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European Union Agency for the Cooperation of Energy Regulators

ACER's Final Assessment of the EU Wholesale Electricity Market Design

April 2022

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Executive Summary

The current energy crisis is in essence a gas price shock, which also impacts electricity prices. With the economic recovery in 2021, global gas demand bounced back to pre-pandemic levels and outstripped supply. Despite increasing LNG deliveries to Europe (linked with the rise in gas prices), sharply decreasing Russian gas pipeline supplies and the related geopolitical uncertainty put strong upward pressure on prices. In 2022, Russia's invasion of Ukraine heightened the crisis resulting in unprecedentedly high gas and electricity prices that severely impact consumers, retail suppliers, market participants and others.

Whilst this ACER assessment is likely to be read against the backdrop of the current energy crisis, its main focus is a somewhat longer-term perspective on the EU's wholesale electricity market design, in line with the original task assigned to ACER by the European Commission. Well before the height of the current crisis, the EU's wholesale electricity market design has been the subject of debate (in technical, academic as well as policy circles), in particular as to whether the current market design is fit-for-purpose given the significant changes needed to deliver the clean energy transition or whether, and if so, to what extent, the market design would need further adjustment.

"The current energy crisis is in essence a gas price shock, which also impacts electricity prices."

Need for improvements to the current market design?

In its 'Toolbox' Communication of October 2021, the European Commission tasked ACER with assessing the benefits and the drawbacks of the EU's current wholesale electricity market design and with providing recommendations for its improvement. This report seeks to deliver on that mandate.

ACER finds that the current wholesale electricity market design ensures efficient and secure electricity supply under relatively 'normal' market conditions. As such, ACER's assessment is that the current market design is worth keeping. In addition, some longer-term improvements are likely to prove key in order for the framework to deliver on the EU's ambitious decarbonisation trajectory over the next 10-15 years, and to do so at lower cost whilst ensuring security of supply.

Whilst the current circumstances impacting the EU's energy system are far from 'normal', ACER finds that the current electricity market design is not to blame for the current crisis. On the contrary, the market rules in place have to some extent helped mitigate the current crisis, thus avoiding electricity curtailment or even blackouts in certain quarters.

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The electricity market design is, however, not designed for the 'emergency' situation that the EU currently finds itself in. The ongoing political discussions on various exceptional interventionist measures bear witness to this.

Whilst not the primary focus of this assessment, ACER nevertheless offers some views on select interventionist measures contemplated in the current emergency situation and their respective risks. ACER also offers reflections on possible structural measures to hedge electricity customers against possible future periods of sustained high energy prices.

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Ill-designed emergency measures could endanger hard-earned benefits of electricity market integration

Over the last decade, cross-border trade and the major efforts undertaken to further integrate electricity markets in Europe have delivered significant benefits for consumers. These benefits are estimated to be approximately 34 billion Euros a year. The benefits are due to the structure of the wholesale energy market enabling cross-border trade between Member States and improving security of supply across a larger geographical area. The electricity market design also facilitates the significant uptake of renewable generation, the acceleration of which is likely to prove a prerequisite for achieving the EU's ambitious decarbonisation trajectory at pace. Ongoing initiatives to further implement the current market design via a number of existing EU rules and regulations will deliver additional benefits.

Conversely, ill-designed emergency measures or distorting price signals by interfering in market price formation may roll back EU market integration and overall competition, thereby endangering the benefits achieved up until now and possibly increasing the overall cost of the energy transition up ahead, as further expanded below.

Future-proofing the electricity market design to help deliver the energy transition

> *"... Whilst increased energy independence vis-à-vis (particular) third-countries is a policy objective of growing importance, realising this may well depend on enhanced energy inter-dependence amongst EU Member States."*

Going forward, the EU's ambitious decarbonisation trajectory requires fast and massive transformation across sectors. Given enhanced electrification of energy demand is amongst the most cost-efficient ways to drive down emissions from the wider economy, this trajectory is likely to be driven in large part by the decarbonisation of the electricity sector.

Electricity market integration across EU Member States will be key to pursue such power sector decarbonisation at lower cost, in turn ensuring security of supply by being able to draw on neighbouring jurisdictions in times of need. Put differently, whilst increased energy independence vis-à-vis (particular) third-countries is a policy objective of growing importance, realising this may well depend on enhanced energy inter-dependence amongst EU Member States.

What implications will this have for the current wholesale electricity market design?

The market design will need to facilitate a massive rollout of low-carbon generation, and in particular renewable generation characterised by high upfront investment costs, while ensuring that flexible resources complement intermittent renewable production where and when needed. Related to this, price volatility in the electricity system is likely to increase in the years ahead, indicating increasing flexibility needs of the system. Hence the market design will need to send adequate price signals to meet flexibility needs going forward, again where and when needed.

All in all, this ACER assessment identifies several areas where policy makers could put further emphasis to future-proof the current electricity market design. These fall under 6 broad headings:

1. Making short-term electricity markets work better everywhere: Overall, short-term markets are working well. In order to realise further benefits, Member States and national regulatory authorities should implement what has already been agreed in EU legislation and beyond. ACER highlights four such areas relevant for enhanced EU market integration: meeting the minimum 70% cross-zonal capacity target by 2025 (thus enhancing electricity trade between Member States); rolling out flow-based market coupling in the Core and Nordic regions as soon as possible; integrating national balancing markets; and reviewing the current EU bidding zones to improve locational price signals.

"... This ACER assessment identifies several areas [...] to future-proof the current electricity market design."

2. Driving the energy transition through efficient long-term markets: Long-term markets and improved hedging instruments need more attention to drive the massive investments needed up ahead. Currently, such long-term markets lack liquidity, particularly beyond three years in the future. ACER highlights that access for smaller market participants to Power Purchase Agreements (PPAs) could be improved (e.g. through public guarantees); that liquidity could be further stimulated via so-called 'market-making' efforts to help independent companies, traders etc. compete with large established firms (e.g. via tenders, mandatory measures or financial incentives); that national forward markets should be further integrated; and that collateral requirements imposed on market participants could benefit from being reviewed. Market-based centralised procurement could complement long-term electricity markets to address market failures (e.g. the procurement of ancillary services) or to speed up the deployment of specific technologies.

3. Increasing the flexibility of the electricity system: Enhanced flexibility resources, covering also for example seasonal flexibility needs, will be key for the electricity system going forward. Here, freely determined and competitive price signals are invaluable instruments for showing true system flexibility needs. These price signals should thus be preserved in order to drive relevant investment efficiently. Hence, national regulatory authorities and system operators should focus on removing barriers to the use of such flexibility resources.

4. Protecting consumers against excessive volatility whilst addressing inevitable trade-offs: Targeted measures to protect vulnerable consumers should be considered in times of sustained high prices, whilst not limiting the ability of e.g. energy communities or aggregators to provide innovative energy services for the benefit of the system and thus also consumers. Preserving some price signalling to incentivise desired behaviour remains important. In addition, Member States should strike a balance between ensuring the financial responsibility of retail energy suppliers for the benefit of consumer confidence, market stability etc., and keeping the market open for new responsible suppliers to reduce costs for consumers.

5. Tackling non-market barriers and political stumbling blocks: Member States should consider enhanced coordination of approaches to and plans for large-scale generation and grid infrastructure deployment, as a likely prerequisite for the efficient and accelerated roll-out of such investment. This in turn will rely on greater attention being paid to cross-border perspectives and needs, supplementing more national perspectives. In addition, addressing barriers and recurrent delay factors to infrastructure roll-out remains key.

6. Preparing for future high energy prices in 'peace time'; being very prudent towards wholesale market intervention in 'war time': The need for interventions in market functioning should be considered prudently and carefully in situations of extreme duress and if pursued should, ideally, seek to tackle 'the root causes' of the problem (currently gas prices). Additionally, ACER points to a few structural measures for hedging, which might be considered to alleviate possible concerns about future periods of sustained high energy prices.

Exceptional emergency measures currently under debate

The current energy price crisis is exceptional in nature. Many Member States have introduced short-term measures to alleviate the impact of the high prices. In addition, governments across the EU debate whether additional interventionist measures should be taken, what the relative benefits and risks of such measures are, and how such measures may jeopardise (or not) the current benefits resulting from electricity market integration across the EU.

Whilst such measures are not the primary focus of this ACER assessment, Section 5 below lists a spectrum of such measures, all of them proposed or hinted at by different quarters across the EU. These range from less interventionist measures that safeguard wholesale market functioning (such as targeted support for vulnerable customers) to the more interventionist (e.g. taxing windfall profits through to capping the price of the electricity market). As a rule of thumb, ACER considers that the more interventionist the approach, the higher the potential to distort the market, especially in the medium to long-term. Such distortions imply that wrong investment choices are likely to be made vis-à-vis future needs and/or that much-needed innovations to address changing system needs are less likely to happen. Furthermore, measures that are more interventionist may dampen private sector investment, influence perceptions of political risk and/or inadvertently exacerbate supply shortages.

Accordingly, when contemplating extraordinary measures here and now, policy makers should carefully consider the potential for negative consequences in the medium and long-term. This is further accentuated by the fact that much effort over many years has been put into creating the current electricity market framework. If it were to be suddenly 'uprooted', as opposed to further improved or enhanced, it could have significant implications for the ability of the electricity market to deliver on key policy objectives over the coming decade. ACER cautions to consider prudently the need for interventions in electricity market functioning in the current circumstances, and if pursued for policymakers to tackle the root cause of the problem (currently gas prices) rather than the electricity market framework itself.

Hence, if Member States consider such a 'root cause' intervention necessary, it would seem relevant to pursue measures that accelerate gas demand reduction (efficiency efforts, fuel switching etc.) and/or deploy additional efforts that can put downward pressure on gas prices (e.g. new supply or lower-price supply coming to Europe), whilst retaining prices that still secure needed liquified natural gas (LNG) deliveries. The latter effort would likely require intense dialogue between governments in the EU and key gas suppliers.

Finally, regarding more structural measures for the future, ACER points to a few options being debated in academic circles for hedging against future periods of sustained high energy prices. These are not immediate options to alleviate the current extraordinary prices, but may alleviate possible concerns about future energy price shocks. One such measure is a 'temporary relief valve' when wholesale electricity prices change unusually rapidly to high levels over a sustained period. Another is a financial option (sometimes dubbed 'affordability option') whereby pre-identified consumer groups are hedged against sustained high prices occurring over a longer period above a certain threshold. ACER points out that each such measure has advantages and drawbacks.

Gas markets require our focus in the coming years

Given the renewed impetus towards diversifying the EU's gas supply, gas prices are likely to be determined increasingly by the global LNG market in the coming years. Accordingly, this ACER assessment considers some of the key developments impacting the LNG market. In particular, ACER suggests for policy makers and others to pay close attention to mechanisms that can limit gas price exposure and secure additional gas supply to offset decreasing supplies of Russian gas. Such measures include for example enhanced long-term contracting and higher gas storage stocks, noting however that both come at a cost. As a result, long-term and short-term gas contracts are likely to coexist for some years to come. Gas storage will increasingly support security of supply, whilst also assisting flexible operation of the energy system.

This assessment is not 'the full story'. As the energy transition unfolds, new challenges are likely

This ACER assessment focuses primarily on the current wholesale electricity market design, looking at what the design is called upon to deliver over the next 10-15 years. In the conclusions section, ACER sets out an overview of the measures it puts forward for consideration by EU policymakers, these numbering 13 in total (a summary infographic is provided below).

This assessment does not seek to be 'the full story' of how energy systems in Europe may evolve over this time frame. By way of example, some of the evolutionary trends not so readily tackled in this assessment are: (a) the increased integration of the energy system across energy carriers, transport, buildings and other sectors (implying e.g. that energy system-wide benefit assessments and planning will become more complex); (b) the application of 'energy efficiency first' principles in an evolving system (likely drawing on enhanced resource sharing and balancing energy savings solutions with low-cost capacity additions); or (c) the relative weight of more centralised, utility-scale solutions vis-à-vis smaller and more localised solutions (the latter possibly bringing enhanced resilience and lower price volatility at the consumer-level whilst perhaps raising questions of overall system costs).

Notwithstanding the considerable breadth of measures put forward, it is likely that new regulatory challenges and opportunities will appear as the clean energy transition further unfolds. Hence, it will be key for governments and regulators to detect and address such challenges early on and to tackle them in a coordinated manner across the EU.

In summary, ACER puts forward the following 13 measures for the consideration of policymakers

13 measures for the consideration of policymakers,
future-proofing the EU wholesale electricity market design

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1. Speed up electricity market integration, implementing what is already agreed

2. Improve access to renewable Power Purchase Agreements (PPAs)

3. Improve the efficiency of renewable investment support schemes

4. Stimulate 'market making' to increase liquidity in long-term markets

5. Better integrate forward markets

6. Review (and potentially reduce, if warranted) collateral requirements

7. Preserve the wholesale price signal and remove barriers to demand resources providing flexibility

8. Shield those consumers that need protection the most from price volatility

9. Tackle avoidable supplier bankruptcies, getting the balance right

10. Tackle non-market barriers, ensuring generation and infrastructure is built at pace

11. Consider prudently the need for market interventions in situations of extreme duress; if pursued, consider tackling 'the root causes'

12. Consider public intervention to establish hedging instruments against future price shocks

13. Consider a 'temporary relief valve' for the future when wholesale prices rise unusually rapidly to high levels

Want to learn more?

Check out the full report on ACER's Final Assessment of the EU Wholesale Electricity Market Design.

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1. Introduction

1.1. Background to this assessment

The recent energy price surge sparked a call by some to reform the EU electricity market design. The European Commission in October 2021, in its 'Tackling rising energy prices: a toolbox for action and support' Communication (hereafter 'Toolbox' Communication), tasked ACER with assessing the benefits and drawbacks of the EU's current wholesale electricity market design and with providing recommendations for its improvement.

ACER published a Preliminary Assessment in November 2021. In that report, ACER made clear that the root of the problem was the rise in global gas prices for various supply and demand dynamics prevalent at the time. Other factors also played a role such as Europe's lower-than-average gas storage stocks; limited additional pipeline gas imports to the EU; rising Emissions Trading System (ETS) allowance prices; and somewhat unusual weather patterns in Europe in 2021 affecting both generation and demand. Since then, a number of developments have significantly impacted gas and thus also electricity prices most notably Russia's invasion of Ukraine in February, leading to high uncertainty as to the near-term outlook for gas supply to the EU.

This report is ACER's final assessment, delivering on the European Commission's mandate.

1.2. Structure of this assessment

This assessment confirms that the current EU electricity market design is based on relevant and enduring principles and that as such, in ACER's view, it should be preserved. However, looking to the future, the current market design should be complemented to support the policy objectives set for the EU as a whole, in particular to deliver on the EU's ambitious decarbonisation trajectory.

Section 2 explains the steep rise in European energy prices over the past year. It describes the evolution of the price shock and illustrates how markets reacted to it. It briefly touches upon the consequences for consumers (addressed in further detail in Section 7), as well as the latest market outlook for energy prices throughout 2022 and into the first quarter of 2023.

Section 3 explains how the current market design works both in 'normal' times and as a mitigating factor during more extreme events such as the current energy price shock. The section describes the relevance of certain market design fundamentals, giving examples of the benefits provided by the current market design and overall EU electricity market integration. Finally, it shows why completing a number of already-decided, but still-to-be-implemented market integration priorities remains key.

Section 4 examines ways to improve the current market design in light of the EU's ambitious decarbonisation trajectory and the resulting changes in the power system. Elements outlined include for example improvements to long-term markets and the availability of hedging instruments (e.g. on enhanced forward markets and wider access to PPAs) as well as the better use of flexibility resources. The section also touches upon the benefits of further coordination amongst Member States as regards generation and grid infrastructure roll-out.

Section 5 notes the calls for temporary interventions in electricity market functioning given the current extreme price shocks. ACER offers certain considerations for policy makers ahead of taking such intervention decisions, suggesting a possible different route that targets the root cause of the current situation (gas prices) rather than the symptoms (electricity prices). Finally, this section points to a few structural measures relevant for 'insuring' or hedging against possible future periods of sustained high energy prices.

Section 6 takes a closer look at the outlook for gas markets, relevant for the EU's attempts to further diversify its gas supply in the coming years. It adds perspectives on likely gas contracting models and the role of gas storages across Member States in the years ahead.

Section 7 focuses on limiting the undesirable impacts of increased price volatility on energy consumers. It considers options that balance the respective interests of retail suppliers, consumers and society as a whole. In addition, it lists some of the learnings from last year's application in many Member States of the so-called Supplier of Last Resort mechanism. Finally, it points to the facilitation of demand-side response as a measure for enhanced system benefit and for the alleviation of unwanted price volatility.

Section 8 concludes with a summary of the 13 measures that ACER puts forward for policy makers' consideration.

2. Price levels and drivers

2.1. 'Roller coaster gas prices': High global LNG prices followed by restricted Russian gas flows send gas prices soaring

Energy prices reached record high levels across 2021 and hit their highest point in the first weeks of March 2022. The price surge can be split into three distinct phases (see Figure 1 below):

- Phase 1 ('the first price crunch') across Summer and Fall 2021, when scarce LNG imports and narrow pipeline flows led to the first wave of price rise;
- Phase 2 ('market-response from LNG'), from late 2021 through early 2022, when high gas prices attracted extra LNG, while Russian pipeline supplies decreased; and
- Phase 3 ('war emergency') from late February 2022, when the Russian invasion of Ukraine further aggravated the price surge.

Figure 1: Overview of events and market fundamentals driving EU gas prices, TTF month-ahead contract (EUR/MWh), (May 2021 - April 2022)

Source: ACER based on ICIS Heren's price data.

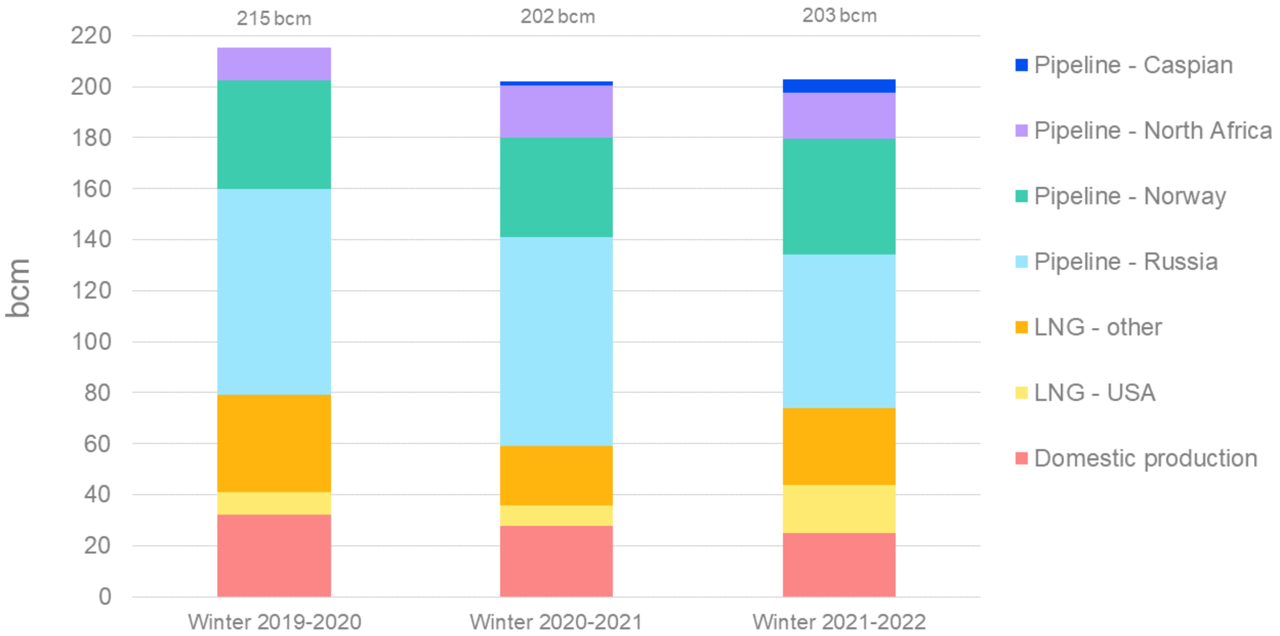
The main price drivers in Phase 1 were increased EU gas demand together with tight global gas supply; this occurring amidst a global rebound in economic activity and unexpected gas production outages. During Phase 2, EU LNG imports (which had decreased in Phase 1 because spot LNG cargoes had been attracted to higher-priced Asian markets) recovered due to stronger EU gas hub price signals. Phase 3 is the period from late-February 2022 onwards when the Russian invasion of Ukraine led to an immediate and sharp rise in gas prices.

"... The current price shock and very significant price volatility would seem to stem less from physical shortages and more from perceived risks of potential significant disruption of Russian gas flows going forward."

Looking more closely at this latest phase, it would seem that price developments are significantly influenced by the extreme uncertainty as to the near-term outlook for gas supplies to the EU. As shown in Figure 2, so far this year, physical gas supplies to the EU have remained close to historical levels, with LNG deliveries replacing Russian gas pipeline flows to a considerable extent. Hence, the current price shock and very significant price volatility would seem to stem less from physical shortages and more from perceived risks of potential significant disruption of Russian gas flows going forward.

As the outlook for such disruptions remains very uncertain for market participants, day-to-day price volatility is unusually high. This in turn has knock-on effects on market functioning, leading e.g. to rising collateral needs[1] for market participants vis-à-vis financial institutions given the latter's concerns about the former's ability to manage the increased price risks and their fluctuations in the very near-term[2].

Figure 2: Evolution of EU gas supply sourcing origins - bcm (Winters 2019 - 2022)



Source: ACER based on ENTSOG and Refinitiv.

Note: Winter season is the sum of Q4 year 1 and Q1 year 2 (i.e. Winter 2021-2022 sums the flows across Q4 2021 and Q1 2022). The assessment does not include storage withdrawals.

[1] Collateral refers to money put aside as a guarantee by the buyer and seller of forward products. This guarantee covers the risk of failure of one of the counterparties.

[2] From the strict point of view of market functioning (whilst of course acknowledging the many other factors and political priorities in play), if greater up-front clarity could be provided as to the intentions of EU governments vis-à-vis Russian gas imports for the rest of the year, it would likely have a price volatility-dampening impact.

Figure 3 below traces the evolution of EU prices (represented by the Dutch TTF hub) and Asian gas prices (represented by the Japan Korea Market price Index) relative to the year-on-year changes in EU LNG (shown in yellow) and Russian pipeline imports (shown in blue) across these three phases. The recovery of LNG imports in Phase 2 demonstrates the value of retaining price signalling as significant volumes of flexible LNG cargoes were redirected towards the EU (attracted by the higher prices). However, the increase in LNG supplies were insufficient to fully offset the overall effect on prices of the limited Russian pipeline flows (as Gazprom did not offer additional volumes at EU hubs beyond its long-term supply commitments). Below-average underground gas storage stocks (attributable to a large extent to limited Gazprom injections) further exacerbated the high gas price environment in Europe. The result was a further tightening of the European gas market and continuous upward pressure on prices.

Going forward, with the outbreak of war and given Russia's role as a major energy and commodity exporter, Europe (like Asia or other gas importing jurisdictions) are likely to face high energy and commodity prices in the near term, see further below.

Figure 3: Comparison of EU and Asian gas prices (EUR/MWh) and year-on-year changes in EU LNG and Russian pipeline imports (bcm) across three phases (May 2021 - April 2022)

Source: ACER based on ICIS Heren, ENTSOG and GIE.

Note: The relative year-on-year changes for Phase I are referenced against the May-September period of the year 2019. The imports across the May-September period of 2020 were non-typical, due to Covid-19 impacts on demand.

2.2. High gas prices drive up electricity prices

The rising costs of gas-fired power generation drove up electricity prices, due to the strong influence of gas-fired plants in setting electricity prices in the short-term EU power markets[3].

Additional factors such as unfavourable wind conditions, maintenance on nuclear reactors and growing emission allowance prices under the ETS further amplified electricity prices[4]. Figure 4 illustrates the main drivers underlying the record-high electricity prices traded on the German EEX market (which serves as a reference for European electricity markets), with spiralling gas prices being the primary driver (compared for example to the price of emission allowances).

Figure 4: Electricity price development in Germany and breakdown of the costs (EUR/MWh) of producing electricity from gas (May 2021 - March 2022)

Source: ACER based on ICIS Heren.

Besides reaching high overall levels, the volatility of electricity and gas prices also reached record-high levels across the EU (e.g. spot-priced gas more than doubled the ten-year average, rising by a factor of four in December 2021). Prices varied with LNG and pipeline supply estimates, weather forecasts (including renewable generation prospects) and in the last phase, with increased geopolitical risks.

The high-risk environment also impacted the liquidity of forward markets. From Q4 2021 some traders found it difficult to maintain their financial positions which worsened by Q1 2022; this in turn affected the ability of companies to hedge their future price risks. Indeed, as prices rose so did the financial guarantees (collaterals) required for trading. Some counterparties were priced out and some became increasingly risk averse. This led some traders and industry representatives to seek potential mitigating measures from public authorities so as to facilitate continuous energy trade, including e.g. reducing or backing-up collaterals or waiving trading cancellation fees. Solutions to mitigate volatility and excessive price spikes are discussed further in Section 4.

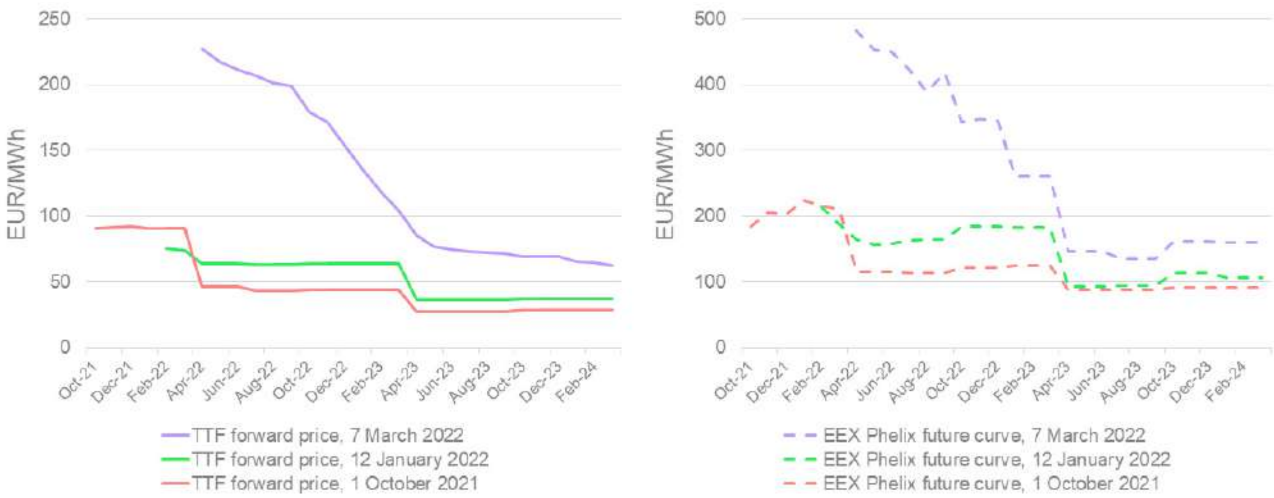
[3] Gas-fired plants often set marginal electricity prices in EU power markets. When hydro plants act as price setting-units instead, they optimise their yearly production and thereby tend to relate their opportunity cost to the costs of generating electricity with gas. Bidding at opportunity costs is thus an integral part of competitive electricity markets. To prevent and address market abuses, ACER and national regulatory authorities (NRAs) closely monitor trading activity under the EU-wide REMIT framework. For further details on the electricity (pay-as-clear) marginal pricing mechanism, see ACER's Preliminary Assessment (November 2021).

