Facing the electricity crisis in Europe

Is it time for emergency intervention or a full revamp?

Executive Summary	05
Soaring European electricity prices	06
A crisis driven by fundamentals	12
Options to fix power price inflation	20
How could consumers and utilities react?	30
Appendix	34
Contacts	42

Executive Summary

1.

Russia's invasion of Ukraine has created turmoil in the European policy landscape and energy markets. Supply disruptions of natural gas have led to record-high electricity prices in Europe.

2.

Electricity market pricing rules specify that the marginal unit, i.e., the most expensive power plant needed, sets the price for all others. Incidentally, gas-fired power plants are often the marginal unit. This has led to historically high electricity prices in the first half of 2022 (5–15x higher than in 2021). As a result, infra-marginal power plants (e.g., renewables, coal, or nuclear) have been making record profits while high electricity prices have been fuelling inflation in most sectors of the economy.

3.

Our analysis indicated that electricity markets did not malfunction during this time, as prices remained aligned with market fundamentals. The predicament is, first and foremost, a natural gas crisis that spread to power markets due to the electricity sector's high reliance on gas-fired generation. This dependency has been reinforced by the plant and infrastructure investments made in the last two decades and is unlikely to be remedied in the short term.

4.

The effects of these market developments on end-users, utilities, and retailers are not only unprecedented but also deemed unsustainable. Policymakers and regulatory bodies throughout the European Union (EU) have started to act, each proposing its own set of market interventions to alleviate the situation. Moreover, core EU market design principles are being fundamentally questioned and reforms are back on the agenda at regional level.

5.

One solution would be to reduce both natural gas and power demand to mitigate supply-side tensions. Saving as much natural gas as possible could help to avoid any scarcity during the winter months, and substantially reduce public and private crisis spending. Although power demand is notoriously insensitive to prices, many opportunities to save energy exist and should be a priority for policymakers.

6.

In addition, several mechanisms could be deployed to soften the impact of the crisis on residential and industrial electricity bills. Yet, market intervention should be limited as much as possible, at the risk of creating additional uncertainty and inefficiencies. A set of measures to redistribute excess profits from energy companies might be one way to soften the price shock. Since such actions risk diluting price signals, they should all be backed up by demand-reduction measures and investment incentives.

7.

Short-term measures carry a risk: they often focus on mitigating the consequences of the crisis, rather than on tackling the root causes of the problem. Decades of delayed investments in new clean energy sources or grid reinforcements have worsened the current crisis. Governments should, therefore, make sure that crisis response measures accelerate the energy transition, reduce European energy and raw material dependencies, and improve energy security for national economies. To this end, expanding renewable energy sources should remain a top priority in order to secure the region’s future, and the current situation should not undermine Europe’s determination to reach its long-term climate objectives.

Soaring European electricity prices

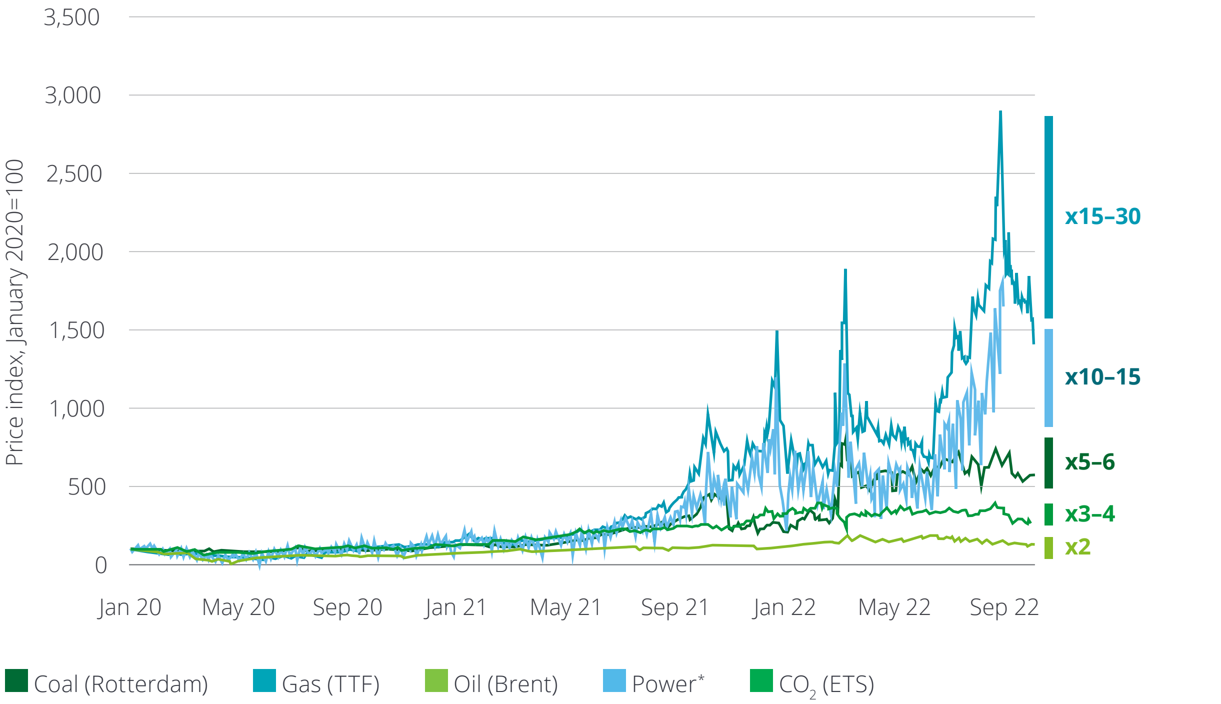
A sharp increase in energy prices
The energy sector has been navigating through intense turmoil over the past two years. The strict COVID-19 lockdowns of 2020 sharply reduced energy demand, causing energy prices to drop. The post-COVID-19 economic rebound increased energy demand amid supply shortages, resulting in energy price hikes even prior to Russia's invasion of Ukraine. Subsequently, Russia's deliberate disruption of natural gas supplies to Europe worsened the pre-existing commodity market tightness. Figure 1 provides an overview of key energy price indicators from 2020 to 2022. Even though Brent oil prices nearly doubled from $68/bbl in January 2020 to a peak of $133/bbl in September 2022, this is far from the price hikes incurred by natural gas. Indeed, the TTF index increased 30X during the same time period, spiking from €12/MWh in January 2020 to more than €350/MWh at its peak.

Wholesale power prices caught in the tidal wave
Power prices have followed a similar pattern as underlying energy commodity prices (Figure 2). Day-ahead prices have grown more than five-fold to over €230/MWh on average in 2022 compared to €40/MWh on average during the 2015-2019 period. The picture is even more striking on a granular time scale, with day-ahead prices exceeding €490/MWh on average in Europe in half of the days in September 2022. Price swings have also increased in magnitude, with average daily price deviations reaching €200/MWh in 2022 compared to about €25/MWh in 201–2020.

However, a period of sustained high prices and large price swings should not necessarily be interpreted as a sign of market failure. Despite price swings increasing in magnitude, daily price volatility has remained stable relative to the scale of prices themselves. While the standard deviation of prices skyrocketed to €200/MWh in September 2022, the relative standard deviation[1] oscillated around 0.385 in 2022, close to its average value in 2015–2022. This indicates that price swings have grown in proportion to prices, which is a sign that inflated market prices have not distorted the fundamentals of the day-ahead market. Importantly, proper functioning of the day-ahead market does not preclude failure in other electricity markets, such as the forward or balancing markets.

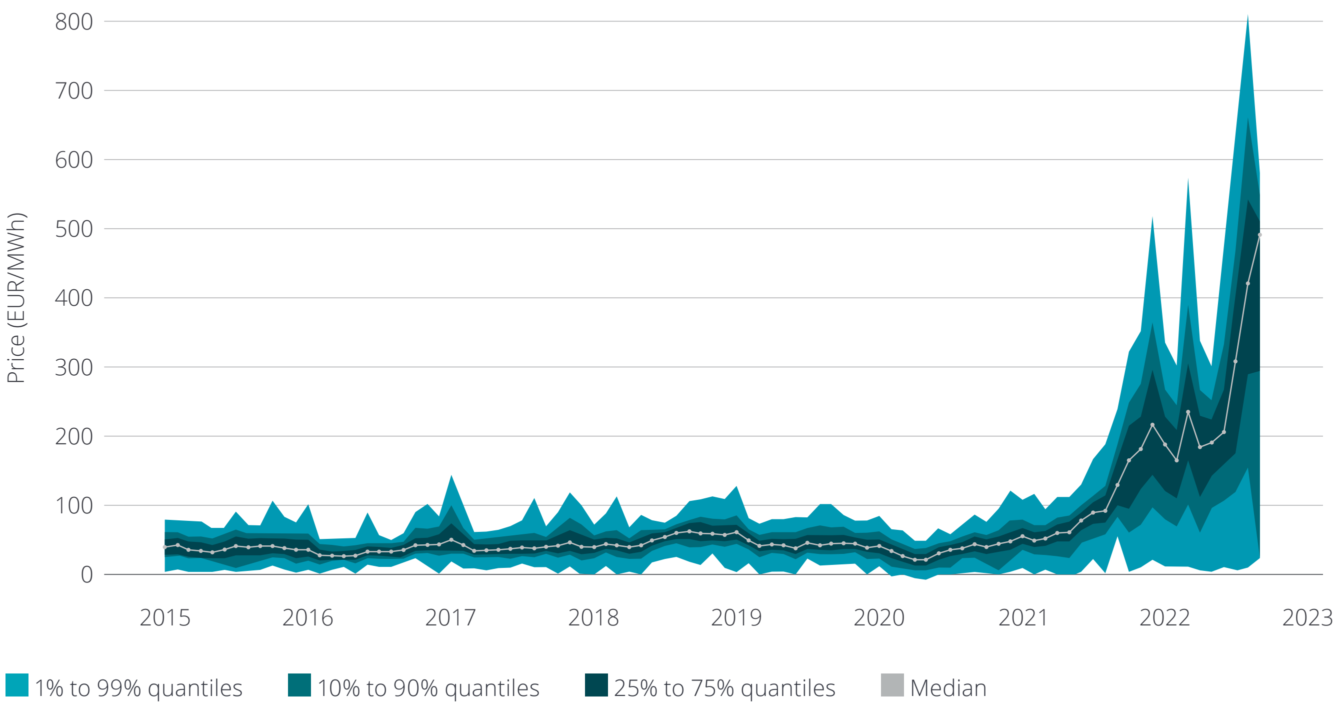
[1] The relative standard deviation is the standard deviation divided by the mean. It is a measure of statistical deviation relative to the average value of the sample. It allows dispersion to be assessed when significant changes in levels come into play.

Fig. 1 – Evolution of the main energy price indicators in Europe, base 100 in January 2020



* Power prices are calculated as the hourly average in the day-ahead prices across continental EU-27 + Norway, Serbia and Switzerland
Source: Deloitte, based on CapitalIQ and Ember

Fig. 2 – Distribution of average monthly day-ahead electricity prices in the EU* since 2015



* Day-ahead prices across continental EU-27 + Norway, Serbia and Switzerland
Source: Deloitte analysis, based on power price data from Ember

No electricity market is spared

To understand what is at stake, it is essential to first align on where the crisis is unfolding. Indeed, there is not a single power market in Europe, but a succession of markets until the electricity is physically delivered. Those markets differ in liquidity and temporality, and in the shares of transactions occurring on central platforms or over the counter (OTC).[2] Hence, electricity markets are unequally affected by the ongoing crisis.

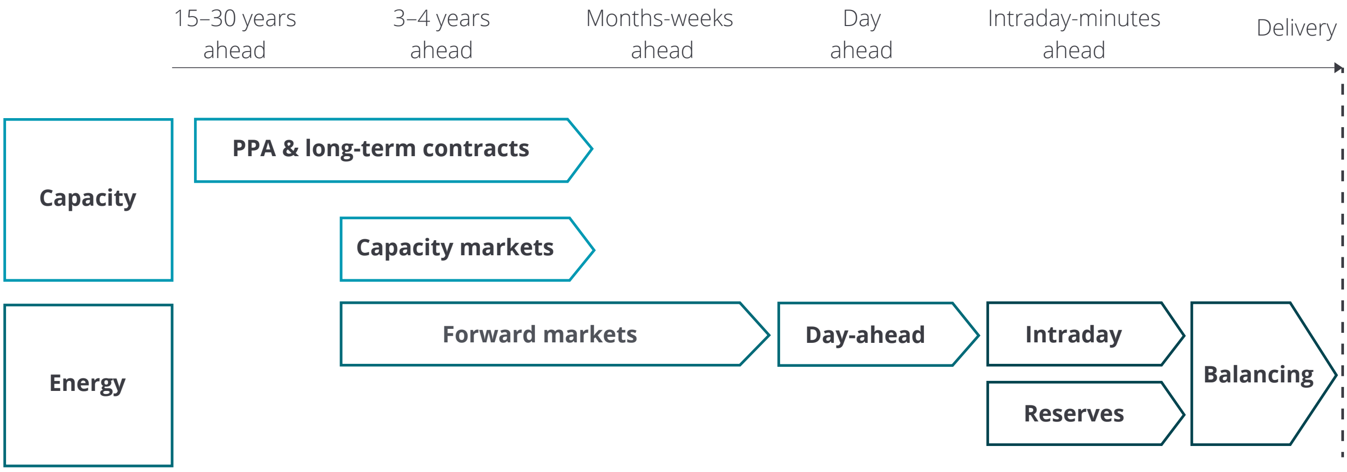
An overview of the sequence of power markets is given in Figure 3. Typically, long-term markets consist of capacity markets and power purchase agreements (PPAs) with renewable producers. These markets allow for securing capacity years ahead of physical delivery, and therefore are less exposed to the current crisis than other markets. They are also a relatively new type of market, and as such, they are not developed in every European country. Through forward markets, buyers can secure power prices anywhere from a few years to months or weeks ahead. Getting even closer to the physical delivery of electricity, buyers can turn to short-term markets that operate a day to a few minutes ahead of the actual need. The day-ahead and intraday markets are also referred to as the "spot market."

Our analysis focuses on forward and day-ahead markets, which are usually what is meant when someone speaks of "the electricity markets." Those two markets make up most of Europe's wholesale electricity trade.

Forward and balancing markets show similar price patterns to the day-ahead market, with even higher prices reached in the French market for peak-hour futures (Figure 4). With values higher than €1,000/MWh being reached, these prices likely reflected fears of rolling outages. These fears reciprocally influenced the day-ahead market, where some notable outliers such as the French power price peak of 3 and 4 April 2022, even exceeded the threshold for triggering an automatic increase in the maximum market price as specified in EU regulation.[3] Currently, the price of electricity during outages is capped at €4,000/MWh.

Baseload prices and upward balancing markets show a strong correlation, above 0.9, as they both reflect the cost of matching electricity supply and demand. Balancing prices tend to run slightly above since they rely on the most flexible units, which are usually the least cost-efficient, and thus are not used for baseload power generation.

