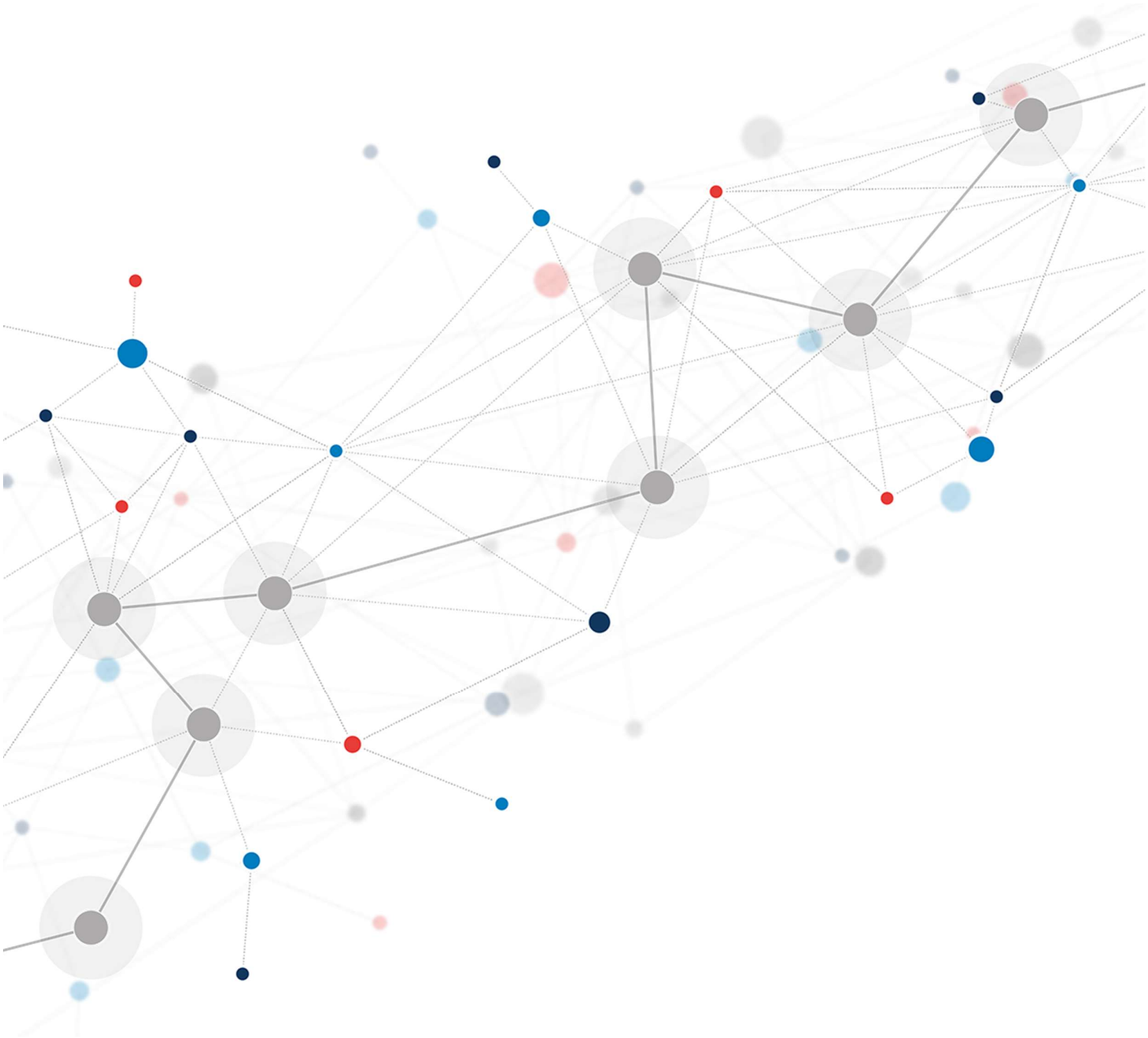
COMPASS LEXECON

Negative prices in EU power markets

Discussion paper
Presented at Eurelectric's Market Design Day 2026

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19 November 2026



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Executive summary

This paper analyses the growing frequency of negative power prices in European power markets and addresses three key questions: (i) What drives negative power prices? (ii) Which supply- and demand-side constraints create opportunity costs leading to negative bids in power markets? (iii) Which measures can mitigate the distortive drivers for negative prices and foster more flexibility where needed?

Negative power prices are increasingly frequent, reflecting a lack of system flexibility

Negative power prices are a market outcome that can be expected when supply exceeds demand so that the two curves meet at a price below zero, often due to a lack of flexibility on the supply side and/or demand side of the market, or generators reflecting the opportunity costs associated with reducing output.

As Renewable Energy Sources (RES) supply keeps growing, demand electrification stagnates, and flexible or storage assets are still insufficiently developed, negative prices have become more common in European day-ahead power markets. The frequency of negative power prices in Europe increased from 2015 until 2024, and seems to follow different dynamics since then, with a reduction or stabilisation in some countries, or an increase in others. Negative price frequency and depth differ across bidding zones, reflecting different levels of e.g. RES penetration or battery deployment, baseload plant manoeuvrability, or other legal or technical constraints. They also vary with the time of day, week, and year.

In a dynamic perspective, negative prices are useful signals for market participants to support efficient system operation while helping steer investment decisions and the evolution of the resource mix towards more flexibility, both on the supply and demand sides. However, structural barriers to the development of flexibility resources (or the retirement of inflexible resources) may result in persistent negative power prices.

Moreover, negative prices can be a cause for concern when they arise from distorted bidding incentives or induce risks and costs that can be hard to manage for some market participants. For instance, negative prices resulting from ill-designed support schemes may lead to inefficient dispatch and ultimately higher costs for consumers.

The key question when assessing the root causes of negative prices and potential remedies is therefore whether negative prices reflect the need for a temporary evolution of the supply and demand side resources in the market, or whether they are rooted in structural distortions or barriers to the development of flexible resources (or exit of inflexible resources).

Incentives embedded in power generators' contracts can distort bidding behaviour and lead to structural negative prices

Structural causes of negative power prices include the opportunity costs and bidding incentives embedded in support contracts, or distortions associated with decentralised generation (e.g. rooftop photovoltaic) that is often partially immune to wholesale price signals and negative prices in particular.

Indeed, producers' bids reflect their marginal cost of production, including all relevant opportunity costs. These may arise from, e.g., ramping constraints for less flexible power plants. Certain (often legacy) renewables production-linked support schemes contracts may create distortive bidding

incentives to continue producing at negative prices to avoid losing the subsidy. Such contracts may incentivise installations to bid below their actual variable cost.

The recent support schemes for clean technologies based on Contract-for-Difference (CfD) seek to address these inefficiencies through different approaches to defining supported volumes and remuneration. These include production-based CfDs with negative price suspension rules, production-independent CfDs that decouple remuneration from actual generation, and hybrid designs combining both approaches. The design of these CfDs entails different trade-offs between efficient dispatch incentives, investment risk allocation, and implementation and oversight complexity.

However, the stock of legacy support contracts for clean technologies represents a challenge, as the remaining long duration of contracts implies that the associated distorted bidding incentives may persist and contribute to structural negative prices. Adapting existing contracts where suitable and against appropriate compensation may contribute to addressing this source of negative prices.

Negative prices can be a signal to enhance the operation and deployment of flexible resources if barriers to their deployment are addressed

Negative prices create opportunities for flexible assets, and contribute to the business case for investment in flexible resources on both the supply and demand side, such as storage and demand response. Negative prices can therefore play a valuable steering role in the dynamic evolution of the resource mix in the context of the ongoing transformation of the European electricity system.

ENTSO-E estimates that European flexibility needs will double by 2033, driven by renewable penetration and deeper demand electrification and higher global uncertainty. The EU framework for national Flexibility Needs Assessments (FNAs) should contribute some useful insights to understand the root causes of negative prices, and the extent to which negative prices can be expected to be a transitory signal of a flexibility gap.

However, some structural barriers to the development of flexibility remain across European power markets, suggesting that negative prices may remain in a number of countries as a structural feature until these barriers are addressed. Still, a range of policies can address these barriers and foster the development of flexible resources, both on the supply and on the demand side.

On the supply side, in addition to addressing issues with support mechanisms bidding incentives, such policy options include for instance, long-term flexibility contracting mechanisms which can improve revenue predictability and incorporate locational signals to address specific system needs. However, such mechanisms need to be designed with care as they may also affect competition with merchant assets in balancing and ancillary services markets.

Demand-side flexibility (DSF) is a major untapped source of potential adjustments to negative price episodes and other flexibility gaps, both through shifting consumption towards periods of abundant electricity supply and through longer-term electrification. However, consumers differ substantially in their flexibility potential, desired exposure to short-term electricity prices and ability to respond to market signals. Potential policies to support the development of DSF include:

- Greater exposure to wholesale price dynamics in retail pricing arrangements. Static time-of-use prices can incentivise structural changes in consumption patterns, while dynamic prices enable a closer response to short-term wholesale market conditions, albeit with greater price risks for consumers. Intermediate arrangements, combining hedged or fixed-price consumption with some exposure to short-term prices, offer a balance between predictability and flexibility, and could be adapted to engaged and flexible consumers.

- Explicit demand-side participation in electricity markets can unlock additional flexibility, particularly through aggregators. Its development depends on the availability of smart metering, automation and control capabilities, as well as market access rules and arrangements governing the responsibilities of aggregators and suppliers, including for upward demand adjustments when it comes to responding to negative prices.

1 Introduction

1 Negative prices have become a common and widespread phenomenon across European power markets. In recent years, the frequency and depth of negative prices in several European countries have reached levels triggering policy attention. Economically grounded negative prices can play an important signalling role, creating incentives to invest into demand electrification and flexibility. At the same time, more frequent and deeper negative power prices can increase revenue risks for some generators, and operational or forecasting risks for system operators, making it important to understand the causes of such negative prices and whether they are caused or amplified by distortions in bidding incentives – which should be fixed.

2 This paper investigates the phenomenon of negative prices in the light of the ongoing transformation of the European power sector. Structural changes to both supply and demand are creating new challenges for market and system operators. In this context, negative prices can be interpreted as signals of the underlying operational challenges for the power system, as well as of the need for new investment in supply and demand flexibility and grids. Decarbonisation, competitiveness and energy independence objectives fuel the rapid rise of renewables, increasing the likelihood of excess generation during periods of low demand, while the level of baseload or dispatchable power plants in the system decreases. In parallel, deeper electrification of industry, transport and buildings expands the demand base, can help absorb abundant clean power generation, and creates a growing potential for demand response, helping to mitigate negative prices.

3 Market clearing rules allow for negative prices to form when the supply and low demand curves meet below zero, with the marginal seller willing to pay to produce, and the buyer paid to consume. Negative bids may result from conjunctural causes reflecting changes in the underlying balance of supply, demand and flexibility, or from structural causes preventing the market from adjusting to conjunctural patterns. Two types of opportunity costs may notably incentivise generators to keep producing at negative prices:

- Policy- or, in some cases, contract-induced opportunity costs, like production-linked subsidies forfeited when output is curtailed, which may incentivise generators to keep producing at negative prices. This may distort the merit order[1] and artificially depress market prices, which in turn distorts the signals for demand electrification and flexibility and creates risks for other generators' revenues (in some cases, borne by the taxpayer) and for system management. In this case, the first-best response may be to correct the underlying distortions embedded in the design of such support schemes.
- Technical opportunity costs reflecting constraints like shutdown and restart costs, output and downtime requirements, ramping constraints, and foregone market revenue during downtime. Negative bids reflecting these costs can be economically grounded, reflecting genuine technical or economic constraints and signalling the value of flexibility.

4 The ongoing transformation of the generation mix raises the need for grid infrastructure and for flexible design and operation of the electricity system to adjust to the variability of generation and

[1] For illustrative purposes, in this paper, the concept of merit order refers to bidding at variable costs.

consumption patterns and to grid availability.[2] ENTSO-E estimates that European flexibility needs will double by 2033, as growing power demand changes load peaks and patterns, higher renewable penetration raises supply and forecast variability, and risks of disruptions from extreme weather events threaten the system.[3]

5 In a dynamic perspective, if negative spot price signals reflect underlying system conditions and can reach market players, the market can be expected to react and trigger more entry of flexible resources and/or exit of inflexible assets which are no longer profitable. Depending on relative costs and local market frameworks, this dynamic adjustment may involve more market-based curtailment, greater deployment or use of storage and DSF, and/or deeper electrification. The role of negative prices in this dynamic adjustment also depends on national policy priorities: some countries may foster a faster development of renewables, with a greater risk to encounter at least a temporary period of low or negative prices as the required flexible resources development may lag behind.

6 However, deep and persistent negative prices may be a symptom of challenges faced by the power system in adjusting to the new operational requirements, e.g. reflecting the impact of potential barriers to electrification of end-uses (e.g., competitiveness of technologies, lack of grid connection capacity), lack of infrastructure (e.g., delays in additional interconnection) or to the deployment of flexible resources needed to absorb excess energy. Negative prices may persist or become more pronounced as the power system adjusts.