[4] These additional factors had a distinct bearing in different time periods. Renewable power generation was particularly low in Q1 and Q2 2021, whilst the nuclear outages experienced in France were more significant from Q4 2021 onwards. ETS prices rose since the end of Q1 2021 and at a faster pace from the end of Q3 2021 when gas-to-coal switches created upward pressure.

2.3. Energy prices will likely remain high in the near term

The latest market estimates indicate that energy prices will remain high for the rest of 2022 and into 2023; this not least in view of the ongoing tension and uncertainty around near-term gas supply. As seen in the electricity and gas forward curves in Figure 5, market participants anticipate a gradual downward trend from Q2 2023, though noting as a general word of caution that forward price estimates can be subject to rapid changes under the current stressed market conditions (spot prices' rapid variations also influence forward prices to some extent). Figure 5 also shows the evolution of forward prices across the three previously identified price phases.

Figure 5: Evolution of gas (TTF) and electricity (EEX) forward prices (EUR/MWh), comparing the contractual outlook (October 2021 and March 2022)



Source: ACER based on ICIS Heren.

"The latest market estimates indicate that energy prices will remain high for the rest of 2022 and into 2023 …"

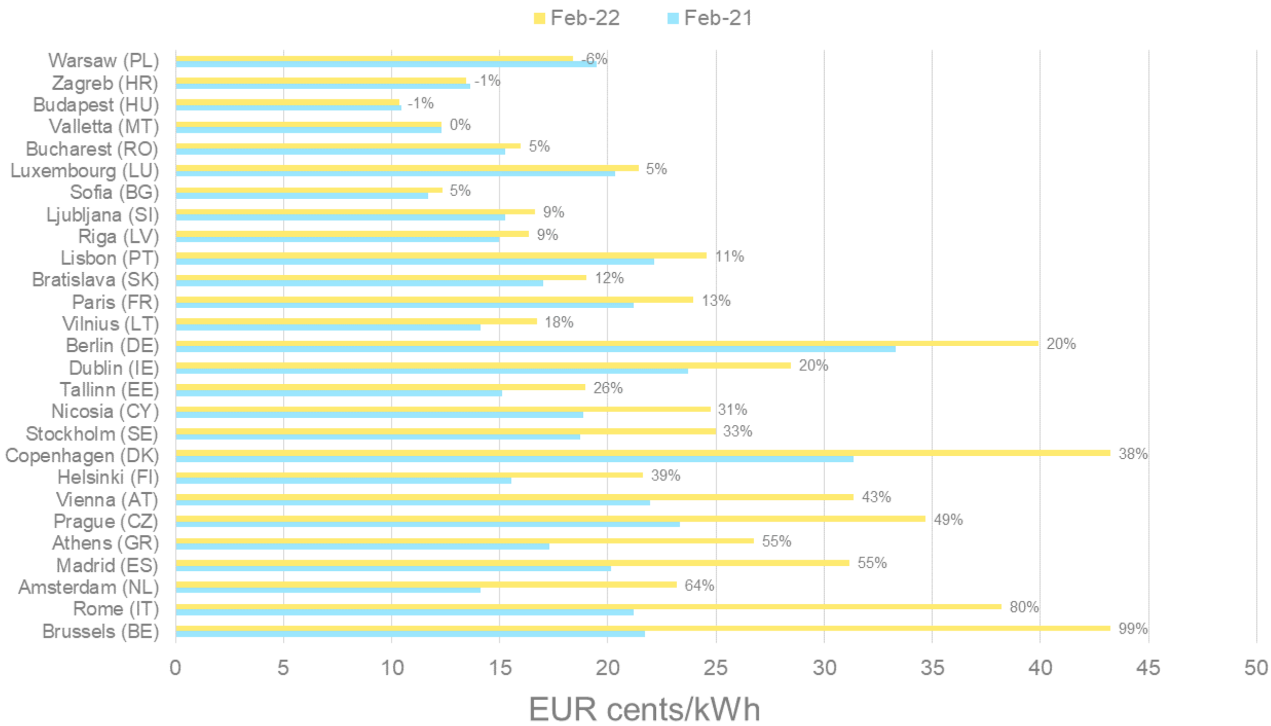
While mid-term electricity and gas prices are highly correlated via gas-fired power generation often setting the marginal price of electricity, a few specific factors explain the different shapes of their respective forward curves. These factors include (among others) seasonal demand patterns, different storage capabilities, gas storage restocking needs and the intermittency of renewable electricity generation[5].

[5] By way of example, renewable electricity production is usually higher relative to demand in the summer, thereby lowering electricity prices. Interestingly, in 2021 despite the record-high average electricity prices, the occurrence of negative electricity prices continued to increase, becoming more frequent than in pre-COVID years (see the most recent ACER Market Monitoring Report data for the year 2021). This results from expanding renewable generation capacity (with negative prices more common when the national subsidy scheme in place is detached from price signals reflecting the system needs) coupled with a lack of cost-efficient storage solutions. The prevalence of negative prices might also indicate additional interconnection capacity needs and, more generally, underlines the need to adequately reward flexibility services (negative prices are more common in market zones with less flexible assets).

2.4. Households and industrial consumers are heavily impacted

The high energy prices led to significantly higher bills, adversely affecting European consumers. Up to February 2022, retail electricity prices rose by 30% on average (65% for retail gas) from February 2021 to February 2022, though with significant variation amongst Member States as seen in Figure 6. The impacts on individual households varied according to the types of contracts and pricing mechanisms as well as the short-term mitigating measures taken by national governments. Unusually, lower prices were recorded in a few Member States in February 2022 compared to the previous year. The highest rise in household electricity prices (99%) was in Belgium.

Figure 6: Evolution of household electricity prices (EUR cents/kWh) and % year-on-year (Feb 2021 - Feb 2022)



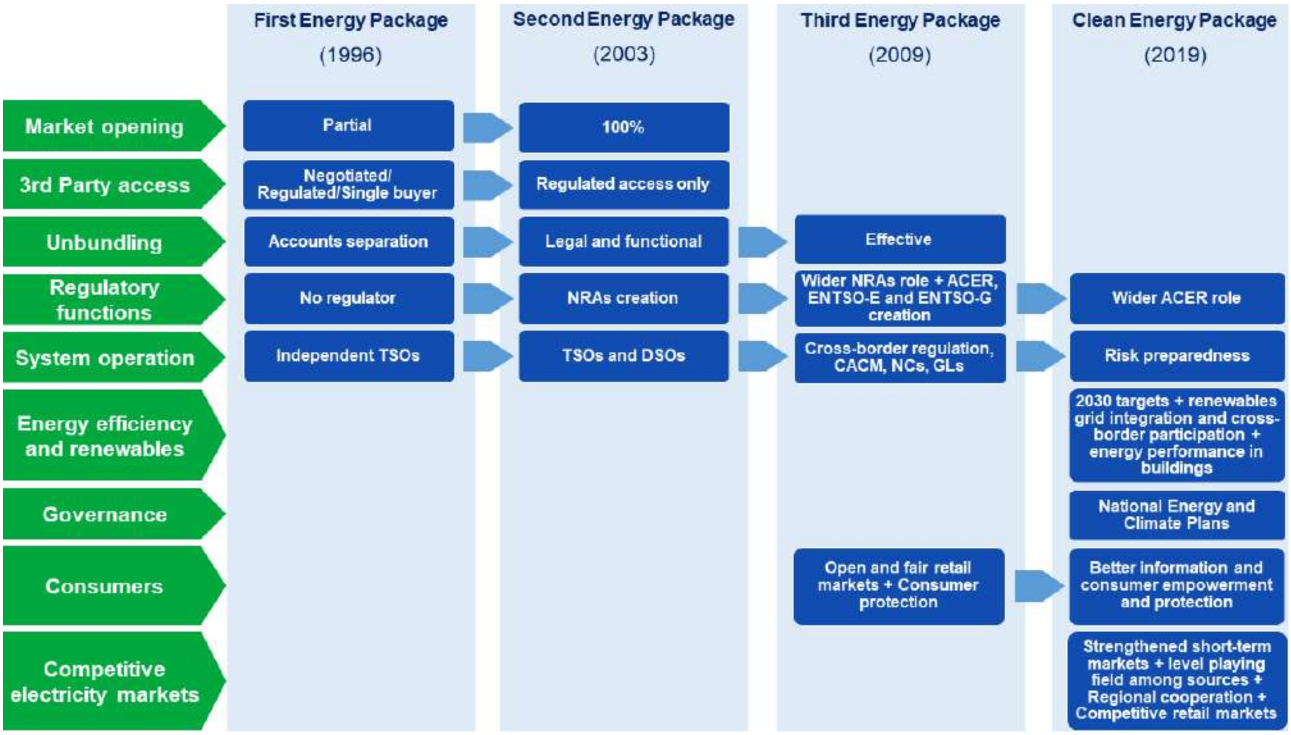
Source: ACER based on Vaasa ETT.

Continued high energy prices could further impact industrial activity. EU industrial gas demand dropped year-on-year by -6% in Q4 2021 and by -9% in Q1 2022, some of this due to reduced production by parts of energy-intensive industry. High gas prices have also triggered a rise in inflation and impacted economic recovery efforts after the COVID-19 pandemic.

3. EU wholesale electricity market design: benefits and remaining implementation challenges

The liberalisation of national electricity markets across Europe and their integration into a single European market (often called the EU's 'Internal Electricity Market') is a massive project which has evolved over the past twenty years (Figure 7).

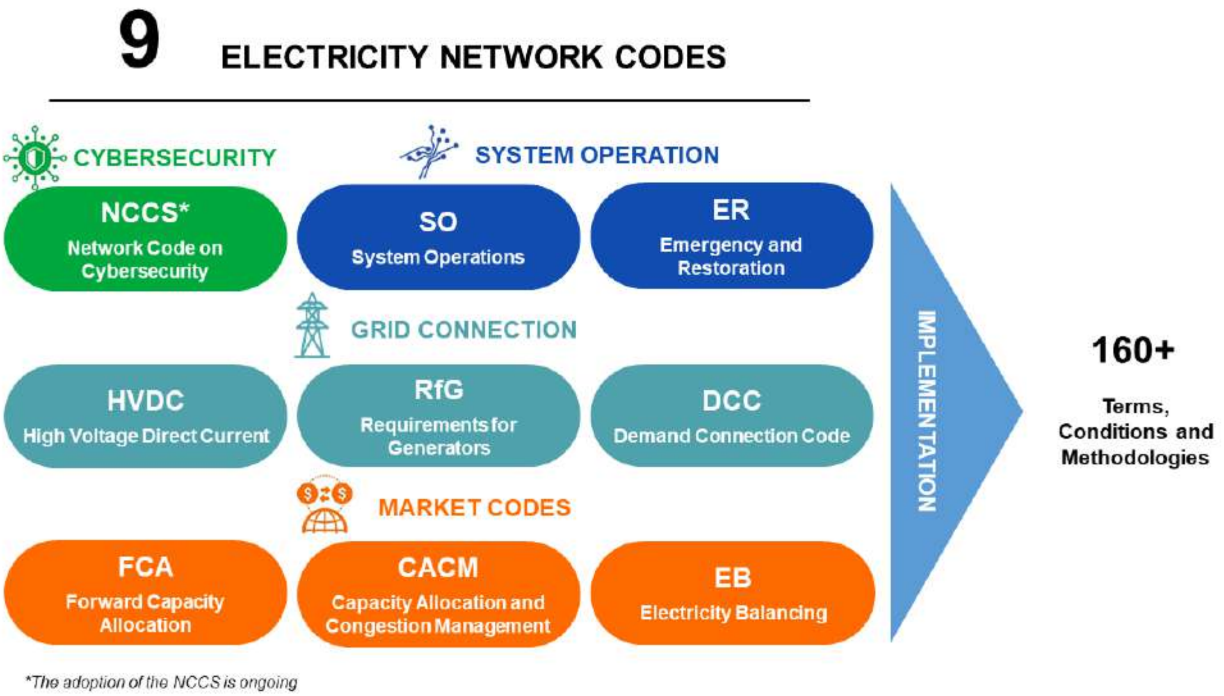
Figure 7: Evolution of EU energy legislation to build the market and support the clean energy transition



Source: ACER elaboration.

For EU electricity market integration to progress at pace, harmonisation of national markets and their integration need to go hand in hand. This is achieved by adopting and implementing the same rules across the EU. This is the role of EU-wide legally-binding rules called 'network codes'. Figure 8 below provides an overview of the range of aspects regulated by EU network codes today.

Figure 8: Overview of the legally-binding EU electricity network codes



Source: ACER.

The alignment and coordination of national policies and rules is key for Europe's integrated market model to deliver on key objectives such as competitive prices, security of supply and decarbonisation. The continued integration of European energy markets will be critical to deliver the EU's ambitious decarbonisation trajectory.

3.1. Some fundamentals (liquidity, price formation, carbon price signals)

The EU electricity market design is influenced by both the characteristics of electricity (e.g. that it cannot be stored easily) and broader policy goals. A few features are noteworthy.

First, markets (from long-term to short-term) need to be sufficiently 'liquid' (i.e. with sufficient buyers and sellers) to function well. The short-term electricity markets aim at optimising operational decisions, whereas the long-term markets focus on hedging risks related to investments. European regulation has so far mainly focused on short-term markets because, among other reasons, strong coordination here is necessary to ensure efficient cross-border trading close-to-real-time.

Long-term markets have received less attention possibly because, in the past, managing uncertainty was slightly less critical compared to today. Whatever the reason, currently there seems to be a mismatch between the increasing levels of price uncertainty and the liquidity observed in long-term horizons, particularly beyond 3 years ahead of delivery. Consequently, long-term markets (including bilateral PPAs) and hedging instruments deserve increased attention. While hedging instruments have been available for many years, their liquidity is very different in different markets. A key question therefore is whether there is a need for measures to strengthen long-term markets and, if so, how. These issues are addressed in Section 4.

Second, in the current EU electricity market design, market prices are freely formed by demand and supply. This ensures not only an optimal market outcome but also a level-playing field across the EU. By contrast, when electricity wholesale prices are regulated, e.g. by introducing price caps, undesired effects including security of supply concerns or market exit issues may arise.

Third, the current electricity market design takes account of the carbon emission pricing signal from the ETS. Fossil fuels (e.g. coal) are rendered more expensive because of the ETS price. Hence, the current market design and ETS taken together incentivise efficient investment in lower-carbon technologies.

Overall, any market design will need to consider the special fundamental characteristics of electricity as a commodity, the evolving challenges of the system as it incorporates a growing share of renewables, the different needs of market participants and the policy objectives set for what the market should deliver. The market design can then be tuned to meet these objectively efficiently and at lower cost.

3.2. Dispelling some myths about the 'pay-as-bid' vs 'pay-as-clear' market design model

"Past analyses tend to reach similar conclusions, namely that in day-ahead markets, a 'pay-as-clear' approach is more efficient than a 'pay-as-bid' approach."

The current price shock situation has led to calls in certain quarters to re-examine the pricing methods in electricity markets. For example a 'pay-as-bid' model was proposed by some as an alternative to the current 'pay-as-clear' model.

Different pricing methods currently coexist for the different electricity market timeframes in the EU. In particular, the 'pay-as-clear' model currently applies for the day-ahead market, the overall reference market for other markets, and will soon apply to pan-European intraday auctions. However, other pricing models apply in other market timeframes, in long-term markets and in intraday (continuous) markets. The 'pay-as-clear' model maximises the social welfare benefits from cross-border electricity trading. In Europe, such trading mostly takes place in the day-ahead and increasingly in the intraday markets.

Whenever electricity prices rise considerably, one sees increased debate over the prevalent market model and pricing system. Past analyses tend to reach similar conclusions[6], namely that in day-ahead markets, a 'pay-as-clear' approach is more efficient than a 'pay-as-bid' approach.

Case: The pricing model and high electricity prices in California (2000) and Great Britain (2001)

In California, wholesale electricity prices increased by 500% between the second half of 1999 and the second half of 2000 (as illustrated in Figure 9 below). In November 2000, the California Power Exchange assessed whether implementing pay-as-bid auctions in the day-ahead market could improve market performance. Experts concluded that such measure would be counter-productive[7]. In particular, the measure was thought to introduce inefficiencies in dispatch and weaken competition amongst generation sources. Instead, experts suggested measures to incentivise new generation, combined with market-based mechanisms to limit energy prices in the spot market.

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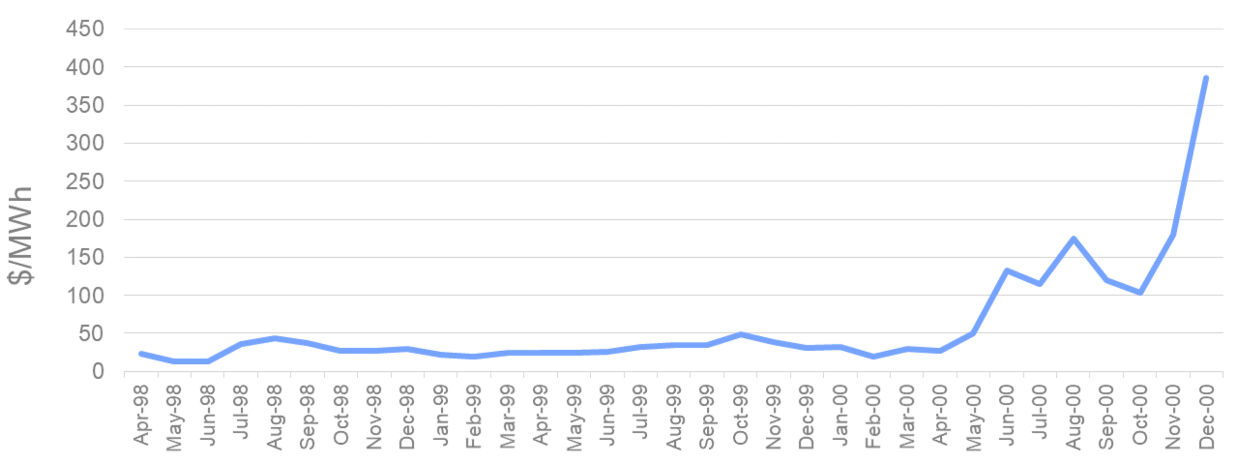
[6] See e.g. the Florence School of Regulation's policy brief on [Recent energy price dynamics and market enhancements for the future energy transition](#).

[7] [Uniform Pricing or Pay-as-Bid Pricing: A Dilemma for California and Beyond](#), Alfred E. Kahn, Peter C. Cramton, Robert H. Porter, Richard D. Tabors.The Electricity Journal Volume 14, Issue 6, July 2001, Pages 70-79.

Figure 9: Average day-ahead prices ($/MWh) in California (April 1998 - December 2000)



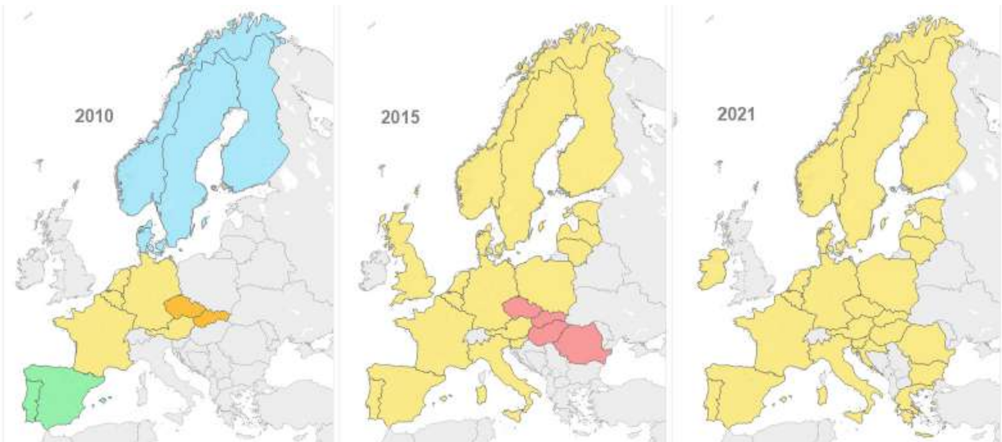
Source: ACER.

Similarly, the UK energy regulator, Ofgem, when considering changes in the New Electricity Trading Arrangements ('NETA') back in 2001, concluded that a 'pay-as-bid' auction would be inappropriate for a day-ahead market[8].

3.3. The current EU electricity market design delivers major benefits

While the EU market design envisages the integration across borders of all electricity market timeframes, short-term markets (specifically day-ahead and intraday) have been the focal point of EU market integration up until now. Their integration relies on a coordinated process that efficiently sets local prices and quantities exchanged across borders, known as 'market coupling'. Figure 10 shows the evolution of the geographical scope of day-ahead market coupling since 2010.

Figure 10: Evolution of EU wholesale electricity day-ahead market coupling (2010 - 2021)



Source: ACER.

Note: The different colours represent the different initiatives that coexisted before their integration into the single day-ahead market coupling.

8 Uniform-Pricing versus Pay-as-Bid in Wholesale Electricity Markets: Does it Make a Difference? Susan F. Tierney, Ph.D., Todd Schatzki, Ph.D., Rana Mukerji, March 2008.

3.3.1. Cross-border trade delivered 34 billion Euros of benefits in 2021 while helping to smoothen price volatility

Day-ahead market integration delivers cheaper electricity across Europe and facilitates the growth of renewables while increasing overall welfare. In particular, market coupling ensures that electricity generally flows from areas with low prices to areas with high prices. When there are limited amounts of wind and solar electricity generated locally, Member States benefit from relatively cheaper electricity (including renewable electricity) produced elsewhere in Europe. Similarly, market coupling enables Member States to benefit from their neighbours' flexibility and adequacy (i.e. ability to guarantee desired security of supply levels) solutions, including back-up generation, storage, or demand-side response. Such solutions will be increasingly necessary to balance the fluctuating generation patterns of wind and solar power plants.

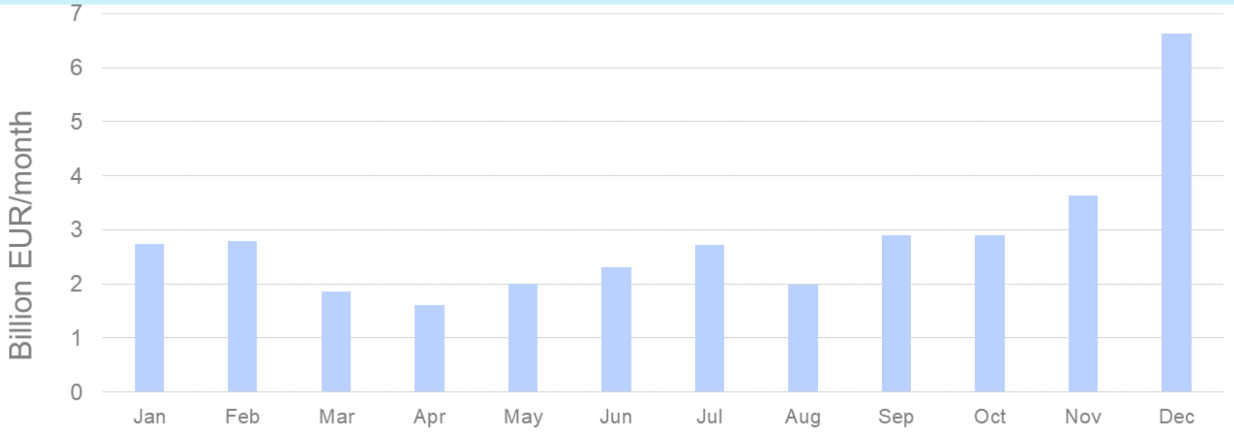
"Day-ahead market integration delivers cheaper electricity across Europe and facilitates the growth of renewables while increasing overall welfare."

In addition, market integration keeps price volatility lower than would otherwise be the case, as confirmed by analysis carried out by the Nominated Electricity Market Operators (NEMOs) at the request of ACER (see case study below).

Case: Cross-border trade delivers substantial benefits and mitigates price volatility

To estimate the benefits from cross-border electricity trading in Europe in 2021, ACER asked the European NEMOs to conduct an analysis for 2021. It compared actual 2021 market results ('historical' scenario) with a scenario where all cross-border capacities were set to zero (the 'zero scenario', implying no electricity trade across Member State borders)[9]. The difference in welfare benefit between the historical and the zero scenario (see Figure 11) is a proxy for the yearly welfare benefits currently obtained from cross-border trade in day-ahead markets. The benefits of cross-border electricity trading amounted to around 34 billion Euros in 2021 (source: ACER based on NEMOs). More than one third of these benefits correspond to the last quarter of 2021, when power prices were at their highest.

Figure 11: Estimated monthly welfare benefits (Billion EUR) from cross-border electricity trade in 2021

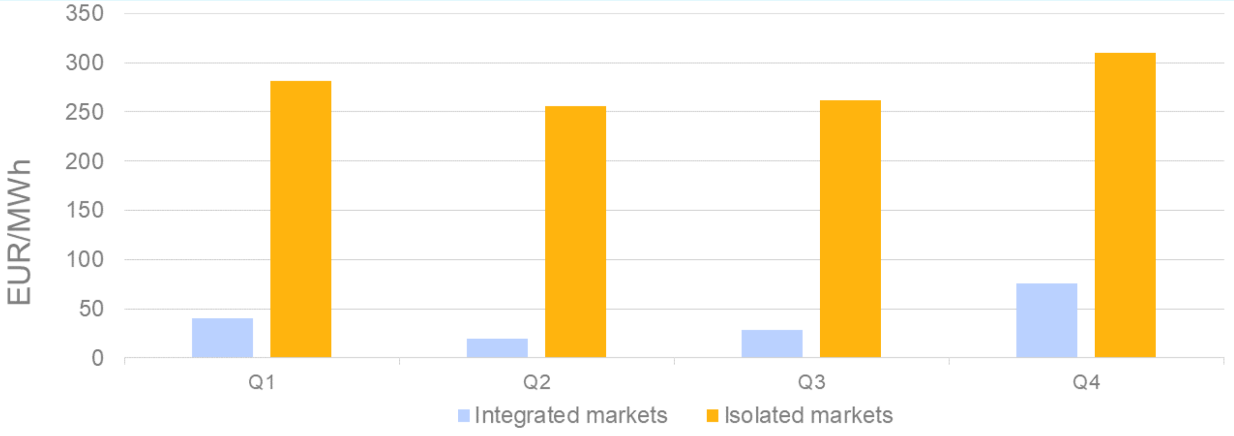


Source: ACER based on NEMOs' simulations.

