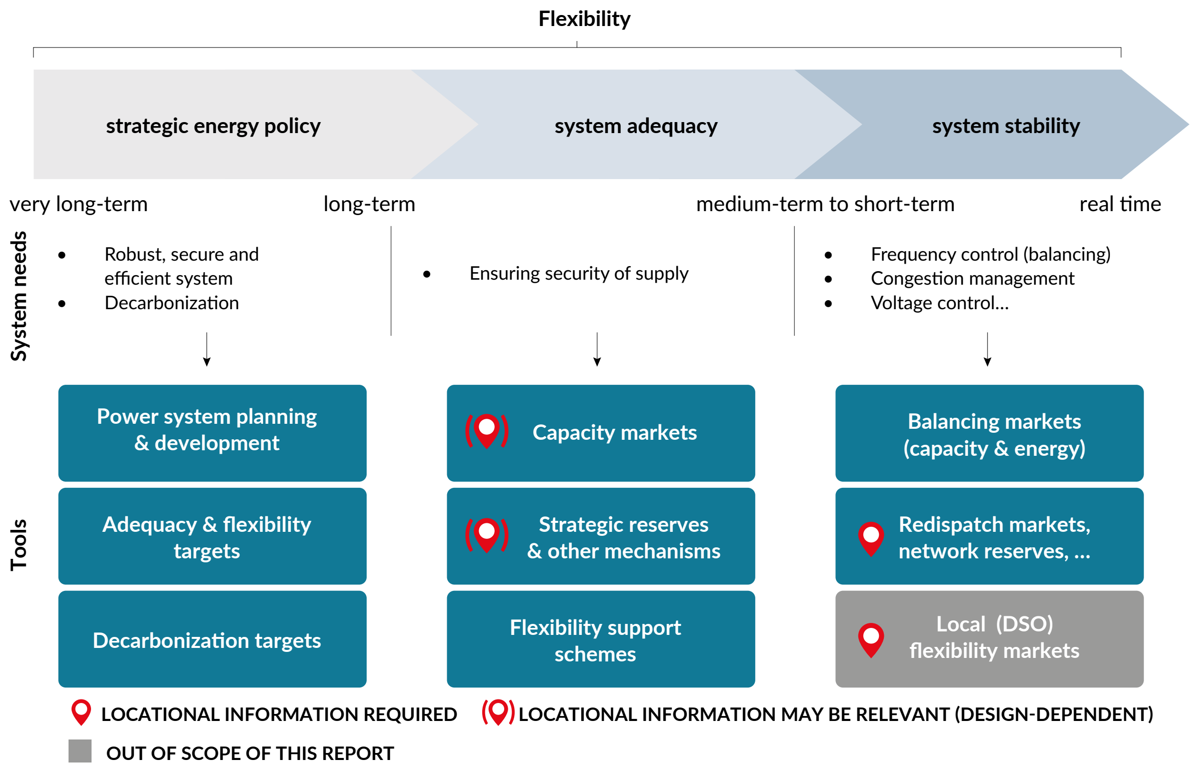
The first area of focus in this report, system adequacy, is concerned with ensuring security of supply, which can be achieved by implementing capacity mechanisms, such as strategic reserves, capacity markets or, in the future, also flexibility support schemes (Figure 3, middle).

1 In this report, "system services" and "ancillary services" in the sense of the amended Electricity Directive are used interchangeably.

The second key area, system stability, is concerned with frequency and voltage control, congestion management as well as other services required in between the short-term and the real time. System stability needs are covered in a number of ways ranging from market-based to cost-based and regulated procurement – depending on the service and the TSO (or DSO) (Figure 3, right).

The system needs are associated with a range of different technical requirements related to e.g. timeframe of availability, duration or speed of activation. Based on the procurement approach, their product requirements and, if applicable, market rules also differ considerably, as described in more detail in the subsequent Section 2.1. As a result, at least from a purely technical perspective, not a single technology is in a position to provide all services needed by the system.

Figure 3. Dimensions and timeframes of reliability, associated system needs and tools to address them



2.2. Existing use cases for flexibility

Table 1 provides more detail about the main use cases[2], the typical speed and duration ranges required, their geographical scope as well as examples of technologies able to provide this or that service. Note that these are the most common use cases[3]. Others like black-start capability, are also conceivable, yet are not further addressed for the sake of keeping the report focused. Moreover, the use cases listed below address system needs and do not include flexibility services that grid users may require themselves, such as for portfolio optimization or participation in wholesale electricity markets.

Inertia: Becoming more and more important for the electricity system as in the past, this service was inherently provided by rotating generators of conventional power plants whose production is now increasingly replaced by variable RES. The service must be activated within a few seconds and last some seconds up to minutes and might therefore be provided by e.g. CCGTs, hydro power plants (HPPs), BESS or RES inverters as virtual inertia. The service is generally procured in a zonal or cross-zonal level. This service is currently not procured in Poland.

2 Some studies mention "avoidance of grid reinforcement" as a use case for flexibility. We rather see it as a positive outcome as long as flexibility can satisfy the needs listed above, especially congestion management and voltage control.

3 For a more detailed overview of the national developments related to flexibility use cases, please refer to Annex A.

Balancing energy: Balancing energy, according to Article 2(4) EB GL, is *"the energy used by TSOs to perform balancing and provided by a BSP"*, i.e. energy used for ensuring system frequency within the admissible stability ranges. Depending on the type of product (aFRR, mFRR or RR), the activation time is required to be from a few seconds up to 15 minutes while the service is continued for several minutes, one reserve replacing the previous one. This also leads to different technologies available to provide balancing energy. The EU's target model envisages cross-zonal and market-based procurement of balancing energy via dedicated platforms (PICASSO, MARI, TERRE) across Europe[4] (cf. Section 0) while currently, balancing energy is procured within the Polish bidding zone only.

Congestion management: To address network congestions, TSOs and DSOs need to alter physical flows within the bidding zone or locally, mostly achieved by means of redispatch, which, according to Art. 2(26) Electricity Regulation, includes curtailment. Depending on the system operators' way of application, such services are either activated with significant lead-time, i.e. after the day-ahead market clearing, or reactively less than one hour in advance. The duration of activation depends on the flow pattern and might vary in terms of several hours. Due to these differences in activation, different technologies are eligible (including demand response). In Poland, this service is used with cost-based renumeration.

Voltage control: TSOs and DSOs need respective services to address sudden increase or decrease in voltage and thereby maintain and restore voltage within feasible ranges. Such system needs occur locally and depending on the technical specifics of the network are required with a speed of activation of seconds to hours and during some minutes up to hours. Therefore, such services could be provided by DR, BESS or inverter-based distributed generation as well as DSOs' own technologies applied in substations and transformers. This service is currently not procured in Poland.

Avoidance of RES curtailment: This use case refers to the aim of limiting the need for RES curtailment in the energy system and would require additional consumption e.g. via DR, BESS, thermal storages or, in the future, electrolysers. It might either be zonal or, depending on the RES location, local. The speed of activation depends on the forecast timings while the duration of activation is generally per hour. A dedicated DR scheme is currently under implementation in Poland – market participants can offer to increase consumption in situations indicated by the TSO (PSE, 2024b).

Longer-term supply deficits: This use case links flexibility with adequacy as it addresses generation deficits across all timeframes (multiple hours up to weekly or longer). The activation of a related service would be with about 4 to 12 hours of lead-time and a duration of multiple hours up to seasonal. It is procured on a zonal or cross-zonal level and generally provided by CCGTs, hydro storage, thermal storage electrolysers. The Polish capacity market is used to serve this use case.

Here it is important to remember that, based on the amended Electricity Regulation, **flexibility** is an umbrella term that:

1) **is relevant both for adequacy and grid stability,**
2) **includes use cases with shorter and longer duration and**
3) **is not only energy-related.**

The last point requires additional clarification. For a long time, flexibility has been associated with energy, or MWh-based, services. In turn, due to its strong connection to investment planning, adequacy has been largely conceptualized in terms of availability, i.e. MW of capacity. However, this distinction is misleading as it confuses what the service is with how, or based on what, it is remunerated. Balancing, for instance, has a long history of being procured both in terms of availability (MW) and in terms of actual activation (MWh). Although the timeframe of capacity procurement for balancing has been progressively shifting from years, months and weeks ahead to closer to the time of activation, the logic remains the same. The TSO reserves (and remunerates) capacity to ensure its available for potential activation (MWh). This logic is similar to the one used in CMs: availability is contracted and remunerated for future availability in times of system stress. Sticking to the balancing market example, energy activation is then (mostly) remunerated separately – albeit not even that is always the case[5].

4 For more information please refer to: https://www.acer.europa.eu/electricity/market-rules/electricity-balancing/balancing-energy-platforms.
5 Even this does always have to be the case: consider FCR markets in most Continental Europe where the energy component tends not to be remunerated due to minuscule activation volumes. This is again different in the Nordic FCR markets.

In contrast, a price tag in CMs is placed on availability while (rather unlikely) energy activation is not remunerated. The main reason for this is that capacity providers are not excluded from participation in the wholesale markets, thus they are expected to obtain energy-related revenues elsewhere. In a nutshell, **regardless of the use case, whether both capacity and energy are procured and remunerated is a given but is a design choice**, as will be further discussed in Section 3.

Table 1 offers an idea of the different technologies that can – at least based on their technical capabilities – prove these services. Sector coupling could also play a role in increasing available flexibility in the power sector. An example is provided in the Case Study of the Polish heating sector below.

Table 1. Overview of existing flexibility use cases and their typical properties as well as example technologies able to provide each of the services

Use Case / Service	Geographical scope	Speed of activation	Duration of activation	Example technologies	Already procured in Poland?[6]
Inertia	Zonal & cross-zonal	A few seconds	Seconds to minutes	CCGTs, hydro, BESS, RES inverters (virtual inertia)	No
Balancing energy	Zonal & cross-zonal	A few seconds to 15 minutes	Minutes	Varies based on balancing product	Yes, market-based
Congestion management	Zonal & local	Depends on how proactive or reactive the affected System Operator is, less than an hour to 24 hours	Several hours	Depends on the speed of activation	Yes, cost-based
Voltage control	Local	Seconds to hours (primary, secondary and tertiary control)	Minutes to hours (depending on control type and DSO specifics)	DR, BESS, inverter-based distributed generation (wind, PV) and DSO-own technologies used in substations and transformers	No
Avoidance of RES curtailment	Zonal & local, depending on RES location	Varies based on forecast availability	Hourly	DR, BESS, thermal storage electrolyzers	Yes
Longer-term supply deficits	Zonal & cross-zonal	4–12 hours	Multiple hours, daily, weekly or seasonal	OCGTs, CCGTs, hydro storage, thermal storage electrolyzers	Yes (capacity market)

Source: Tolstrup K. et al., 2024.

6 See Section 1.1.1. for more details of the Polish national context.

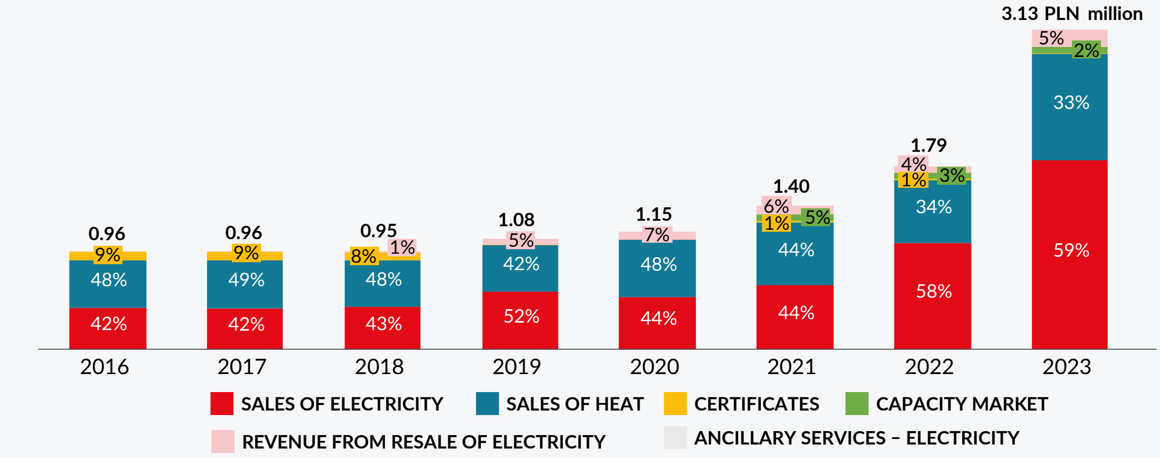
Case study:
Heating sector in Poland – Flexibility potential at the intersection with the electricity markets

The **heating sector occupies a prominent place in the Polish energy landscape**. Yet, **it's flexibility potential is far from exploited**, in particular as the sector is going through a rough economic patch. It **faces structural challenges**, such as the dependence on fossil fuels, insufficient investment in new technologies and infrastructure, low profitability and, most importantly, the lack of a long-term vision for development.

Considering the above challenges together with the EU Green Deal and Poland's ambition to achieve its climate targets, it is crucial to develop and implement a long-term vision for the heating sector in Poland. Such vision needs to set a clear direction by **ensuring the sector's ability to meet the challenges of the energy transition**. By doing so, it is of utmost importance to create a framework, **enhancing sector coupling** by designing a common strategy in which both the heating and electricity sector can profit from joint synergies, especially with regards to available capacity and ensuring flexibility.

A report published by, the Polish energy regulator, URE (2022) stresses the **alarming financial performance** of the sector – in 2022, CHP units recorded a loss of -38.11% and the gross profitability of the entire sector was -22%. Furthermore, according to estimates by Forum Energii (2023), the investment required for the transformation of the heating sector in terms of district heating networks and heat sources alone amounts to almost PLN 90 billion by 2030, i.e. the level of **investment needs to be increased significantly**.

Figure 4. The role of electricity in the CHP business model



Source: Forum Energii.

As shown in Figure 4, a CHPs' income shares in Poland are mainly based on (re)sales of electricity but remain low related to capacity market participation and provision of ancillary services (Forum Energii, 2024). This is despite heating systems in fact being well-suited to provide balancing services and overall significantly contribute to flexibility in the electricity sector (Boldrini A. et al., 2022).

In terms of balancing services in the heating sector, CHPs may provide both positive and negative balancing services, by decreasing or increasing generation if not operating at minimum/maximum load. Conversely, heat pumps and e-boilers can operate in a reserve fashion, i.e. by increasing or decreasing consumption. The type of service a CHP can offer depends on the used technology and in particular the ramping rates to comply with technical requirements of the frequency containment reserve (FCR; 30s), aFRR (5 min) and mFRR (12.5 min) products (Boldrini A. et al., 2022). While e-boilers are assessed as suitable for all types of balancing services, heat pumps are capable of providing aFRR and mFRR only (Boldrini A. et al., 2022). A factor influencing the ability to provide such services is seasonal characteristics of the heating sector, with more flexibility in summer than winter, as well as overall limitation by their primary purpose, heat generation.

One outstanding example is Denmark, strongly enhancing sector coupling to increase flexibility in the electricity sector and first district heating systems providing balancing services, such as one in Jaegerspris (Tilia, 2021).

In Poland, especially old heating systems might face barriers due to long ramping rates, difficulties in installing modern technologies to enhance flexibility, lack of control and monitoring systems or measurement data to forecast electricity and heat production. However, some new and promising projects are under development:

- **Large-scale heat pump in Wrocław:** Poland's largest heat pump, recovering heat from wastewater, which will also be able to use surplus electricity from RES in the future. The installation, worth more than PLN 100 million and with a capacity of 12.5 MWt, is expected to become operational in Q4 2024.
- **The Heat Plant of the Future in Lidzbark Warmiński:** an innovative installation that is 100% powered by RES sources. Combining heat pumps, photovoltaic panels and the first long-term heat storage, it is an example of an integrated and flexible energy system at local level.
- **Electrode boilers in Gdańsk:** PGE Energia Ciepła has installed two electrode boilers with a capacity of 35 MWt each at Elektrociepłownia Gdańsk. In addition, PGE plans to build 383 MWt heat pumps and 690 MWt electrode boilers in the coming years.

Furthermore, the latest developments in terms of establishment of balancing markets (cf. Section 0) in Poland are expected to improve market access for the heating sector and open up for new revenue streams in the electricity market. Similarly, the adjustments of the Polish capacity market (as presented in Part 1 of this report and further in Section 4) are expected to give a boost to the participation of heating-sector assets.