7 As a consequence, the relevant question in the analysis of the root causes of negative prices is whether they reflect underlying supply-demand fundamentals or rather market distortions and barriers preventing an efficient market response.

8 This paper aims to contribute to the market design and policy debate with fact-based evidence on negative prices, and the associated opportunities and challenges faced by the European power systems in the transition towards decarbonisation. In particular, the paper aims to address the following questions:

- What drives negative power prices, and explains different patterns over time and geographies? What makes the flexibility gap conjunctural or structural, and how to address structural deficits?
- What are the different types of barriers on the supply and demand side to flexible operation of the power system, and how do they create opportunity costs and lead to negative bids?
- What are the potential constraints and potential policy measures to foster the deployment of supply-side and DSF as well as design of the power market and the power system?

9 The rest of this paper is structured as follows:

- Section 2 analyses the evolution of negative power prices across Europe since 2015, in particular their depth and frequency at the country level, and seasonal and hourly patterns.
- Section 3 sets out a conceptual economic framework to analyse the root causes of negative prices, and then focusses on a couple of case studies including the events of 1 May 2026.
- Section 4 identifies potential measures to address the root causes of negative prices, namely to correct distorted bidding incentives, and address potential barriers to the deployment of flexibility.

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2 Per ACER's definition of flexibility (available here).

3 ENTSO-E (Dec 2024), System flexibility needs for the energy transition (available here).

2 Evolution of negative prices across Europe

10 Whilst there has been an overall increase in the frequency and depth of negative prices across Europe in recent years, the trend has not been uniform and negative power price episodes tend to occur at different levels of frequency, duration and depth across countries and over time. This section analyses the prevalence of negative power prices across Europe and its evolution over time.

2.1 An evolving trend with differentiated geographical and temporal patterns across EU power markets

11 Negative prices in European power markets primarily arise as the standard outcome of supply exceeding demand. Though they used to mostly occur in the intraday market, negative prices now appear in more frequent and pronounced episodes in day-ahead markets.[4]

12 The year 2024 marked a peak (until today) in the frequency and spread of negative power price episodes, with first-ever records in Greece, Poland, Portugal and Spain. By contrast, Czechia and Denmark had already seen negative power prices occur in 2015. The phenomenon thus shows both temporal and geographical variations.

13 At the European level, the phenomenon of negative power prices evolved through four phases (Figure 1) from 2015 to 2026:

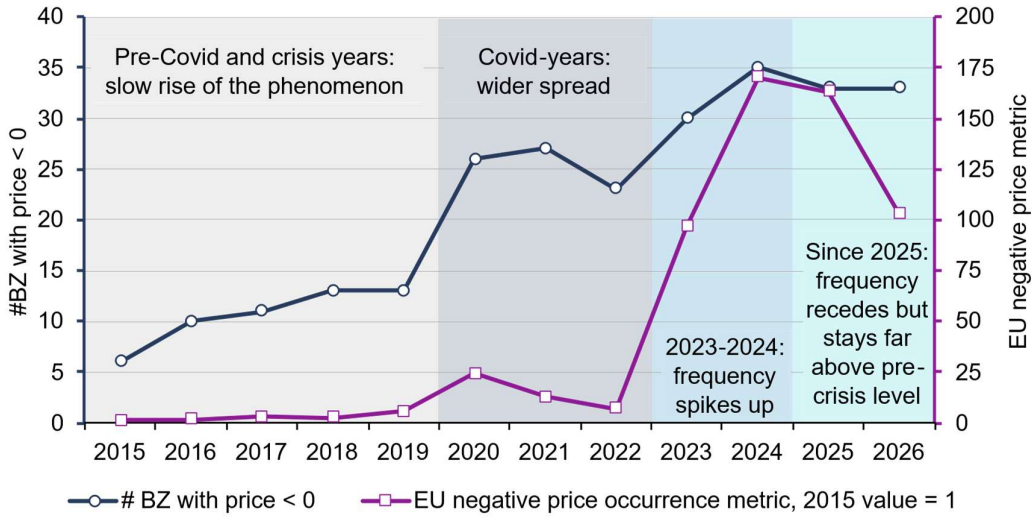
- First, a slow rise of incidence from 2015 to 2019, as the share of renewables slowly increased and some dispatchable or flexible assets exited the market. For instance, in Denmark (DK1[5]), around 1.5 GW of thermal power plants[6] were mothballed or dismantled from 2015 to 2019.[7]
- Second, an increase in the number of bidding zones with negative power prices during the Covid years, likely as the slowdown in economic activity allowed the buildup in renewables to create more oversupply situations.
- Third, a rapid increase in occurrence in 2023 and 2024, due to receding demand and rising supply.[8] The energy crisis caused an enduring increase in power prices and fostered the uptake of energy efficiency measures, leading to a decline in electricity demand. This decline bottomed out in 2023 and began to slowly reverse in 2024, though demand remained below pre-Covid

4 See Eurelectric (2024), Understanding Ultra-Low and Negative Power Prices: Causes, Impacts and Improvements (available here).
5 I.e., Denmark's power market Bidding Zone 1.
6 The figure encompasses gas, oil and hard coal installed capacities.
7 ENTSO-E, ENTSO-E Transparency Platform, "Installed Capacity per Production Type DK1", available here.
8 See for instance RTE bilan 2025 or 2024 (available here and here respectively).

levels.[9] At the same time, more renewable capacity came online, with the addition of 75 and 79 GW of solar assets to the European power system in 2023 and 2024 respectively.[10]

- Fourth, a stabilisation in the occurrence of the phenomenon in 2025 and 2026 in some countries. A combination of factors could be at play behind this reversal, including: (a) electricity demand continuing its rebound towards pre-crisis levels, (b) changes made to renewable support contracts or balancing rules[11] to address distortionary bidding incentives; and (c) development of flexibility sources, either encouraged by policy measures or in response to economic incentives.[11]

Figure 1: Evolution of the negative power price phenomenon in Europe



Source: Compass Lexecon analysis based on data from ENTSO-E Transparency.
Note: EU negative price frequency metric is the product of A: number of bidding zones (out of 46) with negative prices, and B: total hours (taking the average of 15-min market time units after the shift in 2025) with negative prices across all bidding zones. To facilitate comparison, this metric is presented as a relative index to its 2015 value (set to 1); i.e., the chart shows that the 2026 value is about 100 times higher than the 2015 value.

2.2 Analysis of negative power prices' prevalence across bidding zones

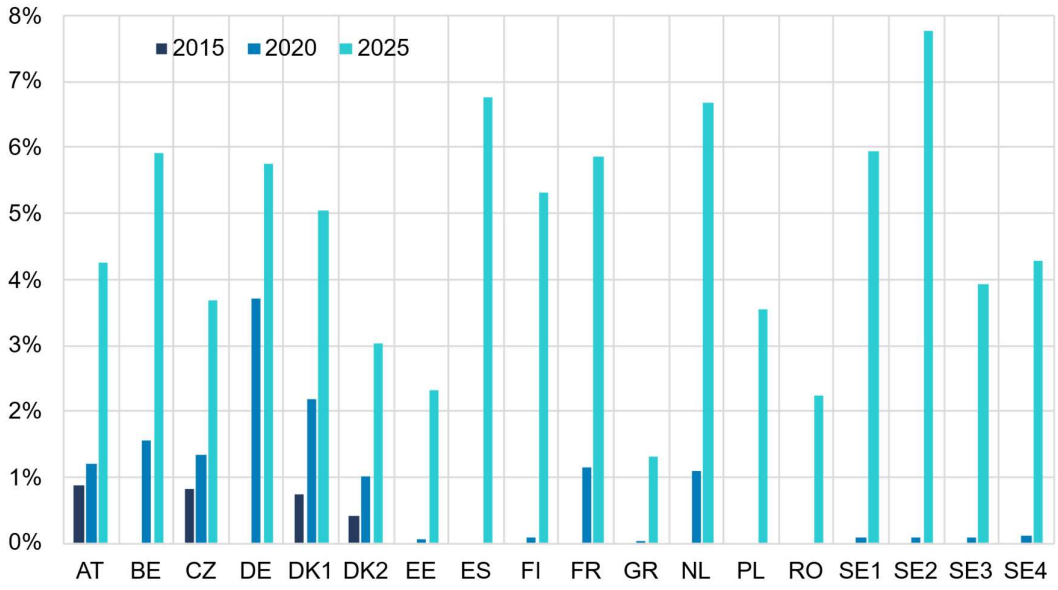
14 The frequency (Figure 2) and severity (Figures 3 and 4) of negative prices differ markedly between countries and at the bidding zone level. In 2025, Spain and the Netherlands recorded a price below zero in nearly 7% of hours, while Estonia only saw 2%. Some countries never recorded a negative price until 2024 (Greece, Poland, Portugal, Spain), while others have seen them occur since 2015 (Austria, Czechia, Denmark).

9 This was the case for instance in Belgium, Germany, Spain, France, Great Britain, and Italy. Source: Compass Lexecon analysis based on TSO data.

10 See data from Solar Power Europe (available here).

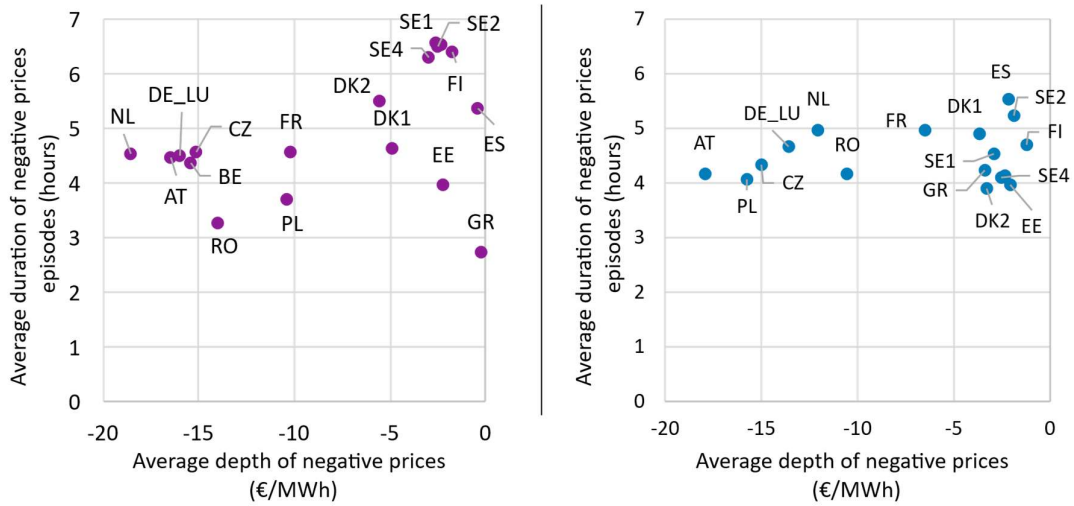
11 This may include efforts to increase the participation in balancing markets of decentralised flexibility (e.g., UK: as part of the REMA process, Italy: TIDE reform, Belgium: Consumer-Centric Market Design) or renewable assets (e.g., Italy: supported assets under FER X, Germany: increased participation or equipment of small-scale renewable assets with Redispatch 2.0 and Solar Peak Act). N.B., some of these changes may take time to yield practical results, making a precise historical causal exercise complex in practice.

Figure 2: Negative power price episode frequency per selected bidding zone (% of hours)



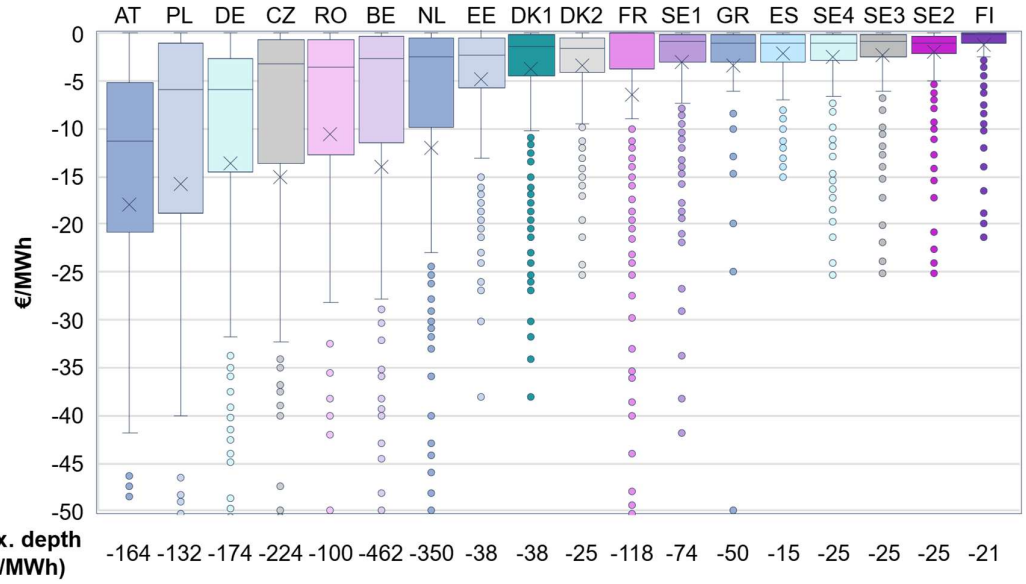
Source: Compass Lexecon analysis based on data from ENTSO-E Transparency.
Note: the name of the "DE" bidding zone was shortened from "DE-LU" for presentation purposes.