9 The geographical scope of this analysis is the countries and borders integrated through single day-ahead market coupling (see Figure 10). The main assumption of the analysis is that for the two scenarios, all elements (market bids, market rules, etc.) except cross-zonal capacities remain unaltered.

In addition to the considerable savings associated with the current level of market integration, the analysis shows that this integration also reduces significantly price volatility. Figure 12 displays the differences in average price volatility between the two scenarios. It shows that price volatility would have been considerably higher (around seven times as high) if national markets were isolated.

Figure 12: Price volatility (EUR/MWh) in integrated and isolated electricity markets in the EU in 2021



Source: ACER based on NEMOs simulations.

Volatility was estimated by using the standard deviation of day-ahead wholesale prices. The standard deviation was calculated per bidding zone for the whole year, then averaged out across the EU.

"Overall, in 2021, cross-border trade delivered an estimated 34 billion Euros of benefits while helping to smoothen price volatility."

Overall, in 2021, cross-border trade delivered an estimated 34 billion Euros of benefits while helping to smoothen price volatility. Additional benefits from higher market integration and cross-zonal capacities include enhanced cross-border competition and a reduced scope for market power, which helps lower the energy bill in the long-run. As further elaborated in Section 5, intervening to significantly alter the current market design may put a substantial share of the above benefits at risk, to the detriment of consumers.

It should be emphasised that these benefits represent the overall value of cross-border trade compared to isolated national markets, rather than the benefits from the implementation of market coupling as such (the latter is accounted for in the afore mentioned benefits[10]). In fact, before market coupling was introduced, cross-border trade (though sometimes limited and inefficient) was already taking place. Market coupling enables the efficient use of interconnectors and renders more than one billion Euros of benefits per year.

[10] See paragraph 288 of the Wholesale Electricity Market Volume of the ACER-CEER Annual Report on the Results of Monitoring the Internal Electricity and Gas Wholesale Markets in 2013 (hereafter the Electricity Wholesale Market Volume of the ACER-CEER 2013 Market Monitoring Report (or '2013 MMR')).

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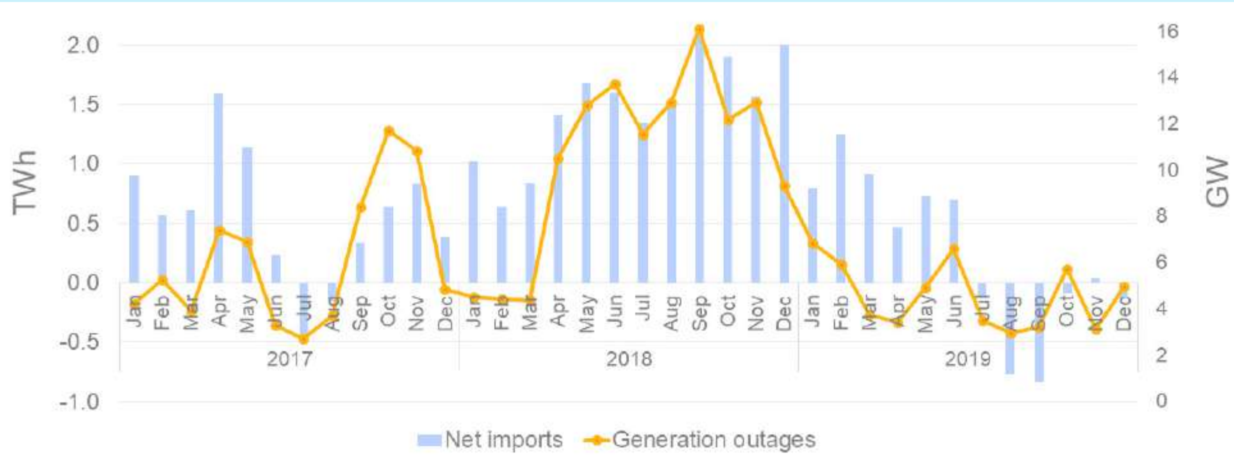
3.3.2. The EU electricity market design enhances each Member State's security of supply and its resilience to price shocks

Another key benefit of EU electricity market integration is that it enhances security of supply and leads to better resilience to short-term price shocks. The two examples below illustrate this.

Case: Belgium imports electricity to meet the shortfall in its own generation (2018-2019)

The first example of how market integration alleviates supply shortage refers to the situation in Belgium in winter 2018-2019. Unplanned and unusually large nuclear power plants outages in Belgium led to a shortage of generation to meet demand. The Belgian Transmission System Operator (TSO) and its neighbours jointly maximised import capacity into Belgium. Subsequently, Belgium's imports allocated through day-ahead market coupling increased sharply, as illustrated in Figure 13. More specifically, Belgium's hourly imports reached almost 2.5 GWh on average in the last quarter of 2018 compared to less than 0.85 GWh for the same months of 2017, thus alleviating the local shortage of generation capacity.

Figure 13: Evolution of net imports and average generation outages (MWh and MW) in Belgium (2017 - 2019)



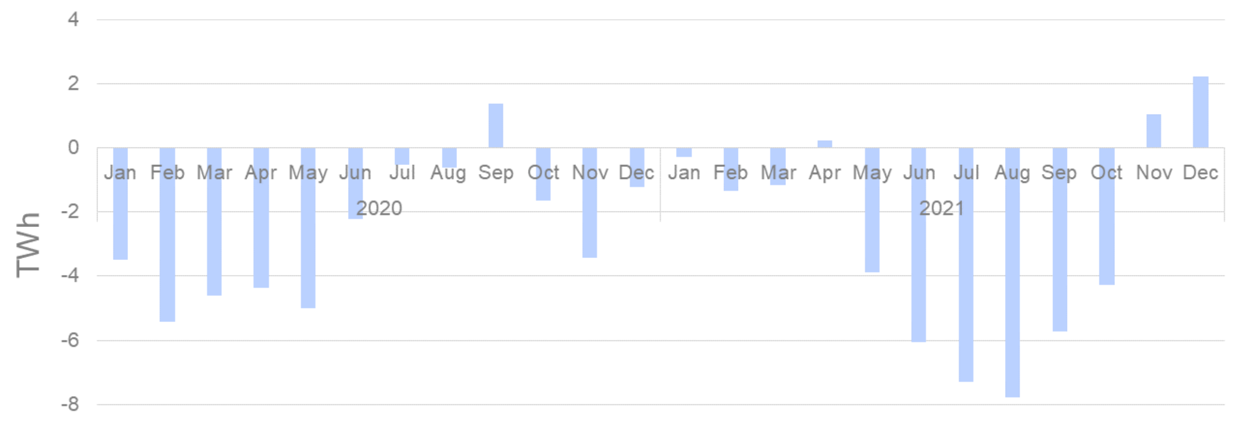
Source: ACER based on ENTSO-E Transparency Platform.

Case: France moves from net exporter to net importer during nuclear power outages (2021)

The second case refers to the evolution of exports and imports in France in 2021 (see Figure 14).

During the first ten months of 2021, as electricity prices in France were lower than in the neighbouring markets, France was a net exporter (as indeed has frequently been the case in the past). In November and December, however, the situation reversed as France faced significant nuclear power plant outages. For many days during these two months the French power system became a net importer, mitigating the sharp increase of electricity prices in France and enhancing French security of electricity supply.

Figure 14: Evolution of net imports (MW) in France (2020 – 2021)



Source: ACER based on the ENTSO-E Transparency Platform.

The two examples above (Belgium's shortfall of generation and France's nuclear outages) illustrate how the notion of 'resource-sharing' (through market integration) benefits Member States. Without this inter-dependency approach, the security of electricity supply of different Member States could have come under stress in such periods. Similarly, as further highlighted in Section 5, the introduction of interventionist measures might put such resource-sharing approaches at risk to the extent cross-border flows are negatively impacted.

Recent national adequacy assessments also highlight the increasing reliance on neighbouring jurisdictions to address security of supply issues. For example, in a 2021 report[11] by TenneT, the Dutch TSO, the issue of whether the Netherlands has enough production capacity to meet national electricity demand was analysed. Among other conclusions, the report found that to cope with increasing uncertainty until 2030, coordination amongst Member States would prove increasingly important to ensure resource adequacy in the Netherlands and neighbouring countries. These findings reiterate the importance of increasing coordination both of underlying policies and deployment of infrastructure (see also Section 4.4.4 for further considerations on the need for better coordination).

In this respect, the European Resource Adequacy Assessment – a seminal new mechanism for enhanced EU electricity market integration introduced via the EU's Clean Energy Package - aims at detecting adequacy concerns in a consistent and coordinated manner across the EU. Once fully implemented, it will enhance co-ordination in the area of security of electricity supply.

Finally, there are additional benefits in the area of security of supply to be garnered by further enhancing cross-border coordination. One example is safer and more reliable and efficient operation of the power system; aiming e.g. to avoid and/or mitigate incidents similar to the so-called power 'system split' of 8 January 2021, which caused a large drop in the frequency of part of the Continental Europe Synchronous Area[12]. ACER considers that an enhanced framework, to ensure a more coordinated and robust reaction when coping with similar incidents in the future, would be beneficial for EU Member States.

11 See TenneT's Monitoring Security of Supply 2021 report commissioned by the Dutch Ministry of Economic Affairs & Climate Policy.

12 On 8 January 2021, a significant operational incident led to a split of the electricity network of Continental Europe. The investigation into the incident revealed uncoordinated approaches to ensuring operational electricity system security across the EU.

3.4. Further potential benefits

Beyond the benefits that EU electricity market integration currently yields, there is significant scope to further improve market integration efforts, in particular regarding:

- The amount of capacity available for cross-zonal electricity trade and the way it is used, and implementing ongoing projects, some of which are delayed;
- The accuracy of price signals to ensure efficient short-term decisions, e.g. related to the daily planning of generation and consumption, and long-term decisions, e.g. related to seasonal maintenance or investment; and
- The barriers to market entry that should be removed to attract innovative and more efficient energy providers, and barriers to efficient price formation that should be removed to lower the overall cost of the energy transition.

3.4.1. Increasing cross-zonal capacity and using the capacity provided more efficiently

"... The amount of interconnection capacity made available for trade with neighbouring jurisdictions needs to increase significantly [...] a prerequisite for being able to fundamentally rely on cross-border trade for one's needs."

Adequate interconnection levels, and ensuring that the related interconnection capacity is made available for cross-zonal trade, are indispensable for a well-functioning EU Internal Electricity Market. In particular, the provision of sufficient cross-zonal capacity to trade across all market timeframes is an essential prerequisite for reaping the market integration benefits; these benefits include the ones described in Section 3.3, and the ones described below. In its so-called '70% monitoring report', ACER finds that the amount of interconnection capacity made available for trade with neighbouring jurisdictions needs to increase significantly in line with the binding 'minimum 70% target'[13]. At its core, this is a prerequisite for being able to fundamentally rely on cross-border trade for one's needs. As such, it is a key component of an integrated electricity market, likely of increasing importance in the years ahead.

Two flow-based market coupling projects in the so-called Core[14] and Nordic regions seek to improve the way cross-zonal capacity is used in the day-ahead timeframe. Unfortunately, both are facing recurrent delays. These projects are essential to ensure the optimal use of cross-zonal capacity in a highly interconnected and interdependent EU power system.

Other ongoing projects are key for the integration of the intraday and balancing markets across the EU. Given the expected increase in renewables in the EU electricity mix, intraday and balancing markets will become increasingly important. Hence, further integration of intraday and balancing markets would seem crucial to facilitate the EU's decarbonisation trajectory.

"... Further integration of intraday and balancing markets would seem crucial to facilitate the EU's decarbonisation trajectory."

[13] The Clean Energy Package requires that at least 70% of physical capacity of critical network elements is made available for cross-zonal trade.

[14] The flow-based market-coupling project in the Core region involves thirteen Member States of Central Europe. Project implementation has been facing recurrent delays, with another delay announced in April 2022.

Intraday markets are key for renewable generators as they can adapt their trading positions closer to real time, based on more accurate information (e.g. in response to weather pattern updates or short-term availability issues). The progressive integration of intraday markets across Europe through the so-called 'single intraday coupling' enables market participants' access to a larger variety of bids and offers to manage their adjustment needs. Concerning the balancing timeframe, market integration contributes to ensure that supply continuously meets demand at a lower cost across the EU. For example, the ongoing integration of balancing energy markets, through the establishment of pan-European balancing platforms, is expected to yield more than 1.3 billion Euros of yearly benefits to consumers[15].

Work is ongoing to upgrade the rules governing the use of cross-zonal capacities. For example, ACER recently issued a recommendation on amendments to the network code governing Capacity Allocation and Congestion Management (the so-called CACM network code). A similar amendment process is expected to update the network code governing Forward Capacity Allocation. This leads to certain considerations as to how this update might help further improve overall market design functioning, see Section 4 below.

3.4.2. Improving the accuracy of price signals to make better investment decisions

An important element of the current market design is the accuracy of price signals, i.e. that electricity prices precisely inform generators and customers when and where power is cheap or expensive. This is often referred to as 'time and space granularity' of electricity markets.

In particular, spatial granularity requires that electricity prices reflect the underlying network congestions. This implies that a bidding zone with supply scarcity would have a higher price than a market area with excess supply. An adequate configuration of bidding zones is widely understood to incentivise efficient operational and investment decisions. The better the bidding zone configuration reflects the physical congestions, the more efficient the price signals.

Case: Accurate price signals enable better investment decisions in Norway and Sweden

Norway and Sweden comprise five and four bidding zones, respectively. These bidding zones are an approximation of the underlying congestions in the grid. Different bidding zones may have different wholesale prices, reflecting the local supply and demand.

For example, prices observed in Norway and Sweden in December 2021 (see Figure 15) illustrate the relevance of accurate locational price signals. During this period, the prices of the bidding zones located in the South were around three times higher than the prices of the bidding zones in the Northern bidding zones.

[15] See footnote 348 and paragraph 582 of the Electricity Wholesale Market Volume of the ACER-CEER 2014 Market Monitoring Report (or '2014 MMR').

Figure 15: Average electricity prices (EUR/MWh) in the Nordic area in December 2021

Source: ACER based on the ENTSO-E Transparency Platform.

These price differences are an important input both in the short-term (e.g. for planning the next days' generation or consumption), and in the long-term (e.g. for seasonal planning of maintenance or investment decisions related to power plants or large consumption units). Current price differentials incentivise generators to be located in the South and large consumers to be located in the North, something that is taken into account when considering the need for network investments[16].

Ignoring these incentives would aggravate the existing grid congestions. Consequently, the perceived needs to invest in network infrastructure would increase, investments may be inefficiently located, and such increased (and partly avoidable) costs would ultimately be borne by consumers.

"... An adequate definition of bidding zones brings substantial savings in the long run ..."

All in all, an adequate definition of bidding zones brings substantial savings in the long run, not only because generation and demand assets would be incentivised to be located where they are needed, but also because it would be easier to identify the most valuable network investments. Whether and how locational market signals may drive a more cost-effective decarbonisation of the energy system is currently subject to debate in a number of jurisdictions, including beyond the EU; such debate includes the possibility of implementing locational marginal pricing, often referred to as nodal pricing[17].

16 Indeed, when considering grid development for the Nordic area, the Nordic TSOs take into account the expectation of more consumption to be situated in the northern parts of the Nordics, see e.g. the 'Nordic Grid Development Perspective (2021)'.

17 See for example the conclusions of a recent presentation published by National Grid.

3.4.3. Removing barriers to the entry of innovative market participants

In its latest Market Monitoring Report[18], ACER identified numerous barriers to market entry and price formation across the different Member States. Those barriers reduce overall welfare. Removing such barriers would allow more market players, such as those offering demand-side response services, to compete on an equal footing. In 2022, ACER will develop a framework guideline setting principles for the participation of demand-side flexibility (amongst other resource providers) in electricity markets; such a guideline will serve as basis for the preparation of EU regulation in this area.

In sum, the accomplishment of the 'minimum 70% target', the completion of the aforementioned integration projects and the removal of barriers to efficient price formation and barriers to entry of new market players are key in ACER's view for maintaining or increasing the substantial welfare benefits described in Section 3.3. In this respect, ACER's Preliminary Assessment from November 2021 showed that continued and strengthened efforts in the areas identified could deliver more than 300 billion Euros[19] in benefits over the next decade. Those efforts and benefits outlined rely on the current market design and its fundamentals. As such, deviating significantly from the current market design may put at risk the benefits already obtained as well as those currently being pursued.

Besides ongoing initiatives to further harness the benefits from EU electricity market integration, the electricity system will face new challenges up ahead as it is called upon to deliver on the EU's ambitious decarbonisation trajectory. The next section describes these challenges and the measures ACER deems relevant to further future-proof the EU wholesale electricity market design in light of these challenges.

[18] See the Electricity Wholesale Market Volume of the ACER-CEER 2020 Market Monitoring Report (or '2020 MMR').

[19] See Section 4.4, in particular Figure 10, of ACER's Preliminary Assessment.

4. Ways to improve the EU wholesale electricity market

The EU power system faces new challenges to deliver on the EU's ambitious decarbonisation objectives. These challenges, and the recent energy price shocks, raise the question of whether the current market design can fully address these challenges and if not, how then to improve the market design.

This section focuses on the following key 'asks' of the current market design going forward:

- First, the need to drive substantial investments in low-carbon generation; and
- Second, the challenges in complementing increasing shares of intermittent renewable electricity, not least via tackling rising price volatility and enhancing the flexibility of the power system.

4.1. Flexible resources are needed to address increased volatility of the power system

The EU needs massive additions of low-carbon electricity generation to reach its decarbonisation objectives. This jump in low-carbon electricity generation is a paradigm shift for the power system and market. As a result, price volatility is likely to be a dominant feature of the energy transition.

Volatility is a natural feature of well-functioning electricity markets. It is the result of frequent and/or sudden changes of market fundamentals and other variables such as weather conditions. Volatility can refer to short-term movements or long-term structural swings. The following elements will likely push volatility upwards:

- Numerous market entries and exits;
- The impact of intermittent generation on the system; and
- Volatility of other underlying market fundamentals.

First, the energy transition is likely to trigger numerous exits especially regarding more carbon-intensive power plants. It will also trigger market entries for generation (not least renewables) and for demand (via increased electrification). A lack of coordination on these elements is likely to significantly affect electricity prices. It is thus crucial that Member States manage these entry and exits to maintain the supply/demand balance throughout the energy transition.

Second, a vast share of new renewable generation is intermittent. At the same time, some dispatchable technologies (such as coal generation) will be phased out. As a result, electricity prices will be low for many hours, but high in other hours when cheaper renewable resources are scarce. As such, price volatility is bound to rise.

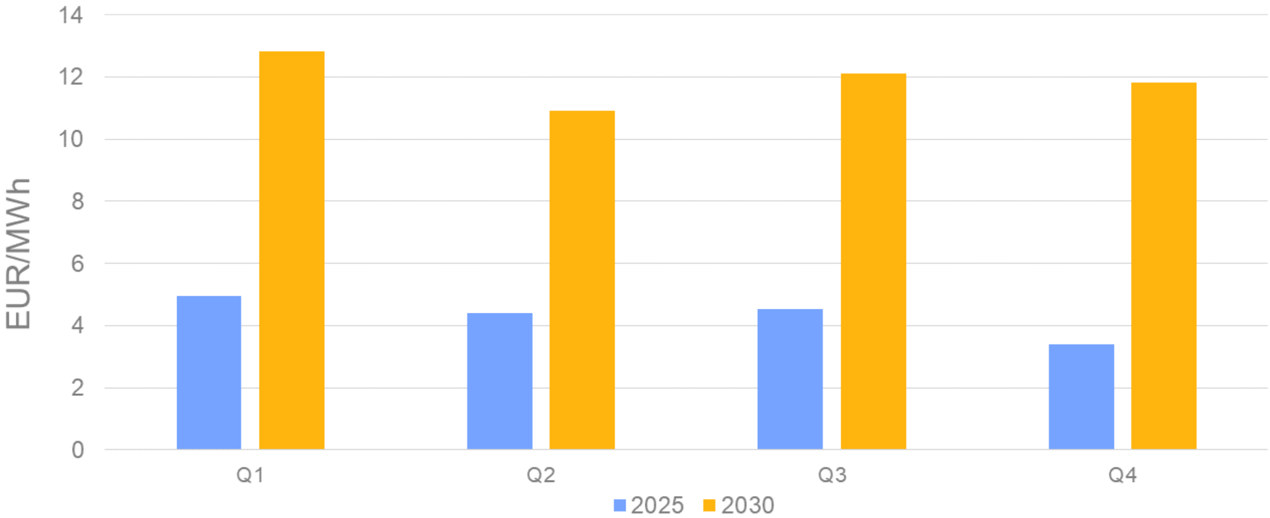
Third, other factors will drive price volatility as well. These include changing fuel and ETS prices, varying availability of dispatchable assets and demand, and changes in bidding behaviour. Extreme events (fuel supply crisis, economic crisis, extraordinary cold spells etc.) affect these factors and can lead to extreme volatility. Precisely because such events can occur, price shocks are difficult to rule out in the future.

There will also be factors that potentially mitigate volatility such as:

- Increases in demand-side response due e.g. to enhanced digitalisation and lower transaction costs;
- Electrification of transport and heating sectors; and
- Lower cost and wider availability of short-term and long-term electricity storage.

Figure 16 illustrates the expected increase in price volatility in 2030 compared to 2025 based on the scenarios used.

Figure 16: Expected evolution of price volatility (EUR/MWh) in 2025 and 2030



Source: ACER based on simulations made by the Joint Research Centre.

Note: For 2025 and 2030, ENTSO-E's Ten-Year Network Development Plan scenarios were adapted to reflect the penetration of intermittent renewable generation envisaged in the MIX scenario of the Fit-for-55 Package. Volatility was estimated by using the standard deviation of day-ahead wholesale prices. The standard deviation was calculated per bidding zone for the whole year, then averaged out across the EU. The figure aims to show volatility trends, however the absolute values shown in this figure are not directly comparable with the values shown in Figure 12 referring to 2021 when prices were exceptionally high. Moreover Figure 12 relies on historical bids and prices while this figures relies on simulated bids.

The power system will need significant and diverse flexible resources to optimise the value of growing shares of intermittent generation and to smoothen the increased volatility.

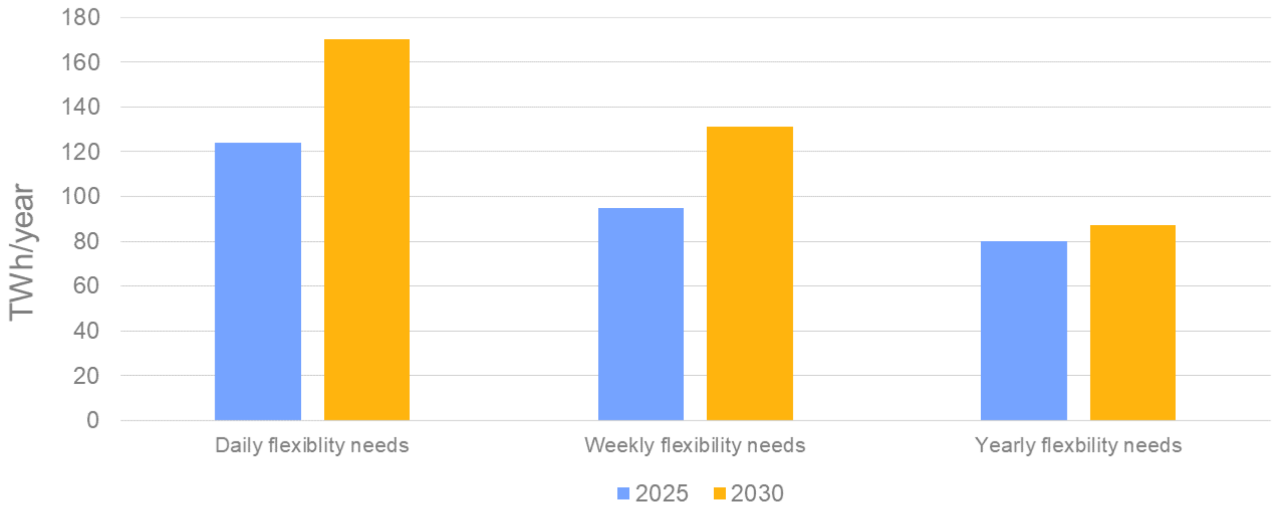
Flexibility is the ability of the power system to adapt to changing needs. Flexible resources enable the safe operation of the system and mitigate price volatility. With sufficient flexible resources, the power system can provide firm capacity to the market, meaning that it can confidently deliver electricity in line with time- and location-specific needs.

"The power system will need significant and diverse flexible resources ..."

Flexibility needs arise at every possible timeframe, from seconds to weeks to years. Similarly, flexible resources operate on the short and/or the long run. Generation, storage, demand and grid infrastructure (such as transmission lines or grid-enhancing technologies) all provide flexibility, each with different characteristics. To manage the major changes highlighted above, the power system will need a combination of flexible resources, noting that efficient grid development and operation, energy efficiency and enhanced sector integration[20] can reinforce the impact of flexible resources or even substitute them. Figure 17 illustrates an increasing trend in flexibility needs towards 2030.

20 Sector integration implies linking the various energy carriers - electricity, heating, cooling, gas, solid and liquid fuels - with each other and with the end-use sectors, such as buildings, transport or industry.