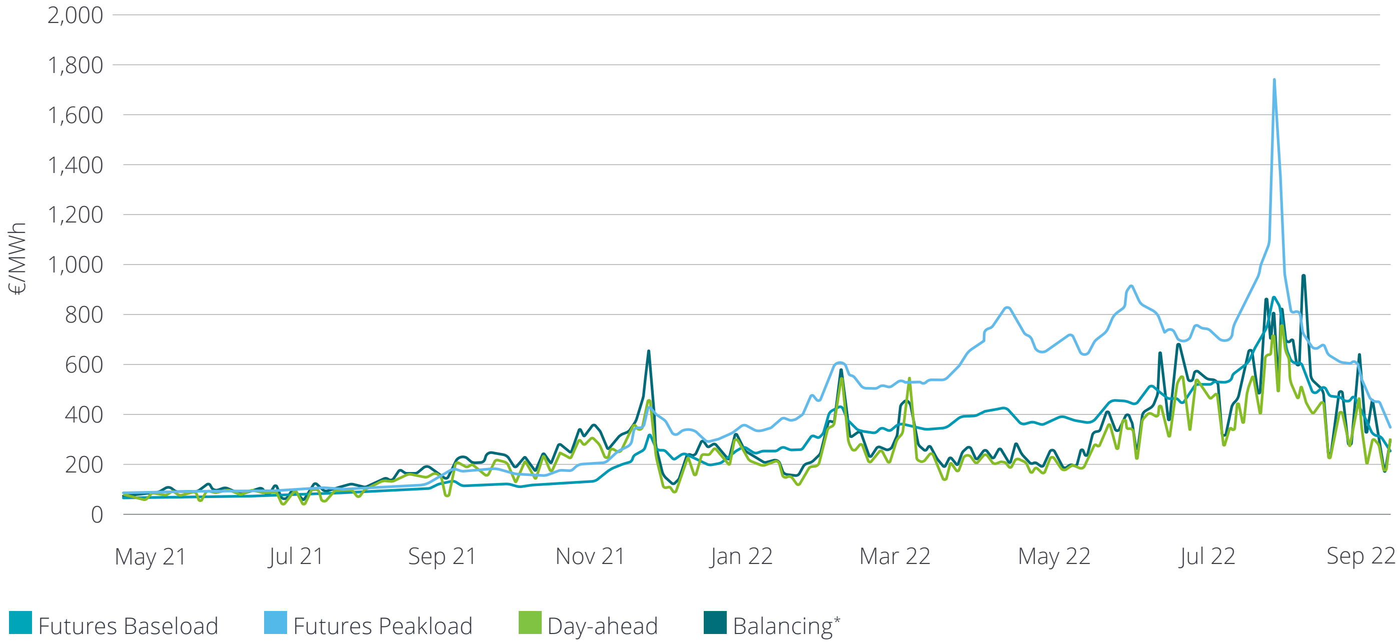
Fig. 3 – Sequential power markets in Europe



Source: Deloitte illustration

[2] Over-the-counter trading takes place outside of centralised power exchanges, either by direct contact or through a broker
[3] Harmonised Maximum and Minimum Clearing Price methodology. This rule, which raises the maximum market prices by 1000 euros every time actual market prices exceed 60% of the maximum, will likely be updated soon.

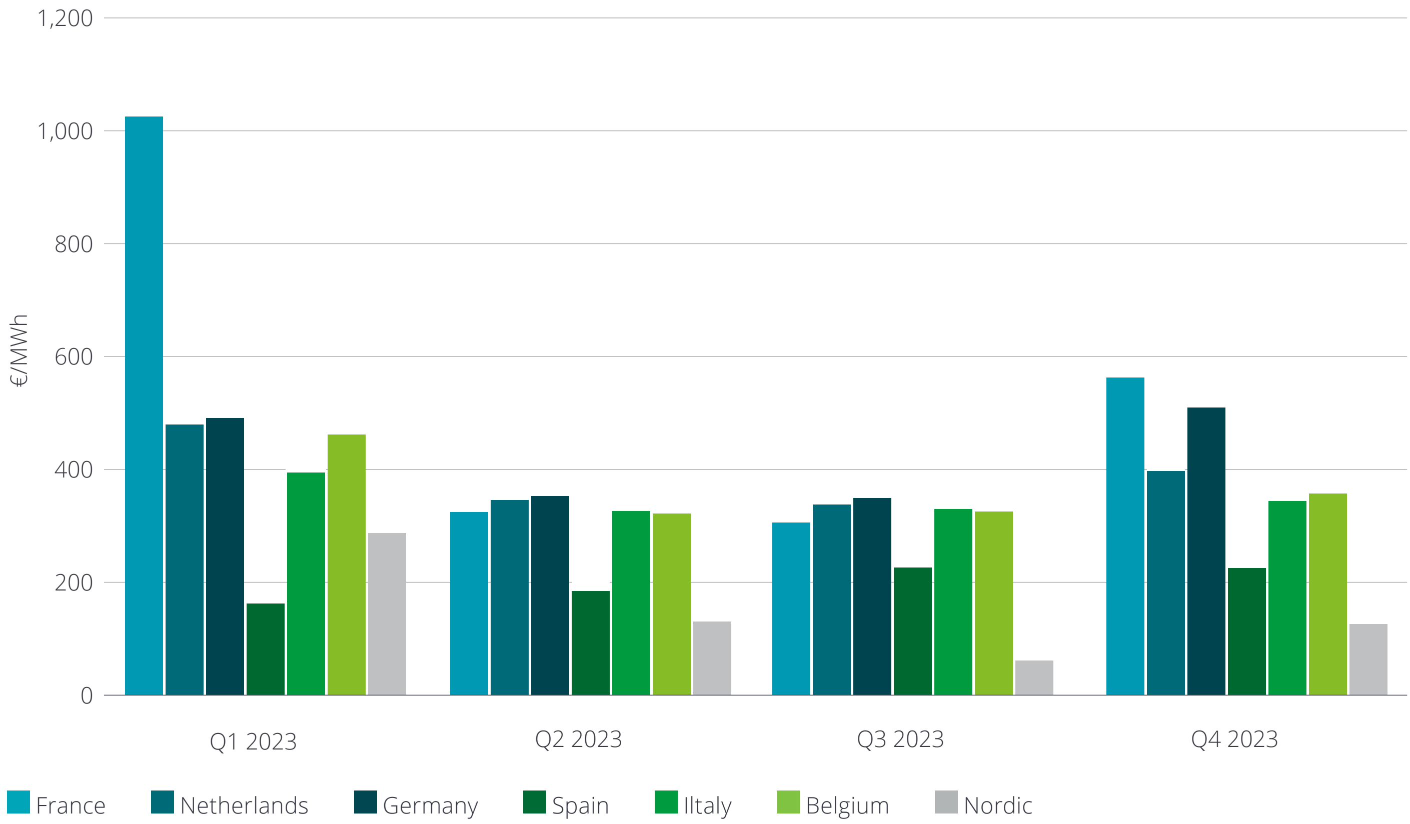
Fig. 4 – Evolution of French power futures, day-ahead and balancing prices



* Balancing refers here to the price of activated mFRR upward reserves
Source: Deloitte analysis, based on power prices from ICE, Ember and Entso-e

Futures prices, which are at record-high levels, reflect the price for the next year, either due to looming tensions on power generation capacity or due to the future prices of natural gas (Figure 5). As such, electricity bills are expected to remain high in the coming months and years, even if short-term measures are taken, since much of the electricity is being procured now. However, the total impact of high forward prices on consumers' electricity bills will ultimately depend on the hedging strategies of the utilities involved.

Fig. 5 – Forward baseload prices for 2023 in a selection of European countries



Source: Deloitte, based on EEX data as of 14/10/2022

Our analysis depicts a situation where both spot and forward markets face a crisis, with prices averaging 10 times higher than in previous years. So far, there has been no sign of market failure in the day-ahead market, but we cannot exclude the possibility of failure in other electricity markets. Part of the danger lies in the delayed impact of high forward prices on electricity bills in the years to come.

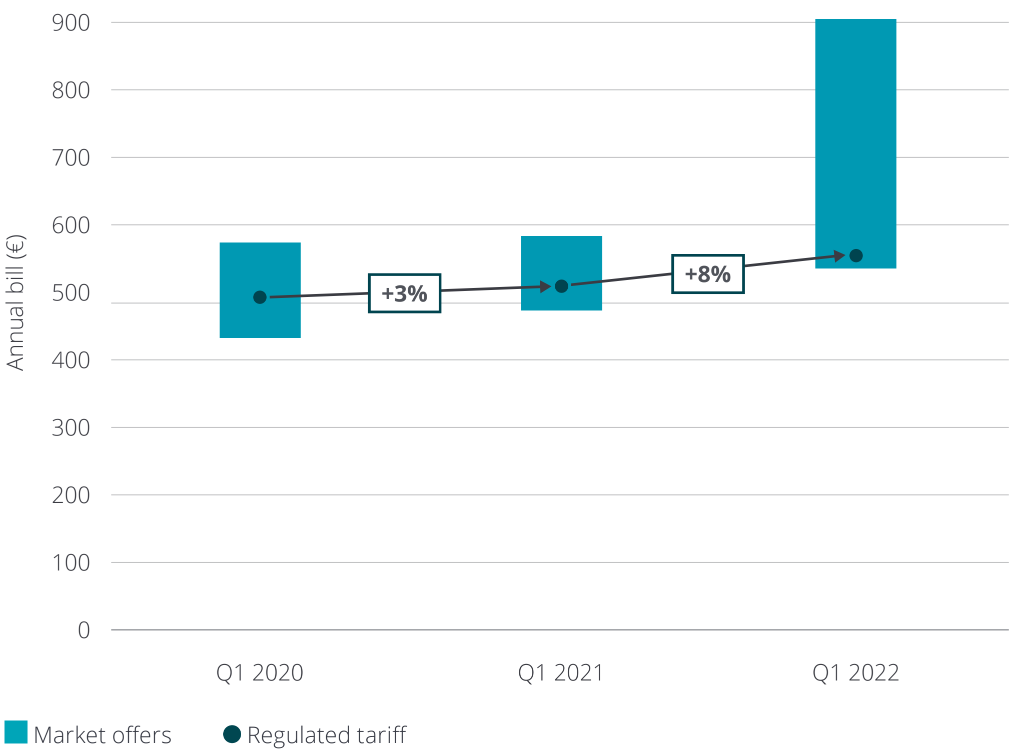
Propagation to retail prices

The correlation between natural gas and electricity prices has prompted major regulatory intervention, as affordable electricity prices are vital for healthy economic activity and citizen well-being. Natural gas represents around 40% of total final energy consumption in the EU The price of gas, whether consumed directly for residential or industrial purposes or indirectly to produce electricity, accounts for about 60% of the energy bill paid by residential and industrial customers in Europe.

This is the main reason behind the call to reform EU electricity market rules. The pay-as-clear system by which natural gas determines the price of electricity has aggravated the burden of the energy crisis on consumers beyond the direct impact of consuming natural gas as a final product. Electricity consumers would pay less under a system in which the price of natural gas had weaker influence on the price of electricity.

In the short-term, it is paramount to reduce inflationary pressures on the power markets through a mechanism as illustrated in Figure 6, whereby increases in wholesale prices are passed through to end-consumers somewhat but not to the full extent.

Fig. 6 – Evolution of retail prices offered to "base" consumers in France between Q1 2020 and Q1 2022



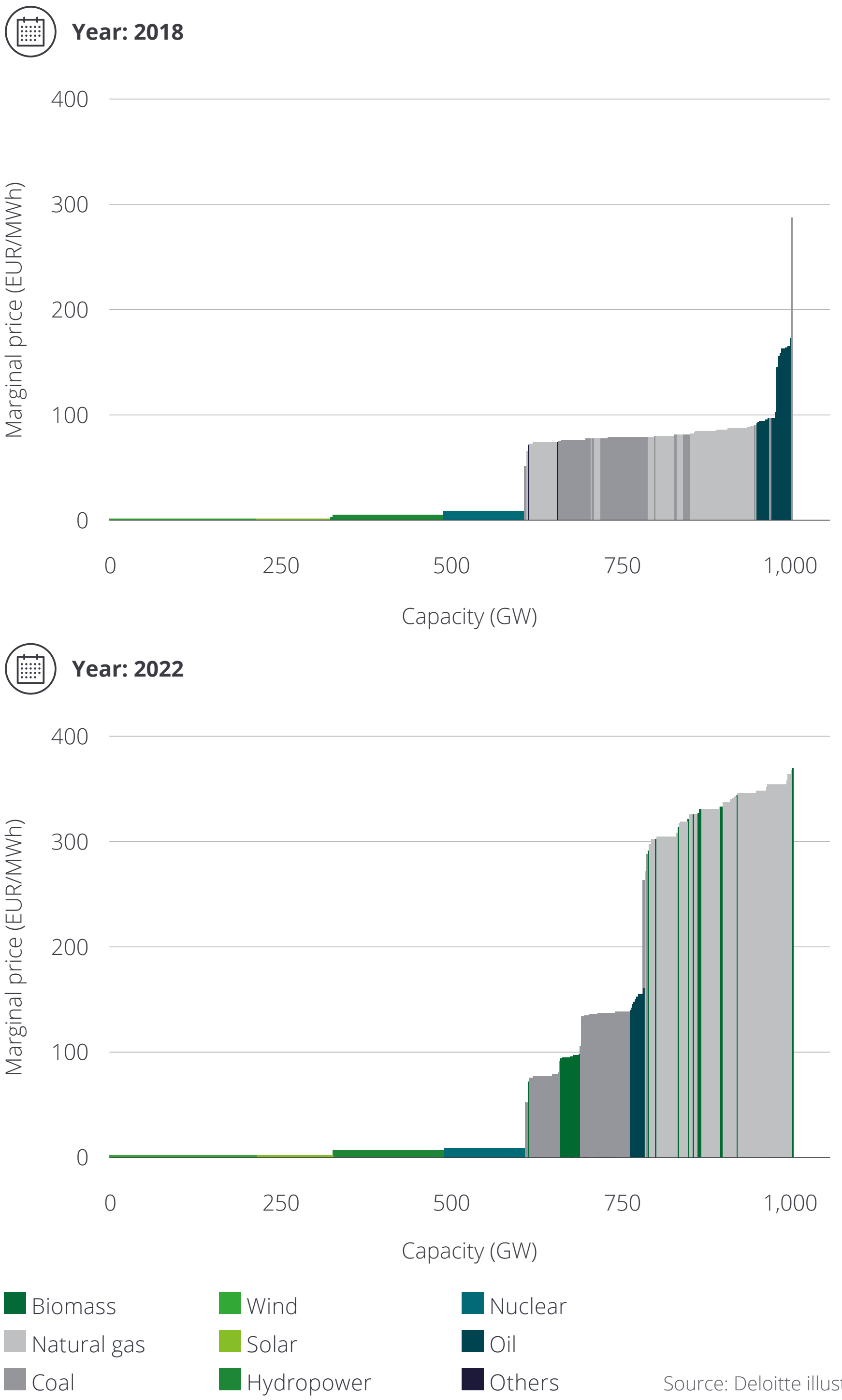
Source: CRE

A crisis driven by fundamentals

Natural gas as the main driver
Electricity prices are set at the intersection of the demand and the supply curves or "merit order," , which is determined by ranking electricity generation units by their variable cost of production (Appendix, Figure 23). An analysis of the merit order in the EU from 2018–2022 reveals to what extent it has been altered by global commodity prices (Figure 7). In a given day, prices can be low when the price-setting unit is a renewable or nuclear facility, higher when it is a coal plant, and much higher when gas-fired generation is involved. The distribution depicted in Figure 3 is, therefore, perfectly aligned with the current merit order.

