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## COMMISSION STAFF WORKING DOCUMENT

### Reform of Electricity Market Design

#### *Accompanying the documents*

**Proposal for a Regulation (EU) of the European Parliament and of the Council amending Regulations (EU) 2019/943 and (EU) 2019/942 as well as Directives (EU) 2018/2001 and (EU) 2019/944 to improve the Union's electricity market design**

**Proposal for a Regulation (EU) of the European Parliament and of the Council amending Regulations (EU) No 1227/2011 and (EU) 2019/942 to improve the Union's protection against market manipulation in the wholesale energy market**

{COM(2023) 147 final} - {COM(2023) 148 final}

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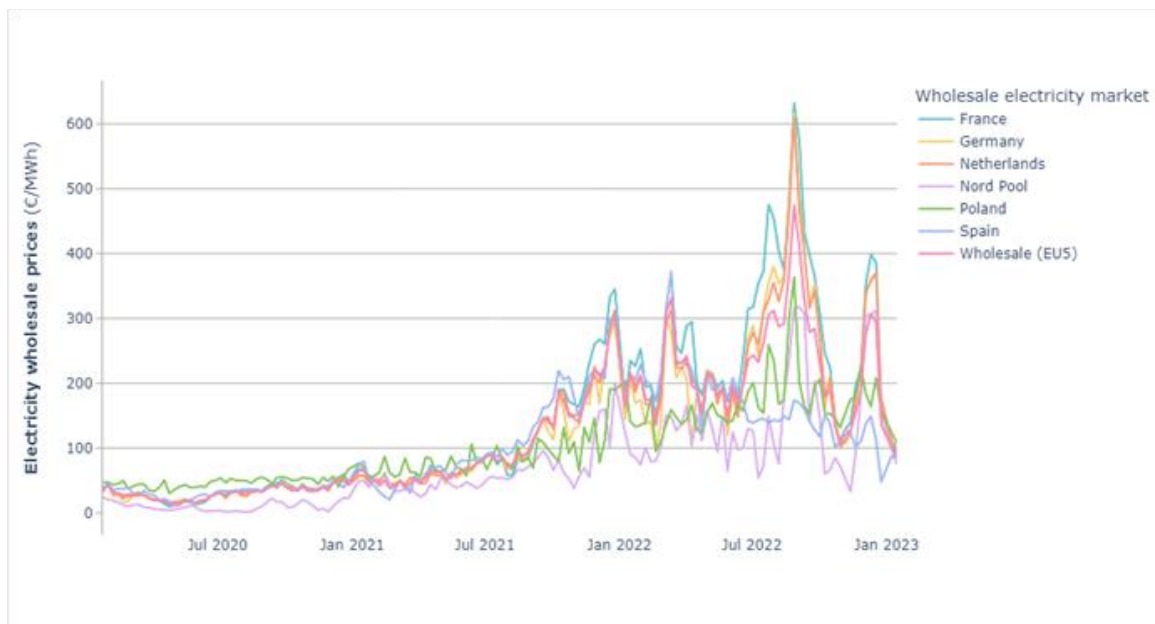
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# 1. Context

## 1.1. Recent energy crisis and European response

Over the last two years, energy prices have been significantly higher than in recent decades. Prices started rising rapidly in summer of 2021 when the world economy picked up after COVID-19 restrictions were eased. Subsequently, Russia’s invasion of Ukraine and its weaponisation of energy sources by withholding capacities from spot markets have led to substantially lower levels of gas delivery and increased disruptions of gas supply, further driving up the gas prices. High gas prices have an influence on the price of electricity from gas-fired power plants as they are often needed to satisfy electricity demand, as illustrated by *Figure 1* below.

*Figure 1: Evolution of the EU electricity wholesale prices (€/MWh) – weekly average*



Source: S&P Global Platts.

Note: Wholesale (EU5) stands for the weighted average of prices of main EU electricity markets (DE, ES, FR, NL) and Nordpool market (NO, DK, FI, SE, EE, LT, LV).

The Commission has been fully engaged since the beginning of the energy crisis to mitigate the effects of high-energy prices on European citizens and companies, and developed, closely with Member States, a series of policy responses at a remarkable pace.

As an immediate reaction to global dynamics and rising prices, the EU provided an **energy prices toolbox**<sup>1</sup> in October 2021 with measures to address high prices (including income support, tax breaks, gas saving and storage measures). This coincided with Russia’s manipulation of energy markets through intentional disruptions of gas flows which led not only to skyrocketing energy prices, but also endangered security of supply. To address this, the EU took swift action to diversify gas supplies and to accelerate energy efficiency and the deployment of renewable energy.

Following the Russian invasion of Ukraine in February 2022, the EU responded with the **REPowerEU plan**<sup>2</sup> on 18 May 2023 – a plan for the Union to rapidly end its dependence on Russian fossil fuels as soon as possible through 3 pillars: energy savings, diversification of energy supplies and accelerated roll-out of renewable energy to replace fossil fuels in homes, industry and power generation. The plan includes an increase from 9% to 13% of the binding Energy Efficiency Target under the ‘Fit for 55’ package of European Green Deal legislation, as energy savings are the quickest and cheapest way to address the energy crisis and reduce bills. With respect to this last pillar, the Commission proposed to increase the headline 2030 target for renewables from 40% to 45% under the “Fit for 55” package. Faster deployment of renewables and further electrification of demand are necessary for a definitive end to the current emergency as they will immediately and structurally reduce demand for fossil fuels and contribute to the decarbonisation objectives in the power, heating and cooling, industry and transport sectors. Due to the continuous improvement of their cost competitiveness, including their low operational costs, an accelerated renewables roll-out will have a positive impact on energy prices across the EU. Furthermore, the faster deployment of renewable energy, together with increased energy system integration, will contribute to fossil fuels phase-out, on which the EU has been highly dependent in the past, and will therefore support the security of energy supply.

To address dependence and to enhance energy security, the Union introduced a gas demand reduction target<sup>3</sup> in 2022, which has been exceeded this winter, as well as minimum filling obligations for gas storage<sup>4</sup>. The level of gas storage has been comfortable during this winter and all Member States are currently on track to meet their intermediate targets ahead of next winter.

In addition to the REPowerEU plan, the Council adopted on 6 October 2022 an **emergency intervention** to address high energy prices in the EU. The Council Regulation introduced common measures to reduce electricity demand and to collect and redistribute the energy sector's surplus

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<sup>1</sup> Communication from the Commission to the European Parliament, the European Council, the Council, the European Economic and Social Committee and the Committee of the Regions Tackling rising energy prices: a toolbox for action and support - COM/2021/660 final

<sup>2</sup> Commission Staff Working Document COM(2022)230 - <https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=COM%3A2022%3A230%3AFIN&qid=1653033742483>

<sup>3</sup> Council Regulation (EU) 2022/1369 of 5 August 2022 on coordinated demand-reduction measures for gas <https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX%3A32022R1369>

<sup>4</sup> Regulation (EU) 2022/1032 of the European Parliament and of the Council of 29 June 2022 amending Regulations (EU) 2017/1938 and (EC) No 715/2009 with regard to gas storage <https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=celex%3A32022R1032>

revenues to final customers. On 22 December 2022, the Council adopted a Regulation laying down a temporary framework to accelerate the deployment of renewable energy projects. The Council also reached an agreement on the operationalisation of the EU Energy Platform for gas purchase and on a temporary Market Correction Mechanism capping the gas prices.

The EU has also responded to the crisis with a **temporary State Aid regime** to allow certain subsidies to soften the impact of high prices, agreed and implemented a strong gas storage regime, price limiting measures to avoid windfall profits in the gas market and effective demand reduction measures for gas and electricity.

High energy prices have affected manufacturing costs for most sectors of the economy, in particular the energy-intensive industries. In parallel, the price of commodities has also increased. On 1 February 2023, the Commission issued the Communication<sup>5</sup> about “**A Green Deal Industrial Plan for Net-Zero Age**”, which put forward several measures to enhance the competitiveness of European industry and to support the accelerated transition to climate neutrality. The Plan aims to provide a more supportive environment for the scaling up of the EU's manufacturing capacity for the net-zero technologies and products required to meet Europe's ambitious climate targets. This Communication also included a chapter on energy which explains that “*the competitiveness of many companies has been severely weakened by high energy prices*”. It also highlights that “*long-term price contracts could play an important role to enable all electricity users to benefit from more predictable and lower costs of renewable power*”. The energy price crisis has shone a particular spotlight on EU electricity markets, the electricity generation mix in EU countries and the continuing influence of fossil-fuel generated electricity on energy bills, despite growing shares of renewable electricity. Long-term price contracts could serve not only the needs of electricity consumers in the EU, but also support the accelerated deployment of renewable energy necessary to meet our Green Deal objectives, the 2030 emissions and the 2050 net-zero target as set out in the European Climate Law<sup>6</sup>.

In its conclusions on 15 December 2022, the European Council invited the Commission to submit in early 2023 a proposal “*on the structural reform of the EU's electricity market, including on the effect of gas prices on electricity prices, making it fully fit for a decarbonised energy system and facilitating the uptake of renewable energy*”<sup>7</sup>. In parallel to the emergency proposals, the Commission therefore started working on proposals to reform the functioning of the electricity market.

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<sup>5</sup> COM(2023)62 [COM\\_2023\\_62\\_2\\_EN\\_ACT\\_A Green Deal Industrial Plan for the Net-Zero Age.pdf \(europa.eu\)](#)

<sup>6</sup> Regulation (EU) 2021/1119 of the European Parliament and of the Council of 30 June 2021 establishing the framework for achieving climate neutrality and amending Regulations (EC) No 401/2009 and (EU) 2018/1999 (‘European Climate Law’) <https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:32021R1119>

<sup>7</sup> <https://www.consilium.europa.eu/media/60872/2022-12-15-euco-conclusions-en.pdf>

This Staff Working Document sets out the explanation and rationale behind the Commission's proposals for a structural response to the high energy prices experienced by households and businesses and to ensure secure, clean and affordable energy for households and businesses into the future. The Commission aims to create a buffer between short-term electricity markets and the impact on consumer bills, while at the same time improving the functioning and oversight of those markets. This will protect consumers, stabilise prices, and ensure that the lower cost of renewable electricity is better reflected in electricity bills. Moreover, a renewable based energy system will be crucial to ensure an affordable, sustainable and independent energy supply and these proposed reforms aim to provide long-term price signals to boost the deployment of renewable energy through improvements to the regulatory framework.

This reform, if adopted, will benefit not just household consumers but all energy end-users and will also enhance the competitiveness of Europe's clean energy industries. The energy transition in Europe needs to be supported by a strong clean technology manufacturing basis. These proposed reforms support the affordable electrification of industry and Europe's position as a global leader in terms of research and innovation in clean energy technologies.

The proposed reform will be subject to ordinary co-legislative procedure.

## ***1.2. Electricity markets in Europe***

- *State-of-Play*

A well-integrated and interconnected EU energy market is the most cost-effective way to ensure secure and affordable energy supplies to EU citizens and companies. Through common energy market rules and cross-border infrastructure, energy can be produced in one EU country and delivered to consumers in another. This keeps prices in check by creating competition and allowing consumers to choose energy suppliers.

The EU electricity market is the result of successive packages of legislation and reforms adjusted to changes in market developments and to take advantage of technological development. The most recent changes came as part of the Clean Energy for All Europeans<sup>8</sup> legislative Package, which was designed to deliver on the EU's Paris Agreement commitments for reducing greenhouse gas emissions and to make the EU electricity market fit for the clean energy transition. The Clean Energy Package contains revised rules to support the integration of a greater share of renewables and new technologies, by ensuring a level playing field and greater flexibility. It has also enabled the emergence of new and innovative products and measures on retail electricity markets – supporting energy efficiency and renewable uptake and helping consumers to have more control over their energy bills through emerging services for providing demand response. Furthermore, these rules build on the increasing digitalisation of the energy system, enabling enhanced

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<sup>8</sup> [https://energy.ec.europa.eu/topics/energy-strategy/clean-energy-all-europeans-package\\_en](https://energy.ec.europa.eu/topics/energy-strategy/clean-energy-all-europeans-package_en)

flexibility through active participation by consumers, which will remain a key element of future electricity markets and systems.

The current electricity market design has delivered well over the years, allowing Europe to reap the economic benefits of a single energy market under normal market circumstances, ensuring security of supply, increasing socio-economic welfare and supporting the decarbonisation process. Cross-border interconnectivity also ensures safer, more reliable and efficient operation of the power system. Over the past years, before the global energy crisis, Member States benefitted from lower electricity prices thanks to the single market delivering cheaper electricity across Europe, increasingly from renewable sources.

In its report published in April 2022 ACER has estimated that the average yearly gain from the integrated electricity market for European consumers is about EUR 34 billion per year<sup>1</sup>. These benefits can be illustrated by enhanced security of supply as a result of cross-border energy exchanges, the optimisation of electricity production to prioritise the least costly technologies across Europe and price competition between all technologies including renewables, flexibility demand response and storage.

- *The merit-order system's contribution to decarbonisation and security of supply*

Given the overarching objective of decarbonisation and the role that fossil fuel technologies still play in the EU electricity system and in influencing the price of electricity, particularly in the short-term markets, it is useful to clarify why the merit-order approach remains fit for purpose for these markets. The EU electricity market is based on a model that keeps the overall cost of the electricity system as low as possible for consumer. Generators are incentivised to reduce costs and bid as cheaply as possible into the market to ensure they are dispatched. Generators bid into the market based on their marginal costs (how much it costs them to run for a given timeframe). This creates a stack of bids that are then ranked from lowest to highest (the so-called “merit order”). The market price is the price of the last producer needed to meet the demand for the given timeframe. All producers who bid below that price are selected and receive that price. The producers bidding above that price are not selected. The market price makes it possible for the generator to cover the cost of fuel (e.g. gas) as well as the cost of investment production capacity (e.g. wind farm).

This model supports decarbonisation because renewables are cheap to run and therefore always dispatched by the market. Even small renewables producers without sophisticated bidding capabilities receive the market price. It also incentivises flexibility because reducing energy use or using energy storage is often cheaper than running a fossil fuel power plant so a demand response or stored energy bid is prioritised over a fossil fuel generator. It is more transparent because it mitigates the effect of information asymmetry and reveals generators' true costs, also improving competition by providing information for new business models.



In addition, the EU market integration is uniquely positioned to respond to short-term security of supply issues. If demand is higher in a certain country (e.g. during a cold spell or an unplanned outage), then the higher price naturally attracts imports from the surrounding neighbours for the hours needed. The longer-term benefits for security of supply are also evident as the integrated market enables the sharing of generation and reserves, making the system more flexible and overall less expensive for consumers.<sup>9</sup>

When considering any reforms to the market design, it is important to bear these elements in mind as European consumers expect that the electricity system will continue to function reliably as we electrify the economy and decarbonise our energy system. Current market rules can stimulate a competitive and innovative energy sector, encouraging new technologies and ways of operating the system to integrate more renewable energy and reach the net-zero target.

- *Expected evolution of the market*

According to the European Commission Staff Working Document implementing the REPowerEU plan<sup>10</sup>, 592 GW of solar PV capacity and 510 GW of wind capacity are required by 2030 to achieve the 69% share of renewable electricity modelled by the Commission. This requires average annual additions of 48 GW for solar PV and 36 GW for wind.

Looking at the recent pace of RES investments - see

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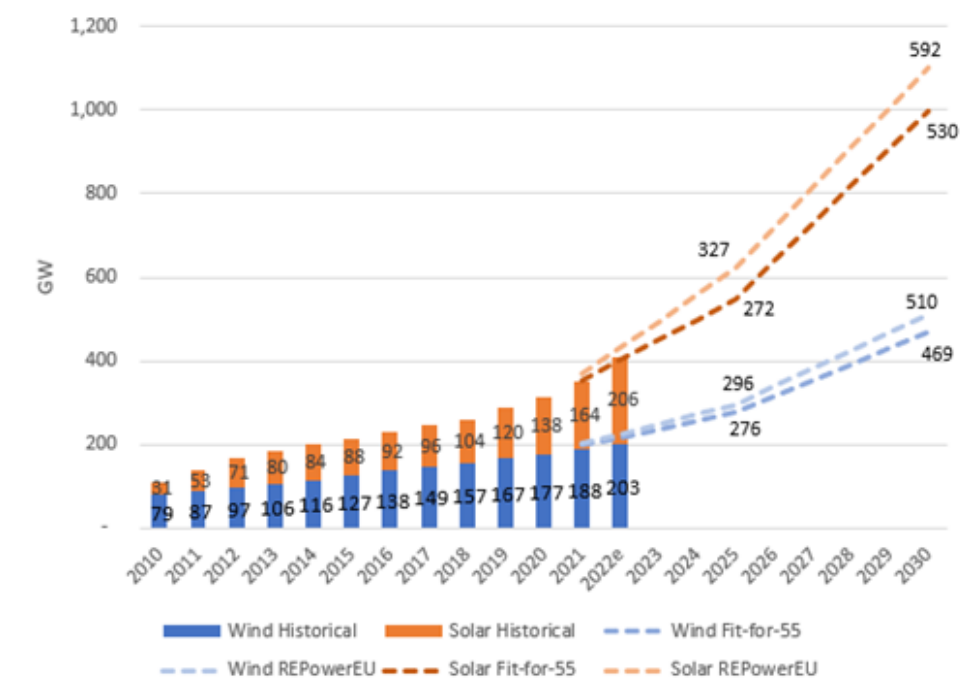
<sup>9</sup> This aspect was highlighted in a 2016 IEA country review of France.

[https://iea.blob.core.windows.net/assets/2264b835-3acb-4816-adb7-893d7b6d3696/Energy\\_Policies\\_of\\_IEA\\_Countries\\_France\\_2016\\_Review.pdf](https://iea.blob.core.windows.net/assets/2264b835-3acb-4816-adb7-893d7b6d3696/Energy_Policies_of_IEA_Countries_France_2016_Review.pdf)

<sup>10</sup> Commission Staff Working Document COM(2022)230 <https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:52022SC0230&from=EN>

Figure 2 below, a significant acceleration of the roll-out of renewable energy will be required over the coming years to meet the decarbonisation objectives. This presents an opportunity for the EU to foster greater energy independence from imported fossil fuels. Through targeted changes to support the evolution of the market design, there is also an opportunity for greater independence for consumer bills from short-term markets, where prices are heavily influenced by fossil-fuel generated electricity.

Figure 2: volume of RES installed capacity in EU, and projection of RES to reach "Fit-for-55" and "REPowerEU" targets



Source: Eurostat (NRG\_INF\_EPCRW), Wind Europe, Solarpower, PRIMES for years 2025 and 2030 (linearly interpolated in between)

To quantify the effect of gas-fired generation on electricity prices, DG Energy and the European Commission’s Joint Research Centre (JRC) applied the METIS power system model to simulate the hourly dispatch of the European power system for the years 2022 and 2030<sup>11</sup>. The results show that, of all fossil fuels, natural gas was the most significant price setter for electricity in 2022. Moreover, the share of hours in which fossil fuels set the price exceeded the share that these technologies have in electricity generation.

Adding more renewable generation to the fuel mix will eventually moderate this effect<sup>12</sup>. By 2030, renewable sources are expected to provide more than two thirds of the EU’s electricity. However, fossil fuels are expected to still set electricity prices during a significant number of hours. Therefore, it is important to accelerate the uptake of demand response solutions that reduce

<sup>11</sup> Upcoming JRC report. The objective of this analysis is to identify the number of hours in which gas fired and other fossil-fired generation technologies are setting the electricity price. The analysis considers the spill over of prices across borders as gas fired generation can also influence electricity prices in neighbouring price zones. The model was tested against overall electricity statistics reported for the year 2022. It does not, however represent a full reanalysis of all electricity markets, given the conceptual approach of the model and since as many parameters necessary for this purpose are not reported. The power system of 2022 is represented by the installed capacities and by commodity prices, as reported. For the year 2030, the model represents the assumptions also made for the policy scenarios for delivering the European Green Deal.

<sup>12</sup> For Member States which have decided to invest in nuclear energy, this technology can have a similar effect.

consumption and hence prices in peaks by reducing the role of gas. Also, accelerating investment in storage will help to keep prices at check. Further results of the assessment by DG Energy and JRC on price-setting technologies in Europe are to be published in a JRC report.

The findings of this analysis demonstrate that a certain amount of fossil fuel technologies will still be needed for system operation and meeting electricity demand in 2030. However, this does not mean that consumers should be fully exposed to these prices on their electricity bills. By ensuring a faster rollout of renewables, that more flexibility can enter the market in competition with fossil fuel technologies and that more electricity is sold on a long-term basis, it will be possible to phase out fossil fuels more quickly and to create a buffer between consumers and short-term markets. For Member State which have decided to rely on nuclear energy as part of their generation mix, this technology and the related investments can also play a role in this respect.

### ***1.3. Areas for improvement in electricity market design highlighted by the energy crisis***

There has been a strong focus in recent years on integrating national markets and ensuring that the EU's cross-border, short-term markets are efficient, support security of supply and the integration of renewables. This has been achieved through introducing market coupling whereby the entire EU electricity system is dispatched in an optimal way with electricity flowing to those markets that need it most. It is therefore essential that Member States continue to implement the existing legislation fully in order to deliver the efficiency, emissions reductions and flexibility potential with the existing generation fleet. Indeed, existing legislation also provides for the protection and empowerment of consumers and the enablers to unlock the flexibility in the system, meaning that its full transposition and implementation is the foundation for a more consumer-centric electricity market.

However, it is important to acknowledge that, although the current market design has over many years delivered an efficient, well integrated market, the energy crisis has highlighted a number of shortcomings, which the reforms proposed by the Commission aim to address. The energy crisis has highlighted the following issues in the current EU electricity market design:

- The sharp increase in natural gas prices observed since Autumn 2021 has strongly influenced wholesale electricity prices. This is due to the fact that, in many hours, gas-fired generation is needed to meet electricity demand and therefore often remains the price setting technology in the electricity market, even though clean energy sources, which have low marginal costs, represent an increasingly larger share of power generation.
- The current regulatory framework regarding long-term instruments has proven insufficient to protect large industrial consumers, SMEs and households from excessive volatility and higher energy bills. Whilst short-term price spikes can in genu emission

- eral incentivise consumers to reduce or shift their demand, sustained high prices over a longer period have translated into unaffordable bills for many consumers and companies.
- As the revenues from many inframarginal generators, who are not subject to any scheme that imposed a revenue ceiling, are dependent on the short-term market prices determined by the marginal pricing system, the crisis has led to unexpectedly higher commercial returns for inframarginal generators while, in parallel, end-consumers were suffering from high prices.
- The extreme price volatility and short-term emergency interventions may undermine investment signals and future investment appetite, which may put at risk the achievement of the EU decarbonisation objectives. At the same time, investments in decarbonisation and green technologies need to be accelerated for the EU to meet its ambitious Green Deal objectives. With rapidly increasing shares of wind and solar in the electricity mix, investments in flexibility, firm generation capacity and storage must also be accelerated. They should go hand in hand with investments in the electricity grid, which will also be needed to cope with new system challenges, such as higher electrification of demand, distributed energy sources, fast demand response, less predictable electricity flows with intermittent generation patterns.
- Short-term markets are needed to ensure an efficient dispatch of all resources, maximising renewables generation. Although these markets have delivered the objective of ordering the different electricity sources efficiently and pricing scarcity, the integration of flexibility sources such as storage or demand response is not happening at the speed and scale needed. Prices signals are necessary to orient the consumption or generation at the right time and place, especially with further electrification of the demand and increasing investment in renewables. Further incentivising investments in flexibility as well as delivering correct price signals will drive the generation and consumption at the right time of the day and in the right location within Europe.
- Retail markets need to further protect and empower consumers. The energy poor and vulnerable customers have been hit hardest by price increases. If consumers had been better able to access renewable energy or provide demand response, they would not have been impacted as much during this crisis as well as helped alleviate the impact of high gas prices. At the same time many suppliers effectively passed on the risks from wholesale markets to customers – as fixed price contracts were removed from the market. Despite the Clean Energy Package, too often practice in relation to electricity markets continues to be based on the old generation-led paradigm. Instead of active customers choosing energy efficient and renewable based energy solutions – they must take the price risk of gas-fired electricity. Demand response solutions find it difficult to participate either in wholesale markets or in providing grid support services to network operators. While the installation of decentralised renewable generation is booming – particularly among households, the full

benefits are not being fully realised. Wider energy sharing is not enabled and provisions on energy communities have only been spottily implemented so far. Active participation in the energy market is inaccessible to lower-income households.

- Finally, recent developments on the market and the experience of implementing Regulation (1227/2011) on Wholesale Energy Market Integrity and Transparency<sup>13</sup> “REMIT Regulation” over last decade have shown that REMIT and its implementing rules require an update to remain fit for purpose. The wholesale energy market design has evolved over the past years and not all data is effectively reported. The existing REMIT framework needs to be updated to tackle all new challenges, including enforcement and investigation in the context of new market realities.

The Commission has also observed that some provisions of the Clean Energy Package are not fully implemented across the Union. This is the case in particular for demand response and storage where an aggregator framework is still missing in the majority of Member States and non-discriminatory access to all electricity markets is not ensured. Furthermore, the ongoing bidding zone review is investigating whether alternative configurations could lower system costs and increase economic efficiency and cross-zonal trade opportunities. It is also crucial that the provisions on streamlined permitting are rapidly implemented both for renewables and trans-European networks for energy (TEN-E). The full implementation of existing legislation will be crucial to enabling the energy transition at least cost to all.

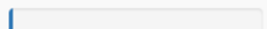
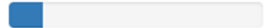
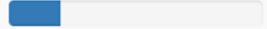
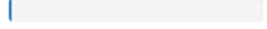

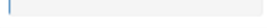
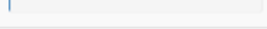
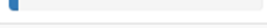
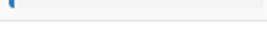
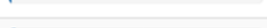
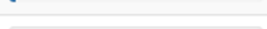

#### ***1.4. Public consultation on Electricity Market Design***

To support its work on the proposals to improve the functioning of the electricity market, the European Commission launched a public consultation about the reform of the electricity market design on 23<sup>rd</sup> January 2023. The European Commission received 1369 contributions to the public consultation. This includes among others a large number of citizens (725), companies (277), business associations (181) and NGOs (53).

*Table 1: Overview of the contributions received, by type of respondent*

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<sup>13</sup> Regulation (EU) No 1227/2011 of the European Parliament and of the Council of 25 October 2011 on wholesale energy market integrity and transparency <https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX%3A32011R1227>

		Answers	Ratio
Academic/research institution		25	1.83 %
Business association		181	13.22 %
Company/business		277	20.23 %
Consumer organisation		18	1.31 %
EU citizen		725	52.96 %
Environmental organisation		4	0.29 %
Non-EU citizen		7	0.51 %
Non-governmental organisation (NGO)		53	3.87 %
Public authority		27	1.97 %
Trade union		15	1.10 %
Other		37	2.70 %
No Answer		0	0.00 %

The majority of *companies and business associations* expressed support for market-based mechanisms and explained the need to keep market price signals in place to avoid distortions.

Several *NGOs* expressed the need for support for RES investments, as a massive RES rollout is needed in the coming years to meet EU decarbonisation ambitions. In their view, this could be achieved by supporting the development of PPAs or CfDs for example.

Most contributions from *individual citizens*, besides the coordinated campaign from Slovakia<sup>14</sup>, came from France and Germany. Additional responses came from Austria, Belgium, Czechia, Slovakia, Sweden.

- Citizens expressed diverging views and for many questions, the share of “no answer” responses is significantly higher than for other stakeholders.
- The clearest conclusion is that a broad majority of responding citizens consider the use of PPAs, CfDs and forward hedging as efficient ways to mitigate the impact of short-term markets on the price of electricity paid by private and industrial consumers and to support investments in new capacity. Only a small minority of respondents did not answer these questions.
- For all other questions, the share of “no answer” is rather high or no clear preference can be identified.

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<sup>14</sup> See Annex for details

The Commission also held a stakeholder workshop on 15 February 2023 to gather views on the public consultation. Overall, there were over 70 participants, representing NRAs, industry, environmental NGOs, academia, and business representatives.

In light of the above, the Commission has prepared several proposals to ensure that consumers – both households and companies – can access affordable and secure energy from sustainable and renewable sources both now and in the long term. The Commission recognises that market arrangements are needed to support these objectives, and where necessary, that they should be adjusted and improved to do so in line with the rapid increase of renewables in the electricity mix. The present document sets out these proposals which aim at delivering a more resilient electricity market for Europe. The present document aims at supporting the Commission proposals around the following topics:

- Making Electricity Bills More Independent from the Short-Term Cost of Fossil Fuels
- Driving Renewable Investments
- Alternatives to Gas to Keep the Electricity System in Balance
- Lessons Learned from Short Term Market Interventions
- Better Consumer Empowerment and Protection
- Stronger Protection against Market Manipulation



## 2. Making Electricity Bills Less Dependent on the price of Fossil Fuels

### Feedback from public consultation

Many respondents explained that short term markets need to be complemented by longer term price signals, as the ones put in consultation by the Commission: CfDs, PPAs, forward markets. The majority of respondents to the consultation found that CfDs, PPAs and forwards were an effective way to mitigate short-term market fluctuations in electricity prices and to support investment in new capacity. These instruments are complementary and the right equilibrium between the different tools should be found. For instance, respondents warned about potential cannibalisation risk of the forward market by PPA and CfDs, as a roll-out of PPAs and CfDs may reduce liquidity in the financial forward market.

The majority of respondents explained that there should not be a mandatory scheme, and that the freedom of choosing the relevant contracts should be maintained. Overall feedback is that the liquidity on forward markets is insufficient, CfDs could lead to price regulation, and PPAs would benefit from standardisation and more transparency.

The energy crisis has highlighted the fact that consumers are exposed to electricity price volatility, and the need to introduce reforms to allow consumers to benefit from greater price stability. The Communication<sup>15</sup> about “A Green Deal Industrial Plan for Net-Zero Age” also highlights that “*long-term price contracts could play an important role to enable all electricity users to benefit from more predictable and lower costs of renewable power*”.

As explained above, recent high electricity prices in the short-term markets stem from the influence of high prices for natural gas and other fossil fuels. More investment in renewables is therefore needed because, when these dominate the electricity mix and energy bills are less dependent on short-term markets, it means not only that less fossil fuel generation is needed, but it also leads to lower prices for consumers due to the low operational costs of renewable energies. For Member States that have decided to rely on nuclear energy, the relevant investments can meet a similar objective. All routes to market should remain open for investments in low-carbon generation capacities, and in particular renewables, to ensure that we can achieve the speed and scale of deployment needed. The benefits of these low carbon sources can be brought to consumers by ensuring that long-term markets and contracts with stable prices increasingly constitute a larger share of the energy component of the final electricity bill. This can be achieved in several ways:

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<sup>15</sup> COM(2023)62 [COM\\_2023\\_62\\_2\\_EN\\_ACT\\_A Green Deal Industrial Plan for the Net-Zero Age.pdf \(europa.eu\)](#)

1. Companies can contract directly over the long-term with power producers. The present reform aims at supporting the development of the **Power Purchase Agreement (PPA)** markets, which are private contracts between producer and consumer over the long-term (typically 5 to 10 years and up to 20 years in the current practice).
2. Member States can contract over the long-term on behalf of consumers. The present reform aims at clarifying ways for Member States to support the roll-out of renewable and low-carbon generation by ensuring predictability of revenues for new investments through **two-way Contracts-for-Difference (CfDs)** (typically more than 10 years). This type of contract brings greater price stability to consumers because revenues collected by the Member States when market prices are above the contracted price will revert to the consumers, and vice versa.
3. Improving the functioning of the **forward market** (up to 3 years ahead) to give consumers and suppliers the ability to correctly cover their price exposure. A well-functioning forward market will incentive the development of fixed-price contracts with consumers, thereby bringing greater price stability to the final consumers.
4. Enabling consumers to contract directly with renewable energy sources through **energy sharing**. The present reform aims to enable energy sharing between active customers to give a wider group of consumers the opportunity to hedge against volatile wholesale market prices and control their energy bills.

Another way to bring the benefits of low-cost renewables to the consumers would be to introduce **more locational granularity** in market prices. This is discussed further in section 8.2 below.

### **2.1. Supporting the Power Purchase Agreement (PPA) market**

#### **Feedback from public consultation**

Overall, stakeholders generally see the use of Power Purchase Agreements (PPAs) as an effective way to mitigate short-term market fluctuations in electricity prices and identified several measures to strengthen their uptake. However, there are also potential risks and challenges that need to be carefully considered.

The use of PPAs is widely considered an **effective way** to mitigate the impact of short-term market fluctuations on electricity prices paid by the consumers, including industrial consumers, according to a large majority of stakeholders in the energy sector. These stakeholders include national or local administrations, regulators, market operators, energy companies, independent energy suppliers, industrial consumers and associations, energy communities, academia and think tanks, citizens, and NGOs. The majority of stakeholders identified supporting

standardisation of contracts, pooling demand, and providing insurance against risks, either market driven or through publicly supported guarantee schemes, as effective measures to strengthen the roll-out of PPAs.

Some stakeholders, mainly energy professionals, also identified other *ways to strengthen the use of PPAs* for new private investments, such as improving access to finance and facilitating cross-border PPAs. However, there were mixed responses from stakeholders on whether stronger incentives should be provided to existing generators to enter into PPAs for a share of their capacity, with potential benefits including lower costs in the short term, and challenges such as market distortion, higher costs in the longer term and potential conflicts with existing contractual obligations.

The majority of stakeholders did not consider that stronger *obligations on suppliers* and/or large final customers to hedge their portfolio using long-term contracts would contribute to a better uptake of PPAs. However, opinions were mixed among companies in the energy sector and energy communities.

Some stakeholders also identified potential *risks* associated with increasing the uptake of PPAs, including reduced liquidity in short-term markets, an unequal level playing field between undertakings of different sizes or located in different Member States, and increased costs for consumers. However, a majority of stakeholders did not consider increasing the uptake of PPAs would entail risks as regards increased electricity generation based on fossil fuels.

- *Introduction*

A Power Purchase Agreement (PPA) is a commercial long-term contract (usually between 5 and 10 years, up to even 20 years in the current practice) between a generator and a buyer, whereby the latter purchases a specific volume of electricity from the former at a predetermined price over a certain period<sup>16</sup> providing price certainty over the long-term for energy consumers. PPAs provide the main alternative to public support schemes for renewable energy generation projects.

For project promoters, a key benefit of PPAs is the predictability and long-term stability of price and cash flows they provide. This allows PPAs to serve as collateral in the financing of new projects, including renewable energy projects. Through a PPA, the buyer enjoys access to power generation to meet its electricity demand at a fixed price over the long term and thus a hedge against price uncertainty. This can significantly strengthen the competitiveness of industrial off-takers. In most cases, as a result of a renewable PPA, the off-taker will also receive the related guarantees of origin which is often an additional motivation to enter into a PPA. Private off-takers

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<sup>16</sup> The buyer in a PPA is normally a private company. Nevertheless, public entities can also procure electricity for their own consumption from renewable energy generators through PPAs.

use renewables PPAs as credible instruments to demonstrate their adherence to sustainability criteria in their energy consumption. Finally, from the point of view of governments, PPAs offer an alternative avenue to foster the deployment of renewables towards their targets or commitments, without committing public funds.