Figure 3: Average negative price episode duration and depth in 2024 (left) & 2025 (right) in a selection of bidding zones (hours)



Notes: includes the following bidding zones: AT, BE, CZ, DE_LU, DK1, DK2, EE, ES, FI, FR, GR, NL, PL, RO, SE1, SE2, SE3, SE4
Source: Compass Lexecon analysis based on data from ENTSO-E Transparency, and inspired by Eurelectric (2024) Understanding Ultra-Low and Negative Power Prices: Causes, Impacts and Improvements (available here).

Figure 4: Depth of negative electricity prices across a selection of bidding zones in 2025 (€/MWh)



Notes: The box represents the interquartile range (25th to 75th percentile) of hourly negative prices; the line within the box marks the median, and the cross (×) marks the mean. Whiskers extend to the most extreme values within 1.5 times the interquartile range from the box ; individual dots below the whiskers represent statistical outliers. "Max depth" indicates the single lowest (most negative) hourly price recorded in each bidding zone in 2025.
Source: Compass Lexecon analysis based on data from ENTSO-E Transparency.

15 These trends reflect to some extent differences in the timing and approach for the power sector transition. For example, in 2024, RES penetration reached 88% in Sweden and 34% in Bulgaria, corresponding to between 7.1% and 8.2% of hours with negative prices in Sweden (depending on the bidding zone) and 0.6% in Bulgaria.[12] In some other countries, the issue is compounded with other causes such as baseload manoeuvrability constraints.[13] Finally, there may be regulatory specificities driving the emergence of negative prices. For example, negative power prices only became a possibility in Spain and Italy in December 2023 (first occurrence in 2024) and 2025 (no occurrence yet) respectively.[14]

16 In addition, the severity of negative prices (measured either as the duration in consecutive hours, or the maximum price depth negative prices reach) also differs across geographies. For instance, the average duration of a negative power price episode in 2025 was 5.54 hours in Spain, but 3.9 hours in Denmark (bidding zone DK2). Likewise, in 2025, the average negative price episode depth was around –18 €/MWh in Austria, but just below –1 €/MWh in Finland.

17 Countries with significant interconnection capacities may be able to mitigate some of the drivers of negative prices insofar as they may be able to export their surpluses of electricity in some hours,

12 Eurostat, Share of Renewable Energy – Electricity. Available here. N.B., the 88% renewable penetration figure for Sweden includes both historical hydropower (around 40% of the domestic generation mix, cf. IEA here) and new wind production added over the past decade.

13 Nuclear power plants in some countries (e.g., France) already contribute to system flexibility through output modulation, subject to occasional constraints related to fuel-cycle management and other operational requirements.

14 Spain (2023), update to the functioning rules of the electricity market, available here. Italy (2024) TIDE reform, explanation from Terna available here.

unless their production is strongly correlated with those of neighbouring countries. This is indeed only possible to the extent that neighbouring countries are not exposed to the same and synchronous factors inducing negative prices. More peripheral or less interconnected countries exposed to the same factors have fewer possibilities to export surpluses and may therefore be exposed to more frequent and profound negative prices.

18 Conversely, negative prices in one country can lead to spill-over effects in neighbouring countries, as negative prices may reach neighbours through interconnectors. Where negative bids result from distortions embedded in national support schemes, market coupling may to some extent export the effect of those distortions to neighbouring bidding zones. This strengthens the case for consistent European principles ensuring that RES installations under support schemes bid at their variable cost or use value and can be curtailed when they are not selected in the merit order.

2.3 The seasonality of negative prices

19 The occurrence of negative power prices also varies with the time of day, day of the week and month of the year (Figure 5). As the phenomenon is a manifestation of excess electricity supply over demand, it tends to occur at time when supply is higher and demand is lower than usual.

20 On the supply side, this typically corresponds to the peak of renewable power generation, particularly from solar photovoltaic (PV) assets.[15] Solar irradiation being the main driver of PV output,[16,17] excess PV generation is more likely to occur around noon and in the brighter months of the year – in Europe, spring and summer.

21 High solar PV output periods also tend to overlap with times when demand is lower. Electricity consumption in buildings tends to be lower in weekends and in the middle of the day when people are outside or at work, and not necessarily using cooking or heating appliances.[18] Likewise, demand from buildings is generally lower in Europe from April to June, as milder temperatures lead to a lower need for heating or cooling.[19] The Spanish market offers practical evidence on these overlaps creating seasonal variations in power prices: future contracts for the second quarter of 2027 and 2028 trade at lower values than in winter quarters for the same years, in an inversely proportional fashion compared to the solar production profile used to compute the Spanish solar power index.[20]

15 Excess wind power generation may also cause negative power prices. This may result in different hourly and seasonal patterns, as the distribution of wind generation peaks obeys different and more complex rules.

16 Bamisile et al. (2025) "The environmental factors affecting solar photovoltaic output", Renewable and Sustainable Energy Reviews, available here.

17 As demonstrated by Bamisile et al., other environmental factors also affect PV efficiency such as higher temperatures and dust accumulation.

18 Eurelectric (2024) Understanding Ultra-Low and Negative Power Prices: Causes, Impacts and Improvements, available here.

19 IEA (2024) Managing the Seasonal Variability of Electricity Demand and Supply, available here.

20 SPEL Base Futures – Quarter. Available here, last retrieved 30 Sep 2026; SPEL solar index, available here.

Figure 5: Frequency of negative prices episodes by month and hour of day for a selection of bidding zones in 2025



Notes: Colour scale based on the number of negative price episodes recorded per month–hour combination in 2025, with red indicating a higher occurrence rate and green a lower occurrence rate. The bidding zones included are the following: AT, BE, CZ, DE_LU, DK1, DK2, EE, ES, FI, FR, GR, NL, PL, RO, SE1, SE2, SE3, SE4
Source: Compass Lexecon analysis based on data from ENTSO-E

22 At times of strong solar electricity production and low power demand, power plants with operational constraints that constrain their minimum production (e.g., fossil or nuclear plant with minimum stable load constraints) or with technical constraints (e.g. ramping constraints or minimum shutdown duration) may be willing, depending on the economic trade-off, to bid through block bids or at a negative price to ensure their dispatch. As a result, the frequency of negative power prices varies hourly and seasonally, and is often (but not always) related to periods of high solar PV output.

3 Conjunctural and structural causes of negative power prices

23 In a dynamic perspective (Figure 7 below), negative prices are signals for market participants that can contribute to steer the evolution of investments and the resource mix towards more flexibility, both on the supply and demand sides.[21] However, structural barriers to the development of flexibility resources may result in persistent negative power prices.

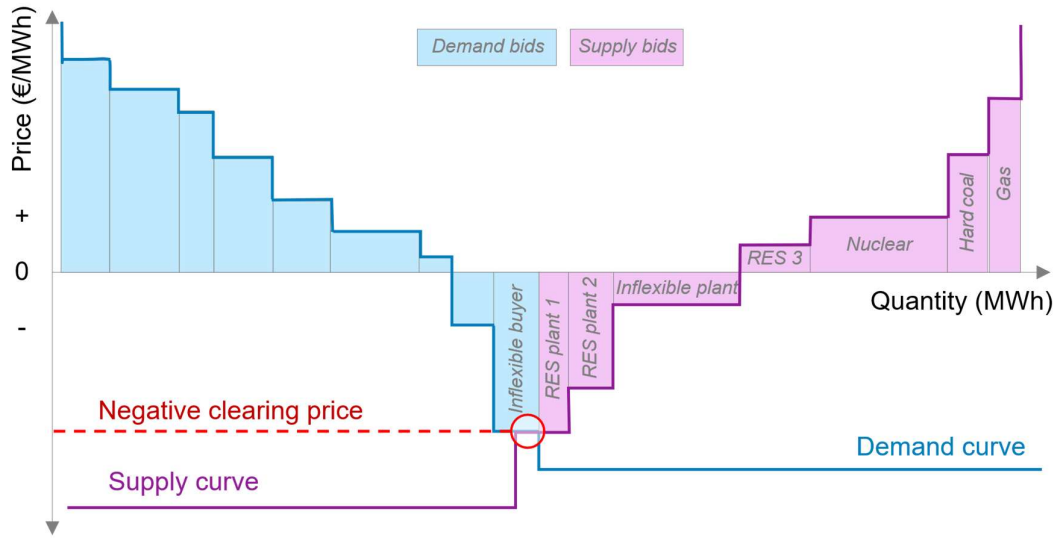
24 This section sets out the conceptual economic basis underlying the formation of negative prices, and then describes in practice the specific drivers at play across Europe. It then delves more concretely into how the drivers materialised in negative power price events such as on 1 May 2026.

3.1 Preamble: Negative prices formation

25 Negative power prices are a market outcome that can be expected when supply exceeds demand so that the two curves meet at a price below zero (Figure 6). Concretely, in day-ahead European power markets, every day at noon, electricity buyers and sellers enter their bid on the market platform. Buyers specify how much electricity they are willing to buy at what price for each quarter-hour of the next day, and sellers how much they are willing to sell at what price. The intersection of the two curves is the clearing price, i.e., the price faced by all successful bidders.

21 EU regulation defines flexibility as “the ability of an electricity system to adjust to the variability of generation and consumption patterns and to grid availability”. Regulation (EU) 2024/1747, available here.

Figure 6: Static view of market clearing during a negative power price period



Source: visual from Compass Lexecon.
Note: this is a simplified visual for illustration purposes that omits some bids for presentation's sakes and may not be representative of actual supply and demand curves on the day-ahead clearing platforms.

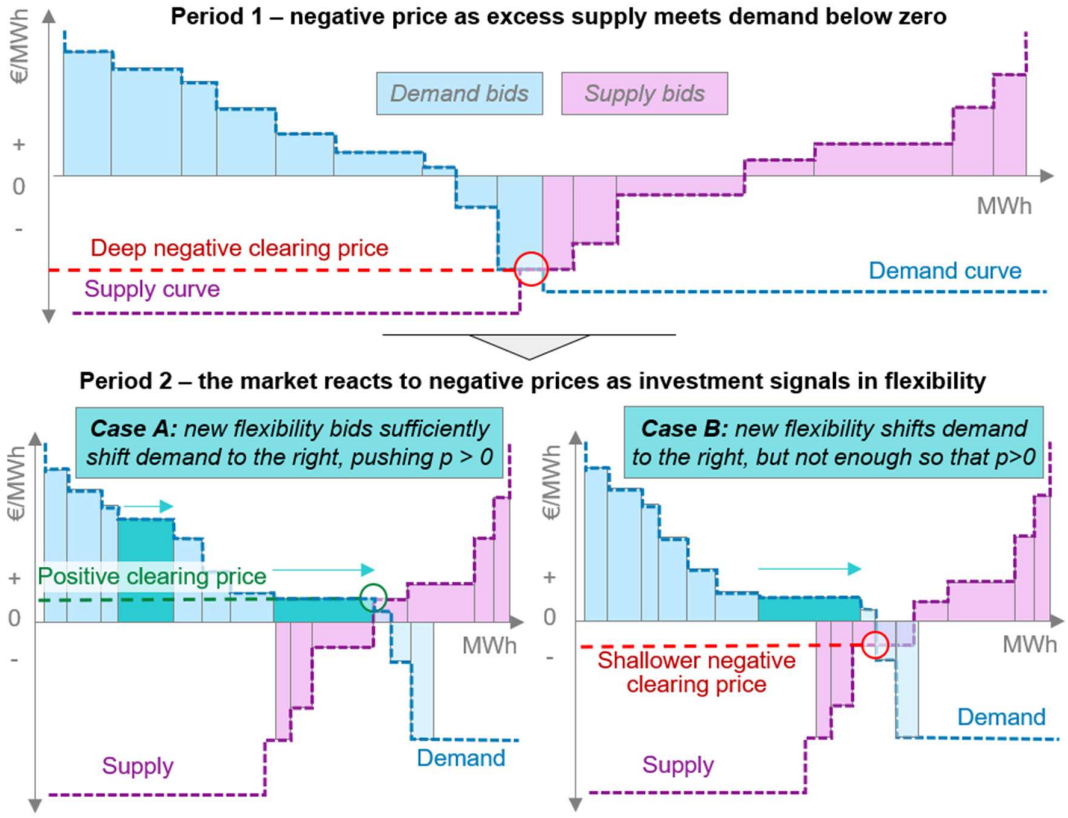
26 Producers' bids reflect their marginal cost of production, including relevant opportunity costs. These may arise from, e.g., ramping constraints for less flexible power plants (nuclear, thermal, etc.), for whom reducing output could also result in lost production and sales before or after the period of negative prices. Certain production-linked contracts (for instance, feed-in tariffs) may also create artificial bidding or generation incentives, as producers risk losing revenues if they do not generate electricity, thus leading to artificially low bids, clearing prices and suboptimal dispatch. The same is true for buyers, who may face net marginal or opportunity costs linked to absorbing more electricity than they need now (e.g., cost of activating storage or electrical appliances).