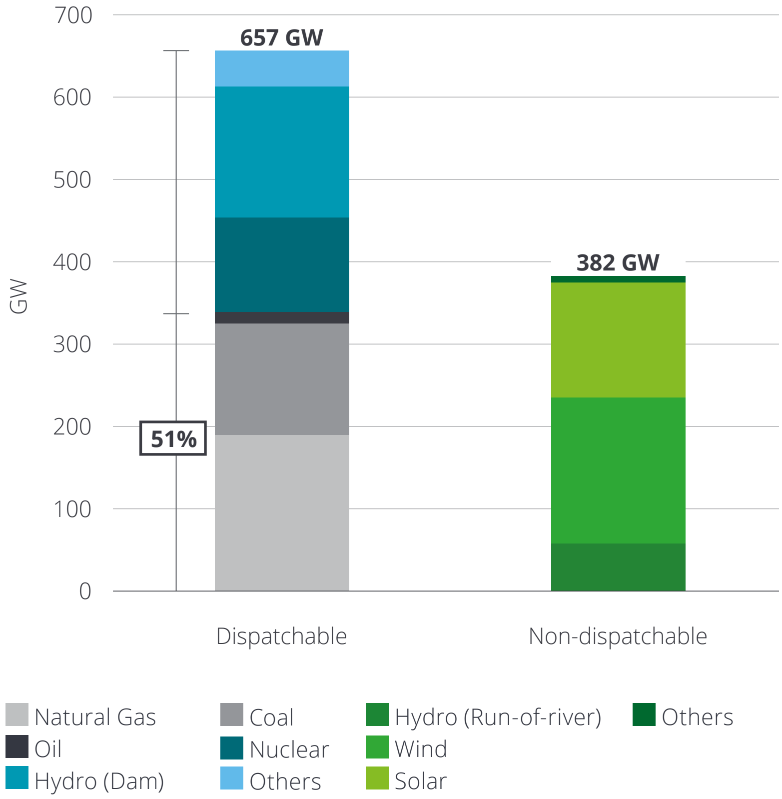
Natural gas and hard coal prices strongly influence electricity prices, as gas and coal power plants still account for a third of installed power capacity in the EU (Figure 8). Since wind and solar PV farms do not yet have sufficient flexibility and total operational capacity, they are rarely the price-setter in the day-ahead or forward power markets. Instead, electricity prices are mostly set by dispatchable units such as hydro, nuclear, and fossil-fuel power plants. The latter (i.e., oil, natural gas, and coal) comprise about 50% of dispatchable capacity. Thus, nearly half of all price-setting units are directly exposed to global commodity market fluctuations. This exposure is exacerbated by the fact that most European nations rely on fossil-fuel imports to cover their demand.

Fig. 7 – Distortions of the European merit order due to current energy commodity prices



Source: Deloitte illustration

Fig. 8 – Installed power generation capacity in Europe in 2021



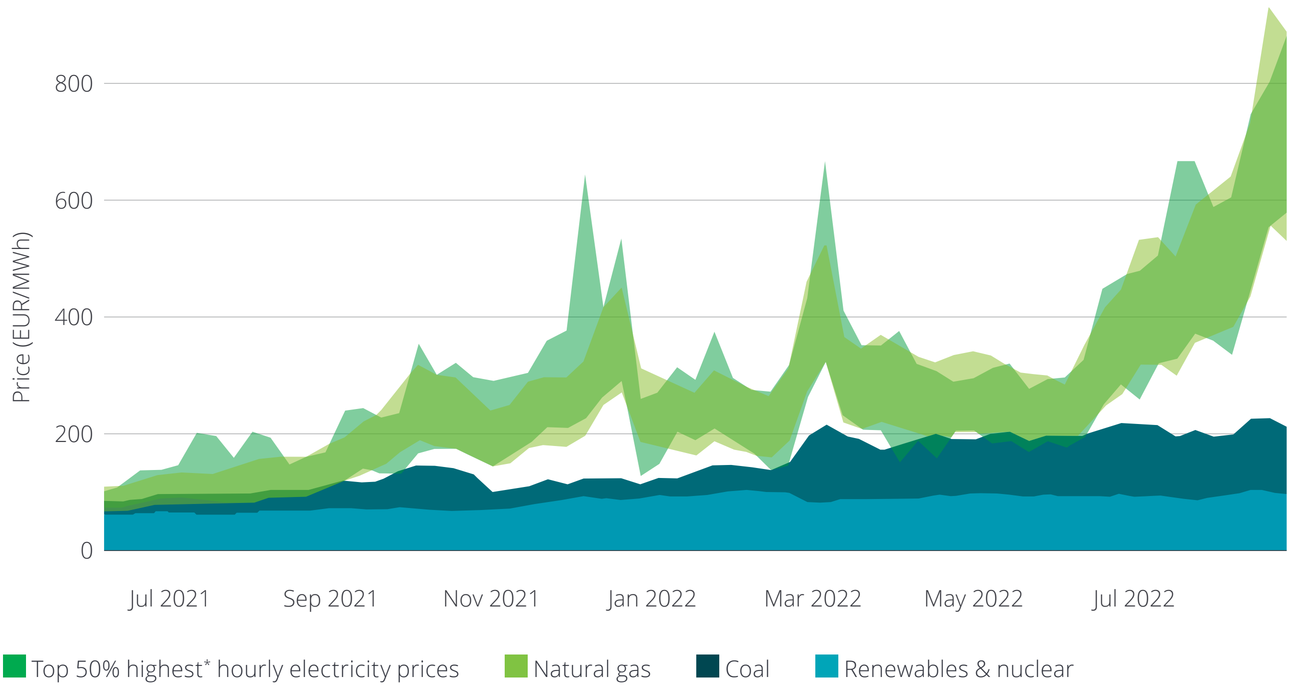
Source: Deloitte analysis, based on energy-charts.info

European countries still rely heavily on fossil fuels for power generation, accounting for 50% of dispatchable. New gas-fired power plants have—to a large degree—offset the closure of oil, coal, and nuclear plants, increasing Europe's exposure to global gas markets and especially to Russian supplies.

Gas power plants have consistently been the price-setter when electricity prices are high, as shown by the overlap in the gas and top-electricity-price ribbons in Figure 9. Coal and gas power plants shared peak load price-setting before the crisis, but despite CO_2 prices rising to €100/tCO_2, gas-fired generation has been more expensive than coal-fired generation since autumn 2021. A decrease in the price of natural gas would therefore immediately reduce day-ahead prices.

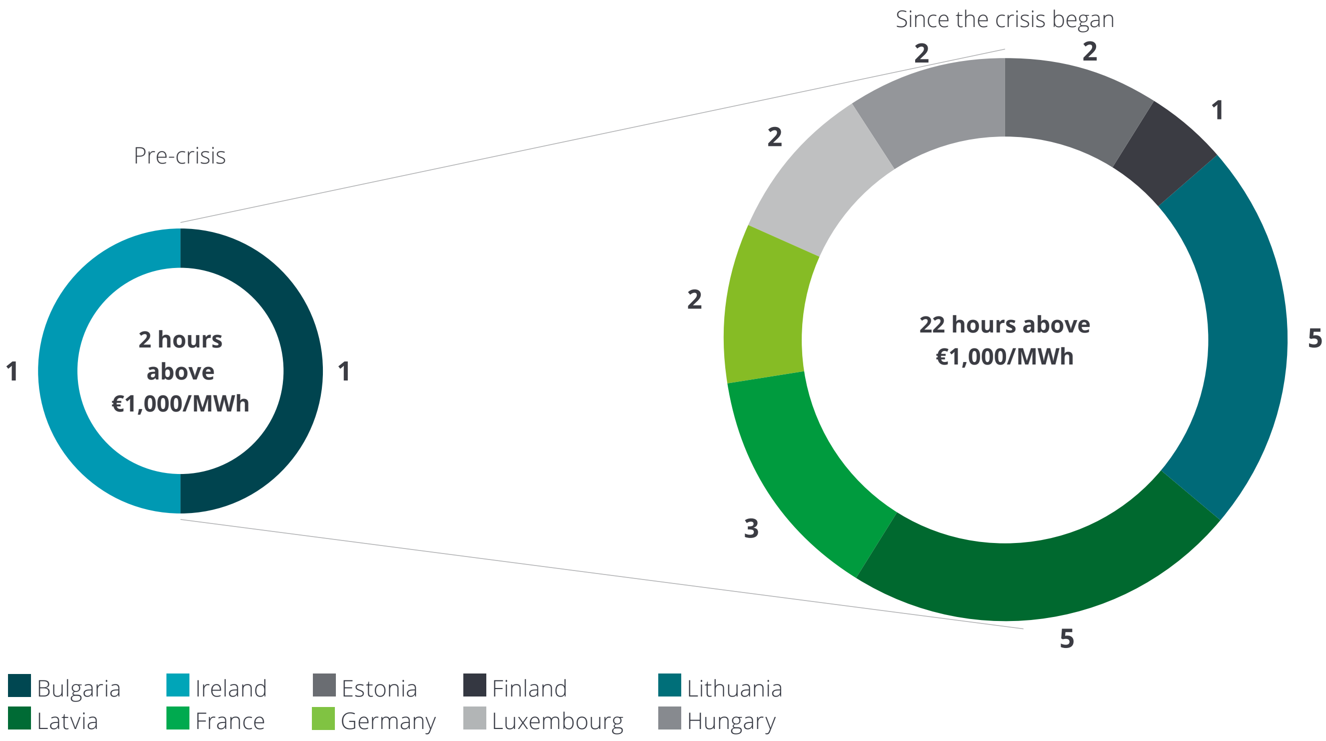
Despite prices rising beyond previously unseen levels in the past year, the number of hours with extreme prices remains within the acceptable range of proper market functioning. Notably, Estonia, Latvia, and Lithuania hit the day-ahead market price cap of €4,000/MWh on 17 August 2022. French day-ahead market prices also reached almost €3,000/MWh on 4 April 2022. In total, there have been 22 instances of day-ahead prices exceeding €1,000/MWh since July 2021, and only two instances from 2015 through June 2021 (Figure 10). However, from a national perspective, there have been less than five hours of scarcity per country per year, a statistic that remains close to the objective of system operators. These indicators point to the market functioning as intended, where scarcity prices due to tight natural gas supplies have been limited, even if unusually high.

Fig. 9 – Top 50% highest* hourly wholesale day-ahead electricity prices in Europe since June 2021 against the estimated marginal costs of gas and coal power plants



*The top 1% of observations have been dropped from the ribbon in order to avoid having scarcity prices (i.e., when demand exceeds supply). In practice, doing this removes 22 hours of scarcity pricing above €1,000/MWh since 1 June 2021.
Source: Deloitte analysis

Fig. 10 – Scarcity hours by country and period in Europe since 2015



Source: Deloitte analysis, baseWd on power prices from ICE, Ember and Entso-e.

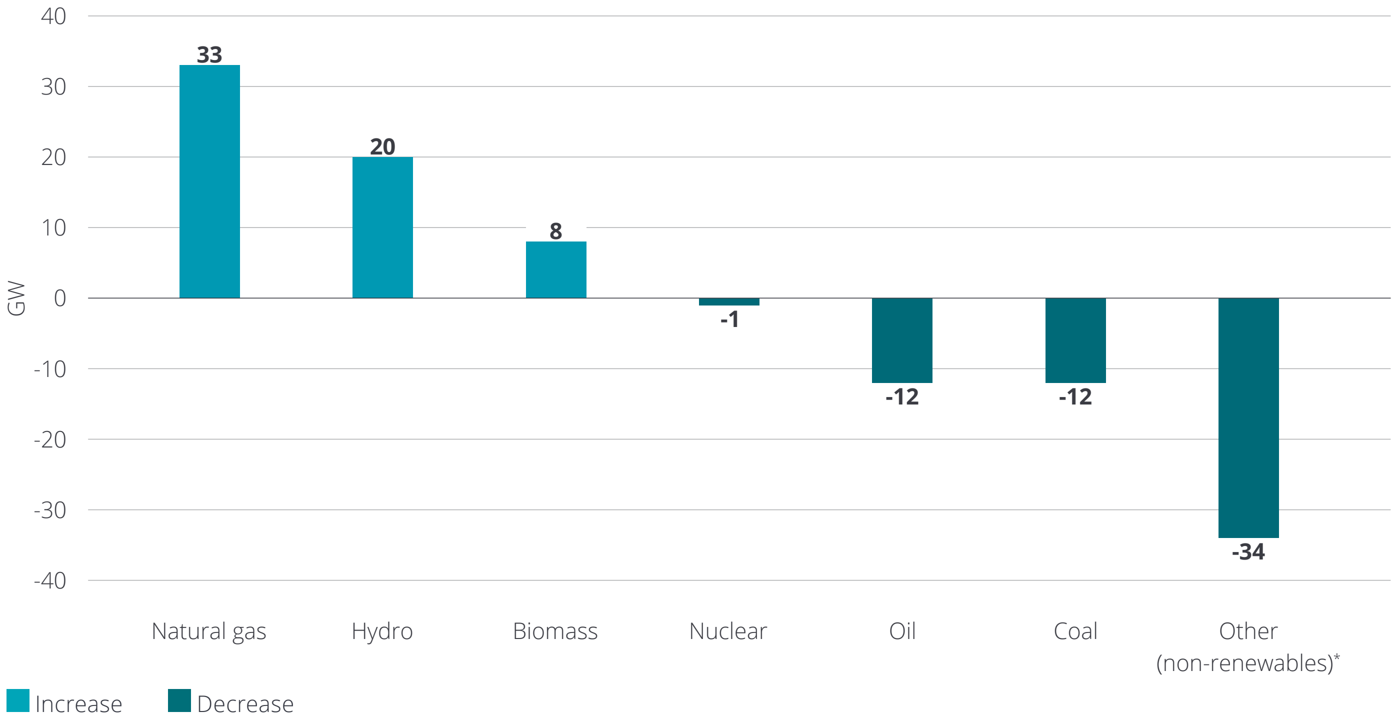
Power markets have consistently delivered prices in accordance with current price-formation mechanisms. Soaring power prices are first and foremost related to the natural gas crisis. A decrease in the price of natural gas would immediately reduce day-ahead electricity prices, especially during peak hours.

Although the natural gas crisis is the main reason for high electricity prices, the power sector has been facing a perfect storm, with decreases in nuclear and hydro generation and increases in EU Emissions Trading System (ETS) prices. A gradual restoration of the nuclear fleet could slightly reduce the effect of natural gas prices on power prices.

Consequences of the coal-to-gas switch

The competition between coal-fired and natural-gas-fired units has been exacerbated in the past year by enforcement of EU climate policies. Indeed, coal and oil power plants are being progressively phased out and replaced in large part by natural gas power plants. Figure 11 illustrates how the closure of 12GW (-8%) of hard-coal power plants in the EU has been fully compensated for by adding 33GW (+21%) of natural gas generation capacity between 2014 and 2021. Whether natural gas can deliver on its role as a bridge fuel towards a climate-neutral power system has been called into question by the current crisis.

