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Position paper

Creating Investment Incentives, Providing Reserve Capacity

Options for the market integration of renewable energy

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Creating Investment Incentives, Providing Reserve Capacity

Options for the market integration of renewable energy

Preface

In order to meet the climate targets, it will be essential to defossilise the energy sector. However, it is not simply a case of meeting current electricity demand with renewable energy – the electrification of the industrial, heating and transport sectors will call for much larger quantities of electricity than are available today.

This combination of rising electricity demand and an increasingly renewables-based supply poses new challenges for the electricity market. How can the electricity market design support the continued growth of renewable energy and ensure that the expansion targets are met? And how can sufficient reserve capacity be created to guarantee security of supply during shortages?

These are among the questions addressed by a working group of the Academies' Project "Energy Systems of the Future" (ESYS). The group's experts investigated how changes to the electricity market design can help Germany to integrate renewables into the market and developed a series of policy options to this end.

A number of challenging requirements will need to be met. A successful energy transition will call for flexible technologies to balance out the variable supply of wind and solar power and the provision of reserve capacity either through storage systems or through additional power plants that can be activated when necessary. The existing market mechanisms will need to be supported by effective and efficient investment incentives in these areas.

The experts emphasise that appropriate short-term financial support will be essential if Germany is to meet its 2030 targets for the expansion of renewable energy installations. In the longer term, however, they believe that it will be necessary to transition to a market system without government financial support for established renewable technologies. The experts argue that targeted reforms based on long-term models are required in order to maintain a continually functioning electricity market.

We would like to express our sincere thanks to the experts and reviewers for their involvement in this project.

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Contents

Abbreviations, acronyms and units

AbLaV	Verordnung über Vereinbarungen zu abschaltbaren Lasten (Ordinance on Agreements on Interruptible Loads)
BMWK	Federal Ministry for Economic Affairs and Climate Action
BNatSchG	Bundesnaturschutzgesetz (Federal Nature Conservation Act)
CfDs	Contracts for Difference
EEG	Erneuerbare-Energien-Gesetz (Renewable Energy Sources Act)
kWh	Kilowatt hour(s)
MWh	Megawatt hour(s)
OTC	Over-the-counter
PPAs	Power Purchase Agreements (see glossary)
PV installations	Photovoltaic installations
WindBG	Windenergieflächenbedarfsgesetz (Wind Energy Area Requirements Act)
WIndSeeG	Windenergie-auf-See-Gesetz (Offshore Wind Energy Act)

Glossary

Capacity reserve (also "strategic reserve")	In the current German electricity market, the "capacity reserve" is used when, despite free pricing, the supply of electricity on the wholesale market is not sufficient to cover the total demand for electricity. The capacity reserve power plants are not allowed to operate actively on the electricity markets (ban on marketing) and are only permitted to increase their output in response to a request from the TSOs.
Capture prices	Volume-weighted average price per unit of energy sold that a generation unit can earn.
Day-ahead trading	Day-ahead trading refers to the trading of electricity for the next day on the national or international power exchanges or in over-the-counter (OTC) trading.
Dispatch	Resource planning for power plants (and storage systems) by the plant operator based on trading transactions.
Dunkelflaute	A "dunkelflaute" is a time when dark weather (or limited hours of sunshine) coincides with windless conditions. It refers to prolonged periods during which wind and solar installations are unable to generate significant quantities of electricity.
Inc-dec gaming	In this position paper, inc-dec gaming refers to bidding behaviour where market participants increase or decrease their bids on the spot market to maximise their profits through offsetting on the flexibility market.
Intraday trading	Refers to the buying and selling of electricity supplied on the same day.
Marginal costs	Marginal costs are the extra costs of producing one additional unit of a product or, conversely, the costs saved by producing one unit less.
Market premium	A market premium is an additional premium paid to operators of renewable energy installations who sell their electricity on the power exchange or through OTC trades.
Merit order	The merit order is the sequence in which power plants are designated to deliver power in the electricity market.
Negative electricity prices	Negative electricity prices can arise on the short-term (day-ahead and intraday) power exchanges. They occur at times when there is an oversupply of electricity, but electricity generators nonetheless prefer to continue generating and are willing to accept a negative price (so they do not lose their premium payments, for example).
Nodal pricing	In a nodal pricing system, the electricity price is in principle calculated specifically for each grid node (i.e. for each point where electricity is fed into or drawn from the grid). This means that the transmission capacity of the electricity grid is fully reflected in electricity pricing.
Over-the-counter (OTC) trading	Also known as direct trading. The trading of electricity outside of the power exchange without intermediaries or clearing houses.
Pay-as-bid	A type of price auction where every selected bidder is paid the price specified in their bid.
Peak load, peak demand	A short period of high electricity demand in the grid.