3. Capacity markets and flexibility procurement: potential future options

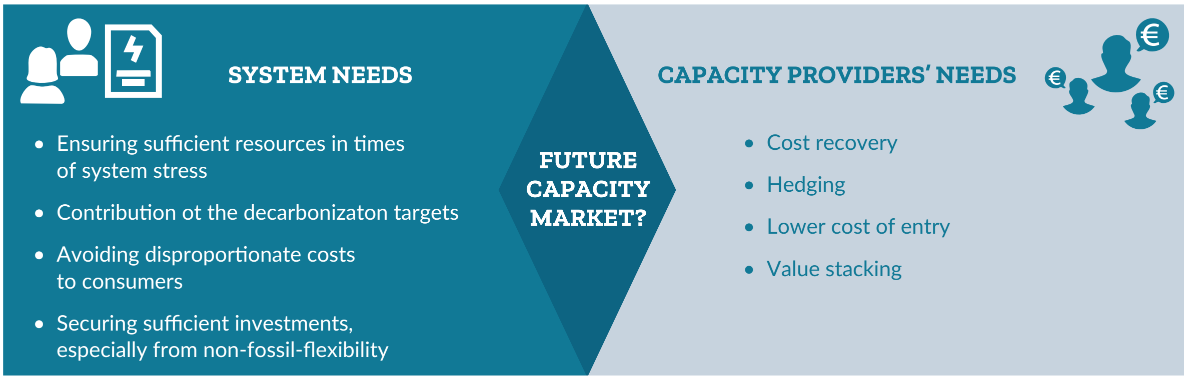
3.1. Types of flexibility and system needs

Key messages:

- The future Polish and EU power systems will require both firm and flexible capacity to maintain reliability, with new investments needed due to anticipated shortages in both areas.
- Flexibility in the system is categorized into four types: long-duration, short-duration, very short-duration, and ramping flexibility – each addressing different timeframes and activation needs within the power market.
- The overlap between adequacy and flexibility, particularly in terms of service duration and applicable technologies, raises the potential for synergies in future market designs to address both steady long-term and rapid short-term activation needs.

It is worth recalling the target state defined in Part 1 of this report when discussing the future capacity market and its design following the reform in 2025 (cf. Figure 5). In fact, the needs of the system (including the consumers paying for the system) and of the providers are rather universal and thus can be applied to the overall Polish market. In the future, Poland, as much as the rest of the EU, will require both firm and flexible capacity to support the power system's reliability. As both will likely be in short supply in the future, sufficient (new) investment in both will be required to reverse the downward trend (Figure 5). The question that then arises is: **assuming that the energy-only market would not do the trick alone, how could the capacity market (together with other mechanisms) or another approach provide the right investment signals?**

Figure 5. The Future Polish Capacity Market: The target state at the intersection of the system and providers' needs



Taking the system needs as a point of departure, we define 4 types of flexibility that should ideally cover these needs and map the existing use cases to them, as shown on Figure 6. We take inspiration from the classification of flexibility proposed by the Belgian TSO, Elia (cf. Elia, 2023), while adapting it to also account for longer-term flexibility:

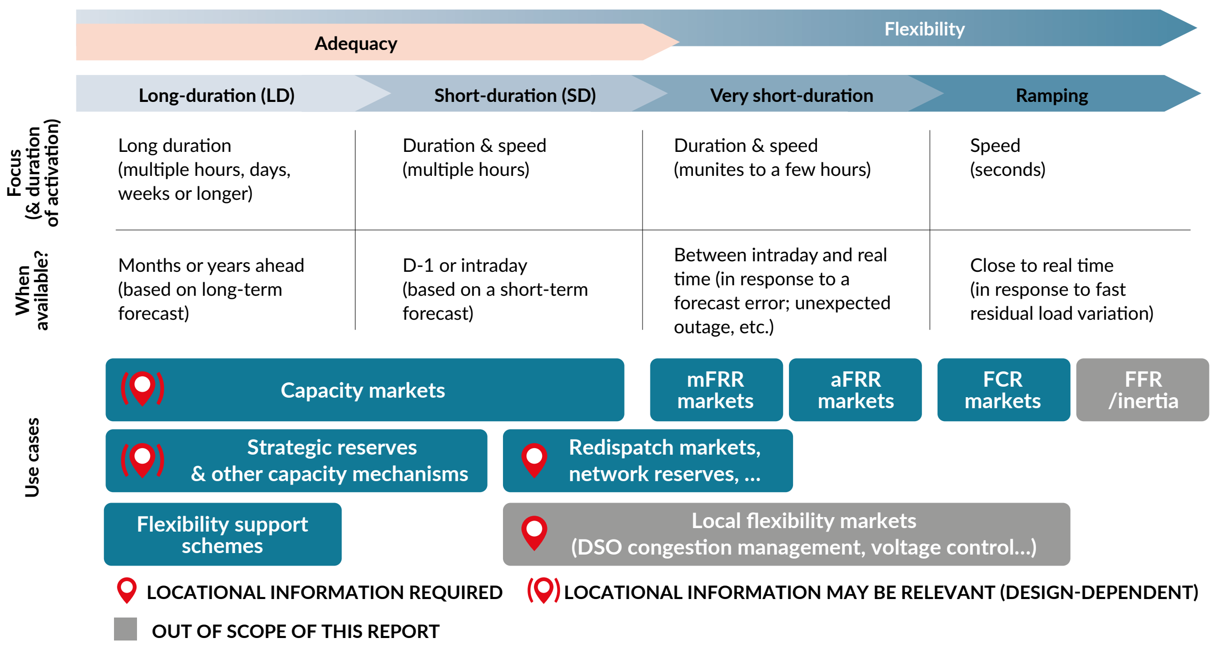
1. **Long-duration (LD) flexibility** is required to cover long-duration, up to seasonal, flexibility needs whereas its availability needs to be confirmed months or year(s) ahead.
2. **Short-duration (SD) flexibility** should be available between the day-ahead and intraday timeframes to be activated based on a short-term forecast for a few hours. Thus, firmness and the duration of activation remains the primary requirement while the speed of activation is less relevant than in the two subsequent categories.

3. **Very short-duration (VSD) flexibility** is required in the intraday timeframe closer to real time and is meant to offset sudden changes in the supply-demand balance, e.g. due to a forecast error or an unannounced outage. Thus, to deal with such short-term unexpected events, the speed of activation is prioritized while the needed duration is limited.

4. **Ramping flexibility** has a very low energy activation but a very high, almost instantaneous speed in order to provide a fast initial response to abrupt residual load variations.

The European electricity system includes multiple markets and/or mechanisms created to cover flexibility needs in the four groups. Some of these, additionally require locational information of the service-providing assets. This is particularly the case for TSO (or DSO-level) congestion management where the effectiveness of an asset in alleviating congestion depends on its position in the grid with the respect to the congestion point.

Figure 6. Four types of flexibility, their main characteristics and associated use cases



Based on the categories' main focus, average duration of activation and availability requirements, the different use cases for flexibility can be mapped as follows:

1. LD flexibility is predominantly associated with guaranteeing security of supply in response to prolonged shortfalls of (renewable) generation. Thus, it is mapped to **capacity mechanisms as, in the future, additional flexibility support schemes.**

2. SD flexibility is able to be activated in the day-ahead or intraday timeframe and is particularly relevant for the sake of **adequacy but also congestion management**. Hence, it includes capacity markets and other mechanisms as well as redispatch mechanisms or markets or network reserves.

3. Depending on the exact requirements, VSD flexibility likely includes **mFRR and aFRR products** as well as redispatch.

4. Ramping flexibility is relevant for **FCR but also for an even quicker fast frequency reserve (FFR) or inertia product**. The latter is motivated by the decrease of system inertia traditionally provided by rotating masses, so to speak, as a by-product, and would smooth out minor supply-demand fluctuations. Hence, some countries (e.g. in the Nordics) introduced a separate product to compensate for "inertia-less" infeed from renewables. Some of the faster voltage control activation can also fall under this group yet are disregarded in this report.

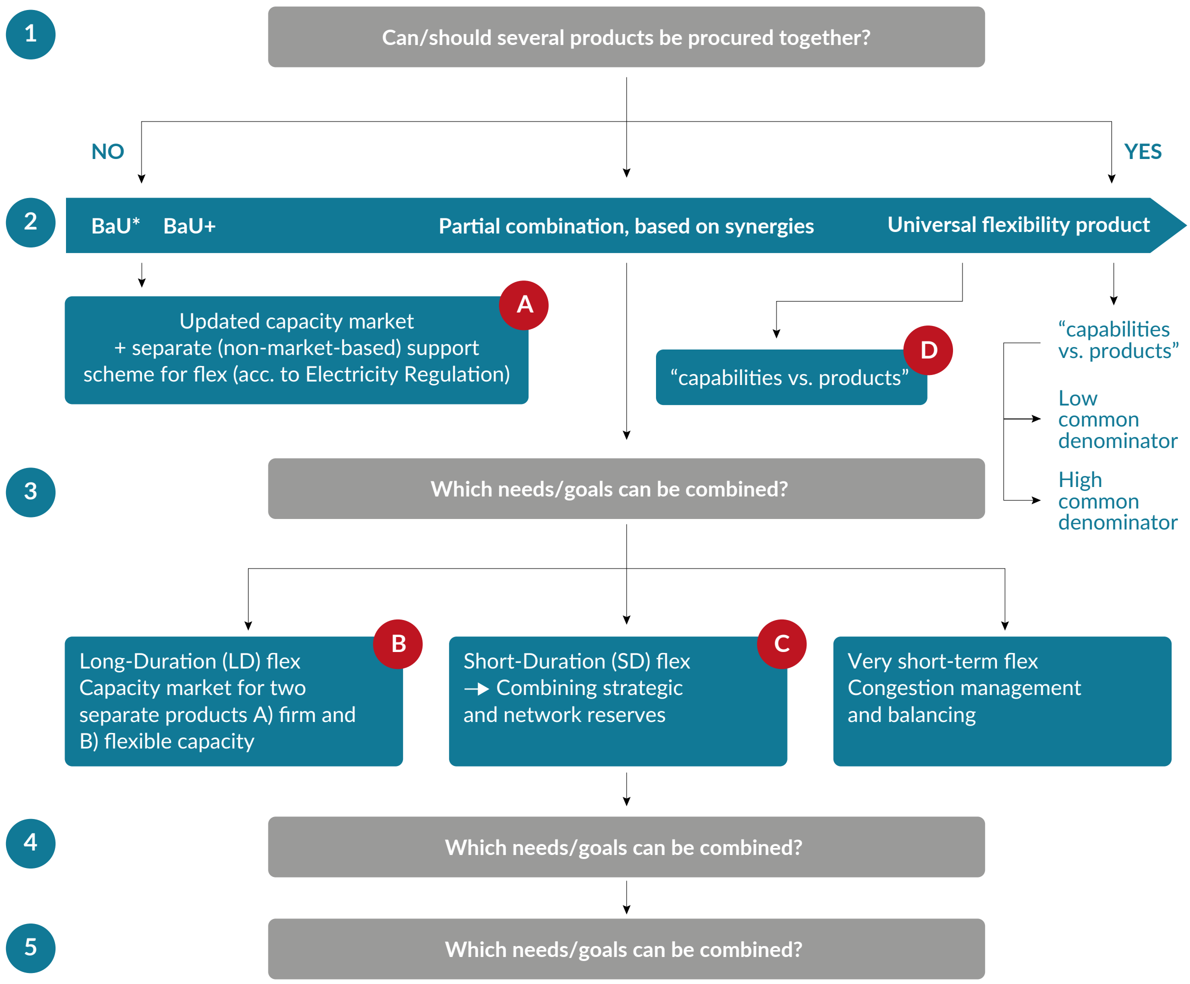
One of the main things to take away from Figure 5 but also from Table 1 in the previous section is that there is an overlap between adequacy and flexibility while the latter is a broader concept. First, this overlap can be observed in terms of the duration of relevant services. Second, it is related to the technologies that are capable of providing those services. This raises a question: **can these synergies be used in a future market design that will require both, firm capacity to ensure steady, long-term (but rather slow) activation and flexible capacity that could quickly react to quick changes of power output?**

As the system and its needs are evolving with the changing technological landscape in Poland and in the EU while both firm and flexible capacity are scarce, it is doubtful that the present capacity market can generate the much-needed incentives alone. Potentially, a capacity market could be combined with other mechanisms to cover the needs, as illustrated in Figure 5.

3.2. Determination of suitable models integrating adequacy and flexibility

The process to determine most promising options can be formulated in 5 steps, as illustrated by a decision tree in Figure 7. In the subsequent analysis we intentionally focus on the capacity market and the options associated with it.

Figure 7. Five steps to consider when exploring procurement of adequacy and flexibility. Selected cases A) to D) are the options that will be analysed in more detail in the next section



* BaU – BUSINESS-AS-USUAL

3.2.1. Step 1. Can (or should) several products be procured together?

Combining the procurement of flexibility services for longer or more short-term system needs through product integration could enhance the efficiency and availability of scarce flexibility across several use cases. Allowing flexibility to be used for multiple use cases can then help reduce system costs: such an approach would at least in theory, increase liquidity and thus competition driving costs down. It can also help optimize resource utilization technologies capable of providing flexibility for several services, including for capacity markets.

On the downside, product integration can have inadvertent consequences. Different flexibility services have distinct requirements (e.g. activation time, duration as presented in section 2.2) that may not be adequately addressed in a combined procurement model. Thus, we use the next steps to understand, which products could be sensibly combined and what the implications would be.

3.2.2. Step 2. What is the spectrum of options?

The possible options for exploring synergies between the different system needs and services can be placed on a spectrum with business-as-usual (BaU) on the one side of the scale and a "universal flexibility product" on the opposite side:

Business-as-usual – implies keeping the existing markets and mechanisms to cover adequacy and flexibility needs in Poland "as is", i.e. a capacity market targeting mostly firm capacity.

BaU+ – refers to a "low-hanging-fruit" option where the current capacity market setup is updated but no product combinations are involved. At this point on the scale, two options were identified:

1. **Updating the current capacity market design** based on the target state discussed in report Part 1 and focused on removing barriers to flexibility, in particular DR and BESS, as per amended Electricity Regulation.
2. **Complementing the updated capacity market with a separate support scheme** for non-fossil flexibility, in the sense of the amended Electricity Regulation that is not market-based.

Partial combination based on synergies – refers to combinations of just a few products where synergies along the needs for different types of flexibility can be identified, as further described in the next sub-section.

Universal flexibility product – refers to a product that a flexibility service provider (**FSP**) offers in a common market, and which can in theory be used for any system need meaning the highest degree of product integration. That is, no products can be distinguished on the FSP side, only the final use of that flexibility by the TSO would be different.

On the face of it, such an approach could considerably simplify the process both for system operators and for FSPs. A universal flexibility product streamlines the market by reducing the number of distinct products, simplifying the bidding and procurement process for even less experienced FSPs and system operators. This can lower administrative costs and make market participation easier for providers. FSPs would only need to develop and manage one type of product, reducing the complexity of meeting different technical requirements and market rules for various services. With the ability to allocate flexibility where it is most needed at any given time, the TSO can respond more effectively to system demands, improving overall system reliability – in the long or in the short term.

By offering flexibility that can be applied to multiple system needs, the universal flexibility product approach ensures that available resources are used more efficiently, reducing the risk of underutilization and optimizing the deployment of flexibility across different timeframes and services. From the perspective of the market itself, a single, integrated product could enhance liquidity in the market by concentrating bids and offers into a unified pool, leading to a great availability and more competitive pricing.

Although these arguments might initially make this option sound rather attractive, a closer look reveals that it is in fact not the simplest but the most complex option, hence it's position at the end of the spectrum. Combining multiple flexibility services under a single procurement process is highly technically and computationally complex as it requires managing and co-optimizing the diverse needs and characteristics of each service.

Combining procurement might reduce the number of bidders, as some providers may only be capable of delivering specific flexibility services. This could lead to reduced competition and potentially higher prices, undermining the cost-effectiveness of the approach. In addition, while product integration may reduce gaming potential by limiting time-related arbitrage in sequential markets, it introduces complexity in optimization and IT infrastructure (Fanta S. et al., 2024).

A unified procurement approach could end up favoring certain technologies over others – depending on how what common denominator is set:

- **If the common denominator is set too low,** i.e. the requirements towards the FSPs are based on the "least technically challenging" product among those combined, the prequalification requirements are de facto lowered for all the services involved. In the worst case, this would mean a significant deterioration of the service quality – using the motto "quantity over quality". That is, increasing overall market liquidity is prioritized at the expense of service quality.
- **If the common denominator is set too high**, the situation is flipped to "quality over quantity". The requirements for all FSPs are more stringent across the board based on the "most challenging" product's characteristics. As a result, technologies better suited to fulfil those requirements would dominate, crowding out other technologies that are crucial for other flexibility services, as having technical capabilities highly valuable for specific or limited number of use cases.