27 In a period when supply is high and demand is low, these bidding behaviours may result in the two curves meeting at a price below zero as illustrated in Figure 6 above. In particular, some producers may be willing to pay to continue generating, while buyers may have limited incentives or ability to increase consumption, even at very low or negative prices. This is exacerbated when demand is relatively price-inelastic, i.e., when it is not exposed and responds only weakly to short-term price signals. We explore these drivers of negative prices in greater detail below.

3.2 Negative prices as signals for investment

28 Where negative prices reflect genuine operational constraints or limited availability of flexibility, repeated negative power prices over time create incentives for flexibility to enter the market or to make existing capacity more flexible. This does not necessarily imply that the negative price signal will be sufficient to bridge the flexibility gap, as there are entry barriers to flexibility which could lead to persistent severe negative price events.

Figure 7: Dynamic view: negative price clearing as a signal to investments in flexibility



Notes: this is a simplified visual for illustration purposes that omits some bids for presentation's sakes and may not be representative of actual supply and demand curves on the day-ahead clearing platforms
Source: Compass Lexecon visual.

29 The market's dynamic response to recurrent negative power prices will depend on whether the flexibility gap is conjunctural or reflects structural barriers to entry or deployment:

- If market signals can incentivise enough new flexibility bids to shift the demand curve so that the clearing price becomes positive, this suggests an effective market-driven adjustment (Figure 7, Period 2, Case A). In this case, negative power prices would become less frequent and severe over time as the mix adjusts with the entry of flexible capacity.
- Conversely, if market signals are insufficient to incentivise enough new flexibility to enter the market, and the resulting clearing price remains negative (albeit shallower in this example), this may indicate structural barriers to flexibility deployment, but does not necessarily imply that the remaining negative prices are inefficient (Figure 7, Period 2, Case B). Under Case B, negative power prices may yet grow more severe and frequent if other background trends (e.g., strong wind and PV growth) persist. At the optimum, some negative price occurrences may remain, reflecting the marginal cost of developing more flexibility.

3.3 Distinguishing conjunctural and structural causes of negative power prices

30 The supply and demand imbalance and the lack of flexibility on either side of the market described above can be the result of a combination of interacting drivers. These include conjunctural trends, like the overall level of power demand and its link to the economy (e.g., low or negative prices in

the Covid years). They also include more structural causes, such as embedded opportunity costs and incentives in support contracts or demand-side electricity prices, or growing patterns like decentralised PV.

31 However, it is important to distinguish between (i) the underlying reasons why market participants submit negative bids, and (ii) the market conditions under which these bids become marginal and therefore translate into negative clearing prices.

3.3.1 Conjunctural causes of negative prices

Variable RES generation growth outpacing flexibility development

32 As solar and wind capacity represents a growing share of the generation mix, there is a growing need for flexible resources in the power system. When the growth of RES generation outpaces the development of flexible resources, this can lead – at least on a transitory basis – to situations driving negative prices. Indeed, periods of high RES output may coincide with limited capacity to absorb or adjust supply in the system. These conditions increase the likelihood and potential impact of forecast errors. As these conditions also lead to more low-to-zero marginal cost RES on the supply side, they also increase the probability that negative bids, including those reflecting embedded incentives (see structural causes below), become marginal and translate into negative prices. The overall effect of the long-term trend of renewable expansion on negative prices depends on the evolving balance between supply, demand, and flexible capacity on both sides.

Lower electricity demand than anticipated

33 Periods of lower electricity demand than anticipated can contribute to the emergence of negative prices, particularly when combined with high renewable output or limited availability of flexible capacity. As an example, the Covid period reduced economic activity and some sources of electricity demand throughout Europe while renewable power production kept rising. This led to the negative power price phenomenon spreading across more zones where they had not previously occurred (Figure 1). Going forward there remains much uncertainty about the evolution of power demand. The electrification of many energy usages to support decarbonization and energy sovereignty is projected to increase electricity demand, but delays in this electrification could lead to periods of temporary misalignment of generation capacity expansion and electricity demand growth.

Market integration and negative prices spill over bidding zones

34 Market integration can both contribute to mitigating the drivers of negative prices and allow them to extend across neighboring bidding zones, depending on the respective conditions in those zones. Exports can help absorb temporary excess supply in a bidding zone if neighboring systems have enough demand or flexibility to take that additional negative-bid energy that will be added near the lower end of the supply curve. However, if periods of low demand, high generation and low availability of flexibility coincide across those zones, exports may no longer be a possibility to absorb excess domestic production. In such cases, negative prices could spill over bidding zones through interconnection and market coupling. The key driver of such spill over is thus the synchronicity of the underlying supply-demand-flexibility conditions, and not per se the level of interconnectivity across countries.

3.3.2 Structural causes of negative prices on the supply side

Incompressibility of generation assets

35 Some power plants cannot increase or reduce output quickly because of technical constraints, while shutting down and subsequently restarting can also involve additional costs. As a result, a generator may be willing to submit negative bids factoring in these opportunity costs and continue operating at negative market prices if the losses from producing are lower than the costs and opportunity costs of shutting down and later restarting. For example, some lignite-fired power plants may face a 48-hour minimum downtime followed by a ramp-up time of 5 to 10 hours.[22] Thus, they may place a negative bid to reflect how much they are willing to pay to remain online and sell electricity in later periods.

36 These constraints differ between technologies and individual plants, as they directly stem from the technical design of the plant. Their importance also varies with each country's electricity system, i.e., the respective weights of the incompressible assets in the mix, and how that interacts with the flexibility and other constraints in the system. For example, a small electricity system with only one large incompressible power plant and some small-scale renewables may find that constraint more difficult to accommodate than a larger, more diverse and more flexible system.

Opportunity costs and other incentives embedded in support mechanisms

37 Contractual arrangements can create additional opportunity costs and incentives that influence generators' bids. In particular, when support payments depend on production, curtailment (i.e., not producing) entails foregoing those payments. Thus, depending on how the contract allocates market price exposure, a producer may be willing to accept negative market prices to retain that support revenue, so long as they offset the loss of selling at a negative price. In production-based Contract for Difference (CfDs), this incentive may also persist across market timeframes: when the day-ahead reference price remains non-negative, generators may retain support payments even when selling additional output at negative intraday prices.

38 These incentives can contribute to negative clearing prices when the associated bids become marginal during periods of excess supply. Unlike the incompressibility constraints described above, these opportunity costs arise from contractual (not necessarily technical) design, which can weaken or suppress incentives to adjust output in response to market conditions.

39 More concretely, support contracts for, e.g., RES, nuclear, or combined heat and power (CHP) plant operators differ by how much they incentivise their beneficiaries to react to negative power prices or other market signals. Incentives to react to negative prices depend on how far below zero the producer would be willing to bid, and under what conditions. Conversely, if support payment is suspended when a reference market price turns negative, producers are incentivised to avoid contributing to negative clearing prices in that market, to preserve their support payment. This primarily depends on the level and conditions under which they face opportunity costs linked to foregone support revenue. Support contracts offer three broad types of such incentives:

- Limited or no incentive to react: the beneficiary is fully or mostly insulated from market signals and will be willing to bid at a (potentially very deep or even 'must-sell', i.e., at the market floor) negative offer price to ensure its dispatch. This category includes Feed-in-Tariffs (FiTs) or similar produce-and-forget contracts whereby the producer receives a fixed price per unit of production, irrespective of actual market prices. These apply to both older contracts for utility-scale

22 N.B., this is an example. It can be similar for other technologies such as nuclear power plants.

renewables, and, crucially, to a large share of new contracts today for small-scale renewables – particularly decentralised PV assets. Under this type of contract, the producer's support payment directly depends on production. A producer under a Feed-in-Premium (FiP) contract may place a negative bid to reflect its willingness to produce until the cost of producing at a negative price exceeds the foregone support payment. In the case of a FiT or other produce-and-forget schemes, exceedance of support payment by a negative price would not be a decision factor, as the producer receives a fixed price outside of market clearing.

- Incentive to react with delay or beyond a certain threshold: the beneficiary is incentivised to reduce or curtail its output after the price was negative in a set number of consecutive market time units (MTU). For instance, 20% of German PV online today sees its FiP suspended after 3, 4, or 6 consecutive hours of negative prices (Figure 8). In this case, the opportunity cost of foregone support payment disappears when the expected negative price period exceeds the duration threshold. The producer may therefore only be willing to bid at zero or above if they expect the negative price event to last longer than that threshold (as in this case, support payment will be gone and the net revenue from selling at a negative price will be negative). This means the producer must correctly anticipate the duration of the event before placing its bids for the next day or adequately use smart bids available on the market.

- Incentive to react without delay: the beneficiary is fully exposed to price signals, and incentivised to reduce or curtail its output in every MTU with a negative clearing price. This is the case when production-dependent support is immediately suspended when the market price turns negative, as under the more recent German *Erneuerbare-Energien-Gesetz* (EEG) rules,[23] or for some of the more recent production independent CfD designs, which decouple settlements from actual output to enhance dispatch incentives.[24] For instance, the 2026 Danish offshore wind two-way capability-based CfD ensures the continuity of support payment based on potential (not actual) production during market-driven curtailments (including in response to negative prices), Transmission System Operator (TSO) ordered curtailments and scheduled maintenance.[25] In terms of exposure to incentives to react to negative power prices, this is akin to merchant production. In this case, the producer may only bid at or above zero, as there is no foregone support payment linked to production.[26]

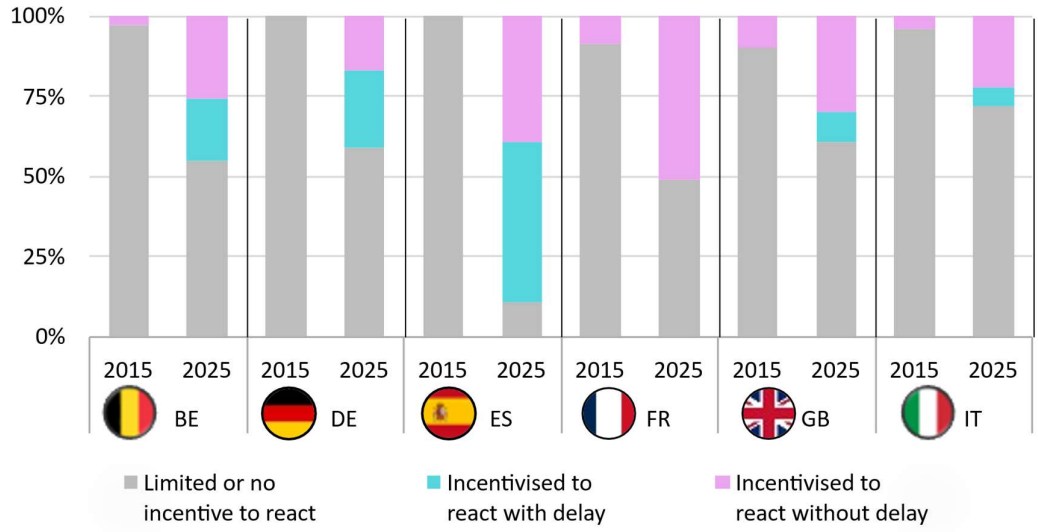
23 See Solarspitzengesetz, EEG rules (available here and here).

24 For an in-depth overview of CfD design, see Compass Lexecon's report for Eurelectric (2024), Unlocking the power of two-way CfDs to accelerate the energy transition (available here).

25 See EC SA.118363 (2026), recitals 114-120 (available here).

26 The loss of support when prices become negative could become a significant risk for RES investors if negative prices become too frequent. Conversely, production-independent CfD may protect investors from the risks of negative prices, at least to a certain extent depending on the exact design.

Figure 8: Historical evolution of installed wind and PV capacity per type of incentives to react to negative prices, based on a CL analysis of the stock of available contracts



Notes: This corresponds to the status quo of available contracts per technology and capacity criteria as known of the start of 2026. Other assumptions were made regarding plant and contract lifetime, and distribution of newly installed capacity according to recent statistics.
Source: Compass Lexecon analysis of historical and projected installed capacity and support schemes for solar, onshore and offshore wind. We allocated capacity across support schemes using reported contracted volumes where available, or estimates based on eligibility criteria (e.g. installation size, location, commissioning date) and installed capacity breakdowns. We then classified capacity by its responsiveness to negative prices, accounting for changes in scheme rules and incentives over time. We treated expired contracts as merchant (fully responsive) and applied assumptions where data were incomplete, notably for small-scale installations and PPAs.