Figure 17: **Expected evolution of flexibility needs (TWh/year) in the EU in 2025 and 2030**

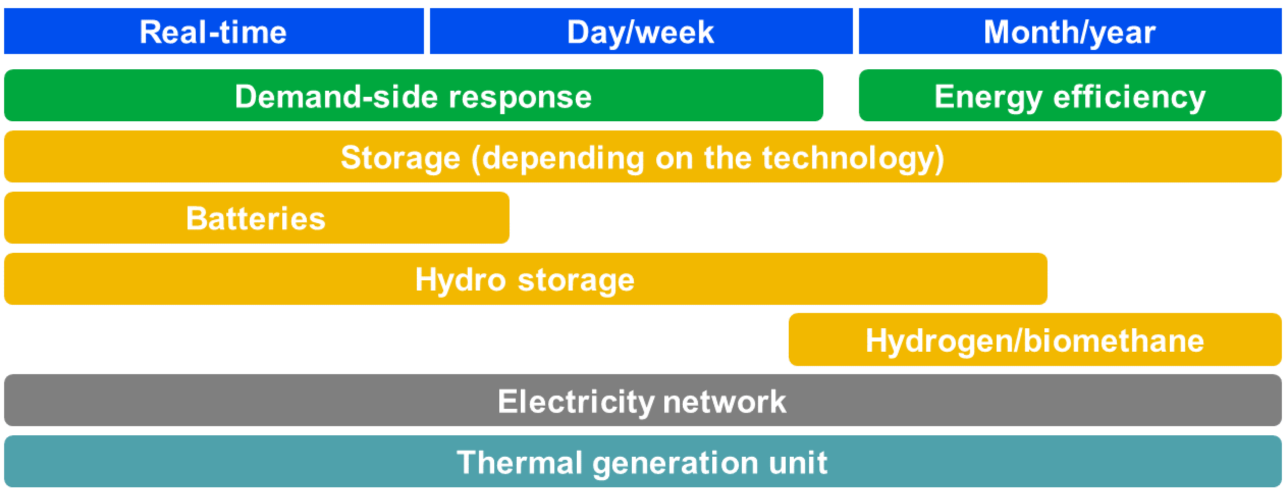


Source: ACER based on simulations made by the Joint Research Centre.

Note: 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, 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.

A market participant's own resources or short-term market trading are the common sources to tackle short-term flexibility needs, ranging from seconds to several days. Dispatchable generation units (such as gas-fired turbines), batteries, pumped hydro storage and demand-side response are typical examples of short-term flexible resources. Electrification of industry and transportation also offer increased potential for demand-side response to tackle short-term flexibility needs.

Figure 18: **Flexibility services provided by various technologies**



Source: ACER.

Note: The list of technologies is non-exhaustive (with e.g. the storage category covering several different technologies). As mentioned, coupling electricity with other energy sectors (sector integration) may provide significant flexibility services.

Figure 18 above illustrates different flexibility services provided by different technologies, across different time-frames.

A key focus area for the coming decade:

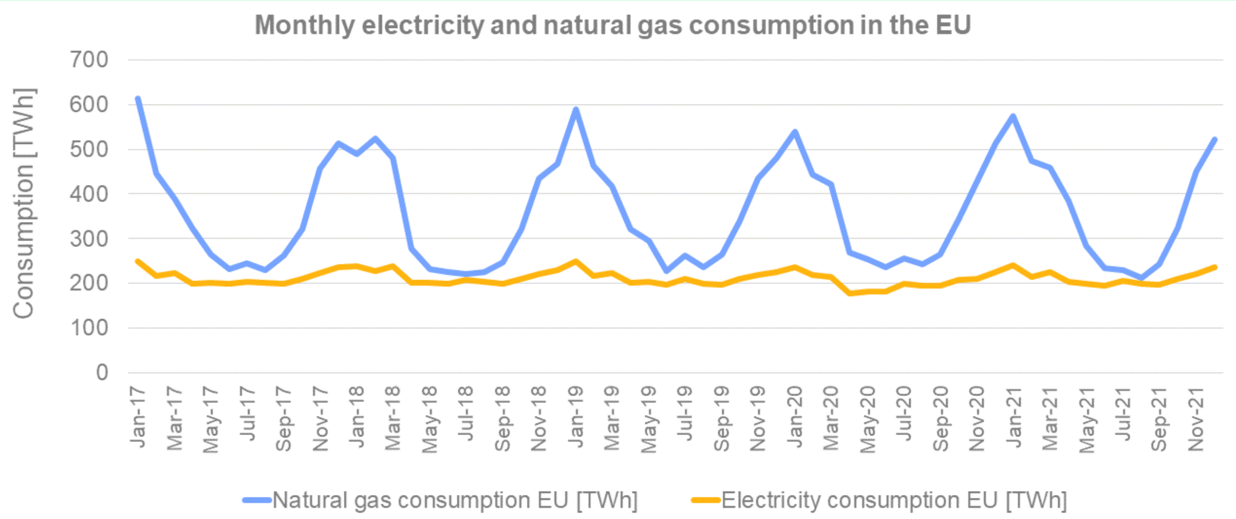
More long-term flexibility is needed for when demand is high or supply is low

A key challenge with increasing volatility is the need for longer-term flexibility (from weeks to several months). Indeed, seasonal demand peaks (possibly exacerbated by further electrification of heating, especially beyond 2030) or long periods with lower renewable generation require longer-term flexible resources.

As shown in Figure 18, fossil fuel power plants (such as gas and coal fired power plants) and hydro power plants with large reservoirs provide seasonal flexibility. When phasing out fossil fuels, alternatives to provide this type of flexibility will be needed. Such alternatives could include low-carbon fuels (such as low-carbon hydrogen, bio-methane and biomass) or more flexible renewables. Increased storage of (renewable) gases, diversification of resources and better interconnections for electricity and (renewable) gases can enhance the potential of these new technologies for providing flexibility.

This challenge is likely to become further acute if policy makers across the EU deem it necessary to transition away from natural gas more rapidly, a key provider of seasonal flexibility needs up until now (noting that further electrification of heating for example, whilst reducing overall gas demand, may shift seasonal swings from the gas system to the electricity system, thereby significantly increasing seasonal flexibility needs in the electricity system). This is also illustrated by Figure 19 below.

Figure 19: Comparing seasonal swings in electricity and natural gas demand in the EU from January 2017 to July 2021



Source: Eurostat data, based on an International Energy Agency (IEA) concept.

A clear price signal is essential to attract investment in flexible resources. Conversely, removing price signals may discourage market entry, in particular of flexibility providers, thus leading to more costly integration of intermittent generation in the long-run.

Thus, the current wholesale market design's ability to attract sufficient longer-term (including seasonal-level) flexibility commensurate with the broader balancing needs of the power system is linked to its ability to indicate an appropriate price for meeting such needs. In the absence of such a price signal, innovation in new technologies or solutions, which currently might not always be price-competitive with fossil fuels (although price evolutions in 2021 and 2022 have temporarily shifted the balance in some respects), will be hampered or may not materialise at all. Hence, the need to retain clear price signals, complementing e.g. upstream research & development support.

The increasing flexible resources entering the power system need market places where their contribution can be recognised and traded. Introducing products that better reflect a changing reality (e.g. products linked with renewable generation or net demand) could offer better hedging solutions and stimulate trading and the related investments in flexible resources. The most straightforward incentive to invest in flexible resources remains the price signal. Indeed, expected price volatility sends a clear investment signal of the need for flexible resources.

Scarcity pricing and capacity mechanisms are two tools that can further trigger investments in flexible resources. Scarcity pricing gives an explicit value to reserves being available in times of scarcity, thereby giving extra incentives to all possible sources (including storage and demand-side response) to offer energy to the market.

Capacity mechanisms support generation, storage and demand-side response to address adequacy concerns by ensuring the availability of enough firm capacity (meaning the electricity is available when and where it is needed). As a result, capacity mechanisms indirectly support investments in flexibility resources, although they do not usually differentiate between flexible and less flexible resources. Figure 20 gives an overview of the different capacity mechanisms in the EU.

By default, capacity mechanisms are national. Coordination at the EU level can achieve more efficient outcomes also in terms of flexible resources (noting the European Resource Adequacy Assessment as a key instrument to drive such enhanced alignment, as mentioned in Section 3 above).

Figure 20: Capacity mechanism in EU Member States in 2020

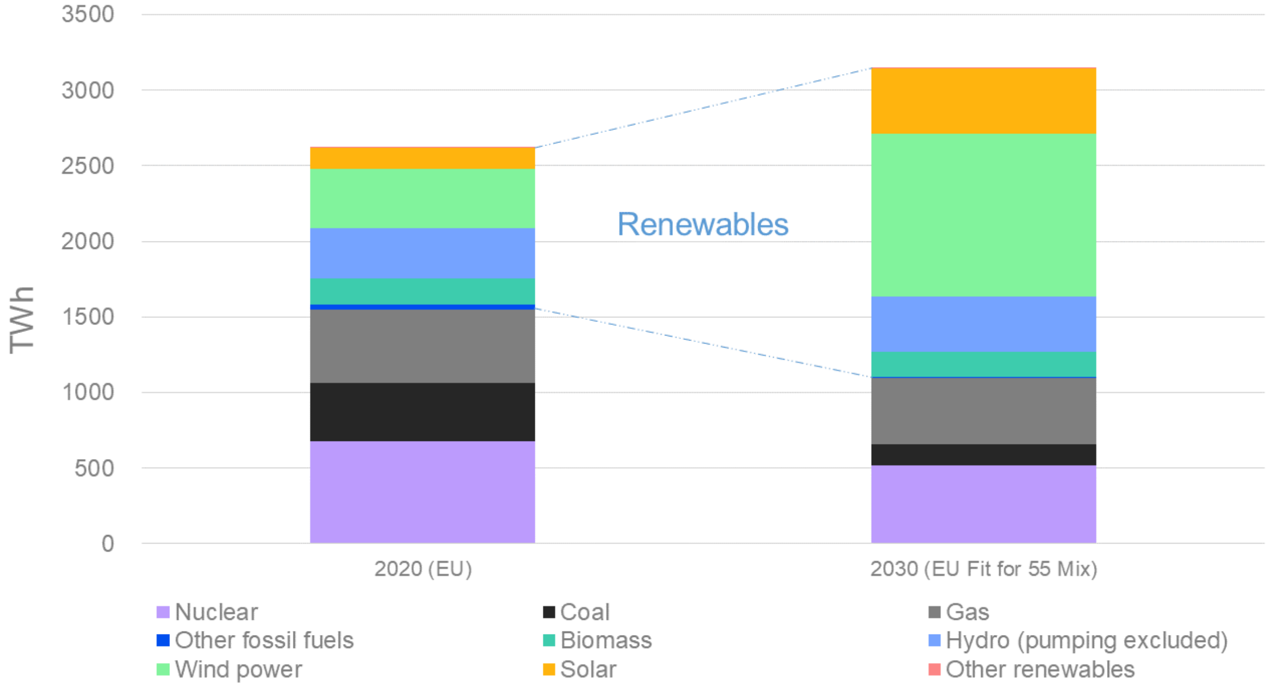
Source: ACER-CEER Market Monitoring Report 2020.

4.2. Investments in low-carbon generation need a massive ramp-up

Significant new investments are needed to deliver the EU's decarbonisation trajectory.

Figure 21 below illustrates the magnitude of this task, taking as point of departure the targets envisaged in the European Commission's 'Fit-for-55' package (seeking a 55% reduction in greenhouse gas emissions by 2030 and carbon neutrality by 2050). It shows the substantial change in the generation mix expected for the next decade. This change will need to happen at speed. A sizeable share of this renewable generation will be connected to distribution grids. As mentioned above, the ETS plays a critical role to incentivise investments in low-carbon technologies.

Figure 21: Expected evolution of the EU-27 electricity generation mix (TWh) in 2020 and 2030



Source: ACER based on European Commission data in the context of the Fit-for-55 Package. For 2030 the European Commission's MIX scenario was used.

Competitive long-term electricity markets play a key role in managing risk, thus supporting investments that carry risk. Furthermore, many EU Member States have introduced different schemes to support investments. These schemes usually aim at supporting renewable energy sources by providing long-term hedging or complementing revenues or they have sought to improve security of supply.

The following government support schemes are used in different Member States:

- Feed-in-Tariff: provides a fixed payment per MWh of electricity produced;
- Constant Feed-in-Premium: complements the electricity market price with a fixed payment, sometimes supplemented by a cap and a floor;
- Sliding Feed-in-Premium: tops up the electricity market price to a reference price, when the market price stays below this reference. The asset owner keeps the market price when it is above the reference price;
- Contracts for Difference (CfD): A CfD pays the asset operator the difference between the market price and a reference price. When the market price exceeds the reference price, the asset owner pays back the difference. The effect of a CfD is similar to a Feed-in-Tariff.
- Other support schemes also exist. These include direct subsidies, tax reductions, exemptions on certain market rules (such as balancing responsibilities), or free grid connection.

"Competitive long-term electricity markets play a key role in managing risk ..."

Tenders or auctions often facilitate the above support schemes as a tool to identify adequate levels of financial support, e.g. by ensuring that prices are set competitively.

Some Member States consider centralised measures to speed up the energy transition, such as the systematic and centralised procurement of energy or capacity whereby regulatory or other public authorities directly procure electricity from specific low-carbon generators. Others allow a fixed regulated price for certain technologies.

Centralised specific measures are sometimes seen as a possible solution to alleged market failures (e.g. the procurement of public goods such as ancillary services) or to kick-start immature markets. As the targets are not necessarily set by the market, the deciding authority (rather than the competitive market) could end up defining the technology mix to pursue. Such centralised approaches therefore need to ensure investments are efficient, to preserve price signals and to strike a balance between technologies.

Support for investments can also originate from the market. A commercial PPA is a long-term contract (e.g. of 5-20 years) between a generator (often a renewable power plant) and a private entity (e.g. a utility, trader or large electricity consumer) purchasing the energy from the generator. Unlike the schemes previously mentioned that involve the government or a public entity as a key procurer or intermediary, a PPA is purely commercial.

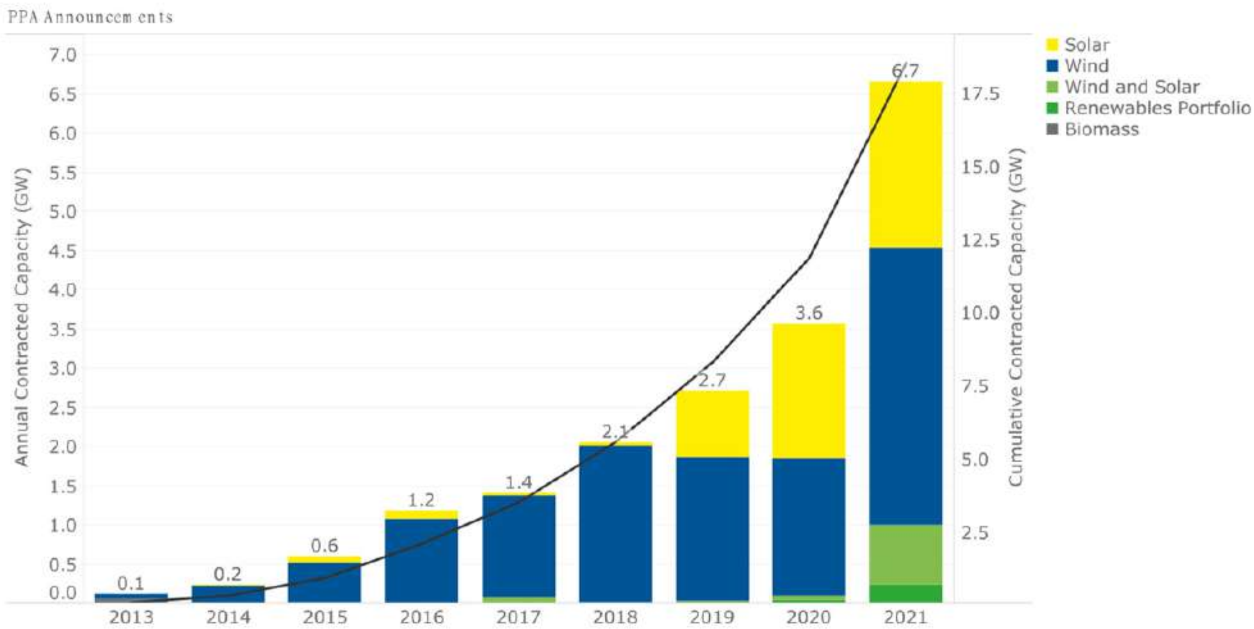
PPAs already play a significant role today. By providing some visibility about the financial viability of a project, PPAs make it easier for renewable project developers to secure funding. To ensure that the long-term commitments are met throughout the contract lifetime, even if the counterparty defaults, market participants may hedge the counterparty risk associated with entering into the PPA.

Many low-carbon generation sources, such as on-shore and off-shore wind farms and solar parks, have in the past benefitted from government-driven support mechanisms. Several such support schemes often coexist in the same country, for example with older plants falling under a Feed-In Tariffs system and new plants supported by more market-based systems like Feed-In Premiums. Subsidising renewables comes at significant cost to consumers. The ACER-CEER Market Monitoring Report (for 2020)[21] shows that on average these subsidies accounted for 12% of consumers' bills.

Several renewable technologies are now mature, accounting for a significant share of generation, and their costs have lowered significantly. In 2018 and 2019, for the first time, several offshore wind farms won auctions without any direct subsidies being awarded. This illustrates how market-based solutions can drive investments in low-carbon generation, maintain a competitive environment and ensure efficient allocation of resources. Figure 22 illustrates the growth in commercially-driven PPAs from 2013 to 2021.

[21] See page 81 of the Energy Retail Markets and Consumer Protection Volume of the ACER-CEER Market Monitoring Report (or '2020 MMR'.

Figure 22: **Annual and cumulative contracted PPA capacity in Europe (2013 - 2021)**



Source: RE-Source (2021).

The allocation of and investment in certain low-carbon generation sources is incrementally shifting towards PPAs and centralised competitive tenders (e.g. auctions for renewable energy sources). An important question is whether commercial instruments are sufficient to drive the investment needs ahead or whether a mix of subsidy-driven and commercially-driven approaches will coexist. A study commissioned by the European Investment Bank (EIB) and the European Commission estimates that, by 2030, PPAs will cover a range of 10% -23% of combined solar and wind generation[22].

4.3. Boosting competitive long-term markets will help hedge against risks and stimulate investments

Many wholesale market participants (traders, retail suppliers, energy-intensive companies, etc.) hedge against risks as a fully integrated part of their business activities. They use advanced hedging strategies and trade energy over different timeframes to smooth out financial flows.

"Many wholesale market participants [...] hedge against risks as a fully integrated part of their business activities."

When considering future costs or revenues, electricity generators and suppliers face significant volume and price risks. They can hedge this risk by trading electricity in advance, in forward markets. Hedging through long-term bilateral contracts (such as multi-year PPAs) are also a means to secure long-term financing for investors (e.g. renewable producers) as the price is set long into the future.

[22] Final Report by Baringa 'Commercial Power Purchase Agreements. A market study including an assessment of potential financial instruments to support renewable energy Commercial Power Purchase Agreements (2022)'.

Hedging: How does it work?

Example: A generator may be interested in hedging its revenues from producing electricity in a given year. If this market participant sells 100 MWh of electricity for every hour of a year at say 50 EUR/MWh in a forward market, it will hedge against the risk of prices (and thus revenues) dropping to say 30 EUR/MWh. On the other hand, it will also give up potential additional revenues if prices were to increase to say 100 EUR/MWh.

At the same time, an electricity-intensive consumer will also wish to hedge its costs. If the consumer buys that annual 100 MWh contract for 50 EUR/MWh, it avoids the risk of losing money if prices increase to 100 EUR/MWh, but gives up on the potential of lower costs of 30 EUR/MWh.

The recent high energy prices have drawn attention to measures that could shield consumers from perceived excessive levels of price volatility that impact affordability. Forward electricity markets enable buyers and sellers to contract at a price well in advance of when the electricity is actually produced or consumed, hence cushioning them from subsequent price volatility. This in turn allows some retailers to offer consumers more predictable prices over a longer period of time. Market participants are free to decide whether to hedge against risks or not and the type of hedging instrument (e.g. how far in advance to lock in a price) that best suits their needs.

Hedging may help cushion the impact of price shocks but it does not remove them. This is mainly due to two factors. First, a perfect hedge might not exist or be too expensive[23]. Second, in line with financial regulation, hedging via trading in forward and futures markets requires collateral. When prices jump and volatility rises, collateral requirements also significantly grow, increasing the financial guarantee that market participants need in order to hedge for future years. Central clearing counterparties (regulated financial institutions that manage the trading parties' credit risk) require high-quality collateral, whilst collateral provision of market participants to banks depends on the participant's credit scores and therefore on the economic situation of a country, thereby adding to the complexity.

Increase in Collateral Requirements

The price evolutions in 2021 and 2022 have resulted in steep increases in collateral requirements and increased awareness about the constraints they can impose on energy suppliers. A survey launched by ACER[24] confirmed the steep increase in the amount of cash tied up in collateral requirements. All but one respondent reported that the total amount of collateral requirements in their markets at least doubled (with some seeing the total amount of collaterals growing more than four-fold) between 21 August 2021 and 21 December 2021.

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[23] In general, the forward risk premium tends to be positive. A large part of the risk can be attributed to the electricity sector per se - risk aversion to scarcity, volatility and extreme events.

[24] ACER conducted this survey in 2022 amongst market surveillance experts of power exchanges and brokers, in the framework of ACER's so-called 'Market Surveillance Forum'.

Such extraordinary increases translate into difficulties in sourcing cash, as reported by market participants.

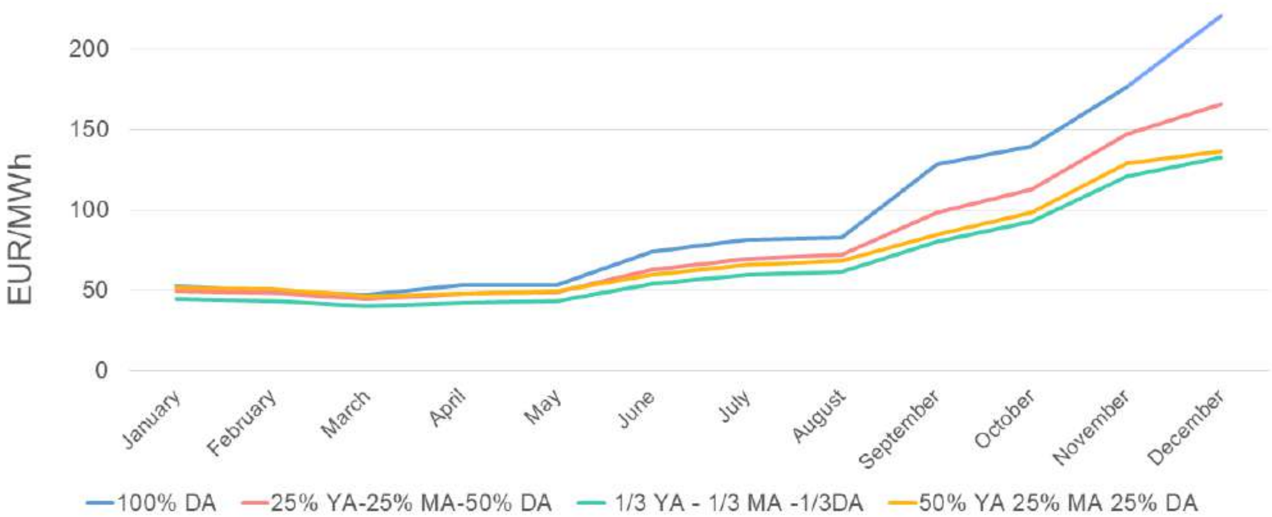
By way of example, at the beginning of January 2022, Uniper, a large German utility, reportedly had to secure liquidity backing in the order of 10 billion EUR in order to cover the collaterals for its trading in electricity and gas. Uniper had to obtain loans from its parent company Fortum and the German KfW IPEX-Bank. Similar liquidity issues were also raised by other (large) market participants. Ensuing developments in the market has lead the German government in the first half of April 2022 to enact broader liquidity coverage measures[25].

Figure 23 displays different procurement strategies that a retailer could have followed in the German electricity market in 2021. The strategies range from fully procuring electricity in day-ahead markets to procuring different shares of month- or year-ahead contracts. The example illustrates that hedging the procurement smoothens the impact of the high prices recorded since September 2021. The longer the hedge, the smoother the price increase observed by the retailer and its customers. Importantly, volatility does not necessarily increase the average cost that the consumer pays over time. Similarly, the long-term procurement in this example does not shield consumers from the price increase over time; it only cushions them from the immediate impact of the high price and spreads the impact of the increase over a longer period of time.

"Hedging may help cushion the impact of price shocks but it does not remove them."

Importantly, forward contracting facilitates planning and avoids the costs of unexpected changes in prices. It allows business to set prices and make forward sales secure in the knowledge of their cost structure, and consumers to plan their budgets. However, forward contracting also fixes those costs. It reduces the ability to take advantage of lower energy costs.

Figure 23: Unit procurement costs (EUR/MWh) of a supplier using diverse hedging strategies in the German electricity market in 2021



Source: ACER based on Platts.

[25] The German government announced a EUR 100 billion financing instrument to assist energy companies having liquidity issues in their hedging.

A key issue is whether the hedging instruments that are available today are sufficient to meet the needs of the various market participants. These needs may be split into:

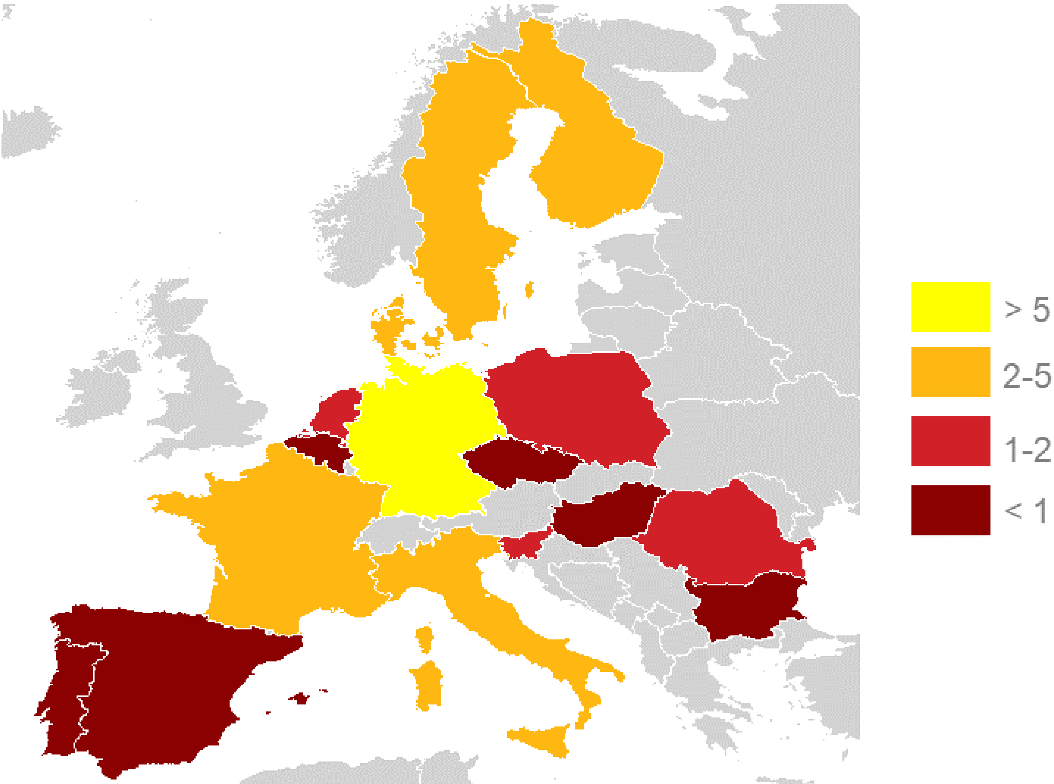
- short-term and medium-term hedging, related to operational needs and seasonal variations; and
- long-term hedging, related to the predictability of the profitability of an asset.