- *State of play*

On the back of the continuing cost decreases of renewable energies, the overall volume of renewables PPAs in Europe (including the UK or Norway) has increased exponentially since crossing the 1 GW threshold in 2016. After reaching 8 GW in 2021, early data for 2022 indicate a first-ever drop in the volume of such deals (to below 7 GW). An initial assessment suggests that this change of trend may have resulted from a number of mixed signals: increased price volatility, uncertainty about future price levels, inflation and increased prices of raw materials. These factors have made the agreement on the price more complex, while also increasing the attractiveness for generators of selling on the short-term market. Regulatory initiatives to address the environment of high electricity prices have also contributed to uncertainty.

Until 2021, the growth of PPAs was largely attributable to a small group of companies in the information technology sector. The 2022 data shows a noticeable increase in interest for PPAs by the industry energy-intensive sector<sup>17</sup>. Nevertheless, the market remains accessible only for large credit-worthy companies.

In terms of geographic distribution, the use of PPAs is still limited to a core group of Member States: so far only in five of them more than 1 GW of cumulated deals have been reported<sup>18</sup> and more than 20 GW in the EU as a whole. In this regard, 2022 has brought new interest, with deals now reported in half of the Member States<sup>19</sup>.

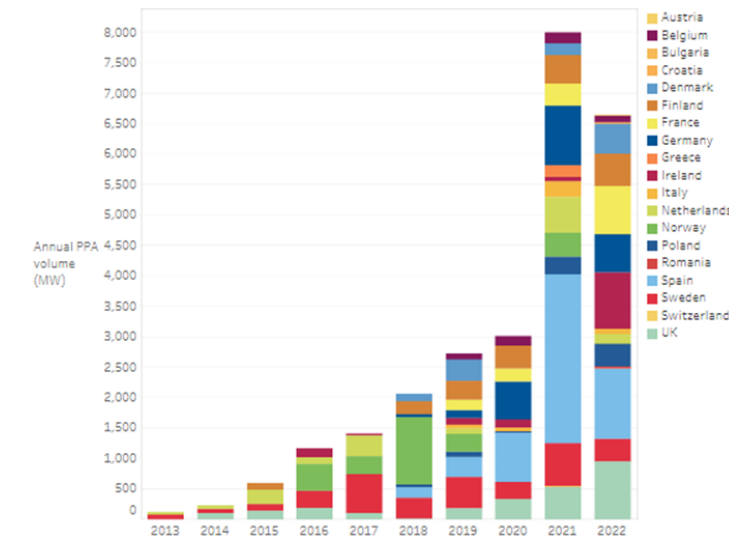
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<sup>17</sup> Re-source platform

<sup>18</sup> Spain, Finland, Denmark, Sweden and Germany - Re-source platform

<sup>19</sup> Re-source platform

Figure 3: Evolution of the PPA market in Europe



Source: Windeurope Intelligence platform

A PPA market study<sup>20</sup> for the European Investment Bank estimated the aggregated volume of PPAs required by renewable energy promoters in the EU to range between 140 TWh and 480 TWh by 2030, the higher figure being equivalent to 170 GW of capacity (8.5 times above the current PPA level) and to 23% of solar and wind generation by 2030. The study adds a second demand estimation based on the EU’s renewable hydrogen policies presented in 2022, leading to a range of between 360 TWh and 980 TWh by 2030.

In other words, the EU PPA market is gradually expanding to new countries and sectors and the market estimates dynamic growth. Nevertheless, this market remains far from its full potential due to a range of obstacles and barriers.

○ *Obstacles and barriers*

There is a significantly differentiated development of PPAs in the EU. One of the main obstacles that prevents a PPA market from flourishing are price risks linked to the uncertainty of future electricity price developments and the long duration of the contract. Before the crisis, many off-takers expected the electricity prices to fall, which reduced the attractiveness of a long-term lock-in of a stable price. Many potential off-takers are not aware of the advantages of a PPA, which remains a relatively new offer. Since the PPA market is still in its early years, contracts are not standardised yet, leading to high transaction costs, limited liquidity and limited availability of

<sup>20</sup> Commercial Power Purchase Agreements. A Market Study including an assessment of potential financial instruments to support renewable energy Commercial Power Purchase Agreements. Final report prepared by Baringa, March 2022

PPAs of different sizes and durations, in particular shorter-term contracts (as from 3-year maturity). When the off-taker requests a generation profile fully adapted to its consumption needs, it adds an additional layer of complexity. Furthermore, in many Member States renewable energy developers have opted for stable revenues from public support schemes providing often a 100% protection from market risks over the long-term (longer than 10 years). Long permitting procedures have also hampered the availability of new projects and thus the development of the PPA market.

Another particular problem with signing PPA contracts is the difficulty of establishing the credit worthiness of potential buyers. For developers, finding a client with a strong credit rating is often a requirement to secure financing for a renewable energy project on the back of a PPA. However, in some Member States, many entities with an appropriate energy footprint for PPAs are not rated by any major ratings agency, even if they do not experience financial difficulties. For off-takers, the main obstacle is to find PPAs that match their consumption profile and the length of their business cycle. The variability of the generation from renewable installations leads to additional complexity and costs in managing volume imbalances through an energy provider or in the spot market. Finally, the PPA market has not been available to small- and medium size enterprises mainly for two reasons: 1) the limited electricity consumption of a SME requires a multi-buyer or aggregated PPA to make an interesting offer to a project developer, and 2) the signing of a PPA still represents a complex deal entailing high transaction costs and requiring energy management expertise.

There are also some regulatory barriers hampering PPAs at national level, such as obstacles to the signature of direct contracts between generators and off-takers. In some cases, the issuance of Guarantees of Origin requested by the off-taker is hindered due to national legislation. In most Member States, with some clear exceptions, there has also been limited attention given to the promotion of PPAs, building policies to promote renewable energy generation projects on public support schemes. If the pipeline of renewable energy is constrained by political or administrative factors and the government issues renewable energy auctions commensurate with its total decarbonisation ambitions, the result can be a situation where most or all projects receive public support. This is why it is crucial that, in order to send a clear medium-term signal to the PPA market, Member States take into account the potential for PPAs to cover part of their decarbonisation objectives, as spelled out in their National Energy and Climate Plans, and plan their public support auctions accordingly.

- *Current EU framework*

The 2018 Renewable Energy Directive contains a definition of renewables PPAs and mandates Member States to assess the related “regulatory and administrative barriers” and remove them, if unjustified, while ensuring that PPAs are not “subject to disproportionate or discriminatory procedures or charges”. The 2021 proposal to revise the Directive introduced amendments on renewables PPAs, including the need for Member States to explore credit guarantees to promote

renewables PPAs and to ensure that the generator can transfer the related Guarantees of Origin to the buyer.

Finally, the same Directive mandates the inclusion of “policies and measures facilitating the uptake” of renewables PPAs in the National Energy and Climate Plans (NECPs). Only some Member States have clearly signalled what share of the targeted deployment they expect PPAs to cover. The 2021 proposal to amend the Directive inserts a reference to renewables PPAs as an instrument to achieve the Member States’ contribution to the EU renewable energy target, alongside public support and mandates Member States to provide in their NECPs “an indication of the volume of renewable power generation supported by” renewables PPAs.

The Electricity Market Regulation, on the other hand, does not explicitly refer to PPAs but ensures that “long-term electricity supply contracts” can be negotiated “over the counter” in order to “allow market participants to be protected against price volatility risks on a market basis, and mitigate uncertainty on future returns on investment.”

EU legislation therefore recognises PPAs, including renewables PPAs, as private commercial bilateral agreements that are compatible and complementary with organised short-term and long-term markets. In addition, the legislation aims at establishing a level playing field for renewables PPAs in achieving the EU’s renewable energy targets, alongside public support and merchant investments.

Beyond legislative texts, the Commission adopted in May 2022, as part of the REPowerEU package, a recommendation to Member States to promote renewables PPAs, accompanied by a guidance<sup>21</sup>.

A higher volume of PPAs will contribute to the achievement of the EU 2030 target for renewables without the need for public support. PPAs can also contribute to transfer the benefits of low-cost renewables to consumers and provide them with stable prices. Although it can be expected that, based on the current legislative framework, PPAs will become gradually more popular across the EU, their promotion through regulatory means is justified in view of the significant environmental, economic and social benefits stemming from the accelerated and wide-spread development of the PPA market.

- *Commission proposals*

The proposed amendment to the Electricity Regulation therefore builds on existing legislation and guidance to ensure that Member States create the conditions necessary for a bigger PPA market to

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<sup>21</sup> Opinion of the European Economic and Social Committee on Communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee and the Committee of the Regions — EU Solar Energy Strategy (COM(2022) 221 final) and Commission recommendation on speeding up permit-granting procedures for renewable energy projects and facilitating Power Purchase Agreements (C(2022) 3219 final) <https://eur-lex.europa.eu/legal-content/EN/ALL/?uri=CELEX:52022AE3515>

develop. There is a range of policy instruments to address the current shortcomings in PPA markets across the EU, which can be used by Member States and enabled by EU legislation:

- The risks associated with a payment default by the potential buyer remains a key obstacle for the signature of PPAs. National governments should ensure that all conditions are in place for the market to provide the required financial instruments to cover against such risks when the potential buyer has the necessary financial stability. Given the intrinsic difficulties associated with new markets, governments shall ensure that instruments, including guarantee schemes, are in place to unlock demand for PPAs from private operators that face difficulties in accessing the PPA market. Such guarantees can be designed in a way that do not constitute State aid.
- State aid for renewable generation and PPAs are perceived as two alternative channels to finance renewable electricity project, but they can also be complementary. Member States should ensure that bidders to public tenders are allowed to (and can in practice) reserve part of the project's generation for a market-based revenue stream, in particular one or several PPAs. Combining State aid and PPAs in a single project can facilitate the financing of new projects and reduce risk exposure. Going further, governments shall endeavour to use evaluation criteria in the public tender to incentivise the access to the PPA market for customers that face entry barriers. This instrument can be used either to kickstart a PPA market in Member States where it is lacking or to expand its reach to smaller operators where a PPA market is already in place.

Finally, PPAs can be expected to play a role in any obligation on electricity suppliers to hedge in order to protect consumers from possible supplier failures (see section on consumer protection and empowerment).

## 2.2. *Contracts for Difference (CfD) for new decarbonised investments*

### **Feedback from public consultation**

A large majority of professional respondents (70%) consider the *use of two-way CfDs as an efficient way* to mitigate the impact of short-term markets on the price of electricity and to support investments in new capacity, where investments are not forthcoming on a market basis.

Similarly, a majority of professional respondents (60%) consider that new publicly financed investments in inframarginal electricity generation should be supported by way of two-way contracts for differences or similar arrangements, as a means to mitigate electricity price spikes of consumers while ensuring a minimum revenue.



With regards to *scheme design*, most participants also consider that two-way CfDs schemes should not be mandatory, not be imposed retroactively, and should focus exclusively on new investments for which prices should be determined via competitive auctions or tenders.

When asked about *the risks* of requiring new publicly supported inframarginal capacity to be procured on the basis of two-way CfDs or similar arrangements, a majority of respondents (including national authorities<sup>22</sup>) cite the risk of distortion on short-term markets.

Other risks mentioned are: the impact on the development of PPAs and forward markets, budget risk for Member States when market prices decrease, termination risk when market prices are high, competition risk by favoring established or dominant technologies leading to non-optimal energy mix, risk of inefficient redistribution mechanism to consumers, risk that supported consumers would be less inclined to use demand management technologies, risk of ending up with a fragmented EU market if CfDs are not applied in an uniform way, risk of inappropriate energy mix, as opposed by market prices.

Most of these risks are associated with a poor design of two-way CfDs. When asked about the *design principles for two-way CfDs*, respondents suggest the following procurement principles and pay-out design:

- to decouple the payout from the dispatched volume;
- the payout to cover only partially the volume produced to leave exposure to market signals;
- the payout to be based on a proper reference price (possibly over a longer time period) to avoid inefficient trading behaviour;
- payout suspension in certain situations (e.g., negative prices);
- a price corridor as opposed to a fixed strike price;
- financial nature as opposed to contracts with physical delivery;
- accompanied by tools ensuring that generated volume is made available on the forward market;
- to be procured on a voluntary basis, as opposed to mandatory imposition of CfDs;
- to be procured by technology neutral tenders. Strike price should be defined as a result of a competitive process, not as a cost-plus regulation;
- to be shielded from potential intervention limiting producers revenues;

<sup>22</sup>

From CZ, DK, EE, FI, FR, HU, LT, MT, NL, ES

- two-way CfDs should comply with approved taxonomy criteria to avoid subsidising technologies which are not climate friendly.

Regarding **eligible technologies**, the majority of respondents answered that two-way CfDs should only be offered to new low-carbon inflexible capacity and only in case new investments are not forthcoming on market-based terms. They explained that flexible resources should remain exposed to price variations. Some respondents also cite non-competitive but promising technologies which the market is unable to deliver (such as immature renewables and innovative technologies). Most of them agreed that fossil energy sources should be excluded. Many respondents insisted on the **voluntary** nature of CfDs, as opposed to mandatory CfDs.

Some respondents explained that the **allocation** of CfD revenues should be a prerogative of each Member State, either to consumers (through levies) or to investments that facilitate the energy transition. Others recommended that the revenues should be channeled back to all consumers on an equal basis according to their electricity consumption. Yet some others suggested that the subsidy should not be proportional to the consumption but primarily allocated to the lowest-income households or used towards subsidising a minimum consumption for basic needs.

A wide majority of professional stakeholders (83%) oppose giving Member States the possibility to impose **two-way CfDs on existing generation capacity**. Furthermore, especially national regulators and market operators see high or very high risks that imposing regulated CfDs on existing generation capacity would mean locking in existing capacity at excessively high prices determined by the current crisis.

Only 31 respondents defined the appropriate terms and conditions for two-way CfDs for existing generation. These respondents – mainly French and Spanish<sup>23</sup> - advocate for price-regulation on existing assets. The French respondents explained that regulated two-way CfDs on existing generation should be limited to the specific case of existing nuclear fleet to avoid a dominant position and address competition issues.

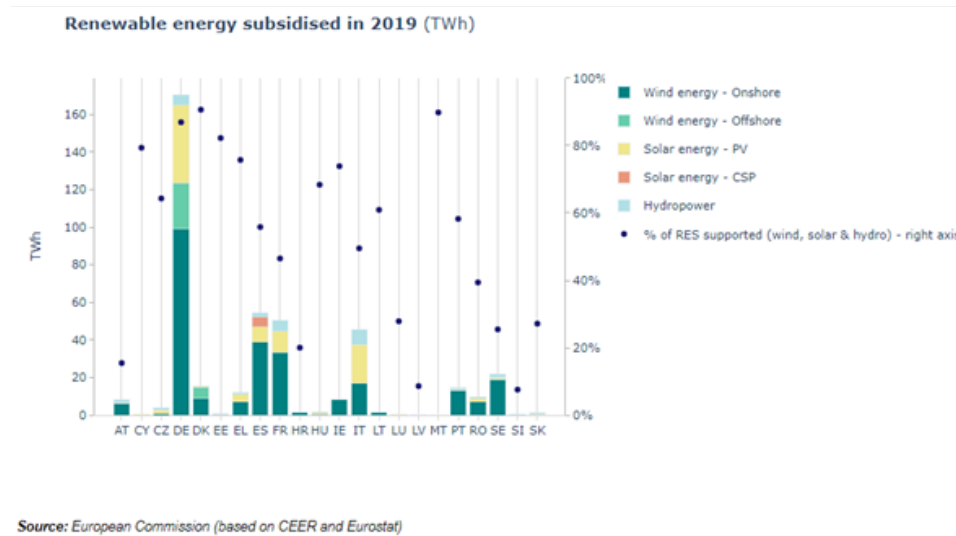
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<sup>23</sup> French authorities, Commission de régulation de l'énergie, RTE Réseau de Transport d'Électricité, EDF (Electricité de France), Parliamentary Group - La France Insoumise, France Chimie, MEDEF - Mouvement des entreprises de France (only for low carbon assets), CLEEE (Comité de Liaison des Entreprises ayant Exercé leur Eligibilité sur le marché de l'Electricité), French Fédération Forge Fonderie, French Verkor, French ERAMET, French VICAT, French SUD Energie, AFEP - The French Association of Large Companies, Association Française Indépendante de l'Electricité et du Gaz, Spanish Ministry for the Ecological Transition and the Demographic Challenge, Fenie Energía S.A., FORTIA ENERGÍA S.L, ASOCIACIÓN DE COMERCIALIZADORES DE ENERGÍA ELÉCTRICA (ACENEL), Asociación de Empresas con Gran Consumo de Energía - AEGE, Asociación Empresarial de Pilas, Baterías y Almacenamiento Energético

- *State-of-play*

The Council of European Energy Regulators (CEER) report<sup>24</sup> found that the volume of supported renewable electricity increased from 489 TWh in 2018 to 529 TWh in 2019 in the EU and in terms of installed capacity this increased from 257 GW in 2018 to 269 GW in 2019<sup>25</sup>. A large share of RES generation has therefore received State support - as illustrated by *Figure 4* below.

*Figure 4: Renewable electricity subsidised in 2019 (volume and %)*



Source: European Commission (based on CEER and Eurostat)

Source: European Commission, based on CEER 2021 Status Review of Renewable Support Schemes report

However, a significant and increasing volume of renewable production has also been brought to the market without receiving any State support in particular as regards onshore wind and solar PV. Furthermore, a study on offshore wind competitiveness<sup>26</sup> shows that the price paid for power from offshore wind farms across Northern Europe fell significantly over the past eight years. The study concludes that offshore wind power generation can be considered commercially competitive in mature markets.

In light of the above, it is important that long-term State contracts are a complement to other privately funded projects (such as for example the Mankala model in Finland). Therefore, Member

<sup>24</sup> CEER (2021) Status Review of Renewable Support Schemes in Europe for 2018 and 2019

<sup>25</sup> Data includes information for EU 27, excluding Poland, Finland and the Netherlands for which there was no complete information

<sup>26</sup> "Offshore wind competitiveness in mature markets without subsidy" - Malte Jansen, Iain Staffel, Lena Kitzing, Sylvain Quoilin, Edwin Wiggelinkhuizen, Bernard Bulder, Iegor Riepin and Felix Müsgens - <https://www.nature.com/articles/s41560-020-0661-2>

States should consider the significant potential for the PPA market (see above), alongside other market arrangements and public support.

When public support is needed to ensure predictability in operating revenues for new investments in fossil-free generation that would not come forward without support, the instrument used should be appropriately designed to be as least distortive as possible to ensure value for money for consumers. The Commission observes that a wide range of State support schemes co-exist, depending on the Member State<sup>27</sup>:

- **Feed-in tariffs (FITs):** FITs usually involve long-term agreements on fixed volumes and prices tied to the cost of production of the energy in question. This protects producers from risks inherent in renewable energy production both in relation to the volume and price and encourages investment and development that otherwise might not take place. FITs are usually differentiated by technology and size to reflect the different generation costs between the various renewable energy technologies. The support level of FITs is determined through administrative procedure, which can lead to overcompensation due to the risk of a long reaction time to respond to changes in renewable energy production costs. Also, FITs may disconnect the producer from market signals and incentivise production when not needed.
- **Fixed feed-in premiums (FIP)<sup>28</sup>:** A FIP allows producers to receive a premium on top of the market price for their electricity production, with electricity from renewable energy sources typically sold on the electricity spot market. Hereby, FIPs provide an incentive for RES operators to respond to price signals of the electricity market, resulting in a somewhat more responsive supply compared to FITs, also being more cost-efficient support schemes for the government to increase renewable energy installations. However, during the high price crisis, many installations benefiting from FIP, on top of high market prices, led to claims that they were accruing “windfall profits”.
- **Sliding feed-in-premiums also known as Contracts for Difference (‘CfD’):** A CfD entitles the beneficiary to a payment equal to the difference between a fixed ‘strike’ price and a reference price, such as a market price, per unit of output (also known as sliding premium). One-sided CfDs aims to guarantee a minimum price to the producer. This type of contract would therefore not address the challenge of excessive remuneration in a high price environment since there would be no limitation on the revenues. Two-way CfDs also

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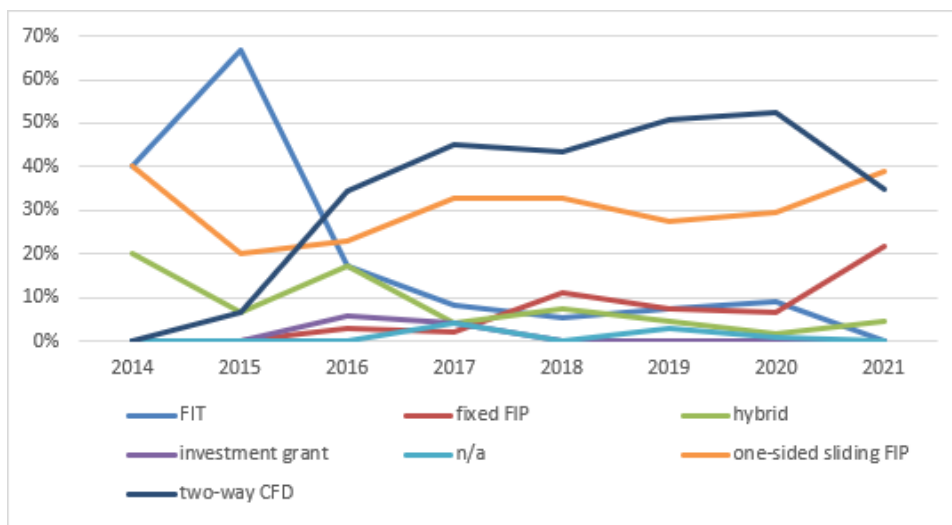
<sup>27</sup> Other support schemes are green certificates, investment grants, taxes or levies. These are not covered in the current Staff Working Document

<sup>28</sup> Fixed feed-in premiums (‘FIPs’) were introduced in several EU member states following the criteria laid down in the General Block Exemption Regulation from 2014 (‘GBER’)<sup>[1]</sup> and the State Aid Guidelines for Environmental Protection and Energy (‘EEAG’)<sup>[2]</sup>. There was a shift from FIT to a progressive mandatory use of FIP and competitive bidding.

involve payback from beneficiaries to the State for periods during which the reference price exceeds the strike price.

In recent years, there has been a move towards a greater use of two-way CfDs. *Figure 5* below shows the increase in the share of competitive procurements that utilise two-way CfDs. Such contracts provide new investments with revenue certainty, thereby reducing investors’ capital cost, while avoiding excessive returns for investors and overcompensation from Member States in periods when market prices are high. In other words, the State will be shielded from high market prices when the wholesale price is above the strike price, but will bear the financial cost when the market price is below the strike price. The reverse can be said for the renewable developer.

*Figure 5: Distribution of renewables auction per support scheme (2014-2021)*



*Source: European Commission analysis<sup>29</sup> based on Aures2 dataset*

The main advantage of two-way CfDs – when designed in an appropriate way – is to ensure stable revenues for the generators, while limiting excessive revenues in a high market prices environment, and they would at the same time also alleviate the pressure of high prices on consumer bills if the revenues are channeled back to consumers.

<sup>29</sup> The table is based on an analysis of 383 auctions between 2014-2021. The figure reports only concluded auctions. The data includes observations for the following countries Croatia, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Lithuania, Luxembourg, Malta, Netherlands, Poland, Slovenia, Spain. The data includes one observation per auction, regardless of the number of lots included in the auction (in the Aures2 dataset a number of auctions are multi-technology and include different entries per technology. We have treated all these entries as a single auction. Two auctions for Portugal have been excluded as it was unclear what was the remuneration scheme. The hybrid auctions included a mixture between sliding and fixed premiums.

To illustrate this point, at the height of the crisis in August 2022, France estimated that it would collect EUR 30.9 billion from renewable-power producers over two years<sup>30</sup>, as the energy crisis boosted wholesale price levels beyond the guaranteed revenues under the existing RES support scheme. The excess revenues collected ultimately benefit the end-consumers and thereby significantly reduce the impact of gas-fired power generation on the end-consumer bills.

On the other hand, existing FIP schemes that did not include a cap on revenues led to some Member States paying a premium to producers, on top of already high market prices.

To quantify the potential effect of CfDs, DG Energy applied the METIS power system model to simulate the potential revenues generated if 75% of new RES capacity would be subject to two-way CfDs as from 2023. The results estimate that such schemes would allow Member States to collect about [4.5-6 bn] EUR in 2023, [9-12bn] EUR in 2024, [13.5 – 18 bn] EUR in 2025 (and so on) to return to companies and households.

- *Design principles for two-way CfDs*

Several types of two-way CfDs are currently in place, with advantages and disadvantages, depending among others on how the reference price index and the reference volume are defined. When providing State support through CfDs, it is of utmost importance that these contracts are designed in a way that drives the required investments in renewables and other low-carbon generation cost-effectively while minimising market distortions and keeps the right incentives in place to respond to market price signals and optimise the dispatch of renewable electricity generation accordingly.

The *reference price* used to define the payment plays a significant role in potential behavioural distortions and inefficiencies of dispatch. When designed inappropriately, two-way CfDs risk inducing “produce and forget” behaviour – by incentivising production in all situations, even when prices are negative. To mitigate this issue, some Member States have included a discontinuation of the premium payment when spot prices are negative. However, such a mitigation clause – easily applicable in the single price day-ahead market - is difficult to apply in the intraday market or the imbalance market, since these timeframes are traded on a continuous basis with no single price signal representative for all market parties. To address the risk of market distortion, other Member States have delayed the publication of the CfDs premium<sup>31</sup> until after-market closure, in an attempt to restore normal bidding behaviour. Respondents to the public consultation also explained that a

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<sup>30</sup> Délibération de la CRE du 3/11/2022 relatives aux charges de service public de l'énergie (CSPE) : <https://www.cre.fr/Documents/Deliberations/Decision/reevaluation-des-charges-de-service-public-de-l-energie-pour-2023>

<sup>31</sup> For example by using the effective Day-Ahead prices as reference (which are known only ex-post after the bidding in the Day-Ahead Market), as opposed to using ex-ante reference prices based on historical averages

price corridor, rather than a fixed strike price, would help incentivise producers to react to short-term supply and demand fluctuations.

In a similar way, the *reference volume* used to define the two-way CfDs payout also plays an important role in preventing potentially inefficient market behaviour. To address this risk, several respondents to the public consultation have expressed the idea of decoupling the CfDs payout from actual production levels:

- Some respondents to the public consultation have submitted the idea of designing “capability-based CfD”, by which the underlying volume determining the payment is based on the expected generation rather than on actual injected energy.<sup>32</sup> In their view, the decoupling of the CfDs payout from the actual injection avoids potential market distortions and inefficient dispatch.
- Others suggested the introduction of “financial wind CfDs”<sup>33</sup>, as a hybrid form of CfDs and forward contracts to mitigate risks and keep incentives to react to market price signals. Financial wind CfDs work as a stream of fixed monthly payment to the producer, while the producer pays back the spot market revenue of that month to the government.
- ACER has suggested the use of a Collar instrument with cap and floor, by which the generator revenues are calculated based on production when prices are high, but based on available capacity when prices are low, to keep incentives for the producer to react appropriately to market price signals.
- An academic has suggested using CfDs with a sliding premium ‘flexibility contracts’ to expose generators to the desired degree of price exposure.<sup>34</sup> Under this type of contract, the generator receives the strike price plus a flexibility bonus per unit produced. The flexibility bonus is the equivalent to the difference between the market price and a reference average price calculated over an extended period. To avoid capacity withholding the contract can also include a penalty. This kind of CfDs exposes capacity owners to price and incentivises dispatch when it is most needed.

All of these schemes have advantages and drawbacks. Each design will have an impact on the electricity system, the value for money for consumers and the full integration of renewables into the market. Careful consideration is needed depending on the Member State, technology type and the reinforcement plans for grid infrastructure in that area. Therefore, *location* is a crucial feature when contracting two-way CfDs. Commission analysis from the Joint Research Center (JRC) has

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<sup>32</sup> See for instance, Newbery, D. (2022): “Designing an incentive-compatible efficient renewable electricity support scheme”, Cambridge Working Paper Series

<sup>33</sup> See Schlecht, I., Hirth, L., and Maurer, C. (2022) “Financial Wind CfDs” Working & Discussion Papers / Preprints, EconStor Direct

<sup>34</sup> Fabra, N., (2022) “Electricity Markets in Transition: A proposal for reforming European electricity markets” CEPR Discussion Paper 17689.

highlighted the risk of extremely high dispatch costs by 2040, if renewables projects are selected solely based on criteria such as highest full-load hours, CfDs price or the available land. In their view, the auction for CfDs supporting low-carbon investment should incorporate some locational elements. This could be implemented by selecting the auction winners not only based on bid price, but by running an expansion model that would select the best combination of bids that achieve the auction targets (in MW or MWh) while minimising system costs.

- *Current EU framework*

Currently, the legislative framework applicable to renewable energy sources is contained in the Directive 2018/2001 on the promotion of the use of energy from renewable sources ('Renewable Energy Directive')<sup>35</sup>. Articles 4 to 6 contain the relevant principles applicable to the design of support schemes for renewables, applicable without prejudice to Articles 107 and 108 TFEU dealing with State Aid and the related legislation and guidelines<sup>36</sup>.

The main principles applicable to design of support schemes for electricity from renewable are included in Article 4 of the Renewable Energy Directive. In particular, support schemes must provide incentives for the integration of electricity from renewable sources and ensure that renewable energy producers respond to market price signals. The Directive provides two possible tools for such support schemes: either a sliding or a fixed market premium. Finally, the support must be granted through open, transparent, competitive, non-discriminatory and cost-effective procedures. Furthermore, Article 6 of the Renewable Energy Directive prevents Member States from modifying the existing support schemes and establishes that they should publish a long-term schedule anticipating the expected allocation of support.

The 2022 Guidelines on State aid for climate, environmental protection and energy ('CEEAG') include an additional set of principles applicable to support schemes for renewables which require state aid, taking into account the binding and ambitious climate targets for 2030 and 2050. The CEEAG establish that when assessing whether aid is compatible with the internal market under Article 107 of the Treaty, the Commission will analyse whether the aid facilitates the development of an economic activity and whether it does not unduly affect trading conditions to an extent contrary to the common interest.

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<sup>35</sup> Directive (EU) 2018/2001 of the European Parliament and of the Council of 11 December 2018 on the promotion of the use of energy from renewable sources

<sup>36</sup> Communication from the Commission – Guidelines on State aid for climate, environmental protection and energy 2022 and the following two texts under review; Commission Regulation (EU) No 651/2014 of 17 June 2014 declaring certain categories of aid compatible with the internal market in application of Articles 107 and 108 of the Treaty; Communication from the Commission Temporary Crisis Framework for State Aid measures to support the economy following the aggression against Ukraine by Russia (it includes a section on accelerating the deployment of renewables to simplify the requirements for this deployment; given the measures are temporary, they will not be described further here).



The 2022 Guidelines on State aid for climate, environmental protection and energy ('CEEAG') establish, among other principles, that aid must be designed to prevent any undue distortion to the efficient functioning of markets and, in particular, preserve efficient operating incentives and price signals. For instance, beneficiaries should remain exposed to price variation and market risk, unless this undermines the attainment of the objective of the aid. Finally, incentives must not be provided for the generation of energy that would displace less polluting forms of energy.<sup>37</sup>

- *Commission proposal*

In order to reach its decarbonisation targets and the objectives set out in REPowerEU to become more energy independent, the EU needs to accelerate the deployment of renewables at a much faster rate. Some Member States are also envisaging new investments in other forms of low carbon, non-fossil fuel electricity generation, such as nuclear. To achieve this, it is crucial that all possible investments from the private sector are mobilised first, in order to limit the pressure on the public budget. Next, when needed to ensure that the necessary investments take place, public support schemes should not crowd out private investments. It is equally important for support schemes to be well-designed, reflecting the experience from the energy crisis and to mitigate some of the risks explained by respondents to the public consultation. As outlined above, many renewable support schemes today are still based on a market premium (a top up on the market price) which led to uncapped and excessive publicly financed returns in the period of market price spikes.

Publicly supported schemes can contribute to long-term price stability and help to lower the cost of energy for consumers and businesses in times of high energy prices. Therefore, the Commission would like - in the context of this reform - to describe more precisely the principles leading to an appropriate design of national support schemes complementing the existing design principles in the Renewable Energy Directive:

- Where public support is needed to trigger new investments in new low carbon non-fossil fuel generation, this should be done via a two-way CfD or a similar contractual formulation which provides, in addition to a revenue guarantee, for an upward limitation on the market revenues of the generator concerned. The payout of long-term support schemes should therefore include an upward limitation of the revenues, to avoid any overcompensation using public funding. New investments in electricity generation include investments in new power generating facilities or investments aimed at repowering existing power-generating facilities, including to prolong their lifetime for example.
- The design of two-way CfDs scheme should include the following features:
  - The payout of the schemes should be in line with the principles set out in Article 4(2) and 4(3), first and third subparagraphs, of Directive (EU) 2018/2001, and be defined to minimise behavioural distortions and keep the incentives to respond to

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<sup>37</sup> Paragraphs 123 and 126 of CEEAG.

the market price signals. The two-way CfDs should indeed be designed so as to avoid a “produce and forget” approach. In addition, the limitation to set out direct price support schemes in the form of two-way contracts for difference should not apply to demonstration for which other types of direct price support schemes may be better placed to incentivise the uptake of innovative technologies which do not yet benefit from the necessary economies of scale to limit investment costs.

- The design of these tenders should allow the participation of projects in the auction that intend to cover part of their production with a PPA or other market-based mechanisms.
  - The revenues collected when the reference market price is above the strike price should revert to electricity consumers in a uniform manner, based on their consumption, in order to allow all consumers to benefit from the scheme on an equal basis. This allocation should be done in such a way that 1) it does not remove the incentives for consumers to shift their consumption to periods when the prices are low; and 2) does not undermine competition between electricity suppliers.
  - The scheme includes penalty clauses in case of early termination of the contract by the producer, with the aim of avoiding that producers opt-out from the contract in periods of high prices where they would have been obliged to pay-back the revenues above the contract strike price.
- As regards the scope of application of these principles, it should be limited to low carbon and renewable energy technologies with low and stable operational costs and to low-carbon technologies which cannot provide flexibility to the electricity system, while excluding (as mentioned above) technologies that are at early stages of their market deployment.

- *Two-way CfDs for existing generation capacity*

The Commission proposal applies to instances where public support is granted for new investments in low-carbon, non-fossil fuel generation technologies. Member States’ decision to impose two-way CfDs retroactively on existing generation capacity intervening in producers’ market revenues could be highly detrimental for the investment climate due to the uncertainty it causes for ongoing and future market-based investment decisions. The possibility for Member States to adopt such measures at any point in time would seriously hamper investors’ ability to estimate their income. This, in turn, would increase investments’ risks and the cost of capital, at the expense of consumers, and ultimately impact the efficiency and pace of the energy transition. This is because such measures could affect investors’ confidence about future revenues, thereby negatively impacting the future investments needed to reach EU decarbonisation objectives. As highlighted by respondents to the public consultation, regulatory decisions to impose two-way CfDs could also

lead to compensating operational inefficiencies. In addition, they could lower incentives for cost-efficient operation and market behaviour, thereby hampering competition in the market. Moreover, such a decision raises significant concerns among respondents about locking in existing capacity at excessively high price levels, with a resulting budget risk for Member States. A retroactive requirement would also entail high legal risks (identified by a significant share of the respondents to the public consultation) and would be incompatible with the provisions in RED II preventing the revision of support granted to renewable energy projects when it affects their economic viability.