40 The variety of support contract designs between and within countries creates a disparity of embedded incentives to react to negative prices (Figure 8). These incentives in turn interact with differences in power generation asset types and sizes. This diversity of situations explains some of the differences observed in the prevalence of negative prices across countries and over time. For instance, much of the Greek PV fleet is utility-scale and thus under more reactive contracts, whereas, in Poland, the PV fleet includes a larger share of small-scale assets that are less exposed to (negative) market prices.[27] Correspondingly, Greece saw fewer and shallower negative power price episodes than Poland in both 2024 and 2025 (Figures 2 and 3).

3.3.3 Structural causes of negative prices on the demand side

41 While the previous section discussed how support schemes can create or amplify negative bidding incentives on the supply side, demand-side inflexibility also contributes to negative power prices. We describe below some of the drivers of negative prices on the demand side.

Increased presence of less controllable / dispatchable prosumers e.g., rooftop PV

42 The growing presence of often less controllable and dispatchable prosumers can affect the predictability of the electricity system. Generation consumed behind the meter such as rooftop or balcony PV reduces net demand from the grid, potentially reinforcing periods of low residual demand when renewable output is high. If this remaining grid demand falls below grid-connected

27 SolarPower Europe (2025), EU Solar Market Outlook 2025–2030, available here.

renewable generation, residual demand becomes negative, increasing the need to manage the surplus.

43 In addition, the lack of dispatchability of small, distributed, behind-the-meter assets can limit the responsiveness to fluctuations in power prices. As the applicable technical standards and operating rules may not require remote control or other digitalised output adjustment capabilities, prosumers may remain unresponsive during excess supply periods, contributing to the conditions under which negative prices typically occur.

A lack of flexibility or price signals in consumer contracts

44 If a consumer's contract does not reflect some of the fluctuations in wholesale power market prices, it may not pass through the financial benefit of shifting or increasing demand during negative price periods. The consumer therefore has no additional incentive from those prices to incur the adjustment costs or foregone utility associated with changing its consumption, even when more demand would benefit the system. For instance, today, 52% of EU and Norwegian households are on single-price, fixed contracts, desensitising them from those signals.[28]

45 Moreover, economic and operational constraints – potentially compounded with regulatory barriers – may outweigh market signals and limit DSF. During a high-price spike, a factory may factor in its bid the opportunity cost of not meeting daily output quotas if it must curtail production to help alleviate system scarcity. Conversely, during a negative-price episode, increasing power consumption to absorb excess supply may require the factory to reschedule production, or produce additional output that must then be stored before being sold. In both cases, these costs may outweigh the benefits of responding to the price signal. In addition, consumers may also improve the responsiveness of behind-the-meter generation or flexibility.

46 Operational constraints may also restrict DSF for retail consumers (particularly households) to adjust their consumption at short notice. Operational constraints include the limited ability of system operators, market participants and consumers to see, anticipate, or control demand. In several EU countries, fewer than 20% of households are equipped with a smart meter[29].

3.4 Country case studies

3.4.1 The case of Finland: market signals contributed to bridging the flexibility gap

47 Finland illustrates a conjunctural flexibility gap that the market response seems to have at least partially addressed. In 2023 and 2024, Finland recorded the highest frequency of negative power price episodes in Europe (5.3% and 8.3% of hours respectively). This frequency receded to 5.3% in 2025 and only 1% (46 hours) in the first half of 2026. Analysts attribute this to the market's response through new installed battery storage capacity, and deeper demand electrification.[30]

48 In particular, the district heating sector has responded to lower and more frequently negative prices with greater degrees of electrification. Electric boiler and heat pump capacity in Finland is slated to increase from nearly 0 MW and 250 MW in 2021 to 3.5 GW and 1 GW respectively by 2027. This growth has been largely market-based, with heat pump profitability being supported by multi-use

28 ACER (2026), High energy bills and fixed contracts continue to prevail in EU retail markets, available here.
29 ACER (2026) Energy retail market monitoring report 2026, available here.
30 Montel (2026), Negative hourly power prices in Finland fall sharply in H1, available here.

(both cooling and heating) and e-boilers' by revenue stacking opportunities similar to batteries (some of the e-boilers already operate in intraday and balancing markets).[31]

49 Key lessons from the Finnish case are twofold. First, where there are no significant structural barriers preventing the growth of flexibility, the market may suffice to generate the signal to invest. Second, lower or more frequent negative power prices can also be a signal to invest on the demand side, notably in favour of electrification. This point is to be balanced on a total system costs perspective, as lower prices also reduce the economic viability of power generation and can lead to market exits.

50 Other countries like France, Belgium, or Germany may face more structural barriers, as they only saw frequency decline slightly in 2026, and also saw negative prices reach the clearing floor of -500 €/MWh on 1 May 2026.

3.4.2 The 1 May 2026 episode of negative prices: a contrasted picture across different markets

51 The interaction between opportunity costs and the power mix can also be traced in the 1 May 2026 episode, where Belgium, France, and Germany saw deep negative prices, but Spain did not:[32] In the former three, around or over half of the wind and PV fleet faced limited or no incentive to react to negative prices (Figure 8). By contrast, in Spain, more RES are under Power Purchase Agreements (PPAs)[33], merchant conditions, or reactive support contracts, and thus may be more incentivised to react. For France and Belgium, incompressibility constraints on nuclear reactors can already lead to large negative bids in the merit order.[34] The high share of less-responsive solar and wind assets added to this momentum, as likely did imported negative prices from Germany (see discussion on the causes of negative prices on that day in Germany in this section below).

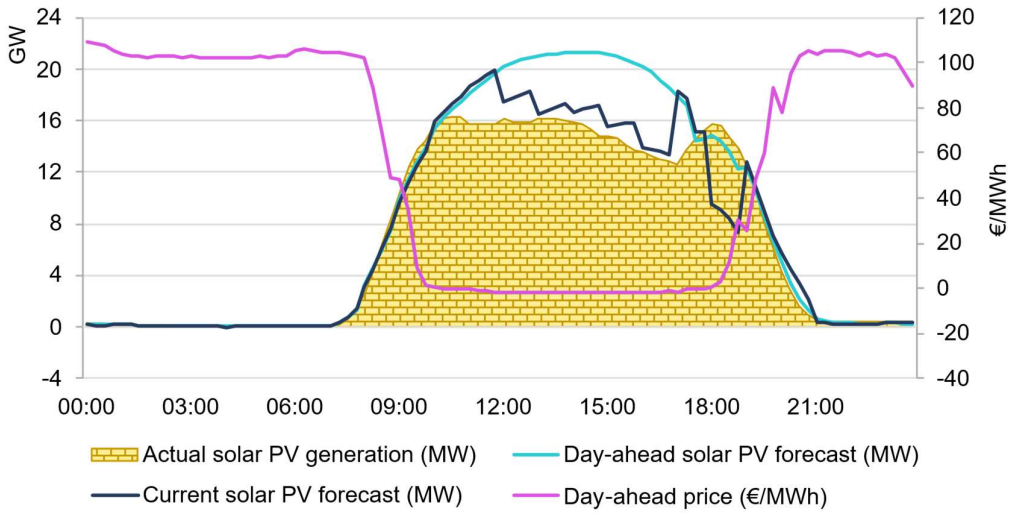
31 Source: data from 2026, graciously provided by Energiateollisuus (Finnish energy association) to the authors.

32 Belgium, France, Germany and the Netherlands nearly reached the minimum single coupling (SDAC) clearing price of -500 €/MWh (SDAC: ACER Decision 02/2026, available here; prices: RTE eco2mix market data, available here).

33 PPAs may preserve exposure to negative prices, including if they are pay-as-produced PPAs, as long as they contain a payment limitation or suspension clause if the price is negative. Since RES price cannibalisation, which is particularly prominent in Spain, puts more bargaining power on the buyer's side, one could expect (at least recently signed) pay-as-produced PPAs to include such clauses.

34 CRE (2024) Analysis of the Phenomenon of Negative Electricity Prices and Recommendations Regarding Renewable Energy Support Schemes, available here.

Figure 9: Zoom on 1 May 2026 in Spain: forecast and actual PV generation in GW; day-ahead market clearing price (€/MWh)



Source: Compass Lexecon analysis based on data from ENTSO-E Transparency

52 In Spain, a larger share of the RES fleet incentivised to curtail output during negative prices likely did (Figure 8 and 9). While such responses may have helped to prevent the formation of deep negative prices, their implications for system balancing depend on how well they can be anticipated. For instance, for PV, the difference between current forecast and actual output reached 5.6 GW at 17:00 and -6.5 GW at 18:15 (Figure 9).[35] Assuming that this forecast deviation stems from negative-price induced curtailment, it underlines that negative power prices, while being a standard market response to oversupply, may also, even at such a shallow level as shown on Figure , lead to risky or costly outcomes for the system. Lastly, the limited interconnection capacity from France to Spain prevented the transfer of some of the excess energy, but also likely helped to contain the spread of deep negative prices.[36]

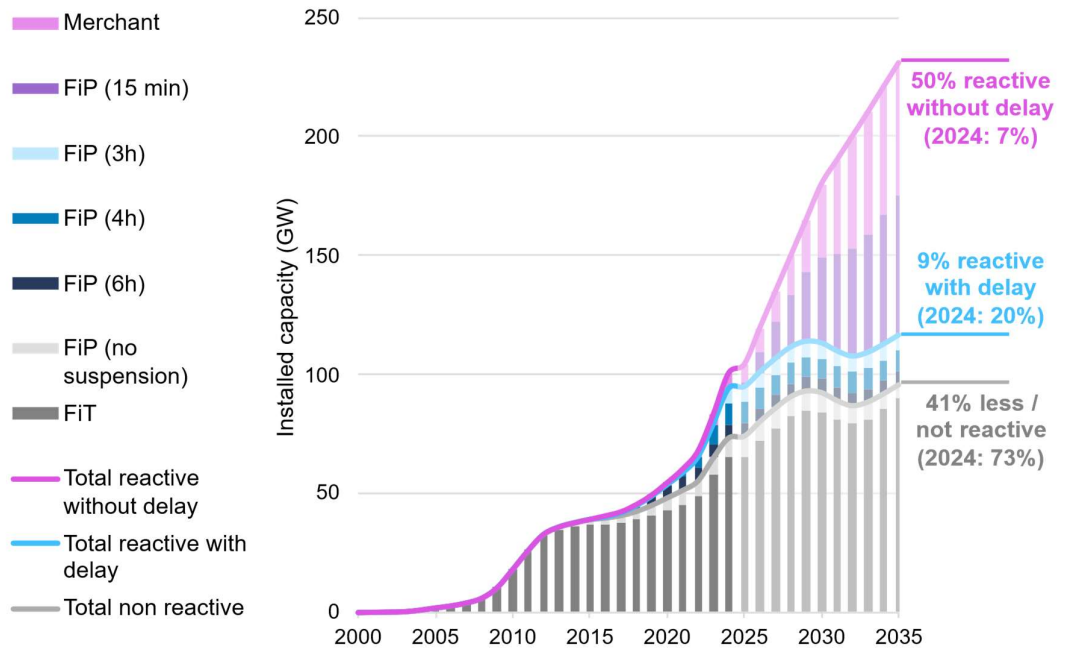
53 Other factors may push producers' willingness-to-bid further down below zero. For example, RES producers may incorporate the expected value of guarantees of origin or other tradable certificates in their bids. As these certificates are often valued around 1-10 €/MWh and do not have the same granularity as market prices (monthly or annual validity),[37] they may also partly explain some of the shallower negative prices observed for instance in Spain (Figure 4).

35 Gap between Day-ahead forecast and actual generation.

36 IEA (2022) Spain Electricity Security Policy, available here. ACER (2024) EU electricity market integration, available here.