By way of an example, if the requirements currently applied to the FCR product characterized by activation time of just a few seconds is used as the common denominator, only the fastest technologies, such as gas turbines and batteries, would be able to compete in such a "universal-flex" market.

On top of that, even determining what "the most challenging product" is – to set a benchmark for how the common rules should be defined – is not straightforward since some products, as shown in Figure 4, "value" duration more while for others speed of activation is of utmost importance. Hence, since it becomes virtually impossible to design such a product – without even taking the regulatory dimension into account – it is excluded from further analysis in Section 3.2.

Nevertheless, there is an intermediate option not fully reaching the status of "universal flex", a so-called **"capabilities market"** instead of pre-determined products. The logic of this approach questions the premise of the current market approach, i.e. that procurement of flexibility should be organized by means of predefined products. Instead of it, it can be viewed from the perspective of its technical properties, or attributes, which can in turn be provided separately in a market-based way.

3.2.3. Step 3. Which needs can be combined?

The decision on which needs can be combined can be made based on the four types of flexibility shown in Figure 5:

- **Long-duration (LD) flexibility** – this option combines two separate products in a capacity market, namely a) firm and b) flexible capacity, as proposed in Part 1 of this report. Fundamentally, this would allow a differentiation between the technical characteristics (relevant for the certification process) and the product characteristics as well as the components that are considered in setting the demand for either. Following the logic of balancing capacity products, such distinction also means that different technologies would be eligible to participate. Seen from the perspective of the Electricity Regulation, can also explicitly integrate a non-fossil flexibility support scheme into the Polish capacity market.

- **Short-duration (SD) flexibility** – based on the mapping in Figure 5, there are several conceivable options combining use cases for SD flexibility:
    - In theory, one could combine the uses of the capacity market for both adequacy and congestion management purposes, i.e. for redispatch. However, such an approach would mean a significant market distortion. Capacity providers under current rules are allowed to participate in the energy markets where they are expected to generate their energy-based revenues. Redispatch bids are activated only if the outcome of the wholesale markets is infeasible and receive compensation for relieving physical congestion. Remunerating reservation of capacity for redispatch while at the same time allowing their participation in the wholesale markets creates a significant gaming potential who in addition to a payment for availability would profit from the actual energy activation from the wholesale market and, in addition, for redispatch (de)activation. Thus, this option is not considered further.
    - As described above, the biggest issue with the previous approach is that the assets are still allowed to participate in energy-only markets leading to overcompensation and market distortion (cf. Hirth L. and Schlecht I., 2020). Alternatively, combining strategic and network reserves could make a combination of the two use cases, adequacy and congestion management (transmission adequacy), possible as these are explicitly excluded from market participation.
- **Very short-duration (VSD) flexibility** – in this timeframe, it is conceivable to combine products for balancing and congestion management, which to an extent, has already been done using different designs, e.g. in the Nordics, in France or in Switzerland. Similarly, when it comes to Ramping Flexibility, inertia has been implicitly procured as part of the FCR product in Continental Europe. Only recently, driven by the expansion of inertia-less RES, the discussion about establishing a separate product for inertia became more topical. For instance, the Nordic TSOs launched a separate balancing product, Fast Frequency Reserve, to cover growing inertia only in 2020. However, these use cases cannot be easily combined with a capacity market and thus is rather mentioned here for the sake of completeness.

3.2.4. Step 4. What are the requirements and implications from the market perspective?

Assuming that several system needs could be combined in a single approach, there will be multiple questions to solve from the technical perspective, i.e. which technical requirements would the flexibility have to fulfil and from the market perspective, i.e. what it means for the product characteristics and market rules.

The combination of product integration and market organization creates a complex landscape where different models must be evaluated based on criteria like benefits for the system, market liquidity, and potential for gaming. Research has shown that the challenge of aligning technical requirements and, in case of international markets, like balancing, aligning the new process with international gate closure times, which complicates product integration. Harmonizing pricing mechanisms is crucial to avoid distortions yet may be incompatible with FSPs' incentives. To maintain liquidity, both technical and market rules need to find a balance between the strictness of requirements and accounting for different types of assets in order not to unduly exclude valuable flexibility, which could have otherwise been used.

In the subsequent Section 4, which focuses on the selected options, they will be analyzed using a number of criteria, such as the benefits and drawbacks for the TSO and FSPs, potential for technical harmonization, complexity of implementation and the effects on gaming and liquidity, similar to Fanta S. et al., 2024.

3.2.5. Step 5. Is it compatible with the (EU) regulation or what needs to be changed?

The regulation on the national but also on the EU level creates a framework that ultimately constrains the choice of viable options. However, in this report, we make a conscious choice beyond the current state of regulation. In the last step, we then check the options for regulatory feasibility and propose potential ways to adapt it to allow for a given option – whenever sensible.

3.3. Options for a future system vision

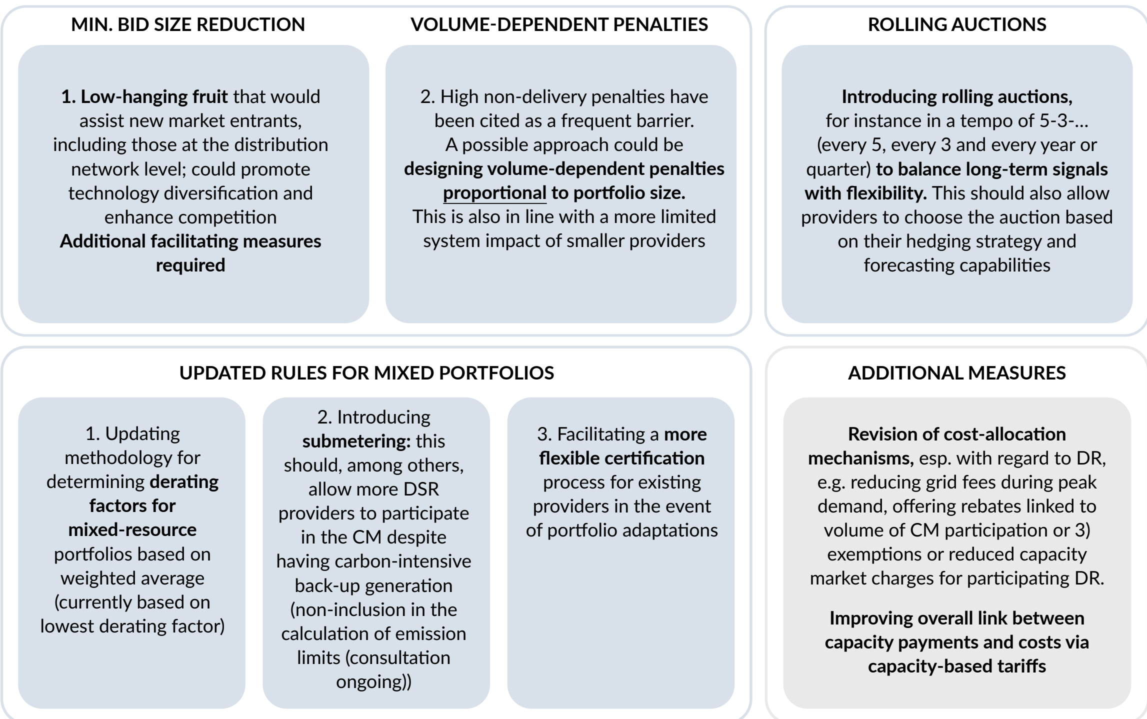
Key messages:

- This section reviews the four potential options for the future possible designs in Poland that would combine both flexibility and firm capacity needs of the future energy system.
- Option A refers to the updated capacity market design directed, as before, at securing firm capacity while a new flexibility support scheme is meant to provide investment incentives to non-fossil flexibility, in line with the latest provisions of the Electricity Regulation.
- Option B refers to a two-product solution for the capacity market, in which flexible and firm capacity products would have different timeframes and activation and certification requirements, which would ensure a more efficient procurement and use of different technology types in scarcity situations.
- Option C could be considered to combine the reserves for both adequacy and congestion management, ideally in this way minimizing the costs for both.
- Option D, a capabilities markets, refers to the bidding based on the technical or others (e.g. locational) characteristics of provided capacities instead of bids whereas a system operator would be able to combine these ad hoc depending on a system need.

3.3.1. Option A: Updated capacity market (in combination with a separate support scheme for non-fossil flexibility)

The details of the measures proposed to improve the current capacity market in Poland ahead of its reform in 2025 are described in detail in Report Part 1 and briefly summarized in Figure 8 below.

Figure 8. Summary of proposed measures to improve the design of the Polish capacity market going forward



The analysis in Report Part 1 further stressed that it is crucial to secure larger investment volumes into non-fossil sources of flexibility. As a reminder, the investment volumes in battery storage and especially in demand response have been growing during the latest 3 auction rounds – yet remain insufficient. This is particularly true against the backdrop of a drastic reduction of contracted capacity from coal-fired generation already in late 2020s and beyond 2035 and Poland having one of the highest LOLE (loss of load) values in the EU, based on the latest ERAA (ENTSO-E, 2024b). This means that **the probability of a scarcity event in Poland is one of the highest in Europe.**

This warrants a question whether the measures summarized in Figure 8 would alone be sufficient to ensure future security of supply, contribute to Polish decarbonization efforts, increase investment volumes while keeping the costs for consumers in check. Based on the synergies identified in the previous chapter, it could be combined with an additional support scheme directed at non-fossil sources of flexibility, such as storage, demand response but also, decarbonized heat or, in the longer-term, flexible electrolyser operation.

The amended Electricity Regulation creates room for Member States to introduce a separate support scheme specifically directed at incentivizing investment in and availability of non-fossil sources of flexibility – with a special focus on demand response and storage (see Section 1.4.1 for further details). Based on the general principles of capacity market functioning, the access to it would remain technology-neutral, that is, would be open to all technologies, including the sources of non-fossil flexibility. A separate support scheme would then be an extra option for such participants as battery storage operators meant to improve their investment incentives. Mostly likely, this would imply that such an operator would have to choose either of the two options to avoid double counting and higher system costs.

In terms of the timing of both mechanisms, they could either run in parallel or a support scheme would have a different timeline, e.g. with annual or seasonal auction (and annual or seasonal determination of demand), which would likely help providers better forecast their actual availability. Depending on the needs of the TSO, the participation in the support scheme could be further encouraged in comparison to the capacity market by offering longer-term capacity contracts to non-fossil flexible providers as a "flexibility bonus". In sum, through more frequent auctions, the forecastability would be improved while a longer contract period would offer better planability and facilitate a positive investment decision. Ultimately, such an approach would allow the TSO to create incentives both for firm capacity using the updated capacity market and flexible capacity using the support scheme accounting for potential differences in requirements and conditions while observing the principle of technology neutrality.

The overall efficiency of option A, however, will depend on the degree of synergies between the updated capacity market and the new non-fossil flexibility support scheme. Based on the amended Electricity Regulation, the demand for flexibility shall be determined by each Member State based on the common flexibility needs assessment methodology. So far, it is unclear whether this will translate into a single number, i.e. overall national volume of flexibility required, or into a number of indicators, which will then determine a more detailed demand curve, or whether a more granular approach would be used (e.g. demand per network level or region, demand per flexibility use case). **Furthermore, option A is not expected to provide adequate conditions for the participation of the heating sector, which is of strategic importance in Poland.** Time dimension of such a change should also not be overlooked: in order to be compliant with the Electricity Regulation, the flexibility support scheme would be introduced after end of 2026–2027, which might not be fast enough to secure the needed resources to guarantee security of supply.

If the synergy in the end is low, it is worth analyzing whether the system would be better off with updating the capacity market itself in a way that provides additional incentives for flexibility.

3.3.2. Option B: Capacity market with two separate products (firm and flexible)

In a two-product market solution, the flexible capacity market would focus on resources that can respond rapidly to grid needs, with shorter product duration and dynamic pricing based on real-time grid volatility, while the firm/baseload capacity market would emphasize long-term reliability and consistent power supply, with more stable, long-term contracts. The design would allow participants to choose the market that best matches their technological capabilities and risk preferences, with flexible technologies able to opt for either market depending on their operational strategies and the trade-offs between revenue stability and upside potential.

Introducing a two-product solution for flexible capacity and firm capacity would fundamentally reshape the market structure by targeting the unique attributes and system needs of these two types of resources. It draws inspiration from the current multi-product design of EU balancing markets – each with different technical requirements and market rules, yet all contributing to guaranteeing power system stability in the event of frequency deviations.

In terms of product requirements, this would mean that flexible capacity would be required to respond rapidly to fluctuations in supply and demand during scarcity situations, e.g. caused by a sudden large variation of RES output or unexpected outages. The response time could be set to a few minutes to ensure capability to ramp up or down quickly without significant performance loss. In contrast, short to medium-duration of activation, that is, power adjustment over few hours rather than more prolonged periods would be expected. Due to lower activation time and its primary use to compensate for the ramp-up lag of slower generation, the availability requirements could be adjusted downwards, i.e. only specific hours of the day rather than 24/7. This would enable such resources as battery storage, heat pumps and demand response as well as gas-fired generators to participate.

Firm/baseload capacity would, similar to the current rules, be required to provide steady, continuous power to ensure system adequacy over longer periods of time. These resources are more stable and operate for sustained periods of time, contributing to peak demand coverage and reliability. High, around-the-clock availability would be required in comparison to flexible capacity. Assets participating in providing this product are then less responsive to short-term fluctuations but provide consistent power during high-demand periods that could last over days. Technologies particularly apt for providing such capacity include, hydro generation, gas-fired power plants but, in the future, also nuclear power, thermal storage or hydrogen-based facilities (combined with hydrogen storage).

The splitting in two products would further allow more flexibility in determining market rules and the timing of procurement per product. The procurement of firm/baseload capacity could follow the same approach used today or adapted to rolling procurement (as described in Part 1 of the report). Multi-year contract duration would be preserved to incentivize investment in capital-intensive firm capacity resources.

As to the flexible capacity product, auctions might be set more frequently to match the dynamic nature of such assets and in this way ease forecasting and alignment of commitments with the participation of flexible assets in other markets. Longer contracts as compared to those for a firm capacity product would be conceivable in order to stimulate the bidding for this new product. Assuming that the participants in both products generate energy-based revenues in energy-only markets and/or ancillary service markets while the probability of activation is rather low, it remains sensible to only remunerate availability, similar to the current setup, to avoid overcompensation.

Some technologies (e.g., gas plants, hydro plants or batteries) could technically participate in either the flexible capacity or firm capacity markets. Unless specific obligations for certain technologies or sizes are in place, they would need to weigh several factors when deciding between the two, such as revenue stability, operational flexibility and availability requirements linked to penalties. For instance, if the flexible capacity contracts offer shorter durations revenues are less predictable, yet potential for higher earnings is also likely higher as system volatility increases. Resources that are technically capable of frequent ramping or fast start/stop capabilities are likely to favor the flexibility product, where these attributes are rewarded. From the CAPEX perspective, technologies with high capital investment and longer lifespans (e.g., nuclear or large thermal storage) would likely favor the firm capacity product, as long-term contracts provide the financial security necessary for such investments. More risk-tolerant participants, especially those with the ability to shift between markets or balance flexibility with other revenue streams (e.g., ancillary services), may find the flexible capacity product more attractive.

The two-product setup opens additional fundamental questions regarding its design, in particular as for the flexibility product:

1. In setting the demand for both products, should the two products be considered independently or should the demand shares correlate?
2. How to predict the demand for flexibility in a longer-term period (e.g. a decade)?
3. For either of the two products, should a centralized market approach be preserved, or would a decentralized market be more appropriate?

Demand setting for the flexible capacity product

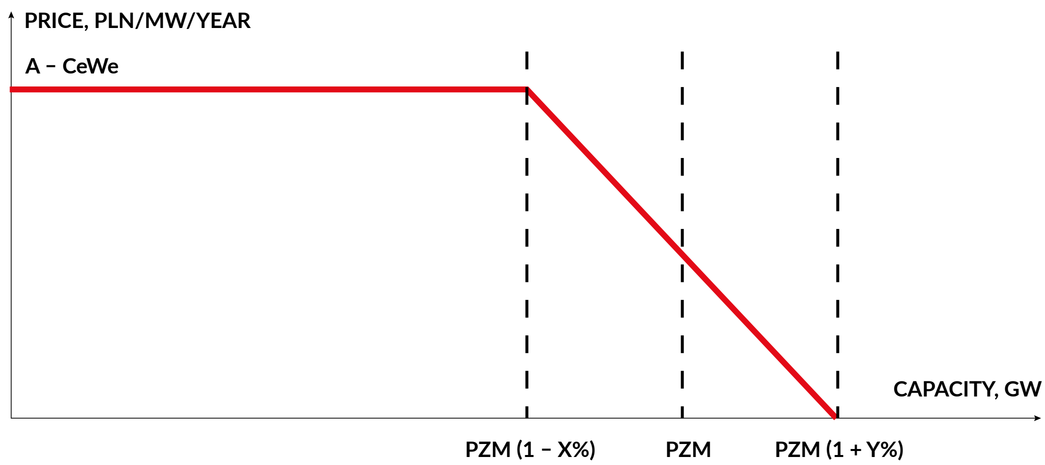
Demand for the flexible product could be determined by a single value (akin to balancing capacity demand in most countries). In this case, we talk about inelastic demand, i.e. a fully vertical curve. Needless to say, that such an approach – albeit arguably easier to set – will not be the most cost-effective. Alternatively, a downward-sloping flexibility demand curve could be used to specify the need for such capacity based on a number of indicators defining the shape of such a curve. This is akin to the logic used in the current determination of demand in the Polish (and most other) capacity market and that would be used for the firm capacity product going forward.