### 2.3. *Improving Forward Markets*

#### **Feedback from public consultation**

While the large majority of professional respondents (83%) consider forward hedging as an *efficient* way to mitigate exposure to short-term volatility for consumers, only a minority (18%) consider that the *liquidity* in forward markets is currently sufficient to meet this objective.

Half of respondents (54%) consider that the *creation of virtual hubs* for forward contracts complemented with liquid transmission rights would improve liquidity in forward markets.

Regarding *potential ways to support the development of forward markets* through changes in the electricity market framework, respondents cite:

- Mandatory regional virtual hubs for trading forward contracts across all EU countries.
- Introduction of Financial Transmission Rights (FTR) obligations instead of FTR options.
- Revision of the collateral requirements, in terms of eligible collaterals, potential EU or State-based participation, possibility of cross-margining between the different clearing houses. Respondents welcome the European Commission's proposal to amend EMIR.
- To stimulate market making activities.
- Improve cross-border trading via Long Term Transmission Rights (LTTRs) for more than one year, more tenders, secondary market, rights with longer maturity (up to Yr+3), as well as seasonal and quarterly products. Several respondents also call for a strict implementation of Forward Capacity Allocation Guideline Article 30, forcing TSOs to support liquidity for cross-zonal hedging.
- More frequent auctions of transmission rights.
- Stimulating the use of counter-trading by TSOs.

- Reduce barriers to entry such as licencing, heavy bureaucratic requirements, reduction of minimum trading volume, lowering entry-threshold to exchanges.
- Regulatory certainty and visibility: respondents explained that market intervention create mistrust and unwillingness to commit for longer timeframes.
- Long-term hedging obligation on suppliers.
- Putting an obligation to generators that receive CfDs to offer at least part of their generation on the forward market.
- Avoid market-distortive subsidies for competitive technologies reducing competitive pressure thereby minimising demand for market-based hedging. Limiting the scope and duration of subsidies.
- Provide support schemes to support the development of flexibility, demand response and storage solutions.
- Development of new products as suitable hedging tools for renewables production.
- Making longer forward contracts than what is currently possible.
- Fewer bidding zones with a balance of natural buyers and sellers respectively, not restricted by national borders.
- Increase transparency and visibility in all transactions.
- More emphasis on investments in the transmission grids.
- Lowering the technical price limits for shorter term markets (especially day-ahead) would lower risks in the forward markets.

With regards to hub trading, 78 respondents with experience of the *existing virtual hubs in the Nordic countries* (57 companies, 11 business associations, 1 academic, 1 NGO and 2 others) rate this experience rather or very positively, with an average score of 6.4 (out of 10).

Many respondents explain that Nordic hub product has been successful in providing more liquidity than what single zone futures would have had. In their view, virtual hubs are an interesting instrument to combine several markets to a larger, more liquid market. However, they insist on the *importance of complementing financial futures with other instruments such as LTTRs or Electricity Price Area Differentials (EPAD) to enable them to work across borders*. Many of the 20 respondents attributing a low score ( $\leq 5$ ) justify it by the lack of liquidity in EPADs and complained that forward transmission capacity is not offered sufficiently.

In contrast with what market players recommended, *European TSOs* warned that forecasting how much capacity will be available in 3 years would only be feasible at a low level of accuracy. They explained that, if such a forecast is overestimated, too many LTTRs will be issued. The question of who is in such cases liable for the resulting excessive LTTR payouts would need to be clearly answered. If TSOs (via TSO tariffs end consumers) end up paying, there would be a shift of financial risks from market participants to TSOs and end consumers. European TSOs explained that capacity made available for maturities superior to one year will most likely have a limited guaranteed volume due to the difficulty of anticipating grid situation several years in advance.

European TSOs also explained that switching to FTR obligations would lead to better alignment with forward/future products, more price discovery and higher tradable volumes. But it would potentially require a higher collateral need and/or the introduction of a new mark-to-market collateral mechanism as there is no cap for the potential losses of a market participant in an FTR Obligation scheme.

- *State of Play*

Both consumers and suppliers need effective and efficient forward markets to hedge their price exposure and decrease the dependence on short-term prices. The recent energy crisis has been rewarding consumers who had hedged their price exposure in the past. Renewable generation is highly dependent on weather conditions and hence, volatile. The rapid deployment of renewable generation over the coming years will increase the need for hedging opportunities due to the expected growing price volatility in the years ahead. The future forward electricity market design needs to provide sufficient hedging opportunities.

According to ACER's policy paper on the further development of the EU electricity forward market<sup>38</sup>, the European electricity forward market appears to be struggling with many issues, such as insufficient liquidity, accessibility, competition and transparency as well as concentrated market power. Supply and demand for hedging instruments is fragmented into different bidding zones and trading venues, with most of them suffering from a lack of liquidity - preventing market participants from hedging their price exposure efficiently.

This lack of liquidity is particularly apparent for instruments with longer maturities and/or in smaller bidding zones. It is revealed through high bid-ask spreads – where the difference between the price that someone is willing to pay (the bid) and to sell (the ask) - is wide. Tighter spreads are a sign of greater liquidity, while wider bid-ask spreads occur in less liquid markets. This lack of

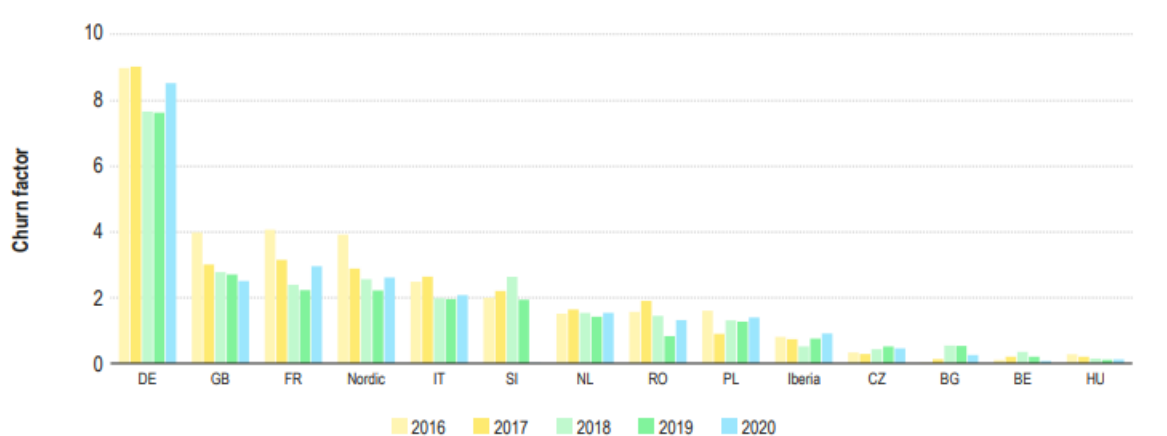
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<sup>38</sup>[https://acer.europa.eu/sites/default/files/documents/Position%20Papers/Electricity\\_Forward\\_Market\\_PolicyPaper.pdf](https://acer.europa.eu/sites/default/files/documents/Position%20Papers/Electricity_Forward_Market_PolicyPaper.pdf)

liquidity and possibilities to trade appears mainly in smaller bidding zones, but also in zones with a dominant market player who can exercise market power, or in zones with few physical assets.

The resulting market fragmentation at EU level can be illustrated by an indicator known as the “churn rate” i.e. the number of times electricity generated in a market is subsequently traded. The wide variation between bidding zones can be seen in Figure 6 below. The churn factor varies from around 8 for the German bidding zone to around 0.15 for the Hungarian bidding zone.

Figure 6: churn factors in major European forward markets – 2016-2020



Source: ACER Market Monitoring Report 2020, Electricity wholesale volume 2020

Market participants in illiquid bidding zones are often “proxy-hedging” themselves in the forward markets of neighbouring bidding zones, complementing this hedge with zone-to-zone LTTRs<sup>39</sup>. The Forward Capacity Allocation Guidelines<sup>40</sup> created a single pan-European platform of TSOs (Joint Allocation Office - JAO), established in October 2018, to explicitly allocate monthly and yearly auction-based cross-zonal transmission rights.

- These transmission rights are however not issued often: they are typically auctioned only at specific times (once a year and once a month).
- There is barely any secondary market for these transmission rights. ENTSO-E policy paper<sup>41</sup> explains that *“the LTTR market displays a relatively high degree of concentration: the first 27 participants (12 % of the total) hold more than 75 % of the allocated volumes, and the first 11 (4.9 % of the total) hold more than 50 % of the market. Furthermore, the*

<sup>39</sup> In central Europe, two kinds of LTTRs are currently issued: physical transmission rights (PTRs) and FTR Options. The JAO hosts a pan-European platform (i. e. the Single Allocation Platform) that performs the explicit allocation of LTTRs on all European borders and for all maturities.

<sup>40</sup> <https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32016R1719&from=EN>

<sup>41</sup> ENTSO-E policy paper – EU’s Electricity Forward Markets – December 2022 <https://www.entsoe.eu/news/2022/12/23/eu-s-electricity-forward-markets-policy-paper/>

*secondary market for LTTRs appears to be stagnant as only 2 % of capacity allocated through monthly auction was re-sold by market participants”.*

- The length of these transmission rights is inadequate, as they are mostly limited to one-year ahead while hedging on the forward market usually takes place up to 3 years ahead. Beyond the 3-year timeframe, the direct interests of consumers and producers to hedge their operations diminishes significantly and what remains is the interest to hedge investments
- Several zone-to-zone transmission rights are required to hedge between non-neighbouring bidding zones, increasing the complexity and difficulty to hedge.

Proxy-hedging activities exacerbate the lack of liquidity in illiquid bidding zones, while still not allowing participants to correctly cover their price risk for the reasons highlighted above. As a result, market participants in small bidding zones face discrimination in market access and an uneven playing field, as they are not able to cover their price exposure to the same extent as market participants from large and liquid bidding zones. This situation does not incentivise market participants to cover their risks nor to offer fixed price contracts to end-consumers.

In the Nordics, trading has been organised around the notion of a virtual hub for many years. A virtual hub is not a trading venue as such, but rather an aggregation of bidding zones characterised by a reference price. A hub has a reference system price, against which market participants can hedge their price exposure. The system price is an unconstrained market clearing reference price for the Nordic region. It is calculated without any congestion restrictions by setting capacities to infinity<sup>42</sup>. To complement the Nordic hub, financial instruments called Electricity Price Area Differentials (EPADs) are issued to enable market participants to cover the price difference between the hub and their respective zone. Market participants can issue EPADs on an auctioning platform and a secondary market takes place on Nasdaq. The creation of a hub has allowed to enhance liquidity by aggregating volumes from individual bidding zones. However, in the public consultation, respondents complained about the declining liquidity of EPADs and explained that forward transmission capacity is not offered by TSOs.

When looking at the application of the Nordics model to the Core region, ACER simulations show that hub-based trading would significantly improve the price correlation between the hub and all bidding zones<sup>43</sup> compared to a situation with current bidding zones-based trading – as illustrated by *Table 2* below. A Core hub would therefore allow market participants from all underlying regions to improve their hedging opportunities on the forward market, leading to greater benefits to both producers and end-consumers. To be successful, it is of utmost importance for the hub to be complemented by liquid long-term transmission rights.

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<sup>42</sup> <https://www.nordpoolgroup.com/en/trading/Day-ahead-trading/Price-calculation/>

<sup>43</sup> Except in DE where the price correlation would only slightly decrease

Table 2: price correlation between bidding zones: comparison between a core hub and DE hub

Correlation** to [%]	HU	NL	PL	SK	RO	SL	AT	BE	HR	CZ	FR	DE
Core hub	96.8	96.8	84.8	97.3	94.9	97.0	98.6	97.2	96.8	98.5	95.6	98.4
DE hub	93.1	95.7	84.5	94.7	91.0	93.1	95.9	95.8	92.9	98.1	89.6	100

Source: ACER presentation of the policy paper on the further development of the EU electricity forward market – 7 December 2022

ENTSO-E policy paper further explains that “*zone-to-hub FTRs could be complementary instruments to the default zone-to-zone products. This can be beneficial for providing stable hedging opportunities for market participants in small, illiquid bidding zones. As an alternative for the forward market of their own illiquid market, they would prefer to hedge themselves on the hub forward market if this one has more liquidity. Via zone-to-hub, FTR market participants can adequately hedge themselves against the price differences of the spot price of their own market against the fixed forward contract on the hub. The paper further explains that “a hub makes it easier for market participants to trade between non-neighbouring bidding zones.”*

- *Commission proposal*

The Commission is of the view that there is room for improvement in the way long-term cross-zonal capacities are used to further integrate forward markets. Existing forward markets do not function as an integrated forward market, which prevents many EU consumers and suppliers from covering their long-term price exposure efficiently and thereby increases their dependence on short-term markets price.

Building on the experience in the Nordic market, the Commission proposes a **transition to hub-based hedging, complemented with accessible longer-term zone-to-hub transmission rights**. The establishment of virtual hubs, by providing a reference price index, will enable to pool liquidity and provide better hedging opportunities to market participants. Virtual hubs are intended to reflect the aggregated price of several bidding zones and are characterised by a reference price; which should be used by market operators to offer forward hedging products. The hub price may represent the volume-weighted average of the day-ahead prices from the regions included in the hub definition (or another calculation method ensuring highest price correlation). Zone-to-hub transmission rights would be issued frequently, with a long maturity (up to 3 years ahead), financially settled and offering continuous access to a secondary market. The allocation of zone-



to-hub capacity could be computed based on a statistical approach applied to past available capacity<sup>44</sup>.

It is expected that hubs would attract demand for futures linked to these hubs - because all long-term transmission rights would be linked to these hubs - and that power exchanges would subsequently offer trading with such futures without the need for regulatory intervention. This measure does not imply a duplication of reporting on top of requirements imposed by financial markets legislation.

The Electricity Regulation would therefore require ENTSO-E:

- To submit a proposal to establish the regional hubs, including definition of their regional scope;
- To submit a proposal regarding the calculation of the hub price, based on an objective methodology.

The Single Allocation Platform would then issue long-term financial transmission rights (in the form of obligations) on behalf of TSOs and allocate them on a regular basis and in a transparent, market-based and non-discriminative manner.

With regards to collateral requirements, the Commission has taken several measures to respond to the challenges faced. Last year, the Commission adopted a Delegated Regulation<sup>45</sup> on temporary emergency measures on collateral requirements to alleviate the liquidity pressure on energy companies. Furthermore, with regards to derivatives, the Commission has adopted – in line with advice from ESMA – two measures designed to ease liquidity stress some energy companies are currently experiencing. The first measure raises permanently the commodity clearing threshold from €3 billion to €4 billion. It means that energy companies will be allowed to enter into more over-the-counter transactions without being subject to margin requirements. The second measure will temporarily (validity: 1 year) expand the list of eligible assets that can be used as collateral to meet margin calls, e.g. adding public guarantees and uncollateralised bank guarantees, subject to conditions. Thirdly, on 7 December 2022, the Commission adopted a proposal to amend the EMIR Regulation<sup>46</sup> in which, among other measures, the Commission proposes that the range of eligible collateral for non-financial counterparties (including energy companies) clearing in EU central counterparties is extended to uncollateralised bank guarantees, public guarantees and public bank guarantees, whether or not these counterparties access the CCP directly.

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<sup>44</sup> For example, the minimum available capacity in a certain % of all times during the observation period

<sup>45</sup> [https://ec.europa.eu/finance/docs/level-2-measures/emir-rts-2022-7536-annex\\_en.pdf](https://ec.europa.eu/finance/docs/level-2-measures/emir-rts-2022-7536-annex_en.pdf)

<sup>46</sup> Proposal for a REGULATION OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL amending Regulations (EU) No 648/2012, (EU) No 575/2013 and (EU) 2017/1131 as regards measures to mitigate excessive exposures to third-country central counterparties and improve the efficiency of Union clearing markets

## 2.4. Enabling energy sharing

### Feedback from public consultation

Stakeholders generally support the idea of giving customers the *right to deduct off-site generation from their metered consumption*, under certain conditions. This provision could encourage local renewable energy production and efficient energy sharing, including within energy communities or peer-to-peer exchanges, without affecting other elements of the energy bill such as taxes, levies and network tariffs.

However, stakeholders have raised *concerns*, such as the need to harmonise protocols for data creation, management and transmission, to ensure cost-reflective network tariffs, to avoid double counting of network charges and to encourage co-location of production and flexible consumption. Care should be taken when implementing such a provision, as it may lead to unfair subsidies or cross-subsidisation of network costs to poorer consumers without generation assets.

Stakeholders have diverging views on the *potential impact* of introducing a right for consumers to deduct off-site generation from their metered consumption on the location of new renewable energy generation facilities. Some believe that this would provide an incentive to build capacity close to consumption, while others fear that it would lead to negative incentives, excessive installation of renewables and huge investment needs in the grid. There are also concerns about the potential socialisation of costs and regulation to establish a distance limit between off-site generation and consumption points.

Respondents suggested that any provision should be implemented *as localised as possible*, based on factors such as ease of implementation, network capacity and cost reflectivity, as well as loss allocation and the calibration of tariffs to reflect the actual location of generation and consumption on the grid. Respondents also stressed the importance of balancing generation and consumption within the same bidding zone and considering network topology rather than geographical distance to limit complexities.

#### ○ *Current state of play*

The crisis has shown that smaller consumers are excessively exposed to wholesale price fluctuations and have limited access to more affordable renewable energy.<sup>47</sup> Under current EU

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<sup>47</sup> MMR\_2021\_Energy\_Retail\_Consumer\_Protection\_Volume.pdf (europa.eu), pp. 17-18.

legal framework,<sup>48</sup> **consumers without private ownership rights over suitable space have limited possibilities to engage with renewables directly,**<sup>49</sup> they need to either find consensus with their neighbours to install solar PV on the roof of their multi-apartment building or be able to invest in an energy community<sup>50</sup>. In some Member States wider energy sharing schemes allowing for collective self-consumption of off-site generation facilities within a local perimeter started emerging<sup>51</sup> but not in most as such schemes are not explicitly recognised at EU level.

In general, the emergence of enabling frameworks for energy sharing at national level has been patchy and slow with some of these schemes remaining out of scope of energy consumer rights and protection framework,<sup>52</sup> which can be attributed to the lack of a clear and harmonised enabling framework for energy sharing at EU level.<sup>53</sup> This is slowing down the uptake of renewables,<sup>54</sup> and

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<sup>48</sup> The Electricity Market Directive enables energy sharing only for citizen energy communities (see Article 16 (3) (e)). The Renewable Energy Directive enables energy sharing for jointly acting self-consumers within multi-apartment building and renewable energy communities (see Article 21 (4) and 22 (2) (b)).

<sup>49</sup> Many citizens cannot access solar PV due to financial (CAPEX intensity, low return on grid exports), spatial (heritage buildings, lack of ownership rights over rooftop) and administrative constraints (decision-making rules for multi-apartment residents and set up of energy community). See Solar Power Europe (2023), 'Framework for collective self-consumption - Solar Power Europe White Paper'. Moreover, alternative instruments such as corporate PPAs are difficult to engage with for SMEs. See European Commission (2022). Staff Working Document – Guidance to Member States on good practices to speed up permit-granting procedures for renewable energy projects and facilitating Power Purchase Agreements – Accompanying the Commission Recommendation on Speeding up permit-granting procedures for renewable energy projects and facilitating Power Purchase Agreements.

<sup>50</sup> Approximately 10.000 energy communities are currently operational across the EU, mostly in West European countries, see [energy-communities-map \(europa.eu\)](https://europa.eu/energy-communities-map). Low-income families often face a financial entry barrier to energy communities. In Germany, the average minimum financial contribution – individuals buy shares to become members – amounts to 545 €. See Hanke, F., Guyet, R., & Feenstra, M. (2022). 12 - Energy communities' social role in a just energy transition (S. Löbke, F. Sioshansi, & D. B. T.-E. C. Robinson (Eds.); pp. 195–208). Academic Press. [https://doi.org/https://doi.org/10.1016/B978-0-323-91135-1.00027-4](https://doi.org/10.1016/B978-0-323-91135-1.00027-4).

<sup>51</sup> Wider energy sharing schemes at national level go beyond multi-apartment building and energy community level. See for example in Portugal where energy can be shared between 2-20 km radius depending on voltage levels where the self-consumption unit is connected to. See [Decreto-Lei n.º 15/2022, de 14 de janeiro | DRE](#)). Other examples can be found in countries such as France, Spain, Slovenia and Lithuania.

<sup>52</sup> Some emerging energy sharing arrangements are based on investment, rental or lease agreements rather than sales agreements. This has implications in terms of applicable consumer protection rights. See in this regard, BEUC (1 February 2023), 'Consumer rights in energy communities: a how-to guide to make energy communities go mainstream' ([Consumer rights in energy communities: a how-to-guide to make energy communities go mainstream \(beuc.eu\)](#)).

<sup>53</sup> See Roland Tual et al. (2022), Energy sharing regulation in the EU – REScoopVPP first policy and market recommendations'.

<sup>54</sup> Solar growth is driven by regulatory incentives and internal rates of return. In PT, a framework for energy sharing and collective self-consumption has according to E-REDES triggered a growth of these schemes with four operational initiatives and 30 more under registration, involving 220 participants. Greenvolt Comunidades, an investment company in Portugal, has already signed 65 projects to be implemented as collective-self consumption projects, which correspond to circa 35 MW (3 MW already concluded and 3MW are under construction). See [Greenvolt Comunidades - Comunidades de Energia](#). In Greece, under the impulse of volatile wholesale market prices, energy sharing projects, based on virtual net-metering, increased by 62,5% in number

leaves a wider group of consumers vulnerable to unfair commercial practices and unable to decouple from volatile wholesale market prices<sup>55</sup>.

○ *Commission proposal*

An enabling framework for energy sharing in the Electricity Market Directive is added to clarify relevant roles, rights and responsibilities of involved actors, and operationalise existing frameworks for energy communities<sup>56</sup> and multi-apartment residents<sup>57</sup>, as well as wider ones, where excess production is shared with off-site consumers by individual prosumers, or a group of consumers jointly lease, rent or own an off-site generation or storage facility managed by a third-party facilitator. For more information on different use cases and how energy sharing can help empower consumers, including energy poor households and tenants, see section 6.4.

Consumers shall have the **right to have injected electricity deducted from their total metered consumption** within a set time-interval and within the same bidding zone for the purpose of calculating the energy component of their energy bill. This shall be without prejudice to applicable taxes and network charges to total metered consumption. System operators or other relevant designated bodies will have the responsibility to put in place the necessary back-end IT infrastructure to operationalise this right. Member States such as Belgium<sup>58</sup>, Austria,<sup>59</sup> Lithuania, Luxembourg, Portugal and others<sup>60</sup> have shown that it is possible to implement this model relatively quickly (1-2 years) and at a reasonable cost.<sup>61</sup>

The Commission's proposal will leave several dimensions of energy sharing framework to the discretion of individual Member States, including the calculation and allocation methods for the sharing of renewable energy, the possibility to implement the model in stages (from local to bidding zone level), the appropriate measures to ensure accessibility to energy poor and vulnerable

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and 140.3% in capacity within one year time. See The GreenTank (2023), 'Energy Communities in Greece and its lignite areas #3'.

<sup>55</sup> A study commissioned by Federal Ministry for Economic Affairs and Energy in Germany estimates that approximately 3.8 million households could have access to the Mieterstrom model. See <https://www.bmwk.de/Redaktion/DE/Publikationen/Studien/schlussbericht-mieterstrom.html>. In Lithuania, projections suggest that by 2030 there could be 170-190 thousand prosumers with total installed capacity of 1.2-1.3 GW when combining onsite and offsite self-consumption. See <https://www.vz.lt/pramone/2022/06/06/2030-m-gaminantys-vartotojai-pagamins-7-lietuvos-elektros-energijos-poreik>.

<sup>56</sup> See for example [Hyperion](#), where a community of consumers organised through a cooperative form have shared ownership over solar PV.

<sup>57</sup> See Solar Power Europe (2023), 'Framework for Collective Self-Consumption: SolarPower Europe White Paper'.

<sup>58</sup> See [Energiedelen en persoon-aan-persoonverkoop | VREG](#).

<sup>59</sup> See <https://energiegemeenschappen.gv.at/messung-und-aufteilung/>.

<sup>60</sup> Such as Spain, Italy, France.

<sup>61</sup> See Aliene van der Veen et al. (2023), 'multi-supplier models and decentralised energy systems: energy sharing implementation approaches'.

households, and the design of model contracts with fair and transparent contractual terms and conditions for peer-to-peer trading agreements between households as well as rental, lease and investment agreements. When participating to energy sharing, final customers shall continue to benefit from all consumer rights as final customers, without prejudice to peer-to-peer trading between households.

○ *Benefits for consumer bills and renewables deployment*

By operationalising and enabling at EU level existing and wider energy sharing arrangements within a single bidding zone, **a wider group of consumers will have the opportunity to hedge against volatile wholesale market prices and control their energy bills.**<sup>62</sup> In turn, this can mobilise additional private capital investments<sup>63</sup> in roof and ground-based renewable energy (including wind turbines in offshore and rural areas) and increase the uptake of renewables.<sup>64</sup> With the integration of storage and when exposed to time-differentiated price signals and accessible flexibility markets, energy sharing can also contribute to cost-effective deployment and integration of renewables.<sup>65</sup>

Estimates show that in 2022 a collective of 40 residential consumers engaged in sharing of electricity produced for 50% from solar and 50% from wind could have saved as much as 1269 EUR in Denmark, 999 EUR in Romania, 1213 EUR in France, 1045 EUR in Belgium, 1220 EUR in Italy, 1040 EUR in Greece and 765 EUR in Portugal.<sup>66</sup> Benefits are lower in 100% solar scenarios due to lower self-consumption rates. When household demand is met using 50% solar and 50% wind installations, self-consumption increases from 39.6% to around 66% on average across these seven countries, illustrating the importance of allowing for sufficient geographical flexibility for the integration of wind technology.<sup>67</sup>

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<sup>62</sup> In Lithuania, 9267 households out of 40577 prosumers produce electricity in remote parks. In Belgium, which has operationalised energy sharing in 2022-2023, there are above 2000 consumers participating to energy sharing.

<sup>63</sup> It is estimated that 6.5-12.8 billion EUR of citizen capital could be invested in Germany alone. See [https://www.ioew.de/publikation/energy\\_sharing\\_eine\\_potenzialanalyse](https://www.ioew.de/publikation/energy_sharing_eine_potenzialanalyse).

<sup>64</sup> See Borna Doračić et al. (2020), 'Prosumers for the Energy Union: mainstreaming active participation of citizens in the energy transition'.

<sup>65</sup> See SmartEn (2022), 'Demand-side flexibility: quantification of benefits in the EU'.

<sup>66</sup> Marten Ovaere (2023) 'Collective energy sharing: Cost-Benefit Analysis and Survey Evidence of the Willingness to Invest'.

<sup>67</sup> Marten Ovaere (2023) 'Collective energy sharing: Cost-Benefit Analysis and Survey Evidence of the Willingness to Invest'.

Table 3: The average benefits of collective self-consumption across the seven studied countries, for the market conditions in 2020 and 2022 and for a 100% and a 50% solar / 50% wind generation mix.

Year of the data used	2020		2022	
Degree of self-consumption	Collective		Collective	
Generation mix	100% solar	50% solar 50% wind	100% solar	50% solar 50% wind
Self-consumption (%)	39.69	66.12	39.44	65.96
Benefit of self-consumption (€)	272.53	442.04	586.00	930.24
Benefit of surplus energy sold (€)	61.57	33.69	292.30	148.88
Total benefits (€)	<b>334.10</b>	<b>475.72</b>	<b>878.30</b>	<b>1079.12</b>
Investment cost (€)	2234.92	2447.29	2234.92	2488.72
Payback period for constant market conditions (years)	7.22	5.59	2.57	2.33

Source: Marten Ovaere (2023), 'Collective energy sharing: Cost-Benefit Analysis and Survey Evidence of the Willingness to Invest'.

To operationalise the right to energy sharing, cost impacts are expected for consumers, retail suppliers and system operators.<sup>68</sup> System operators will have to invest in the order of a few million euros to put in place the back-end IT infrastructure; a cost that can be seen as a wider digitalisation effort of market processes. Active consumers will continue to use the grid to share electricity and to meet their excess demand contributing to investment and operational costs of the overall energy system.

System operators should be able to recover all costs incurred and across all network users to avoid cost-socialisation to lower-income households that cannot participate to energy sharing due to the high financial entry barriers for individual<sup>69</sup> and joint<sup>70</sup> investments. Active consumers may reduce at times congestion at higher voltage levels, depending on location of relevant injection and consumption points, as well as the level and timing of congestion at transmission and distribution

<sup>68</sup> See Aliene van der Veen et al., 'multi-supplier models and decentralised energy systems: energy sharing implementation approaches' (2023) (to be published).

<sup>69</sup> See <https://www.irena.org/publications/2022/Jul/Renewable-Power-Generation-Costs-in-2021>.

<sup>70</sup> For example, it costs on average 545 EUR per share to join an energy community in Germany. See Hanke, F., Guyet, R., & Feenstra, M. (2022). 12 - Energy communities' social role in a just energy transition (S. Löbke, F. Sioshansi, & D. B. T.-E. C. Robinson (Eds.); pp. 195–208). Academic Press. <https://doi.org/https://doi.org/10.1016/B978-0-323-91135-1.00027-4>.

level in each Member State. Flexibility markets and time-differentiated network tariffs are the most appropriate instruments to provide monetary incentives for relevant congestion management services.

Depending on the setup per Member State, traditional retail suppliers are expected to incur costs related to billing for individual prosumers, and to face difficulties with forecasting of consumption profiles leading to increased imbalance risk and higher unit supply costs.<sup>71</sup> Suppliers should be able to recover costs effectively incurred due to the activation of energy sharing from involved consumers.

## 2.5. Offshore Transmission Access Guarantee

### Feedback from public consultation

Many respondents acknowledged the particular *challenges facing offshore renewable energy projects* located in an offshore bidding zone. It was highlighted that a *coordinated investment program* to ensure that the transmission capacity and offshore capacity develop in tandem as a hybrid project would be the best guarantee of access to markets and would mitigate the need for this provision. Overall, out of the 314 respondents to the question, 200 consider that a *Transmission Access Guarantee (TAG)* is appropriate to support offshore renewables projects.

Some respondents believe that a TAG is necessary to avoid discrimination compared to onshore renewables in larger bidding zones who would receive compensation for curtailment, and they state that it would de-risk investments and support the development of offshore PPAs. Others do not believe that it goes far enough to support the development of offshore renewables and that it should also cover some form of price support for renewables projects.

However, some concerns were also raised such as needing to ensure a *level playing field* between onshore and offshore generation and competition between technologies, cross-subsidisation, costs for consumers (regarding both compensation level and development of grid infrastructure), ensuring that project operators are not overcompensated, need to ensure futureproofing for a combination of gas (H2) and electricity offshore in future.

### ○ State-of-play

One of the key pillars for enabling the decarbonisation objective will be offshore renewables. With enormous untapped potential, increasingly competitive prices (i.e. levelised cost of electricity) and

<sup>71</sup> Leen Peeters et al. (2022), 'Muse Grids impacts: A critical stocktaking across various aspects of community energy'.

technological global leadership, the EU is well placed to exploit offshore renewable resources. The policy direction set by the Commission's offshore renewable energy strategy<sup>72</sup> has been confirmed at political level by Member States at numerous occasions, including the [Esbjerg Declaration](#)<sup>73</sup>, the [Marienborg Declaration](#)<sup>74</sup>, the [NSEC Joint Statement](#)<sup>75</sup> in 2022 and the non-binding [sea-basin goals](#)<sup>76</sup> agreed by Member States in 2023 pursuing TEN-E Regulation<sup>77</sup>.

The strategy, setting the overall policy direction, was complemented with a guidance on electricity market arrangements<sup>78</sup> describing how the establishment of offshore bidding zones (OBZs) is the most efficient and affordable way for consumers to integrate large-scale offshore renewables into the system when these are connected via hybrid interconnectors. With OBZs, among other benefits, electricity flows are optimised accounting for physical reality, minimising redispatching costs that are borne by consumers and would substantially increase with other market arrangements, and increasing security of supply by not pushing TSO corrective actions towards real time. To attain such and other benefits, Member States may decide to implement OBZs, while it is not a mandatory market arrangement.

In addition, the strategy outlined a number of follow-up activities aiming at promoting the rapid and efficient deployment of offshore renewables. One was a study<sup>79</sup> analysing the market risks that offshore renewable plants in an OBZ interconnected to several markets may face. The main risk identified is a volume risk, where offshore wind farm operators in an interconnected system may at times not be able to export the energy that they would be able to produce if the TSOs do not give enough transmission capacity to the market<sup>80</sup>. The uncertainty in generation volumes that

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<sup>72</sup> COM/2020/741 final

<sup>73</sup> The Esbjerg Declaration - Regeringen.dk

<sup>74</sup> The Marienborg Declaration - Regeringen.dk

<sup>75</sup> 220912\_NSEC\_Joint\_Statement\_Dublin\_Ministerial.pdf (europa.eu)

<sup>76</sup> [Member States agree new ambition for expanding offshore renewable energy \(europa.eu\)](#)

<sup>77</sup> Regulation (EU) 2022/869

<sup>78</sup> SWD(2020) 273 final

<sup>79</sup> [https://energy.ec.europa.eu/system/files/2022-09/Congestion%20offshore%20BZ.ENGIE%20Impact.FinalReport\\_topublish.pdf](https://energy.ec.europa.eu/system/files/2022-09/Congestion%20offshore%20BZ.ENGIE%20Impact.FinalReport_topublish.pdf)

<sup>80</sup> The European Commission took due consideration of the findings of the studies 'Market arrangements for offshore hybrid projects in the North Sea' and 'Support on the use of congestion revenues for offshore renewable energy projects connected to more than one market' as well as extensive feedback from stakeholders, noting that the major additional risk that offshore renewable plants experience in comparison to onshore plants is a volume risk as outlined. On the other hand, the price effects in an OBZ stemming from an optimised market arrangement reflect the value of both the renewable and transmission assets, as is the case for onshore assets in well-designed bidding zones. Incorporating "price compensation" to mirror OBZ prices with onshore bidding zones and linking them to congestion income would not only suppress the appropriate signaling of the value of the assets (lowering incentives for demand such as hydrogen to emerge nearby), but also could introduce substantial detrimental effects such as cross-subsidisation and additional pressure on the financing of interconnectors. Where possible, Member States should strive to give visibility on the market arrangement applicable to offshore assets ahead of the respective tender procedures. The market arrangement is not expected to alter substantially whether there is a need for State aid for offshore projects; cooperation mechanisms such



the renewable plant operator can practically offer to the market represents a risk for the project developer over which they have no control. It is a risk that is particular to offshore renewable assets, given that onshore renewables are not connected directly to interconnectors. TSOs through ENTSO-E are working on a new way of calculating capacities (Advanced Hybrid Coupling) that should improve certainty of access to the hybrid interconnectors. However, even when this is implemented, there might still be occasions where market access is removed or reduced.