Liquidity is key to ensuring efficient hedging[26]. In some Member States, forward markets offer a relatively liquid platform to trade standard products of up to 1-3 years ahead of delivery. However, further in the future, forward markets are illiquid. Investors, which typically take a 20-year horizon to amortise their investments, will therefore face difficulties to hedge over this time horizon. Illiquid hedging tools may therefore create a hurdle for investments in low-carbon generation or flexibility sources. Hedging through long-term bilateral contracts (such as multi-year PPAs) is thus a commonly-used option to secure long-term financing for investors in some markets.

"... Volatility does not necessarily increase the average cost that the consumer pays over time."

Figure 24 shows varying liquidity in major European forward markets from 2016-2020, as expressed by the respective churn factors[27].

Figure 24: Liquidity of forward markets in major European forward markets (2016 - 2020)



Source: ACER-CEER Market Monitoring Report 2020.

Note: The figure includes only volumes traded or cleared at power exchanges and volumes traded through brokers. Colours are linked with the following churn factors: yellow – 5; orange - 2; red – 1; dark red – below 1.

[26] Liquidity refers to a sufficient amount of buyers and sellers regularly making transactions in a market.

[27] The churn factor represents the overall volume traded through exchanges and brokers expressed as a multiple of physical consumption. It constitutes a common measure of liquidity.

As can be seen from the map, only Germany is averaging relatively high levels of liquidity. Another question though is the duration of the forward contracts on offer (irrespective of whether the market is liquid or not).

Figure 25 shows for Germany the long-term trading over products ranging from 1-20 years in the future. It shows that German market participants mainly trade up to two years in the future. Year-ahead trading accounts for over three-quarters of the traded volumes, with a slow increase in trading of longer-term products from 2019 to 2021.

Figure 25: Relative shares of trading volume per year in the future in Germany (2019 - 2021)

Source: ACER data.

Note: The blue, yellow and grey bars respectively sum up to 100% (over all timeframes). For 2020 (respectively 2021), Year +1 means products for delivery in 2021 (respectively 2022).

Beyond the liquidity of national markets, it is also crucial to ensure liquidity of cross-border hedging products to enable market participants to trade energy across borders in the long-term. Moreover, liquidity in long-term markets benefits from reducing market barriers (e.g. transaction costs).

Finally, in order to ensure properly functioning long-term markets, market participants need to trust the market to yield fair and competitive prices. The application of REMIT (the framework for detecting market manipulative behaviour across the EU) provides the necessary surveillance and enforcement across Europe to achieve this.

4.4. Which measures for policy makers to consider to further future-proof the EU's electricity market design?

Implementing key market integration measures that have already been agreed in EU legislation and beyond is vitally important (see Section 3 above). In addition, because of the changes ahead (e.g. accelerated investment needs and enhanced flexibility services provision) a number of measures should be put forward, in ACER's view, for consideration by policy makers.

4.4.1. Consider promoting and facilitating wider access to Power Purchase Agreements

Power Purchase Agreements (PPAs) are typically open to large investors (e.g. vertically integrated incumbents) and are mainly national. Enabling other actors to enter into such agreements would enlarge the PPA market, thereby stimulating investments in low-carbon generation and flexible resources.

Small suppliers often have limited access to PPAs, as they have difficulties to demonstrate their bankability and their ability to last over a long time period. They might also have varying time horizons or needs in terms of volumes to offtake. Opening PPAs up to a multitude of different actors would bring at least two benefits. First, developers would more easily sell the energy from their projects, as more possible buyers would be able to bid. Furthermore, smaller suppliers would benefit from the price predictability and hedging that PPAs enable.

Governments, other authorities and commercial entities can each play a role in improving the accessibility of PPAs. The EU's Renewable Energy Directive asserts that Member States need to remove regulatory and administrative barriers to long-term renewables PPAs and to describe in their national energy and climate plans how they will facilitate PPAs.

One way to ease access to PPAs would be to pool smaller sellers and buyers. For example, participation in PPAs could be opened up to groups of smaller consumers or suppliers. This approach would allow more market participants access to electricity, mostly from low-carbon generation, at a fixed price. In this case, the pool of buyers could be jointly responsible to tackle counterparty risk.

Supporting guarantees could be another way to stimulate PPAs. By taking over part of the guarantee and thus reducing risk and collateral requirements for private entities, a government could facilitate PPAs between smaller actors. Obviously, reducing the risk of high collateral requirements needs to be balanced with the risk of defaulting on the PPA's requirements themselves. Such guarantees should not discriminate or give price support specific to local industry. The box below describes credit guarantee schemes in Norway and Spain.

Case: The Norwegian credit guarantee scheme and the Spanish reserve fund for energy

The Norwegian Export Credit Guarantee Agency (GIEK) offers guarantees for PPAs. These guarantees support investments in renewable energy and enhance industrial companies' access to PPAs.

A guarantee to the electricity seller hedges against the risk of a buyer's failure to honour the agreement. A guarantee to the banks or other lenders hedges against the risk of the buyer defaulting on the repayment of loans. The guarantees are reserved for buyers registered in Norway active in wood processing, metal production or the production of chemical products.

Source: http://www.eksfin.no/en/produkter/power-guarantee

The Spanish Export Credit Insurance Company (CESCE) manages a guarantee reserve fund for electro-intensive entities (FERGEI). The fund gives a payment guarantee to large consumers who purchased at least 10% of their annual electricity demand via a renewable energy PPA. A guarantee to the electricity seller hedges against the risk of a buyer's failure to honour the agreement. Earlier this year, Spain approached the European Investment Bank to enquire as to whether the bank could consider providing similar financial guarantees for PPAs.

Source: https://www.cesce.es

4.4.2. Consider improving the efficiency of renewable investment support schemes, limiting their use to the needs assessed

When considering measures to underpin accelerated investment in renewable generation capacity, the choice and thus design of the support framework obviously matters.

There is no one-size-fits-all approach to such support frameworks. However, given the evolution of the electricity sector and the capacity needs further ahead, some rules-of-thumb seem warranted.

Based on the experience gained in the recent past, when designing mechanisms to steer renewable energy projects in particular, there seems to be a trade-off between promoting such projects ('build at scale and speed') and efficiently integrating them ('get the most out of the support rendered'). Also, based on even more recent experience, there seems to be a political premium in some quarters on ensuring that the revenue certainty provided to private operators by virtue of the support mechanism to underpin their investment is counterbalanced by mechanisms for feeding back unusually high market prices into the economy (e.g. to alleviate the impact of such prices for consumers). This is akin to an ex-ante excessive or 'windfall' profit taxation scheme.

Hence, if governments prioritise the build-out of new low-carbon generation at scale and at speed, whilst at the same time prioritising an overall ceiling on revenue that the generators thus supported can legitimately earn, opting for production-oriented schemes that remunerate equally each MWh produced would seem appropriate. This could be achieved e.g. by means of CfDs, noting the outcome could be somewhat equivalent to Feed-in-Tariff schemes.

If governments on the other hand prioritise the most efficient integration of new low-carbon capacity without necessarily considering ceilings for generators in times of high prices, opting for capacity-oriented schemes would seem more appropriate. This would mean, all things equal, that the support framework is less oriented towards the amount of electricity produced and more towards system value. When the emphasis is not only on total production, developers will take decisions at the time of the investment that increase the alignment between production and demand profiles in light of the market signals in place. Simply put, the most valuable projects would not necessarily be those that produce more electricity in total; the projects favoured would be those that produce more, where and when it is most valuable for the system. For systems with increasingly dominant shares of renewable generation, the rationale for moving in this direction seems strong.

Irrespective of which of the two approaches is favoured, there is a strong case for reviewing and, where relevant, updating the support scheme(s) in place commensurate with the broader objectives sought. The sheer volume of new generation investment needed across the EU to meet the decarbonisation goals will require not only a lot of investment, but also investment that is spent wisely, meaning on projects that deliver actual decarbonisation at scale (as opposed to generation that is curtailed or subject to vast network congestion) and that keep prices affordable for end-consumers. For both approaches, centralised auctions or tenders could be deployed as a tool to enhance competitiveness amongst offers.

4.4.3. Consider improving the liquidity of forward power markets

As explained above, liquid forward power markets help both buyers and sellers manage risks. Because of the benefits that hedging brings, increasing forward market liquidity (particularly beyond three years) is an important element to support investments in low-carbon and enhanced flexibility solutions.

Power exchanges have recently started to offer longer-term forward products on their markets, suggesting there may be demand for such products. Yet, additional efforts would seem to be needed to improve liquidity for these products. This can be achieved by further standardisation of products across Member States, by removing barriers for market participants to trade in forward markets (such as high fees) and by stimulating so-called ‘market making’[28] in otherwise illiquid (long-term) markets. Such market making stimulation ideally originates from the power exchanges and brokers (for example by reducing fees for market makers), alternatively from governments or regulatory authorities. New Zealand offers one such example of market making stimulation.

28 ‘Market making’ refers to certain traders submitting at the same time orders to buy and sell, in order to increase the amount of orders in the market. These orders will spur trading.

Case: Market making services in New Zealand

ASX, the wholesale market forward trading platform for New Zealand, introduced market making services on its platform in 2010. In the ASX New Zealand market, the four largest generator-retailers each provide market making services on a voluntary basis. In April 2021, the New Zealand Electricity Authority introduced a permanent mandatory backstop to the market making activities, meaning market making becomes mandatory when certain conditions are not fulfilled.

More specifically, the generators sign a contract with ASX to provide these services. ASX incentivises the market makers primarily through reductions on the platform's transaction fees. The New Zealand Electricity Authority monitors the market making.

Source: https://www.ea.govt.nz/

Governments could play a role in building up the necessary market liquidity. Such a role may take different forms. For example, regulators or other public authorities could open a call for tenders to designate a market maker for illiquid markets or by mandating market making. Governments and legislators could also mitigate the impact of very high collateral requirements which can act as a deterrent against engaging in longer-term markets. With unprecedented high prices, such collateral can represent substantial amounts of money and drives liquidity away from markets. Criteria to meet collateral requirements could be reviewed in light of such prices (e.g. criteria for market participants towards their banks). Moreover, in case of perceived market failure, central entities can also provide financial guarantees to reduce the costs related to collateral.

Products that enable the trade of electricity across borders, such as long-term transmission rights, may also provide an opportunity to improve liquidity in forward markets. Today, these products provide access to alternative hedging possibilities for market participants in smaller bidding zones with illiquid forward markets. This means that market participants can procure forward products in larger and more liquid markets, with transmission rights bridging the difference to their home market. However, such a hedging strategy may also lead to further shifts in liquidity from smaller to larger bidding zones, which is not necessarily optimal.

ACER believes that mandating TSOs to allocate long-term cross-zonal capacities in a way that enables the 'coupling' of national forward markets (as in the single day-ahead and intraday coupling), may provide an efficient pooling of liquidity in forward markets. Extending the time horizon for the allocation of cross-zonal capacities beyond one year would also stimulate liquidity in forward markets in longer horizons. A possible review by the European Commission of the Forward Capacity Allocation regulation could take on board such considerations. Finally, TSOs should maximise the long-term cross-zonal capacity, as a prerequisite for well-functioning and integrated forward markets.

4.4.4. Consider tackling non-market barriers and political stumbling blocks for enhanced coordination

Irrespective of the particular market design applied, tackling key non-market barriers will also be crucial. Enhanced grid infrastructure, such as transmission lines, will be key to enable the energy transition, e.g. connecting renewables generation and flexibility resources across wide geographic areas.

Numerous issues, especially related to permitting and local opposition, have delayed infrastructure rollout. For example, ACER's latest monitoring of the Projects of Common Interest finds that more than 40% of delays for electricity projects relate to permit granting. Part of the European Commission's REPowerEU Communication of March 2022 explicitly targets infrastructure bottlenecks, with the Commission calling for a simplification and shortening of permitting procedures.

Efficient grid development and operation, as well as energy efficiency measures, can reinforce the impact of flexibility sources or even substitute them (within and between Member States). Coordinated infrastructure planning, likely becoming increasingly complex in line with greater energy system integration, will thus become ever more important.

This challenge is not unique to grid deployment. A successful energy transition trajectory will rely on holistic policies that target both demand and supply and that focus on both the short-term and long-term.

Major decisions around power generation options, whether for new-build or retirement, can have major implications and create opportunities for other Member States. They may also impact significantly major investment decisions for electricity-consuming industry. Hence, enhanced coordination including across borders, visibility of planning and proactive involvement would seem to be a necessary feature of electricity generation policy going forward.

One pertinent illustration of such enhanced coordination needs is represented by the huge offshore wind resource endowments in the North Sea and the expressed desire to exploit these for sizeable shares of electricity demand across the European continent.

Offshore wind power: Scaling it up requires increased Member State collaboration

The countries in the North Seas Energy Cooperation (NSEC) recognise the importance of regional energy cooperation on a wide range of issues such as maritime spatial planning, grid planning, support schemes and tendering, financing, and the development and implementation of concrete projects[29].

[29] North Seas Energy Cooperation: 'Political Declaration on energy cooperation between the North Seas Countries and the EC on behalf of the Union', December 2021.

By way of example, the EU Energy Commissioner has expressed the importance of cooperation for the success of the project:

"NSEC is an outstanding example of how regional cooperation at sea basin level contributes to reach the EU Green Deal objectives, by setting a common direction and working together on ambitious cross-border offshore wind projects." (Ms Kadri Simson, EU Commissioner for Energy)

Recently, a Joint statement of European governments, power transmission operators, and industry on the expansion of offshore wind in Europe, signed on 6 April 2022, further emphasises the need for accelerating offshore wind deployment through coordination, proposing e.g. further visibility of respective offshore projects pipelines, removing barriers and streamlining consenting, coordination on planning, investing in research etc..

"… Coordination at the bilateral, regional or EU level can optimise investment decisions […] and remove hurdles for speedy and efficient investments."

Coordination efforts amongst and between TSOs, Member States, regulators, project developers and others has built up over the past two decades. These include, but are not limited to, actions taken in the context of implementing the Ten-Year Network Development Plan, the EU-wide Network Codes and the European Resource Adequacy Assessment. Such coordination needs to be further enhanced. In an EU-wide context, coordination at the bilateral, regional or EU level can optimise investment decisions (such as the desired locations of renewables, flexibility or transmission assets), provide visibility about likely market entries and exits, and remove hurdles for speedy and efficient investments. Beyond the electricity sector, diversifying fuel supply would also likely require coordination, e.g. regarding where to build, how to operate LNG facilities as well as to ensure that they are connected to downstream markets.

4.5. Consider structural measures that enhance the hedging potential of the system, thus helping to shoulder future periods of sustained high energy prices

"… ACER points to a few options … [that] may alleviate concerns that even with an improved and adjusted electricity market design …, one might need additional 'insurance' against future energy price shocks."

Finally, as a more structural measure for the future, ACER points to a few options being debated in academic circles for enhancing the hedging potential of the current system. These are measures that policy makers may want to consider to guard against future periods of sustained high energy prices. Such measures are not immediate options to alleviate the extraordinary price pressures experienced here and now, but may alleviate concerns that even with an improved and adjusted electricity market design fit for the coming decade, one might need additional 'insurance' against future energy price shocks.

Two specific measures are further explored below, namely a regulatory intervention inspired by financial hedging, and a 'relief valve' inspired by measures prevalent in certain electricity markets outside of the EU. In order for measures such as these to offer high degrees of regulatory stability, they should be implemented in a clear and transparent way, well in advance of those high energy price periods which they are designed to mitigate against. Should policy makers wish to move in this direction, ACER points out that each such measure has advantages and drawbacks, and advises that further analysis be done as to how they best fit with the jurisdiction in question.

Measures that exclude extreme risks from materialising, or mitigate the effects thereof if they do, can serve as insurance for certain groups of consumers. For example, a regulatory or other public entity may buy long-term hedging instruments on behalf of (groups of) consumers. This transfers the risk from consumers (who are usually risk-averse and have little means or knowledge to hedge properly) to electricity producers who can provide the hedge. Such a transfer, in turn, creates a need for producers to hedge themselves (for example by building flexible resources), thereby in turn increasing liquidity in long-term markets. Reliability options, 'affordability options' and cap-and-floor mechanisms constitute examples of such measures. They obviously come with a cost (no insurance is free), the allocation of which could be subject to different political considerations.

Reliability Options and Affordability Options

Reliability options, such as those implemented in Ireland or Italy, constitute a contract between capacity providers and a buyer (here a TSO). Each time the established reference market price rises above the strike price of the option, the seller pays the difference between the reference price and the strike price to the buyer. The main purpose of reliability options is for buyers to benefit from enhanced security of supply (adequacy). At the same time, the reliability option serves as a hedge against price spikes. Sellers of reliability options receive a regular payment for keeping capacity available.

So-called 'affordability options'[30] are measures introduced in anticipation of or as hedging against extreme price shocks in the future. They are subject to a centralised auction for long-term options, the execution of which depends on the average market price over a pre-defined period (e.g. a month)[31]. Only when the average price over the period exceeds the strike price, will the option be executed. Such options therefore maintain the exposure of consumers to shorter-term market signals but hedge them against sustained high prices and correspondingly high electricity bills.

[30] The 'affordability option' is described in Batlle et al (2022), Power Price Crisis in the EU: Unveiling Current Policy Responses and Proposing a Balanced Regulatory Remedy and in Batlle et al (2022), Power Price Crisis in teh EU 2.0+: Desparate times call for desperate measures. The measure proposes that a regulatory entity buys long-term Asian call options (which has a pay-off depending on the average over a time period rather than a single expiration date) from generators on behalf of the targeted consumers.

[31] These are also referred to as 'Asian call options'. Contrary to so-called 'European options' or 'American options' where the payment linked to the execution of the option depends on the price of the underlying asset at a specific point in time, the execution of 'Asian options' depends on the average market price over a pre-defined period.

A different mechanism which policy makers could also consider is the establishment ex ante of a temporary price limitation mechanism, triggered under clearly specified conditions (e.g. unusually high electricity price rises in a short period of time), the effect being to pause a return to full price formation for a specified period of time (e.g. a few weeks or a month). The measure would need to ensure that sufficient revenue is earned by generators and would require a compensation mechanism for those generators who are able to prove sourcing costs above the limitation ceiling[32].

Such a mechanism could prove a significant intervention in price formation, As such, it carries risks. However, this risk is partly mitigated by the advantage of giving regulatory stability provided the measure is implemented well in advance of the triggering events and provided its defining characteristics are clear and transparent. Should such a measure be deemed desirable, it would benefit from being coordinated at EU level, drawing on lessons from the jurisdictions where it has been implemented.

Temporary Relief Valve Mechanisms

So-called ‘relief valve’ mechanisms such as ERCOT's ‘Peaker Net Margin’ (Texas, United States) or ‘Cumulative Pricing Threshold’ in the National Electricity Market[33] (Australia) constitute examples of such a measure. Both markets foresee a normal market clearing, with regular price signals, including from price spikes, up to the point where sustained high prices have reached the mechanism’s pre-defined threshold.

The ERCOT ‘Peaker Net Margin’ measure calculates the accumulated profits over a year as a difference between the operating costs, defined by natural gas, and the real-time electricity price. The threshold is set at three times the cost of new entry of new generation plants. When the threshold is reached, the maximum price on the market is temporarily lowered and then, according to certain criteria, automatically raised again later on ensuring full price formation.

The Australian National Electricity Market imposes a so-called ‘Administered Price Period’ when the sum of the spot prices for the previous seven days reaches the ‘Cumulative Pricing Threshold’ (CPT) or when the sum of the ancillary service prices for a market ancillary service in the previous seven days exceeds six times the CPT. In 2019-2020, the CPT was equivalent to an average spot price of 658.04 AUD/MWh. The administered price cap during the administered price period is set at 300 AUD/MWh. The ‘Administered Price Period’ ends when the cumulative price has fallen below the CPT.

[32] See as an example of a 'temporary relief valve' M Hogan et al (2022), Price shock absorber: temporary electricity price relief during times of gas market crisis.

[33] See for example the Operation of the administered price provisions in the national electricity market briefing paper from the Australian Energy Market Operator (AEMO), July 2019.

5. Extreme price shocks leading to considerations of temporary, targeted measures

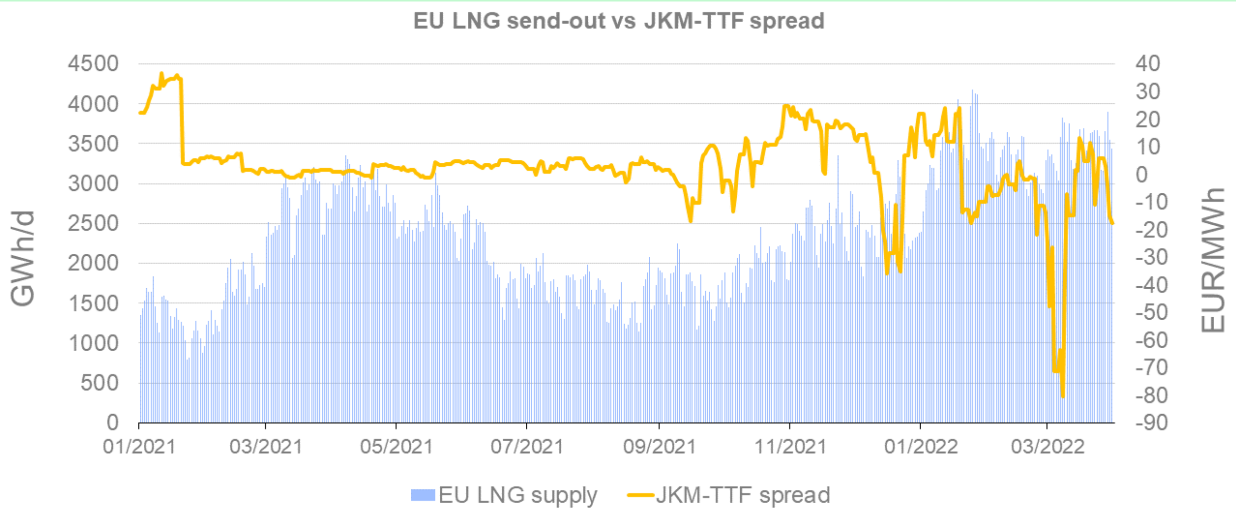
The extreme price situation as of end February 2022, described above as Phase 3 ('war emergency'), is the result of a rare, unexpected and difficult-to-mitigate energy price shock. It is exacerbated by high geopolitical tension and significant uncertainty around the energy supply outlook; this obviously linked to Russia's war against Ukraine and its possible consequences. The threat of war and the subsequent invasion gave rise to significant price rises and high price volatility, the former leading to increased LNG deliveries to Europe, as illustrated in the text box below.

Price signals delivered more spot LNG cargoes since the end of December 2021

In 2021, LNG volumes traded on a spot and short-term basis accounted for 38% of global LNG trade[34]. Spot LNG tends to flow to the region with the highest price. Due to growing, but still limited, contractual and end-point flexibilities, LNG cargoes are subject to short-term redirections and price arbitrages, making LNG deliveries more price responsive than in the past.

From December 2021 to March 2022, total LNG supply to Europe has significantly risen (+65% year-on-year, for the average of the fourth months) driven by the high European gas prices. This is exemplified in Figure 26, which compares the evolution of EU LNG supplies against the price spread between the European (TTF) and Asian (JKM) gas regions. The analysis shows that when, at the end of 2021, EU hub prices started to become higher than Asian ones (i.e. JKM-TTF price spread is negative in the graph), the total LNG supplies into the EU increased[35].

Figure 26: Total LNG supply to Europe (GWh/day) vis-à-vis European-Asian spot price (EUR/MWh) spreads (January 2021 - March 2022)



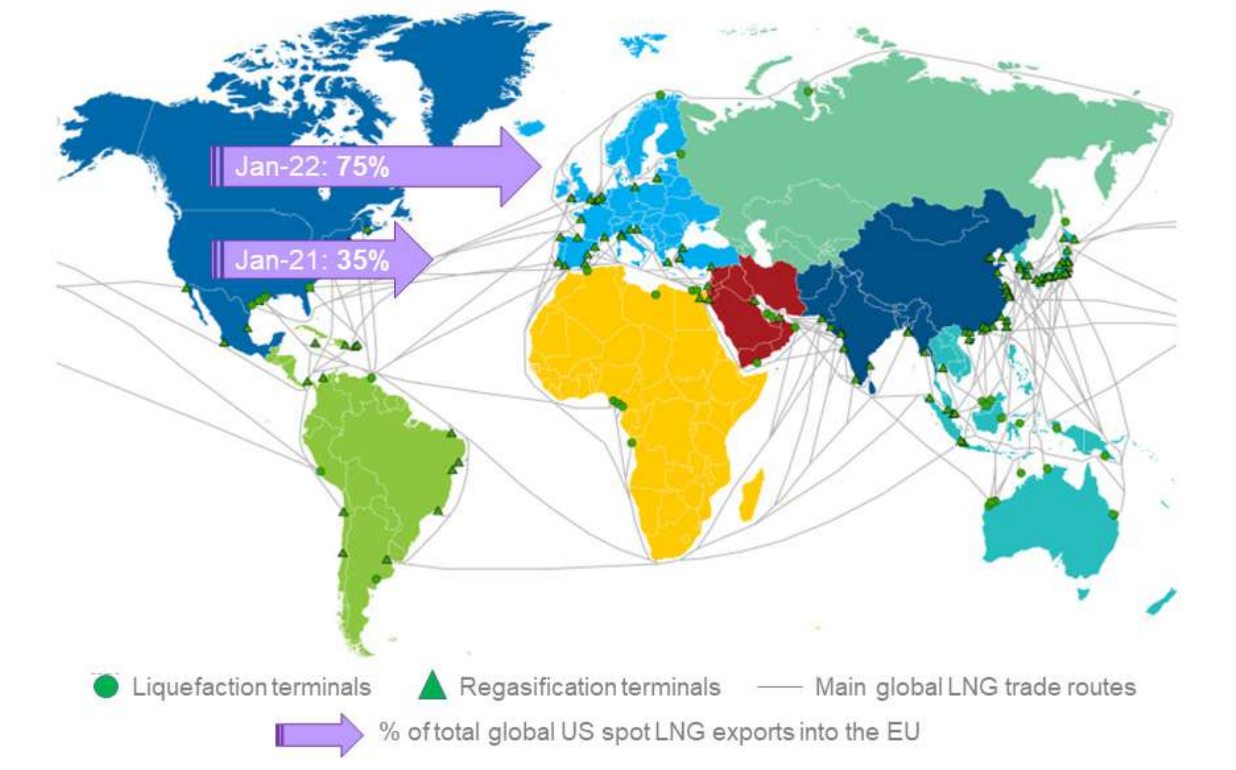
Source: International Gas Union and ICIS Heren.