As reminder, the capacity market demand curve is determined by several values marking its start, end and its inflection points (cf. Figure 9). The **capacity demand curve (PZM)** represents the volume of capacity that should be procured for a given delivery period. The PZM is determined through stochastic analysis, which involves simulating multiple scenarios to assess demand and available capacity. The key steps include:

1. For each quarter, a specific PZM value (PZM1, PZM2, PZM3, PZM4) is calculated based on the expected number of hours in which scarcity (or energy not served) occurs, ensuring the system meets a reliability standard.
2. These scenarios include hourly forecasts of grid demand and available capacity from units not participating in the capacity market.
3. A surplus above the forecasted grid demand is calculated, accounting for reserve capacity for frequency regulation and the reliability of self-generation by end-users. This surplus remains fixed throughout the delivery period.
4. Available capacity from units outside the capacity market is calculated, including units in other capacity mechanisms and state-aided units.
5. PZM calculations can consider several alternative scenarios, including interconnector capacity, maximum capacity from non-participating units, and total/peak energy demand.
6. PZM is finalized using stochastic methods or a loss-minimization approach, with the lowest quarterly value determining the maximum capacity for purchase in the main auction.

Additionally, capacity prices and auction parameters are based on factors like **the cost of new unit construction** (**CeWe** point on the Y axis in the graph), fixed and variable operating costs, and potential revenue from electricity sales and ancillary services.

Figure 9. Capacity demand curve as set out in the Polish capacity market rules



Source: PSE (2020), Section 8.2.

The **demand curve for flexibility** would be determined by the specific needs of the power system for fast-responding and adaptable resources that can address grid imbalances, handle variability from renewable energy, and maintain system stability. Unlike capacity, which is focused on ensuring enough generation to meet peak demand, **flexibility** relates to how quickly and reliably resources can adjust output or consumption in response to grid conditions.

Key factors determining the flexibility demand curve could then include:

- **Residual load,** which refers to the difference between total demand and the output for renewable generation, for a given timeframe, e.g. as [MWh/h] or [MWh/15'], could serve as an indicator of the magnitude of flexibility need. Positive residual load means that RES generation is insufficient to cover all the demand. The opposite is true for negative residual load. Both directions could have a negative impact on system reliability, thus an absolute value would be worth considering. Scarcity, in terms of flexibility, would then mean instances where 100% of the residual load cannot be covered by other sources of generation or through DR (or imported/exported). This a proxy for the volume of flexibility needed.
- This indicator could be coupled with **a frequency factor,** i.e. how often does the difference between the residual and other resources reaches a certain threshold. This is a proxy of the probability of flexibility shortages.
- **Cost-of-new-entry indicator** would then account for fixed and operating costs and potential revenues from other markets, specifically for (a more limited range) of highly flexible technologies. Technically, it could be adapted upwards using **a scarcity factor** for periods characterized by a high risk of a shortage to reach a so-called "Value of Lost Flexibility" (akin to value of lost load in "regular" capacity markets). These are, however, understandably more difficult to pinpoint for long lead time, like several years in advance but could, for instance, be more feasible for e.g. seasonal auctions.

As more than the required flexibility is secured, prices would fall, reflecting the **decreasing marginal value** of additional flexible resources and the downward-sloping part of the curve. Once the system has more than enough flexibility the price per unit of flexibility would drop significantly, indicating the saturation point hitting the X axis.

Long-term forecasting of demand for flexibility

Long-term flexibility forecasting is a highly complex task, which in the future will follow a methodology specifically designed by ENTSO-E and EU DSO Entity, a so-called **Flexibility Needs Assessment (FNA)** Methodology. It is part of the requirements stated in the updated Electricity Regulation of July 2024 (see also Section 1.4.1). Looking at the mandated timeline, ACER is expected to approve the proposed FNA Methodology by Q3 of 2025, after which Member States will have one year (i.e. till mid-2026) to submit their national FNAs to ACER and the European Commission. The outcome will in turn be used to determine national indicative flexibility targets. From this perspective, the Polish capacity market reform is quite aligned with the timeline for the national FNA, which PSE will likely be tasked with.

There is, however, still very little known about the actual method for this assessment or the indicators that will be used. In a dedicated report, we analyzed the most important aspects to consider and, by drawing a parallel with the methodology for European Resource Adequacy Assessments, pinpointed the design elements for such a methodology (Tolstrup K. et al., 2024).

Long-term demand for flexibility is influenced by a range of factors, including the range of use cases such as balancing products, congestion management, voltage control, and longer-term needs like mitigating renewable energy fluctuations (see also Section 2.2.). The needs stemming from system use cases often compete with the demands of market participants (e.g., to manage forecast errors) and consumers (e.g., for self-consumption optimization), impacting the actual availability of flexibility for system services. The demand for flexibility is further influenced by technological developments, energy system targets, the geographic scope and even the network level under consideration. It will also vary based on factors like the degree and speed of renewable energy integration, seasonal effects, and market liquidity, which can be explored through sensitivity analyses (Tolstrup K. et al., 2024).

The national flexibility needs reports, mandated by Article 19e(2) of the amended Electricity Regulation, must assess flexibility needs across multiple timeframes (seasonal, daily, and hourly) and consider various factors such as market prices, demand, and generation assumptions. These reports must also evaluate the potential of non-fossil flexibility sources and account for cross-border flexibility.

Importantly, the assessment of flexibility needs should align with the ERAA methodology as required by the Electricity Regulation, though practical differences will likely arise challenging for full consistency. In fact, there are key differences, such as the FNA's focus on system-specific flexibility requirements, which need higher spatial and temporal granularity than ERAA. **As a result, methodologies for assessing flexibility will likely differ across temporal and spatial resolutions, making it essential to adapt them to the specific context and timeframe in which flexibility is required.**

The FNA methodology introduces new complexities, like assessing the flexibility needed for diverse use cases (e.g., balancing, congestion management, and voltage control) with distinct technical requirements (e.g., speed and duration of activation). It must also include distributed system operators (DSO) perspectives, account for demand response potential, and integrate new investment needs for flexibility. The FNA faces significant data challenges, particularly at the distribution level, and will require indicators beyond those used in ERAA. Moreover, economic dispatch for flexibility is expected to be more dynamic and granular, involving interactions between various flexibility use cases. Overall, this means that while ERAA and FNA share common elements, FNA's focus on detailed flexibility needs introduces additional layers of complexity and data requirements, particularly as it will guide the establishment of national flexibility targets and support schemes, similar to the one described under Option A in section 3.2.1.

Centralized vs. decentralized approach

To understand the benefits and potential pitfalls for a decentralized capacity market approach, it is useful to refer to the experience of such a market in France, whose design is described in Exhibit 1.

The choice between the two approaches is a question of the overall philosophy: is it more important to socialize the risk while potentially reducing its costs or guarantee security of supply while tolerating higher costs? The experience of France, however, also shows that the answer to this question is not black-and-white and what one might save in costs maybe counteracted by a much higher volatility and lower predictability.

Exhibit 1. Decentralized capacity market design in France

The decentralized capacity market in France was launched end of 2016 to ensure the security of electricity supply by requiring suppliers to ensure availability of capacity through acquiring capacity certificates from its operators (EPEX Spot, 2016). It thus differs from centralized capacity markets by involving various market participants directly, rather than relying on a central authority to procure capacity.

In the French CM, electricity suppliers (i.e. retailers) have an obligation to secure enough capacity to meet the consumption of their customers during peak periods. This demand for capacity is based on the expected peak consumption of the supplier's customer base, adjusted by a load profile. The focus is on peak demand periods, which are defined as hours during the winter when the French grid is most strained. The specific hours are set by the French TSO, RTE.

Power plant as well as DR and storage operators can obtain capacity certificates from RTE. The auctions for capacity guarantees/certificates are operated by EPEX Spot. These certificates correspond to their ability to generate or reduce consumption during the specified peak periods.

Concerning the timing of procurement, suppliers are required to meet their capacity obligations each year. They must procure enough capacity certificates before a defined deadline, which is several months before the actual delivery period. RTE provides forecasts of required capacity four years in advance to give participants an indication of the amount of capacity that will be needed. The duration of capacity contracts is generally one year, corresponding to the delivery year (e.g. a supplier must secure enough capacity for 2025 in 2024). New generation or DR assets may be eligible for longer contracts (up to seven years), to incentivize investment in new capacity. The system encourages demand-side participation, allowing large consumers to reduce their consumption during peak periods in exchange for capacity certificates.

Generators, storage facilities, and DR providers are the main sellers of capacity certificates, while suppliers are the buyers. Industrial consumers who can reduce demand during peak periods may also participate by selling capacity. Prices for capacity certificates are set through bilateral contracts. There is no single market-clearing price.

In such a decentralized setup penalties also apply. If a supplier fails to secure sufficient capacity certificates to cover its obligation during peak periods, it faces significant financial penalties. Similarly, capacity providers must be available during peak hours to avoid penalties. RTE plays a central role in certifying capacity, verifying the availability of capacity during peak periods, and ensuring that obligations are met.

Lessons learned from the French decentralized capacity market are:

1. Many market players find it **too complex** and struggle to fully understand it, leading to suboptimal participation in the capacity certificate market.
2. **Severe fluctuations** in auction prices (e.g. a drop from €60k/MW for 2023 contracts to €6.2k/MW for 2024 contracts) introduce financial risks for all (e.g. Montel, 2022 and Haya, 2024).
3. The national energy company, EDF, has a **dominant influence** on both the supply and demand sides during auctions, which can skew market outcomes.
4. Actors often certify their capacities at the last minute rather than the ideal four years in advance, leading to **unpredictable shifts in supply and demand.** This unpredictability increases system risks and complicates planning.

The advantages of the two approaches, centralized and decentralized, can be further analyzed from the system and from the capacity providers' perspectives, which are summarized in the two tables below.

System perspective

	Centralized capacity market	Decentralized capacity market
Advantages	• Centralized markets ensure that the system operator has a clear view of the total required capacity, improving the ability to maintain system reliability and security of supply. • The centralized approach allows for better coordination in planning and procuring the necessary capacity, avoiding under- or over-procurement. • Centralized markets can offer greater transparency, as the entire process is managed by a single entity that is accountable for ensuring fair and non-discriminatory practices	• Decentralized markets can potentially better address regional and local reliability issues • Decentralization reduces the risk of systemic failure, as capacity procurement is spread across multiple entities and regions. • With more entities involved in capacity procurement (as they are obliged to do so), there could be increased competition, leading to potentially lower costs
Disadvantages	• Centralized markets might not fully account for the specific needs of different areas within the grid and the constraints of individual technologies, potentially leading to inefficiencies. • A central authority might err on the side of caution, leading to over-procurement of capacity, which can increase overall system costs. • The system's reliability heavily depends on the effectiveness of the central authority (TSO), which could be a single point of failure in the event of mismanagement or poor planning	• Decentralized markets can lead to coordination challenges, with multiple entities procuring capacity independently, potentially leading to gaps in capacity coverage or redundancy. • Without a central authority overseeing the entire system, there is a higher risk of failing to secure enough capacity to meet demand, especially during peak times or emergencies. • Decentralized markets may struggle to achieve economies of scale, leading to higher overall costs for capacity procurement per MW

Capacity providers' perspective

	Centralized capacity market	Decentralized capacity market
Advantages	• Centralized capacity markets often provide more predictable revenue streams through auctions with fixed payments, which reduces the risk for capacity providers. • Larger, centralized auctions can result in more efficient outcomes, where capacity is procured at lower costs due to competitive bidding and scale. • The TSO provides clear market signals and ensures a more organized process for capacity procurement, making it easier for capacity providers to make investment decisions	• Participants have greater flexibility to negotiate contracts that fit their specific needs and risk profiles. • Decentralized markets can generally encourage more innovative approaches to capacity provision, including demand response and new technologies. • Participants can diversify their revenue streams by engaging in multiple contracts
Disadvantages	• Larger players might exert market power, leading to outcomes that could disadvantage smaller capacity providers. • Changes in regulation or market rules by the central authority could significantly impact the profitability and operations of capacity providers. • The centralized structure might limit the ability of participants to tailor their offerings or strategies to specific market needs, potentially reducing innovation	• The lack of a single, centralized auction process can create uncertainty and complexity for capacity providers, who must navigate multiple contracts and intricate market rules. • Revenue streams may be less predictable, with greater exposure to market fluctuations and bilateral contract negotiations. • Depending on the exact design, smaller, decentralized markets may suffer from fragmentation, limiting liquidity and potentially leading to inefficient outcomes

To sum up, market participants in a centralized system may enjoy stability but face reduced flexibility, while in a decentralized system, they may benefit from greater control but with increased risks. From an **electricity system perspective**, centralized markets offer a more controlled environment, whereas decentralized markets may better accommodate local conditions but with potential coordination difficulties.

A combined or hybrid market, as described in Exhibit 2, may help strike a balance between the two but the implementation complexity and lots of open design questions may outweigh potential benefits.

Exhibit 2. Latest considerations in Germany – introducing a hybrid (centralized and decentralized) capacity market

As published by the Federal Ministry of Economy and Climate (in Ger. BMK) in August 2024, Germany is considering the introduction of a combined capacity market including both a centralized and decentralized component. The first component consists of centrally organized tendering of new, additional capacity, i.e. generators compete for investment support provided by means of long-term contracts. The decentralized component in turn is based on the obligation of balance responsible parties (in Germany aggregated to balancing groups) to secure their demand in peak load situations with capacity certificates. Alternatively, they may use their own flexibility and, thereby, reduce their demand and, thus, obligations in terms of certificates. The certificates are offered by certified capacity providers based on their contribution to system security (de-rating), including those of new capacities secured with the centralized tendering, and are valid for specific 'obligation periods', expected to be one year each. The central certificates are put forward to the decentralized auction by a public body, i.e. the awarded capacities of the central tender agree to their capacities being handed over to the public body.

Timing. In terms of timing, the centralized tendering is proposed to take place with 5 years lead-time, to be repeated yearly until the required new capacities are secured. The decentralized auctions are to take place with 4 years lead-time. Continuous trade of certificates then allows for suppliers to adapt according to their expected demand. Importantly, the authors stress that the introduction of the centralized and decentralized element does not have to occur at the same time, but e.g. centralized tenders could already take place while the decentralized component is yet to be implemented.

Dimensioning. The dimensioning of the centralized tender volume should be based on simulation-based calculations and might also lead to zero in case no new investments for some years are needed. On the contrary, the dimensioning of the decentralized component reflects the system's peak load of each obligation period, i.e. the supplier's demand at times of the system's peak load determines the individual obligations.

Financing. The profit of auctioning the central certificates by the public body is used to finance a share of the costs of the central capacity market component and, in addition, a levy on end consumers might be introduced. The decentralized component should not have any inherent costs, except for administrative. With regards to the profit of awarded capacities, it is considered necessary to introduce mechanisms such as reliability options, to ensure transfer of profit in case e.g. the day-ahead market price exceeds a certain strike price.

According to the German Ministry, such combination may, if well-designed, leverage the benefits of both elements: secured investments in new capacities with long refinancing periods, centrally dimensioned; and demand coverage with minimized costs by means of market-based dimensioning based on decentralized knowledge and options for adapting according to market participants needs. This approach, however, has been heavily criticized.

Source: BMWK (2024c).

3.3.3. Option C: Combined strategic and grid reserves

The combined market mechanism integrates the need for both system adequacy and congestion management, focusing on capacity resources that can contribute to both functions. In a number of countries, the latter is covered through so-called grid reserves (e.g. Germany or Austria – see Exhibit 3 for the German case).