- *Commission proposals*

To address this risk, the Commission proposes to develop a “Transmission Access Guarantee” (TAG) where the TSOs responsible for limiting the export possibilities of offshore wind farms would compensate the offshore producer for any market time units where the border is closed or reduced, not allowing the export of energy that could have otherwise been offered to the market. This compensation would be paid from the congestion income collected by TSOs when borders are congested and is consistent with the principle of one of the current allowed uses of congestion income: guaranteeing the availability of cross-border transmission capacity. This congestion income re-allocation would therefore incentivise TSOs not to reduce transmission capacity made available to offshore wind farms, while targeting such reallocations to the source of the risk<sup>81</sup>. The Commission proposes to amend the Electricity Regulation to enable a Transmission Access Guarantee, thereby ensuring market access for offshore renewables, with further implementing details to be set out in upcoming amendments to the Guideline on Capacity Allocation and Congestion Management.<sup>82</sup>

It is useful to highlight that this proposal carefully balances the perspective of offshore developers who are seeking to de-risk these investments with the views of TSOs and NRAs who expressed concerns about maintaining a level-playing field, avoiding cross-subsidisation and minimising the costs to consumers. The proposal takes on board these concerns by limiting the TAG to addressing the “volume risks” associated with these investments i.e. market access for offshore renewables that might be affected by TSO actions. However, it does not cover the revenue uncertainty that

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as those indicated in the Renewable Energy Directive (e.g. joint projects or joint support schemes) may prove useful to promote further cross-border offshore renewable projects.

<sup>81</sup> A non-targeted reallocation would not be feasible, with growing needs to finance hybrid and other transmission projects, and considering that ACER notes that already 95% of the annual congestion income is used for the priority objectives established by the Electricity Regulation in support of the market (Use of Congestion Income 2021 ACER Monitoring Report of 11 October 2022)

<sup>82</sup> It should also be noted that OBZs in interconnected markets maximise social-welfare in the region, which may at times impact, to a limited extent, the revenues of offshore wind farm operators to the benefit of consumers, reflecting the real value of transmission infrastructure needs. The study “Support on the use of congestion revenues for Offshore Renewable Energy Projects connected to more than one market“ raises serious concerns about any reallocation of congestion income for this price risk, which would lack a market basis and risk cross-subsidisation and discrimination. More appropriate ways of addressing revenue certainty and sustainability where necessary are corporate PPAs and joint support schemes based on contracts for difference set by cooperating Member States.

comes from participating in the electricity market. This “price risk” is better addressed by private PPAs or public support as outlined in earlier sections of this document.

### 3. Limiting revenues of inframarginal generators

#### Feedback from public consultation

A majority of respondents were *against maintaining a revenue limitation on inframarginal generators*, and highlighted the following risks and shortcomings of such an option:

- The inframarginal revenue cap and its heterogenous implementation across Member States have created uncertainty and complexity for investors and give negative signals for new investments;
- The measure is difficult to implement, and its administrative costs are high when compared with its benefits;
- The uncoordinated implementation is undermining the integrity of the market;
- The emergency situations should be dealt only during emergency situations, and not beyond;
- The inframarginal revenue cap, when set at a low level as some Member States did, might lead to generators reducing their production while the cap is in place;
- Distributional concerns are better handled outside the market structure, for example via social policies.

Only a minority of respondents supported the idea that some form of revenue limitation of inframarginal generators should be maintained. They signaled that it would ensure that excess profits are channeled back to final consumers, and some of them claimed that the drawbacks from the current inframarginal revenue cap derive from the short timeframe for its implementation.

#### ○ *State of play*

During the current energy crisis, temporary emergency measures have been put in place under Council Regulation 2022/1854 of 6 October 2022 on an emergency intervention to address high energy prices. One of these measures is the so-called inframarginal revenue cap which limits the revenues of inframarginal generators. The aim of introducing this inframarginal cap was to limit

the impact of the natural gas prices on the revenues of all inframarginal generators and to generate revenues allowing Member States to mitigate the impact of high electricity prices on consumers.

The inframarginal revenue cap was proposed and adopted as one of the emergency measures for tackling the energy crisis due to its advantages when compared with other alternatives, namely that it does not entail an increase in gas consumption and does not impact the outcome of the electricity market, so that there is no artificial change to the technologies used to meet demand, and no distortion of the cross-border flows, both within the EU and between the EU and its neighbours.

However, during its implementation, several Member States and stakeholders have pointed at several challenges and risks of the inframarginal revenue cap:

- The heterogenous implementation across Member States (for example, several Member States, as provided for in the Emergency Regulation opted for a lower cap level below 180 EUR/MWh, differentiated by technology or a different implementation period than provided in the Regulation) has resulted in a patchwork of national measures across the EU, with stakeholders reporting that the linked regulatory uncertainty might end up hindering new investments in the EU.
- The measure is only effective when market prices are above the cap. Some Member States have reported that in a low-price scenario, the benefits retrieved by the measure might not compensate for the cost of implementing it.
- Difficulties in implementing the measure, since it requires to establish revenues from inframarginal producers. Some Member States have implemented the measure in a way that it also affects energy sold under long-term contracts, which are not dependent on spot prices. This did not only create an additional layer of investor uncertainty, but it also hinders the attractiveness and stakeholder confidence in forward markets.

- *Commission proposal*

While well-designed ad-hoc time-limited measures can bring benefits in times of energy crises, embedding the inframarginal revenue cap or similar emergency measures as a permanent feature of the market design would entail unnecessary risks and costs, namely:

- the risk of harming the forward markets, that have been identified as a key component to ensure price stability for the consumers, by decreasing its reliability and liquidity;
- the risk of affecting the investment attractiveness of the technologies needed for the electricity system decarbonisation;

The Commission will continue to monitor the effect of inframarginal revenue cap measure after the second reporting date (set on 30 April 2023). By then, the Commission expects to have a better view of potential revenues collected and net impact for the end-consumers. Such conclusion will then feed the discussion on the potential prolongation of the Regulation beyond 30 June 2023.

#### 4. Improving the efficiency of short-term markets

##### Feedback from the public consultation

##### Intraday markets

The majority of respondents consider that short-term markets are functioning well, and do not see an alternative to the **marginal pricing model**. Liquidity and level playing field are however quoted as weaker elements.

Moving the **closure of cross-zonal intraday trades closer to real time** is a welcome change by many respondents, in particular market participants. It is considered as a key aspect to integrate further renewables, since they are highly weather-dependent and their production forecasts improve closer to real time. However, it will be important to consider operational security when getting closer to the time of delivery, and possibility to adapt some design element of the balancing market.

The majority of respondents consider that **market operators should share their liquidity** also for local markets. Respondents who disagree consider that this would harm innovation. TSOs note that the remaining liquidity will be shared on European balancing platforms (for prequalified units). Furthermore, some note that with the development of local flexibility markets, sharing liquidity between local and zonal wholesale markets will be important, through coordination and data exchanges.

##### Day-ahead markets

The majority of respondents consider that **mandatory participation in the day-ahead market** (notably for generation under CfDs and/or PPAs) would not be an improvement compared to the current situation. Such measures could however be envisaged if a concerning drop of liquidity is witnessed.

Freedom to choose trading venues is considered as fundamental. However, transparency is a key element, hence the importance of liquidity in organised marketplaces.

On the issue of reflecting **further locational and technology based information** in the bidding in the market, further locational information could help reflecting the physics of the grid and its congestions in the market design. However, portfolio bidding and aggregation remain critical functionalities for many market participants to preserve. Locational tags can be useful and could ease regulatory oversight.

### **EU Emission Trading System**

Many respondents did not reply to the question on the EU emission trading system and its incentive on the development of low carbon flexibility and storage. Most respondents were in favour of the EU emission trading system, explaining that the market can decide freely where and how it is most efficient to abate emissions. They explained that, by internalising costs of carbon emissions, emitting becomes more expensive, making low-carbon flexibility and storage solutions more attractive. However, some stakeholders expressed their reluctance since the prices for carbon emissions are volatile and sensitive to regulation changes, which might dampen the willingness for capital intensive investments in generation. Few stakeholders opposed the EU emission trading system, criticizing the price increase for end consumers and highlighting the need for EU industry to remain competitive in the global markets.

#### **4.1. Intraday Gate Closure time**

- *State of play*

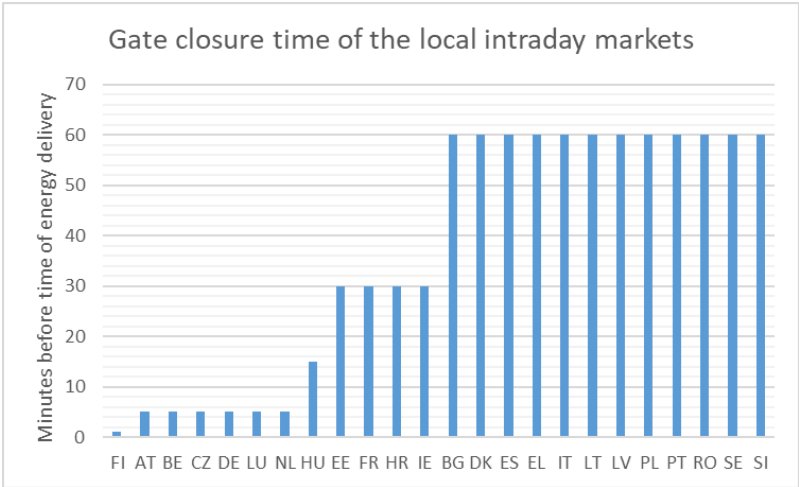
The Clean Energy Package built on previous legislative packages to put a focus on **short-term markets** and related price signals in order to support the development of variable and more distributed generation. Functioning short-term markets (day-ahead, intraday and balancing) are indeed a key tool for the integration of renewables in the electricity system, as they enable trading of surplus and shortages of energy closer to the time of delivery, especially for those resources that are more flexible such as demand response or storage. The price reflected by short-term markets gives a signal of scarcity, encouraging market participants to react to it and guaranteeing that different assets are used in the most efficient manner. It is also crucial for security of supply because higher prices attract imports ensuring that electricity flows to where it is most needed. Keeping this price signal is key to enhance flexibility and integrate variable renewables reliably in the system.

**Intraday markets** are especially important for the integration of renewable energy at the least cost. While most electricity is traded the day-ahead of delivery or before, it is only a couple of

hours closer to the time of delivery that wind and solar producers can accurately estimate their actual electricity production. However, since they sell their production in the markets before having an accurate estimation, they often produce more or less electricity than what they sold. It is thus important that they can balance their position as close as possible to the time of delivery, and that they have trading opportunities via a liquid market.

EU day-ahead and intraday electricity markets are coupled, meaning that the dispatch of generation and demand response is organised across Europe in a single process. The European cross-border intraday market currently closes one hour before the time of delivery. Some Member States have enabled trading closer to the time of delivery at national level, as illustrated in *Figure 7* below.

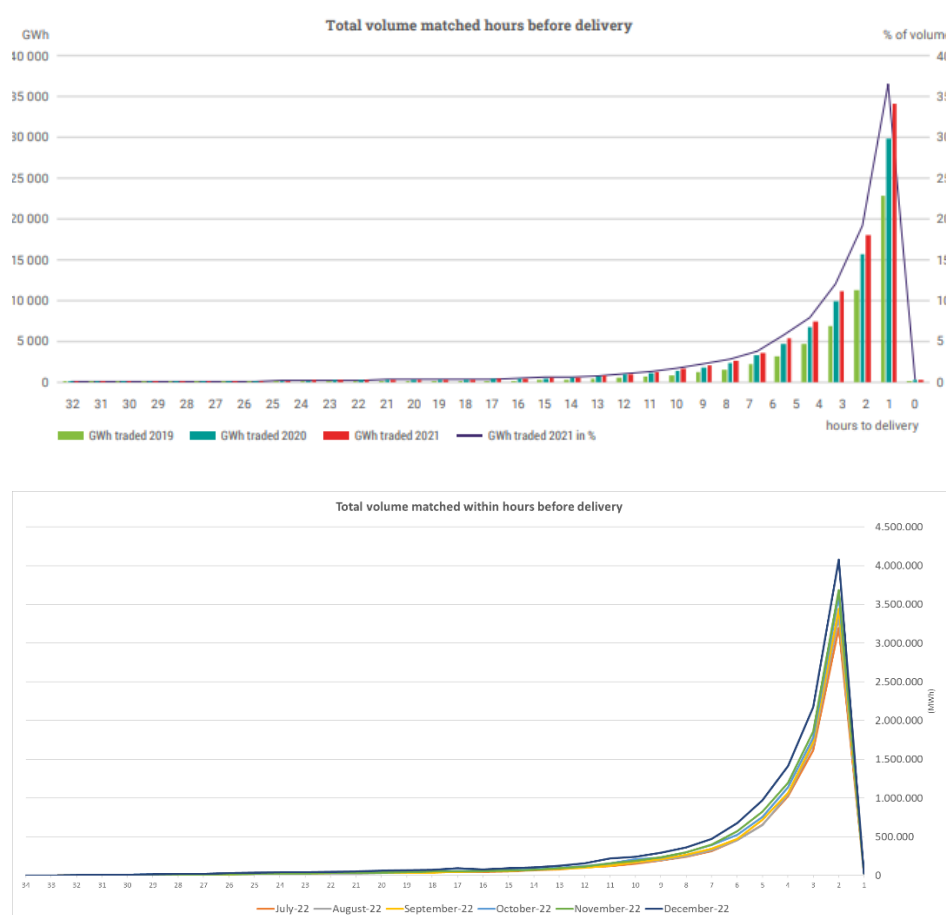
*Figure 7: Intraday gate closure times in different Member States*



*Source: Nominated European Market Operators (NEMOs)*

Trading closer to the time of delivery enables market participants to balance their position, and in particular to optimise the integration of variable renewables in the power system. *Figure 8* below shows how trades increase drastically when getting closer to the time of delivery, illustrating the importance of these very short-term trades for market participants.

Figure 8: Traded volumes of electricity depending on the time before delivery of electricity (yearly in 2021 to the left, monthly in the second half of 2022 to the right)



Source: CACM Annual report 2021 ([CACM Annual Report 2021 \(nemo-committee.eu\)](https://www.nemo-committee.eu/CACM-Annual-Report-2021)) and NEMOs

- *Commission proposal*

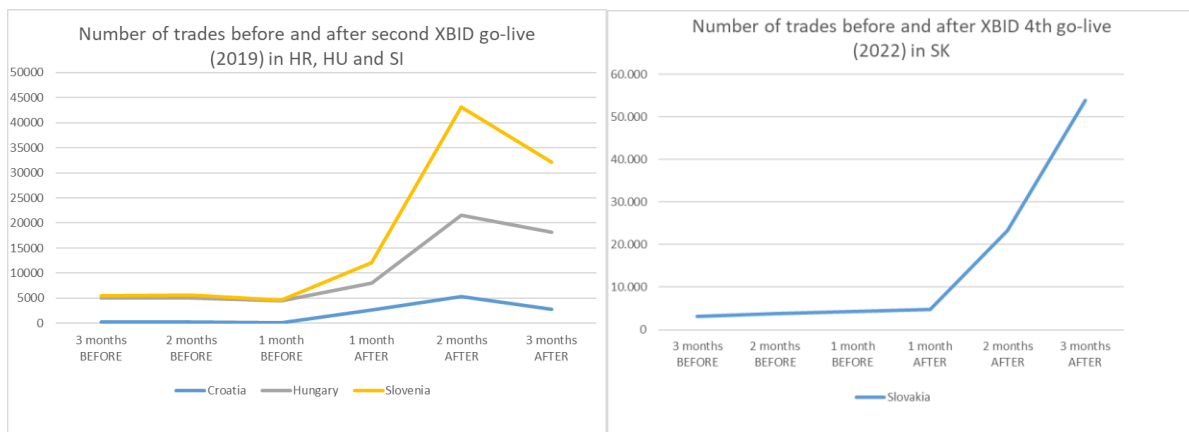
While short-term markets seem to deliver adequate price signals, further improvements could lead to increased efficiency.

The Commission proposes to set the *cross-border intraday gate closure time closer to real time*, in order to allow market participants to trade as close as possible to the time of delivery of the electricity.

#### 4.2. Sharing of order books and minimum bid size

Since EU day-ahead and intraday electricity markets are coupled<sup>83</sup>, liquidity and therefore the efficiency of the markets has considerably increased. *Figure 9* below illustrates how trades have increased when Member States have joined the common intraday coupling platform (called XBID).

*Figure 9: Number of trades before and after the XBID platform go-live in selected Member States*



Source: NEMOs

However, as soon as the cross-border intraday market closes, these benefits disappear: within the same bidding zone, market participants can no longer trade with each other if they do not bid on the same power exchange platform, considerably decreasing the liquidity and opportunity for matching the variability of renewables close to real time.

- Germany provides a relevant example, as approximately 40% of all intraday trades are executed in the last hour before the time of delivery – this percentage is steadily increasing as more renewables connect to the system. Ahead of the last hour before the delivery time, the two NEMOs active in Germany, Nord Pool and EPEX, experience substantial levels of activity in terms of buy and sell orders being matched and resulting in actual trades. One hour before the delivery time, when the cross-border intraday market closes, the liquidity in the shared intraday platform drops to almost zero, with no order receiving a match or resulting in a trade<sup>84</sup> *Commission proposal*

The Commission proposes to increase the liquidity in the intraday market also when cross-border trade is not possible, by extending the benefit of the coupling of intraday market through *sharing*

<sup>83</sup> The market coupling is organised by nominated electricity market operators (NEMOs) and there can be more than one NEMO in a Member State

<sup>84</sup> Source: Nordpool



*of the order books within bidding zone*. This will improve the competition and liquidity of intraday trades, as it will maximise the opportunities for market participants to trade shortages and surpluses of electricity. This will contribute to better integrating variable renewables in the electricity system.

In addition, the Commission proposes to set the *minimum bid size* for intraday and day-ahead market to 100 kW or less in the Regulation, to ensure that a maximum of flexible sources can participate in the market. This would provide a coherent framework for market parties in different short-term markets: it would align with what has been implemented in the day-ahead and intraday market coupling and with the foreseen change for balancing markets in the future Network code on Demand response<sup>85</sup>.

## **5. Facilitate and incentivise non-fossil flexibility services for renewables integration**

### **5.1. Introduction**

- *State-of-play: Flexibility needs*

Flexibility solutions, together with grid developments, are necessary to cope with variations in electricity generation from renewable resources, and to enable the electricity system and grid to adjust to the variability of generation and consumption patterns across different time horizons. They will enable an optimal use of electricity generation from renewable resources and will minimise curtailments thereby supporting the decarbonisation objective and limiting the costs of the electricity system. To illustrate, Germany curtailed 6 146 GWh of renewable electricity in 2020, 5818 GWh in 2021, and 5419 GWh in the first half of 2022<sup>86</sup>.

*Figure 10* below illustrates the increasing trend in flexibility needs<sup>87</sup> towards 2030 in different time horizons.

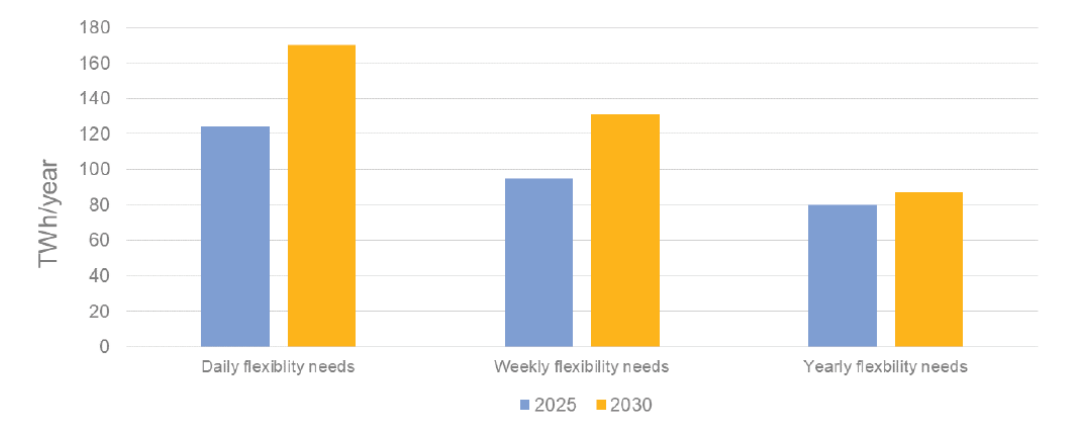
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<sup>85</sup> Framework Guideline on Demand Response, ACER, 2022

<sup>86</sup> Zahlen Ganzes Jahr 2021.pdf (bundesnetzagentur.de)

<sup>87</sup> The estimation of the flexibility needs was based on the methodology described in section 2.2.1 of the European Commission report Mainstreaming RES Flexibility portfolios - Design of flexibility portfolios at Member State level to facilitate a cost-efficient integration of high shares of renewables as tasked by the European Commission. Compared to the original methodology, some simplifications were applied by ACER, e.g. to calculate the residual load, only information on load and wind and solar generation was used, as information on other intermittent renewable sources and must-run generation was not available to ACER.

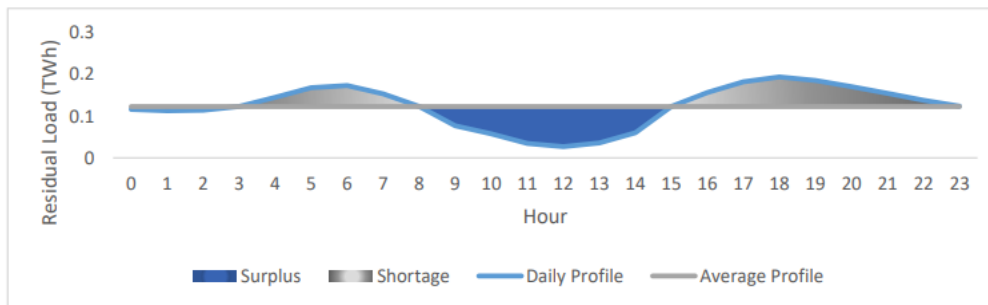
Figure 10: expected evolution of flexibility needs in the EU



Source: ACER (Final assessment of the EU wholesale Electricity market design, April 2022)

The variability introduced by increasing shares of renewable generation will further increase those flexibility needs. Figure 11 below illustrates the 2030 residual load<sup>88</sup> curve in the EU, averaged per hour and across all Member States.

Figure 11: Daily flexibility needs



Source: JRC, Flexibility requirements and the role of storage in future European power systems 2022

More specifically, daily flexibility needs are expected to increase on average by 133% across all countries between 2021 and 2030. Across Member States, 2030 daily flexibility needs will vary

<sup>88</sup> Residual load indicates the production left for conventional power plants to meet demand, after taking into account renewable generation

between 4% and 17.5% of total demand. Comparing 2050 to 2030, daily flexibility needs will further increase on average by 250% in the EU<sup>89</sup>.

- ***Development of non-fossil flexibility***

Generation, storage and demand can provide flexibility, each with different characteristics. However, the role of gas in providing flexibility to the system is still dominant currently. Fossil-fuel free flexibility such as demand response (reduction of the consumption or shifting the consumption in time) and storage has the potential to reduce the role of natural gas in the short-term market.

Cumulative installations of batteries and pumped hydro reached respectively 10 GW and 40 GW in 2022, with volumes expected to reach more than 50 GW for batteries and 50 GW for pumped hydro by 2030<sup>90</sup>. The Italian TSO Terna recently carried out an assessment on storage needs for 2030<sup>91</sup>: the storage capacity needs are estimated to be around 15 GW, which is about 15% of the total variable renewable capacity. It must be noted that peak power is not the only relevant parameter when assessing the need and how storage could contribute to fill the flexibility need: how long it can charge or discharge for is also an important element.

Around 21 GW of demand response has been active in the system in 2019<sup>92,93</sup>. Some estimations highlight a potential of more than 130 GW of demand side flexibility in 2030 (the impact assessment for the CEP<sup>94</sup> estimates a potential of 160 GW and a study from DNV GL estimates a total of 164 GW upward flexible power and 130 GW of downward flexible power<sup>95</sup>). This potential is not being developed today at the speed and scale required to support our decarbonisation targets, nor equally within EU Member States.

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<sup>89</sup> JRC, Flexibility requirements and the role of storage in future European power systems 2022

<sup>90</sup> Delta-EE and EASE European Market Monitor on Energy Storage 2022

<sup>91</sup> Terna (2022): Documento di descrizione degli Scenari 2022.

<sup>92</sup> COMMISSION STAFF WORKING DOCUMENT IMPACT ASSESSMENT Accompanying the document Proposal for a Directive of the European Parliament and of the Council on common rules for the internal market in electricity (recast) Proposal for a Regulation of the European Parliament and of the Council on the electricity market (recast) Proposal for a Regulation of the European Parliament and of the Council establishing a European Union Agency for the Cooperation of Energy Regulators (recast) Proposal for a Regulation of the European Parliament and of the Council on risk preparedness in the electricity sector

<sup>93</sup> The companies represented by the European business organisation SmartEn are currently responsible for 13 GW of flexible demand (source: SmartEn)

<sup>94</sup> COMMISSION STAFF WORKING DOCUMENT IMPACT ASSESSMENT Accompanying the document Proposal for a Directive of the European Parliament and of the Council on common rules for the internal market in electricity (recast) Proposal for a Regulation of the European Parliament and of the Council on the electricity market (recast) Proposal for a Regulation of the European Parliament and of the Council establishing a European Union Agency for the Cooperation of Energy Regulators (recast) Proposal for a Regulation of the European Parliament and of the Council on risk preparedness in the electricity sector

<sup>95</sup> [https://smarten.eu/wp-content/uploads/2022/09/SmartEN-DSF-benefits-2030-Report\\_DIGITAL.pdf](https://smarten.eu/wp-content/uploads/2022/09/SmartEN-DSF-benefits-2030-Report_DIGITAL.pdf)

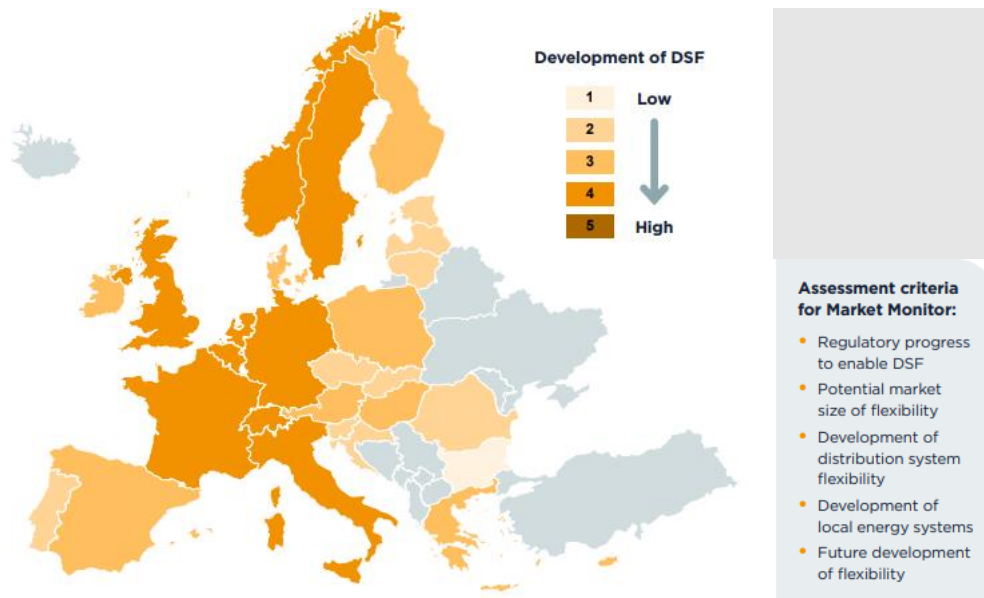
The Clean Energy Package adopted in 2019 has been an important step in attempting to bring more flexibility in form of demand response and storage services to the electricity markets and to improve their integration across the EU. It sets out that renewables, demand response and energy storage should be able to participate in all markets, that every final customer has the right to participate in demand response schemes, and that system operators have a legal basis to access and use flexibility services.

In addition, the EU Strategy for Energy System Integration of 2020 stressed the importance of flexibility as key to facilitate sector integration through electrification of end use sectors based on renewables – industry, buildings and transport. For example, electric vehicles can participate in demand response enabled through smart charging, thus allowing to optimise the electricity grid. To ensure this, the Commission proposal on the revised Renewable Energy Directive of July 2021 (subject to negotiations to be agreed by end of March) contains specific requirements to facilitate non-discriminatory participation of electric vehicles and storage assets in the flexibility services and to increase awareness of customers and relevant market actors of those possibilities via transparency requirements for system operators to provide data on the actual share of renewables and greenhouse gas emissions content in the electricity supplied.

While the timely and correct transposition of the related provisions of the Clean Energy Package is crucial to develop this flexibility, it can be observed that *transposition is lagging behind* in the majority of Member States. Non-fossil flexibility sources, such as demand response and storage, are progressively participating in the wholesale markets following the implementation of the Clean Energy Package, but the development remains slow.

*Figure 12* below illustrate the opening of the short-term wholesale markets to demand response in EU Member states.

Figure 12: Development of demand side flexibility in wholesale markets



Source: SmartEn (<https://smarten.eu/wp-content/uploads/2023/02/DSF-Market-Monitor-2022.pdf>)

Demand response is also increasingly participating in the ancillary services market but the development remains heterogenous between Member States, and overall slow<sup>96</sup>.

## 5.2. Procurement of flexibility service by system operators and tariff regulation

### Feedback from the public consultation

- The majority of respondents consider that a stronger role of operational expenditures for **system operators' remuneration** would incentivise the use of demand response, energy storage and other flexibility assets. Some respondents point out that in addition to incentivising demand response and energy storage, a stronger role of operational expenditures would greatly incentivise the use of grid enhancing technologies, such as Dynamic Line Rating, Advanced Power Flow control, innovative solutions and digital platforms etc. National regulatory authorities, TSOs and DSOs agree and note that

<sup>96</sup> When looking at the percentage of balancing capacity volume procured from DSR facilities in comparison to total procured balancing capacity for mFRR, and percentage of balancing energy volume activated from demand-side response facilities in comparison to total annually activated balancing energy for mFRR. Survey on Ancillary services procurement, Balancing market design, ENTSO-E, 2021. Available here: [https://eepublicdownloads.blob.core.windows.net/public-cdn-container/clean-documents/mc-documents/balancing\\_ancillary/2022/2022-06-20\\_WGAS\\_Survey.pdf](https://eepublicdownloads.blob.core.windows.net/public-cdn-container/clean-documents/mc-documents/balancing_ancillary/2022/2022-06-20_WGAS_Survey.pdf), p.179 and p.183.

different regulatory regimes coexist in Europe for the treatment of costs. They agree that the use of efficient and innovative solutions (that lead to smarter use of the grid) should be better incentivised to complement the vast investments in the physical grid that are necessary to reach the EU's climate neutrality goals.

- Several respondents point out that a stronger role of operational expenditures in the system operators' remuneration is not sufficient because of a time-lag for recognising operational expenditures in the remuneration. In most national regulatory systems, OPEX would only be adapted with a considerable time-lag. Several respondents propose the introduction of *further incentives* to better manage flexible resources.
- Several respondents advocate for increased *network transparency*, in particular on grid congestion, to further incentivise flexibility. Respondents also propose performance indicators linked to renewables integration. Some respondents call for the further development of decentralised flexibility markets as a market-based mechanism for system operators to procure flexibility services.

○ *State of play*

Investment in grids will be key to enable the integration of high shares of renewable energy and for accommodating the electrification of end users. They are becoming a growing share of the total investments of the energy transition. In fact, the share of costs related to electricity grids increased from 27% to 37% of the supply costs (grid costs and generation costs) between the 2010s and the 2020s, with a total of electricity grid investments over the current decade estimated at EUR 584 billion<sup>97</sup>. It is essential that transmission and distribution tariffs reflect such developments, encouraging projects that support the long-term network needs, are cost-reflective and give incentives for the deployment of smart electricity grids and innovative solutions that contribute to the reduction of network losses.

In addition, enhancing the digitalisation of the energy system will also be instrumental to achieving our energy and climate goals. NRAs are currently defining common smart grid indicators, as well as objectives for these indicators, so that they can monitor smart and digital investments in the electricity grid annually as of 2023.

An efficient use of the grid is needed to limit the costs of the energy transition. The use of non-fossil flexibility services, such as demand response and storage, by system operators, be it for balancing services activated by TSO or for congestion management or other grid services activated by TSOs and DSOs, can contribute to an efficient use of the grid and an efficient operation of the

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<sup>97</sup> [https://energy.ec.europa.eu/news/member-states-agree-new-ambition-expanding-offshore-renewable-energy-2023-01-19\\_en](https://energy.ec.europa.eu/news/member-states-agree-new-ambition-expanding-offshore-renewable-energy-2023-01-19_en)

electricity system. It is therefore important that TSOs and DSOs have the right incentives to procure such flexibility services.

The Electricity Directive already sets out that the DSOs should be incentivised to procure flexibility services based on market procedures, in order to efficiently operate their networks and to avoid costly network expansions.

Both TSOs and DSOs are launching local initiatives to further develop and use flexibility services, through different types of tools ranging from data sharing to a local marketplace for specific services<sup>98</sup>.

Table 4 below illustrates some national initiatives developing market-based procurement of services, in particular for congestion management by the DSOs.

Table 4: market design specifics in some local flexibility markets

Design characteristic	sthlmflex	IntraFlex	NorFlex	GOPACS	enera	UK tenders	ENEDIS tenders
Locational organisation	Congestion zones	Congestion zones	Congestion zones	Congestion zones and connection points	Congestion zones	Congestion zones	Congestion zones (not all points eligible)
Long-term contracts	X	—	—	—	—	X	X
Evaluation criteria	Availability offer	—	—	—	—	70 % price / 30 % technical criteria	On price except for voltage-related tenders
Call-up	Once per year	—	—	—	—	Twice per year	Ad hoc
Price caps	Published	—	—	—	—	Published	Non-published
In all cases, the pricing mechanism is pay-as-bid for both the availability and the activation components							
Short-term market	X	X	X	X	X	—	—
Start of trading	D-7	D-7	D-7	D-1 to T-6h	D-3 to T-1h	—	—
Gate closure time	Nominal 120 minutes, in practice at 09.00 D-1	90 minutes	120 minutes	As per Intraday Market	Nominal 15 minutes, in practice some hours before	—	—
MTU	60 minutes	30 minutes	60 minutes	15 minutes	15 minutes	—	—
DSO trading	Implicit price caps	Active bidding	Active bidding	None	Implicit price caps	—	—
In all cases, continuous trading is employed, evaluation of offers are made based on price and the pricing method is pay-as-bid							
Buying parties							
DSO	X	X	X	X	X	X	X
TSO	For balancing and congestion	—	For balancing and congestion	For congestion	For congestion	—	—
BRPs	—	—	—	X	—	—	—
Network operators' coordination							
Procurement rule	DSO over TSO	N/A	DSO over TSO	Separate procurement	DSO over TSO	N/A	N/A
Security coordination	Subscription rights	None	To be developed through the FDR	TSO/DSO analysis	Cascading top-down	None	None

D-1 means 1 day before delivery, T-6h means six hours before delivery

Source: JRC, *Local Electricity Flexibility Markets in Europe, 2022*<sup>99</sup>

<sup>98</sup> Review of Flexibility Platforms, A report prepared by Frontier Economics for ENTSO-E, September 2021. Available here: [210957\\_entso-e\\_report\\_neutral\\_design\\_flexibility\\_platforms\\_04.pdf](https://www.entsoe.europa.eu/media/10000/2021/09/210957_entso-e_report_neutral_design_flexibility_platforms_04.pdf) (azureedge.net)

<sup>99</sup> Local Electricity Flexibility Markets in Europe, JRC Technical Report, European Commission, 2022. Available here:

While these initiatives constitute a very good starting point, their scope and application remain limited.