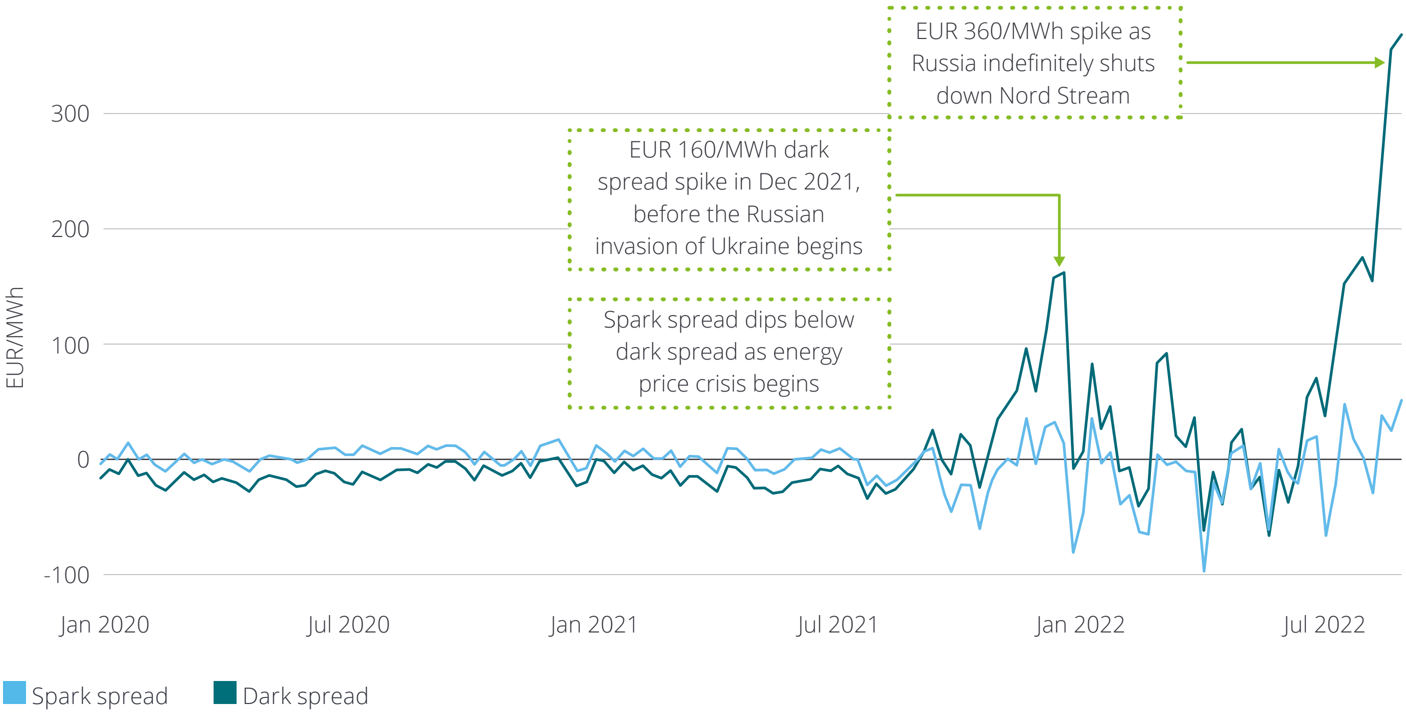
Fig. 11 – European power generation capacity change between 2014 and 2021



* Other (non-renewables) includes fossil coal-derived gas, fossil oil shale, fossil peat, and others as defined by Entso-e
Source: Deloitte analysis, based on energy-charts.info and Entsoe-e

Given rising wholesale prices and the number of scarcity hours, coal power generation has grown highly profitable in day-ahead markets during the crisis. That is not necessarily the case for all natural gas power plants, some of which have become less profitable from being the price-setter in most hours. The spark spread measures the difference between the market price of electricity and the variable cost of gas-fired power generation units, including CO_2 costs. The dark spread measures the same difference for coal units. Both spreads represent the profitability of a natural-gas-fired or coal-fired power generation unit. On paper, the spread would be close to zero for a unit that is setting the price and bidding its breakeven point on the market. Inframarginal units would typically have a spread above zero, while those with a negative spread would not run, as they would have to sell below costs. The crisis caused the dark spread to rise to unprecedented levels (Figure 12), thus resulting in highly profitable coal units. Even though natural-gas power plants pushed electricity prices to record highs, the clean spark spread remains close to zero, since natural-gas-fired turbines remained the price-setting technology.

Fig. 12 – German spark and dark spreads on the day-ahead market, averaged out per week



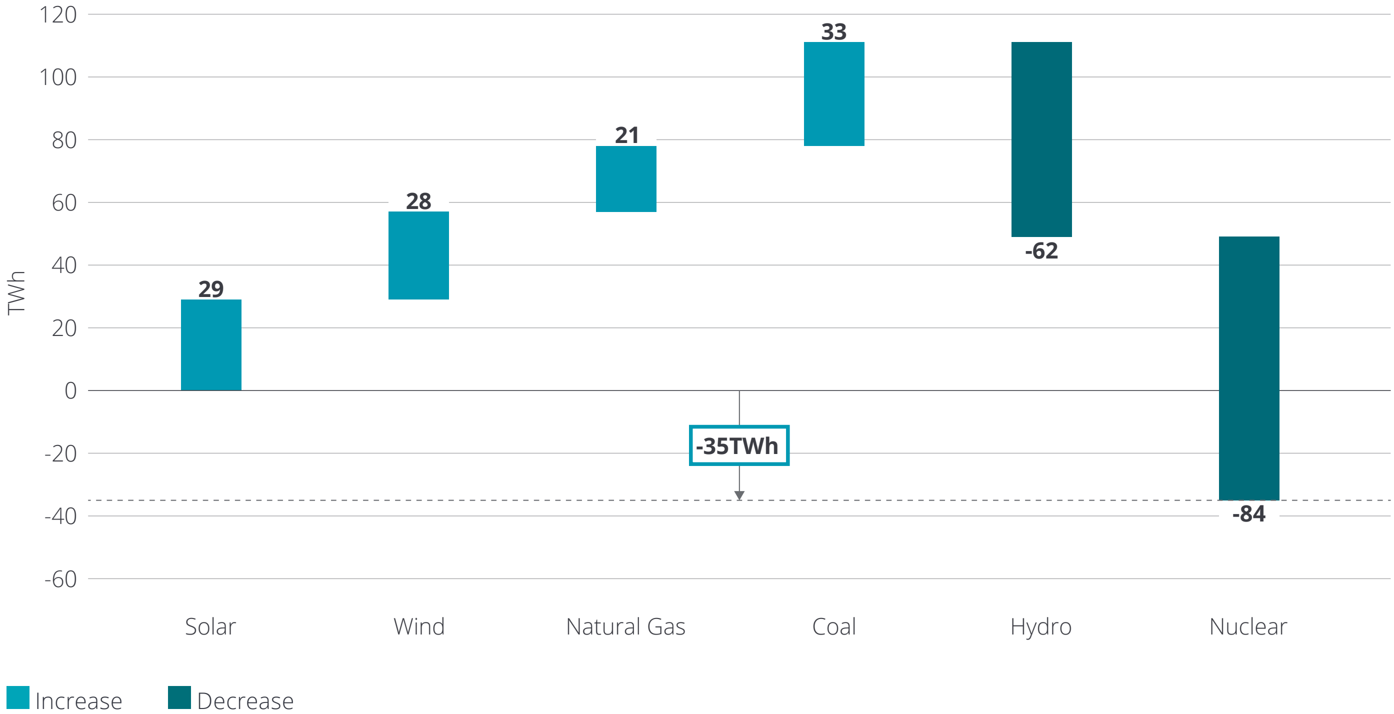
Source: Deloitte analysis, based on power prices from ICE, Ember and Entso-e

Other drivers of electricity price inflation

Although high gas prices are primarily driving the power price surge, other factors are also aggravating the crisis. First, the operating nuclear fleet in France shrunk to a record low size in 2022[4] and is still a long way from fully recovering. This loss amounts to 84 TWh, which is equal to the annual electricity consumption of Finland. Such a severe shortage increased reliance on natural gas. It is of utmost importance to consider the ageing of the French nuclear fleet in the coming years, as it will increase the risks of reduced nuclear output. Commissioning times are also significant for new nuclear projects, like the Flamanville EPR project in France, for which construction began 15 years ago. This means there is no short-term substitute for nuclear power other than existing natural gas and coal capacity. In the mid- to long-term, renewables will need to be developed faster in order to replace nuclear phase outs while reducing emissions.

Another aggravating factor was the historically dry summer in Europe in 2022. Record-high temperatures and sparse and irregular rainfall severely impacted hydropower generation (Figure 13). The lost hydropower output had to be compensated for by increased generation from other sources, including gas and coal. However, the growth of wind and solar power helped to offset some of the lost hydro generation.

Fig. 13 – Year-on-year output difference of EU power generation



Source: Deloitte analysis; based on energy-charts.info

[4] Twenty-nine reactors shutdown out of 56, or 30 GW out of 61.4 GW.
[5] See Trading Economics' data viewer.

Together, nuclear-power unavailability, drought, and soaring commodity prices explain why Europe has been highly exposed to natural gas prices in recent months. The nuclear and hydropower situation is expected to improve in the near term, but European power markets should learn from this experience and build resilience for the future. Although the market behaved as expected—with rising electricity prices reflecting the scarcity of power generation—it is crucial to ensure sufficient supply-side flexibility so that the market does not significantly harm consumers and industries in the event of a lasting crisis.

The increasing price of CO_2 in the EU, which has risen from less than €30/tCO_2 in 2008–2020 to over €90/tCO_2 this year, is also contributing to higher power prices, albeit to a lesser degree than the aforementioned factors. CO_2 prices have risen due to tighter EU climate policy and higher coal usage, which raised the demand for CO_2 quotas since coal power plants emit nearly twice as much CO_2 per kWh of electricity as natural gas power plants. Although CO_2 prices directly impact the variable cost of both gas-fired and coal-fired generation, the overall effect on power prices is much smaller in magnitude than the other causes mentioned here, notably natural gas prices.

[6] A good approximation of those values is 490 gCO_2e/kWh for gas and 820 gCO_2e/kWh for coal power plants

Options to fix power price inflation

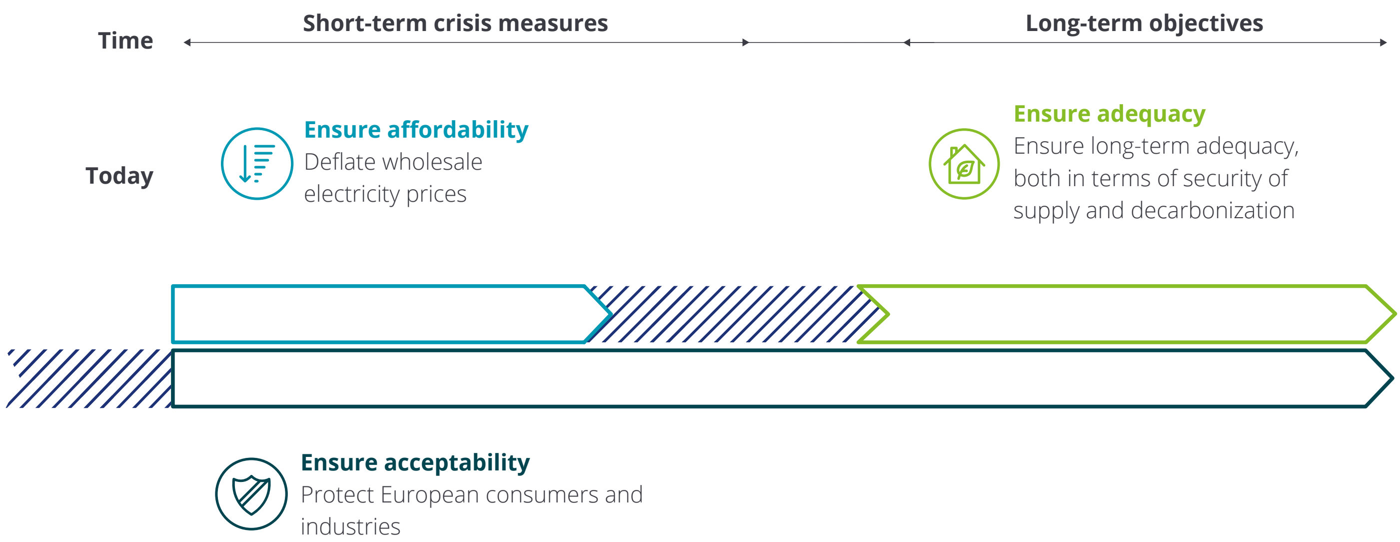
Balancing affordability, acceptability and long-term adequacy

The correlation between natural gas and electricity prices has prompted policymakers to consider major regulatory intervention, as affordable electricity prices are vital for the well-being of the economy and society. Hence, many policymakers are largely focused on reducing inflationary pressures on wholesale power markets. Since wholesale power prices are passed on to consumers to some extent, another option is to regulate them in such a way that the electricity prices paid by end users do not reflect the full scale of wholesale power price increases, as discussed in Section I.

In addition, many policymakers are looking to ensure that some actors do not disproportionately benefit from the current crisis at the expense of others. Governments are ultimately responsible for protecting European industries and vulnerable consumers. As such, many policy discussions are centred around redistribution mechanisms targeting actors in the power and gas sectors that are profiting to the largest degree. For example, system operators, which are regulated across Europe, collected unprecedented rents between January and September 2022 due to soaring power prices[7] (Appendix, Figure 26).). Similarly, excess profits made by private actors could be perceived as unfair and might be leveraged to release the pressure on exposed consumers.

Finally, the European Union is moving toward climate neutrality; therefore, it needs to ensure adequacy, both in terms of supply security and decarbonization, for the coming decade. Attractive short-term interventions could distort the market in the long-run. Accordingly, options for curbing power-price inflation should be assessed against the objectives of ensuring adequacy as well as affordability and acceptability before implementing any market-redesign options (Figure 14).

Fig. 14 – Timeframes and policy objectives to consider when tackling the current power crisis



Source: Deloitte illustration

[7] ACER, 2022

Proposed power market fixes

The European Commission, EU member states, and academics have proposed solutions to weather the crisis. Those proposals span a wide range of methods and goals. They also differ in temporality, as some suggestions primarily aim for a short-term reduction in power prices. In contrast, others advocate a permanent change in the core design of electricity markets.

Proposals can be roughly grouped into four categories (Table 1) and then assessed against the three objectives of adequacy, affordability, and acceptability (Appendix, Table 2). The four categories are:

1. Power demand-reduction measures.

2. Direct interventions in the current wholesale energy market, either via quick or temporary fixes or by a more fundamental review.

3. Fiscal policies that address fairness and equity concerns about the distribution of producer and consumer rents in certain markets.

4. Changes to the overall regulatory environment designed to ease the burden on consumers, such as adjusting emission allowances or feed-in tariffs.