In terms of demand for capacity, providers would be required to meet two primary objectives: ensuring adequacy during peak demand periods and offering operational flexibility to manage grid congestion in a specific location. Thus, the demand for capacity would be determined by system adequacy needs and expected congestion volumes. Since more or less accurate prediction of congestion volumes is only possible in short (e.g. weekly or daily) timeframes, the areas prone to congestion could instead be determined based on statistical analysis of historical data and considering projected grid developments and volumes of installed capacities. Given the use cases, all certified resources would likely be required to provide locational information of their assets needed to evaluate whether they will be efficient at solving grid constraints.

Similar to other types of reserves, the remuneration would likely be based on an auction outcome and the commitment specified in bilateral contracts subject to payments for reservation as well as at-cost reimbursement for actual activation. Assets participating in the combined reserve would be prohibited from participating in electricity markets in order to avoid market distortion, which would, however, likely limit participation to technologies with fossil-fuel-based assets rather than a broader technological range of providers. Capacity providers would need to be available when called upon by the TSO, whether during scarcity periods and/or when congestion events arise. Monitoring and verification of availability as well as penalties for non-delivery would be crucial for ensuring compliance.

Exhibit 3. German grid reserve (and overlaps with strategic reserve)

Some EU Member States have introduced grid reserves. Looking at the German case, the reserve was introduced both in the energy law ('Energiewirtschaftsgesetz'; EnWG), covering high-level principles, and a dedicated legislation ('Netzreserveverordnung'; NetzResV). It was first approved by the EC under state aid rules in 2016 for a period of four years, but the German government did not apply for an extension as it does not consider the grid reserve in Germany to be state aid relevant (BMWK, 2022).

Its main objective is the safety of the electricity system, in particular congestion management and voltage stability as well as grid restoration, and it is composed of:

- non-operational power plants which are to be put back into operation due to their 'system relevance' and following a TSO's request,
- relevant power plants which have announced a preliminary or final decommissioning to the TSO, and
- suitable power plants in other countries (§ 13d(1) EnWG).

The NetzResV governs the procurement process: first, the dimensioning is approved by the NRA each year, based on an analysis, jointly performed by the TSOs, covering the period of April to March for the upcoming year. In case of an identified need for procuring grid reserve, the TSO(s) publish requirements and invite interested parties to submit declarations of interest. In case of the same technical suitability to serve system security, the offers with minimal costs shall be accepted. The power plants included in the grid reserve are to be kept outside of the electricity markets and used by TSOs based on their forecasts and technical conditions. Costs for availability and usage of the grid reserve are to be covered by the connecting TSO but shall exclude costs which anyway would have been induced by the planned commissioning.

Importantly, §13d(2) EnWG also covers the overlap of the grid reserve and the existing strategic reserve, also kept outside of the market, in Germany: power plants obliged under the grid reserve may participate in the tendering for the strategic reserve. If successful, they are only reimbursed via the latter mechanism but continue to be obliged to follow TSOs' instructions under NetzResV and general redispatch principles.

3.3.4. Option D: "Capabilities market"

On a scale between business-as-usual and full product integration into a single "universal-flex" product, a capabilities market is the closest to the latter, as illustrated in Figure 7. Although, in contrast to the "universal-flex" product, there is not a single product for all possible system use cases, the products themselves are not defined in advance and rather "constructed" *ad hoc* based on a current system issue or issues.

In this option, the TSO would have a maximum freedom to determine, which capabilities are currently required and pool the resources accordingly to satisfy a system need. In this way, a capabilities market can be theoretically used to address capacity needs for adequacy or other needs, such as system stability or congestion management. It can also apply to the availability of firm or flexible capacity for activation.

The way such a setup could look like is illustrated in Exhibit 4 for NODES flexibility platform operated in the Nordics. Basically, the bid is not a given price-volume pair but an explicit price tag is put on a specific property or parameter.

It is worth noting, however, that the this solution currently covers a limited geographical area at the distribution network level making computational complexity more manageable.

In a “capabilities market,” different energy resources (e.g., generators, batteries, demand-side response) would be valued and traded based on their specific technical capabilities rather than being limited to predefined roles in existing segmented markets with standardized products. The capabilities could include, for capacity, energy or both:

- grid location,
- speed of activation,
- duration of activation,
- profile adjustment (i.e. ability to modulate output or demand in response to a control signal),
- availability timeframes (e.g., peak hours, low-demand periods).

The system operator would optimize the selection of resources based on the combination of these capabilities needed to meet grid reliability or other goals. Technically, participation of aggregated resources is not excluded, though this would largely depend on the obligation (or lack thereof) to provide a precise grid location for all units participating in the market.

Ideally, such an approach would incentivize investment in assets with system-relevant capabilities (at the needed location) and drive investment in technologies complementary to variable RES.

Pricing of bids would then be made explicit for these different capabilities. For instance, a markup may be used for units with a high estimated efficiency, that is, in a location relevant from the perspective of a congested critical network element.

Thus, different capabilities would be likely priced differently based on real-time conditions. For example, the ability to respond within milliseconds during a grid disturbance may be priced differently than providing a steady output over several hours.

Arguably, such an approach might be more cost-reflective and transparent since the different properties are explicitly priced. The system operator(s), in turn would have a possibility to use the resources both for standard products as well as for more specific needs. However, such pricing is not necessarily the most cost efficient and information asymmetries between the TSO and the providers (that always know their own costs better) remain.

Such an approach is also somewhat reminiscent of the approach to balancing bids used in the Polish balancing market in the past (see e.g. Mielczarski W., 2005), where different volume bands were priced individually and separately for upward and downward regulation while a separate band with a price tag of its own was used to explicitly represent start-up costs. It should, however, be remembered, that this approach was used in a central-dispatch setup and a capabilities market would also represent a move back to central dispatch.

From the point of view of overall efficiency, a capabilities market could streamline the procurement of all required services in a single platform. This would – at least theoretically - reduce administrative complexity and ideally improve market efficiency by pooling liquidity.

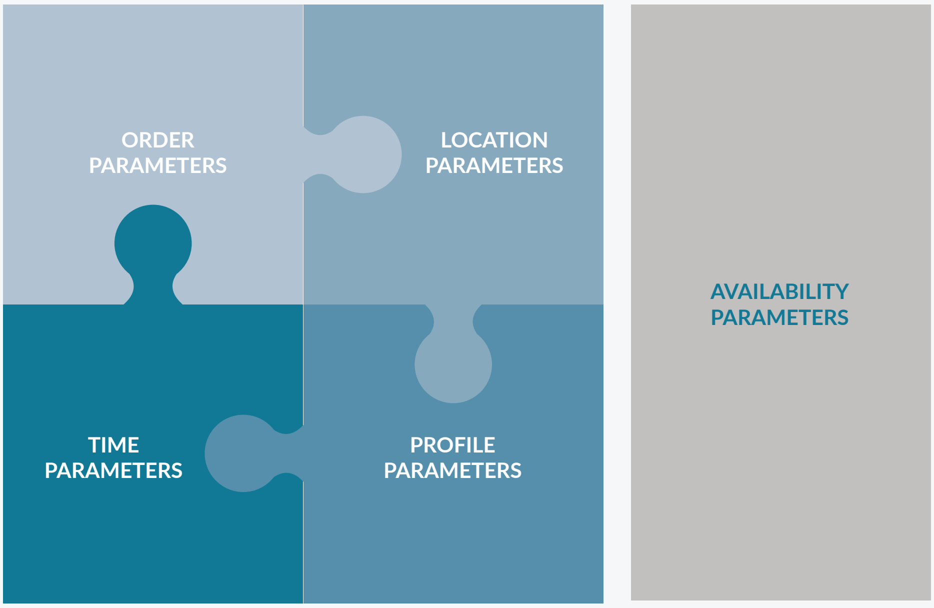
Yet, the clearing of such a market then presents a much larger challenge. A highly sophisticated clearing algorithm would be necessary to match the supply of capabilities (e.g., a storage system offering quick response but limited duration) with the grid’s demand for those specific attributes (e.g., fast response for a balancing product or longer duration for peak shaving). The algorithm would also need to account for inter-temporal constraints (e.g., how long a battery can provide output) and ensure that the optimal mix of resources is procured. It would also likely require a co-optimization approach across several use cases. A combination of these requirements makes an optimization problem, especially on a large, national scale, highly complex and likely slow while the risk of non-convergence is high. Similarly, developing adequate settlement procedures would be technically challenging.

In a nutshell, a capabilities market offers flexibility by allowing products to be dynamically constructed based on current system needs, with bids reflecting specific technical attributes like location or activation speed. This approach could ideally enhance market efficiency through co-optimization of grid services and more cost-reflective pricing as well as incentivize investment in system-relevant capabilities. Yet**, this approach represents a hypothetical scenario rather than something that could be implemented in Poland in short to medium term whereas its benefits would likely be outweighed by implementation challenges, especially concerning advanced clearing algorithms and settlement procedures.**

Exhibit 4. NODES platform

Nodes is a platform facilitating flexibility procurement between system operators and FSPs. Importantly, and making it different to other flexibility platforms, products are not standardized but offers can be specified using different parameters (Schittekatte T. and Meeus L., 2020). These parameters, clustered in different groups such as order, time, location, profile and availability of the offer (cf. Figure 10; NODES, 2020), allow buyers to filter and choose offers according to their needs and the capability of FSPs' offers. NODES also enables system operators to create templates for parameters they would like to see specified.

Figure 10. Parameter groups of the NODES platform



Source: NODES, 2020.

The advantages of such approach are that:

- this allows satisfying specific system operator needs (as also the EB GL allows for specific balancing products if the need demonstrated by TSOs and approved by the respective NRA), and
- it increases flexibility in offering for FSPs as they can customize their bids and even ask for a premium if a product has valuable attributes (Schittekatte T. and Meeus L., 2020).

3.4. Regulatory implementability

Key message:

Under current EU regulatory framework, Options A and B are the most feasible, with Option A potentially requiring more preparatory steps and time due to new processes and targets, but both options involve relatively low regulatory effort compared to the other two alternatives. EU regulatory amendments for Options C and D, by contrast, are unlikely given the recent regulatory update in 2024.

To assess regulatory implementability, the described options are assessed in relation to the currently applicable legal framework on EU level. As introduced in Section 1.4, the main principles for capacity markets, non-fossil flexibility support schemes, balancing markets and congestion management are set by the (amended) Electricity Regulation. Any change to the current capacity market design, even if only updated, will require amendments to the respective Polish national law or rules which is out of scope of this report.

Furthermore, any mechanism and its detailed conceptualization will need to be assessed with regards to state aid rules and might need the EC's approval. Please note that for the following high-level assessment, it is assumed that any capacity market in Poland (incl. related improvements) will continue to be implemented in compliance with the design principles defined by the Electricity Regulation.

Option A – implementable under current EU regulatory framework: An updated capacity market with an additional non-fossil flexibility support scheme – fulfills the requirements of EU legislation, if designed correspondingly. In fact, it is based on the measures included by the latest regulatory framework to address respective concerns. However, as the steps preceding the introduction of non-fossil flexibility schemes are yet to developed and completed (FNA methodology, national report and definition of national indicative targets for flexibility), the timeline for the introduction of such scheme is expected to take several years.

Option B – implementable under current EU regulatory framework: The regulatory framework on EU level does not exclude the design choice of having two separate products (firm and flexible) under a capacity mechanism. However, the general aim of the mechanism is defined as addressing resource adequacy, excluding measures related to congestion management and ancillary services (Art. 2(22) Electricity Regulation), which must be respected. Additionally, the Electricity Regulation sets general design principles for capacity markets (Art. 22) which must be complied. Therefore, the interactions between the two products are to be considered carefully to avoid market distortions and going beyond what is necessary to address the adequacy concern, as required by the Electricity Regulation (Art. 22(1)).

Option C – not implementable under current EU regulatory framework: The definition of capacity mechanisms, including strategic reserves, excludes the usage for congestion management or ancillary services (Art. 2(22) Electricity Regulation). Furthermore, the design and in particular the activation of strategic reserves is very limited to last resource situations i.e. only allowed if balancing resources are likely to be exhausted to establish an equilibrium between supply and demand (Art. 22(2) Electricity Regulation). To account for this, the Electricity Regulation (Art. 22(2)(b)) also requires that imbalances are settled at least at the value of lost load or at a higher value than the intraday technical price limit, whichever is higher. Therefore, procurement of one combined reserve for both resource and transmission adequacy is currently not implementable in compliance with the EU regulatory framework. If this option is to be pursued, the newly adopted Electricity Regulation would require another amendment adapting the definition of capacity mechanisms in a first place but also allowing for joint procurement and usage. This seems unlikely, also in terms of support by the EC, as the approvals of grid reserves in e.g. AT also point to network development and seem to rather perceive the grid reserve as a transitional measure until it is completed.

Option D – not implementable under current EU regulatory framework: Covering the entire range of flexibility use cases by setting up a capabilities market with procurement of flexibility no longer organized by means of predefined products is not covered by the applicable legal framework on EU level.

On the contrary, the Electricity Regulation requires the separate establishment of balancing markets (Art. 6) and national (with cross-border participation) capacity mechanisms (Art. 20-22) - not allowed to be used for congestion management or ancillary services - and establishes rules for national (market-based) redispatch (Art. 13). In particular, the first are further regulated by the EB GL with a target model of implementing several balancing platforms across the EU with harmonized standard products for the different services (Art. 19-21). The implementation of this option would therefore require a fundamental change of the current market design, i.e. the amendment of at least the Electricity Regulation and the EB GL, which is not expected in the near future.

Summing up, in terms of regulatory implementability, Options A and B are the most straightforward due to their compatibility with the current EU legislation while the other two options would require amendments of at least the Electricity Regulation, and for Option D also of the EB GL, which cannot be carried out in the near term. Such amendments also seem unlikely since the recent amendment has just entered into force in 2024. When comparing Option A and B, Option A, including the introduction of a non-fossil flexibility support scheme, requires preparatory steps as described above. In particular, the development and adoption of the FNA methodology involves several parties, subsequent national reports are the first of their kind and, finally, the definition of indicative national flexibility targets by the Member States might be a (politically) challenging process. Therefore, it could take more time or be possibly delayed. However, the effort in terms of **regulatory implementability is in a comparably rather low range for both Options A and B,** i.e. only requiring amendments to national law or implementing rules of capacity mechanisms as well as obtaining a new approval of the EC.

3.5. Evaluation of the four options

Key messages:

- **Option A** implies a relatively low implementation effort while efficiency highly dependent on the synergies between the CM and support scheme. The latter is non-market-based and only includes non-fossil flexibility, as per Electricity Regulation, which might lead to overall higher costs. Demand for the support scheme should be determined in a national Flexibility Needs Assessment.
- **Option B** has the highest score on the KPIs and compatibility with the future system needs and is further compliant with the main CM design principles as per Electricity Regulation. For this option, it is crucial to ensure a coordinated approach in determining the demand for the two products.
- **Option C** could be especially useful to reduce RES curtailment while using same resources for both security of supply and congestion management. It is associated with a relatively low implementation effort but also low efficiency. Generally, it is not recommended as a substitute for a CM but a combination with Option A or Option B can be considered.
- **Option D** implies a dynamic product construction and a co-optimization across use cases. While theoretically more efficient, this approach is also linked to high ambiguity about design, clearing algorithm and is coupled with high technical and regulatory effort due to complexity. This makes it a hypothetical option in the medium term.