Power Purchase Agreement (PPA)	Long-term electricity supply agreement between two parties.
Real-time pricing	End customer prices that vary in time, reflecting wholesale price volatility.
Redispatch	In order to relieve imminent grid congestion, grid operators instruct power plants and storage facilities up- and downstream of the grid bottleneck to adjust their operating schedules (dispatch).
Strategic reserve	See capacity reserve.
Strike price	Together with the average spot price (market value), the strike price is used to calculate the market premium. It is the main financial support rate for renewable energy. The strike price is quoted in cents per kilowatt hour and (as assumed in this position paper) can be determined by auction.
Uniform pricing	A type of price auction where every selected bidder is paid the price of the highest accepted bid.
Waterbed effect	The waterbed effect can occur if the total amount of emissions in the overall system (for example the ETS) is capped. While direct interventions in one place (for example direct subsidies in Germany) may reduce emissions locally, the saved emissions will simply be freed up for use elsewhere until the emissions cap is reached again. In the worst-case scenario, this means that direct interventions merely displace emissions rather than actually reducing them.
Windfall profits	Unforeseen profits due to unexpectedly high spot prices. It is assumed that windfall profits were not included in the cost calculations and are thus not a key factor in determining an installation’s profitability.

Summary

The expansion of renewable energy in Germany due to the energy transition has profoundly transformed the electricity system and the associated electricity market. Although the electricity market has demonstrated its fundamental ability to function effectively in recent years, the energy transition nonetheless poses a number of challenges. The nature of renewable energy gives rise to investment problems, not least in the following two areas of the electricity market:

- A future climate-neutral energy supply will require a massive expansion of renewable energy, especially wind and solar installations, which will generate most of our electricity. In view of the ambitious expansion targets and high financing requirements, the goal should be to establish a market system based on a cross-sectoral **carbon price by 2030**. In the interim, the **carbon price** should be steadily increased alongside **market premium models** that are gradually phased out.

- The transition to more decentralised, renewable energy generation poses new challenges for ensuring security of supply in the overall system. From an economic perspective, there is also an externality problem, since under the current system it is not possible to attribute individual responsibility for security of supply in accordance with the "polluter/user pays" principle. It is thus doubtful whether the current **energy-only market** will be able to guarantee an adequate level of security of supply in the medium term. Even today, Germany already needs an additional strategic reserve. Consequently, the establishment of **central** or **decentralised** capacity markets should be investigated as a means of providing long-term security of supply.

- It will be essential for implementation of the above policy options to be accompanied by complementary measures geared towards leveraging the flexibility potential of the current electricity system.

The need for a new electricity market design and the key challenges

The massive expansion of renewable energy is a fundamental part of the energy transition. Renewables are expected to account for eighty percent of electricity generation by 2030 and one hundred percent of electricity generation in the G7 countries by 2035. However, the nature of renewable energy means that its increasing integration into the market will give rise to two key investment risks:

Investment risks of renewable energy:

1. **Merit order effect**: Wind and solar installations have virtually no variable costs. Their very low marginal costs put them at the ‘top’ of the merit order, above other types of power plant. Since spot prices are determined by the last power plant used, if wind and solar installations account for a high percentage of electricity generation, a general reduction in spot prices ensues.