Additional incentives are needed to further enhance the use of flexibility solutions as an alternative to grid development, where possible. In that respect, in most Member States, the current regulatory framework treats capital expenditures (CAPEX) of system operators, such as network expansion costs, different from their operational expenditures (OPEX), resulting in a bias in favor of capital expenditure. This could disincentivise system operators from choosing a flexibility solution resulting in operational expenditure rather than an investment in infrastructure resulting in capital expenditure. Removing this bias in the regulatory framework will allow system operators to select the most cost-efficient solution for their networks.

All Member States concerned by an initiative of market-based procurement of flexibility services by the DSOs listed in *Table 4* above have adopted a TOTEX (total expenditure) approach for the remuneration of system operators, which allows the DSOs to choose OPEX or CAPEX or a mix of both to meet network demands without a regulatory bias towards capital expenditures.

- *Commission's proposal*

The Commission reiterates that a full implementation of the Clean Energy Package is key to unleash non-fossil flexibility assets, such as demand response and storage<sup>100</sup>. Moreover, the Commission together with ACER has started the work on new rules to further support the development of demand response, including rules on aggregation, energy storage and demand curtailment, and to address remaining regulatory barriers. A study will be conducted in 2023, underpinning the drafting of the Network Code.

In the present reform, the Commission proposes to further develop regulatory frameworks based on relevant expenditures necessary to operate the network in the most efficient way and finding the right balance between capital expenditure and operational expenditure. This would incentivise system operators to further develop innovative solutions to optimise existing grid and procure further flexibility services.

Grid investments play a crucial role for the energy transition and there is a need for a predictable and forward-looking regulatory framework for such investments. Transmission and distribution grids will need to evolve rapidly to be able to incorporate the vast amounts of new renewable generation and new electrified and digitalised demand. An example comes from the high offshore renewable ambitions indicated by Member States, where network development planning will give visibility on long-term network needs both in new offshore grids as well as onshore

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<sup>100</sup> For example, in relation to Article 17(4) of the Electricity Directive, Member States should ensure that it is implemented in a way that ensures the financial compensation is fair and does not create a market entry barrier.



reinforcements. These investments, also anticipatory investments in some cases, would need to be planned for in the respective tariff regimes.

Additionally, the ongoing work on smart grid indicators is crucial to guide and speed up investments in smart and digital electricity grids and will help to operationalise the shift in tariff structures, incentivising an efficient mix of operational and capital expenditure.

### ***5.3. Use of sub-meter data for the settlement and observability of demand response and flexibility services***

#### **Feedback from the public consultation**

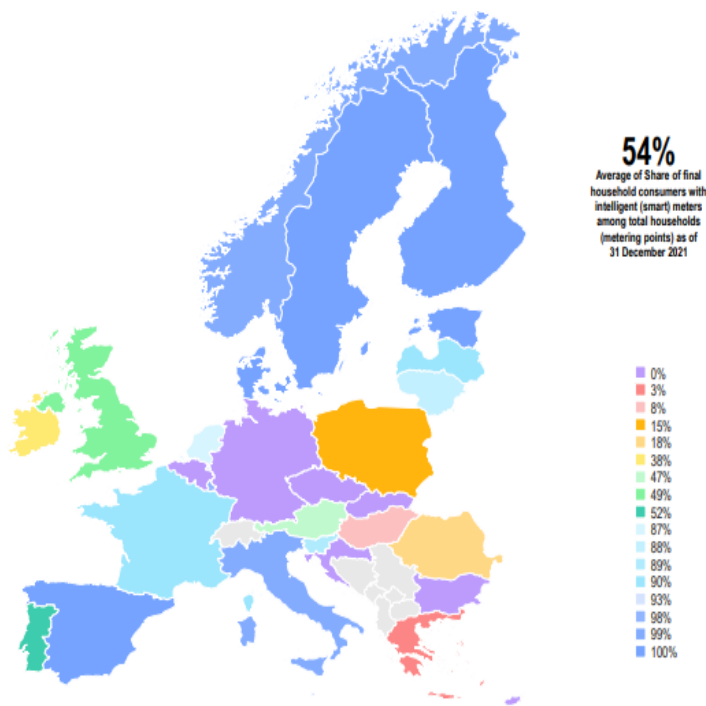
- The majority of respondent would welcome the **use of sub-meter data**, including private sub-meter data, for settlement/billing and observability of demand response and energy storage and considers that the use of sub-meter data would support the development of demand response and energy storage. Some respondents noted that the use of submeter data creates a big market potential as it opens the door for multiple market actors, including demand response providers and storage providers, to become active simultaneously on one connection point. Sub-metering would allow active consumers to sell their flexibility to the markets, participate to energy communities, proceed to energy sharing or peer-to-peer transactions, contract different suppliers for different appliances behind the main meter, or to offer services to system operators.
- Respondents stressed the need to ***ensure the quality*** of the sub-meter data and to verify the consistence with the main meter. Several respondents considered that the sub-metering system must be certified
- Several respondents consider that the ***Measurement Instruments Directive*** 2014/32/EU (MID) would need to be reviewed as its requirements are too restrictive and hamper the use of sub-meter data. Other respondents call for a clarification of the applicability of MID to sub-meter data.
- Some respondents voice concerns about using sub-meter as this data could bring significant ***complexity*** and create risk of gaming between the meters. The focus should stay on the full roll-out of smart metering systems, which should remain the central point of measurement.
- Several respondents consider that the role of sub-meters and their use should be further defined and detailed in the future ***network code on demand response*** to be developed on the basis of Art. 59 of the Electricity Regulation 2019/943.

○ *State of play*

The Electricity Directive provides for the deployment of smart metering systems in all Member States to facilitate the more active participation of customers in the electricity market and in the energy transition. However, not all Member States have completed the full rollout of smart metering systems and the share of final household customers having a smart metering system installed varies significantly among Member States.

Basing the measurement of demand response and flexibility services on smart metering systems installed by DSOs risks limiting the development of demand response to markets with full deployment of smart metering systems, depriving some customers from the possibility to engage and value their flexibilities as well as preventing electricity system from benefiting from the flexibility of customers without smart metering systems.

*Figure 13: Status of the roll-out of electricity smart meters at the end of 2021*



Source: ACER Market Monitoring Report 2021<sup>101</sup>

<sup>101</sup> Annual Report on the Results of Monitoring the Internal Electricity and Natural Gas Markets in 2021 - Energy Retail and Consumer Protection Volume, ACER/CEER, October 2022. Available here: [MMR\\_2021\\_Energy\\_Retail\\_Consumer\\_Protection\\_Volume.pdf \(europa.eu\)](https://europa.eu/energy/energy-retail-consumer-protection-volume)

Even where smart metering systems are installed, the technology is not always able to provide the level of granularity of data needed for the measurement of certain services and will thus not allow to tap into the full flexibility potential of the demand side.

If sub-metering systems providing data with appropriate accuracy are available, system operators should be entitled to use sub-meter data (including from private sub-meters) for settlement and observability processes of demand response and flexibility services, including energy storage. The use of sub-meter data should be accompanied by requirements for the sub-meter data validation process to check and ensure the quality of the sub-meter data.

- *Commission proposal*

The Commission proposes to enable system operators to use sub-meter data (including from private sub-meters) for settlement and observability processes of demand response and flexibility services to support the development of these services and facilitate the participation of active customers in electricity markets.

The use of sub-meter data should be accompanied by requirements for the sub-meter data validation process to check and ensure the quality of the sub-meter data.

The principles and roles for the use of such data will be detailed in the future network code on demand response, including rules on aggregation, energy storage and demand curtailment based on Article 59(1), point (e) of the Electricity Regulation 2019/942.

This provision is linked and complements the provision that customers shall have the right for more than one meter installed in their premises and sub-metered consumption to be separately billed and deducted from the main metering and billing (see section “Adapting metering to facilitate demand response from flexible appliances” in the section on “Better consumer empowerment and protection”).

#### *5.4. Incentives for non-fossil flexibility such as demand response and storage, and remuneration schemes*

##### **Feedback from the public consultation**

##### **Demand response**

The majority of respondents consider appropriate to **enable a product to foster demand reduction and shift energy at peak times** as an ancillary service, aiming at lowering fuel consumption and reducing the prices. However, many respondents also consider that such peak shaving actions should happen through wholesale markets, without any intervention from the TSO, and that such a product could be a barrier to these developments. Such a product could be considered as specific and transitory solutions to kick start demand response.

Some respondents note that all ancillary services should favor carbon-free solutions, or that the services should be reviewed to better enable demand response participation.

The majority of respondents do not recommend some form of **demand response requirements that would apply in periods of crisis**. They mainly consider that developing market-based solutions to promote demand reduction can prevent these crisis situations before they occur and can spur further investment into flexibility assets. However, some market participants recommend a demand reduction target as a permanent feature. If such concept should be pursued, some respondents consider it should take the form of critical peak pricing auctions (some form of dynamic capacity mechanisms for peaks), while transparency on the need and auctions would be key.

Respondents share **several proposals as way forward to further develop demand response, energy storage and other flexibility assets**:

- The **full implementation of the Clean Energy package** provisions should remain a top priority, opening all market to demand response and storage. Some respondents ask for more oversight from the European Commission and ACER in this respect and encourage sharing of best practices. The future Network Code on Demand Response should provide the necessary provisions to address any remaining barriers.
- Providers of demand response and storage should be able to **stack value from different markets** (including local congestion management).
- Alternative market-based mechanisms providing long-term investments signals such as **capacity remuneration for demand response and storage** could be desirable, to reach the necessary levels of storage and demand response development, which come together with renewable targets.

- **Targets for flexibility** (demand response and/or storage) could be set at national level, through e.g. a grid designed at 95% of the peak load in network development plans, or through requirement for balance responsible parties or suppliers to reduce their perimeter's peak load.
- The **minimum bid size** on short term markets could be lowered, to enable smaller actors to participate.
- Transparent and easy access to **prices**; dynamic publication of **imbalance settlement prices** with no delay
- Auctions for CfDs could **consider hybrid assets** (renewables + storage); **CfDs for flexibility** could be in a form of public support scheme.
- Stronger **locational and temporal signals** could be given in prices or grid tariffs.
- **Flexible grid connection agreements** could be more used.
- **Local flexibility markets** should be incentivised.
- **Consumers contracts** should keep demand response incentives (limitation of the volume at fixed price, critical peak period contracts as a pure spot price reference).
- **Scarcity pricing** to boost demand response.
- **Flexibility registers** to accelerate the development of harmonised products for system services and enable single registration point for flexibility assets.
- **System operators could own storage** in specific and limited situations, to ensure an efficient grid management.
- A clarification of **demand response versus energy efficiency** as a service may be needed.

Regarding electrical vehicles development, some respondents note that visibility is needed, and that controllable/bidirectional charging stations should be encouraged.

### **Capacity mechanisms**

The majority of respondents consider that the current setup for **capacity mechanisms** is not adequate to respond to the investment needs as regards firm capacity, in particular to better support the uptake of storage and demand side response. They fear a lock-in effect in fossil-fuel based technologies. While existing CRMs already allow participation of **demand response and storage**, future designs should enable them to participate to the full extent possible and further incentivise carbon-free solutions.

Respondents **share the following proposals:**

- To consider not only the peak load, but also rapid variations of renewables (“flexibility adequacy”);
- To smoothen the process;
- To contemplate more targeted capacity remunerations (such as interruptibility);
- To further consider national assessments;
- To better harmonise European approaches, and address cross-border barriers for sharing resources;
- To bring capacity mechanisms as a full part of the market design.

Some respondents consider capacity mechanisms are not suitable as a robust **investment framework**, since they cannot deliver a one-size-fits-all signal that targets all type of investments. **Specific support schemes** may be better fit to ensure proper investments, going beyond pure security of supply question (such as renewables integration and the corresponding flexibility need).

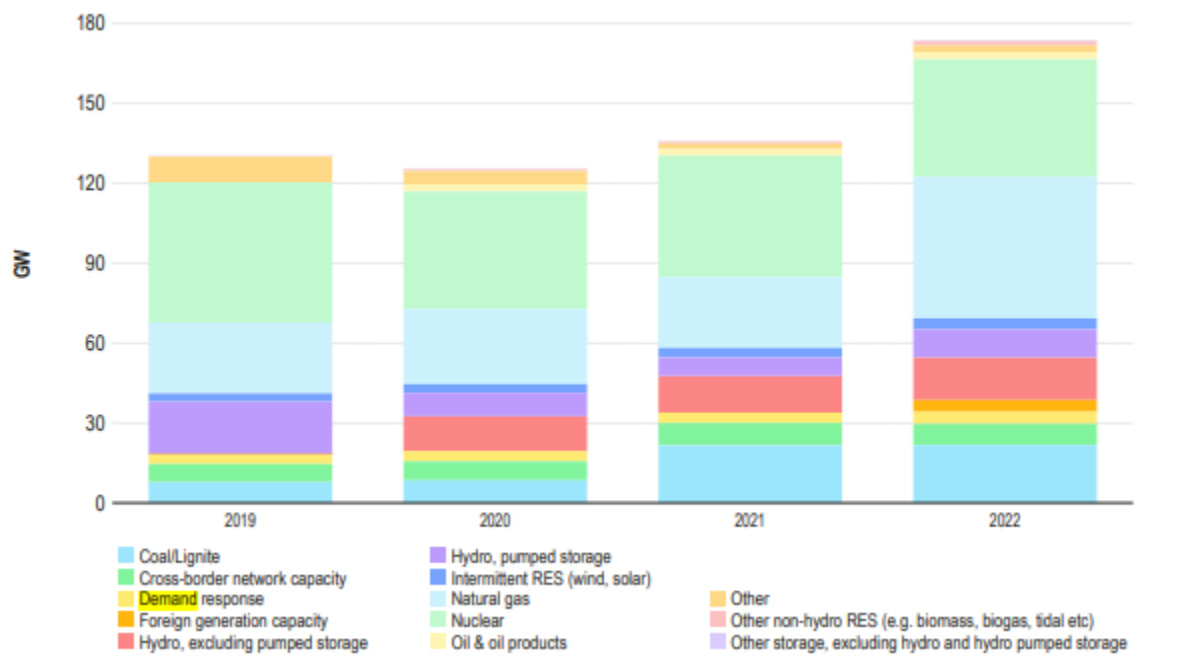
○ *State of play*

Over the period 2019-2022, demand response participation in capacity mechanisms has increased to over 4 GW, while storage is still at very low levels (below 300 MW in 2022)<sup>102</sup>.

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<sup>102</sup> ACER, *Security of EU electricity supply in 2021: Report on Member States approaches to assess and ensure adequacy*

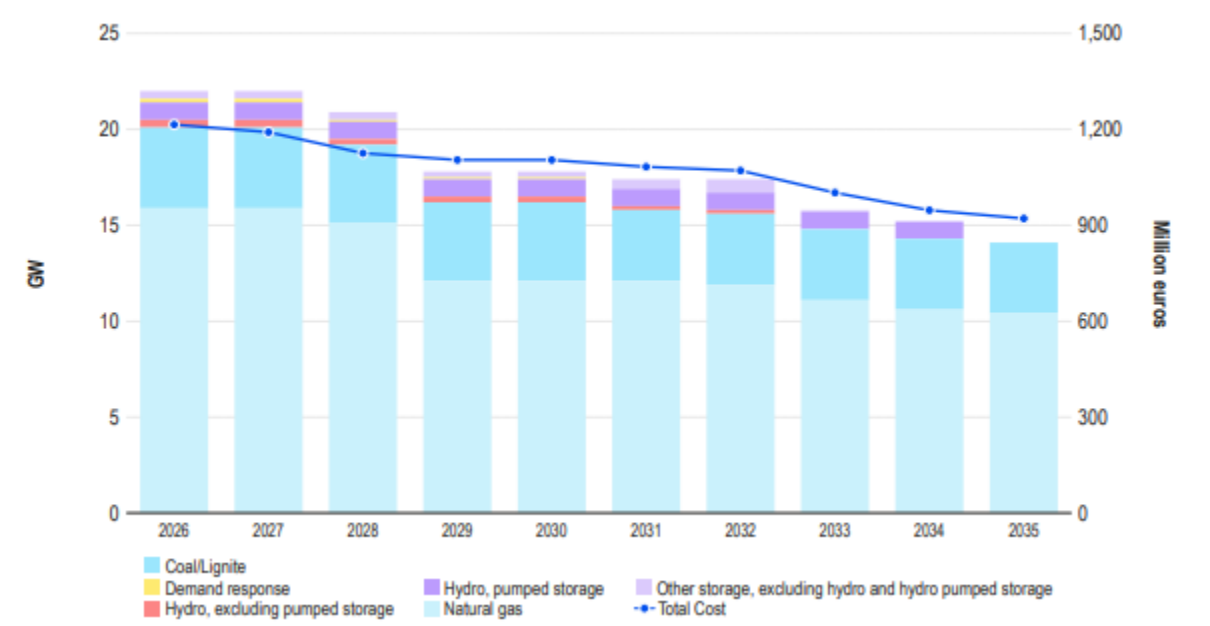
Figure 14: Capacity remuneration through capacity mechanisms per type of technology in EU-27 2019-2022



Source: ACER (Security of EU electricity supply in 2021: Report on Member States approaches to assess and ensure adequacy)

Despite a trend towards diversification, most of the long-term contracted capacity is allocated to natural gas and coal/lignite power plants. Although this will reduce when new emissions' limits come into force in 2025, capacity mechanisms are still expected to continue to support fossil-fueled power plants beyond 2030<sup>103</sup>.

Figure 15: Long-term contracted capacity and costs by type of technology in the EU-27 on the period 2026-2035



Source: ACER, *Security of EU electricity supply in 2021: Report on Member States approaches to assess and ensure adequacy*

This trend shows the difficulty for non-fossil-fuel based flexibility (like demand response and storage) to effectively compete in the electricity system as a buffer to renewables variations.

In some Member States, there has been a significant increase in the participation of energy storage and demand response, in particular in recent auctions. As an example, Poland awarded over 1.5 GW for demand response out of a total of 5 GW for 2027 in the latest auction of its capacity mechanism<sup>104</sup>. In the latest auction of the Italian capacity mechanism, storage accounted for about 30% of the total newly allocated capacity for 2024 (3,8 GW)<sup>105</sup>. Such developments are lower in some other Member States: Ireland awarded 490 MW of demand response and about 450 MW of storage, against 8,8 GW of total awarded capacity for 2025-2026<sup>106</sup>. Belgium awarded 287 MW of demand response and 41 MW of storage over a total of 4.4 GW of contracted capacity for 2025-2026<sup>107</sup>.

In Member States with existing capacity mechanisms, efforts to encourage non-fossil flexibility participation can be based on additional “green and flexible” criteria as provided for in the state

<sup>104</sup> <https://www.pse.pl/documents/20182/98611984/Wyniki+aukcji+glówniej+na+rok+dostaw+2027>

<sup>105</sup> <https://www.terna.it/it/sistema-elettrico/mercato-capacita>

<sup>106</sup> <https://www.sem-o.com/documents/general-publications/T-4-2025-26-Final-Capacity-Auction-Results-Report.pdf>

<sup>107</sup> <https://www.elia.be/en/grid-data/adequacy/crm-auction-results>



aid guidelines (CEEAG)<sup>108</sup>. However, when a Member State does not have a capacity mechanism or where the amount of non-fossil flexibility such as demand response and energy storage coming from these mechanisms proves to be insufficient to support the Member States’ renewables’ target, it should be possible to further support required flexibility. A dedicated capacity payment could be envisaged as a solution (further details in the next section), enabling further renewable integration, in the form of non-fossil flexibility support schemes such as demand response and storage.

As an example, in France, the participation of consumers in balancing and wholesale markets is further boosted by dedicated capacity payments. As a temporary measure, demand response providers are remunerated via regular, competitive tenders. This mechanism has shown an increased interest over the past years.

*Table 5: Participation in capacity auctions dedicated to demand side response in France -*

Tender for year	Contracted volume (MW)
2018	733
2019	590
2020	770
2021	1,366
2022	1,982

*Source: ACER, Security of EU electricity supply in 2021: Report on Member States approaches to assess and ensure adequacy*

Belgium is also considering launching a dedicated scheme for low carbon technologies (new storage and batteries, as well as demand response) to procure capacity for winter 2024-2025<sup>109</sup>.

Finally, demand response should be allowed to further contribute to integrating renewables in the system and help coping with critical situations in the electricity system. Where market development is unsatisfactory, such a role of demand response could take the form of a dedicated ancillary product, to be used by the system operator. This would allow using renewables at their full potential, by shifting the consumption to a moment with higher renewables production.

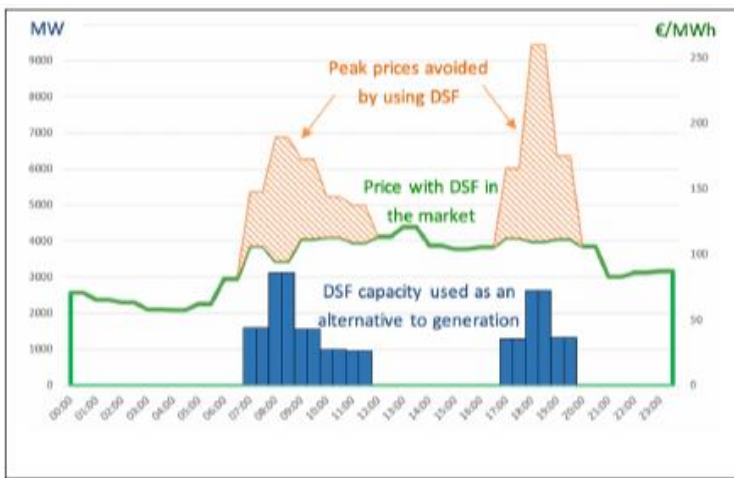
Furthermore, when consumption is high and the renewables’ generation insufficient to cover it, demand reduction could partially replace the use of gas power plants, contributing to lowering the prices and the gas consumption volumes<sup>110</sup>.

<sup>108</sup> COMMUNICATION FROM THE COMMISSION Guidelines on State aid for climate, environmental protection and energy 2022 (2022/C 80/01)

<sup>109</sup> [Formal public consultation on the Functioning Rules for the tender for low carbon capacities \(elia.be\)](https://www.elia.be/en/consultation-formal/public-consultation-on-the-functioning-rules-for-the-tender-for-low-carbon-capacities)

<sup>110</sup> *Based on observed hourly generation during the period between January and August 2022, a reduction of 5% during the 10% hours displaying the highest level of demand for electricity would bring the average demand during these hours to the level of the first non-selected peak hours. This would therefore result in a smoothing*

Figure 16: illustration of demand side flexibility effect



Source : Compass Lexecon, *Study on the quantification of Demand Response benefits to electricity suppliers and consumers in Europe in 2030 on its way to achieve deep decarbonisation, 2021*<sup>111</sup>

○ *Commission proposal*

The Commission proposes to request NRAs, based on inputs from transmission and distribution system operators, to periodically *assess the need for flexibility* in the system, based on harmonised methodology, proposed by ENTSO-E and EU DSO entity and adopted by ACER. Based on the national assessments, ACER should give an overview at European level, with recommendations of cross-border relevance. The Member States could use this assessment to determine a national objective for non-fossil flexibility such as demand response and storage, also reflected in their NECP.

The Commission proposes to support the development of clean flexibility solutions with low-carbon capacity payments by making clear in the Recitals how the Electricity Regulation and State-aid guidelines can be read together to create a *low-carbon capacity mechanism*<sup>112</sup> (i.e. by setting a low CO<sub>2</sub> cap and adding flexibility requirements).

In addition, the Commission proposes to make it possible for Member States to design a non-fossil flexibility support scheme in the form of a *capacity payment*, to enable renewable targets and

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*of the hourly consumption profile. Moreover, since gas is generally the marginal technology during the hours with the highest demand, this targeted 5% reduction can lead to a reduction of gas consumption estimated around 1.2bcm over a 4-month period. This represents around 3.8 % of gas consumption for power over the same period. Recent studies<sup>110</sup> show that the current potential of demand response could fulfil the mandatory target, having a positive impact on electricity prices and on volumes of gas savings*

<sup>111</sup> [http://dr4eu.org/wp-content/uploads/2021/05/CL-DR4EU-DSR-study-06052021\\_vdef.pdf](http://dr4eu.org/wp-content/uploads/2021/05/CL-DR4EU-DSR-study-06052021_vdef.pdf)

<sup>112</sup> CEEAG Art. 345

based on the assessment described above. Such additional support scheme should be designed as a competitive bidding process. The dimensioning of the scheme should take fully into account investments which come on a pure market basis or through a capacity mechanism whilst aiming at phasing out fossil sources from the mix. Such a scheme would provide more stable revenues to non-fossil flexibility (such as demand response and storage), while preserving full exposure to market price signals.

Finally, the Commission proposes to allow system operators to develop a *“peak shaving” product*, to incentivise consumption reduction at peak time (i.e., in times of high demand for electricity and/or limited generation from renewables). System operators could then call for demand reduction during certain hours of the day, and the consumers would get paid for this reduction. Such product could help to decrease fossil fuel generation and optimise the use of renewable electricity.

## **6. Towards better consumer protection and empowerment**

### **Feedback from the public consultation**

#### **Energy sharing**

See section 2.4

#### **Right to a second meter/sub-meter**

The consultation found that majority of respondents supported introducing a right for customers to a second meter/sub-meter to distinguish electricity consumption/production by different devices. However, cost-effectiveness and ownership were caveats. The implementation of sub-metering was divisive, with some favouring customer choice and installation by service providers, while others insisting on DSO oversight. The main meter according to some respondents should remain the central point of measurement, balance settlement, and billing. Sub-meters were supported if there is a single source of truth for billing and settlement, and compensation agreements are in place, and there are no lock-in effects. Harmonised protocols for data creation, management, and transmission were suggested to provide accurate, stable, and transparent data. Sub-meters supporting demand response and storage were seen as complementary to smart meters in developing flexible, efficient and sustainable electricity, and fostering competition. It was argued that sub-metering should be encouraged to reduce barriers for new entrants in the market, so long as it does not compromise system security. It was also pointed out that the Electricity Directive already includes useful provisions promoting flexibility and tools to support it, while details on the role and use of sub-meters as means for flexibility should be set in the future network code on demand response. A minority viewpoint cautioned

that implementing sub-metering without specific safeguards would create a new category of final customers without the same rights and responsibilities as other retail electricity customers.

### **Offers and contracts**

Stakeholders have diverging views about the obligation for suppliers to offer fixed-price and fixed-term contracts for households. While some stakeholders explain that such obligations violate free market principles and argue that market-based fixed-price contracts should be offered voluntarily, majority of consumer organisations, NGOs and public authorities support the introduction of such obligation. Some stakeholders propose to offer hybrid contracts, with both fixed and dynamic pricing, to meet different individual needs. Respondents suggested that customer choice should guide the duration of such contracts, with suggestions ranging from a fixed duration of one year to a range of three months to five years while the biggest support was for one year contracts

Respondents agreed that termination fees for fixed term and fixed price electricity contracts should reflect costs and not undermine competition and the ability of consumers to switch suppliers and contracts. While many stakeholders would welcome further clarification of termination fees, only some agree with mandating national regulatory authorities to establish ex ante approved termination fees. Also, consumer organisations as well as some industry representatives mentioned that the existing provisions in the Electricity Directive are sufficient. Representatives of regulatory authorities pointed out that it is difficult to set ex ante termination fees for fixed-price, fixed-term contracts because different suppliers have different costs. **Risk management for suppliers**

Most respondents across different stakeholder groups supported the establishment of prudential obligations on suppliers to ensure they are adequately hedged. However, some respondents mentioned that such rules would impede the entry of new suppliers and harm competition. While many agreed that this is a common regulatory approach to mitigating the risk of supplier default, some pointed out that suppliers should hedge for the share of their retail portfolio that corresponds to fixed-price contracts. According to a few stakeholders, suppliers should have the freedom to choose their hedging policy, but stress tests could be imposed as a prerequisite for licensing electricity sales. A minority of respondents suggest that such obligations should be differentiated for small suppliers and energy communities.

### **Suppliers of last resort**

Stakeholders mentioned that the supplier of last resort mechanism was implemented across the EU but its design varies. Majority of respondents believe that the EU regulatory framework should set general rules for and responsibilities of suppliers of last resort providing further clarity but some stakeholders pointed out that certain aspects should be left to the national level as the situation in retail markets differs.

## **Regulated prices**

Respondents are equally divided on the question of regulated prices. Majority of public authority respondents are in favour of including an emergency framework for below cost regulated prices. The advantage seen would be the possibility of preparing functional tools in the national market model that would allow price regulation to be easily activated in exceptional cases. Majority of business associations and companies believe that regulated below-cost prices distort the market, cancel the price signal and reduce incentives to invest in renewables and energy efficiency. Emergency measures should therefore be implemented outside the electricity market. They recognize however in comments that in spite of their opposition regulated prices could be a solution for energy poor and vulnerable consumers. If price regulation is introduced, it should be time-limited and only address essential energy needs. They also mention more appropriate social policies and tools to protect less flexible or more vulnerable consumers from unlimited exposure to potential extreme or sudden increases in retail prices. Some respondents from companies also suggest that consumers of all types be ultimately protected from extreme price fluctuations by hedging products offered in combination with dynamic price contracts.

### **6.1. Introduction**

Energy prices significantly increased throughout 2021 and 2022 due to Europe's overreliance on gas. During this period, several countries reported an increase in exits due to a significant increase in supplier bankruptcy. Many remaining suppliers have passed their risks onto their customers – for example by only offering contracts which track wholesale market prices. This resulted in customers being exposed to extremely volatile wholesale energy prices. This was the case not only for those who had a variable tariff but also for those who were initially protected from wholesale price volatility by being on a fixed-price contract. Consequently, many households, not only those who are most vulnerable but increasingly also middle-income families, have been facing difficulties when paying their bills.

Moreover, crisis context also revealed that consumers lack understanding regarding what contract they were on. For instance, many people were not aware that the contract they signed up for foresees electricity prices that were linked to wholesale prices. Many also thought that the prices they were paying for electricity were fixed for the entire duration of the contract which was often not the case.

There was a major movement of customers onto regulated, capped or otherwise protected variable offers. Member States developed different measures, targeted or untargeted, to keep energy affordable for all households and businesses. These measures are nevertheless very expensive and weighing on national budget.

In addition to putting affordability into question, consumers have been lacking opportunities to engage in the market – benefiting from multiple contracts or benefiting from low-cost renewables.

## 6.2. *Offers and contracts to better protect consumers against volatile prices*

### ○ *State of play*

Fixed-price contracts can protect consumers from short-term price volatility.

Since the end of 2021 and even more throughout 2022, suppliers reduced their offers and fixed-price and fixed-term contracts became scarce. In several markets, consumers are left with the option to sign up for electricity contracts with a tariff linked to wholesale prices or to fixed-price tariffs which incur substantial risk premiums. The vast majority of contracts now available allow suppliers to change the price they charge at any time. This was often insufficiently clear to customers who believed that they had entered into fixed price contracts and illustrates low awareness about and understanding of offers.

Consumer organisations reported examples where suppliers switched customers from fixed-price contract to variable price without adequate information, announced significant price increase on page 2 of a letter with energy tips, unilaterally terminated open-ended contracts with customers who did not accept imposed price increases or where suppliers did not advertise the full price of electricity when a new tax was introduced.<sup>113</sup>

Lack of understanding of electricity offers is also demonstrated by several surveys by consumer organisations and regulators. A survey done by the Belgian National Regulatory Authority, CREG, showed that half of the consumers was not aware whether they had a fixed or variable priced contract and that one in two also felt not sufficiently informed about the difference between fixed and variable prices.<sup>114</sup> According to the research commissioned by the Irish Energy regulator, CRU, the comparison of electricity offers is difficult for majority of consumers.<sup>115</sup>

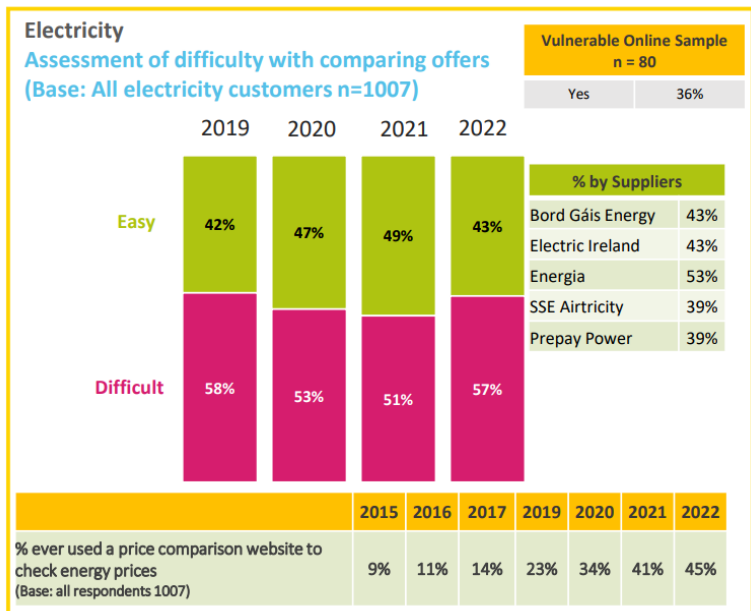
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<sup>113</sup> An electricity market that delivers to consumers, BEUC position paper on the upcoming revision of the provisions on consumer rights in the Electricity Directive, October 2022

<sup>114</sup> CREG, Rapport relatif à l'enquête et l'étude sur le comportement des consommateurs résidentiels sur le marché de détail belge de l'électricité et du gaz naturel, June 2021.

<sup>115</sup> CRU Residential Electricity & Gas Market Survey Results 2022

Figure 17: Consumer difficulty with comparing offer in Ireland



Source: CRU Residential Electricity & Gas Market Survey Results 2022

As suppliers are facing a significant increase in hedging, it is likely that consumers will have less access to fixed price contracts in 2023. At the same time, consumers may need to be provided information as to how such changes may impact them financially.<sup>116</sup>

o *Commission proposal*

The Commission’s proposal enables consumers to have access to wide range of offers so that they can choose the best deal for them. To ensure consumers have sufficient choice, suppliers with more than 200 000 customers will be obliged to offer fixed-price contract for at least 1 year, and at least one fixed price contract will need to be available in all Member States. This mirrors already existing obligation for large suppliers to offer dynamic price contracts.<sup>117</sup> Suppliers will be free to determine the price themselves but will not be allowed to unilaterally modify the terms and conditions before such contract expires.

Offers will need to be designed in a way to incentivise final customers to save electricity and should be clearly communicated to consumers prior signing the contract. Irrespective of the type of contract consumers are on, they will always be provided with clear pre-contractual information in a simple and consumer-friendly format.

<sup>116</sup> Annual Report on the Results of Monitoring the Internal Electricity and Natural Gas Markets in 2021 - Energy Retail and Consumer Protection Volume, ACER/CEER, October 2022. Available here: [MMR 2021 Energy Retail Consumer Protection Volume.pdf \(europa.eu\)](https://www.europa.eu/energy/energy-retail-consumer-protection-volume)

<sup>117</sup> Article 11, Directive 2019/944

### 6.3. Risk management

- *State of play*

Under stable market conditions, suppliers make long term commitments to their customers to supply them energy – often at fixed prices. To fulfil these obligations they must either have access to their own generation facilities or buy the electricity from the wholesale market. If suppliers have made firm commitments to their customers, without buying the necessary electricity on forward markets (i.e. hedging) then they are vulnerable to increases in wholesale prices – in effect they are speculating on low prices continuing, risking significant losses when wholesale prices rise. There are several hedging instruments (long-term forward and financial futures contracts) which have been available and traded for many years, see section 2 above).