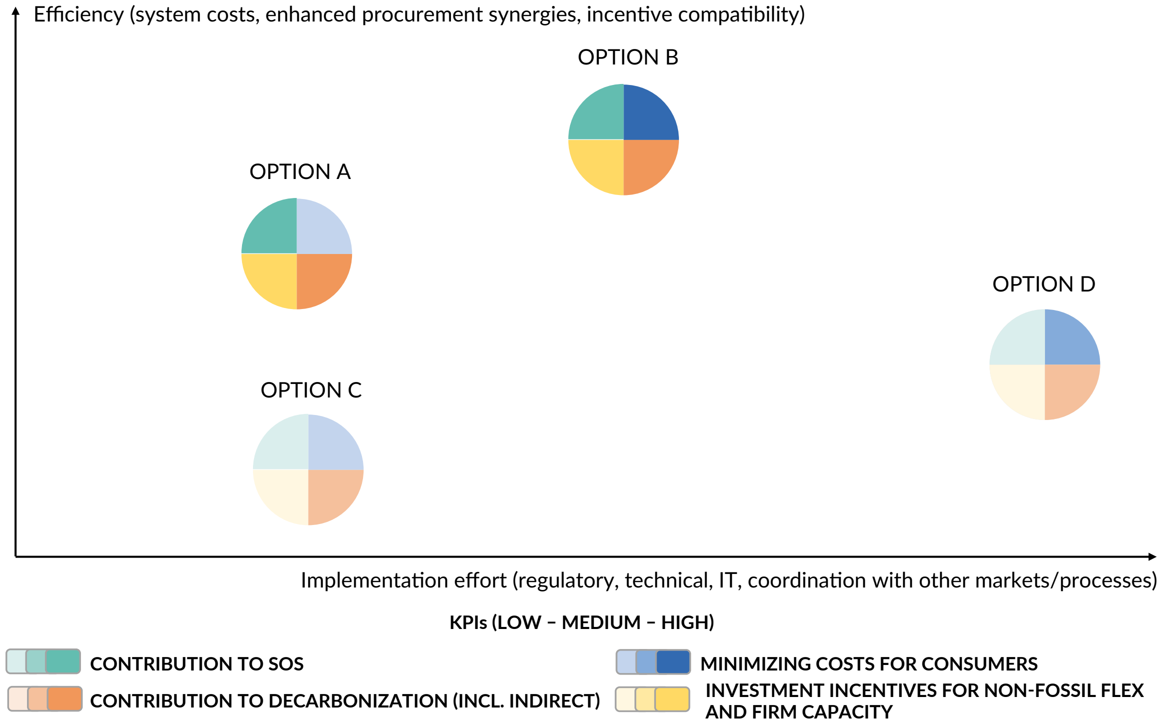
Based on the overview of the four options above, these are evaluated using a two-dimensional matrix combined with a number of KPIs linked to the target model addressed in Section 3.1:

- The X axis of the matrix evaluates overall implementation effort associated with each option, based on the technical implementation requirements as well as on the current regulatory conditions.
- The Y axis addresses the efficiency dimension per option. “Efficiency” in this context includes such aspects as minimization of the system costs, maximizing synergies between difference use cases and strengthening investment incentives.
- The achievement of the four KPIs listed in the legend are illustrated per option: the darker the color, the higher the degree of achievement of a KPI (ranging between low, medium and high).

Note that this evaluation does not provide absolute value estimation concerning this or that KPI. Instead, the values per option are in relation to other studied options. For instance, incentive signals in Option B are estimated as being the highest in comparison to the other 3 options. We thus do not exclude a possibility of another option being even more efficient in this regard.

Specific reasons for the evaluation results of each option are clarified in the following sub-sections.

Figure 11. Assessment of the options based on their efficiency and implementation effort



3.5.1. Option A

Implementing a capacity market, supplemented by an extra support scheme for non-fossil flexibility (via availability payments), comes with several implications - both positive and negative.

A capacity market ensures resource adequacy by securing enough firm capacity to meet peak demand. By adding a flexibility support scheme, additional incentives are created for non-fossil resources to be available for quick activation, improving system responsiveness during fluctuations caused by variable RES. Flexible resources are crucial in handling short-term volatility, while the capacity market ensures longer-term adequacy, providing a balanced approach to grid management.

Such an extra support scheme, focused on non-fossil flexibility, would encourage investment while reducing dependence on fossil fuels and potentially better tapping into sector coupling potential (through synergies with the heat or hydrogen sectors). Thus, **contribution to security of supply as well as to enhancing investment incentives is expected to be high.**

On the flipside, introducing two overlapping mechanisms could distort the market, particularly if the incentives overlap or are poorly calibrated. This might lead to overcompensation of certain resources, reducing the cost-efficiency of the overall system. It is thus crucial to ensure that double-counting is avoided by allowing simultaneous participation in only one of the two mechanisms.

A dual mechanism could increase total system costs if synergies are low. Moreover, managing two separate but interrelated schemes add significant complexity to market design and operations.

This includes ensuring clear definitions of products, avoiding overlaps, and designing fair settlement and procurement processes. Additionally, an availability requirement also applicable to the support schemes means that an additional monitoring and verification process will need to be developed to ensure providers deliver the required services. **Thus, a limited or negative contribution to minimizing costs for consumers in expected.**

From the perspective of contributing to decarbonization, the impact of this Option is ambiguous. If the flexibility scheme only supports non-fossil resources, as required by the amended Electricity Regulation, there may be a risk of stranded assets or under-utilization of existing fossil resources, such as CCGTs, OCGTs or some CHPs, that provide flexibility today. However, if fossil resources are still allowed in the capacity market, this could slow the transition to cleaner energy sources.

This approach could strengthen grid resilience by securing both long-term adequacy and shorter-term flexibility from non-fossil resources, promoting a clean energy transition in Poland. However, it introduces risks related to market distortion, higher costs, and increased complexity, which would need careful management to ensure the benefits outweigh the downsides.

3.5.2. Option B

Introducing two distinct capacity products in an electricity capacity market — one for flexible capacity (quick response but shorter duration) and another for firm capacity (slower response but longer duration) — could significantly reshape the market. Based on our analysis, summarized in Figure 11, it is ranked as the highest in terms of overall efficiency thanks to maximizing the synergies between the two different needs, creating additional investment incentives and minimizing system costs. On the other hand, this option is associated with a likely higher implementation effort as compared to Options A or C due to the need for a new separate product definition as well as of a *de facto* two-market solution with separate demand and clearing mechanisms.

Firm capacity generally ensures that there is enough generation available during peak demand periods. Yet, alone may struggle to address fast, short-term fluctuations in supply and demand, e.g. following a sudden generation shortfall during changing weather conditions.

A two-product solution is expected to improve security of supply with the two products being activated either separately or in a stepwise fashion in a scarcity situation (akin to sequential the activation of balancing reserves depending on the magnitude and duration of a frequency deviation). The flexibility product would address fast fluctuations that traditional firm capacity cannot manage. Meanwhile, firm capacity would still ensure that longer-duration needs are met, such as during multi-hour or multi-day demand peaks, or extended periods of low renewable generation (e.g., "Dunkelflaute" periods in winter).

The needs for both products are then made explicit and capacity providers would have freedom to choose bidding for a product which is better aligned with the technological capabilities of their assets and impact the setup of their portfolios.

It does, however, raise a fundamental question of whether there would be an overlap between such a solution and current balancing markets since a sudden change of a supply-demand balance goes hand-in-hand with frequency deviations. Thus, a synergy between such capacity market design and balancing capacity markets may be pondered. If identified, it would for example help reduce balancing demand, which is usually associated with very high costs.

By splitting capacity procurement into flexible and firm products, the market could more efficiently allocate resources to both. Flexible capacity (e.g., batteries, demand response or heat pumps) is typically cheaper to procure for short-term activation. As a result, consumers might benefit from a better resource allocation and, consequently, **lower overall costs**, as the grid does not need to rely on expensive firm capacity for short-duration events. On the downside, there is **a risk of higher administrative costs** linked to two products rather than one.

The current focus on firm capacity often favours conventional, fossil-fuel-based peaking plants because they are reliable for long-duration adequacy. However, this approach may not fully utilize the potential of low-carbon flexible resources that could help manage short-term variability in a more carbon-efficient way. The experience from the Polish capacity market auctions demonstrates growing but largely insufficient shares of new technologies.

By creating a dedicated product for flexible capacity, more resources like batteries, demand response, and renewable energy with combined with electrochemical or thermal storage are more likely to be utilized thanks to a dedicated certification process likely more aligned with their technical restrictions. For instance, the duration of activation of 15 minutes to one hour for a flexibility product would suffice, as opposed to a firm capacity product, which requires availability for at least 4 hours, according to the current rules. As a result, **this approach is expected to improve investment incentives into new non-fossil flexibility without jeopardizing the market position of existing firm capacity.** One potential downside is that splitting the capacity market into two products could fragment investment signals. Some investors may find it unclear which market to participate in, or may perceive greater complexity, which could slow investment in both categories if not well coordinated.

This Option is further likely to have the highest contribution to decarbonization efforts in Poland as compared to the other three options. With flexible capacity available, the grid can better handle the intermittency of renewable energy thus reducing RES curtailment currently on the rise in the country. As a positive spillover effect, this would improve the economic case for further renewable energy investments. If the firm capacity product also encourages low-carbon technologies like long-duration storage (e.g., pumped hydro, hydrogen storage) or dispatchable renewables (e.g., biomass or geothermal), it could accelerate decarbonization in the firm capacity segment as well.

A dedicated market for flexible capacity would create clear investment signals for fast-response technologies. Investors would have confidence that these resources can be monetized through reliable revenue streams, thus driving greater deployment of non-fossil flexibility technologies. At the same time, maintaining a market for firm capacity would still provide incentives for longer-duration resources, such as large-scale storage, gas peaking plants (for now), or new low-carbon technologies designed to provide firm capacity (e.g., hydrogen or biomass plants). **This approach is therefore deemed to be the most compatible with Poland's long-term energy and decarbonization goals.**

3.5.3. Option C

Combining the procurement of strategic reserves (for ensuring adequacy) and grid reserves (for congestion management) into a single mechanism, as described in Section 3.2.3, the implementation effort is anticipated to be low to medium, thus comparable with Option A but lower than for Option B. Similar to Option A, it will require an additional application to the European Commission but the technical implementation is expected to be rather limited, as opposed to Option B.

The overall efficiency of such an approach alone is estimated to be the lowest – hence, we also analyse whether it would be sensible to combine it with an updated centralized capacity market (e.g. as described in Option A). Option C is further shown to have a relatively low performance on the four KPIs, as compared to the other three options.

Contribution to the security of supply is ranked as insufficient. A single reserve mechanism might struggle to strike the right balance between the different needs, leading to either excess procurement (which raises costs) or insufficient capacity (which reduces security of supply).

On the positive side, by combining the procurement of both types of reserves, system operators could ensure a more holistic and coordinated approach to grid stability, balancing both resource and transmission adequacy. Based on the experience of other EU countries with high RES shares, such as Germany or the Netherlands, the situations where both resource and transmission adequacy are affected are bound to increase in Poland as well. By exploiting the synergies between the two use cases and making the same source of flexibility available for both and in this way making utilization more efficient, overall costs for consumers are likely to be optimized – provided the occurrences of congestion also increase. However, if that is not the case, likely over-procurement of otherwise uneconomic assets would increase consumer costs. An additional risks factor is linked to the locational aspect of grid reserves as these are meant to contribute to relieving congestion in a specific stretch of the power grid. If the capacity required for both adequacy and congestion management is concentrated in certain geographic areas (e.g., congested parts of the grid), the competition for these resources could increase procurement costs. Thus, **the effect of costs is seen as low for this option** in Figure 11.

The effect on system decarbonization may in fact be positive as CO_2 emissions ultimately stem from power production and not its reservation. Assuming that this combined reserve is only rarely activated while the participating assets are out-of-market, the emissions could in fact decrease.

However, in the short term, a single mechanism could lead to a high reliance on natural gas generators to meet both capacity adequacy and congestion management needs. Plus, this approach comes at a risk of extending the lifetime of otherwise uneconomic and polluting assets – having a negative effect on decarbonization in the longer term. **Contribution to decarbonization is thus seen as rather low.**

The complexity of serving two different purposes (adequacy and congestion management) under a single mechanism might create uncertainty for investors. They may hesitate to invest without clear differentiation between the revenue streams or how their assets will be called upon under various conditions. Theoretically, also low-carbon or carbon-free assets could take part in the mechanism. This is however highly unlikely as market participation is not allowed and the revenues would most likely be insufficient to provide investment incentives for new assets complying with the emissions limits. Hence, **no or negligible positive impact on investment incentives is expected.**

Option C – or at least strategic reserves - could potentially be combined with Option A or B, especially considering Poland's still rather high reliance on coal-fired generation and, to an increasing extent, on gas-fired resources. This option is analysed in more detail in Section 3.4.5.

3.5.4. Option D

As compared to the other three options, the effect of a capabilities market both on addressing system needs and improving incentives for providers is the most ambiguous. This is also due to lack of overall experience with such an approach or lessons learned. Against this backdrop and the regulatory as well as design complexity discussed in Section 3.2.4, we estimate the implementation effort to be by far the highest. In terms of its potential efficiency, it will largely depend on the range of use cases addressed and how well an algorithm for such a market could be implemented. While it could maximize the synergies among different product and the use of scarce flexibility, it also risks reducing market transparency and complicating the bidding process.

While such a market would optimize for technical capabilities, it may not always provide long-term signals for investment in capacity. This could lead to a mismatch between short-term flexibility needs and long-term adequacy requirements. Adequacy requires a higher volume of resources, which are then more difficult to procure in a short (e.g. daily as is the case with balancing markets) timeframe, which would not be sufficient from an adequacy perspective or from the perspective of providing robust investment incentives.

It could also allow to use the same source of flexibility for multiple use cases thus increasing overall availability of resources for activation. Yet, security of supply could be jeopardized in the short term if the market design is too complex or fails to converge quickly. While a capabilities market is more dynamic, it could also shift focus away from ensuring long-term adequacy, which is essential for securing supply during scarcity conditions. **Due to this high level of uncertainty, the contribution to the security of supply is anticipated to be rather low.**

The market would more accurately reflect the real costs of providing specific capabilities, such as rapid response or location-specific services, as their pricing is made explicit. By optimizing the procurement of multiple capabilities in a single market, this approach could reduce administrative costs and inefficiencies related to running multiple markets (e.g., separate capacity and flexibility markets). Ideally, this would lead to lower overall costs. A capabilities market further reduces the risk of overcompensating resources, as payment is directly linked to the value of specific attributes rather than broad categories like capacity or energy. This could result in cost savings for consumers.

At the same time, since a co-optimization approach would likely be needed to select the bids for different use cases, from a purely economic perspective, this would lead to lower costs as opposed to different products being optimized separately. However, it is also unrealistic to assume that service providers' bidding strategies would remain the same as compared to business-as-usual. Moreover, transition to such a different solution would likely translate into higher initial costs that would be passed to consumers.

A highly sophisticated clearing mechanism would be required, which could increase operational costs. These costs might be passed on to consumers in the form of higher prices while the system is likely to be slow or inefficient in its early stages.

Capabilities-based bidding would also substantially increase bidding complexity, which may deter at least some of potential providers or increase risk premiums associated with the bids. **Thus, the contribution to minimizing costs for consumers is estimated to be medium – yet again, subject to a high degree of uncertainty.**

The focus of such a market of individual technical capabilities may offer more revenue opportunities for a broader range of providers, including e.g. non-fossil distributed flexibility. For instance, resources able to offer fast response times or localized services, might be made available to reduce curtailment volumes of RES generation thus aiding decarbonization and creating a stronger financial case for such technologies. However, this does not exclude fossil-fuel-based plants that could still compete based on their capabilities (e.g., quick ramp-up times). Without specific restrictions, this could delay full decarbonization if these resources continue to be valued for certain capabilities, even as clean technologies are developed. **The market's contribution to decarbonization is limited because it depends on the mix of providers and their technologies as well as on the design. Since the market focuses on capabilities rather than specific products, fossil-fuel-based resources could still be favoured if they meet the required capabilities.**

The explicit pricing of capabilities such as fast response, and locational value would likely drive investment in technologies like energy storage or DR to provide system-relevant services. Given the nature of such a market, however, the final pricing will likely be much less transparent and the signal less robust making actual revenues from specific investments more difficult to estimate. In addition, since the capabilities market focuses on specific real-time technical attributes, there is a risk that investments might overly concentrate on flexibility services, neglecting the need for large-scale capacity to meet peak demand in times of scarcity. The likely absence of long-term payments and reliance on short-term procurement increases risk for participants, making investments in flexible and firm capacity less attractive. Co-optimization reduces market participants' control, further heightening uncertainty and reducing incentives to invest. **That said, investment incentives are anticipated to be low.**

3.5.5. Can strategic reserves be combined with Options A or B?

Considering Poland's specific situation while transitioning away from a high dependency on fossil, in particular coal-fired generation, the question rises if Option A or B, scoring the highest in the above assessment, might be combined with a strategic reserve (SR). This section tries to provide a first direction in terms of answering this question, while it must be noted that it by no means can be understood as a comprehensive legal analysis.

In general, the (amended) Electricity Regulation prefers the introduction of a SR, kept fully outside of the market, over other types of CMs. In particular, Art. 21(3) of the Electricity Regulation reads as follows: *'Member States shall assess whether a capacity mechanism in the form of* ***strategic reserve is capable of addressing the resource adequacy concerns. Where this is not the case, Member States may implement a different type of capacity mechanism****.'* This provision indeed is a prioritization in terms of type of capacity mechanism and might also be interpreted as rather favoring having one (SR) **or, if not capable,** the other. **On the contrary, it does not explicitly prohibit the combination of both.** However, such combination would require a proof that only both the SR and another type of capacity mechanism can address the identified resource adequacy concern. Differently said, a proof that a SR alone is not able to do the trick, but a remaining concern e.g. such as respecting shorter ramp up times must be addressed by an additional mechanism. Such argumentation points back to Option B since it is also based on the assumption that a separate flex-focused product will be required to ensure overall system stability.