[34] The figure refers to LNG volumes delivered up to three months from the transaction date. According to IEA estimates, that share was 30% in 2019.

[35] LNG supplies – i.e. gas regasified from the LNG terminals into the network - tend to relate well to total LNG imports, with some days of time-gap.

The major part of the increased EU LNG imports came from the US, which is the largest global spot LNG seller, accounting for 30% of total global spot LNG sales. As illustrated in Figure 27 below, 75% of the total global US spot LNG sales reached the EU in January 2022 (attracted by the higher European prices) in contrast to 35% one year earlier. In March 2022, US LNG deliveries accounted for 44% of total EU LNG imports, compared to 28% in 2021.

Figure 27: Share of global US spot LNG deliveries that reached the EU (January 2021 vs January 2022)



Source: International Gas Union and ICIS Heren.

With significant geopolitical tension and increased risk of gas supply impacts, EU prices have soared above Asian hub premium prices. As mentioned in Section 2, the current energy price shock and very significant price volatility stem less from physical shortages and more from perceived risks of and lack of clarity on potential significant disruptions of Russian gas flows going forward. This current situation has also given rise to decisions seeking to rapidly decrease the considerable reliance of many EU Member States on Russian gas and other energy commodities.

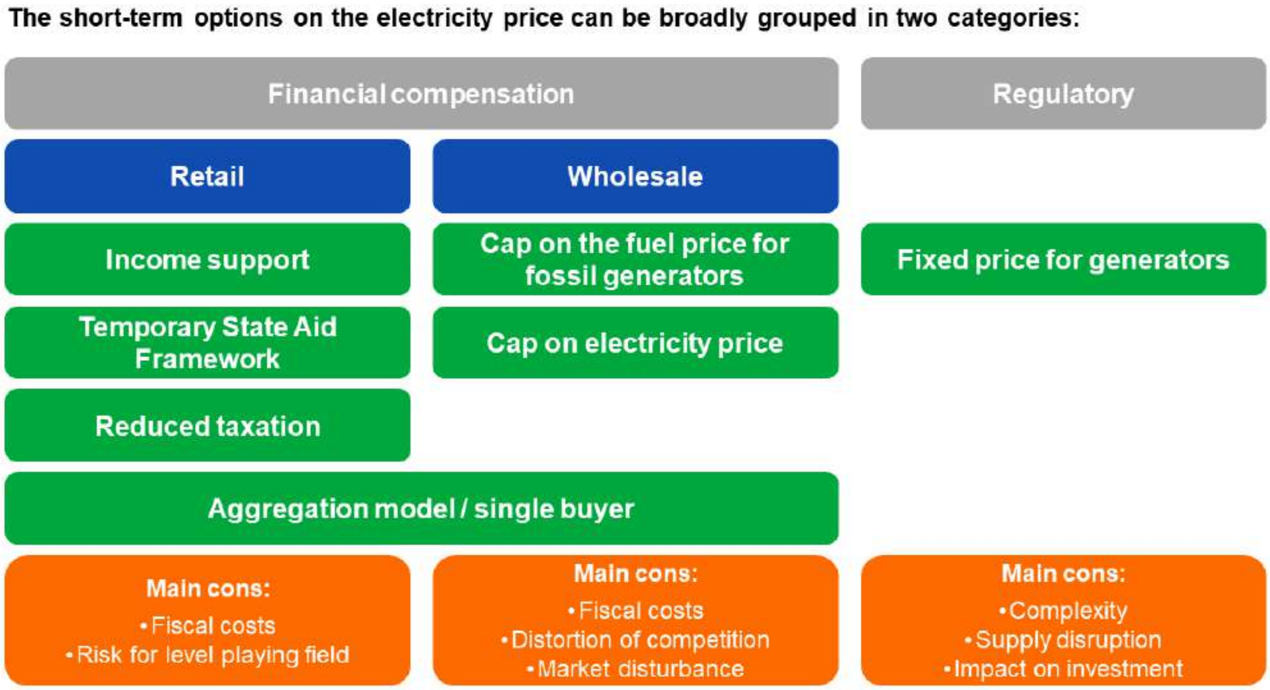
5.1. Differing political approaches to possible temporary measures

Well before the current emergency situation, over the autumn of 2021, several Member States introduced a variety of national measures to mitigate the effects of rising energy prices on households and businesses. These measures were in part informed by the European Commission's 'Toolbox' Communication of October 2021.

On 10 – 11 March 2022, following Russia's invasion of Ukraine, the EU heads of state invited the European Commission to propose a plan to phase out the EU's dependency on Russian fossil fuels. On 8 March, the Commission published its 'RePowerEU: Joint European action for more affordable, secure and sustainable energy Communication'. This Communication outlined tentative measures to respond to rising energy prices in Europe and the need to replenish gas stocks ahead of next winter. It also pointed to the need to diversify the EU's sources of gas supply, to speed up the roll-out of renewable electricity sources as well as renewable gases, and to replace gas in heating and power generation. The Commission is expected to publish its detailed RePowerEU plan in May 2022. This will likely include options to optimise the electricity market design, following the publication of this ACER assessment.

On 23 March 2022, the Commission adopted a follow-up Communication, touching upon e.g. common gas purchases and minimum gas storage obligations within the EU. It included a legislative proposal establishing a gas storage policy for the EU, seeking to ensure gas storage is filled to a minimum of 80% capacity by 1 November 2022, rising to 90% minimum gas storage obligations in the following years. In addition, the Communication grouped a number of ideas for short-term emergency measures as had been put forward by certain Member States to limit high electricity prices (see Figure 28 below). These ideas include intervening in the wholesale electricity market (e.g. via a cap on electricity prices or introducing a fixed price for fossil generators), intervening at retail level (e.g. via direct support or reduced taxation for specific consumer groups) or via introducing a so-called 'single buyer model' acting as intermediary between supply and demand.

Figure 28: European Commission's overview of short-term options to address high electricity prices (as per their 23 March 2022 Communication)



Source: European Commission Communication of 23 March 2022: 'Security of supply and affordable energy prices: Options for immediate measures and preparing for next winter', COM/2022/138 final.

The European Commission's Communication makes clear that all of the options outlined have costs and drawbacks. It concludes that the root cause of the electricity price crisis is the recent gas supply shock and its impact on gas prices. As such, it sets out options for interventions in the gas markets such as capping gas prices (or setting a price band) as well as ideas for an EU-level negotiation strategy with relevant suppliers so as to lower prices for LNG and/or pipeline gas deliveries.

In line with the European Commission's original tasking back in October 2021, this ACER assessment focuses on the benefits and drawbacks of the EU electricity market design, not least in terms of its ability to deliver the EU's decarbonisation trajectory over the next 10-15 years. At the same time, ACER of course acknowledges the significant political debate as to whether targeted extraordinary measures are needed on a temporary basis (e.g. to cushion the adverse impacts of high prices for particular groups and/or to structurally intervene in the energy market in the current emergency situation). Whilst the ACER assessment did not set out to tackle such issues, ACER takes the opportunity to offer its considerations on the use of such measures in order to address the current high energy price situation in the EU.

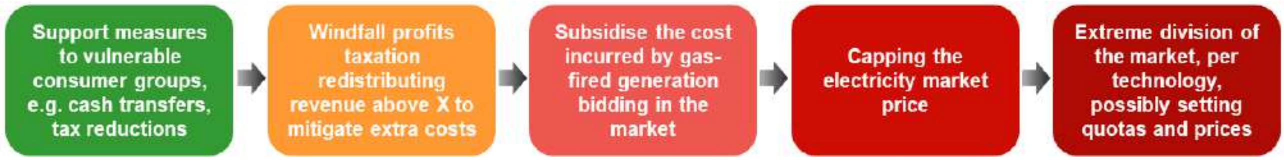
A spectrum of possible intervention measures are being tabled by different EU Member States. These range from the less interventionist measures that safeguard wholesale market functioning (such as targeted support for vulnerable customers) to the more interventionist (e.g. taxing windfall profits through to capping the price of the electricity market). As a rule of thumb, ACER considers that the more structural-interventionist a measure, the higher the potential to distort the market, especially in the medium to long-term. Hampering security of supply, distorting cross-border trade, jeopardising investor confidence are some of the risks ensuing from the more structural-interventionist measures being considered. Hence, prudent and careful consideration by policy makers at EU and national level would seem warranted before embarking upon such measures.

Firstly, interventionist measures carry the risk of rolling back, or perhaps even abolishing, the significant benefits already achieved by EU electricity market integration over the past many years (for details, see Section 3 above). Secondly, significant structural interventions in the market may make it more difficult to achieve the EU's ambitious decarbonisation objectives in the medium-term, especially if private investor confidence in an appropriate and stable market framework were to be negatively impacted. This is because lower private investor confidence would likely lead to a rise in 'political risk' premiums, making the decarbonisation trajectory more costly.

"As a rule of thumb, ACER considers that the more structural-interventionist a measure, the higher the potential to distort the market, especially in the medium to long-term."

Figure 29 is a stylised depiction of the spectrum of energy measures currently contemplated and/or advanced by different Member States across the EU. These measures are ranked according to the impact and level of structural interventionism.

Figure 29: Spectrum of possible structural-interventionist measures relevant for the EU electricity market (non-exhaustive)



Source: ACER.

Note: the further a measure is depicted to the right, the deeper the level of intervention and/or alteration of the market framework in ACER's view.

The first and least distortive category of measures (on the left hand side of the spectrum) are national measures to protect vulnerable consumers (e.g. through energy vouchers or direct cash transfers, efforts to reduce the overall energy bill, or to stimulate energy efficiency). As stated in ACER's Preliminary Assessment published in November 2021, such measures will be more effective if directed towards more vulnerable consumer groups, including the energy poor. Some Member States have opted for broad-based measures (e.g. lowering tax, lump sum payments) for all (or nearly all) consumers. Whilst of course in the end reflecting a political choice, such less-targeted measures generally end up being more costly and less effective.

A second category seeks to recover possible 'excessive' (also referred to as 'windfall') profits in a period of very high energy prices. Under some schemes in place in the EU today, companies are subject retrospectively to specific taxes on alleged 'windfall' profit, seeking to redistribute the impact of high prices from those who are deemed to earn the most to those who are suffering the most. The notion of excessive profit is the difference between the revenues from extraordinarily high electricity prices, and the 'standard profit' that a market participant could reasonably have expected (e.g. based on its generation costs, original investment costs, various risks and overall return-on-investment expectations).

Whilst redistributing welfare from generators to consumers in times of extreme high prices might intuitively seem fair and justified, such measures carry significant implementation challenges, as already witnessed in some jurisdictions. In particular, it is difficult to assess profits made vis-à-vis pre-contracted power volumes already sold at lower prices, e.g. through long-term markets. It might well be that generators did not earn the 'profits' being targeted, in which case the tax may render a loss for the generators in question. As a result, in such cases, 'windfall profit' interventions may risk jeopardising investor confidence or act as a disincentive to invest. Nonetheless, if such schemes manage to tackle genuinely extraordinary profits, the level of structural intervention seems lower than capping prices per se.

Whilst not necessarily framed as a 'windfall' profit redistribution scheme, other national measures may have similar effects and could thus have similar drawbacks. An example is mandatory long-term contracts for specific generators. If these aim at offering below-market prices for consumers (through administratively-set prices or limited competition on the buying side), they may well result in profit redistribution as well[36].

[36] Some have argued that this type of measure would be appropriate in a market characterised by one or a few firms holding a dominant position. However, such measures may still lead to undesired effects ranging from an increase of perceived risks, in turn leading e.g. to higher financing costs, and to non-recoverable welfare losses for the system as a whole.

In principle, one could also envisage measures that target the price of gas power plants in the electricity merit order (the third box in Figure 29); this in light of the fact that gas can often be the price-clearing technology in the market, in particular in times of lower-renewable output. Lowering the bid price of gas-fuelled power plants (whilst still covering separately the higher gas sourcing costs for those power plants who end up in the merit order) would in principle reduce the impact of high gas prices on electricity prices. Such measures could be designed in different ways, all of them however carrying significant risks.

For example, besides numerous implementation challenges, these measures may jeopardise security of supply should cost-recovery be perceived as a risk; may significantly distort cross-border flows (as the artificially lowered prices may no longer reveal full scarcity); and would likely lead to inefficient dispatch decisions. In addition, such a measure carries significant direct costs, namely the difference between the (capped) bid price of the gas-fuelled power plant in question and its sourcing costs; costs which need to be carried by the government budget and thus indirectly paid for either by the taxpayer or the electricity consumer. Accounting for, monitoring and paying for these additional costs would also entail significant administrative burden.

In practice, and by way of comparison with the fourth box in Figure 29, lowering the bid price of gas-fuelled power plants would limit the electricity price for many hours, whenever the gas-fuelled units set the electricity price; however a direct cap on the electricity price would limit the electricity price for all hours, irrespective of the marginal technology. This would thus seem an even more extreme intervention in the market carrying greater risks.

Finally, one could imagine an even more structurally-interventionist measure in the form of a division of the electricity market into distinct technologies (the fifth box in Figure 29), perhaps with administratively-set production quotas and prices for each technology. ACER is not aware of any jurisdiction where such a mechanism has been recently implemented, in essence being more akin to ‘war-time’ measures (the analogy being e.g. manufacturing industry directed in war-time to produce certain equipment deemed essential with a certain revenue level being allowed). ACER has serious doubts as to whether such a model would be feasible in an EU context and whether it could secure supply, short of a quasi-nationalisation of the energy industry in question.

Broadly speaking, an important consideration of the measures briefly introduced above is how much they discriminate between generation technologies and/or among consumer segments. When a measure targets certain technologies only, it risks fragmenting the market, compromising competition and creating regulatory uncertainty about the potential for similar measures in the future. The more structurally ingrained a measure, the more likely it is to hamper innovation in future technologies and offerings, and accordingly the less likely it is to support investor confidence in new low-carbon investments. Moreover, if Member States implement such measures in a non-coordinated or non-aligned way, this might exacerbate the adverse impacts on cross-border trade and flows.

Overall, when addressing short-term needs, policy makers need to be careful about the negative medium- and long-term implications of the measures contemplated, such as the regulatory risk involved, the impact on future financing costs for private operators and the retention (or loss) of benefits hitherto accrued by way of current market functioning. In any case, Member State transparency on the measures being contemplated and a clear end-date or end-criteria for their expiry would seem particularly important. This reduces uncertainty and as such would likely have an immediate effect on longer-term market prices.

5.2. A different possible route; tackling the root causes (gas markets) rather than the symptoms (electricity prices)?

The aforementioned structural measures interfere in the EU wholesale electricity market, with those from the middle and towards the right of the spectrum outlined above likely having major distortive effects.

> ***"Targeting the gas market and its price dynamics may well prove less distortive, given such a measure would not directly intervene in the electricity wholesale market functioning."***

Should policy makers see a need to take immediate structural action under the current extraordinary energy price circumstances, a different possible route would be to target 'the root causes' of the situation, namely the very high price of gas, resulting from the considerable risk of and uncertainty around a severe gas supply shortage or disruption in the coming months; this rather than targeting 'the symptoms' (i.e. the high electricity prices).

Targeting the gas market and its price dynamics may well prove less distortive, given such a measure would not directly intervene in the electricity wholesale market functioning. Should governments seek to intervene in wholesale gas price-setting, they would need to make sure that the EU gas market remains sufficiently supplied (as otherwise, supply concerns and thus overall high price levels would risk being further exacerbated).

This means in particular that the EU market needs to remain attractive for flexible LNG shipments subject to increasing global competition (see also Section 6 below). Attracting sufficient LNG is of particular importance, as this is the main supply alternative to offset lower Russian supply over the coming months and years. Such a 'root cause' intervention would seem to require extensive dialogue with the main gas suppliers outside of the EU.

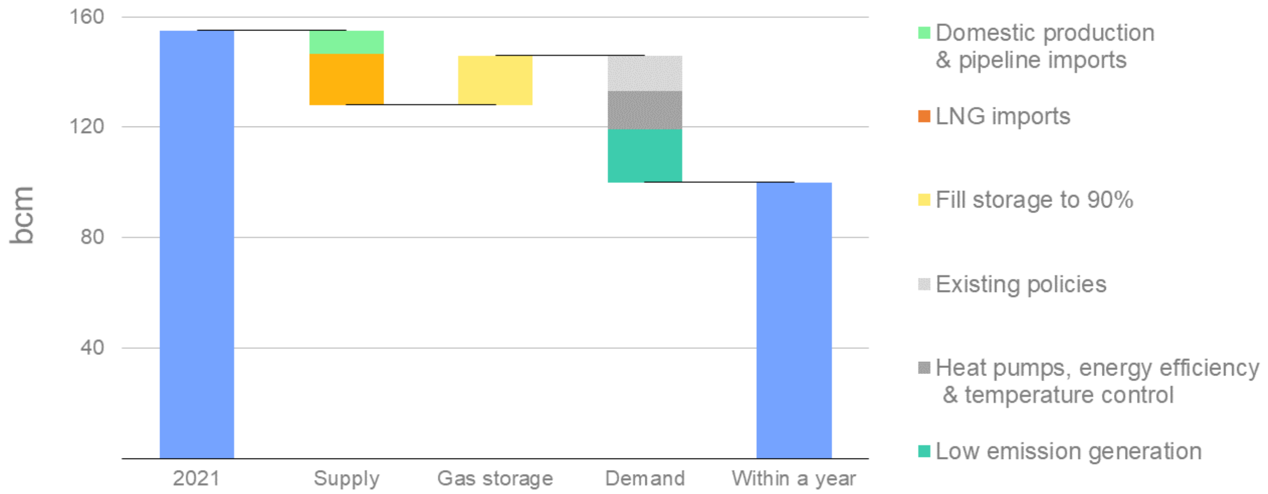
Finally, ACER notes that the current political debate has brought suggestions from some quarters to accompany this focus on gas market intervention with a particular price cap on gas being sold in the EU. At first glance, ACER finds it not fully clear what such a cap would contribute additionally to the aforementioned discussions with the main gas suppliers to the EU, noting once more the need in particular for LNG prices to remain competitive vis-à-vis alternative destinations for such cargoes.

Given that broader gas wholesale market functioning is not part of the European Commission's tasking in the aforementioned 'Toolbox' Communication, we will not pursue this avenue further in the context of this ACER assessment.

5.3. Getting better prepared for possible future supply or price shock events

Recent IEA analysis (depicted in Figure 30) has pointed to a number of near-term measures that could contribute significantly to lower EU dependency on Russian gas, thereby partly mitigating the impact of lower or uncertain future Russian gas supply on EU gas prices. No-regret measures to reduce dependency on Russian gas should include demand-side measures, fuel-switching efforts e.g. towards accelerated renewables deployment, and the diversification of gas supply sources. If implemented, such measures would also help the EU be better prepared for possible supply or price shocks in the future.

Figure 30: Breakdown of various measures lowering near-term EU gas supply dependency on Russia



Source: IEA.

Notwithstanding such near-term measures, the current extraordinary circumstances in which the EU finds itself, with adverse impacts on many consumer groups, suggests there is value in considering 'insurance options' to mitigate possible future periods of sustained high energy prices. These are not immediate options to alleviate the current extraordinary prices, but may alleviate concerns about future energy price shocks.

As further elaborated in Section 4 above, one such measure to be considered is a 'temporary relief valve' for when wholesale electricity prices rise unusually rapidly to high levels over a sustained period. Such a measure features in certain electricity markets outside of the EU. Another such measure is a financial option whereby pre-identified consumer groups via a regulatory intervention are hedged against sustained high prices occurring over a longer period above a certain threshold.

6. Mid-term prospects of gas markets

This section assesses the mid-term prospects of gas markets relevant for the likely impact on electricity prices over the coming years. In turn, this leads to some considerations about EU gas market design and contracting models going forward.

6.1. EU gas prices will become increasingly dependent on global LNG supply

The latest gas market outlook of the IEA[37] shows that under normal weather conditions EU gas demand is expected to decline by 6% in 2022, as an outcome of the high energy prices hampering economic activity alongside reinforced energy efficiency efforts and gas to coal switches in power generation.

LNG supplies will likely remain strong, as some previously offline capacity returns to the market along with the EU securing additional shipments (plus European forward prices remaining at premium to Asia through the rest of 2022). In this respect, the European Commission and Member States have stepped up their collective efforts to jointly acquire LNG from a variety of global gas producers and secure gas from more diversified sources (an EU Energy Purchase Platform has been set, to voluntarily coordinate common gas procurement[38]). For example, following a recent high-level EU-US agreement, the United States will strive to make available at least 15 bcm of additional LNG to Europe in 2022, with volumes expected to increase going forward.

"... In the absence of strong policies to curb demand, global gas supply tightness could well persist."

While this additional supply should help put moderate downward pressure on prices, it will not fully mitigate concerns about possible Russian supply disruptions. The need to refill depleted EU gas storages up to 80% by November of this year will create additional price pressures during the injection season, as also captured by the forward price curves in Figure 5.

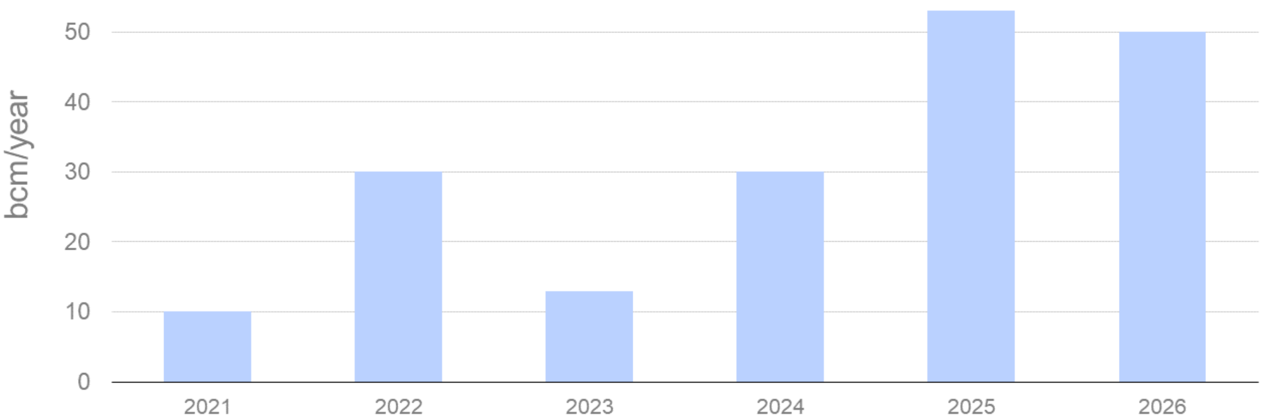
Over the coming years, as EU markets gradually shift away from Russian gas to more diversified supply sources, EU gas prices will be increasingly affected by regional and global price dynamics. Global gas demand is projected to grow steadily across the coming decade, with gas taking a leading role in meeting the growing energy needs of emerging economies, whilst helping to decarbonise their power sector, hitherto often reliant on coal generation.

[37] See the IEA's 'Gas Market Report, Q2 2022'.
[38] The EU Energy Purchase Platform will ensure cooperation in areas such as demand pooling, efficient use of infrastructure and international outreach.

As the EU aims at reducing its gas supply dependency from Russia, it will need to substantially increase LNG imports (with notional European Commission estimates referring to an additional 50bcm per year, approximately 10% of today's total LNG global supply[39]). Therefore, the IEA cautions that in the absence of strong policies to curb demand, global gas supply tightness could well persist[40].

A key factor in this regard is the expansion rate of LNG export capacity in the coming years. As Figure 31 shows, the bulk of this new LNG capacity is expected from 2025 onwards. Moreover, some of the additional supply coming online is likely to be more expensive than current gas pipeline supply originating from Russia, thus putting upward pressure on EU gas prices compared to 'normal' years in the recent past.

Figure 31: Start-up year of forthcoming global LNG (bcm/year) capacity (2021 - 2026)



Source: IEA.

6.2. The EU's 'pay as clear' electricity market design helps attract cleaner technologies, including low-carbon gas

The gradual phase-out of coal-fired power plants across the EU could further increase the prevalence of gas prices as a key driver of electricity prices in the coming years. In spite of recently announced life-time extensions of the nuclear fleet (e.g. in Belgium) or considerations to bring back otherwise mothballed or held-in-reserve coal-fired generation in some Member States, the impact of gas prices on electricity prices is likely to remain until various energy efficiency measures and/or new electricity capacity additions have taken hold.

That said, high gas prices and thus high electricity prices provide strong incentives for other solutions, such as demand-side response offerings and energy storage solutions, to participate in the electricity market. Such solutions, alleviating both gas demand and broader electricity system flexibility needs, would 'outcompete' gas by virtue of their increasingly competitive price bids in the electricity merit order should gas prices remain high. This is also discussed in Section 4 above.

[39] The figure is notionally assessed on the basis of the unused EU regasification terminals' and cross-border pipeline capacities in 2021. The extent to which these projections materialise will depend on the availability of additional global LNG and on the interplay of regional price signals. IEA's estimates halve the amount of LNG likely to be sourced to the EU, at least in 2022. Moreover, gas flows will need to substantially reroute if the EU system becomes increasingly independent from Russian supply, requiring reassessment of system operation and targeted infrastructure investment.

[40] The IEA estimates that global gas upstream spending is lower than what is required to achieve the most ambitious global decarbonisation scenarios. Despite the current record-high prices, new investments are still low relative to assessed needs; this not least due to investor uncertainty about the role of gas in the energy transition (a factor also leading to higher costs of investment capital).