Not all suppliers are equally able to access these hedging products. Energy community suppliers hedge by trying to match the consumption of their members with their own production capacity. Energy communities with sufficient installed capacity have shown at times greater resilience against volatile wholesale market prices than commercial suppliers.<sup>118</sup> However, in countries where RES support has been less consistent,<sup>119</sup> these initiatives remain to a larger extent dependent on external production in order to meet the full demand of their customers at all times. As these initiatives struggle to obtain necessary bank guarantees and scale to access power purchase agreements,<sup>120</sup> they need to operate on day-ahead and intra-day wholesale market leaving them exposed to volatile wholesale market prices and leading to a loss of membership, customers and liquidity.

The crisis showed that some suppliers did not hedge their supply portfolio sufficiently which resulted in some of them going bankrupt when wholesale prices started to increase.<sup>121</sup> According to the ACER-CEER market monitoring report there was a significant increase in supplier bankruptcy following unprecedented wholesale energy price increases in 2021. For example, in Czechia, sixteen suppliers went bankrupt between October 2021 and January 2022. The major supplier, Bohemia Energy, had 1 million customers. In Germany, several electricity and gas suppliers went insolvent or terminated their contracts with household customers in 2021. This wave of bankruptcies and contract terminations affected approximately 950,000 household customers, who had to involuntarily switch to other suppliers.

This imposes real costs on consumers – who must find a new supplier at short notice – often during periods of high prices – and whose own financial planning is disrupted. Moreover, supplier failure

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<sup>118</sup> See for example Ecopower CVBA: [Samen investeren in hernieuwbare energie · Ecopower](#).

<sup>119</sup> For example, Ireland, Spain, Italy and Romania.

<sup>120</sup> European Commission (2022). Staff Working Document – Guidance to Member States on good practices to speed up permit-granting procedures for renewable energy projects and facilitating Power Purchase Agreements – Accompanying the Commission Recommendation on Speeding up permit-granting procedures for renewable energy projects and facilitating Power Purchase Agreements.

<sup>121</sup> ACER-CEER Market Monitoring Report 2021



results in the socialisation of some of their costs, including network charges owed to TSOs and DSOs and potentially imbalance costs. This is because the costs of unpaid network charges owed by the failed supplier are often passed on to other market participants or all consumers.

Moreover, supplier failures during a crisis can also result in a breakdown in competition at precisely the time when consumers should benefit most – and are most interested in switching. Member States may feel compelled in this situation to implement major interventions to protect consumers.

- *Commission proposal*

While prudent suppliers already voluntarily implemented appropriate hedging, the experience of the crisis has shown that some suppliers did not – either because they tabled on additional profits from lower market prices or because they had difficulty accessing longer term contracts. This last concern should be less preminent in the context of the envisaged improvements to longer term markets and improved access to PPAs - which can be used as hedging instruments.

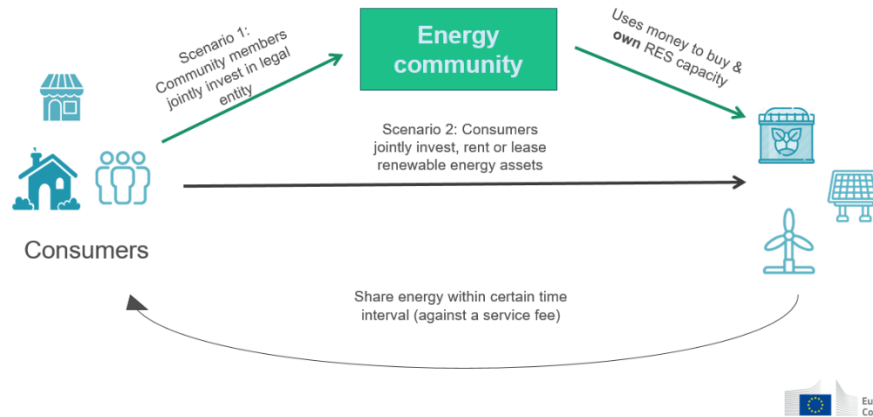
The Commission’s proposal will oblige all suppliers’ responsibility to have in place and implement appropriate hedging strategies in order to limit the risk of changes in wholesale electricity to the economic viability of their contracts with customers. It will be for Member States to assess those strategies. An appropriate strategy should take into account the supplier's access to its own generation and capitalisation of the supplier as well as its exposure to changes in wholesale market prices.

The appropriateness of the hedging strategy will also depend on their size and business model. In this regard, the proposal also calls on Member States to endeavour to ensure accessibility of hedging products such as PPAs for energy communities.

#### **6.4. *Enabling energy sharing***

Energy sharing can be an effective instrument to empower consumers that do not have available space, technical capacity and/or financial means to become prosumers in an easy and cost-efficient way. This group of consumers can access renewable energy by leasing, renting or investing in a renewable energy generation or storage facility and sharing the generated electricity among themselves (**model 1**), or a single prosumer can empower other consumers, including low-income families by sharing with them excess production (**model 2**).

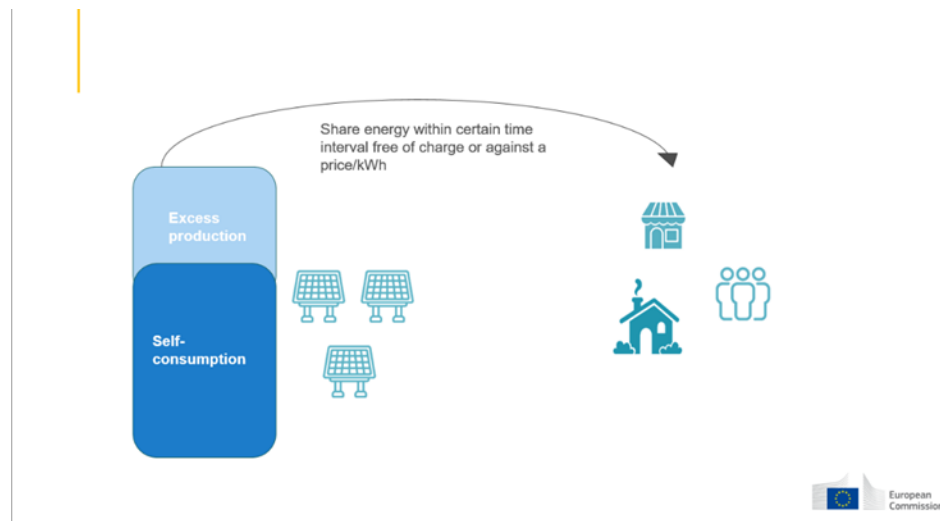
## Model 1. Sharing of energy generated by a facility that is collectively owned, leased or rented



### by consumers

Tenants and homeowners without (exclusive) ownership rights over the common rooftop of a multi-apartment building, or residential consumers with unsuitable rooftops face difficulties accessing low-cost renewables. Enabling joint investments in and leasing or renting of off-site generation facilities may help overcome such barriers. Examples of this model range from energy communities sharing electricity produced by community owned renewable energy installations (e.g., Hyperion) to citizens in Lithuania investing in remote solar PV parks to share the electricity it generates<sup>122</sup>.

## Model 2. Sharing of excess energy generated by a facility of an individual prosumer with other consumers.



<sup>122</sup> See [CLEAR-X collective purchasing campaign](#).

Low-income households face difficulties to access low-cost renewables due to the high level of capital expenditure for solar PV<sup>123</sup> as well as high financial entry barriers for joint investment initiatives<sup>124</sup>. Enabling individual prosumers, including public bodies to share energy can help overcome such barriers, as exemplified in Spain,<sup>125</sup> Portugal,<sup>126</sup> and Greece<sup>127</sup>. In addition, this model would allow for individuals to share excess electricity with their neighbours,<sup>128</sup> as well as larger companies sharing excess electricity with families and companies<sup>129</sup>.

The empowerment of consumers through energy sharing leads in turn to a growth in renewable energy investments, as well as financial benefits derived from the decoupling from the wholesale market dampening the effect of high and volatile wholesale markets on consumers' energy bill, as discussed in section 2.4.

### **6.5. Facilitating demand response and increasing choice of contract through sub-metering**

#### *o State of play*

Fit-for-purpose smart meters can help manage high-energy prices and demand for electricity by providing accurate measurements, eliminating estimated bills, and allowing consumers to adjust their usage based on market signals. The data collected by smart meters can help energy providers and network operators manage demand, while also creating opportunities for consumers to actively participate in the energy market and developers to create new services and products.

The roll-out of smart metering systems is moving slower than it was initially foreseen. It is estimated that currently over 50% of EU electricity consumers have access to a smart meter. Based on the data from the ACER/CEER Market Monitoring Report, at the end of 2021, in twelve Member States the rollout rate of electricity smart meters has reached an 80% penetration or higher. Denmark, Estonia, Spain, Finland, Italy, Luxembourg, Sweden, recorded a 98% rollout rate or higher, followed by Malta, France, Latvia, the Netherlands and Slovenia, with rollout rates between 88% and 93%. In seven other Member States (Portugal, Austria, Ireland, Romania, Poland, Hungary, Greece), penetration of smart meters is lower than 80%, with a wide scale roll-out being underway in most of them.

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<sup>123</sup> <https://www.irena.org/publications/2022/Jul/Renewable-Power-Generation-Costs-in-2021>.

<sup>124</sup> For example, in Lithuania, it costs between 1379-1400 EUR for 1kW share in solar PV park.

<sup>125</sup> E.g., “Zero. Energia de proximitat” programme in Valencia, Spain.

<sup>126</sup> E.g., Santa Casa Misericordia in Portugal.

<sup>127</sup> E.g., Municipality of Larissa, Greece.

<sup>128</sup> See [Energiedelen en persoon-aan-persoonverkoop | VREG](#).

<sup>129</sup> E.g., Edificio PCInvest.

Table 6: Roll-out of smart meters in electricity across the Member States

	Cost Benefit Analysis	Share of metering points ACER/CEE R	Real time / hourly energy pricing ACER/CEER	Additional information <i>Update from Member States (EC request: ARES(2022)7302800) and National Regulatory Authority Reports</i>	CBA revision (where applicable)
AT	Positive (2010)	46.6%	X	Roll-out in progress; planned roll-out targets: 40% by end of 2022, and 95% by end of 2024	N/A <sup>130</sup>
BE	Positive (Flanders) / Inconclusive (2018)	0.0%		According to 2022 NRA Report, 80% penetration is foreseen in Flanders by end 2024 and 100% by 2029. In Wallonia and Brussels-Capital Region rollout to niche cases. Based on ESMIG <sup>131</sup> in Belgium in 2020 was 9%.	
BG	Negative (2013)	0.0%			
CY	Inconclusive (2014)	0.0%		Planned roll-out milestones: 200 000 smart meters by Q3 2024, 400 000 by Q2 2026 (a delay to this timeline is possible).	N/A (decision to roll-out)
CZ	Negative (2016)	0.0%		Decision for selective roll-out of 1.7 million smart meters by 2027 (e.g. LV customers with over 6 000 kWh annual consumption, energy communities, consumers with generation). Roll-out to commence Q3 2024.	
DE	Negative (2013)	0.0%	X	Plan of installing over 20 million smart meters by 2030.	
DK	Positive	100%	X		N/A
EE	Positive	99.7%	X		N/A
EL	Positive (2012)	2.6%		420 thousand smart meters have been installed. Plan of installing 7.3 million meters.	N/A
ES	Positive	99.6%	X	By the end of 2019, 99.64% (out of 28.362 million meters of up to 15 kW) had been installed.	N/A
FI	Positive (2008)	99.9%	X		N/A
FR	Positive (2013)	90.0%	X		N/A
HR	Positive (2017)	0.0%		According to 2020 NRA Report, nearly all MV Billing Metering Points (BMPs) and LV non-household consumers have smart meters installed. 7.9% of all LV BMPs (non-household and household) have a smart meter.	N/A
HU	Pending (2018)	7.8%			
IE	Negative (2017)	37.5%		Roll-out in progress; according to national plan 2.25 million will be installed by 2024. By November 2022, 1.064 million meters had been installed.	N/A (roll-out in progress)
IT	Positive (2014)	98.5%			N/A
LT	Inconclusive (2018)	6.4% <sup>132</sup>		Plan to install 1.2 million smart meters by 2026. 110 thousand meters had been installed by October 2022.	N/A (decision to roll-out)
LU	Positive (2016)	98%			N/A
LV	Positive (2017)	90.4%	X		N/A
MT	No CBA	93.0%		Full roll-out has been concluded (residential and commercial customers with 60A per phase). Second generation smart meters roll-out commenced in 2020, 15% (of total meters) had been installed by October 2022.	N/A
NL	Positive (2010)	87.4%	X	Large scale roll-out in progress; 88.5% smart meters (of a total 8.4 million) had been installed by October 2022.	N/A
PL	Positive (2014)	15.4%		19.65% of smart meters had been installed by Q2 2022. Deployment is ahead of schedule which foresees 80% by 2028.	N/A
PT	Positive (2015)	52.0%		Full roll-out to be implemented by 2024. 4.5 million meters out of 6 million (75%) had been installed by November 2022.	N/A
RO	Positive (2012)	17.7%			N/A
SE	Positive (2015)	100%	X		N/A
SI	Positive (2014)	88.1%			N/A

<sup>130</sup> Not applicable due to positive assessment.

<sup>131</sup> ESMIG data based on figures from Berg Insight Report (April 2021).

<sup>132</sup> Commission's calculation based on information provided by Member State.

SK	Inconclusive (2013)	0.0%	X	Selective roll-out of 431.5 thousand smart meters (around 23% of LV supply points) concluded at the end of 2021.	Planned for Q1 2023
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*Sources: ACER/CEER Market Monitoring Report (October 2022), bilateral updates by Member States and National Regulatory Authority Reports.*

Smart meter data with sufficient granularity allow consumers to have a detailed insight to their energy use and save energy by adapting their consumption habits, as well as to select the most suitable pricing contract and reduce their bills. This is also particularly important in the context of the current energy crisis for reducing or shifting demand, especially at critical times for the system, and thus avoiding expensive fossil fuel generation.

In Member States where smart meters with appropriate functionalities are available, more advanced pricing schemes such as dynamic price contracts or/and time-of-use tariffs are in place, providing the option to consumers to respond to price signals and shift their consumption from periods of high electricity prices to periods of cheaper electricity (price-based demand response), as well as to participate in incentive based demand response providing for instance ancillary services to the system.

While traditionally, consumers have had only one main supplier, this is expected to change with the rollout of new technologies such as heat pumps or electric vehicles and related charging infrastructure. Consumers might want to have a fixed price contract to protect themselves from market volatility for their basic domestic services, while for consumption that can be automatized such as a heat pump, they might want to combine their own generation through solar panels with digital solutions to engage in the energy market and benefit from lower prices during off peak times.

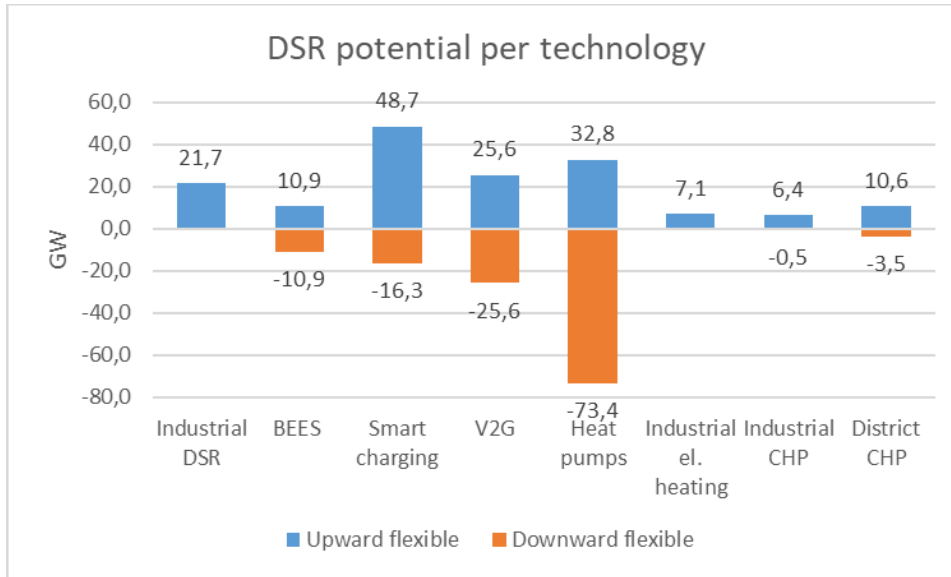
The roll out and uptake of demand response has been slower than desired. One of the reasons for this has been the very complex relationships between suppliers and aggregators. The greatest demand response possibilities often come from individual appliances – in particular behind-the-meter storage, heat pumps and electric vehicles. Enabling dedicated suppliers and aggregators to offer contracts covering just these appliances could help both speed up the roll out of these appliances and increase the amount of demand response in the system. The Electricity Directive already provides that customers are entitled to more than one supplier, but this has been seen to require a separate connection point increasing costs for customers significantly.

According to a report on the potential of demand-side flexibility prepared by DNV and smartEn<sup>133</sup> over 70% of upwards DSR flexibility (decrease of consumption) and over 95% of downwards DSR flexibility (increase in consumption) could be covered by electric vehicles, heat pumps and batteries behind the meter in 2030.

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<sup>133</sup> Demand-side flexibility: Quantification of benefits in the EU", smartEn and DNV, 2022. Available here: [Demand-side flexibility: Quantification of benefits in the EU DNV](#)

Figure 18: Demand side response potential per technology



Source: 'Demand-side flexibility: quantification of benefits in the EU' (2022).

Activation of this about 120 GW potential may require in many cases additional metering to provide more representative data of energy consumed and realised by this units. As keeping separate circuit and meter for this installation may cause additional costs (additional capex for construction and additional network charges in case of energy transfers within premises) large portion of this potential may be lost to the system.

- *Commission proposal*

The Commission proposes to change the current provisions of the Electricity Directive to clarify that customers who wish to have the right to have more than one meter (i.e. a sub-meter) installed in their premises and for such sub-metered consumption to be separately billed and deducted from the main metering and billing.

The proposal will allow consumers to conclude a contract with more than one supplier at their premises. This is to allow consumers with heat pumps and electric vehicles, using dedicated sub-meters, to contract with different electricity suppliers and benefit from innovative electricity offers. Where smart meters with the appropriate functionalities are not available, alternative tools such as dedicated metering devices that are connected to or embedded within appliances that have flexible loads, can be used, as referenced in section 5.3.

At the same time, the proposal is to avoid possible barriers such as the requirement for a separate grid connection for supply or restrictive rules on sub-meters (similar to those observed during the rollout of smart meters).

## 6.6. *Right to access energy through Suppliers of Last Resort*

### ○ *State of play*

The energy crisis and several supplier bankruptcies, as discussed under section 6.3. on prudential supplier obligations, showed the important role of suppliers of last resort<sup>134</sup> which are currently only an option in EU legislation.

All Member States have implemented a system of supplier of last resort, either de jure or de facto. In all Member States but Finland and Malta, electricity supplier of last resort (SOLR) mechanisms safeguard customers in the case of supplier failure and guarantee continuous electricity supply. In some countries, SOLR mechanisms are also in place to protect inactive consumers or to further protect consumers struggling with paying their bills. SOLR could be incumbent suppliers or even DSOs.<sup>135</sup>

However, the implementation varies significantly (in terms of scope, designation procedures, the role of National Regulatory Authorities, price setting mechanism, contractual conditions etc.) and price levels are generally higher than average prices.

During the crisis, supplier of last resort processes underwent a “stress test”, revealing some limitations. All customers were at risk of losing the right of universal service, customers suffered from even higher prices and uncertainties of procedural and timing aspects of SOLR services besides widespread reluctance of suppliers towards greater customer acquisition during critical circumstances.

Recent bankruptcies also indicated that the transition to a supplier of last resort was in some cases not very smooth and led to situations where consumers were worried that they may lose access to electricity. In some cases, consumers received very limited information on what happens with their electricity supply, which supplier they were being assigned to and what were the next steps after their supplier went bankrupt.

### ○ *Commission proposal*

To ensure continuity of supply for consumers when a supplier fails, The Commission’s proposal will oblige Member States to transparently appoint suppliers of last resort. The proposal aims to

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<sup>134</sup> In 2021, approximately 70 electricity and 60 gas supplier failures initiated the start of SOLR across Europe. Source: ACER-CEER Market Monitoring Report 2022

<sup>135</sup> Annual Report on the Results of Monitoring the Internal Electricity and Natural Gas Markets in 2021 - Energy Retail and Consumer Protection Volume, ACER/CEER, October 2022. Available here: [MMR 2021 Energy Retail Consumer Protection Volume.pdf \(europa.eu\)](https://www.europa.eu/press-room/media/33444/ACER-CEER-Annual-Report-2021-Volume-2-Consumer-Protection)

improve the overall concept of supplier of last resort, especially clarifying the role of the supplier of last resort and strengthening the information about the process when customers are switched onto the supplier of last resort.

#### **6.7. *Price regulation as an emergency measure***

- *State of play*

The possibility during the crisis to allow Member States to cap prices for households and SMEs has clearly proved useful as several Member States have taken the opportunity to extend existing schemes or to create new one in very short timelines. Even Members States that before the crisis opposed to the idea of introducing some form of price setting intervention have evolved on the subject, during the crisis.



Table 7: Overview of the price setting intervention during the energy crisis. (Source: Commission)

MS	Price setting intervention in the form of retail price regulation in place	Out of which including also social tariffs	Preexisting scheme	Measures based on the existing scheme during the crisis (Extension of the scope of existing scheme, freeze of the tariff)	Creation of new schemes during the crisis	Specific measures introduced for SMEs
Austria*						
Belgium	X	X	X	X		
Bulgaria	X		X	X		
Croatia	X				X	
Cyprus	X					
Czech Republic	X				X	X
Denmark*						
Estonia	X				X	X
Finland	X				X	
France	X		X	X		
Germany*						
Greece	X	X	X			
Hungary	X		X	X		X
Ireland*						
Italy	X	X		X		
Latvia*						
Lithuania	X		X	X		
Luxembourg	X				X	X
Malta	X					
Netherlands	X				X	X
Poland	X		X	X		X
Portugal	X	X				
Romania	X		X	X		X
Slovakia	X	X	X	X		
Slovenia	X				X	X
Spain	X	X		X		
Sweden*						

\* AT, DK, DE, IE, LV and SE had other price setting intervention (actions on tax, levies, rebates, compensation schemes, etc)

Source: The table is based on notifications from Member States, reporting from National Regulatory Authorities and measures self-assessed by Member States.

In spite of the high number of price intervention schemes developed during the crisis, there are significant downsides to regulated prices. In particular, they can reduce energy efficiency incentives and undermine competition to the long-term detriment of consumers. These concerns underline the normal rules applicable in the Electricity Directive 2019/944, which the Council Regulation (EU) 2022/1854 of 6 October 2022 on an emergency intervention to address high energy prices<sup>136</sup> derogates from. If similar increases in energy prices were to occur again in the very short term or in spite of all the other measures to reduce exposure of consumers to short-term

<sup>136</sup> [EUR-Lex - 32022R1854 - EN - EUR-Lex \(europa.eu\)](https://eur-lex.europa.eu/eli/reg/2022/1854/oj)

price volatility, without specific provision in the Electricity Directive or a prolongation of the Council Regulation (EU) 2022/1854, Member States would not be able to apply such measures.

○ *Commission proposal*

The Commission's proposal will put in place a special derogation procedure where Member States can at times of emergency apply for price intervention for households and SMEs, below cost, for a limited volume of electricity consumption, and for a limited period of time. Under the proposal, the Commission will be responsible for determining the reality of the emergency situation based on pre-set criteria.

Definition of the trigger of emergency

Under the proposal, the Commission will define the possibility of activating this article when a regional or Union-wide price crisis is reached when the three cumulative criteria are met:

- Very high prices in wholesale electricity markets at least two and a half times the average price during the previous five years occur which are expected to continue for at least 6 months ;
- Sharp increases in electricity retail prices of at least 70% occur which are expected to continue for at least 6 months;
- The wider economy is being negatively affected by the increases in electricity prices.

These criteria reflect the basis on which the equivalent provisions in Council Regulation (EU) 2022/1854 of 6 October 2022 on an emergency intervention to address high energy prices were justified. By removing the need to propose and adopt new legislation, the Union will in the future be better placed to face similar situations. The Commission already monitors closely developments on energy markets, will be able to assess all available data to assess the need for future activation of these thresholds (incl. ENTSO-E transparency platform, available data on retail market by National Regulators Authorities, Eurostat data...). In doing so it will of course also be able to engage closely with Member States and national authorities.

Definition of the consumption threshold

Regulated prices are effective in lowering the price of energy faced by end consumers – however, they have several potential negative consequences. Below cost regulated prices can end up encouraging energy use – and subsidising high consumption (the example is often given of subsidising heating swimming pools). This is the opposite of what is needed in an energy crisis. Another negative impact is compensating suppliers for supplying below cost can put strain on the public budget. A cap on the consumption covered mitigates both of these impacts.

The Council, in its 2023 recommendation on the economic policy of the euro area<sup>137</sup> then recommend to “replace broad-based price measures with a cost-efficient two-tier energy pricing that ensures incentives for energy savings.”

The Commission’s proposal reflects this approach and restricts regulated prices to 80% of the median consumption for households and to 70% of historical consumption for SMEs, in line with Temporary Crisis Framework<sup>138</sup>. This will give the opportunity to keep incentive for demand reduction. The approach based on consumption ceilings, allowing a price signal for demand reduction is already implemented in several Member States schemes.<sup>139</sup>

## **6.8. Increased protection from electricity disconnection for vulnerable customers and energy poor**

### *o State of play*

The energy crisis has exposed already energy poor and vulnerable consumers across the internal market to additional higher energy costs, further eroding their ability to continue paying their energy bills. In spite of the unprecedented and costly support measures that have been made available across the EU, many vulnerable families are facing a stark choice between paying for their energy and buying other essentials or falling into debt and risk seeing their supply cut off. Civil society organisations active on the ground have been warning that the majority who do not pay are those who have the greatest difficulty<sup>140</sup>.

Protection from disconnections exists in the Electricity Directive. It is referred implicitly in Article 28(1) in relation to obligation to define vulnerable customers. In general, Member States have established disconnections from electricity due to non-payment to protect vulnerable households on specific days (e.g., weekends), seasons (e.g., winter truce, summer truce) or specific circumstances (e.g., consumers critically depending on electricity for life-supporting appliances). A few countries do not apply any “truce” for disconnections, but rather use period of reminders to avoid disconnections. Overall, it is not in the interest of the supplier to disconnect a customer for debt, which would be an additional cost, but to retain it at least until the point of full repayment.

At the same time, Article 10(11) requires that electricity suppliers provide all household consumers with adequate information on alternative and appropriate measures to disconnection, sufficiently in advance of any disconnection due to non-payment, such as payment plans, assistance from

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<sup>137</sup> [2023 Euro area recommendation \(europa.eu\)](#)

<sup>138</sup> [EUR-Lex - 52022XC1109\(01\) - EN - EUR-Lex \(europa.eu\)](#)

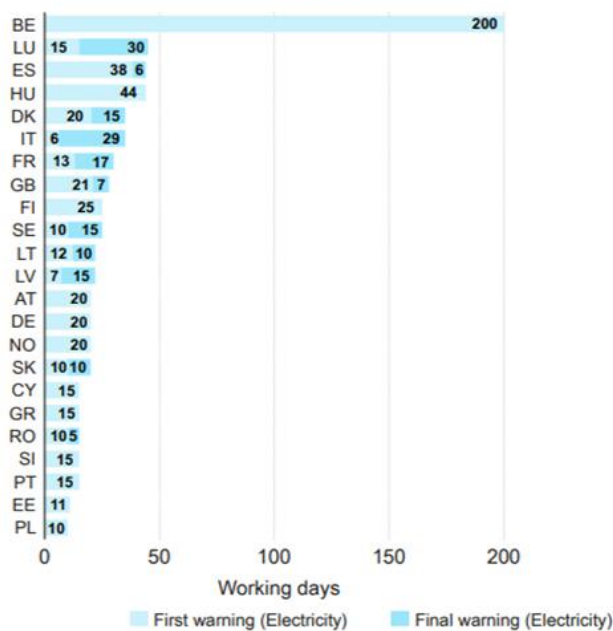
<sup>139</sup> AT, HR, NL, DE, RO

<sup>140</sup> [BEUC-X-2022-106\\_Letter\\_Introducing\\_moratoria\\_in\\_the\\_energy\\_and\\_financial\\_sectors.pdf](#);  
[https://righttoenergy.org/wp-content/uploads/2022/03/Gas-crisis\\_-Civil-Society-Response.pdf](https://righttoenergy.org/wp-content/uploads/2022/03/Gas-crisis_-Civil-Society-Response.pdf).

social services, energy efficiency advice and financial support to manage their energy use and costs, alternative supply contracts and any other alternatives to counter disconnection, including disconnection moratoriums and bans. It has to be acknowledged that the way in which communication is approached has an impact on encouraging a vulnerable customer to engage with the process, due to additional cultural and social barriers.

However, there seems to be a risk that the interpretation and practical implementation of these provisions may lead to uneven outcomes across Member States, with regard to the level of consumer protection and support available for the most vulnerable. Evidence in the last Retail and Consumer Protection Market Monitoring Report published by ACER and CEER<sup>141</sup> confirms this preliminary assessment. To give an example: there is a considerable variation in disconnection duration in electricity across Member States, with reminders and warnings ranging from approximately two weeks (10 working days) to nine weeks (see Figure 19 below). It is commonly understood that a lengthier disconnection process increases the likelihood of payment or allows customers to seek alternatives.

Figure 19: Legal minimum duration of the electricity disconnection process in EU MSs, Great Britain and Norway – 2021 (Number of working days).



Source: CEER database, 2022.

Source: ACER-CEER, Annual Report on the Results of Monitoring the Internal Electricity and Natural Gas Markets in 2021 Energy Retail and Consumer Protection Volume.

<sup>141</sup>[https://www.acer.europa.eu/sites/default/files/documents/Publications/MMR\\_2021\\_Energy\\_Retail\\_Consumer\\_Protection\\_Volume.pdf](https://www.acer.europa.eu/sites/default/files/documents/Publications/MMR_2021_Energy_Retail_Consumer_Protection_Volume.pdf).

Article 59 of the Electricity Directive requires national regulators (NRAs) to monitor, among others, disconnection rates. However, based on the most recent figures in the ACER Retail and Consumer Protection Market Monitoring Report<sup>142</sup>, it should be noted that disconnection rates due to non-payment among household customers are currently only reported by a minority of NRAs.. Besides, the responses to the public consultation suggest that further clarity and reassurance is needed on the framework in place for protection from electricity disconnection for vulnerable customers.

Along these considerations, on 12 December 2022, the Commission facilitated the signing of a Joint Declaration to enhance the protection of all consumers during this winter<sup>143</sup> by key stakeholders, representing consumers, regulators and energy suppliers and distributors, who committed to taking a series of voluntary measures, including not to disconnect the particularly vulnerable. This initiative reflects the willingness of key stakeholders to take their part, in close cooperation, and sets out the grounds for the need and scope for further action.

- *Commission proposal*

The Commission's proposal will require Member States to take all appropriate steps to ensure that the most vulnerable of EU citizens are adequately protected from disconnection at least at "critical times", period to be defined according to national circumstances. This initiative comes from the recognition of the need for increased efforts and greater social cohesion at critical time of response.

## **7. Enhance the transparency of the energy market and protection against market manipulation**

### **Feedback from public consultation**

- Most of the respondents, including private companies, business associations, market operators and national authorities, agree on the need to ***extend the scope of REMIT by adapting the framework*** to the evolving market circumstances to cover all current and future markets and products, specifically to all of those referred in the EU wholesale energy legal framework. The majority of TSOs, some market operators and business associations are in favour of clarifying and updating definitions of wholesale energy markets and wholesale energy products. Additionally, the need to clarify the notions of market manipulation, insider information and insider trading, to be coherent to those included in financial regulations was highlighted.

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<sup>142</sup> ACER-CEER, Annual Report on the Results of Monitoring the Internal Electricity and Natural Gas Markets in 2021 - Energy Retail and Consumer Protection Volume

<sup>143</sup> [https://energy.ec.europa.eu/declaration-enhanced-consumer-protection-winter\\_en](https://energy.ec.europa.eu/declaration-enhanced-consumer-protection-winter_en).

- Some regulators argue that the supervision task performed over PPATs could be *harmonised* and reinforced by enlarging the supervision scope. It was often highlighted that the REMIT framework could benefit as well from *extending its cooperation duties* to other regulatory bodies such as national tax authorities, the European Securities and Markets Authority (ESMA), the EUROFISC group or other bodies including the European Commission by exchanging information and data or forming investigation groups.
- Various respondents, especially the national/local authorities as well as some private organisations believe that the current *cross-border supervision* is not effective enough; therefore, ACER's role could be enhanced in those cases involving multiple cross-border participants since it is best positioned to monitor cross-border issues at European level. Some respondents, including regulatory bodies, business associations and market operators, think that the REMIT framework should correct discrepancies among Member States by harmonising administrative and penalty sanctions applied by the NRAs at national level by applying a common regime in the EU.
- Lastly, there is also a strong support from many stakeholders on the fact that *ACER* should have power and duty to issue binding guidance.

## 7.1. Introduction

Regulation 1227/2011 on wholesale market integrity and transparency ('REMIT') ensures that consumers and other market participants can have confidence in the integrity of electricity and natural gas markets, that prices reflect a fair and competitive interplay between supply and demand, and that no profits can be drawn from market abuse. The current context of high prices and high volatility on the wholesale energy markets and the unprecedented changes observed in the ways of trading (e.g., the rise of high frequency trading) constitute an important argument to revise the existing legislative framework. In case of no actions and lack of REMIT enhancement, the Union and Member States are not sufficiently equipped to protect the wholesale energy markets against market abuse.

There is therefore a need to urgently ensure that REMIT framework is up to date and robust. Further improvements would increase transparency, monitoring capacities and ensure more effective investigation and enforcement of cross-border cases in the EU to support new electricity market design.

- *Status quo: How does REMIT work?*

The scope of REMIT was designed over a decade ago to accommodate the operational complexity of physical energy markets and specificities of the energy sector (electricity and natural gas) and to appropriately complement the market abuse legislation covering the financial sector. Market abuse covers market manipulation and insider trading. REMIT prohibits market participants to engage in or attempt market manipulation. This includes entering into false or misleading transactions, positioning the price at an artificial level, transactions involving fictitious devices or deception, and the dissemination of false or misleading information. REMIT further obliges market participants to publicly disclose their inside information and prohibits using or disclosing inside information or recommending other persons to use inside information – with few strict exemptions.

REMIT applies to ‘wholesale energy products’. It includes (i) contracts for the supply of electricity or natural gas where delivery is in the Union; (ii) derivatives relating to electricity or natural gas produced, traded or delivered in the Union; (iii) contracts relating to the transportation of electricity or natural gas in the Union; (iv) derivatives relating to the transportation of electricity or natural gas in the Union. However, contracts for green certificates and emission allowances do not fall under REMIT.