It could be argued that Poland, in its peculiar situation with having one of the largest adequacy gaps in the EU and opting for both the decarbonizing of the energy system away from coal-fired generation and the adaptation of its capacity market towards ensuring both firm and flexible capacity, requires both a SR and a separate mechanism. Importantly, as explicitly required for by Art. 22(1)(c) of the Electricity Regulation, capacity mechanisms '*shall not go beyond what is necessary to address the adequacy concerns […]*'. **This principle must be ensured, even more so for a combination of two mechanisms since both types and their interactions increase the risk of overdimensioning.** This leads to the question of how to correctly dimension both CMs and, considering the above, whether the bigger share should be attributed to the strategic reserve.

Assuming the legislator would agree with the reading that a combination of mechanisms is possible, Poland might consider introducing a SR as a transitional and temporary measure to bridge the gap between today and the full development of the adapted capacity market, requiring more time to accumulate the needed volumes.

Depending on the exact design, the SR could rather address long-term scarcity events (longer provision of service, i.e. several days) and outside of the market, and the CM targeted at ensuring necessary investments for achieving the energy transition and, in the long run, the coal phase-out. In this regard, the design could also differ in terms of CO_2 emission targets, i.e. the SR with a higher level (considering Poland's opting for a derogation) since activation is only triggered to address last resort demand coverage. This in fact would allow to keep coal-fired capacities further available (but mostly unused) until enough new firm and flexible capacities are built under the updated/new capacity mechanism. Such forward-looking approach seems reasonable both to maximize the chances of approval by the EC and contribution to decarbonization since the expected activation of these assets is likely to be close to zero – unless a serious scarcity event would occur. In this case, however, it is exactly valuable to have the CM with a flex product that could "kick in" faster and only if the scarcity event lasts longer, coal generation could still compensate the shortfall.

Nevertheless, in terms of costs, two separate mechanisms would be more cost intensive as not leveraging synergies in terms of joint procurement and requiring more administrative expenses for procedures, monitoring, etc.

In any case, considering Art. 69(3) of the amended Electricity Regulation – *'[...] **By 17 April 2025, the Commission shall, after consultation with Member States, submit proposals with a view to simplifying the process of assessing capacity mechanisms as appropriate.**'* - engaging in discussions and providing Poland's position and reasoning as soon as possible seems favourable.

Finally, looking at Poland's neighbours, the question of whether the German example can be followed is addressed in Exhibit 5.

Exhibit 5. Germany's Power Plant Strategy

In September 2024, the German Ministry BMWK started a public consultation on the new law governing the so-called Kraftwerksstrategie (Power Plant Strategy) which is to be brought forward to the EC for state aid approval. The strategy is based on three pillars:

- Pillar 1: support for H2-ready power plants and long-term storage to be approved under 4.1 CEEAG, i.e. as aid for the reduction and removal of greenhouse emissions including through support for renewable energy and energy efficiency.
- Pillar 2: support for gas-fired power plants under 4.8 CEEAG, i.e. aid for security of electricity supply.
- Pillar 3: transition towards the defined long-term target of having an integrated capacity market with a central and decentral component in 2028 (see Exhibit 2); i.e. pillars 1 and 2 are transitional measures to in the long run move towards the integrated capacity market.

Focusing on pillar 2, being described as a capacity mechanism linked also to the allowed emission levels according to the Electricity Regulation, the design elements seem to rather classify it as a capacity market and not a strategic reserve. In particular, the consultation prescribes capacity payments for new investments, able to provide energy in scarcity (min. 96h run time), paid out over a 15-year period after commissioning. The selection is based on the offered price (CAPEX), applied de-rating and considering the requirement that at least 2/3 are to be provided/built in the south of Germany to address network congestion. Awarded generation must be developed within six years of the procurement and will be subject to rules preventing windfall profits.

Based on the above, **the power plants strategy cannot be used as a blueprint for Poland and wits coal fleet. However, in DE, a grid reserve for congestion management (cf. Exhibit 3) is currently used in addition, including several coal power plants (BMWK, 2024a; BMWK, 2024b)**.

4. Future system vision and final recommendations

Key messages:

- Poland is transitioning from coal to renewables and other technologies, aiming for a reliable, cost-effective, and sustainable energy system through a diverse energy mix.
- With a significant expected adequacy gap by 2030, Poland's CM needs redesign to support both reliable and flexible resources, accommodating growing renewable volatility.
- Introducing separate "firm" and "flexible" capacity products would allow varied technologies (e.g., batteries, gas turbines, heating-sector assets) to participate according to their strengths, improving system reliability.
- Volume coordination between firm and flexible resources is essential to prevent over-procurement and manage consumer costs, with phased introduction of the two products or transitional price caps suggested to potentially handle initial market volatility.
- Support for H2-ready gas could potentially serve as a transitional, decarbonization-aligned solution whereas a CM combination with strategic reserves considered too costly and not compatible with the future system needs.
- It is further recommended to revise CM cost allocation and DR incentives. Capacity-based tariffs and revised CM cost allocation could encourage demand response, as these incentives help reduce peak demand and promote fairer cost distribution. Transition measures, including price caps, may be needed to stabilize costs and participation rates.

Similarly to other EU countries, Poland is moving towards a decarbonized future, where carbon-free renewables are playing an increasingly prominent roles, while at the same time addressing its long-lived legacy linked to coal-fired generation. Already today, the country is moving towards cleaner alternatives, such as gas-fired generation. Yet, what is clear is that it is not a single technology that is able to deliver the energy transition in Poland while ensuring its security of supply. Instead, **a potential from a diversified mix of technologies, including from other energy sectors, like heating, will be needed to fulfill the main needs of the future system, reliability, sustainability and flexibility while keeping the overall costs to consumers in check.**

Already by 2030, Poland is expected to have one of the largest adequacy gaps in the EU, that is, the probability and magnitude of scarcity events where supply cannot reliably cover demand. This indicates that the need for a capacity market in Poland will persist in the future, both in order to avoid (early) retirement of existing assets and to enable large-scale investments into new generation capacity and demand response. Yet, the way the energy system has evolved since the first introduction of the CM in Poland means that the CM design used so far needs to be adapted. As the system with growing shares of RES becomes more volatile, it is not only firm capacity able to deliver longer-duration system support in times of scarcity is needed. It is also essential to ensure that the reserved assets can react to sudden large changes in supply-demand balance fast. In other words, highly flexible assets are needed. **The current market does not deliver targeted incentives for this kind of assets, be that battery storage, e-boilers or gas turbines, while at the same time it may limit their participation through low derating factors or long-activation requirements.**

Thus, in this study **we recommend implementing a two-product approach** in the future Polish CM in order to capture a broad range of firm and flexible technologies in the future in a technology neutral manner. The different approaches towards the certification requirements, activation duration and speed would allow different technologies to participate in the CM "according to their strengths" while jointly contributing to fulfilling the common goal of securing system reliability and security of supply. Thus, compared to three other options studied in this report, **a two-product solution is expected to have the highest chances of achieving the future system needs while creating incentives for a broad range of technologies.**

More specific characteristics of this approach include:

- Product requirements and market timeframes can be defined separately for the two products. For instance, the flexible product requirements would include a shorter activation duration of 15 minutes to 1 hour (as opposed to 4 hours) but a shorter start-up time. Such a product would then be most appropriate for fast-reacting technologies, such as OCGTs, battery storage, e-boiler or heat pumps or even inverter-based RES.
- Longer contact durations as a "flex bonus" could be used to increase bid volume for the flexibility product.
- The flexibility product could potentially provide for lower availability requirements (i.e. limited to certain periods) as compared to the firm capacity product.
- Observing the criterium of technology neutrality, an asset or pool that can provide either product can bid in either, depending on the strategy.
- Decentralized market approach for the flexibility product generally *not* recommended due to high complexity, volatility and risk for both investors and the system operator.

Moreover, **it is crucial to coordinate the volumes procured for both firm and flexible capacity in order to avoid over-procurement, higher consumer costs and demonstrate that the two products indeed do not "go beyond" the necessary measures to ensure system adequacy.** For instance, it can also be considered that, given already secured large volumes of firm capacity until 2033, the first few auctions could be focused on procuring flexible capacity alone – before the two-product solution is fully implemented. This would also allow the TSO and market participants to gauge the price levels in this new segment and a potentially smoother transition to a full-fledged solution.

It should be further noted that Initial price spikes and volatility in both products are likely inevitable. Hence, **transitional measures** such as a price cap can be considered for a limited period of time but the level should be critically assessed. It the cap is set too low, it can lead to undesirable effects, such as low participations rates consequently driving prices upwards.

This study also found that a combination with SR is not excluded from the regulatory point of view. However, is not considered to be a viable option due to the requirements for activation and pricing of it (after balancing reserves exhausted and paid at value of lost load), which likely makes into a solution that is too expensive for the Polish consumers. As an alternative, it could be considered, similar to the German Power Plant Strategy described above, to support H2-ready gas generation or similar assets as a transitional measure – however under decarbonization support rather than as a capacity mechanism.

Last but not least, **the future CM design should also consider the allocation of CM costs particularly to enhance incentives for demand response, as also highlighted in Part 1 of this study.** Currently, explicit demand response (participation in the CM) is significant, but out-of-market, or implicit DR, should also be encouraged for improved grid adequacy. Implicit DR encourages consumer responsiveness to price signals e.g. through dynamic energy pricing or grid fees (including CM costs). In the future, it should be revised how

CM costs are passed to consumers through grid fees based. Distinguishing between DR participants and non-participants should help avoid blanket cost allocation that burdens DR-investing consumers and may hinder broader DR adoption.

A specific way to encourage implicit contribution of DR to system adequacy is the use of capacity-based rather than energy-based grid tariffs. Capacity-based tariffs improve system adequacy and security by incentivizing consumers to lower or shift their peak demand, reducing grid strain during critical times. Since grid stress and potential outages occur during peak periods, **capacity-based tariffs more accurately reflect the costs of maintaining system adequacy.** Consumers who contribute to high demand at peak times bear a greater share of the cost, promoting a fairer distribution of system maintenance expenses.

4.1. Implementation of a two-product solution in Poland from a regulatory perspective

As briefly described in Section 3.4, option B is generally compatible with the current legislative framework of the EU. A two-product mechanism is not excluded by regulation but as for every capacity mechanism, the exact design has to fulfill the principles prescribed by Art. 22(1) of the Electricity Regulation. This includes - besides the obvious need for a competitive, transparent and non-discriminatory process, openness to participation of all resources as well as incentives to ensure availability in times of system stress – that a capacity mechanism shall '*not go beyond what is necessary to address the adequacy concerns […]*' Art. 22(1)(c). This is especially relevant for a two-product design since **it is necessary to carefully determine and reason the demand for both products while accounting for their interactions.**

As described in Section 3.3.2, both products of the updated CM target different capabilities of their providers, i.e. valuing longer delivery duration and slower activation time for the firm and faster reaction time but shorter provision for the flexible product. Therefore, developing a new and separate demand curve for the flexible product, potentially also considering the FNA methodology (to be developed in 2025) and the subsequent national flexibility needs assessment, will be needed.

In terms of the overall demand for the CM, the Electricity Regulation (Art. 25) defines **the reliability standard, identifying the maximal acceptable number of hours with load not served, which must be set by each Member State applying a capacity mechanism.** It thereby provides for a threshold ensuring that procured volumes do not go beyond what is necessary to safeguard security of supply. This is considered as the point at which costs of rewarding more capacity outweigh the benefits of increased security of supply. Considering that the reliability standard should also account for system needs in terms of flexibility in case of a two-product CM, **it could be advisable to include also indicators for the flexible demand in its setting.**

Finally, with regards to the objectives and reasoning for option B, trying to address adequacy and flexibility, it is important to consider the general notion of the amended Electricity Regulation, encouraging Member States to adapt their capacity mechanisms to incentivize non-fossil flexibility. Both Recital (47) and Art. 19(g)(1) emphasize that Member States should opt for adapting their capacity mechanisms to achieve necessary investments in flexibility while non-fossil flexibility support schemes are considered as additional tools:

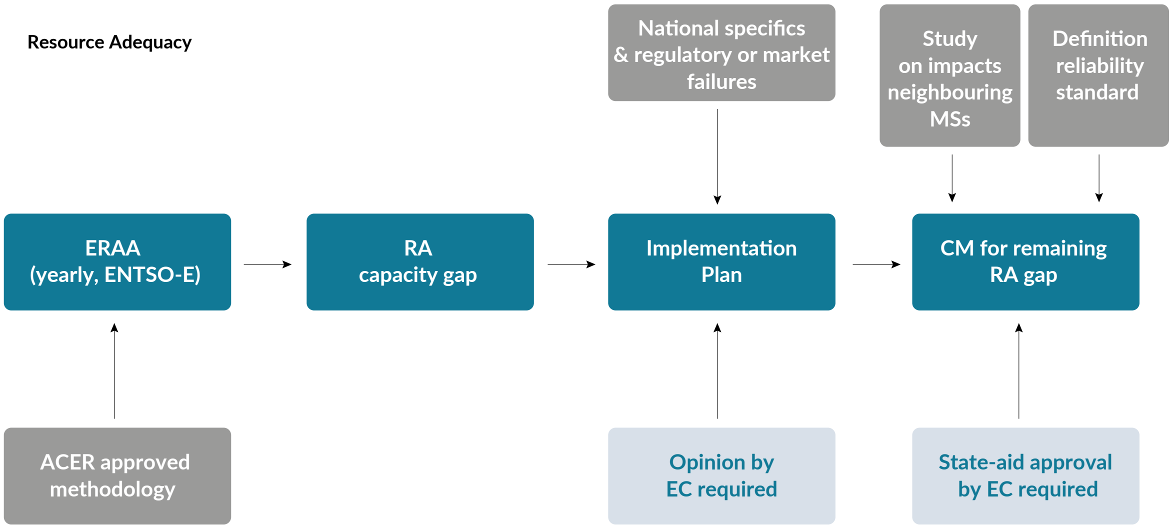
- Whereas (47): '*Member States that already apply a capacity mechanism should also be able to apply non-fossil flexibility support schemes if those schemes are necessary to achieve the indicative national objective for non-fossil flexibility,* ***in particular while adapting their capacity mechanisms to further promote the participation of non-fossil flexibility*** *such as demand response and energy storage.*'
- Art. 19(g)(1): '*Where investment in non-fossil flexibility is insufficient to achieve the indicative national objective or, where relevant, provisional indicative national objectives defined pursuant to Article 19f, Member States may apply non-fossil flexibility support schemes […]. Member States which apply a capacity* ***mechanism shall consider to make the necessary adaptations in the design of the capacity mechanisms to promote the participation of non-fossil flexibility*** *such as demand side response and energy storage, without prejudice to the possibility for those Member States to use the non-fossil flexibility support schemes referred to in this paragraph*'.

Furthermore, having only one mechanism is likely to prevent over-dimensioning, and, considering the main design principles of both tools (Art. 22 and Art. 19h Electricity Regulation), a capacity market as market-based solution is favoured over a potentially non-market-based non-fossil flexibility support scheme. **Considering the above, an innovative capacity market design with two-products addressing the exact matter of additionally attracting non-fossil flexibility seems well-founded in the amended Electricity Regulation.** As stated in its Art. 19(g)(1), it would still be possible to introduce a non-fossil flexibility support scheme at a later stage, if deemed necessary, to achieve the national indicative targets for flexibility.