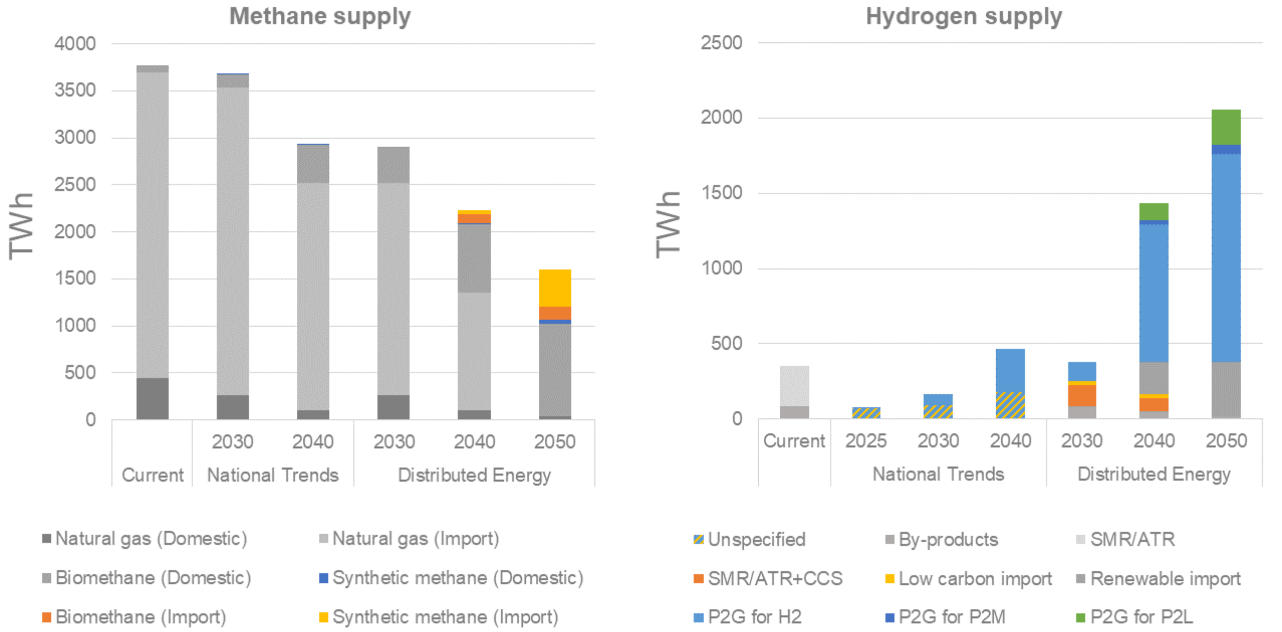
Importantly, the opposite is also likely to hold true. Without such a price incentive, the 'innovation or deployment incentive' for such technologies, competing with gas as to what ultimately clears at the margins and thus sets the overall clearing price, would be lower, thus impacting the uptake of these technologies.

Herein lies an important reason for policy makers, when contemplating extraordinary interventionist measures here and now, to consider prudently and carefully potential negative consequences of such measures in the medium- and long-term.

With the EU's ambitious decarbonisation trajectory, EU gas demand and supply patterns are likely to change. EU gas consumption is expected to decrease in the coming decades, driven not least by strong expansion of low-carbon electricity capacity and lower gas-based space heating requirements due to the electrification of heat, coupled to broader energy efficiency efforts. These pursuits have been given extra impetus by Russia's invasion of Ukraine and the ensuing need to lower the EU's energy dependency on Russia[41].

On the supply side, the transition towards domestically produced renewable and low-carbon gases will decrease the EU's external gas supply dependency. Cost reductions in technology (together with more efficient feedstock gathering and cheaper renewable power input) would make decarbonised gases more competitive. Nonetheless, their cost range is expected to be higher in the next couple of years compared to conventional natural gas prices of past years (though they may be competitive vis-à-vis the current record-high prices). Figure 32 shows two of the latest ENTSOG scenarios for bio-methane and hydrogen penetration. While there is ample technical potential to upscale such production, the cost-competitiveness of these technologies relative to conventional gas will be a crucial factor for their uptake rate. On balance, the EU's reliance on external gas supply is likely to remain high at least until 2040, amidst declining conventional EU domestic natural gas production.

Figure 32: EU methane and hydrogen supply (TWh/year) prospects (2030 - 2050)



Source: ENTSOG Ten-Year Network Development Plan 2022. Various scenarios.

[41] As an example, the European Commission's 'RePowerEU' Communication of March 2022 lists a 35 bcm biogas target in 2030, which would be equal to 25% of Russian piped gas supplies in 2021.

Gas supply patterns are also likely to evolve, mostly due to the more flexible operation of gas-fired power plants, meeting peak and/or seasonally contingent electricity demand as intermittent renewable generation increasingly dominates the electricity mix. In turn, this will likely reduce the revenues of gas-fired power plants over the longer-term. Hence, some of the current generation fleet might exit from the market, requiring other solutions and technologies to undertake that role. Once again, the price-setting mechanism of the current electricity market design provides relevant economic incentives in this respect.

6.3. What mechanisms can best limit gas price exposure whilst securing supply?

6.3.1. Long-term bilateral contracts will coexist with hub-trading

The current gas price situation in the EU has led to debates on the significance and structure of long-term gas supply contracts going forward. Despite the fact that these contracts have declined in recent years and will likely continue to do so, they still account for 75% of EU gas demand. Around 40% of these long-term volumes are signed with Gazprom.

When scarce flexible supply led to record-high gas prices in recent months, not only short-term hub prices but also the price of long-term supply contracts rose. This is because long-term contracts typically, though not exclusively, are linked to various hub-price references (the specific price increase being dependant on the time-lags and price formulas of the contract in question). Under the assumption that enhanced hub liquidity and competition puts downward pressure on prices, and to mitigate high energy prices for consumers, gas producers could further increase the supply volumes directly offered at hubs (hub prices are also crucial because they are the key reference used to determine the opportunity prices of the electricity bids of gas-fired power generators). Enhanced hub forward liquidity would help to better hedge prices and reduce price exposure.

ACER acknowledges, however, that views on this matter may differ. Several producers - as well as some buyers - could prefer to hold bilateral long-term contracts in order to ensure a secure return on production investments and/or lock deliveries in at possibly more stable prices. To the extent that new contracts are linked to the development of new gas fields and/or associated with substantial new infrastructure development (a well-established driver of long-term contracting), the prevalence of long-term contracts may remain.

All in all, the relative weight of long-term contracted versus direct hub-based supplies will be set by market participants' preferences, drawing lessons from the current tense supply situation. Individual portfolios are likely to contain mixed hedging strategies and price references and, on average, more diversified supply sourcing origins.

6.3.2. Higher gas storage stocks will benefit security of supply and flexible system operation

Another issue attracting attention relates to the future role of underground gas storages, key both to securing supply to meet seasonal demand swings (thus exerting downward pressure on prices during tight supply situations) and to supporting flexible system operation. The concerns about security of supply worsened in the aftermath of Russia's invasion of Ukraine, given uncertainty about Russian gas flows going forward. Such concerns have reinforced the supply security role of gas storage sites across the EU.

A key focus area here are the so-called Summer-Winter spreads which in the current high price situation provide little to no financial incentive for companies to fill storages over the summer. This is also acknowledged in the European Commission's Security of Supply and Affordable Energy Prices Communication of March 2022, which calls for EU storage sites to be filled to at least 90% of their capacity by 1 November each year (the target for the year 2022 being 80%, although some Member States may set it higher)[42].

Currently, underground gas storages are a key provider of seasonal flexibility for gas and for electricity (by way of example, storage withdrawals cover around 25% of gas consumption in winter). As such, storages are a crucial asset for hedging related forward prices. Moreover, the role of gas storage in enabling flexible short-term operation in both the gas and power system may increase in the coming years with the increase in intermittent renewable power generation. Hence, gas storages will need to find an optimal balance between these two operational time frames and market roles, i.e. between the provision of seasonal flexibility and shorter-term market balancing (noting this balance will also be influenced by the physical characteristics of the storage site in question).

Over time, low-carbon hydrogen – through storage and offtake of (renewable) electricity production – will likely complement the flexibility currently offered by underground gas storages, though views differ as to the expected rate of hydrogen uptake.

[42] The European Commission's legislative proposal for a regulation on gas storage, accompanying the aforementioned Communication in March, requires Member States to set a certain filling trajectory and measures to achieve the threshold. Discussions are taking place to determine the most effective approaches, taking into consideration solidarity principles but also the differences between Member States in terms of their respective storage availabilities relative to national demand.

ACER

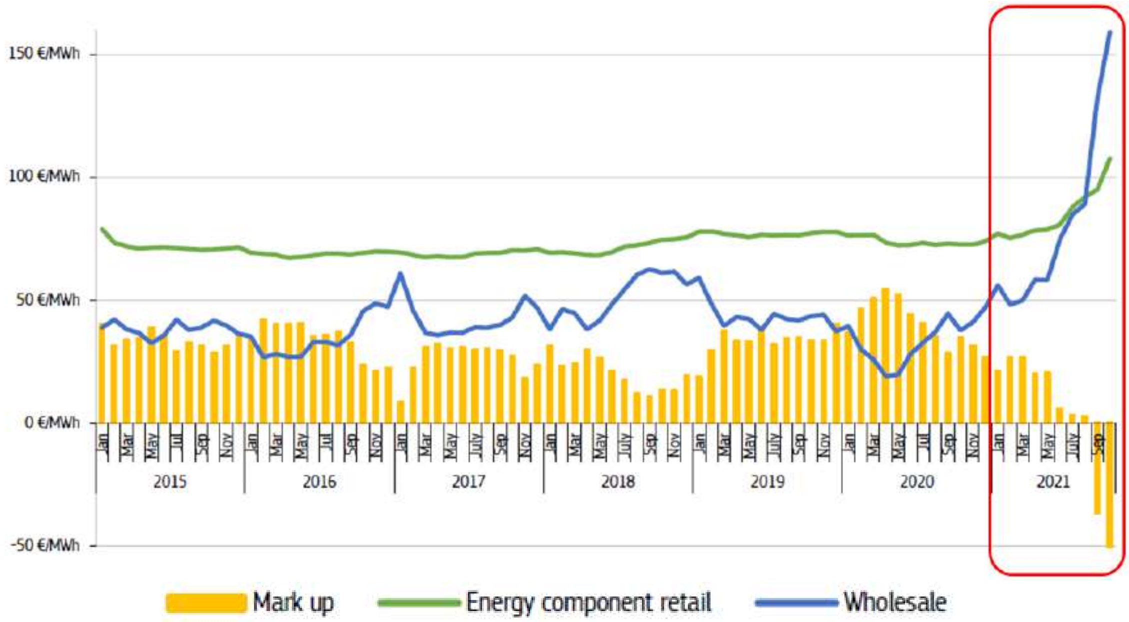
7. Retail energy markets and consumers

7.1. Record-high energy prices have negatively impacted consumers and retail suppliers

Following wholesale energy price increases of 200% (electricity) and 400% (gas), household energy prices in Europe increased sharply in 2021, reaching record levels (see Figure 33 below). Unfortunately, these price figures do not reveal the full story as it will continue to unfold.

As Figure 33 indicates, wholesale costs have been higher than the retail energy component. Ultimately, when wholesale costs are high over time, consumer prices must cover the costs of supply. Higher wholesale prices will ultimately be reflected in retail prices, although this may take time to pass through as retail suppliers may well have hedged or consumers may have signed fixed price contracts for a certain time period. Nonetheless, such differentials are unsustainable for suppliers in the longer term and it would thus seem likely that many energy consumers will see significant price increases in 2022.

Figure 33: European wholesale and retail electricity component prices (EUR/MWh) (2015 – 2021)



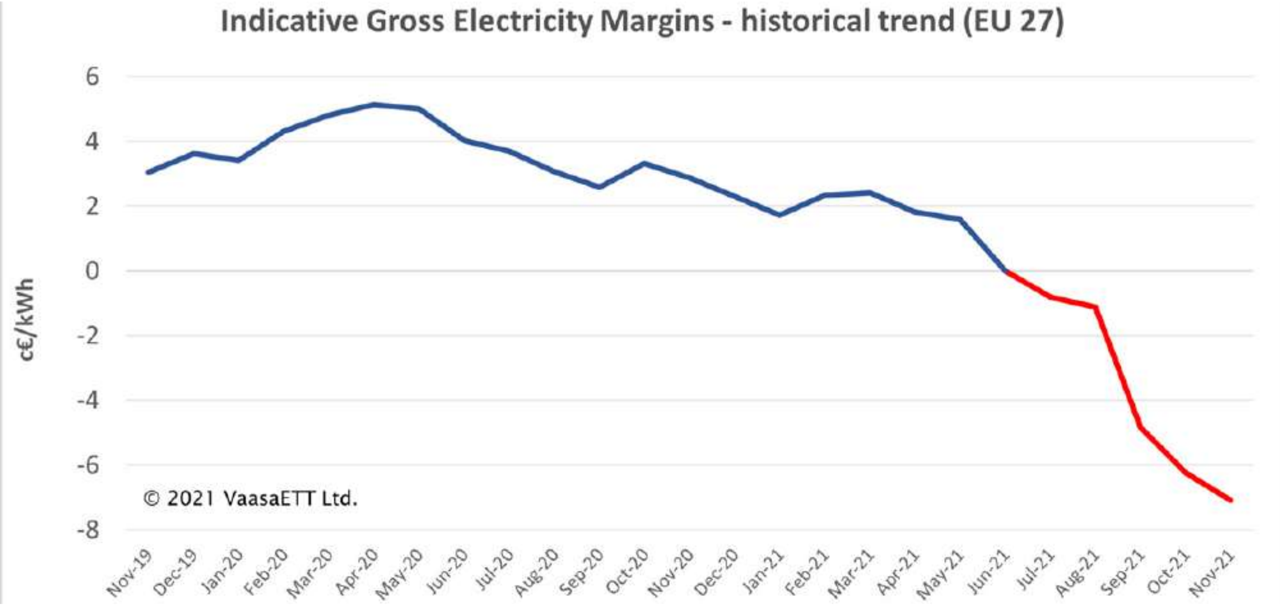
Source: European Commission: 'Quarterly Report on European Electricity markets Q3 2021'.

Note: Mark-up refers to the difference between the wholesale energy component and the retail energy component.

Besides consumers, the increase in energy prices has significantly affected electricity and gas retail suppliers. With many retail suppliers exiting the market, and consumers concerned about their energy supply, the so-called Supplier of Last Resort mechanisms have been activated in many national markets. This mechanism is a reactive measure, which moves consumers to a fall-back supplier in the event of a supplier's exit. While the mechanism ensures continued supply to consumers, it does not protect them from facing higher costs associated with this transfer. The risk of a cost increase is particularly high in a period of high wholesale energy prices, as the new supplier has to buy the additional volumes of supply to secure demand for the transferred consumers; and this would be done (all things equal) at those higher prices. Some lessons from the workings of the Supplier of Last Resort mechanism in recent months are set out below.

In response to wholesale electricity price increases, retail profit margins have been negative since June 2021 on aggregate (see Figure 34 below). This shows the significant financial pressures placed on energy suppliers, leading to many retail supplier bankruptcies across Europe. While this pressure may have been mitigated by hedging efforts of certain suppliers, as with any business, consistently negative profit margins are unsustainable in the longer term.

Figure 34: Indicative supplier profit margin (Jan 2020 – Jan 2022)



Source: https://www.vaasaett.com/european-retail-energy-prices-reach-record-levels/.

Note: Indicative supplier gross-margins assess the difference between the energy price charged to household consumers and the actual power-procurement costs for retailers. Retailers' costs depend on procurement strategies. The financial losses are higher when solely considering short-term power purchasing.

Some EU consumers felt the impact of rising energy prices more rapidly depending on their retail tariff structure. In some cases, cost increases were immediately passed onto final consumers (via so-called dynamic-price contracts) whereas in other cases (fixed-price contracts), consumers were faced with price increases at a much slower rate. The opposite has also been true in the past: In some instances, those on dynamic price contracts immediately saw cost decreases when wholesale prices came down while those on fixed-price contracts were locked into a higher price for a period of time.

By way of example, in Spain during 2021, consumers on dynamic tariffs (PVPC tariff) were impacted immediately and significantly by increasing wholesale energy costs. On the other hand, prior to 2021, the PVPC tariff delivered an average of 12% savings to consumers when compared to the standard domestic rate[43].

[43] See table 16 of the '2019 Retail Electricity Market Monitoring Report' by CNMC.

7.2. Options to shield consumers from unwanted price volatility impacting affordability

With a few exceptions, retail energy consumers traditionally have little or no interaction with wholesale energy markets. Even if consumers today have more choice with regard to their energy supplier, many are unable to understand complex energy market risks. More self-consumption and aggregation may impact this dilemma as market interaction patterns may change, at least for some electricity consumers.

All in all, the past months of high energy prices provide a particular backdrop for considering the balance of risk between retail suppliers and retail consumers going forward. In particular, some measures could be considered that would reduce the likelihood of retail supplier failure and/or to mitigate the consequences of such failure.

Measures to reduce the likelihood of supplier bankruptcies could include introducing hedging requirements for retail suppliers. While the recent wholesale price increases are unprecedented, it is clear that some energy suppliers were quite unprepared for significant wholesale price volatility. This lack of financial resilience resulted in supplier bankruptcies in some Member States, transfer of consumers to a Supplier of Last Resort, and consumers seeing an increase in their energy price.

Hedging limits a supplier's exposure to price increases and thus lowers their risk of going bankrupt, which in turn can protect consumers from sudden price increases and contract terminations. Hedging also ensures some predictability regarding consumers' energy bills. Similarly, a minimum level of financial robustness (akin to MiFID-like requirements for financial markets) could be required for retail suppliers. Such considerations would benefit from further discussions between energy and financial regulators.

"... Some measures [...] would reduce the likelihood of retail supplier failure and/or ... mitigate the consequences of such failure."

As regards possible measures to mitigate the consequences of retail supplier failures, one could consider upfront financial guarantee requirements for suppliers. An alternative could be a broader consumer levy socialising the costs of certain suppliers exiting the market.

More specifically, requesting upfront financial guarantees or financial security from retail suppliers means that these guarantees could be used to mitigate negative consequences for energy consumers in the event of a sudden supplier exit from the market. Equally, in the event of a market exit without negative impacts on other suppliers or energy consumers, the guarantee would be returned to the exiting supplier.

A consumer levy mechanism could consist of common contributions to a fund to reduce the impact of cost increases borne by consumers impacted by a sudden supplier exit. In the event of a Supplier of Last Resort being appointed, such a fund would be drawn upon to limit the impact of cost increases on those consumers transferred to that new supplier. A consumer levy is not without significant costs and as such, may not be the most appropriate option for consideration.

Enhancing supplier responsibility: Financial Responsibility Principle - United Kingdom

The Financial Responsibility Principle (FRP) is an enforceable overarching rule requiring suppliers to minimise the costs to be borne by competitors in the event of failure. The FRP aims to ensure that suppliers act in a more financially responsible manner and take steps to bear an appropriate share of their risk.

The FRP expects that the supplier provides evidence that it has:

- plans in place to meet its financial obligations;
- effective processes, that are consistent with existing licence requirements, for example setting direct debit levels and for checking and returning customer credit balances;
- sustainable pricing approaches that allow it to cover its costs over time, or if it is pricing below cost that the risk sits with investors and not consumers;
- robust financial governance and decision-making frameworks; and
- the ability to meet its financial obligations while not being overly reliant on customer credit balances for its working capital.

Introducing this new principle allows Ofgem (the energy regulator) further regulatory powers, along with other tools such as milestone and dynamic assessments, to take enforcement action against irresponsible behaviours in the market. The FRP will help to ensure that suppliers adopt sensible practices in managing their costs.

Whatever the mechanism considered, it is important to recognise the trade-offs involved. Increased consumer protection comes at a cost, ultimately likely to be borne by consumers themselves.

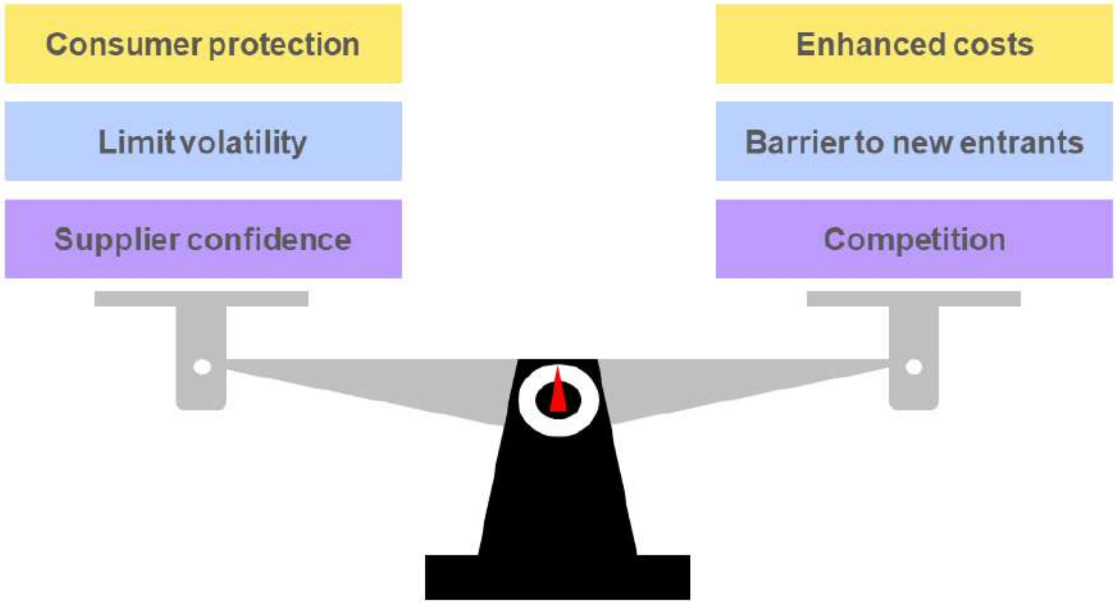
By way of example, expanding certain requirements for retail suppliers would likely limit entry of new market entrants and/or possibly hamper the introduction of innovative retail contracts. Under such approaches, vertically-integrated and more established suppliers will be in a stronger position to withstand additional financial requirements. Hence, a relatively closed supplier market of established (and likely big) incumbents would seem a probable development.

Similarly, broad-based consumer levies would socialise the cost of a poorly-managed supplier, perhaps giving undesirable (perverse) incentives towards unduly aggressive market behaviour, undertaken in the knowledge that a socialised fund would lower the risk of such behaviour. Hence, the drawbacks of such a measure likely outweigh the benefits.

“... It is important to recognise the trade-offs involved. Increased consumer protection comes at a cost, ultimately likely to be borne by consumers themselves.”

There is thus a balance to be struck between on the one hand measures to enhance protection and confidence of consumers in case of high price volatility impacting affordability, and on the other hand to secure a competitive market for retail offerings, allowing new market players to enter without unnecessarily high barriers. This balance is more likely to be struck at national level rather than at EU level, given the different regulatory and market traditions prevalent across the EU. In any case, given the pressures energy suppliers currently face, it may be prudent to reflect on the appropriate timing to introduce additional measures, where deemed necessary.

Figure 35: Considering a balanced approach to protect consumers against price volatility impacting affordability



Source: ACER.

7.2.1. Consumer risks, consumer contracts and time-differentiated tariffs

In some ways, consumers are at the centre of the energy transition and are expected to take a more active role in their energy consumption. However, it is important that the consumer is both ready, capable, and willing to do so. Expecting that all domestic consumers will be active participants in their energy consumption may not be reasonable. While some consumers may be willing to become truly active, many consumers will likely manage their consumption (or generation) less actively.

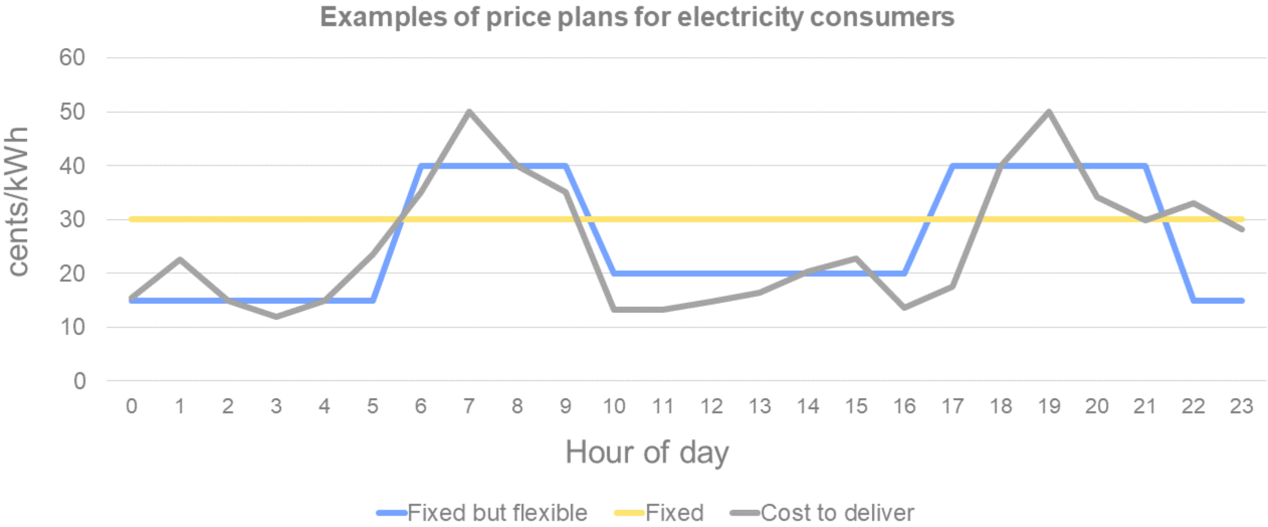
Similarly, consumers have access to a wide range of information. However, having access to such information does not necessarily mean that consumers are fully informed of the risks associated with each supply contract. While a consumer may decide upon the cheapest available contract, they may not be fully aware that they may be exposed to significantly higher bills in the event of an increase in wholesale energy costs. Even though information may in principle be fully available, it would seem appropriate not to operate with a ‘default contract’ containing significant risk. Rather, it may be seen as more acceptable to provide a level of predictability for certain categories of consumers and to approach ‘default contract’ options with this in mind.

Given the above, it may be appropriate to require, before a consumer subscribes to more flexible electricity supply contracts (e.g. contracts indexed to day-ahead market outcomes), that suppliers ensure that consumers are fully informed of the risks and benefits associated with such contracts. Where consumers are on dynamic-price contracts, it might also be appropriate for suppliers to provide regular updates regarding price variations. Such information could be provided via text messaging or similar, enhancing consumer awareness of both their consumption and current costs of energy.

Many consumers may wish to have a simple fixed price for the energy they consume, notwithstanding the cost of delivering energy varies over time. The costs to deliver energy to a home vary throughout the day based on the type of generation used to meet the consumer demand. As such, going forward, it is important to consider what retail pricing structures are most appropriate from a system point of view. Just operating with a default contract offering consumers a fixed price may not be the most appropriate in the future where the cost to deliver varies significantly. Such default pricing structures might of course differ for larger industrial energy users and smaller/domestic energy users.