Tab. 1 – Energy market intervention proposals

Type of proposal	Description of the main proposals	Sources
	A. Energy rationing	
A1. Reduce power demand	· **European Commission proposal:** Reduce gross electricity consumption by 10%, and in peak hours by 5%. Member states are left to identify the peak hours themselves. At least 10% of hours in a month must be peak hours.	· EC proposal
	B. Wholesale power markets intervention	
B1. Impose a cap on the price of gas	• **Iberian measure:** The price of gas is capped at €40/MWh until December 2022, after which it will increase by €5/MWh every month to €70/MWh until the measure ends in June 2023. • **European Commission proposal:** Cap prices on physical and financial flows at gas hubs (including TTF), with importers being compensated for the difference through the EU budget. • **European Commission idea:** Limit the price of Russian gas, possibly capping prices only on Russian pipeline imports.	· Iberian measure · EC proposal · EC idea
B2. Split the market in two	• **Greek proposal:** Divide the electricity market into two types of power plants: "when available" (mostly nuclear and renewables) and "on demand" (mostly fossil fuels). "When available" would be remunerated via contracts, while "on demand" would receive the spot price.	· Greek proposal
B3. Implement pay-as-bid	• **Academic idea:** Remunerate activated power generators at the price they bid for, and use a weighted average of the bids to determine the final price incurred by the consumer.	· Example from a recent scientific article

Type of proposal	Description of the main proposals	Sources
	C. Indirect welfare redistribution – tax & subsidies	
C1. Shield vulnerable consumers	• **German relief packages (February, May, September 2022):** Offered lump-sum transfers, heating support, tax breaks (VAT & income), and electricity price subsidies (grid fee removed); froze scheduled increase of CO_2 tax on fuels for now. • **French measure:** Provided a €100 to €200 lump-sum transfer for lower income households (i.e., the bottom 40%).	· German relief packages, energy shield package · French measure
C2. Cap market revenue	• **European Commission proposal:** Tax all revenue made by infra-marginal power generators, except coal plants, that sell electricity above €180/MWh. • **French implementation of EC proposal:** Same as above, but tax basis can be reduced by 10–40%.	· EC proposal · French implementation
C3. Tax windfall profits	• **European Commission proposal:** Place a 33% tax on all profits above 20% of the average annual profits since January 2019 (base is zero if the average profit in the past three years was negative). This applies only to profits generated in the fiscal year starting on or after 1 January 2022. • **French implementation of EC proposal:** Same as above, but averaging profits over the last four years and with only oil and gas companies being in scope.	· EC proposal · French implementation
	D. Regulatory environment	
D1. Tone down CO_2 pricing	• Increasing the number of CO_2 permits in the EU emission trading scheme would lower the price of CO_2 in the system, as demand would be unchanged. This could be a temporary measure that would revert back to the scheduled trajectory after the crisis.	· No formal proposal
D2. Accelerate permitting	• Lengthy permitting procedures are slowing down not only the growth of renewable capacity in the EU but also the expansion of energy infrastructure, including much-needed LNG import terminals.	· Temporary Crisis Framework
D3. Nationalise power producers	• **French nationalisation of EDF:** France has announced its intention to renationalise EDF, its legacy power producer. A budget of €12.7 billion has been set aside to buy shares. • **German nationalisation of Uniper:** Germany has nationalised Uniper with an €8-billion bailout package and an extended credit line of €13 billion with a state-owned bank.	· Nationalisation of EDF · Nationalisation of Uniper

This table has been prepared using previous work from ACER, Agora Energiewende, Bruegel, and the FSR.

[8] S&P Global, 2022

Delving into the European Commission's measures

On 6 October 2022, the Council of the EU adopted Council Regulation 2022/1854—an emergency intervention to address high energy prices that deploys several tools. These tools seek to address the three objectives illustrated in Figure 14:

- To ensure affordability, the first short-term measure involves reducing demand (A1). The regulation sets a voluntary overall reduction target of 10% of gross electricity consumption, and a mandatory reduction target of 5% in peak hours. Member states shall define peak hours corresponding to a total of at least 10% of all hours during the period between 1 December 2022 and 31 March 2023. Member states can determine the measures used to meet these targets at their discretion.

- Such measures would be complemented by a cap on the price of gas-fired power generation (B1) in order to deflate power prices.

- In addition, consumer support measures should be proposed by the member states (C1). Such measures generally will not be designed to tackle the root cause of power price inflation, but rather to ensure affordability from a consumer perspective.

- The regulation includes two other provisions to help provide the funds required to implement the intervention package. The first is a revenue cap for inframarginal power generation set at 180€/MWh (C2). The second consists of a tax on excess profits (C3).

The intervention seeks mainly to attain short-term affordability and acceptability. In an additional "non-paper",[8] the EC presented further policy options to mitigate the impact of natural gas prices on electricity bills. The proposals draw some lines in the sand, where any market reform should only address the essential elements of the market design that can be implemented rapidly. One of the main options discussed consists of long-term contracts for difference (CfD). It would, however, concern only renewable energy sources and nuclear, which would be remunerated at their true production costs.

Our analysis (see Appendix) suggests that this set of measures strikes a decent compromise between the policy objectives of adequacy and affordability. The main drawback is political and legal acceptability.

Reducing demand to lower prices

Many stakeholders insist on reducing power demand, as this would be the most effective way to lower electricity prices without requiring further power-market intervention (Figure 15). Yet, electricity demand has historically been insensitive to short-term price changes, which poses a challenge. Indeed, most consumers have little-to-no alternatives to electricity for most of their appliances. The same holds for many industries, where most savings occur by cutting output, which can hardly be considered a desirable way forward. In addition to voluntary curtailment, the current drop in output also stems from competitive losses due to high energy prices and sometimes even closures in sectors sensitive to natural gas prices, like the fertiliser industry.[9] Unsurprisingly, despite record-high electricity prices, little savings have materialised—only -3.5% compared to the average power demand prior to COVID-19 (Appendix, Figure 25).

Cutting power demand by 3.5% is still an achievement. However, demand will need to be curtailed much further to reduce monthly gross electricity consumption by 10%—and by 5% during peak hours, as targeted by the European Commission. Hitting these targets would effectively reduce natural gas consumption in power generation. Yet, the effect on power prices is uncertain, given that natural gas units will likely still be the peak-load price-setters. For example, Figure 15 depicts a situation where diminished electricity demand does decrease natural-gas consumption but it does not initially lower wholesale electricity prices. Furthermore, mandatory cutbacks are unpopular and could be even more politically challenging if requested during a harsh winter. Additional proposals thus target the supply side of power markets in an effort to ensure affordable electricity prices.

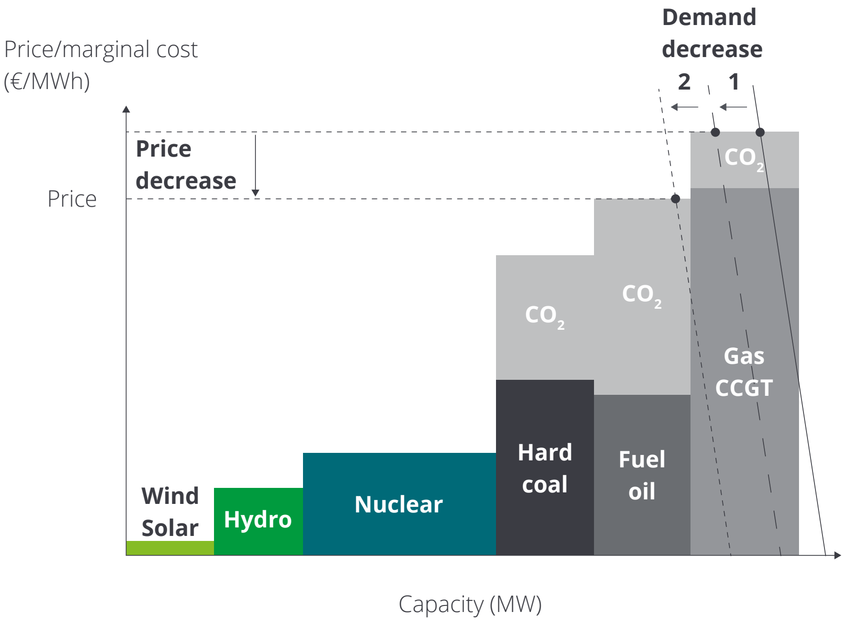
[9] Fertilizers Europe, 2022.

Tackling the root cause with a gas-to-power price cap

As such, another measure inspired by the Iberian gas-for-power price cap is being discussed at the European level (Figure 16). First, this measure directly reduces power prices by subsidising the natural gas units that would bid below their true costs. It would then lower the inframarginal rent of the other technologies, further improving consumer welfare.

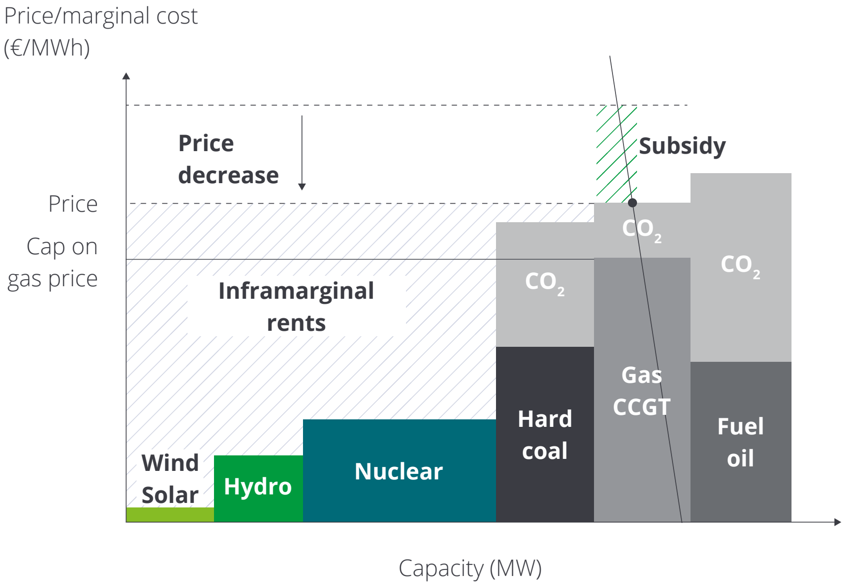
The net effect on the customer's bill is questionable, as subsidising natural gas power plants will translate into a new tax for power consumers. Yet, reducing inframarginal rents will likely benefit the consumer. The main drawback of such measures is the diminished incentive to limit gas-fired generation, which might become cost-competitive with oil or coal units depending on the level of the subsidy (Figure 16). In addition, a gas-to-power cap could create a financially attractive situation for some gas-fired units; therefore, governments should make sure that the subsidies do not stimulate price speculation in the natural-gas markets.

Fig. 15 – Illustration of demand-reduction impact on merit order



Source: Deloitte illustration

Fig. 16 – llustration of capping the gas-fired generation bid price



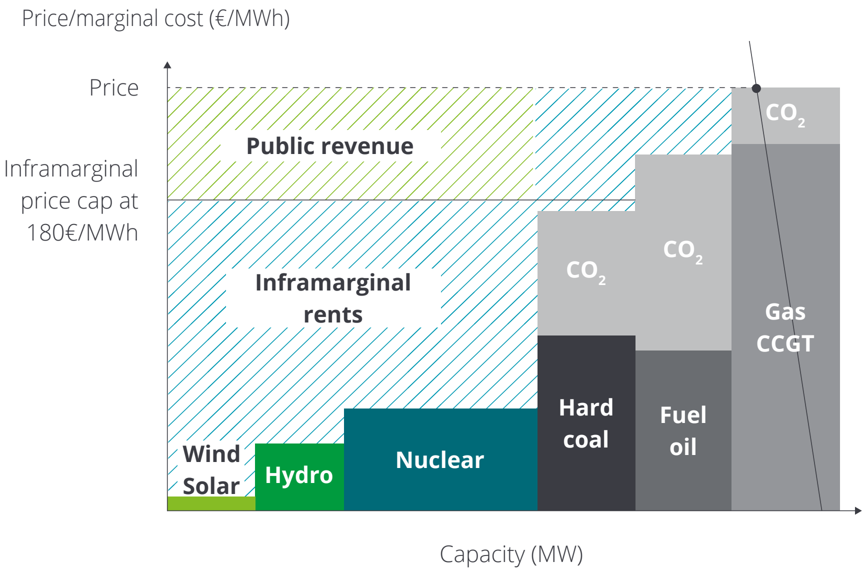
Source: Deloitte illustration

Capping producers' inframarginal rents for redistribution
An additional proposal suggests capping inframarginal electricity market revenue (Figure 17). It is one of the most favoured redistribution proposals described in the "Proposal for a Council Regulation on an emergency intervention to address high energy prices" from 29 September 2022. The inframarginal revenue cap is already being discussed by many governments, some of which plan to enforce it in the near future.

As mentioned previously, the EC's proposal aims to cap all market revenue generated from a power price above €180/MWh. This cap is well above electricity producers' initial expectations. This would be applied only to inframarginal power plants, and it would allow them to cover their production costs and part of their capital costs as well as to earn a reasonable margin. The EC proposal's definition[10] of inframarginal technologies includes biomass, lignite, nuclear, oil, and renewable power plants, excluding hydro with reservoir.

The European Commission estimates that EU countries could "collect up to €117 billion" from the revenue cap while preserving reasonable profit margins for renewable and nuclear power generators whose fuel costs have barely been impacted by the crisis. However, two significant concerns about the proposal are implementation practicality and uncertainty about anticipated revenues. The combination of this proposal with the aforementioned gas-fired-generation price cap can also be questioned, as it would reduce the total public revenues collected.

Fig. 17 – Illustration of the inframarginal price cap



Source: Deloitte illustration

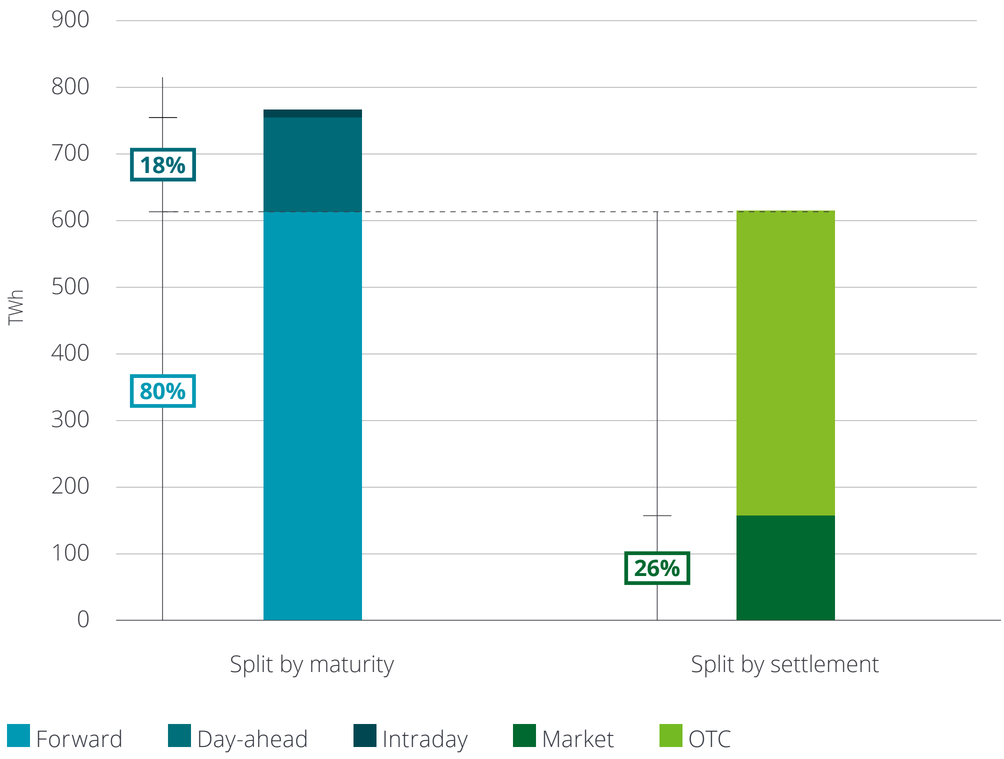
[10] European Commission, 2022

Technical implementation challenges
Revenue caps face technical implementation challenges because retailers can purchase electricity through multiple markets (Appendix, Figure 27). Since electricity consumption never falls below a certain mark, a retailer can secure baseload power capacity many months or even years before delivery. This electricity is purchased on forward markets, directly over the counter (OTC), or eventually through a power purchase agreement (PPA) or a national procurement system such as ARENH in France. Similarly, a given amount can be secured for peak-load hours based on typical load shapes, which can be anticipated with reasonable certainty. Only the hourly spot block would be purchased on the day-ahead market. The balancing area would then be handled directly by system operators or via intra-day and balancing markets.