Wholesale energy products are traded in the ‘wholesale energy markets’ which means any market within the Union on which wholesale energy products are traded. Wholesale energy markets encompass both commodity markets and derivative markets, which are of vital importance to the energy and financial markets, as price formation in both is interlinked.

Market participants have to report all wholesale energy market transactions at EU level to ACER. ACER is legally mandated to collect all relevant trading data in wholesale energy markets and to monitor the European wholesale energy markets (electricity and natural gas).

When a REMIT breach is found in EU wholesale energy markets, the final enforcement decision of such a breach lies with the relevant regulatory authority. ACER facilitates the delivery of consistent decisions at European level from the regulatory authorities, by coordinating the follow-up of any possible REMIT breach. ACER also coordinates with the European Securities and Market Authority (ESMA), financial authorities, competition and other relevant authorities. ACER has, however, no powers to conduct investigations.

- *Why is reform necessary?*

Gaps in REMIT data as well as a lack of enforcement of reporting obligation on the EU level are resulting in monitoring framework that is not sufficiently robust to fully protect against market abuse on the EU wholesale energy market into the future. Moreover, the decentralised enforcement system based on national investigations is not efficient in more complex cross-border cases which can result in insufficient market surveillance and oversight.

## Data collection, enforcement of reporting and market monitoring

There are various inconsistencies in the definitions of market abuse as well as for other definitions between REMIT and the EU financial market legislation. These inconsistencies cannot be explained by the specificity of wholesale energy products. For instance, while MAR defines market manipulation as the fact of entering into any transaction, issuing any order to trade or entering into any other behaviour that can give false or misleading signals or set the price at an artificial level, the REMIT definition of market manipulation focuses on transactions and orders. The category ‘or any other behaviour’ is missing from the REMIT definition, what prevents REMIT from capturing certain behaviours such as capacity withholding, which by definition do not involve any order or transaction on the market. Moreover, there is no effective framework to disclose inside information.

Moreover, under the current REMIT framework, ACER’s supervisory powers over Registered Reporting Mechanisms (RRMs) are very limited having a negative impact on integrity and transparency of the EU wholesale energy. The quality of the data that ACER receives and uses to fulfil its mandate of monitoring the EU wholesale energy markets in order to detect possible market abuse is in question. Article 8 of REMIT, in connection with Article 11(1) of the REMIT Implementing Regulation<sup>144</sup>, provide for the obligation for reporting parties to register with ACER for reporting purposes. In 2022, approximately 17 different non-compliance events (categories) have been identified. Altogether around 80 potential non-compliance issues had been detected. In effect, potential non-compliance issues have been opened for around 30 RRM.

According to Article 15 of REMIT, persons professionally arranging transactions (PPATs) shall notify to regulatory authorities their suspicions of market abuse. They shall also establish and maintain effective arrangements and procedures to identify market abuse. Around 44% of the total number of active PPATs arrange transactions on products for delivery in multiple Member States (there are in total 48 PPATs arranging transactions in more than one country). Their oversight and the enforcement under Article 15 of REMIT proved to be very complicated and inefficient, due to the fact that: (i) the regulatory authority of the Member State where the PPAT is established has no incentive in supervising if the PPAT complied with its Article 15 obligations in relation to products for delivery in another Member State and (ii) the regulatory authority of this other Member State has no jurisdiction over a PPAT not established on its territory. In 2021, only 12 PPATs were submitting suspicious transaction reports (STRs) to NRAs. These 12 PPATs notified 81 out of the 129 STRs received in 2021. Overall, only about 10% of the PPATs submit STRs to NRAs. Improving the supervision of PPATs is crucial to ensure that all of them put arrangements in place to effectively monitor their market and to detect and report market abuse to NRAs and ACER.

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<sup>144</sup> Commission Implementing Regulation (EU) No 1348/2014 of 17 December 2014 on data reporting implementing Article 8(2) and Article 8(6) of Regulation (EU) No 1227/2011 of the European Parliament and of the Council on wholesale energy market integrity and transparency Text with EEA relevance



The recent energy crisis showed that timely and efficient information exchange between relevant authorities is of utmost importance to supervise and monitor markets. The Commission is currently not included in the potential sharing of REMIT information, but the energy crisis has demonstrated that it would benefit from ACER's REMIT information to increase market insights. In addition, information exchange between national competent authorities under Regulation (EU) No 596/2014 on market abuse and national regulatory authorities is supposed to take place at national level, whilst information sharing under REMIT with relevant national authorities is exclusively mandated to ACER. This creates inefficiencies in the cooperation of competent authorities at national level. Therefore, all burdens for data sharing possibilities between relevant national authorities, ACER and the Commission should be reduced.

Moreover, the increasing share of financial instruments traded on EU energy markets also calls for a stronger cooperation between energy and financial regulators, including ACER and ESMA.

Finally, with the diversification of EU natural gas supply in the aftermath of Russian invasion of Ukraine, and in line with the REPowerEU plan, the EU's LNG market has grown in importance. Over the last months, LNG has become critical in ensuring gas security of supply in the EU, replacing most of Russia's supply of pipeline gas (which represented 40% of the total imports at the start of 2022 and now is below 10%). However, the pricing of LNG imports within the EU could still be unduly influenced by existing infrastructure bottlenecks and questions remain as to the representativeness of the current indexes. At the same time, perceptions of malfunctioning in the financial markets for energy undermine public trust.

In conclusion, gaps in data, lack of data reporting enforcement and outdated scope of data coverage calls for urgent improvements in order to strengthen Union and Members States' ability to monitor and efficiently supervise wholesale energy market. High quality and complete data constitutes a fundamental requirement for effective protection against market abuse cases, especially during crises.

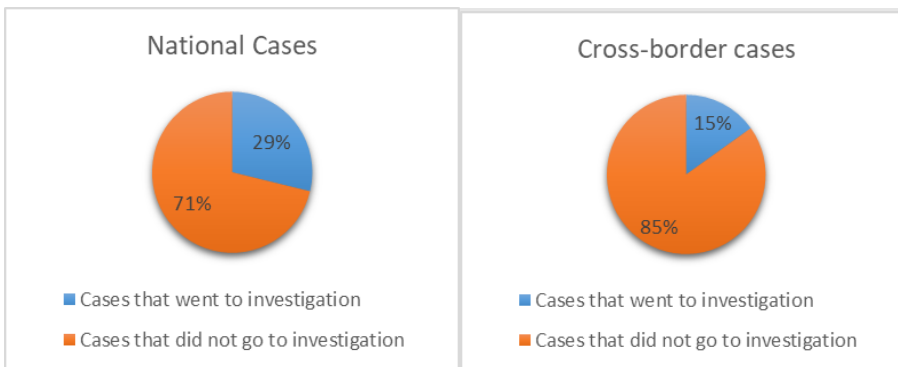
#### Investigations and enforcement of REMIT breach cases

The shortcomings identified in the current framework mostly relate to the decentralised model. While ACER is in charge of monitoring wholesale energy markets at EU level, any investigatory and enforcement powers lie at national level and hence regulatory authorities have full discretion on whether to follow-up on a suspicious reporting by ACER's market surveillance. This decentralised approach leads to the following consequences:

- The diversity of ways in which REMIT was implemented at national level is at the origin of jurisdictional gaps, rendering REMIT inapplicable under certain circumstances and/or to certain behaviours. On this matter, ACER estimates that at least 10% of all closed cases were closed because of a lack of investigatory or sanctioning powers by the NRAs;

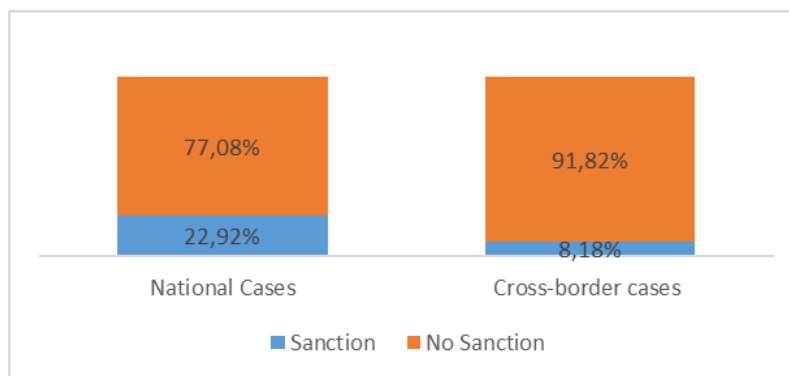
- Regulatory authorities have been allocated uneven resources across Member States and national procedural rules further restrict their competence, which leads to the under-enforcement of REMIT;
- A need for prioritisation makes NRAs favour cases of national nature over those of cross-border nature. This claim is supported by the statistics reported in Figure 21 and Figure 22 that illustrate the percentage of national and cross-border cases that reached the investigation stage, and the percentage of national and cross-border cases that led to a sanction;
- Individual NRAs are not well equipped to handle cases of a multi-market or cross-border dimension, and their enforcement actions focusing on national effects only are limited by nature.

Figure 20: Percentage of cases that reached the investigation stage



Source: ACER’s Case Management Tool – Business Intelligence (2022)

Figure 21: Percentage of cases that led to a sanction



Source: ACER’s Case Management Tool – Business Intelligence (2022)

In conclusion, significant shortcomings in the investigation and enforcement system require an urgent change, the justification of which became even more obvious with the energy crisis, to ensure that all suspicious behaviours can be quickly investigated and penalised, where necessary.

#### Fines set by national regulatory authorities

REMIT is not prescriptive as to the level of the fines that regulatory authorities can impose at national level to sanction a REMIT breach. The implementation of REMIT at national level resulted in discrepancies between the sanctioning practices of Member States. It notably raises the issue of the maximum amount of the fine that the regulatory authority can issue as a sanction, which is insignificant in some Member States, and therefore not a deterrent. For example, the maximum amount of the pecuniary sanction for a breach of the obligation to disclose inside information can reach up to 8% of the total turnover of the market participant in one Member States, when it is only 10,000 EUR in another.

The actual deterrence and effectiveness of sanctions issued by regulatory authorities is at stake.

In conclusion, urgent action is required to strengthen and harmonise the sanctions regime at national level to ensure that illegal behaviours on energy market, if identified and confirmed, can be effectively and proportionally penalised.

## **7.2. *Better data collection and market monitoring***

### **Adaptation of the scope of REMIT to current and evolving market circumstances**

Due to further integration of the EU energy market, it is beneficial to extend the scope of data reporting to new electricity balancing markets and coupled markets as well algorithmic trading. Market coupling and the use of algorithmic trading over recent years have led to an increase of 85% of collected data to 4.4 billion records collected in 2022 alone.

Considering the existing interlinkages in terms of market impact between spot and derivative wholesale energy products, there is a need for stronger, more established and regular cooperation between energy and financial regulators, including ACER and ESMA.

As an immediate follow-up for the amendment of REMIT Regulation 2011, there is also a need to revise REMIT Implementing Regulation from 2015 to ensure consistency with the new measures and provisions in the amended REMIT Regulation. Any changes in the electricity market design, but also the intended scope increase to hydrogen markets in the Hydrogen and Gas Decarbonisation Package and LNG market developments as a result of the increased importance of LNG trading need to be reflected in the REMIT Implementing Regulation in order to have a meaningful data collection for market monitoring purposes.

In addition, order book providers should be fully subject to the reporting obligations under Article 8 of REMIT, and the reporting needs to happen in a consolidated manner at EU level. It is necessary to cover explicitly the order book providers such as the operators of the single day-ahead market coupling, the intraday market coupling and the EU balancing platforms to ensure better market transparency and enhance market monitoring.

### **Improving process for the collection of inside information and market transparency**

It is necessary to align the process for the collection of inside information to the one existing for collecting trade data reporting in order to facilitate monitoring to detect potential trading based on inside information and the data quality of collected information. Inside information is currently relying on web feeds. This does not allow to make use of the data quality rules in the collection of inside information and instead requires handling data quality of inside information collected from 15 Inside Information Platforms manually. Hence, to strengthen the transparency of EU wholesale energy markets, it is necessary to further streamline mandatory disclosure of inside information by market participants through platforms. In order to ensure a level playing field of inside information platforms at EU level and their continuous reliability, ACER should have supervisory powers over them and assess their compliance with relevant technical standards to which these platforms should adhere.

Moreover, a centralised, more robust and coordinated monitoring of wholesale energy markets by extending the notification obligation also towards ACER would bring additional benefits for transparency of the market.

It is of utmost importance to ensure robust enforcement of data reporting in order to monitor the energy market. Financial regulation and ESMA powers could serve as a blueprint and best practices should be used as well for the energy market.

The REMIT Regulation applies to trading in wholesale energy products. It is without prejudice to the application of Regulation (EU) No 600/2014<sup>145</sup>, Directive 2014/65/EU<sup>146</sup> and Regulation (EU) No 648/2012<sup>147</sup> as regards activities involving financial instruments as defined under Article 4(1)(15) of Directive (EU) 2014/65 as well as to the application of European competition law to the practices covered by this Regulation.

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<sup>145</sup> Regulation (EU) No 600/2014 of the European Parliament and of the Council of 15 May 2014 on markets in financial instruments <https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=celex%3A32014R0600>

<sup>146</sup> Directive 2014/65/EU of the European Parliament and of the Council of 15 May 2014 on markets in financial instruments <https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=celex%3A32014L0065>

<sup>147</sup> Regulation (EU) No 648/2012 of the European Parliament and of the Council of 4 July 2012 on OTC derivatives, central counterparties and trade repositories <https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX%3A32012R0648>

### **Enhance supervision of reporting parties and data sharing**

To better monitor the wholesale energy market, ACER should be equipped with additional supervisory tools such as the improvement of the supervision of the compliance with the reporting obligations at EU level. It is equally important to better supervise Registered Reporting Mechanisms (RRMs) and to ensure that ACER can take administrative sanctions for potential breaches of the REMIT reporting obligation defined in Article 8 of REMIT, including supervisory powers accompanied with the possibility to adopt administrative sanctions and other administrative measures.

Last but not least, it is beneficial to allow and facilitate the exchange of REMIT data between relevant national authorities (e.g., tax authorities), ACER and the Commission. This would increase the coordination between relevant public authorities and allow acting faster and in more informed manner.

### **Enhance supervision of persons professionally arranging transactions (PPATs)**

The effective application of Article 15 of REMIT requires that PPATs are obliged to notify their suspicions to ACER as well as to the regulatory authorities, and not only exclusively to NRAs. Furthermore, ACER should have supervisory and enforcement powers over PPATs arranging transactions in at least three Member States, to palliate the lack of enforcement of Article 15 by NRAs.

### **Enhance market transparency through an LNG price assessment and benchmark**

Given the need to provide for stable and predictable pricing for LNG imports on a structural basis, which are indispensable to ensure a continuous supply of gas to Europe, Council Regulation 2022/2576<sup>148</sup> established, a daily LNG price assessment and LNG benchmark. It tasked ACER to create within a short time frame an objective price assessment tool on the physical deliveries of LNG into the Union, and over time a benchmark,<sup>149</sup> on a daily basis, whereas the LNG price benchmark will be published as of 31 March 2023.

In line with the commitment taken upon adoption of the Council Regulation the current amendment of the REMIT Regulation should establish the LNG price assessment and LNG benchmark as a permanent element of REMIT framework.

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<sup>148</sup> Council Regulation 2022/2576, of 19 December 2022, enhancing solidarity through better coordination of gas purchases, reliable price benchmarks and exchanges of gas across borders

<sup>149</sup> [https://aegis.acer.europa.eu/terminal/price\\_assessments](https://aegis.acer.europa.eu/terminal/price_assessments)

### ***7.3. Strengthening of investigation, harmonisation of fines to better protect against market abuse***

#### **Stronger role for ACER in investigations of significant cross-border REMIT cases**

REMIT would benefit from a better alignment of its definitions of market abuse with the ones existing under the financial legislation. These alignments would ease the applicability hence the efficiency of the REMIT framework.

The exercise of investigatory powers for cross-border cases at EU level would bring an added value. ACER is already in charge of monitoring of the EU wholesale energy market, therefore it is best placed to perform investigations to deal with certain selected cases while maintaining the role for regulatory authorities in remaining cases. The cases over which ACER should have jurisdiction for investigation are those where:

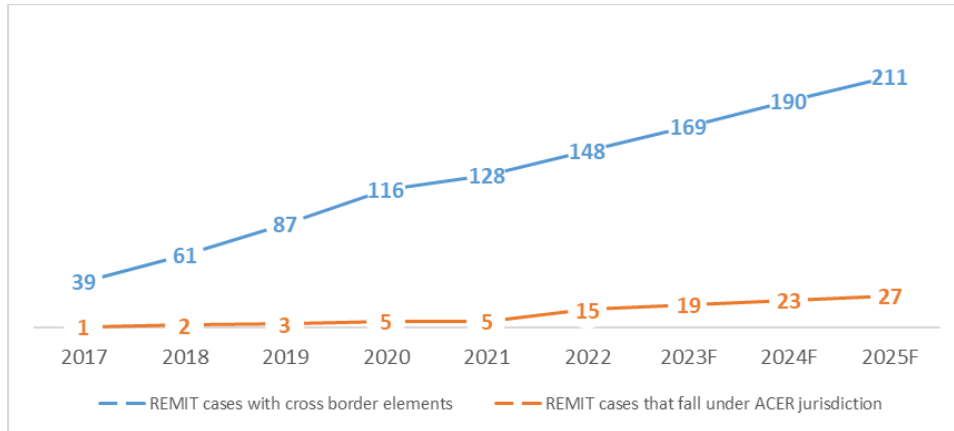
- at least three products delivered in different Member States are affected;
- two or more products delivered in different Member States are affected and the legal or natural person carrying out the acts is registered or established in a third Member State or outside the EU;
- the REMIT information considered is likely to significantly affect the prices of wholesale energy products for delivery or potential delivery in at least three Member States; or
- the NRA does not take the necessary measures in a timely manner to comply with a request to open an investigation from the Agency under Article 16(4)(b).

In exercising its powers, the Agency shall take into account the inspections in progress or already carried out in respect of the same cases by a regulatory authority pursuant to this Regulation as well as the cross-border impact of the investigation.

On completion of its actions, ACER should draw up a report which should be made public. If ACER concludes that the breach of this Regulation took place, it shall inform the regulatory authorities of the Member State or Member States concerned accordingly and require that such a breach is dealt under REMIT.

*Figure 22* below displays the evolution of cases with cross border elements and the evolution of the cases that would fall under ACER's jurisdiction according to the envisaged new ACER competences.

Figure 22: Evolution of the stock of REMIT cases over time



Source: ACER data (until 2022). Estimates from 2023 based on evolution in the previous years and DG COMP performance parameters.

At the end of 2022, there were 15 open REMIT cases that would fulfil above mentioned criteria (around 4.3% of the total stock of cases), 11 of which were notified in 2022. The growth in the number of cross border cases that will eventually meet these criteria is substantial higher than the general growth in the number of REMIT breach cases (last 6 years: 20% vs 7.7%).

### Harmonisation of fines set by regulatory authorities at national level

Having converging levels of fines at EU level is an important element of the efficient implementation and enforcement of the REMIT framework. Therefore, it is necessary to harmonise the level of fines that can be imposed at national level by indicating a minimum threshold for the maximum administrative pecuniary sanctions per type of REMIT breach. Harmonisation shall be set to ensure the deterrence, proportionality and effectiveness of sanctions.

## 8. Generation and system adequacy for a decarbonised electricity system

### 8.1. Generation adequacy and Capacity Mechanisms

#### Feedback from public consultation

On the topic of how to further *accelerate the deployment of renewables*, a broad majority of stakeholders mentioned that speeding up permitting procedures, boosting flexibility and fully

implementing the existing legislation would make a significant impact. Furthermore, the importance of necessary grid investments (including the deployment of more flexibility) to overcome current bottlenecks and facilitate more connection capacities was widely mentioned. The usefulness of identifying ‘renewable go-to-areas’ and efforts to improve public acceptance were also mentioned.

Most of the respondents acknowledge that the power system has evolved into a system with a higher amount of renewable generation capacity. Some consider that **Capacity Mechanisms** should be treated as a permanent feature of the European energy market to ensure that firm and reliable capacity is made available to support the increasing penetration of intermittent RES capacities.

A majority of respondents have noted that the current regulatory framework applies **strict pre-requisites** for the introduction of a Capacity Mechanism and that the **approval process is cumbersome and lengthy**. They call on the Commission to facilitate Member States' introduction or amendment of capacity mechanisms through faster and clearer approval processes. Many would like a clear, harmonised framework at EU level on capacity mechanisms to grant visibility and stability to investors. In contrast, other stakeholders (especially TSOs) have suggested shifting the decision-making process around Capacity Mechanisms to the national authorities.

On the **adequacy assessment**, many stakeholders have argued that the responsibility to assess the necessity of a capacity mechanism should lie with the Member States. They invite the Commission to reconsider the role of national adequacy assessments as complementary to the ERAA, since they provide more granular and dedicated sensitivities. They ask for a review of the ERAA approval process, with a strengthened role of Member States.

Unlike some Member States that have advocated for the expansion of the capacity market access for the most emission-heavy generators, a large majority of stakeholders have suggested to align capacity mechanisms with climate neutrality objectives and to favour the participation of **fossil-free technologies**. They suggest that the Commission reviews and decreases the current emissions threshold in order to accelerate decarbonisation of the power system and to avoid lock-in effects of fossil fuel technologies.

Most respondents have argued that the current capacity mechanism set-up does not drive the necessary investments to **demand-side** and **storage technologies**. For a flexible, decarbonised grid, they recommend capacity mechanisms to be market-based in order to increase competitiveness and remove barriers to ensuring the participation of all resources.

As outlined in previous sections, to reach net-zero by 2050, and the 2030 and 2040 targets before then, a substantial increase in investments in our energy system is needed. These investments will



not just be in renewable energy but also in the enabling technology and infrastructure. Technology advancement and a dynamic and competitive European energy sector will be crucial to these goals. Public policy can support this shift and create certainty on the direction of travel for our European businesses and manufacturing sector.

This is because the energy system is becoming more complex and future looking. Regarding infrastructure, TSOs and DSOs should account for long-term needs, such as meshed offshore grids based on hybrid interconnectors, smart electricity grids enabling market-based demand response and energy communities, and streamlined permitting regulatory frameworks for renewables, including go-to renewable areas. National regulatory authorities should increasingly promote the development of grids that consider the medium and long-term system needs and be fully transparent about capacities available for new connections. Grids are typically financed via network tariffs, complemented with congestion income for cross-border transmission projects. Transmission and distribution network tariffs should be regularly updated to account for the changing energy system and increasingly active role of distribution system operators. In addition to considering operational expenditures as outlined in Section 5.2, other relevant aspects that NRAs should review when setting network tariffs or their methodologies, for example, are how they set long term incentives, for example to shift peak demand and support technologies that increase the efficiency and operability of the grids. This, in turn, would support consumers in having a more resilient energy system at affordable prices. To alleviate part of the impact that the substantial grid investment might trigger on electricity consumers, Member States may want to make use of public budgets<sup>150</sup>.

Moreover, the smarter use of our overall energy system architecture and the increasing rollout of energy efficiency measures throughout the EU will serve to use our grids as efficiently as possible and also reduce or shift electricity consumption peaks. This, in turn will integrate renewables fully into the grid and reduce the amount of dispatchable capacity needed for when the wind is not blowing or the sun is not shining.

In addition to the long-term contractual support for investments in renewables discussed in previous sections, the Commission is aware that lengthy permitting procedures and the availability of connection agreements are among the biggest challenges faced by renewables developers. The Commission fully supports faster permitting procedures. On the issue of grid connections, the Commission proposes greater transparency from TSOs and DSOs on the availability of connection capacity.

However, it is also the case that for the foreseeable future, fossil-fuel based dispatchable capacity will be needed to meet peak demand and ensure security of supply. We have seen, in particular, in the last 10 years that the number of hours that fossil fuel generation runs in the market is decreasing all the time. As noted in section 1.2, this trend is expected to continue with higher levels of

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<sup>150</sup> See Guidelines on State aid for climate, environmental protection and energy 2022 (2022/C 80/01), chapter 4.9

renewables penetration and increasing competition from demand side response and storage pushing out fossil fuel technologies. For the moment, however, certain amounts are needed to ensure generation adequacy and security of electricity supply. Capacity Mechanisms have been introduced in several EU countries to give more revenue predictability and ensure security of supply, enabling Member States under certain conditions, to provide subsidies to power generators and other technologies, such as demand response and storage. These mechanisms can play an important role in ensuring the adequacy of the electricity system and foster investments in the capacity needed to complement the deployment of intermittent renewables installations, the production of which is weather dependent.

As they can have a significant impact on the internal electricity market and because the costs of these mechanisms are paid by electricity consumers, the Clean Energy Package introduced, for the first time, a framework at European level to govern capacity mechanisms. To ensure that the internal market level-playing field is preserved, the legislative framework prescribes that subsidies are granted only when an adequacy issue exists or will arise in the future. Moreover, the current legislation also mandates that capacity is procured in a competitive auction open to all providers that can contribute to ensure security of supply. This reduces the costs for consumers, fosters competition, and ensures investments in new capacity, including demand response and storage which have been coming forward more and more through these auctions across Member States<sup>151</sup>.

The Electricity Regulation allows Member States to set technical performance standards and CO<sub>2</sub> emissions' limits that restrict participation in these mechanisms to flexible, fossil-free technologies<sup>152</sup>. The recently revised State aid rules go a step further: they encourage Member States to introduce green criteria in capacity mechanisms and contain stricter rules for the approval of subsidies to coal and gas-fired power plants. This enables Member States to design green and flexible capacity mechanisms, and support investments into low carbon technologies. The Commission proposes to clarify this in the amending Regulation with a Recital explaining how the Regulation and State-Aid Guidelines can be read together to design a green and flexible capacity mechanism.

In addition, from discussions with Member States and stakeholders as part of the public consultation, it is clear that the procedure for the adoption of capacity mechanisms is perceived as being burdensome and lengthy. It is often the case that discussions in the State aid approval process tend to focus on the need for the capacity mechanism. The introduction of a capacity mechanism is subject to the identification of an adequacy concern in the European resource adequacy assessment (ERAA) and in the national resource adequacy assessment (NRAA). Both assessments must be based on the ERAA methodology and are the subject of an ACER opinion. According to

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<sup>151</sup> For example, 1.5GW of demand response came forward in the recent auction in Poland in January 2023.

<sup>152</sup> As of 2025, coal-fired power plants that still operate in the market are no longer able to receive subsidies under capacity mechanisms due to the emissions limit in Article 22 of the Regulation. Member States may go further with stricter emissions limits.

the ERAA methodology, the identification of the adequacy concerns should be based on one central reference scenario. This facilitates decision-making but also makes it challenging due to the current unpredictability of global events and their effect on the energy sector. The Electricity Regulation envisages the possibility of having more than one scenario, however.

In order to simplify the approval process, the Commission will work with ENTSO-E and ACER to introduce more than one scenario in the methodology for the identification of adequacy concerns that Member States could use to justify the introduction of a capacity mechanism. At the same time, in order to preserve the role of the European assessment in limiting costs for consumers and to preserve the EU level-playing field, the scenarios would need to be reasonable, realistic and sufficiently circumscribed to avoid that they are a pretext to justify over-procurement of capacity, which is very costly for consumers and companies.

Apart from these avenues that will be pursued by the Commission, Member States with adequacy concerns can also look at the options possible at national level under the capacity mechanism rules and elsewhere to support security of supply. For example, as discussed in section 5 on flexibility, Member States should consider whether new schemes to support flexibility and demand response can address their flexibility needs. This could be a simpler way than introducing a capacity mechanism in the first place. In addition, there is also the possibility under the capacity mechanism rules for Member States to set their own reliability standard at national level. This means that, even under the existing scenario, Member States can opt for a more secure reliability standard than they had in the past, which although more costly, insures the system against adequacy risks to a higher degree.

Furthermore, as part of the ongoing bidding zone review process, Member States can ensure that their bidding zones reflect structural congestion. Where economically beneficial to do so, Member States could reconfigure their bidding zone to use the grid most efficiently and ensure that the market can support security of supply. When applying a capacity mechanism in a Member State with more than one bidding zone, it enables targeted investments where they are most needed as the locational elements are inherent in the design.

Indeed, as the patterns of electricity flows change with the many new investments needed to decarbonise and electrify the energy system, stronger locational price signals may be needed into the future to ensure that investments take place where they are needed. To ensure that the system can continue to work reliably at national level and across borders, we should strive for an electricity market that reflects the physical reality of the grid and supports incentives for cross-zonal long-term contracting.

## 8.2. *Locational signals*

### **Feedback from public consultation**

Only 37% of professional respondents expressed support for a more granular approach to market prices. Among categories of respondents, a majority of academics, TSOs, regulators, environmental organisations, EU citizens, NGOs and public authorities support a more granular approach while the approach is globally not supported by business associations, energy companies, energy suppliers and industrial consumers.

- Respondents see the following *benefits*: reduced overall energy system development costs, reduced need for electricity grid reinforcement due to improved matching of market and physics, promotion of competition and innovation, improved integration of distributed energy resources (such as demand response and energy storage) into the grid, and competitive hydrogen production costs. In their view, this approach can lead to a more flexible, efficient, and sustainable energy system, with improved energy security and reliability, and lower costs for energy consumers.
- Some respondents explained that locational pricing enable the direct inclusion of *congestion and network constraints* into the electric market price, while the current zonal design may provide financial incentives to create congestions in real-time if not well-configured. In their view, a zonal design hampers the efficient integration of offshore bidding zones and large scale flexible assets and demand response.
- Others explained that granular locational signals would help taking *appropriate investment decisions* (including for hydrogen production).
- A regulator explained that a nodal design would strongly *simplify the European design*, as there would be no need for (i) a bidding zone review; (ii) a capacity calculation methodology; (iii) analysing if this capacity calculation methodology is non-discriminatory; and (iv) a redispatching and cost sharing methodology.

On the other hand, respondents against the idea highlighted the following:

- Some highlighted the following *risks*: potential lack of liquidity in smaller bidding zones, risk of market dominance, and risk of high local prices.
- Others explained that they do not see the benefits for the day-ahead and intraday markets, but that locational signals are needed in *more short-term markets* e.g. for flexibility for system needs.

- Some respondents explained that it could raise *distributional challenges* to societies as prices might differ considerably within countries which could go against political objectives of a country.
- They also explained that *transparency on the price formation process* risks being significantly reduced (due to complex algorithm).

Several respondents explained that it is possible to introduce locational elements *in several alternative ways*: tariffs, improved bidding zone configuration, integrating so-called "dispatch hubs" in the market coupling, nodal market design, location dependent investment incentives also considering ancillary services, and/or by taking real congestion into account in the market coupling.

*About implementation*, respondents explained that such a development requires a political consensus as well as long technical implementation time. In their view, there could be a focus on the most congested bidding zones first – and different levels of spatial granularity may be applied across the EU, depending on regional/national specificities.

Many respondents consider that a change to more granularity represents a fundamental change, which requires a *deeper analysis*, which does not seem feasible in the desired timeline of the market design reform. In their view, such analysis could be used as input to a more comprehensive market design reform aiming at future-proofing the electricity market design for the net zero system.

Under the current market design, wholesale electricity prices only represent supply and demand for the whole bidding zone, without taking into account the actual geographical location of that supply and demand within the bidding zone and the actual physical limits of the transmission system that may exist. The concept of bidding zones is static and not designed to swiftly adapt to changes in grid or composition/location of supply and demand, as any configuration change is subject to the bidding zone review process<sup>153</sup>.

In a more granular market, the market structure would appropriately reflect congestions in the grid and electricity prices will in general be lower at locations with abundant production of electricity from renewables than in areas where fossil-fuelled generation is needed to meet demand. This allows local consumers to reap the benefits of renewables and – at the same time – provide incentives for new electricity intensive industries to locate there, which is also crucial in light of the EU hydrogen objectives. At the same time, it would make electricity more costly in regions where the potential for renewables is lower for space or environmental reasons, potentially increasing the need for more transmission networks in that area.

<sup>153</sup> Pursuant to Commission Regulation (EU) 1222/2015 of 24 July 2015 establishing a guideline on capacity allocation and congestion management

While the present proposal does integrate some locational elements in the current market design, a deeper change to move to more locational pricing would require significant changes to the legislative framework and to the current market design. The Commission will however continue to analyse the effect, possible benefits and risks of stronger price signals. In particular, it will study which level of granularity brings the most benefits to European citizens, enables the most efficient use of renewables, and how to overcome potential implementation challenges.

## **9. Concluding remarks**

In conclusion, this package of reforms, if adopted, is expected to significantly improve the structure and functioning of the European electricity market. It is another building block to enable the delivery of the Green Deal objectives; it takes stock of the shortcomings revealed by the energy crisis and seeks to address them.

It would protect and empower consumers currently facing high and volatile prices by creating a buffer between them and short-term markets. This proposal can decouple the high prices of fossil-fuel technologies operating in the electricity market from the energy bills of consumers and businesses. More long-term contracting in the form of PPAs, CfDs and forward markets will ensure that the part of the electricity bill exposed to short-term markets is greatly reduced. In addition, including a hedging obligation on suppliers and an obligation for fixed price contracts will significantly reduce the price volatility of electricity bills. Consumers will also have better information on offers before signing up and Member States will have an obligation to establish suppliers of last resort and can enable access to regulated retail prices in a crisis. The right to share energy is a new feature that will support the decentralised rollout of renewable energy and give consumers more control over their energy bills.

This reform would also enhance the competitiveness of EU industry in a way that is fully complementary to the Net-zero Industry Act. Member States will be required to ensure the right conditions exist for PPA markets to develop, thereby providing industry access to affordable and clean electricity over the long term. The improvements to the forwards markets will provide far greater access to cross-border renewables for industries and suppliers up to three years in advance, a significant improvement on today. Overall, public support schemes for renewables will increase the energy independence in Member States and the penetration of renewables into the system while supporting local jobs and skills.

Finally, if adopted, this reform will accelerate the rollout of renewables and tap into the full potential of firm generation capacity and flexibility solutions to enable Member States to integrate ever higher levels of renewables. The Commission proposes that Member States assess their need for power system flexibility and introduces the possibility for new support schemes for demand response and storage. The proposal also introduces extra possibilities for renewables to trade closer

to real time at cross-border and national level. In this way, the market can better support the integration of renewables and the business case for flexibility solutions that can contribute to security of supply.

This proposal responds to the request from the European Council to assess ways of optimising the functioning of the electricity market design in the context of the energy crisis. It aims to protect consumers, creating a buffer between them and short-term electricity markets through longer-term contracting and to make those short-term markets work in a more efficient way for renewables and flexibility solutions, with better regulatory oversight. This proposal ensures that the market rules remain fit for purpose to drive the cost-effective decarbonisation of the electricity sector and increase its resilience to energy price volatility.