Figure 36 below compares two potential price plans for electricity consumers[44]. Both provide consumers with a level of predictability regarding their energy consumption. Under the fixed price plan (yellow line), the consumer always pays the same price. The supplier also receives some certainty about future energy requirements. However, fixed prices do not 'nudge' the consumer towards adjusting their consumption patterns in line with the costs of delivering the energy at different times during a day (grey line). This can result in the system operators calling upon less efficient generation during periods of peak energy demand, increasing the cost of electricity. The fixed price contract should thus reflect this additional cost.

Figure 36: Fixed but flexible price example v fixed price example



Source: ACER.

On the other hand, a default fixed tariff that flexes (blue line) during the traditional peak hours of the day and for which the hourly price remains stable over a few months or years[45], could provide a balance between the flexibility needs of the system and the desire of the consumer for predictability. Consumers would be nudged towards consuming when it is more beneficial for the system as a whole, thus delivering significant savings.

[44] Default pricing structures may also differ between Member States. In some Member States the customer can chose the type of contract, including the supplier of last resort. Hence, where consumer choice exists, a fully fixed tariff contract should not be the default contract.
[45] The tariff may also consider predefined higher prices during a few days per year, in order to help manage system stress.

Overall, for less active customers who invest limited effort in adjusting consumption, a ‘system friendly’ default tariff could combine:

- Some predictability of the tariff into the future, providing certainty; and
- Some time-variation of the tariff, triggering demand-side response.

Finally, there is significant variation in the frequency of energy bills across the EU ranging from every two months to once a year. Suppliers and national regulatory authorities could encourage consumers to establish a monthly payment plan to manage their energy expenditure. This would reduce the impact of energy price volatility, e.g. in the winter heating period by spreading annual cost via a monthly payment. While such payment plans would not have prevented consumers being impacted following the wholesale price increases in 2021, they could cushion some of the price volatility for the consumer going forward.

7.2.2. Lessons learned from resorting to the Supplier of Last Resort

Numerous supplier exits over the past months have put the mechanism of Supplier of Last Resort to a considerable ‘stress test’. It is thus appropriate to draw some initial lessons.

With the rise in energy prices, some suppliers refused to become the Supplier of Last Resort, thereby also refusing additional customers, arguing that this would represent too big a challenge in current market circumstances. In other instances, the appointed Supplier of Last Resort in turn went bankrupt, meaning the consumers involved were transferred to yet another such last-resort supplier.

Timing issues are key with regard to the transfer of consumers under this mechanism. In particular, it would seem essential to ensure that the Supplier of Last Resort is responsible for supplying energy (and paying the related grid tariff) from the time the previous supplier exits the market to avoid costs incurred not being unaccounted for vis-à-vis the system operators.

While the Supplier of Last Resort mechanism overall seems to have worked, it did cause an economic burden on many designated last-resort suppliers due to the massive influx of new customers. Some national regulatory authorities report that consumers transferred to such a last-resort supplier faced higher prices than those paid by existing consumers of that supplier. While such increases were perhaps unavoidable in some instances given the wholesale cost increases which the last-resort supplier would need to cover, the strengthening of retail supplier resilience might limit the occurrence and impact of such developments.

Not surprisingly, given the different retail market approaches across the EU, experiences vary from one Member States to another. One particularly difficult phase of supplier exits occurred in the Czech Republic.

Case: Managing the transfer to a Supplier of Last Resort – ERU, the energy regulatory authority of the Czech Republic

In 2021, 16 energy suppliers failed in the Czech Republic resulting in 960,000 customers being transferred to a Supplier of Last Resort. This represented approximately 10% of the total energy consumers, an unprecedented amount for that mechanism. While the transfers overall were successful, some issues were observed during the process.

Customers faced extremely high prices as the supplier of last resort had to procure energy on a prompt basis; also, as the supply of last resort fell on the winter months, the bulk of heating customers' costs were spread across six months as opposed to the usual twelve months as amounts owed for consumption needed to be recouped within the time-limit for last resort supply. As a result, consumers saw an immediate and significant increase (4-5 fold) in their energy costs.

Furthermore, the extremely high and volatile wholesale prices limited the available offers for new customers and delayed the on-boarding of some consumer groups. This further prolonged the period for which consumers were faced with high energy costs.

In response to the sudden supplier market exit and subsequent transfer of consumers, ERU (the energy regulator) is reflecting on the balance between the risks shared by energy suppliers and consumers. For instance, the contract between the supplier and the consumer may give the supplier an undue advantage in changing supply conditions more easily. Another example is considerations as to who should bear the costs of supplier failings, including whether it is reasonable for those consumers losing their supplier to pick up all the costs.

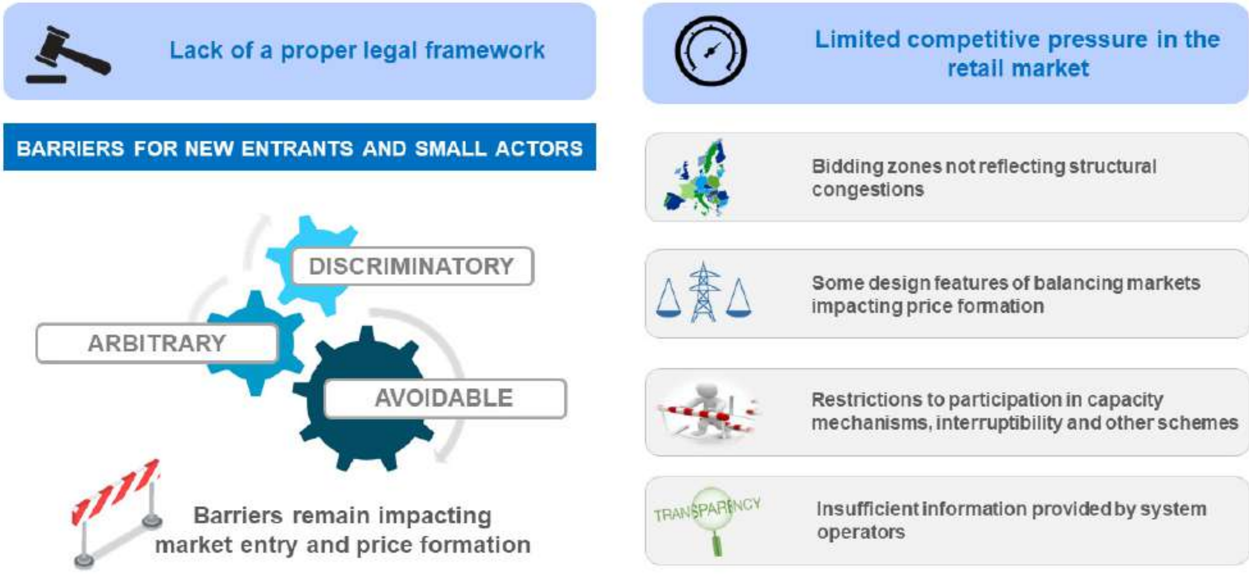
7.3. Pro-actively support demand-side response to help address volatility and solve system needs

The EU's electricity market will face new challenges as it seeks to deliver on Europe's ambitious decarbonisation trajectory. One objective of energy policy and supportive energy markets should be to allow consumers to avoid consuming during periods of higher prices, shifting demand instead to periods of lower prices. This allows consumers to lower their costs, and at the same time reduces overall system costs, facilitating the energy transition.

As further developed in Sections 3 and 4, with new intermittent generation capacity being added, the electricity system will be required to manage higher levels of volatility. Demand-side response should increase to assist energy systems in enabling enhanced renewable penetration. Demand-side response measures are currently in place in many Member States across the EU. However, most existing measures focus on the utilisation of demand-side response in specific circumstances, such as helping to tackle security of supply concerns.

To address this, Member States should consider focusing on the removal of barriers currently preventing the uptake of demand-side response. The most recent ACER-CEER Electricity Wholesale Market Monitoring Report provides an extensive overview of barriers to new market entry and small actor participation that are relevant for the further enhancement of demand-side response[46]. While barriers vary across Member States, barriers that limit retail competition, market entry and price formation are stifling the opportunities that demand-side response can provide to the power system and consumers. The removal of barriers is required to ensure the kick-starting of demand-side response products and services.

Figure 37: Overview of barriers possibly impeding demand-side response products and services



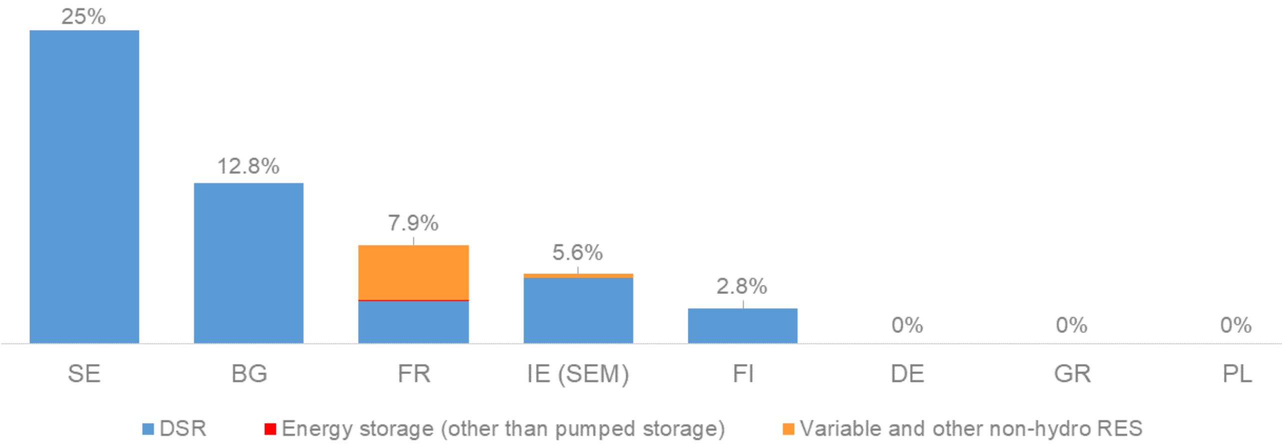
Source: ACER-CEER Electricity Wholesale Market Monitoring Report 2020.

By way of example, ACER identified that even though some national capacity mechanisms are theoretically open to demand-side response, certain requirements effectively hinder their entry and participation[47]. Figure 38 below shows the degree of demand-side response, energy storage and renewables remunerated through capacity mechanisms in 2020[48]. As can be seen, limited demand-side response is being awarded, showing scope for improvement in the coming years.

> ***"The removal of barriers is required to ensure the kick-starting of demand-side response products and services."***

[46] See Section 7 of the Electricity Wholesale Market Volume of the ACER-CEER Market Monitoring Report for the year 2020 (or '2020 MMR').
[47] See page 98 of the Electricity Wholesale Market Volume of the ACER-CEER Market Monitoring Report for the year 2020 (or '2020 MMR').
[48] See page 99 of the Electricity Wholesale Market Volume of the ACER-CEER Market Monitoring Report for the year 2020 (or '2020 MMR').

Figure 38: **Capacity of demand-side response, RES generation, and energy storage remunerated through capacity mechanisms in Member States**



Source: ACER-CEER Wholesale Electricity Market Monitoring Report 2020.

Lessons from certain jurisdictions outside Europe could prove instructive. As an example, the Australian demand-side response model provides an opportunity for large energy users to earn revenues while reducing their consumption during periods of peak demand, thus delivering a service to the electricity system.

Case: Demand-side response – Australia

Australia approved a wholesale demand-side response mechanism in June 2020, opening up the demand response market to consumers and aggregators as of October 2021. The focus is mainly on large customers (such as industry) capable of curtailing demand.

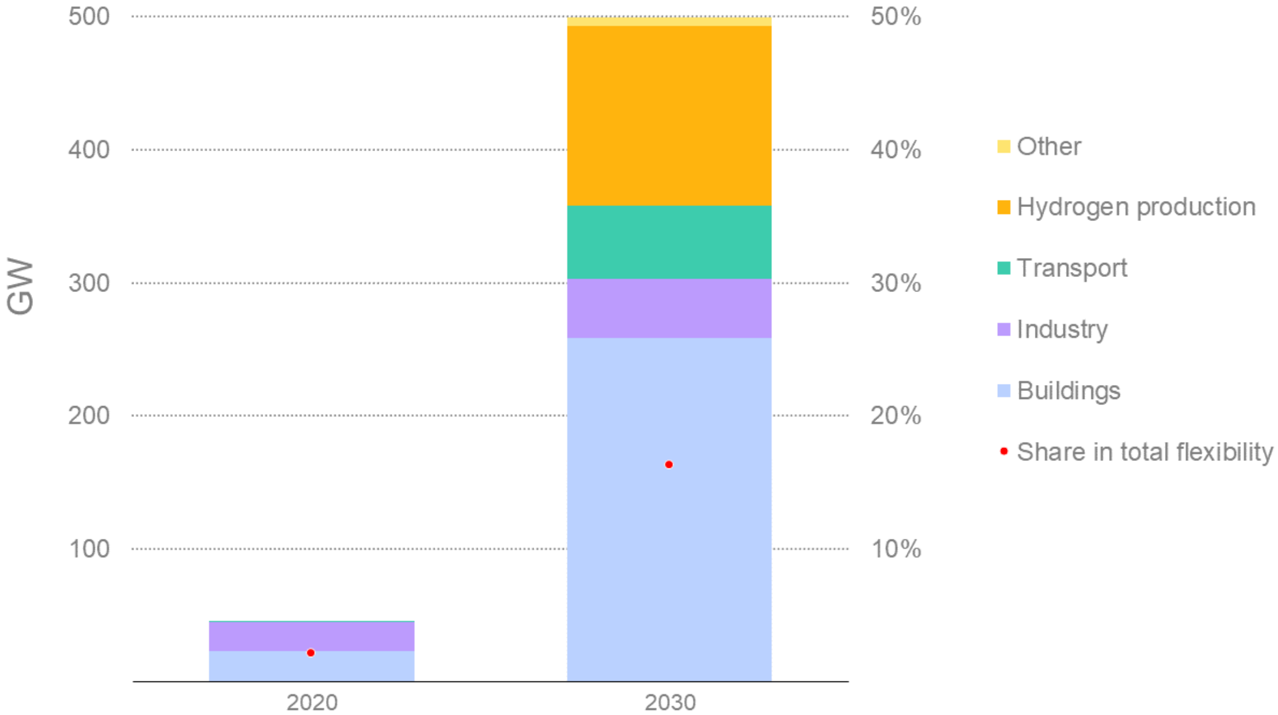
The wholesale demand-side response mechanism allows consumers to bid their willingness to consume electricity at different prices into the wholesale market, thus reducing dispatch costs. The mechanism requires consumer loads to be controllable for the purposes of scheduling and predictable for the purposes of baselines.

For small customers, a number of opportunities emerge under the current arrangements. However, it was decided that extending this mechanism to small customers would significantly increase complexity (and thus cost and implementation time) of the mechanism, while providing limited additional benefits at this stage.

It is no coincidence that the Australian model focuses on large consumers. As previously identified by the IEA, industrial and large commercial customers today represent the majority of demand-side response capacity available for use[49]. Figure 39 shows the potential opportunities for demand side response as identified by the IEA.

[49] See the IEA 'World Energy Outlook 2018'.

Figure 39: Worldwide potential for demand-side response



Source: IEA[50].

While smaller consumers should be permitted to participate in demand-side response, the larger potential in the near- to medium-term is likely to remain with the bigger energy usage segments (industry, buildings, and increasingly transportation, including aggregators of such segments). Given the limited roll-out of smart metering for smaller electricity consumers in some Member States, it may well be more appropriate for the purpose of facilitating demand-side response at scale to focus on larger energy consumers initially.

The increased electrification e.g. of transport and heating needs will further change the electricity demand curve in the future. The impacts of such changes are likely to be managed both by policies and by behavioural shifts. Businesses and households should be incentivised e.g. to avoid charging electric vehicles during peak demand periods to reduce peak loads, network congestion and the requirement for network reinforcement. The implementation of time-differentiated distribution network tariffs can be an important tool in this regard.

At present, average EU electricity consumption is 3,500KWh per household per year. In contrast, where electrification of heat and transport is more widespread (e.g. in some Nordic countries), average domestic consumption is close to 16,000KWh per annum. While at present, there may be limited opportunities for the household consumer to participate in demand response, in the future the potential benefits for consumers in reducing costs will likely be substantially higher. Tariffs can play a role in this as discussed above.

[50] A significant majority of the buildings-related potential comes from space heating, water heating or cooling (see 'IEA Demand Response Tracking Report' (November 2021).

8. Conclusions

This ACER assessment examines the benefits and drawbacks of the current EU electricity market design. It seeks to determine whether the current market design is fit-for-purpose in order to deliver on the EU's ambitious decarbonisation trajectory over the next 10-15 years.

Overall, ACER finds that whilst the current market design is worth keeping, some longer-term improvements are likely to prove key in order for the framework to deliver on this decarbonisation trajectory, and to do so at lower cost whilst ensuring security of supply.

As such, the assessment identifies several areas where policy makers could put further emphasis to ensure the EU wholesale electricity market design is fit for purpose. These areas fall under 6 broad headings, covering a combined total of 13 measures, each having various advantages and drawbacks. An overview of these measures is captured in the following table.

Table 1: ACER's assessment of the key challenges, measures for policy makers to consider and their respective advantages and drawbacks

Challenge	Measures to consider	Advantages and drawbacks
Making short-term electricity markets work better everywhere		
Currently, only a share of the potential benefits of EU electricity market integration are realised	 **1. Speed up electricity market integration, implementing what is already agreed:** National regulatory authorities and Member States should implement what is already agreed, focusing in particular on four areas: i) meet the 'minimum 70% target' (for enhancing electricity trade between Member States) by 2025; ii) roll out flow-based market coupling in the Core and Nordic regions as soon as possible; iii) finalise the integration of national balancing markets; iv) review the current EU bidding zones to improve locational market price signals, leading to a decision in 2023. See Section 3.3.	+ The listed measures contribute to mitigate price volatility, enable efficient cross-border trade and enhance security of supply. - Meeting the 70% target (action i) is a pre-condition to unlock most of the benefits underlying actions ii and iii. Currently, uncoordinated approaches and varying degrees of commitment to meet the 70% target exist.
Driving the energy transition through efficient long-term markets		
Trigger massive investments in low-carbon generation	 **2. Improve access to renewable Power Purchase Agreements (PPAs):** Member States should improve access to PPAs provided commercially in the market, e.g. through public guarantees or pooling smaller sellers and buyers. See Section 4.4.1.	+ Reduces costs for smaller renewable developers by making it easier to secure funding. Access to long-term contracts helps smaller developers manage their risks. + A public guarantee covers the counter-party risk, thereby reducing the risk premium covered by market participants. + Moves more renewables away from (costlier) support mechanism and towards commercially-driven PPAs. + The long-term contract hedges consumers against future price volatility. - Managing smaller actors with access to PPAs increases complexity and raises need for coordination. - Public guarantees do not solve the risk that some actors might default on the PPA requirements.

Challenge	Measures to consider	Advantages and drawbacks
How to get best value for money when driving investments	**3. Improve the efficiency of renewable investment support schemes:** Member States should decide whether and how to support particular technologies. Member States should review and, where relevant, update the support scheme(s) in place per their broader objectives. Prioritising build-out of new generation at scale and at speed, whilst prioritising a revenue ceiling for generators, may well point to 'Contracts for Difference'-type schemes. On the other hand, if most efficient integration of new low-carbon capacity is the priority, opting for capacity-oriented schemes may be more appropriate. See Section 4.4.2.	+ Centrally-steered support speeds up investment, whereas market-led investments drive efficiency and competition between technologies. + Hedges against some price volatility. - Risk that certain contracts, e.g. based on fixed remuneration for the energy produced, unduly limit exposure to market prices, negatively impacting short-term efficiency and demand-side response - Centralised procurement may transfer too much risk to the central entity
Limited liquidity in long-term markets, in particular beyond three years	**4. Stimulate 'market making' to increase liquidity in long-term markets:** Member States, power exchanges and brokers should consider stimulating liquidity through 'market-making' in an effort to help independent companies, traders etc. compete with large established firms e.g. via tenders, mandatory measures or (financial) incentives. See Section 4.4.3.	+ Market-making improves electricity market liquidity which in turn attracts more entrants, increases competition and ensures a level-playing field between vertically integrated companies and independent companies. - Market-making can be costly to incentivise.
	5. Better integrate forward markets: The European Commission should consider reviewing the Forward Capacity Allocation regulation with a view to further integrate forward markets, thereby enhancing liquidity in these markets. See Section 4.4.3.	+ More efficient, wider access to hedging. - Heavy implementation and operational efforts (similar to those undertaken for coupling short-term markets).
	6. Review (and potentially reduce, if warranted) collateral requirements: The European Commission should, together with the European Securities and Markets Authority (ESMA), financial regulators, etc. monitor needs for potentially reducing certain collateral requirements for trading in long-term wholesale electricity markets, particularly in times of rapidly increasing requirements. See Sections 4.3. and 4.4.3.	+ Frees up cash flow for the actual trading of electricity. - Increases the risk of being exposed to market participants failing on their obligations. - In extreme situations, possibly aggravates contagion risks.
Increasing the flexibility of the power system		
Need for increased flexibility in the system	**7. Preserve the wholesale price signal and remove barriers to demand resources providing flexibility:** Free, competitive price signals best denote true flexibility needs, and are thus efficient instruments for driving investments in flexibility resources, including those providing seasonal flexibility. Hence, national regulatory authorities and system operators should focus on the rapid removal of barriers to utilising such resources. See Sections 4.1. and 7.3.	+ Eases market integration of intermittent renewable generation and helps deliver on the EU's decarbonisation trajectory. - None.

Protecting consumers against excessive price volatility whilst addressing inevitable trade-offs		
Shield consumers from excessive price volatility	**8. Shield those consumers that need protection the most from price volatility:** Member States and national regulatory authorities should protect vulnerable consumers in times of high prices, where needed, whilst not limiting the ability of e.g. energy communities or aggregators to provide innovative energy services for the benefit of the system and consumers. Furthermore, Member States and national regulatory authorities should ensure that retail suppliers provide consumers with simple and clear information about their retail contract, in particular regarding the risks and benefits related to dynamic contracts. See Sections 7.2.1 and 7.3.1.	+ Protects the consumers most in need. + Enables consumers to take informed decisions. - Broader measures may prove inefficient and result in retail market concentration.
Mitigate the negative impact of retail energy supplier bankruptcies on end consumers	**9. Tackle avoidable supplier bankruptcies, getting the balance right:** Member States and national regulatory authorities should strike a balance between ensuring the financial responsibility of retail energy suppliers, and keeping the market open for new responsible suppliers. See Section 7.2.	+ Retains consumer confidence throughout the energy transition. + Supports responsible supplier behaviour. - Increasing retailers' collateral/hedging responsibilities increases costs, which ultimately are paid by consumers. - Difficult balance to strike, potentially jeopardising retail services innovation.
Tackling non-market barriers and political stumbling blocks		
Need for enhanced coordination and communication	**10. Tackle non-market barriers, ensuring generation and infrastructure is build at pace:** Member States should consider enhanced coordination and an increased focus on cross-border perspectives, as a prerequisite for efficient and accelerated roll-out of low-carbon generation and grid infrastructure, and for supporting security of supply. See Section 4.4.4.	+ Leads to more efficient decisions in the longer-term and faster deployment of projects. - Requires increased investment and greater attention to cross-border perspectives and needs, supplementing national perspectives
Preparing for future high energy prices in 'peace time'; being very prudent towards wholesale market intervention in 'war time'		
Keep bills relatively affordable during periods of sustained high energy prices	**11. Consider prudently the need for market interventions in situations of extreme duress; if pursued, consider tackling 'the root causes':** Member States should accelerate gas demand reduction (efficiency efforts, fuel switching) and deploy efforts that put downward pressure on gas prices (e.g. new supply or cheaper supply coming to Europe, considering the use of the new common Energy Purchase Platform), whilst retaining prices that secure LNG delivery. See Section 5.2.	+ Retains the benefits of current electricity market functioning. + Promotes savings of the fuel source aggravating the current situation. + Tackles the 'root cause' and mitigates potentially negative knock-on effects. - Can be difficult to deploy in a coordinated manner in a short period of time.

	 **12. Consider public intervention to establish hedging instruments against future price shocks:** Taking inspiration from financial options, Member States could consider an intervention whereby predefined consumer groups are hedged against sustained high wholesale prices (above a certain threshold, dubbed ‘affordability options’). See Section 4.5.	+ Hedges vulnerable consumers against sustained high prices arising in the future. + May create cascading needs to hedge (as generators providing the hedging tools would likely need to hedge their own positions), thereby increasing the liquidity of long-term markets. - Hedging comes with a cost for the ones who pay for the option. - It might be difficult to identify sufficient generators that would provide such hedging at moderate cost.
	 **13. Consider a 'temporary relief valve' for the future when wholesale prices rise unusually rapidly to high levels:** Member States could consider establishing ex-ante a temporary price limitation mechanism kicking in automatically under clearly specified conditions (e.g. unusually high electricity price rises in a short period of time), pausing the return to full price formation for a specified period of time (e.g. a few weeks or a month). The measure would need to ensure significant revenue is earned by generators and would retain compensation for generators who can prove sourcing costs above the limitation ceiling. See Section 4.5.	+ Predefined threshold and framework for normal and temporary relief conditions. + Limits the impact of sustained high prices, thus indirectly also setting boundaries for perceived excessive profits. - Risks market exit or requests for financial compensation. - Threshold-setting may prove difficult. - Risks endangering security of supply, if generators who prove sourcing costs above the limitation ceiling are not compensated adequately. - Risks dampening signals for demand-side response.

EU Agency for the Cooperation of Energy Regulators (ACER)

ACER, the EU Agency for the Cooperation of Energy Regulators, contributes to Europe's broader energy objectives, including the transitioning of the energy system at lower cost, by:

- Developing competitive, integrated energy markets across the EU via common rules and approaches, thereby enabling reliable and secure energy supply at lower cost;
- Contributing to efficient trans-European energy infrastructure and networks, enabling energy to move across borders, thus enabling energy choices at lower cost and furthering the integration e.g. of renewables;
- Monitoring the well-functioning and transparency of energy markets, deterring market manipulation and abusive behaviour.

ACER was established in March 2011 and is headquarted in Ljubljana, Slovenia, with a small liaison office in Brussels. Over time, the Agency has received additional tasks and responsibilities relevant for the further integration of the European internal energy market and for monitoring how energy markets are working.

Each energy National Regulatory Authority (NRA) in the EU Member States participates in ACER and is a voting member of the Agency's Board of Regulators. Regulatory oversight is shared between the Agency and NRAs, whilst enforcement is done at national level.

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