37 EEX (2026) FAQ on Guarantees of Origin Futures, available here.

Figure 10: Installed PV capacity in Germany by support mechanism and price responsiveness, 2000–2024 (GW)

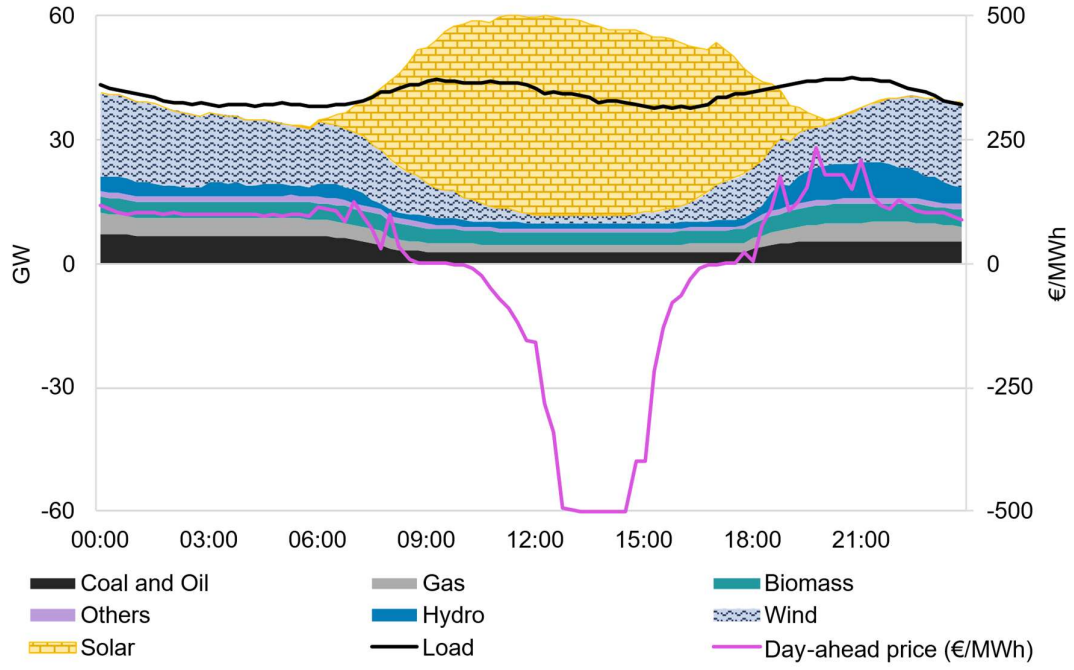


Notes: FiT: Feed-in-Tariffs; FiP: Feed-in-Premium. This corresponds to the status quo of available contracts per technology and capacity criteria as known of the start of 2026. Other assumptions were made regarding plant and contract lifetime, and distribution of newly installed capacity according to recent statistics.
Source: Compass Lexecon analysis

54 In Germany, the RES fleet under less-responsive support was a key driver of deep negative prices. Around 75% of Germany's PV fleet of over 100 GW (which exceeds typical demand at noon in May)[38] is under simple FiT contracts (Figure 10). These can be older assets with legacy contracts, or smaller assets, including rooftop PV, that fall below capacity thresholds for reactive contracts. Indeed, Germany has over 5 million solar assets installed, including a large majority of small sites. These older and smaller assets typically face pay-as-produce incentives, desensitising them from negative power prices. As a result, in high PV output periods, a large share of PV capacity continues to produce and bid negatively on the market or push down residual demand for embedded PV.

38 ENTSO-E Transparency Platform (2026) "Total Load – Day Ahead /actual DE-LU", available here.

Figure 11: Zoom on 1 May 2026 in Germany: generation mix in GW and day-ahead market clearing price (€/MWh)



Source: Compass Lexecon analysis based on data from ENTSO-E Transparency

55 Baseload unit incompressibility also contributed to excess supply in Germany on that day. Around 10 GW of non-PV or wind units (i.e., fossil-fired, bio, and hydro assets) remained online throughout the day, compared to a maximum of 24 GW in the evening (Figure 11). Domestic supply exceeded demand by 18 GW when prices reached -500 €/MWh. Like the suggestion to curtail some of the non-reactive RES fleet, reducing the output of the 10 GW of baseload units could have helped to bridge that gap, although this may have had operational security implications. This could have potentially prevented the price from reaching the clearing floor.

4 A framework to address negative power prices driven by flexibility needs

56 As mentioned in the previous section, economically grounded negative prices can play an important signalling role in the power system as they create incentives for demand and supply flexibility to be activated (in the short term) and to enter the market (in the long term). However, negative prices resulting from artificial bidding incentives, notably those embedded in support schemes, constitute distorted signals.

57 From an economic perspective, the objective should therefore not be to eliminate negative prices, but to ensure that they reflect efficient market signals, by addressing the root causes of distortive bidding incentives, ensuring an efficient risk allocation, and addressing entry barriers for flexibility.

58 Without aiming to be exhaustive, this section builds on these conceptual principles and identifies a range of options to address some of the underlying root causes of distorted negative prices and the barriers to the deployment of flexibility. It first examines measures to improve bidding incentives through the design and adaptation of support schemes. It then discusses the Flexibility Needs Assessment (FNA) framework that can provide important information to market participants before examining the potential measures to leverage additional flexibility from supply and demand, based on case studies and best practices from different countries.

4.1 Supply-side measures: best practices for support schemes design and/or adaptations

59 Renewable integration and deeper electrification drive the need for system and network flexibility. For power plant operators, this may translate into requirements or market-based incentives to quickly and orderly adjust their output to assist system operators in decongesting or balancing the grid. However, the regulatory framework may not adequately reflect those new requirements. Section 3 showed contract design may hinder market signals, leading to deep negative prices or uncoordinated curtailment. This is both a dynamic and a legacy problem:

- The dynamic part: some of the new clean generation capacity may not be coming online under the appropriate state-of-the-art support contract design encouraging grid and market-friendly behaviour.
- The legacy part: some countries have accumulated a large amount of support contracts with designs that may lead to negative bids reflecting opportunity costs, or disorderly curtailments.

60 Moreover, the absence of direct exposure to balancing costs for smaller installations in some countries may also affect the responsiveness of these installations. In many countries for instance, decentralised PV at household level is not directly exposed to balancing costs and is located at a Balance Responsible Party (BRP) (such as the household supplier or a mandated buyer), that cannot control these assets and can only try to forecast and balance this output as best as possible.

4.1.1 New CfD designs that balance financial support and market exposure

61 As explained above, the simple historic designs of support contracts tied to production entail inefficiencies and can create incentives for negative bids (see section 3). Recent CfD designs seek to address these inefficiencies via different definitions of volumes and remuneration.[39] The European Commission's 2025 CfD guidance examines these approaches and their implications for market signals and investment risks, distinguishing three types:[40]

- Production-based CfDs: the contract payment's reference volume is always based on the plant's actual measured output. This is the most common type of existing CfD, and is still awarded to new RES in some countries today.[41] In its simplest form, it rewards production irrespective of its (potentially negative) system value. To tackle this, the 2014 Energy and Environmental Aid Guidelines (EEAG) required new RES support schemes introduced from 2016 onwards to prevent incentives to generate during negative price periods, subject to certain exemptions.[42] Some States added to new contracts a rule suspending CfD payments for negative price episodes lasting more than a preset duration. In some schemes, this was then reduced to instant suspension. For instance, the UK added a six-hour suspension rule in the Allocation Round 2 (AR2) in 2017, and then tightened it to a full payment suspension during all negative MTUs from Allocation Round 4 (AR4) in 2021 and onwards.[43] However, the UK government identified three distortions that may persist despite negative-price suspension rules under this production-based design: (1) generators are incentivised to bid in the day-ahead market below their marginal cost, undermining market signals (as the bid could only reflect the incentive to secure CfD payment), (2) generators are incentivised to exclusively trade in the day-ahead market to reduce basis risk, but also to trade any remaining output at negative intraday prices if the day-ahead market clears above zero, and (3) this approach creates revenue risks for investors, in particular insofar as negative prices are becoming more and more frequent and uncertain in frequency.[44]

- Production-independent CfDs: the contract payment's reference volume is always based on a production profile or on the plant's capability to produce, estimated using methods such as a normative load factor. Because payment is decorrelated from actual output, production-independent CfDs do not provide artificial incentives to generate at time of zero or negative prices. For instance, payments under the planned Belgian offshore PEZ wind farm's CfD will be based on the farm's available power and wind conditions rather than its actual output, and the reference price is set to zero during negative-price periods, incentivising curtailment.[45] More generally, by decoupling support payments from actual generation, production-independent CfDs can improve producers' exposure and responsiveness to day-ahead, intraday and balancing market signals, incentivising them to design, operate and maintain their installations so as to maximise the market value of their production rather than the volume generated. While this provides better dispatch incentives, one should be careful about the risk implications for producers, as this may create higher revenue or hedging risks for producers and investors. This

39 For a more in-depth read on CfD design, see Compass Lexecon for Eurelectric (2024), Unlocking the power of two-way CfDs to accelerate the energy transition (available here).

40 EC (2025), Guidance on the design of two-way contracts for difference (available here).

41 See EC State aid decisions on support contracts for RES, e.g., Romania (available here).

42 EC (2014), Guidelines on State aid for environmental protection and energy 2014–2020 (EEAG), recital 124(c) (available here). Germany followed this rule, gradually adding negative price duration-based suspension.

43 See UK government documents on its different CfD Allocation Rounds (AR2 here, AR4 here).

44 See UK government (2026), Reformed National Pricing Delivery Plan, p.73-74 (available here).

45 EC State aid decision on the CfD for the Princess Elisabeth offshore Zone (PEZ) wind farm (available here).

can be particularly acute during periods of very high prices, in case of substantial difference between the actual and reference outputs.

- Fusion CfD: the contract payment's reference volume can be production-based or independent, depending on specific circumstances. For example, the reference volume could switch to production-independent in case of negative prices, or during a redispatch or balancing order. This could curb the oversupply incentive of production-based CfDs, and avoid the measurement problem and lack of balancing signal exposure of production-independent CfDs. The Italian FER X mechanism illustrates this concept (see case study below). Compared with production-independent CfD, it may reduce risks for producers and investors, but also incentives to an efficient dispatch (e.g. to respond to intraday price signals that may differ from day-ahead).

Deep dive on the FER X, a fusion CfD for new wind and solar assets in Italy[46]

The FER X is a fusion CfD introduced in Italy in 2024 to support new wind and solar capacity. Schematically, a producer's revenue under FER X can be represented as follows:

$$Revenue = P_{DA} \times Q_{DA} + E \times (1 - exposure\ factor) \times (S - M_0)$$

With:

- P_{DA}: day-ahead market price
- Q_{DA}: quantity sold on the day-ahead market
- E: actual metered output or estimated producible output (potentially capped, see below)
- Exposure factor: set at 5% for sites > 1MW; reduces payment share covered by the CfD
- S: strike price (reference tariff)
- M_0: day-ahead (J-1) spot price, at 15-minute (MTU) resolution

A key feature of the Italian FER X scheme is that remuneration during zero or negative price periods is based on the plant's available generation capability rather than solely on actual metered output. When the day-ahead price is positive, the reference volume is the plant's actual output. However, when day-ahead prices are zero or negative, support payments are generally suspended, during (i) redispatch, (ii) TSO balancing orders, or (iii) zero or negative price events, it switches to the site's estimated producible output based on technical and weather data. This design, initially introduced under the transitional phase, was officially adopted and implemented under Italy's newly enacted FER X Definitivo framework (Ministerial Decree of 18 June 2026). The associated GSE Operational Rules were approved on 7 August 2026, primarily to specify the procedures for accessing the scheme and participating in competitive auctions.

However, the scheme includes specific rules to distinguish between energy that could technically have been produced and energy that was actually scheduled in the market. In cases (ii) and (iii), the production-independent volume is capped at the volume of energy offered in the balancing market. The reference volume for remuneration purposes is therefore linked to the installation's production capability, combined with the operator's market behaviour and balancing market actions, avoiding creating incentives for generators to continue injecting electricity into an oversupplied system simply to collect support payments. By linking remuneration rules to the plant's available generation capability and market schedules, the scheme preserves efficient dispatch signals while ensuring that renewable generators are not

46 EC (2024) FER X State aid decision (available here). N.B., here, to simplify, we discuss conditions for sites >1MW.

unduly penalised when reducing output in response to negative price signals. In practice, the mechanism seeks to reward efficient market behaviour rather than pure physical production, thereby encouraging generators to react appropriately to periods of system surplus and supporting a more flexible electricity system, which reduces the measurement issue and the lack of balancing signal exposure of production-independent CfDs.

The 5% exposure factor preserves a residual incentive for producers to optimise the timing of their production. For example, timing annual maintenance in spring when excess supply is frequent, to be able to produce throughout winter when demand is higher.

Having a long-term private PPA of at least 10 years serves as a priority selection criterion in case of capacity saturation during competitive auctions. Under GSE's rules, this priority status is managed through an ex-ante verification process: developers must register their PPA on the GME platform before submitting their "Preliminary Qualification" request to GSE, allowing GSE to confirm this priority requirement ahead of the competitive auction and prevent administrative delays during final capacity allocation.