4.2. Roadmap

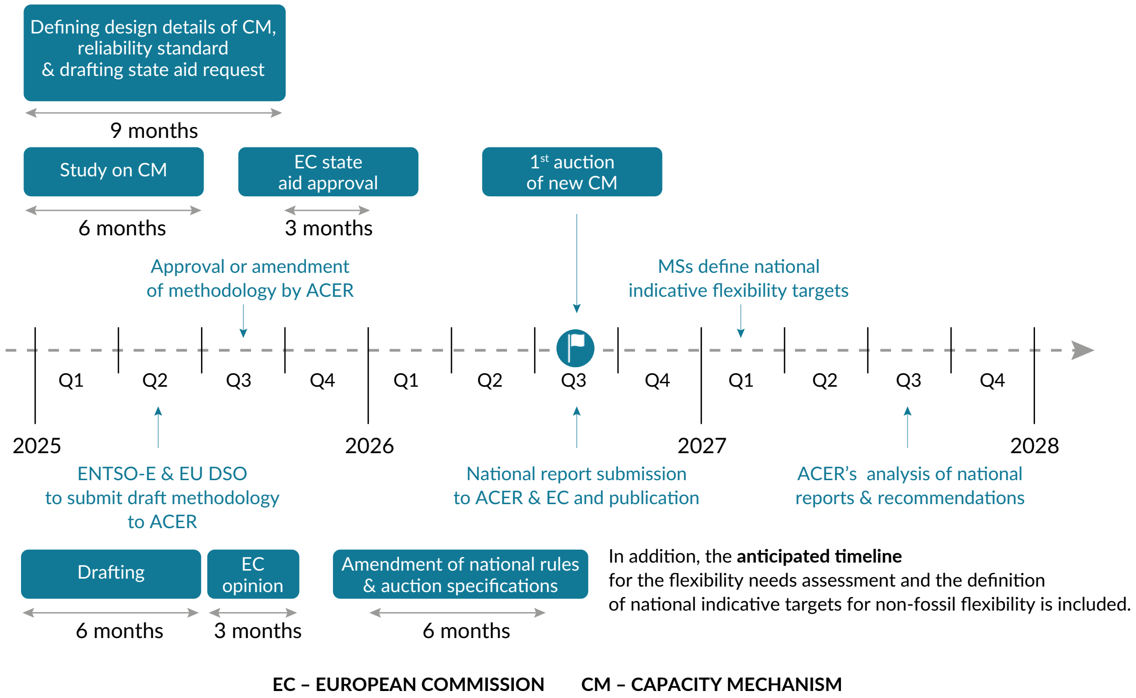
The roadmap to finally implement the updated CM with two products leads back to the outlined steps and prerequisites as established by the Electricity Regulation. As illustrated in Figure 12, the basis is the yearly European Resource Adequacy Assessments (ERAA), performed by ENTSO-E based on an approved methodology, identifying a resource adequacy (RA) gap, as was the case for Poland in the previous iterations. This gap is to be addressed by a national implementation plan, capturing national specificities, regulatory or market failures or distortions, whose relief would lead to an improvement in terms of security of supply. Every implementation plan is to be submitted to the EC for its opinion, which is also a prerequisite for introducing a capacity mechanism addressed at the remaining resource adequacy gap. The plan is of course to be implemented and the progress to be reported regularly. In case of Poland, an implementation plan was already once provided for the introduction of the first capacity mechanism and might likely require an update (e.g. to account for the latest reform of the balancing market) instead of an entire new assessment. Furthermore, before introducing any capacity mechanism, the Member States concerned shall conduct a study analysing the impacts on neighbouring Member States and define a reliability standard based on a methodology approved by ACER. Finally, every CM requires state-aid approval by the EC.

Figure 12. Schematic illustration of assessing resource adequacy and establishing a capacity mechanism



In terms of concrete timelines and further considering the more technical and national steps, a **high-level roadmap** has been developed and elaborated to anticipate the time needed for finally holding the first auction of the updated CM. The timeline is shown in Figure 13 and provides for an optimistic approximation of time needed to complete the steps required for updating the current capacity mechanism. Please note that in particular the EC's reaction time cannot be anticipated.

Figure 13. High-level roadmap for implementing the updated CM with two products



The timeline indicates approximate timings needed to complete relevant steps as well as national tasks such as defining the detailed design of the CM as well as, after state-aid approval, amending national rules and developing auction specifications. It is generally assumed that several steps would progress in parallel, i.e. the detailed design drafting (Q1 to Q3 2025), the study on impacts on neighboring Member States (Q1 to Q2 2025) as well as the development of the implementation plan and its submission for the ECs opinion (Q1 to Q3 2025). All these steps should lead to the state-aid approval of the EC until the end of 2025 (assuming an approval timeline of three months).

It is important to note that, as the FNA methodology will only be approved in Q3 2025 (earliest) and a first national report of Poland is expected to follow one year after, it would only be possible to consider those aspects in terms of demand for flexibility provisionally in the design details or at a later stage. Finally, the amendment of respective national rules and specifying of auction characteristics would follow in Q1 and Q2 2026, leading to readiness for a first auction in the second half of 2026.

The most important message derived thereof is that **a first auction under the new regime could be held in Q3 2026**, i.e. two years from now. Nevertheless, this is subject to several preparatory steps involving different parties, which might lead to delays or prolong the anticipated time spans.

Annex A. Recent developments related to capacity markets and flexibility in Poland

This Annex provides an overview of recent developments in Poland linked to the capacity market and flexibility procurement for different services, as both are addressed within this present report. Note that flexibility addresses several timeframes and is typically used to provide balancing, congestion management and demand response, hence these are included here.

Capacity market reform

The current Polish capacity market (CM) was introduced in 2018 as a response to identified adequacy concerns. Initially, the CM primarily supported traditional coal-fired generation, which was becoming unprofitable otherwise. Over its first five years, coal dominated the awarded capacity. However, stringent emissions limits introduced in 2019 drastically reduced coal's share, leading to its exclusion from the market starting from the delivery year 2026[7]. Despite the CM's intention to ensure energy supply, its cost has steadily risen while it has only slowly and insufficiently driven new investments, marginally increased flexibility or reduced CO_2 emissions. These outcomes are described in detail in Part 1 of this report.

As Poland looks beyond 2025, with the final auction under the current framework set for delivery in 2030, the country faces a significant challenge in maintaining resource adequacy[8]. With coal plants phased out due to ageing, emission limits and potential future restrictions on gas plants, there is a growing risk of insufficient supply and escalating costs. The government plans to continue the CM beyond 2025 to secure energy supply, but it must adapt the market design to support the transition to low- and zero-carbon energy sources while ensuring cost efficiency. **This evolving landscape underscores the need for a long-term vision that aligns the CM with Poland's broader energy transition goals.**

Balancing market reform

Another notable recent development in Poland relates to its balancing market, amended with a reform, effective since June 14, 2024. The reform aims at incentivizing market participants to increase their flexibility and match their production or off-take with the current needs of the electricity system (URE, 2024b). This relates e.g. to the reduction of the imbalance settlement period (ISP) to 15-minute intervals (from previously one hour), but also to the introduction of balancing capacity and balancing energy to be procured by the Polish TSO PSE (Sołtysiński, Kawecki & Szlęzak, 2023). Balancing capacity is procured separately for up- and downward regulation for different types of balancing services. Furthermore, the balancing market is now open for minimum bid capacity of 0.2 MW, lowered significantly from previous 1 MW (URE, 2024b).

In terms of balancing market integration, Poland is yet to join the European balancing platforms for the exchange of balancing energy from automatic and manual frequency restoration reserves (aFRR; mFRR) (PIACSSO) and mFRR (MARI). Both the accession to the platforms for aFRR and mFRR, called PICASSO and MARI respectively, are currently planned for mid-2025 (ENTSO-E, 2024a).

7 Note that this refers to these units' participation in subsequent auction rounds and does not mean that all coal-fired generation was excluded from already allocated payments leading to some providers being part of the CM up to 2035.

8 In May 2024, ACER approved ENTSO-E's European Resource Adequacy Assessment (ERAA) for 2023. The results indicate that, while already considering approved out-of-marked measures for Poland, the national 'loss of load expectation' (LOLE) and 'expected energy not supplied' (EENS) values for the upcoming years will further increase, with a maximum of a LOLE of 8.5h/y and EENS of 6.06 GWh in 2033 in the reference scenario (ENTSO-E, 2024b). This constitutes the largest adequacy gap in the EU.

Regulatory dimension of balancing service procurement

Article 6 of the Electricity Regulation introduces the general concept for **balancing markets** in the EU, first of all in its paragraph 1, requiring them (and the prequalification process) to i.a. ensure non-discrimination between market participants and in terms of access (including aggregation, RES, DR and BESS), services to be defined in a transparent and **technologically neutral manner** and procured in a market-based manner.

Upward and downward balancing capacity shall be procured separately. and shall **not be procured earlier than one day before** its provision and its **contract period shall not be longer than one day**, unless derogations are approved by the respective NRA (Art. 6(9)). Balancing energy prices shall not be predetermined in contracts for capacity (Art. 6(2)). In case balancing energy bids are used for redispatch, they shall not set the balancing energy price. (Art. 13(2)). Further, Art. 6(4) requires that market participants are allowed to bid as close as possible to real-time, and **balancing energy gate closure times shall not be before the intraday cross-zonal gate closure time**. With the amendments to the Electricity Regulation (Art. 8(1)), the intraday cross-zonal gate closure time will be no more than 30 minutes ahead of real-time as of January 2026[9].

Besides the general principles of balancing markets covered by the Electricity Regulation, the Balancing Guideline (EB GL) introduces further details on how the integration of balancing markets across Europe is to be implemented. In particular, the EB GL sets out the principles for establishing the **European platforms for the exchange of balancing energy from replacement reserves (RR) and FRR (automatic and manual) and for imbalance netting** (Art. 19–22). The TSOs nationally continue to be responsible for the procurement of balancing services (Art. 14(1)) while these platforms enable the efficient activation and exchange of the respective balancing energy across Europe. It further defines harmonized **standard products for balancing energy** (in subsequent legislation), which are to be used by TSOs[10]. The standard product specifications include the respective gate closure times for BSPs' energy bid submission which are currently set to 25 minutes before delivery for both aFRR and mFRR and 55 minutes for RR (ACER, 2022a; ACER 2022b; ENTSO-E, 2018)[11].

Other relevant national developments

As outlined in Clyde & Co (2024), with regards to RES deployment, it is worth noting that Poland started experiencing **negative electricity prices** on spot markets in 2023. As of 2024, also **RES curtailment**[12] is taking place more frequently. Since the beginning of the year, RES production has been curtailed by 632 GWh, and at least 225 GWh were exported on an intervention basis during restricted hours. This means that 857 GWh, representing 2.4% of potential RES production, did not enter the national power system (Forum Energii, 2024).

Flexibility can further be used for **congestion management,** which the TSO can address using redispatch, i.e. changing the dispatch of some power plants to alleviate congestion. New rules for redispatch were introduced by an amendment to the Energy Law in 2023 described by Clyde & Co (2024). Previously, the Law included a general obligation to comply with dispatch orders, focusing on centrally dispatched units. The amendment obliges the TSO to introduce standardized rules for both market-based and non-market based redispatch with an interim period during which all units might be subject to non-market based redispatch, downward redispatch based on pro-rata curtailment. Compensation is to be defined in bilateral agreements between generators and the TSO. However, cost-based compensation is only provided to generators with connection agreements containing guarantees of firmness (Mrowiec P., 2024; Madejski A., 2024). New connections, however, are predominantly non-firm and thus do not get compensated (Szczdora A. & Tomaszewicz P., 2024). The latest report of ACER (2023a) covering 2022 reported that DSOs in Poland do not take any congestion management measures.

9 Please note that derogations until January 2029 are possible in case of approval by NRAs (Art. 8(1a) Electricity Regulation).

10 A derogation may be approved for special balancing products by the NRA in case standard products are not sufficient for operational security or resources not able to participate in balancing markets with such products a (Art. 6(14) Electricity Regulation).

11 TSO then return national results to the platforms by t-10 (aFRR), t-12 (mFRR) and t-40 (RR) minutes.

12 Curtailment has so far only affected generators with installed capacity above 50kW and regulation gives priority dispatch to small generators (Mrowiec P., 2024).

As discussed in Part 1 of the report, **demand side response (DSR)** units participate in the current capacity market with increasing numbers (PSE, 2024a) and are further allowed to participate in balancing markets. Nevertheless, at least prior to the balancing market reform, ENTSO-E's balancing report shows that in 2022 and 2023 only one such unit was participating as a balancing service provider (BSP) (ENTSO-E, 2024a). Similarly, **battery energy storage systems (BESS)** have been participating in the capacity market in the last two auctions and entered the balancing market with the implementation of the reform. However, with only limited BESS capacity in operation and the balancing market reform being very recent, the significance of BESS for the balancing market is still hard to assess (URE, 2024a).

Regulatory dimension of congestion management

Article 13 of the Electricity Regulation describes the principles for applying redispatch[13] for congestion management, necessary to ensure system stability: The target model is the **market-based** selection of resources, including all generation technologies, including BESS and DR as well as resources located in other Member States, unless technically feasible. Importantly, **financial compensation shall be provided** to the affected resources. Non-market-based redispatching may only be used in predefined cases as outlined in the Regulation.

According to Art. 13(7), where non-market based redispatching is used, it shall be subject to financial compensation by the system operator[14] except in the case of producers that have accepted a connection agreement under which there is no guarantee of firm delivery of energy.

Finally, in some Member States (e.g. Germany and Austria), congestion management is addressed by means of dedicated **network/grid reserves**. These are not regulated explicitly within the EU electricity sector's legal framework but, according to the European Commission (2021), may be put in place under certain conditions to ensure generation adequacy and security of supply as provided for by state aid guidelines. The respective provisions are generally included in the Member State's national legal framework. They are deemed to be temporary measures to bridge the time gap for reducing structural congestions and, hence, are also linked to Art. 16(8) of the Electricity Regulation, requiring TSOs to provide a minimum level of cross-zonal capacity or achieve it by means of linear increase according to an adopted action plan[15].

Network Code Demand Response

EMDR stressed an increasing need for DSR and other sources of non-fossil flexibility and taking measures to unlock its potential. Multiple studies have identified persistent barriers to market participation of new flexible technologies (e.g. ACER, 2023a). Network Code on Demand Response (NC DR) is the EU's first attempt at providing a legal background for lifting some of these barriers, especially in relation to TSO and DSO system services. It provides guidelines and requirements specifically directed at facilitating market access and the contribution of distributed resources to power system stability and security at all network levels. Importantly, despite its name, it covers not only load but also distributed generation and storage facilities.

The draft NC DR was submitted by ENTSO-E and EU DSO Entity for review in March 2024 while ACER was expected to submit its revised version to the Commission by March 2025.

NC DR is based on several guiding principles, including technology neutrality, non-discrimination, and applicability to all network operators, TSOs and DSOs. It aims to enable market access for all resource providers in both retail and wholesale markets and promotes coordination between DSOs and DSOs as well as between DSOs and TSOs.

13 Please note that according to the Electricity Regulation, the term redispatch includes curtailment (cf. Art. 2(26)).

14 Art. 13(7) Electricity Regulation: Such financial compensation shall be at least equal to the higher of the following elements or a combination of both if applying only the higher would lead to an unjustifiably low or an unjustifiably high compensation:
(a) additional operating cost caused by the redispatching, such as additional fuel costs in the case of upward redispatching, or backup heat provision in the case of downward redispatching of power-generating facilities using high-efficiency cogeneration;
(b) net revenues from the sale of electricity on the day-ahead market that the power-generating, energy storage or demand response facility would have generated without the redispatching request; where financial support is granted to power-generating, energy storage or demand response facilities based on the electricity volume generated or consumed, financial support that would have been received without the redispatching request shall be deemed to be part of the net revenues.

15 Poland adopted an action plan in 2019 (ACER, 2024).

The rules intend to balance harmonizing European electricity system operations with respecting Member States' rights to develop national network codes where no cross-zonal trade exists. The NC DR strives to strike a balance between a prescriptive yet flexible approach that fosters innovation and accommodates future technologies, ensuring they align with European energy transition goals.

In sum, the NC DR – pending the final text – is expected to have three main benefits for flexibility providers, especially for aggregated small-scale distributed resources, such as BESS, heat pumps or other assets on the demand side:

1. Streamlined prequalification rules based on a table of equivalences and accelerated prequalification processes in the event of portfolio adjustments.
2. Clarity concerning aggregation requirements and associated compensation schemes.
3. Potentially additional sources of revenue from congestion management or DSO-level services.

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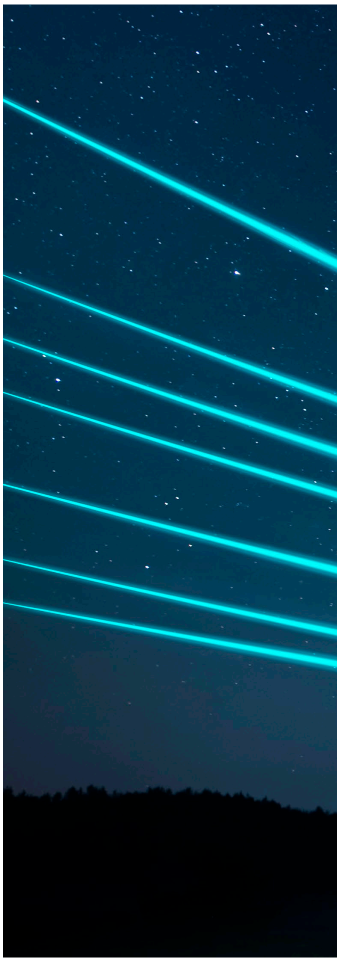
Notes

Redesigning Poland's Capacity Market and System Flexibility

Part 2



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