Breaking down power trade volumes by maturity levels reveals that less than 20% of trade occurs on day-ahead markets (Figure 18). As such, the cap on inframarginal plants would mainly concern forward contracts, most of which are traded over the counter. This makes implementing the revenue cap less straightforward because OTC transactions are not centralised by nature, unlike trading on power exchanges. Moreover, given that many forward contracts had been secured long before the crisis, the impact of the revenue cap would largely be delayed until years 2023 and 2024.

The main advantage of this type of market adjustment is that it would capture producers' inframarginal rents, which could be redistributed to targeted consumers, unlike the gas-to-power price cap. However, this adjustment would provide only ad-hoc consumer support without deflating wholesale market prices. In addition, not all countries would benefit equally from this revenue stream, depending on their power mixes. Indeed, collected revenue would mainly consist of rents from renewable energy sources, nuclear, or lignite generation. In contrast, all European countries face high power prices due to gas units being the most frequent price-setter. Electricity exports are another elephant in the room. Exporting countries could collect revenue on domestic production that is then consumed elsewhere. Therefore, it would be necessary to set up a level playing field in the EU to prevent companies in some countries from gaining a competitive advantage over those in other countries.

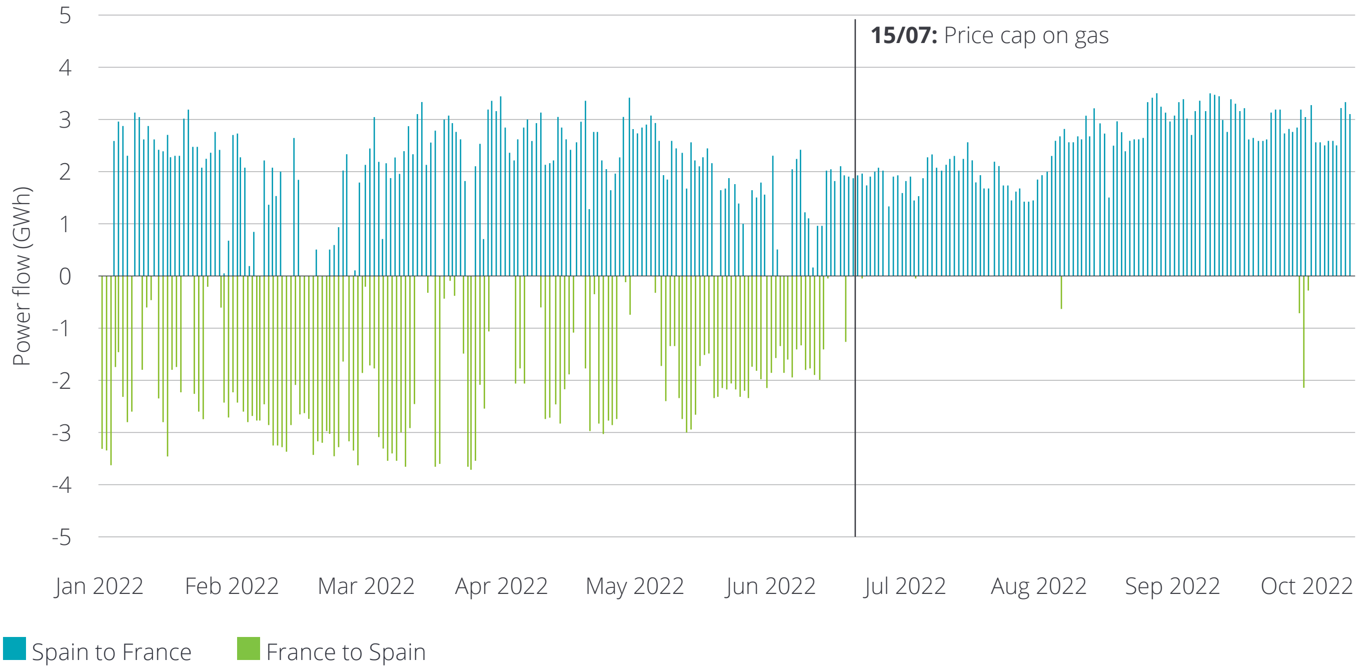
Fig. 18 – Traded volume distinguished by maturity and settlement types in France in 2021



Source: CRE

Political implementation challenges
Some market distortions and European tensions have already arisen due to unilateral market interventions. This is illustrated by the Iberian gas-for-power price cap implemented in mid-July 2022. Although it has effectively reduced wholesale power prices, the Iberian implementation has markedly distorted power trade flows between France and Spain (Figure 19). This example shows that uncoordinated actions can result in adverse consumer effects and non-cost-optimal dispatch of generation units. Indeed, the asymmetrical price cap implemented in Spain distorts the merit order, favouring Spanish gas-fired power plants, even though some French gas-fired units might be more cost-efficient without the cap. Consumption figures back this claim: Spain has shown a smaller decrease in year-on-year natural gas consumption compared to all other European countries.[11]

Fig. 19 – Impact on power flows of the Iberian gas-to-power price cap



Source: Deloitte, based on data from Entso-e

[11] European Commission, 2022

Tackling the residual price increase
Overall, the three measures previously discussed (i.e., reducing demand, gas-to-power price cap, and limiting inframarginal rents) would allow for some benefits, either by reducing the power prices to some extent or by reducing producers' rents for redistribution to consumers. Yet, extra short-term measures are needed to shield European consumers and industries, given the complexity of implementing market reforms in a setting as diverse as the EU energy sector. Consequently, most European governments have announced they will subsidise electricity prices in the short-term.

This consumer support primarily consists of four types of governmental action:

- Reducing taxes and levies on electricity bills. — Most European countries announced reductions in the energy tax (VAT) to limit the price increase. Similarly, additional levies were removed on electricity bills, such as the Erneuerbare-Energien-Gesetz (EEG) surcharge in Germany and the CSPE in France.

- Regulated tariffs. — These have been proposed to protect consumers from wholesale price increases. For instance, France capped power-price increases at 15% for households in 2023. Similar measures have been decided in the Netherlands, with a cap placed on household electricity prices based on January 2022 values and below a certain consumption threshold.

- One-off payments to targeted consumers. — For instance, Germany's energy price lump-sum support grant of €300 was sent to all taxpayers.

- Retailers propose new tariffs. — This could come in the form of increasing block tariffs. Such new tariffs would ensure a low electricity price for a predetermined, baseline level of electricity consumption, and prices would gradually increase as consumption rises. This measure has the advantage of incentivising further reductions in electricity demand. However, the main drawback is that consumers are seldom aware of their cumulative electricity consumption. An ongoing, gradual deployment of smart meters could somewhat solve this information problem.

Most of these measures shield consumers from current wholesale electricity prices. However, they also prevent them from reacting to increases in power prices, resulting in a relatively low decline in electricity consumption, and accordingly, little decrease in natural gas usage for power generation. Therefore, policymakers should ensure that demand reduction targets are ambitious enough and properly incentivised to motivate consumers to save electricity, even if they are not facing high prices.

Unlike wholesale power-market design, each country has its own policy on retail pricing and offers varying levels of public support. This support can be funded via the market design (i.e., captured rents), additional debt, and public funding (Figure 29). Disparities in the levels of state support across countries can also stem from import/export opportunities, the generation mix, and where a company is headquartered. Those disparities could create additional dissent within the European Union, as standard rules could put some countries at a disadvantage, but a lack of consensus could result in market distortions as well.

Additional funding availability: a solidarity contribution
European governments have thus considered one last lever to provide financial support to final energy consumers and tackle surplus profits. This lever consists of a temporary "solidarity contribution," or tax, which is based on the taxable profits of EU companies in the oil, natural gas, coal, and refinery sectors. The applicable rate would be at least 33% of the taxable base and it would apply to companies in all member states. Again, this measure would impact countries differently, depending on where companies have their tax residence in the EU However, as the energy crisis affects the entire energy sector, collected revenues would be used for a broad spectrum of measures, not all of which would target power prices. For instance, the "solidarity contribution" could be used to promote energy efficiency measures, help energy-intensive industries, or increase investments to enhance the energy autonomy of the European Union.

How could consumers and utilities react?

Change in risk policies and hedging approaches

Most, if not all, electricity consumers will likely try to lower their exposure to market prices, given the current situation. This holds for energy-intensive industries, final consumers, and retailers that purchase electricity from producers and sell it to end customers. For energy-intensive industries and power retailers, the current crisis will likely propel two related trends: 1) a revised approach to hedging, including more hedging activity to guarantee physical deliveries as well as adjustments to the hedging corridor for future years; and 2) greater use of power purchase agreements (PPA), which allow buyers to secure prices for the next 10-to-20 years.

The energy price crisis is manageable for utilities that were hedged long before prices began to soar, but today's crisis could grow into tomorrow's problem. Looking at the hedging ratios and average locked-in prices for 2022 (Figure 20), almost 100% of electricity volumes sold have been hedged for 2022, and 60-80% are already hedged for 2023 at prices well below €100/MWh on average. The risk thus lies in the remaining share of electricity that has not been procured for 2023. For 2023, hedging ratios average approximately 60%, and power prices are currently above €200/MWh except within the Nordic countries and Spain (Figure 5). As such, we can expect that the bulk of the crisis from a consumer point of view will happen next year, notably in France, where forward prices indicate loss of load during the first quarter, with prices above €1,000/MWh. The more hedged retailers are, the better they can weather the crisis, either by avoiding expensive purchases on the spot market or by having the opportunity to re-sell a portion of their hedged electricity if they had taken long positions.

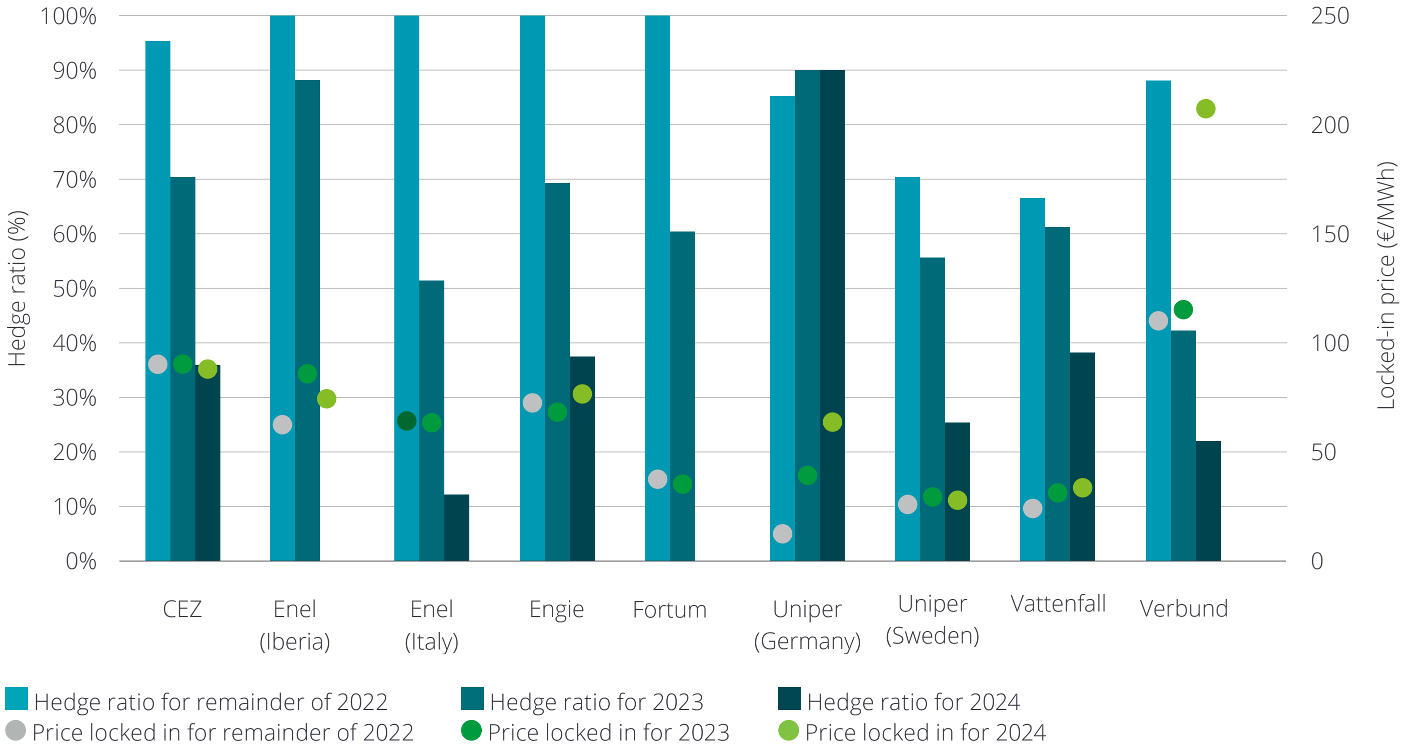
These risk-management shifts concern not only retailers' hedging strategies but also supply security in Europe. To this extent, revising the capacity market might be required in order to guarantee that prices will not reach unsustainable levels due to fears of loss of load. It might also be necessary for having sufficient capacity that is not all based on a given energy commodity, but rather a diversity of generation sources. The idea is to create a safety net capable of handling supply disruptions in natural gas, coal, or oil, which are all exposed to global markets. Achieving greater supply security will also likely involve investing in pumped-hydro storage, hydrogen, or biogas backup capacities or demand-side response. In addition, having a more regional approach across Europe would allow existing infrastructure to be considered when evaluating supply-security concerns and risk-mitigation options.

Change in energy procurement behaviour

There are many ways to improve current markets so that consumers and retailers can better hedge against a crisis. One option for enhancing both hedging capabilities and supply security is to introduce regulated incentives for deploying power purchase agreements (PPA) so that no entity is left with unsustainable exposure. PPAs give producers and consumers visibility into power prices well into the future, typically 10–20 years.