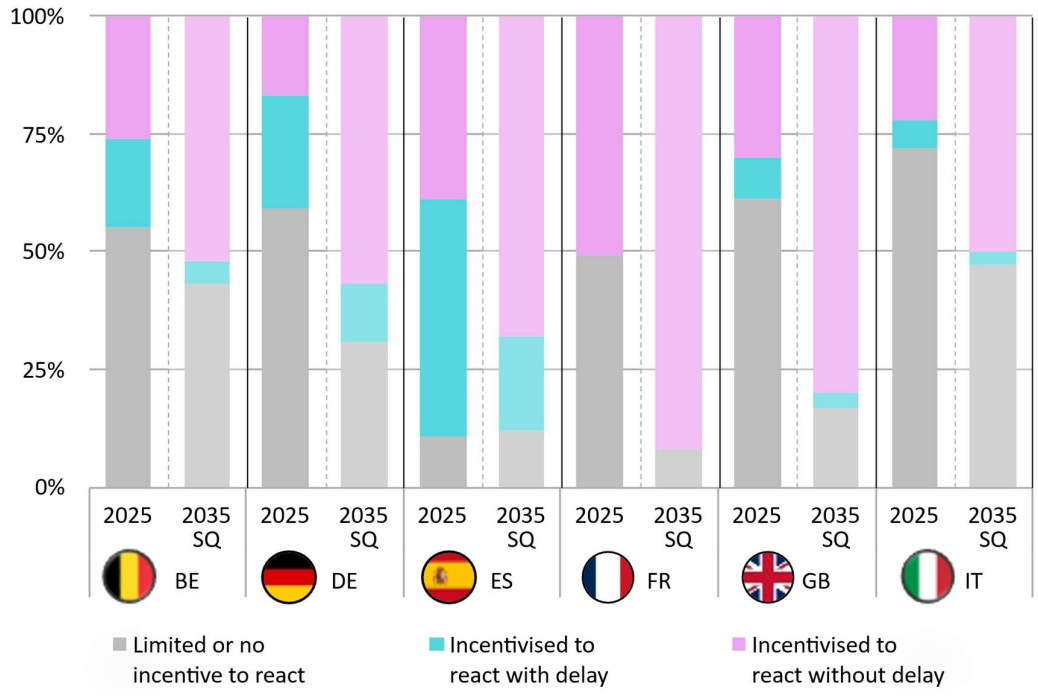
The CfD-PPA compatibility is embedded in the support scheme's core design: since the 20-year two-way CfD covers 95% of the plant's production (reflecting a 5% exposure factor for assets above 1MW), it leaves a 5% market exposure. This hybrid model allows developers to combine public support with long-term private physical or financial PPA hedging on the remaining production, maximising bankability without crowding out private markets.

Overall, FER X illustrates how public support schemes could complement rather than crowd out private risk-management arrangements. Following this example, future support design could opt to remain compatible with PPAs, forward markets and financial hedging products in order to preserve efficient risk allocation and market liquidity.

4.1.2 Managing the legacy support contracts

62 Introducing new types of support contracts that do not lead to bidding distortions is a good step forward across Europe. Yet, the stock of legacy support contracts with limited market signal exposure may remain a long-lasting source of bidding incentives' distortions and contribute to negative prices. Indeed, as shown on Figure 12 below, in some countries, the legacy contracts may still represent a large share of RES volumes in the years to come, which may contribute to persistent negative price periods.

Figure 12: Projected evolution of the reactivity of the wind and PV fleet, showing 2025 historical data and a Status Quo (SQ) scenario for 2035 (%)



Notes: This corresponds to the status quo of available contracts per technology and capacity criteria as known of at the start of 2026. Other assumptions were made regarding plant and contract lifetime, and distribution of newly installed capacity according to recent statistics. For 2035, we show a Status Quo (SQ) scenario, where we apply the currently available contracts as known of at the start of 2026 to our Compass Lexecon outlook for PV onshore and offshore wind capacity.
Source: Compass Lexecon analysis based on the same principles as explained below Figure 8, and using our own modelling projections for installed capacity per technology type (solar, onshore wind, offshore wind).

63 The inertia in the stock of legacy contracts means that fixing the flow of new contracts may not be sufficient in some countries to address associated bidding incentives distortions leading to negative prices. Support contracts are indeed typically long term: 15-25 years for renewables or 30-40 years for nuclear. In addition, new contracts for smaller assets may not be designed to provide efficient signals, e.g. household PV, which may contribute to keeping a large part of RES volumes under distorted bidding incentives.

In some countries, regulators tried and adapt the existing stock of contracts, in order to address the issues that cause bidding distortions and make some installations less reactive to price signals. However, regulatory stability is a key principle of sound regulatory practice. In case such adaptations of existing contracts are deemed necessary by regulators, they should be based on voluntary renegotiations to adapt existing support contracts, and entail appropriate compensation to make investors whole in case they affect potential expected revenues.

4.1.3 Leveraging additional flexibility through long-term flexibility contracting

64 Fast tracking investments in new flexibility resources raises a number of issues regarding the commercial viability of such investments, including whether price signals and expected revenues are likely to be sufficient to support sustained investments given the risks of cannibalisation of revenues. To address these issues, different types of contracting measures could be envisaged to enhance revenue predictability, including for instance capacity mechanisms and flexibility contracting.

65 In cases where the FNAs may identify a persistent clean flexibility gap that would remain after support-scheme distortions, regulatory barriers and network bottlenecks have been addressed, capacity mechanisms can contribute to providing long-term investment signals for flexible assets, but need to be open to them and properly designed to reflect their contribution. Alternatively, and complementarily, Member States can introduce flexibility contracting mechanisms (the "non fossil flexibility support schemes", or NFFSS). Different approaches to filling the residual flexibility gap identified by national FNAs are possible, such as integrating flexibility contracting under Capacity Remuneration Mechanisms (CRMs), or keeping firm and flexible asset contracting separate but coordinated. We discuss these approaches and how to coordinate the contracting framework in some of our previous work.[47]

66 These long-term contracting mechanisms provide a guaranteed remuneration which can help bridge the financial gap between costs and expected market revenues and enhance revenue predictability for the necessary flexibility assets. To address the network constraint issues, locational provisions may be reflected in these contracting mechanisms, guiding investors to locate new assets in adequate areas from a grid perspective. According to the EU State aid guidelines, such mechanisms should be technologically neutral and open to all assets technically capable of providing the identified system service.

Case study 2: Example of a flexibility contracting scheme – the Italian MACSE

The Italian regulatory scheme MACSE *(Meccanismo di Approvvigionamento di Capacità di Stoccaggio Elettrico)* is an example of such contracting mechanism for standalone storage capacity, aiming to deliver new storage capacity useful for grid operations while ensuring long-term revenue predictability for asset developers.

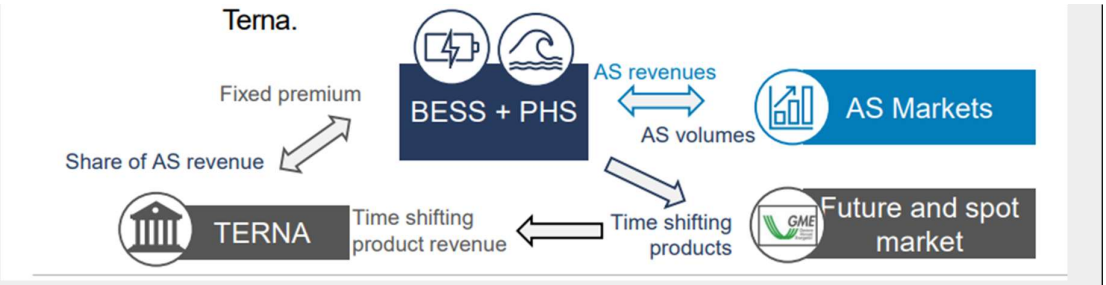
Designed as Italy's pioneering regulatory response to address the long-term flexibility gap, the scheme is governed by the latest MACSE Discipline approved on 27 March 2026, and operates through a centralised procurement framework managed by Terna. To help developers secure high upfront investments, the scheme awards long-term contracts with differentiated delivery periods (15 years for battery energy storage system (BESS) and 30 years for hydro facilities) making new Li-ion battery storage projects highly bankable (the actual applicability of MACSE to new pumped-hydro storage is still under evaluation).

At its core, the mechanism operates through a tripartite contractual framework aiming to make time-shifting products emerge and to help optimise the use of storage and grid assets across the country. Under this structure, Terna acts as the central intermediary, procuring capacity from developers through long-term contracts and selling standardized time-shifting rights to market participants via GME's trading platform. This framework enables market participants to hedge their exposure to price volatility and negative prices by shifting renewables surplus generated during peak solar hours to peak demand periods.

To ensure operational efficiency, selected developers return 80% of their realised market contribution margin to Terna on the established MBR (*Mercato per il Bilanciamento e il Ridispacciamento* and European balancing platforms). This split keeps operators actively exposed and responsive to real-time price signals.

Figure 13: Illustration of the functioning of the MACSE

47 See for instance, Compass Lexecon for CATF (2025), Accelerating the deployment of clean power technologies to reliably decarbonise Europe through enhanced planning and contracting mechanisms, available here.



Source: Compass Lexecon analysis

MACSE is an example of a technology-specific mechanism designed to address specific system flexibility needs in Italy. Notably, beyond batteries, it allows the participation of pumped hydro storage (PHS), which may otherwise struggle to participate in support mechanisms whose procurement and delivery timelines are poorly aligned with the long development and construction periods of PHS. However, MACSE restricts participation to specific storage technologies, thereby departing from the principle of technology neutrality. Technology-specific mechanisms should therefore remain exceptional and require evidence that a technologically neutral procurement would not deliver the identified service within the required timeframe and at a lower total system cost. Conversely, most non-fossil flexibility procurement schemes should remain technology-neutral and service-based, allowing the full spectrum[48] of technologies to compete on equal terms according to the services they provide.

Beyond procuring flexibility, MACSE provides a long-term revenue stream that can help address the investment risk and potential 'missing money' faced by capital-intensive storage projects. Indeed, the financing of such projects may not be viable on a purely merchant basis. However, some concerns have been raised by some market participants regarding the mechanism's potential impact on competition and merchant investment. Indeed, MACSE-supported storage assets may to some extent affect the expected revenues and investment incentives in unsubsidised flexible assets. The extent of these effects will depend on the volumes procured, the competitive conditions in each zone, and the interaction between MACSE contracts and market-based revenues. In that regard, MACSE also incorporates explicit locational signals through area-specific auctions, reflecting flexibility requirements in individual bidding zones and inter-zonal transmission capacity.

4.2 Sizing the gap: flexibility needs assessments

67 The rise of negative power prices also echoes the need to increase the EU power system's flexibility. Compared to early 2020s levels, EU-wide system flexibility is projected to increase about twofold by 2033, and sixfold by 2050.[3,49]

68 In this context, the 2024 EU Electricity Market Design Reform (EMDR) set up an EU process to assess and address flexibility needs.[50] This process started in July 2025, with ACER publishing a methodology for national Flexibility Needs Assessments, to identify gaps over time and across

48 Batteries, pumped hydro storage, thermal storage, demand response, industrial flexibility, electrolysers, district heating assets and hybrid generation facilities, to cite a few.

49 For a detailed breakdown of flexibility needs estimates, see Compass Lexecon's flagship report for Eurelectric (2025), Energy security in the age of electricity (Figures 16 and 17, available here). Other useful sources include: FSR (2026), Flexibility in power systems: what's there beyond the buzzword? Available here. ACER (2023), Flexibility solutions to support a decarbonised and secure EU electricity system, available here. JRC (2023), Flexibility requirements and the role of storage in future European power systems, available here.

50 ACER webpage and timeline on Flexibility Assessments (available here).

timeframes.[51] Subsequently, Member States had until July 2026 to conduct their national FNA per ACER's methodology, and submit the results to ACER and the European Commission. At the time of drafting this paper, few of the 27 EU Member States have published a national FNA. Next, by January 2027, each Member State must use the results of their FNA to define indicative national targets for non-fossil flexibility – i.e., their flexibility gap. The EMDR then expects Member States to set up the measures required to bridge any identified flexibility gaps. Lastly, by July 2027, ACER must publish a report providing EU-wide flexibility needs estimates, and recommendations on flexibility issues with cross-border relevance.

69 ACER's methodology provides common definitions and requirements to enable cross-country comparison and a deeper overall analysis of flexibility needs.[52] It introduces three distinctions to help answer key questions around negative prices: how much of what type of flexibility is needed, what causes those needs, and whether existing infrastructure can meet those needs or more structural measures are required.

70 The national FNAs will provide some perspective on flexibility needs, but only a partial view, as their geographical scope will only be national and flexibility also interacts with other needs such as adequacy. For instance, flexible capacity also contributes to adequacy, as it can help shift demand away from the scarcity periods on which the adequacy gap is measured. On the one hand, flexibility needs can emerge from local congestions that can be properly addressed in national assessments. On the other hand, the national scope of FNAs makes it important to account for cross-border flexibility and market integration, including their potential to reduce the need for additional flexibility resources at national level.

71 The national and European FNAs will provide important insights to understand the root causes of negative prices, and the extent to which negative prices can be expected to be a transitory signal of a flexibility gap. Moreover, these assessments may also help identify (i) to what extent removing distortions and barriers to entry, if still any, would be sufficient to ensure sufficient flexibility development, and (ii) more specifically, the type(s) of flexibility needed.