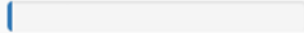
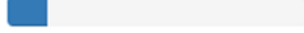
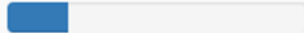
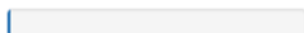

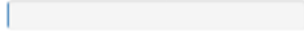
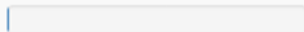
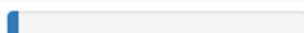
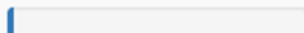
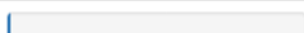
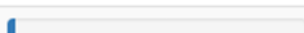
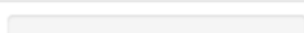
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# ANNEX I: Additional summary of the public consultation on Electricity Market design

## 1. Overview of respondents


I am giving my contribution as




		Answers	Ratio
Academic/research institution		25	1.83 %
Business association		181	13.22 %
Company/business		277	20.23 %
Consumer organisation		18	1.31 %
EU citizen		725	52.96 %
Environmental organisation		4	0.29 %
Non-EU citizen		7	0.51 %
Non-governmental organisation (NGO)		53	3.87 %
Public authority		27	1.97 %
Trade union		15	1.10 %
Other		37	2.70 %
No Answer		0	0.00 %

## 2. Answers from professional/non-citizens respondents















Answers to the open questions have been summarised directly in the Staff Working Document under each sub-sections. Therefore, this annex focuses on answers to the multiple choice questions.

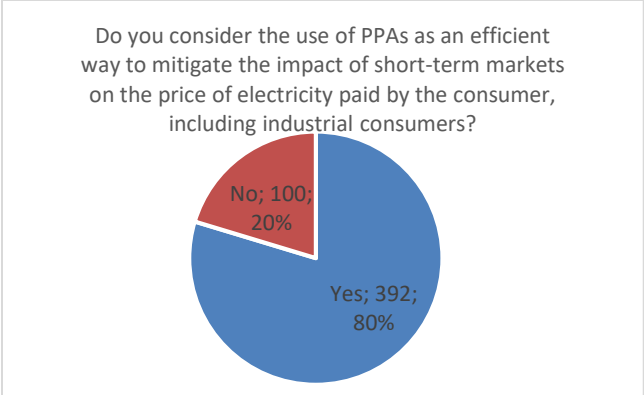
Organisation size

		Answers	Ratio
Micro (1 to 9 employees)		141	22.93%

Small (10 to 49 employees)		139	22.6%
Medium (50 to 249 employees)		102	16.59%
Large (250 or more)		233	37.89%

To which category of stakeholder do you belong?

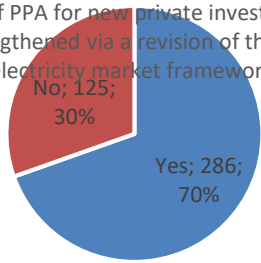
		<b>Answers</b>	<b>Ratio</b>
a) National or local administration		27	4.39%
b) National regulator		7	1.14%
c) Transmission System Operator		25	4.07%
d) Distribution System Operator		42	6.83%
e) Market operator		35	5.69%
f) Energy company with generation assets		154	25.04%
g) Independent energy supplier with no generation assets		23	3.74%
h) Company conducting business in the energy sector no included in f) or g)		65	10.57%
i) Industrial consumer and associations		161	26.18%
j) Energy community		15	2.44%
k) Academia or think tank		39	6.34%
l) Citizen or association of citizens		4	0.65%
m) Non-governmental organisations		72	11.71%
n) Other		68	11.06%
No Answer		0	0%



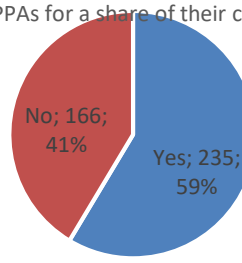
Do you consider that the following measures would be effective in strengthening the roll-out of PPAs?

		<b>Answers</b>	<b>Ratio</b>
a) Pooling demand in order to give access to smaller final customers		324	52.68%
b) Providing insurance against risk(s) either market driven or through publicly supported guarantees schemes (please identify such risks)		337	54.8%
c) Promoting State-supported schemes that can be combined with PPAs		280	45.53%
d) Supporting the standardisation of contracts		288	46.83%
e) Requiring suppliers to procure a predefined share of their consumers' energy through PPAs		100	16.26%
f) Facilitating cross-border PPAs		266	43.25%
No Answer		141	22.93%

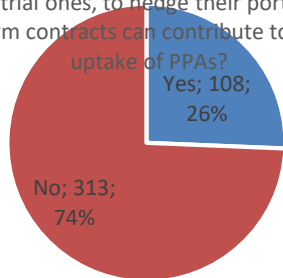
In addition to the measures proposed in the question above, do you see other ways in which the use of PPA for new private investments can be strengthened via a revision of the current electricity market framework?



Do you see a possibility to provide stronger incentives to existing generators to enter into PPAs for a share of their capacity?



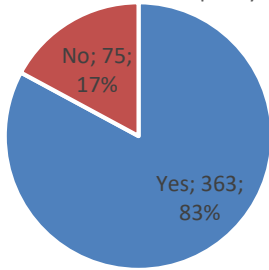
Do you consider that stronger obligations on suppliers and/or large final customers, including the industrial ones, to hedge their portfolio using long term contracts can contribute to a better uptake of PPAs?



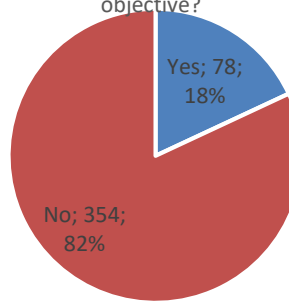
**Do you consider that increasing the uptake of PPAs would entail risks as regards:**

	Yes	No	No Answer
(a) Liquidity in short-term markets	159	242	214
(b) Level playing field between undertakings of different sizes	203	187	225
(c) Level playing field between undertakings located in different Member States	185	187	243
(d) Increased electricity generation based on fossil fuels	46	341	228
(e) Increased costs for consumers	159	230	226

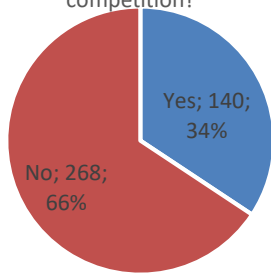
Do you consider forward hedging as an efficient way to mitigate exposure to short-term volatility for consumers and to support investment in new capacity?



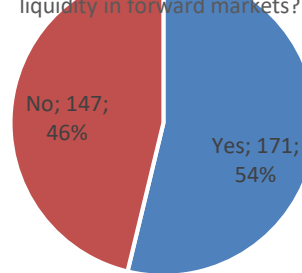
Do you consider that the liquidity in forward markets is currently sufficient to meet this objective?



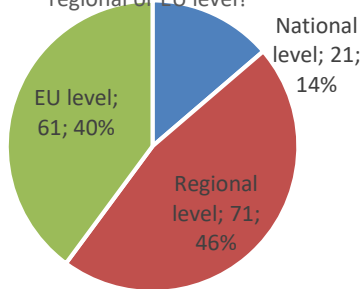
In your view, would requiring electricity suppliers to hedge for a share of their supply be beneficial for consumers and for retail competition?



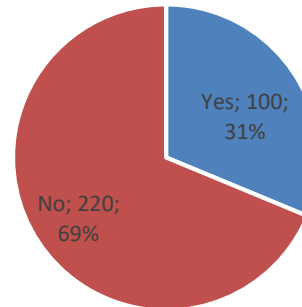
Do you consider that the creation of virtual hubs for forward contracts complemented with liquid transmission rights would improve liquidity in forward markets?

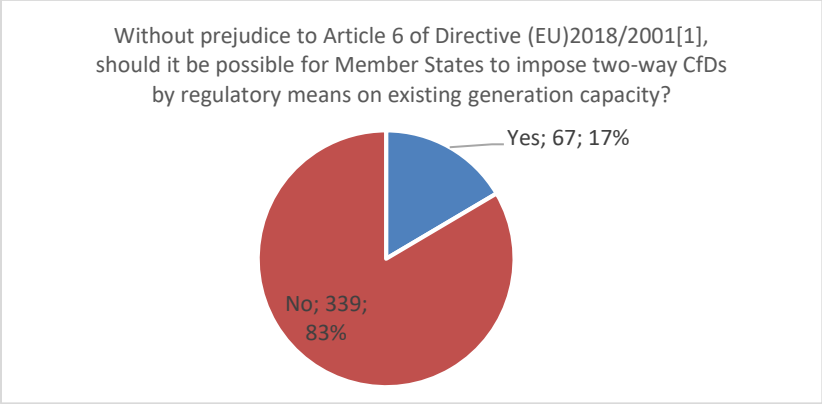
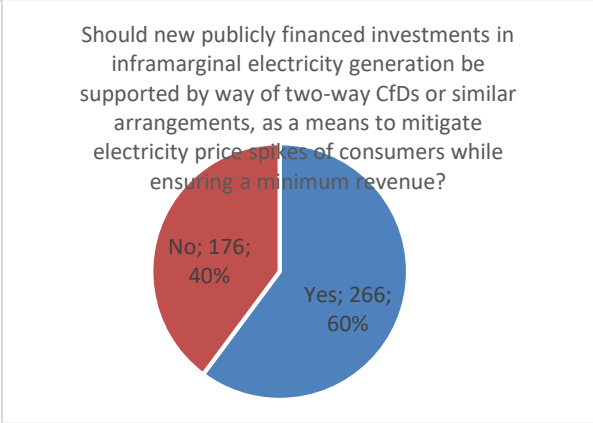
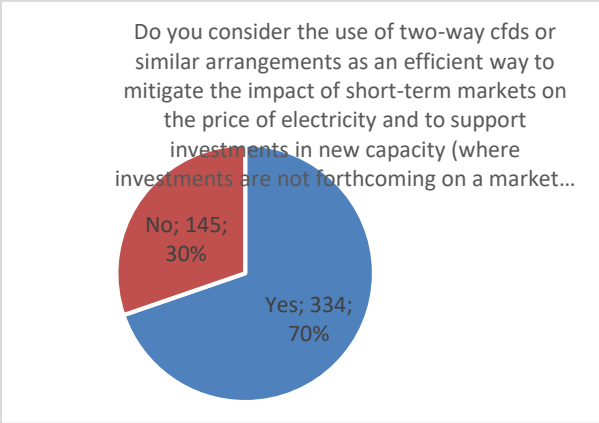
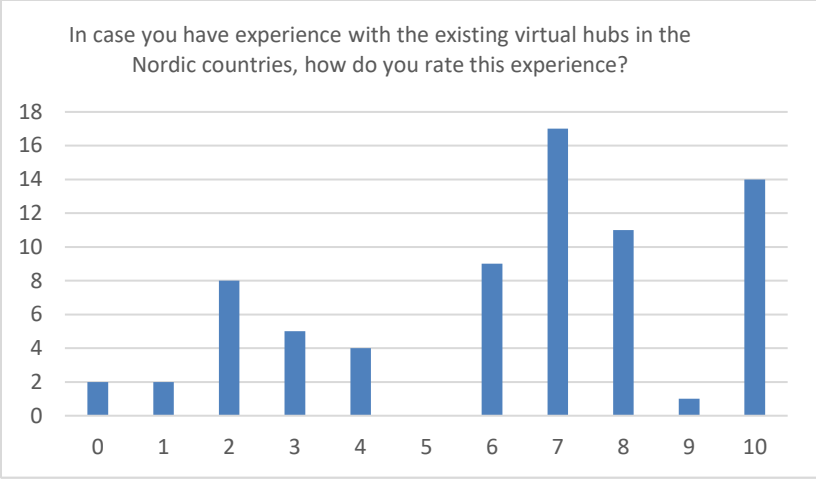


If yes, do you consider that such virtual hub(s) should be developed at national, regional or EU level?



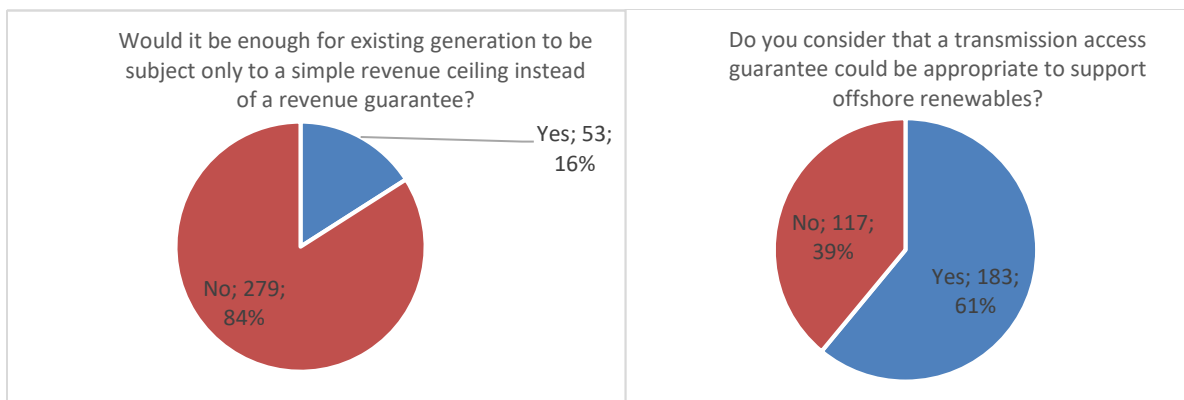
Do you have experience with the existing virtual hubs in the Nordic countries?





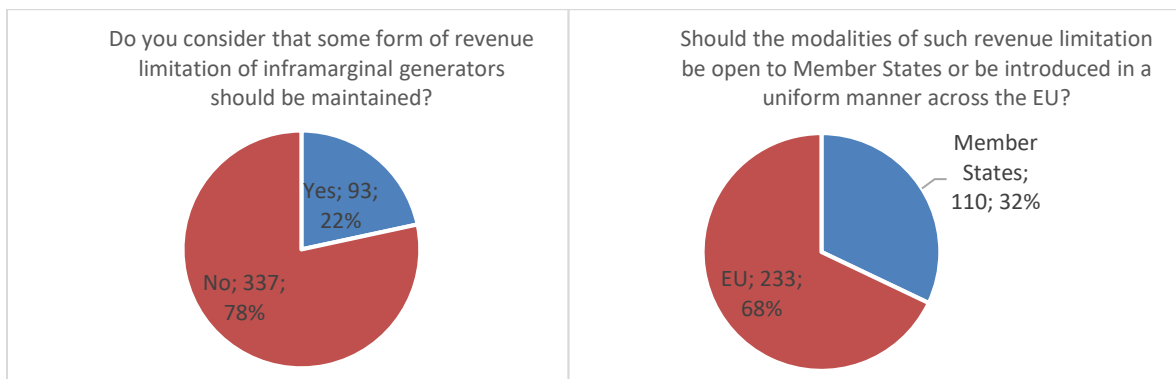
How would you rate the following potential risks as regards the imposition of regulated CfDs on existing generation capacity?

	Negligible	Low risks	Medium risk	High risks	Very high	No Answer
Legitimate expectations/legal risks	13	25	35	64	221	257
Ability of national regulators/governments to accurately define the level of the price levels envisaged in these contracts	11	18	45	140	149	252
Locking in existing capacity at excessively high price levels determined by the current crisis situation	16	35	92	107	99	266
Impact on the efficient short-term dispatch	20	55	67	73	136	264



**Do you see any other short-term measures to accelerate the deployment of renewables?**

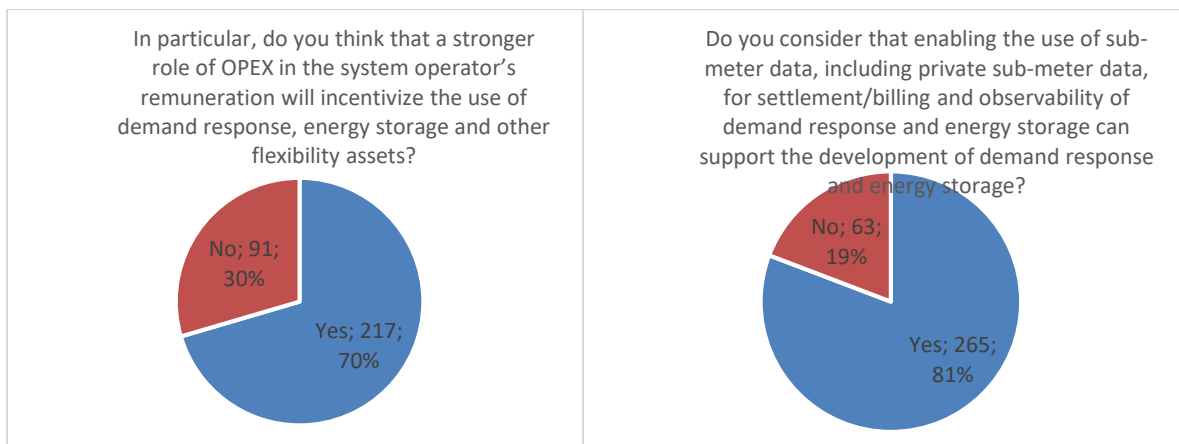
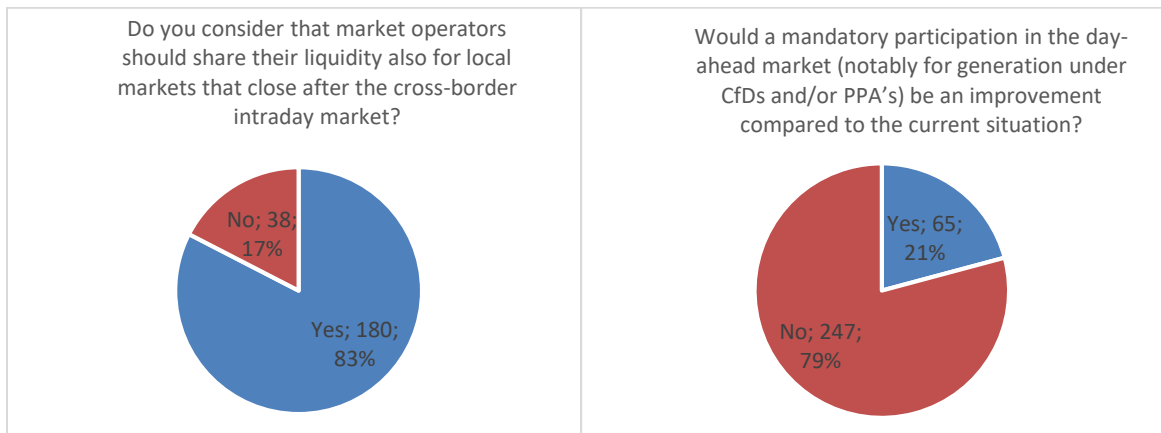
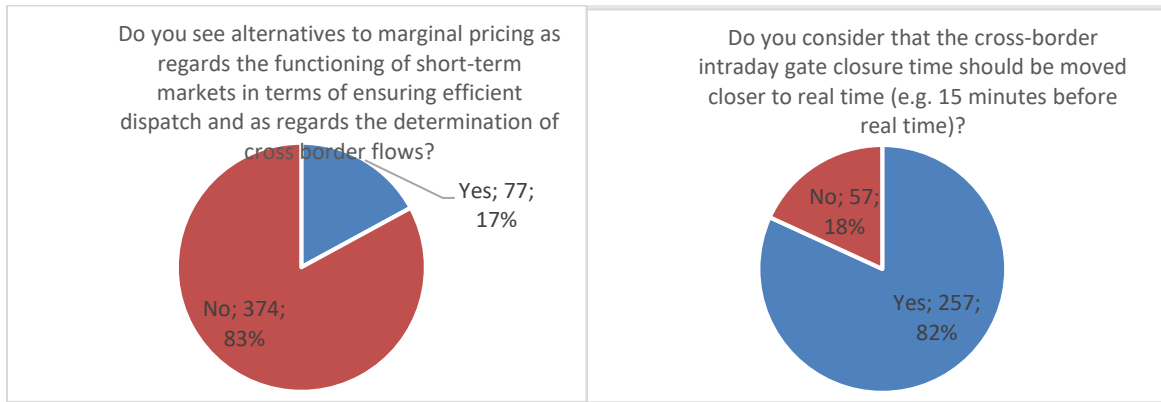
	Yes	No	No Answer
At national regulatory or administrative level	385	22	208
In the implementation of the current EU legislation, including by developing network codes and guidelines	307	45	263
Via changes to the current electricity market design	177	161	277
Other	140	54	421



	0	1	2	3	4	5	6	7	8	9	10	No Answer
(a) the effectiveness of the measure in terms of mitigating electricity price impacts for consumers	161	33	48	22	6	18	9	12	19	5	18	264
(b) its impact on decarbonisation	214	28	36	19	8	9	1	5	6	3	8	278
(c) security of supply	191	39	31	16	9	12	2	4	7	4	8	292
(d) investment signals	227	45	25	15	4	4	4	3	7	1	7	273
(e) legitimate expectations/legal risks	193	28	25	20	13	8	6	7	6	0	7	302
(f) fossil fuel consumption	170	18	35	16	6	18	5	7	7	2	4	327
(g) cross border trade intra and extra EU	173	28	24	15	11	15	3	2	5	1	6	332
(h) distortion of competition in the markets	175	36	24	19	5	14	0	6	8	2	22	304
(i) implementation challenges	159	31	34	23	3	9	11	3	7	1	19	315

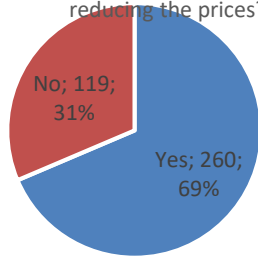
**Do you consider the short-term markets are functioning well in terms of:**

	Yes	No	No Answer
(a) accurately reflecting underlying supply/demand fundamentals	366	73	176
(b) encompassing sufficiently liquidity	331	84	200
(c) ensuring a level playing field	304	101	210
(d) efficient dispatch of generation assets	363	58	194
(e) minimising costs for consumers	261	147	207
(f) efficiently allocating electricity cross-border	322	76	217

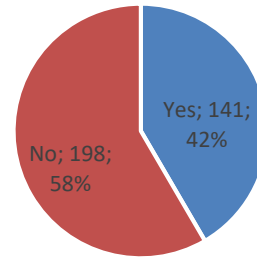




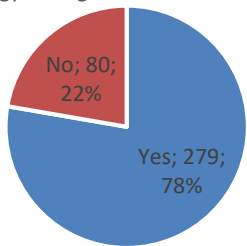
Do you consider appropriate to enable a product to foster demand reduction and shift energy at peak times as an ancillary service, aiming at lowering fuel consumption and reducing the prices?



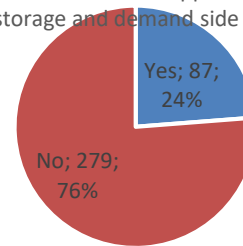
Do you consider that some form of demand response requirements that would apply in periods of crisis should be introduced into the Electricity Regulation?



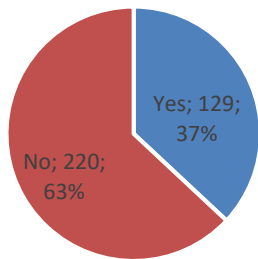
Do you see any further measure that could be implemented in the shorter term to incentivize the use of demand response, energy storage and other flexibility assets?



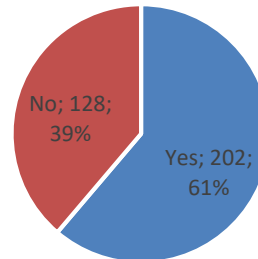
Do you consider the current setup for capacity mechanisms adequate to respond to the investment needs as regards firm capacity, in particular to better support the uptake of storage and demand side response?



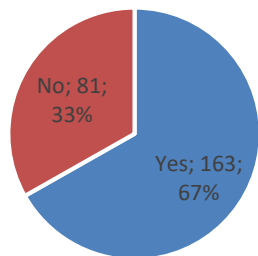
Do you see a benefit in a long-term shift of the European electricity market to more granular locational pricing?



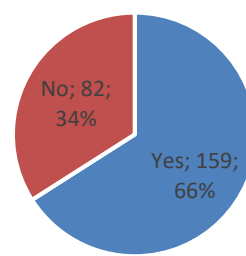
Would you support a provision giving customers the right to deduct offsite generation from their metered consumption?



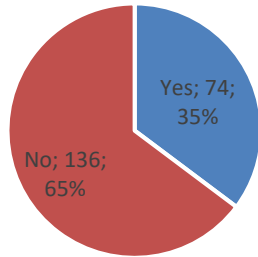
(a) Would it affect the location of new renewable generation facilities?



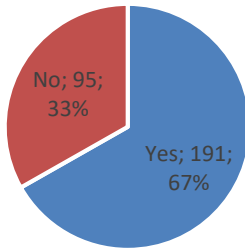
(b) Should it be restricted to local areas?



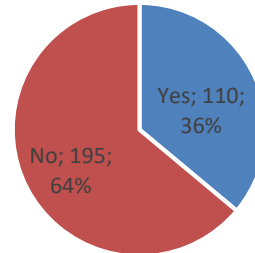
(c) Should it apply across the Member State/control/zone?



Would you support establishing a right for customers to a second meter/sub-meter on their premises to distinguish the electricity consumed or produced by different devices?



Would you support provisions requiring suppliers to offer fixed price fixed term contracts (ie. which they cannot amend) for households?

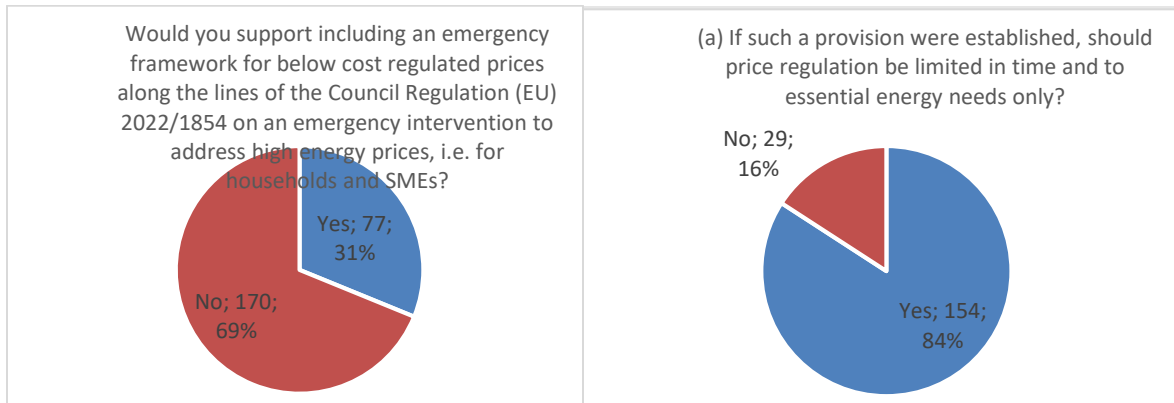
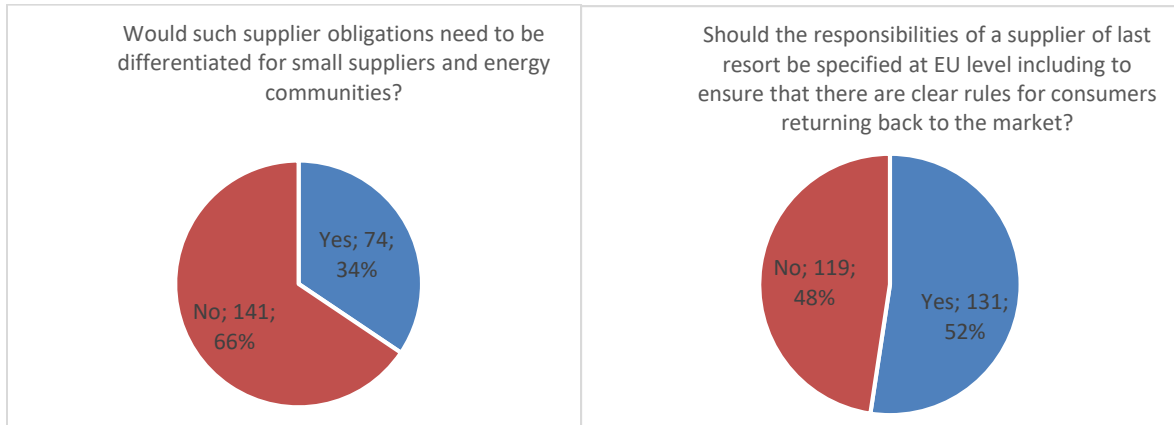
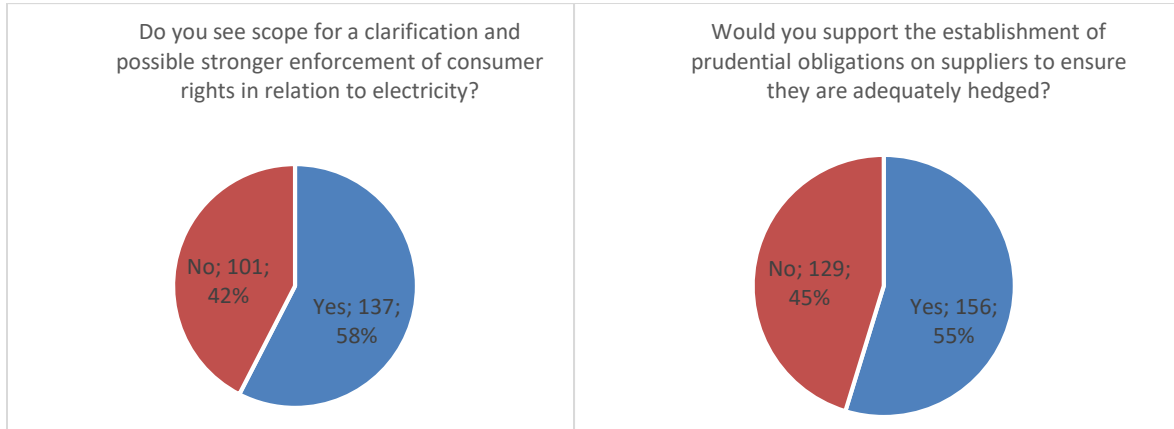


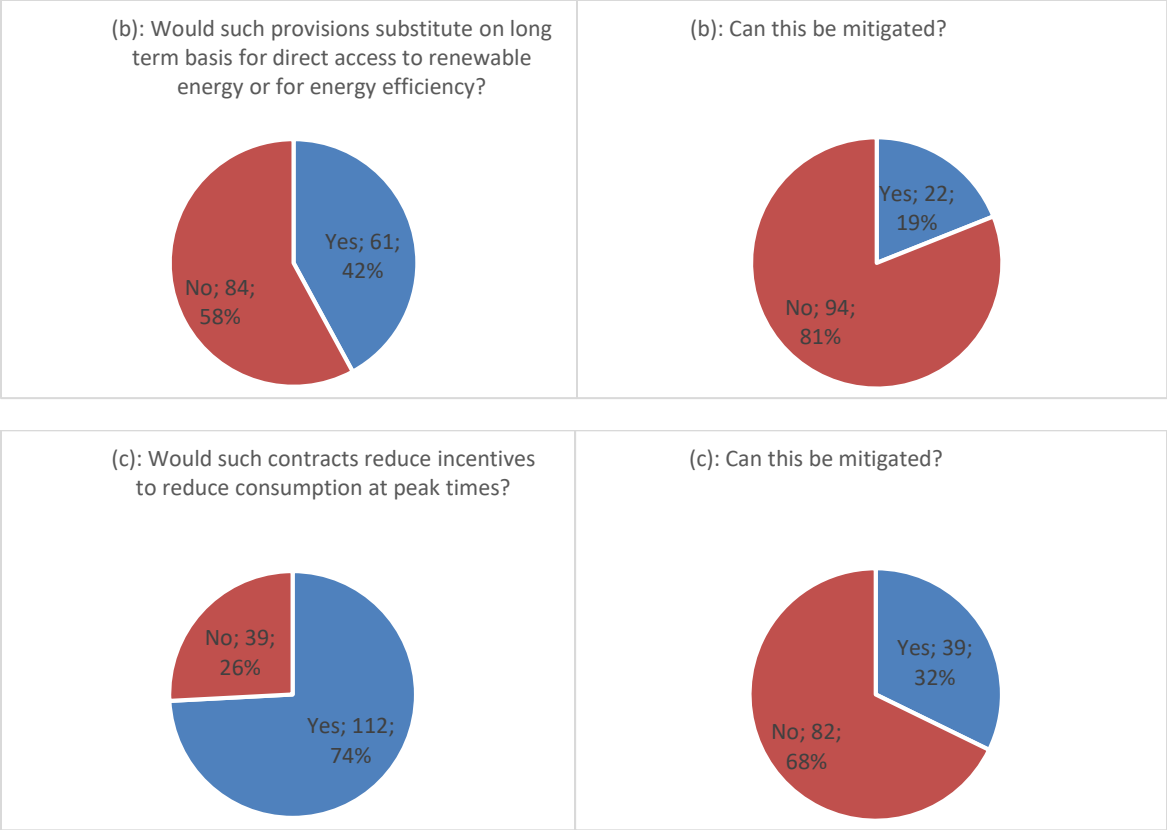
**If such an obligation were implemented what should the minimum fixed term be?**

		<b>Answers</b>	<b>Ratio</b>
(a) less than one year	■	32	5.2%
(b) one year	■	76	12.36%
(c) longer than one year	■	39	6.34%
(d) other	■	63	10.24%
No Answer	■	405	65.85%

**Cost reflective early termination fees are currently allowed for fixed price, fixed term contracts:**

	Yes	No	No Answer
(a) Should these provisions be clarified?	155	49	411
(b) If these provisions are clarified should national regulatory authorities establish ex ante approved termination fees?	76	106	433





### 3. Answers from citizens

#### 3.1. “Slovakian campaign”

Almost all of the more than 550 responses from Slovakia appear to be part of a co-ordinated campaign. Slovakian citizens consider PPAs as an efficient and risk-free way to mitigate the impact of short-term markets on the price of electricity but are of the opinion that current EU legislation prevents existing generators to enter into PPAs. They advocate a stronger obligation on suppliers and/or large final customers to hedge their portfolio, the standardisation of contracts and facilitating cross-border PPAs. They advocate to give national regulators the power to prevent the export of electricity to other Member States.

These respondents support giving Member States the right to impose two-way CfDs on existing generation, despite legal risks and are of the view that public support schemes should exclude renewables that do not generate at least a minimum number of hours per year. They also strongly advocate increasing competence and independence of the national regulator.

Almost all respondents which are part of the co-ordinated campaign oppose a revenue limitation set at EU level. They see it as task of the national regulator. They also consider that emissions trading hampers competitiveness and should be abolished.

Overall, they consider that short-term markets are functioning well and respondents see no alternative to marginal pricing. They do not support a change in the cross-border intraday gate closure time or the proposed measures to incentivise flexibility with the exception of a product to foster demand reduction and shift energy at peak times as an ancillary service and increasing awareness and promotion of mini- and micro-resources. Mandatory participation in the day-ahead market is supported, since it would put downward pressure on prices in their view. A long-term shift to more granular pricing is considered beneficial as is stronger enforcement of consumer rights.

The respondents explained that REMIT should be improved in order to prevent speculative practices by market participants in a timely manner.

### ***3.2. Views of the other around 120 individual citizens***

Most contributions from individual citizens, besides the co-ordinated campaign from Slovakia, came from France, Slovakia and Germany. A few responses came from Austria, Belgium, Czechia, Slovakia, Sweden. Those citizens have diverging views and for many questions the share of “no answer” responses is significantly higher than for other stakeholders.

A clear majority of these citizens considers the use of PPAs as an efficient way to mitigate the impact of short-term markets on the price of electricity paid by private and industrial consumers. Only a small minority of respondents did not answer this question. A majority of them also considers forward hedging as an efficient way to mitigate exposure to short-term volatility for consumers and to support investment in new capacity. Only a small minority did not provide an answer to this question. For all other questions, the share of “no answer” is rather high and no clear tendency can be identified.

Only a small number of citizens responded to the questions related to REMIT. These responses mainly indicate concerns about high energy prices or if electricity markets are functioning to the benefit of consumers.