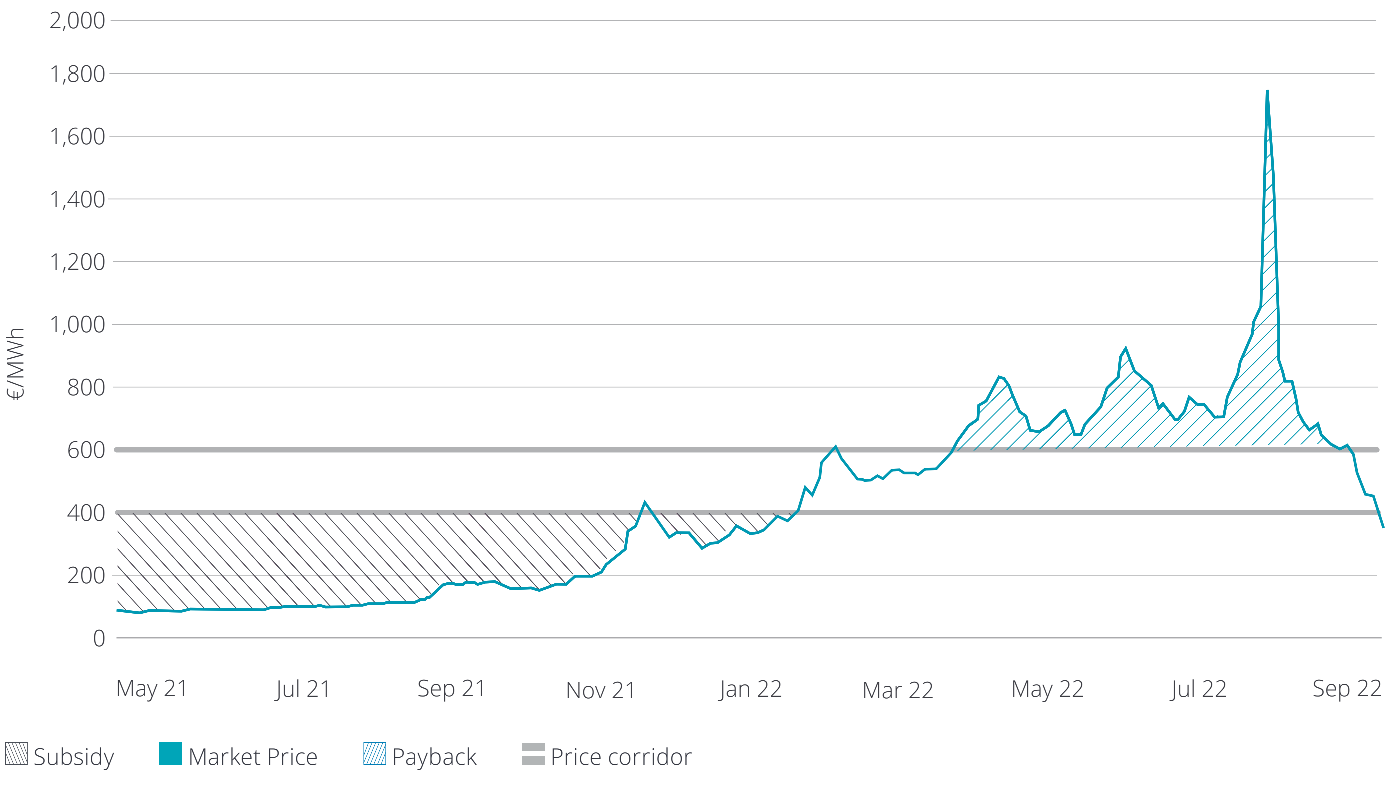
Such agreements could take the form of CfD, which are increasingly discussed in the context of the power crisis. Such schemes consist of making potential producers compete in tenders for developing projects whose revenue will be set by market prices yet limited by a pre-determined price corridor (Figure 21). If market prices are above the price corridor, developers pay back the difference, and if market prices are too low, governments pay operating subsidies. Having such a contract could have avoided excess profit-taking during the crisis, since it caps inframarginal rents when market prices are too high. In addition, CfD foster the deployment of new capacity and could apply to technologies other than renewables, like nuclear, without requiring power-market redesign. CfD also prevent excessive revenue volatility for contracted power producers, as the instrument sets prices within a reasonable corridor that could evolve over time.

Fig. 20 – Hedge ratios and locked-in average prices for contracted electricity hedges for selected European utilities as of H1-2022



Source: Deloitte, based on data from Scopegroup

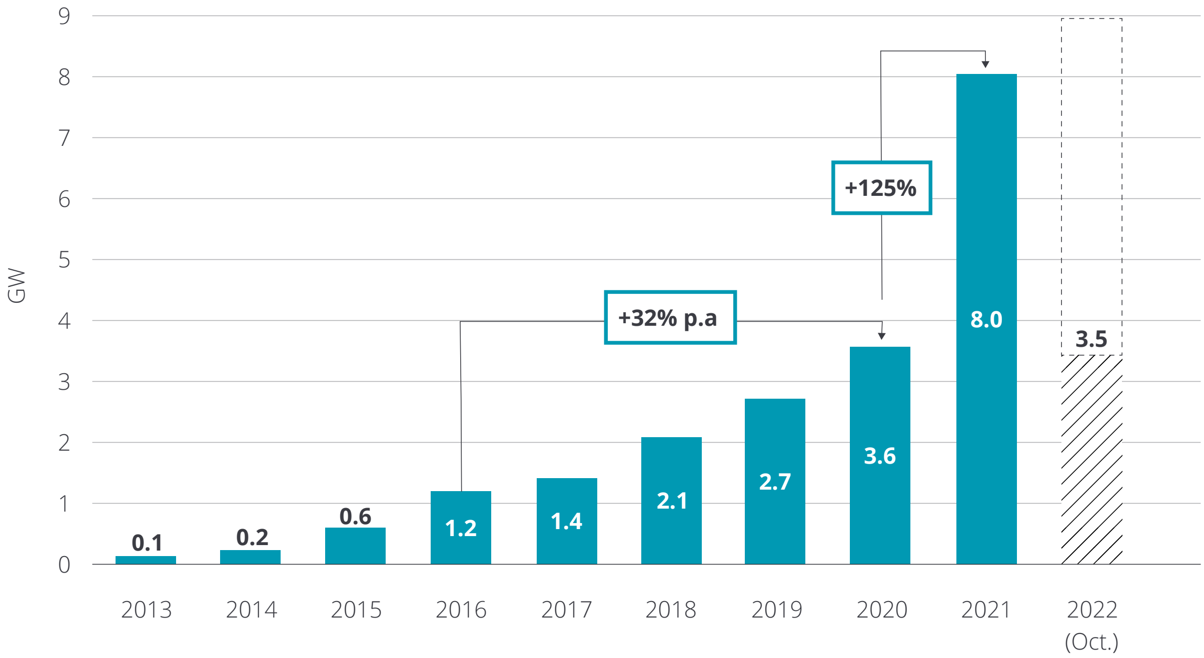
Fig. 21 – Illustration of Contract for Difference (CfD)



Source: Deloitte illustration

There is a clear trend regarding contracted PPA capacity per year, with an uptick starting in 2016 (Figure 22). PPAs have grown 30% on average year-on-year and demand is expected to continue to increase with greater volatility in markets with a high share of renewables.[12] Yet, investors' merchant appetite is also expected to increase as they seek to capture higher returns, and as monthly PPA prices soar, having doubled compared to last year. In addition, sellers' bargaining power has strengthened, especially given the growing interest in securing PPAs in the context of permitting delays and supply chain constraints.

Fig. 22 – Annual PPA contracted capacity in Europe



Source: Deloitte, based on WindEurope

[12] Pototschnig, Alberto, Jean-Michel Glachant, Leonardo Meeus, and Pippo Ranci Ortigosa. 2022. "Recent Energy Price Dynamics and Market Enhancements for the Future Energy Transition." European University Institute. https://fsr.eui.eu/publications/?handle=1814/73597.
[13] Further information available at: https://pexapark.com/price-reports/Further information available at: https://pexapark.com/price-reports/

Accelerating long-term levers for consumers

On the consumer side, supplier switching may increase in the coming months as many end-users face rising electricity bills. This would favour fixed or regulated tariffs compared to market offers, which are more volatile since prices are not necessarily set for a whole year. However, this trend could potentially stifle retail market competition, especially if regulated tariffs are offered only by incumbents.

In addition, regulated tariffs rarely provide price signals to end consumers. This trend would go against demand-side response and the aggregator's business model, which are key to responding to the growing need to develop peak-load reduction levers. This has long been a missing piece of the power-market puzzle. In the future, the demand side will likely need to participate more in increasing load flexibility, which is becoming an increasingly hot topic due to the current crisis. For example, French utility EDF is now pushing forward its "tempo" tariffs, which adjust end-user power prices daily depending on the tension in the power markets. Unlocking more flexibility from the demand side would be a much more desirable solution than the current emergency cut-off scheme, which has little acceptability compared to voluntary power reduction.

Despite soaring electricity prices, electrification incentives are still effective, and might be even more so now, due to high natural gas prices. For instance, applications for federal funding to install heat pumps in Germany have grown more than tenfold between January and August 2022, marking a strikingly large switch away from fossil-fuel-based household heating sources.[14] Such electrification trends should not be curtailed but rather encouraged amid soaring power prices because they reduce Europe's reliance on gas and are aligned with its long-term decarbonisation objectives.

Finally, local energy procurement represents an emerging trend that could accelerate in the near future. The current power price crisis may incentivise consumers to source their energy locally. This could pique interest in community energy projects and in self-sufficiency for industries that can deploy their own distributed energy resources, such as solar and wind generation, clean hydrogen, and batteries.

[14] Politico, 2022.

Appendix

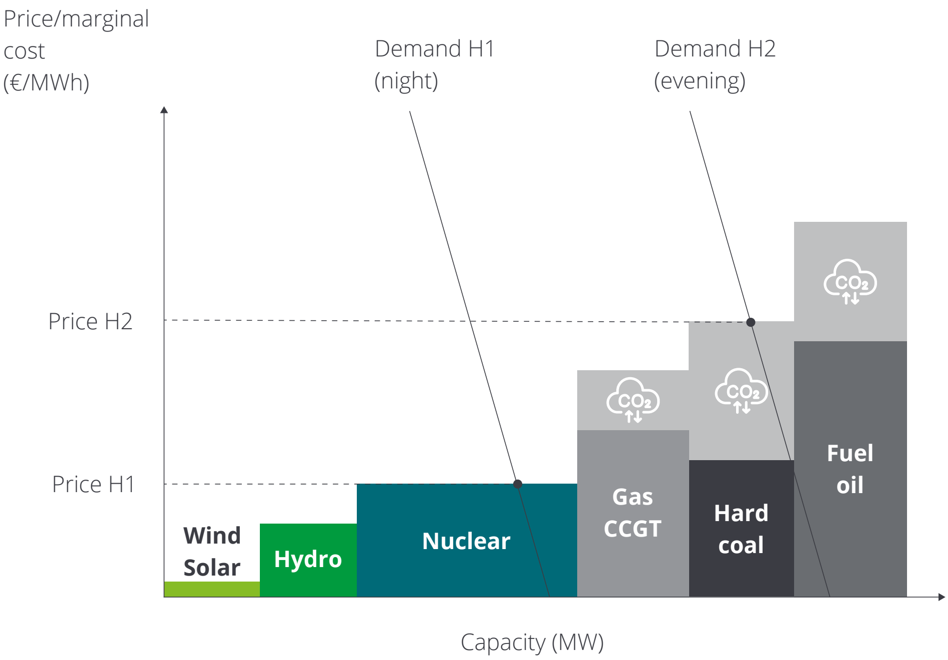
A crisis driven by fundamentals

Price formation explained

In power markets, electricity generation units are ranked by their variable cost of production to form a "merit order," or supply curve (Figure 23). Available units are then activated one-by-one following this merit order until supply meets demand. Electricity prices are set hourly by the variable cost of the last electricity generation unit called upon to meet the hourly value of demand. Demand shows very little price sensitivity in a given hour but varies considerably throughout the day, with peaks in the morning and evening hours. Available supply is also increasingly subject to variations throughout the day due in large part to the growing share of renewables in power generation.

Since wind and sunlight are free and nuclear has low variable costs, renewable and nuclear power plants are typically at the lower end of the supply curve. Fossil-fuel-based electricity generation units, whose variable costs are determined by fuel and CO_2 costs, are at the higher end of the supply curve and sometimes are only called upon during peak-demand times. The relative positioning of fossil-fuel-fired power generation units (i.e., oil, coal, and natural gas) in the merit order thus largely depends upon fuel and CO_2 costs. Two power generation units using the same fuel can also be ranked differently within the merit order due to differences in the efficiencies of their respective technologies. For instance, combined cycle gas turbines (CCGTs) are more cost-efficient than open cycle gas turbines (OCGTs).

Fig. 23 – Price formation in power markets: the merit order concept



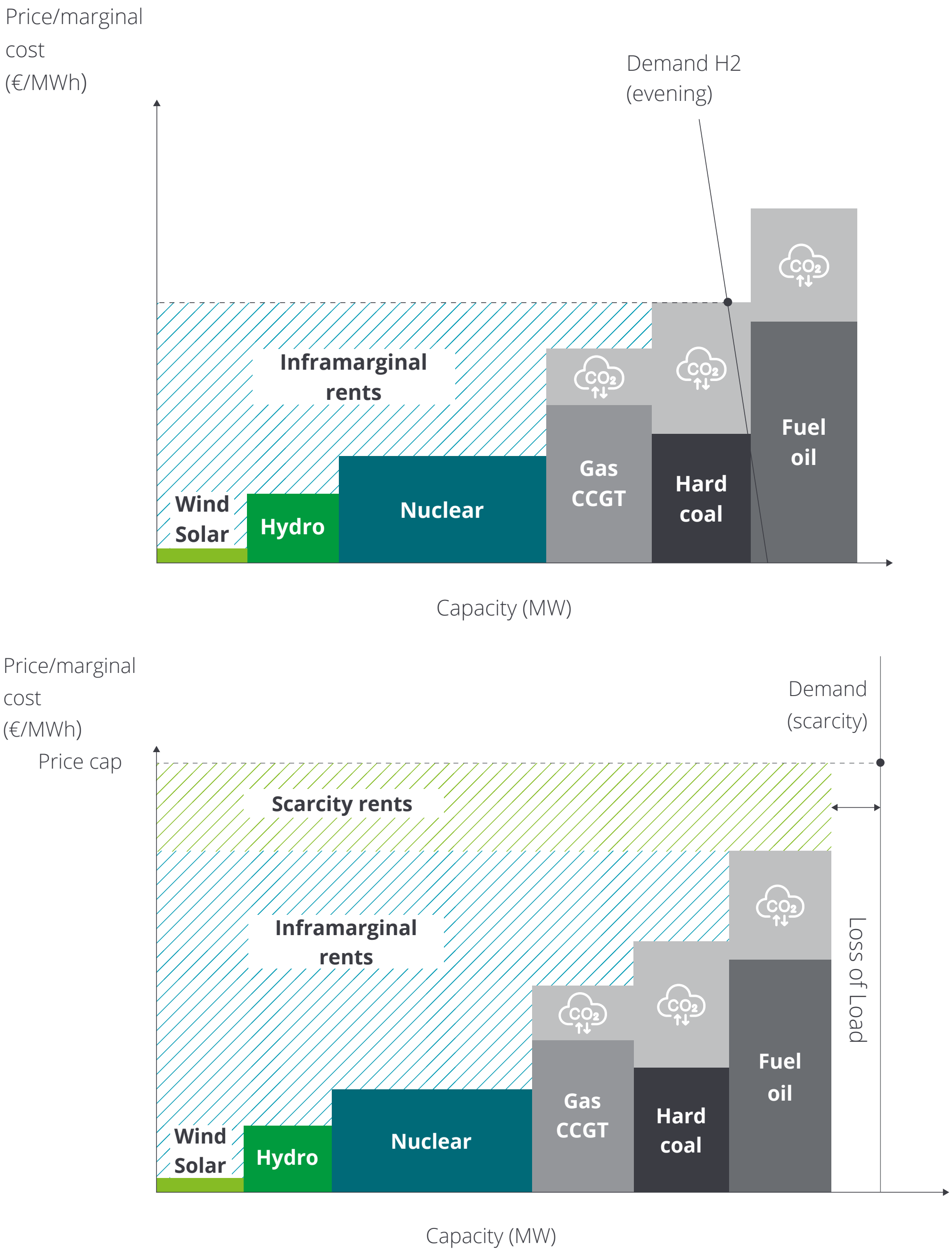
Source: Deloitte illustration

Scarcity rent explained

The theory underlying the pay-as-clear option is that all companies would bid at their variable cost of producing electricity. As all units are remunerated at the level of the last unit called upon, they would be able to cover their fixed costs by collecting inframarginal rents (i.e., below the marginal cost or price) rents throughout the year. Scarcity rents would incentivise investments in case of insufficient capacity (Figure 24). Therefore, provided that the market is sufficiently competitive and without significant entry barriers, rents would eventually become equal to operating margins in the long-run.

This power market design has been successful in facilitating cost-efficient, economic dispatch over the last two decades, but it is now being questioned in light of excessive prices. Nuclear and coal phase-outs, in many instances, have left gas power plants as the only source of firm power to meet demand during times of high load or low availability of renewables. Based on the merit order principle, it is no surprise that soaring gas prices in Europe are underpinning the rise in power prices.