72 Additional insights could be unlocked by integrating FNAs into a comprehensive and coordinated framework for assessing system needs, to deliver on the EU policy goals of decarbonisation, competitiveness, and security of supply, as highlighted in several reports, including our past work.[53] These include joint assessments of flexibility, adequacy and other system or network needs, coordinating the needs across sectors and geographies, including cross-border flexibility needs and resources.

73 Such a more coordinated and holistic assessment of system needs – including flexibility – would provide the full perspective required by Member States to assess whether and which structural measures are needed to address the issues underpinning negative power prices.

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51 ACER (2025), Decision on the FNA methodology: Annex I (available here).

52 To cite a few, national FNAs are subject to a common horizon (at least 5 to 10 years, with at least one target year aligned with EU policy goals), reporting structure (data table templates), and methodology (also consistent with EU and national resource adequacy assessments).

53 Compass Lexecon for Eurelectric (2025), Energy security in the age of electricity (available here). Compass Lexecon for CATF (2025), Accelerating the deployment of clean power technologies to reliably decarbonise Europe through enhanced planning and contracting mechanisms. Available here.

4.3 Demand-side solutions: enhancing flexibility of industrial and household consumers

74 Beyond the supply-side measures mentioned previously, demand-side solutions represent a large source of additional flexibility. End-consumer flexibility may be key to tackle structural oversupply leading to negative power price episodes. Without always requiring real-time flexibility, incentivising consumers to increase their consumption when negative power prices are likely to occur may help to reduce episode frequency and severity.

75 Moreover, low or recurring negative prices can also provide important market-based signals for DSF and electrification, in the absence of structural barriers. The following section describes the principles to support consumer demand flexibility and how to do so, discussing the potential structural barriers to lift.

4.3.1 Principles to support consumer flexibility

76 Electricity consumers have diversified consumption profiles and abilities to react to price signals. Their load profiles (including peak and total consumption, and time-varying consumption patterns) and ability to monitor and control their reaction to market signals or explicit requests determine how much flexibility they can provide and how it can be used.

77 Non-household electricity consumers, such as industrial consumers, commercial buildings and public services, account for about two-thirds of final electricity consumption in the EU27.[54] As such, they represent a large potential source of demand flexibility. This category encompasses a broad range of load profiles, from small businesses with limited demand and daily peaks to large-scale industrial facilities with a constant baseload profile and an annual consumption in the GWh to TWh range.

78 Household consumers make up the remaining third of final electricity consumption in the EU27.[55] The household segment has its own distinct characteristics affecting possible flexibility options. The segment is made up of many small consumers with predictable consumption peaks linked to daily and seasonal routines. The flexibility a single household can provide is small and limited by its equipment, notably smart metering, but also electrical appliances including EVs, heating, etc. However, aggregated, it can become material even at system level. Considering constraints around the mobilisation of household flexibility, the best approach may be to make the necessary tools and pricing options available without imposing behavioural changes.

79 The diversity among electricity consumers means that the methods used to incentivise demand flexibility must be tailored to different types of consumers. While all consumers could be in theory responsive to signals in retail prices, provided they receive these signals, they may differ in their ability to actively modulate their consumption. Household and smaller end-users may be to some extent less able currently in some countries to participate directly in markets due to a range of associated technical, operational, and administrative issues. Combined with economies of scale and scope, larger consumers may be better suited to offer demand response capacity in the context of flexibility contracting or capacity remuneration mechanisms.

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54 Compass Lexecon calculation based on Eurostat data (available here), for the year 2024 and in the EU27.

55 See above. This back-of-the-envelope calculation ignores other smaller sectors (ex: transport, about 3%).

4.3.2 Potential measures to increase DSF

80 Different approaches to increase DSF are possible, including static and dynamic retail price signals, explicit rewards for adjusting consumption and explicit participation in the markets e.g. through an aggregator. In this spectrum of options, the potential approaches to increase DSF will depend on end-users needs, consumption patterns, and ability and willingness to respond to those signals.

Developing DSF through retail prices

81 Static retail prices with Time-of-Use (ToU) differentiation may encourage the structural changes in consumption patterns required to help bridge the flexibility gap. Concretely, adding pre-fixed peak and off-peak hours in static retail prices could induce behavioural shifts – e.g., heating water off-peak instead of during peak hours. By providing predictable signals, these offers can support demand-side investment and lasting changes without requiring consumers to monitor market prices continuously, and may help displacing load in periods of likely or frequent oversupply.

82 However, such signals alone cannot address all flexibility needs, particularly those arising from short-term and not recurring market conditions. Moreover, the positioning of the different types of periods needs to be well coordinated between system operators and suppliers in order to make sure that they can provide adequate signals both for the network and the supply sides. Lastly, their time bands should also evolve with structural changes in the power system, e.g. reflecting the differences between weekdays and weekends or midday low prices due to increasing PV production.

83 At the other end of the spectrum, some end-consumer sourcing or retail contracts may be fully dynamic, reflecting short-term wholesale electricity prices.[56] This level of exposure to market prices may accurately convey price signals for DSF, and encourage both short-term adjustments in consumption and long-term investment. However, responding effectively to dynamic ToU signals may require a degree of responsiveness, digitalisation, anticipation, control and measurement capabilities, that many consumers may not be able or willing to muster. It comes with an exposure to short-term prices and additional risks for consumers when they cannot respond, that may deter them from entering such arrangements.

84 Intermediate arrangements that combine protection against price volatility with incentives to respond to short-term conditions are also possible. This could include composite retail prices with a predominantly fixed-price or predefined static ToU component to preserve bill predictability, and some dynamic elements to provide additional signals.[57]

85 For industrial consumers, long-term sourcing contracts can combine price certainty and flexibility. Industrials typically secure their baseload with long-term contracts or in forward markets, hedging the bulk of their consumption needs. They could however be subject to the day-ahead market prices for the difference between their hedged volumes and actual consumption. If flexible, they can

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56 The uptake of dynamic contracts varies considerably across the EU. Dynamic pricing has developed furthest in a handful of Northern European markets: as of 2025, dynamic contracts accounted for c.85% of household electricity contracts in Norway, and were prominent in Denmark and Sweden. In most of the EU, however, dynamic contracts represent a marginal share of the household market. In several Central and Eastern European countries, including Poland, Romania, Hungary and Czechia, the uptake of dynamic contracts stood at 0% in 2025. ACER (2026), 2026 Market Monitoring Report, available here.

57 These dynamic elements could take the form of critical peak pricing arrangements, such as those used in one of the French regulated retail power prices contracts (*Tempo*).

leverage this short-term price exposure to reduce their bills by reducing their load in periods of high prices and conversely.

86 Suppliers can also develop additional flexibility rewards or capabilities to complement those retail offers.[58] Likewise, new pricing options could also leverage the growing number of smart electrical appliances to reward grid-friendly behaviour.[59]

ToU network tariffs could provide complementary signals for DSF investment and structural changes in consumption patterns

87 While fully respecting the cost-reflective principle for network tariffs (which is key to deliver an efficient grid use signal) adapting the timing or duration of predefined peak and off-peak periods can improve these static ToU signals, while ensuring sufficient consistency with market signals, and unlock additional flexibility.

Developing DSF through explicit market participation of demand-side response (DSR)

88 Lastly, more could be done to lift the barriers to DSF and leverage its full potential. In particular, aggregation and remote-control capabilities, on a voluntary basis, could help unlock previously untapped resources. Robust technical standards and clear operational rules are necessary to ensure reliable delivery and compatibility with local network constraints. This is a prerequisite for Distribution System Operators (DSOs) to trust and utilise these resources for efficient local network operation. These rules should also allow the stacking of revenues across different services and market products (e.g. combining wholesale arbitrage with balancing or local grid services). Also, these rules should ensure a fair allocation of costs, revenues and responsibilities between aggregators, suppliers and consumers, particularly if independent DSR activation affects suppliers' energy positions or balancing responsibilities.

89 Conversely, unnecessarily complex and costly administrative and technical requirements can prevent Flexibility Service Providers (e.g. aggregators of smaller distributed energy resources (DERs)) from entering capacity, wholesale, balancing and ancillary service markets. Where this is the case, streamlining these processes is essential to make DSR participation practically feasible.

90 Market access for DSF varies considerably across the EU. According to SmartEn, Great Britain and France stand out as the most advanced markets, combining relatively high smart meter penetration with a clearly defined independent aggregator framework that allows demand-side resources to trade directly in wholesale markets. By contrast, several Central and Eastern European countries score poorly on this composite measure, reflecting a combination of less mature aggregator frameworks and, in some cases, slower smart meter roll-out.

New flexible load – through electrification or digitalisation – can also help mitigate negative price episodes

91 The development of electricity demand in parallel to low-carbon technology deployment can support the decarbonisation of the economy while tapping into cheap electricity, especially during periods

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58 As an example, Engie integrates in some of its Belgian retail contracts a fixed 15 €/MWh reward for smart charging the household's EV during favourable moments. See Engie, *Recharge Intelligente*. Available here in French.

59 Octopus Energy's trial on 135 UK households with bidirectional EV chargers showed the aggregated fleet could respond to dispatch instructions within time and cost ranges that would make it viable in balancing markets. ESO & Octopus Energy group (2023) Powerloop: Trialling Vehicle-to-Grid technology, available here.

of low or even negative prices. As such, negative prices and low average prices can be a signal for the electrification of existing energy end-consumption, and the development of new uses.

92 This development should – to the extent possible – come with a certain degree of flexibility associated with the additional load, so that these new users can capture low prices while avoiding adding demand to periods of scarcer electricity. Indeed, this may make their electricity bills more expensive, but also tighten power supply in these periods of scarcer electricity.

93 For example, data centres could potentially contribute to addressing Europe's structural flexibility gap and mitigating negative price events. However, their flexibility potential depends on operational constraints and the extent to which their electricity demand can be shifted without compromising their service requirements. A thorough assessment could help analyse the flexibility they could bring across different timeframes.

5 Conclusion

94 Whilst negative prices are useful signals for market participants to support efficient system operation and that can contribute to steering investments and the evolution of the resource mix towards more flexibility, structural barriers to the development of flexibility resources (or the retirement of inflexible resources) may result in persistent negative power prices. Moreover, negative prices can be a cause for concern when they arise from distorted bidding incentives or induce risks and costs that can be hard to manage for some market participants.

95 Overall, different steps could be envisaged to address structural or persistent negative power prices and ensure efficient market signals:

- Limiting distortive incentives embedded in support schemes may contribute to restoring efficient market signals and preventing persistent negative power price episodes driven by the internalisation of distortive opportunity costs in market bids. This is true for any other barriers to price signals, such as price interventions, that could be lifted to facilitate efficient price signals.
- Insofar as such distortions are kept to a minimum and barriers to efficient price signals and market entry are removed, market signals, including remaining, economically healthy, negative prices, could contribute to driving investments in flexibility, storage, demand-side response and electrification, without any need for additional public intervention.
- Flexibility Needs Assessments will help identify whether any structural flexibility gaps are likely to persist once distortions have been addressed and market-driven investments accounted for. It would be valuable for these assessments (i) to identify to what extent removing distortions and barriers to entry, if still any, would be enough to ensure sufficient flexibility development, and (ii) to identify more specifically the type(s) of flexibility needed. Where such residual flexibility gaps are likely to persist, contracting mechanisms for flexibility may help to foster the required investments.

96 This would help ensure that public intervention responds to genuine system needs rather than compensating for distortions created elsewhere in the regulatory framework, while preserving efficient signals, avoiding distortions, and limiting unnecessary support costs.

Acronyms and Abbreviations

AR2 / AR4	Allocation Round 2 / Allocation Round 4
BESS	Battery Energy Storage System
BRP	Balance Responsible Party
CfD	Contract for Difference
CHP	Combined Heat and Power
CRMs	Capacity Remuneration Mechanisms
DERs	Distributed Energy Resources
DSF	Demand-Side Flexibility
DSO	Distribution System Operator
DSR	Demand-Side Response
EEAG	Energy and Environmental Aid Guidelines
EEG	*Erneuerbare-Energien-Gesetz*
EMDR	Electricity Market Design Reform
FER X	Proper name of the Italian support mechanism
FiP	Feed-in-Premium
FiT(s)	Feed-in-Tariff(s)
FNA(s)	Flexibility Needs Assessment(s)
GC	Green Certificates
MACSE	*Meccanismo di Approvvigionamento di Capacità di Stoccaggio Elettrico*
MBR	*Mercato per il Bilanciamento e il Ridispacciamento*
MTU	Market Time Unit
NFFSS	Non Fossil Flexibility Support Schemes
PHS	Pumped Hydro Storage
PPA	Power Purchase Agreement
PV	Photovoltaic
REMA	Review of Electricity Market Arrangements
RES	Renewable Energy Sources
RG	Renegotiation (scenario label)
RRE	*Régimen Retributivo Específico*

SDAC	Single Day-Ahead Coupling
SQ	Status Quo (scenario label)
TIDE	*Testo Integrato del Dispacciamento Elettrico*
ToU	Time-of-Use
TSO	Transmission System Operator

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