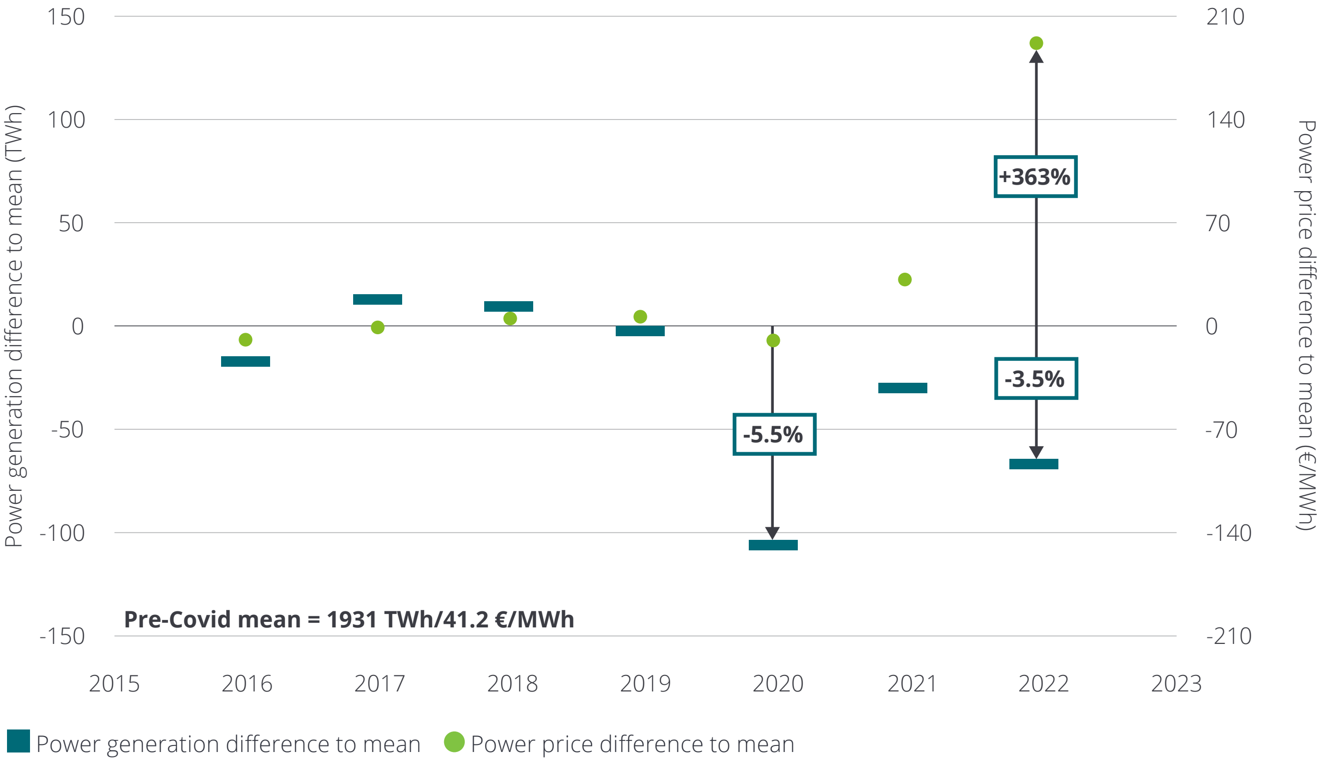
Fig. 24 – Rent formation in the pay-as-clear market design



Source: Deloitte illustration

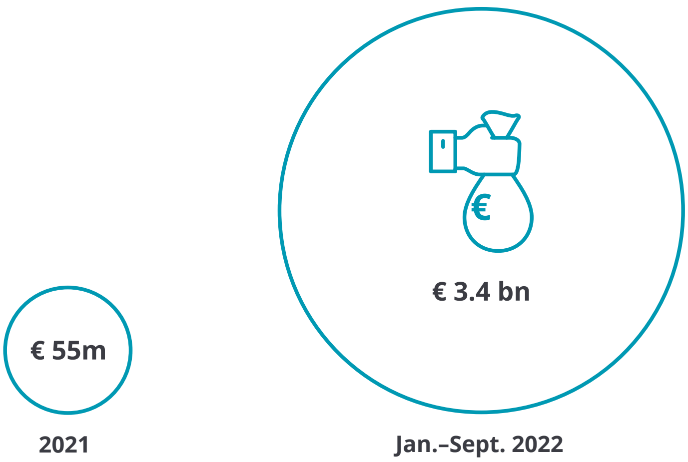
Options to fix power price inflation

Fig. 25 – Deviations from the pre-Covid average power price and power generation in the European Union (Jan–Sept)



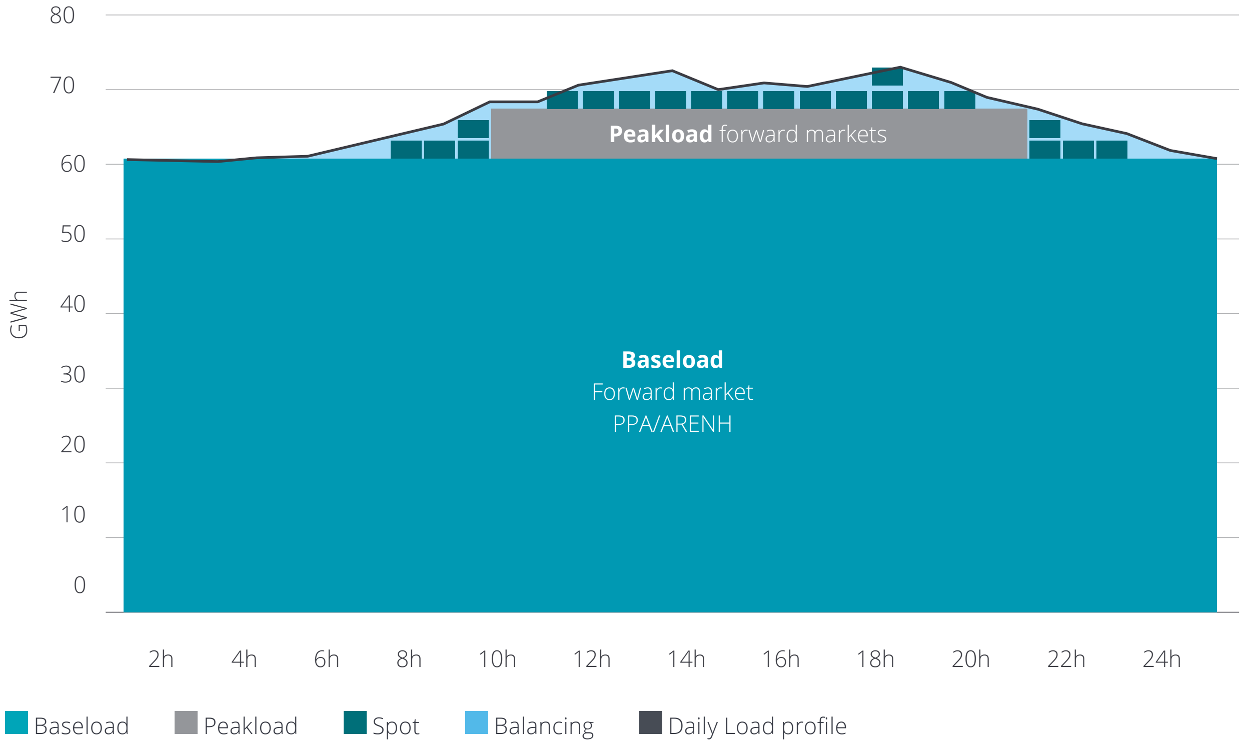
Source: Deloitte, based on Ember and energy-charts.info

Fig. 26 – Congestion rents collected on cross-zonal interconnectors by system operators across Europe



Source: ACER

Fig. 27 – Markets used for hedging in power markets



Source: Deloitte illustration

Tab. 2 – Detailed assessment of the proposals

Overall assessment

Proposition	**Objective 1** Ensure affordability	**Objective 2** Ensure acceptability	**Objective 3** Ensure long-term security of supply and decarbonisation
A. Energy rationing			
A1. Reduce power demand	• Unlocks short-term demand reductions, the main short-term goal • Uncertainty on whether it will stop gas always being the price-setter	• Winter is coming: reducing heat-ing or basic energy needs will become socially and politically difficult to ask	• Beneficial for supply security if temporary power demand reduction translates into long-term efficiency gains, eg., via heat pump deploy-ment or home renovations • Likewise for decarboni-sation
B. Wholesale power market intervention			
B1. Impose a cap on the price of gas	• If successful, gas and power prices are lowered instantly • However success is not guaranteed (OTC trading, Asia outbids EU..) • Cheaper gas means consumers are not incentivised to spare energy	• Social acceptability is guaran-teed if it makes power and gas cheaper • Political acceptability in all EU Member States is less certain, with the key differentiator being industries' level of Ras: or power-Intensity	• Poor investment signals for potential LNG or pipeline gas trade partners, which hurts Europe's security of supply • Lower investment signals for inframarginal technologies if electricity price is reduced by gas price cap
B2. Split the market in two	• Lower power price in wholesale market passing through to retail • Cheaper power means consumer are not incentivised to spare it, especially in times of scarcity	• Legal and political feasibility of such a reform is very lowin the short-term	• Lower incentives to build renewables compared to a scenario in which gas power plants remain the price-setter
B3. Implement pay-as-bid	• If successful lower wholesale power prices pass through to retail • No guarantee that prices will be lower, as pay-as-bid does not necessarily reveal marginal costs	• Low short-term legal/political feasibility	• Weaker investment incen-tives for renewables, which are now less able to recover fixed costs on peak hour prices

Positive Negative Neutral/uncertain

Proposition	Objective 1 Ensure affordability	Objective 2 Ensure acceptability	Objective 3 Ensure long-term security of supply and decarbonisation
C. Indirect welfare redistribution – tax & subsidies			
C1. Shield vulnerable consumers	• Protects consumers from currently high and volatile prices • No incentive for those consumers to reduce their energy consumption	• European consumers have been campaigning for affordable energy	• No incentive to reduce energy demand or switch to non-fossil-fuel energy
C2. Cap market revenue	• Incentive to reduce consumption of electricity remains due to spot price being untouched by the cap • Tax revenue will be used to shield consumers from high energy prices	• Tax revenue will relieve the economy • Diversity of energy mixes across the EU jeopardises single cap and calls for cross-border revenue transfers • Coal exceptionalism will be difficult to justify as the EU was phasing it out	• Gas price is unaffected, which means potential trade partners are still encouraged to invest in export capacity • Long-term incentives to decarbonise and electrify demand remain untouched • Coal lingers in the EU's energy mix
C3. Tax windfall profit	• Generates public revenues for the government to provide economic or consumer support	• Can be seen as a form of social justice, especially by vulnerable consumers • Industries that are to be taxed will likely campaign against these taxes • Taxes legally cannot be implemented at EU level without a unanimous vote	• Tax revenue can be reinvested into decarbonisation or security of supply • Temporarily reduces taxed companies' capacity to invest • This temporary measure could harm investors' trust permanently
D. Regulatory environment			
D1. Increase the number of EU ETS CO_2 allowances	• Will reduce power prices • Effect on power prices is diluted • Fossil fuel demand could increase	• Symbolically goes against the Green Deal, thus could be politically difficult, especially in "pro-Green" EU countries	• Weakens the EU's main instrument to curb GHG emissions (and CBAM)

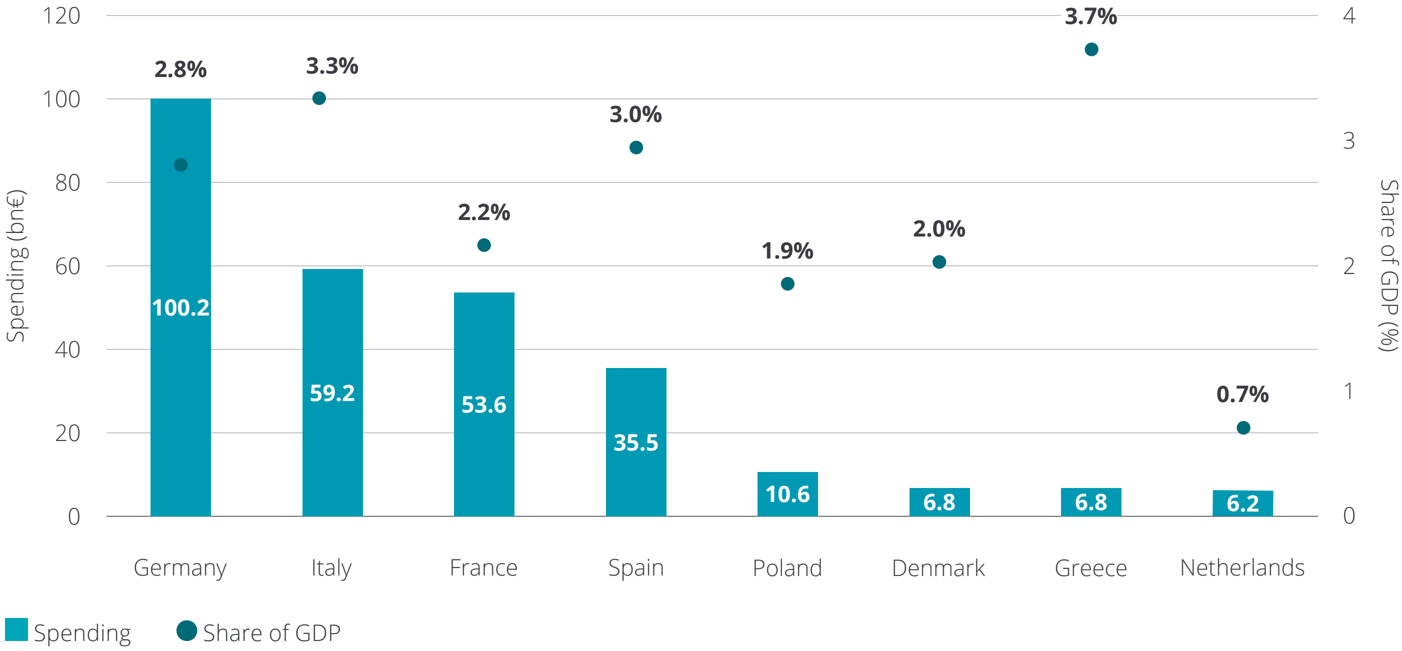
Positive | Negative | Neutral/uncertain

Proposition	Objective 1 Ensure affordability	Objective 2 Ensure acceptability	Objective 3 Ensure long-term SoS and decarbonisation
D2. Accelerate permitting	• No cost associated with this measure • Does not resolve power price issue • No energy demand signal	• Faster permitting could collide with "not in my backyard" mentality, making it an unpopular political project	• Renewable growth is beneficial for supply security and decarbonisation • Will help build up energy import infrastructure faster (LNG, hydrogen....)
D3. Nationalise power producers	• Can lower wholesale power price if nationalised firm is often price-setter • Efficacy to lower prices is uncertain • Bailout plans can be expensive	• Could distort competition if firm has regulated tariffs or vertical integration • Political or social acceptability varies with public opinion on the company	• Windfall profits can be reinvested into decarbonisation or supply security instead of being redistributed to shareholders • Less competition means less innovation

Positive Negative Neutral/uncertain

How could consumers and utilities react?

Fig. 28 – Examples of European spending on energy subsidies as a percentage of GDP*



*Data are collected until 21/09/2022.
Source: Deloitte, based on data from Bruegel

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