2. **Cannibalisation effect**: At any given time, the amount of electricity fed into the grid by a weather-dependent renewable source such as a wind installation is strongly correlated with the amount fed in by other installations of the same technology. The more electricity these installations feed in, the more they are affected by the merit order effect.

The challenge for investments in providing security of supply:

1. **Providing flexibility in a system with a high percentage of renewables**: The growing proportion of weather-dependent wind and solar installations is making electricity generation increasingly inflexible. To compensate for this, it is necessary to provide incentives for storage systems, more flexible demand and flexible additional capacity so that curtailments and temporary power cut-offs can be avoided.

2. **Changes in Germany’s electricity supply**: With the phase-out of nuclear power and its long-term plans to end coal-fired power generation, Germany will lack the capacity to cover the base load in the medium term. As a result, the role of natural gas is becoming increasingly important. To achieve full decarbonisation, other means of providing flexibility such as storage systems will also be necessary to replace the missing base load.

3. **Responsibility for security of supply**: From an economic perspective, the current electricity market has an externality problem: the cost of providing security of supply is borne by individual parties, whereas the benefits are collective. The electricity market’s competitive design offers little incentive for the individual actors to contribute to security of supply. This means that there is a danger of systematic underinvestment in flexible technologies or reserve capacity.

Market support versus grid support: The future market structure will combine the supply of renewable energy through the European grid system with large numbers of individual and decentralised structures. This will cause conflicts between the overall market's need for flexibility (market support) and the reduction of grid load and grid expansion requirements (grid support).

Options for a new electricity market design

Key Question 1: What are the most effective and efficient ways of **supporting renewable energy installations** and how can the electricity market design help renewable energy to prevail in the market **without financial support** and a government safety net?

At a glance: Four policy options for an efficient and effective model to support renewable energy

Policy option 1A: Fixed market premiums

- **In brief:** Fixed payment in addition to proceeds from selling on the power exchange.
- **Pros:** Incentive to act in a manner that supports the market and respond to price signals, reduces investment risk, can be flexibly adjusted to regional circumstances and specific technologies, can be combined with Power Purchase Agreements (PPAs), no legal obstacles to approval of properly designed market premiums.
- **Cons:** Direct marketing investment risk remains, danger of installations receiving too much/too little financial support, danger of windfall profits, limited incentive for curtailment in the event of negative market prices.

Policy option 1B: Sliding market premiums (current model)

- **In brief:** Premium prevents price from getting too low: 'guaranteed minimum selling price'.
- **Pros:** Confidence regarding minimum selling price, reduces investment risk, incentive to act in a manner that supports the market, prevailing model for supporting renewable energy in Germany (no need for major regulatory changes).
- **Cons:** Little incentive to respond to market price changes, limited incentive for curtailment in the event of negative market prices.

Policy option 1C: Contracts for Difference (CfDs)

- **In brief:** Premium offsets high and low prices: 'guaranteed selling price'.
- **Pros:** Highest investment security compared to other premium models, no direct risk of windfall profits.
- **Cons:** No incentive to act in a manner that supports the market, no incentive to invest in more flexible technologies or technologies that support the market, danger of inefficiencies and additional costs to businesses and the economy as a whole.

Policy option 1D: Focus on carbon pricing

- **In brief:** Instead of a premium, provides 'indirect support' through internalisation of carbon-intensive generation.
- **Pros:** Very cost-efficient, highly effective means of meeting climate targets, technology- and location-neutral, stronger market-based incentives than market premiums.
- **Cons:** Higher investment risk due to lack of direct financial support, danger of prices falling if there is a high proportion of renewable energy.

Key Question 2: Is the current market design **(energy-only market)** able to guarantee a **high level of security** of supply in the long term or are **additional investment incentives** required?

At a glance:
Four policy options for guaranteeing a high level of security of supply

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Policy option 2A: Energy-only market

- **In brief:** The necessary flexibility is provided implicitly via price signals.
- **Pros:** Simple and cheap to implement, market-based incentives, cost-efficient, no need for structural changes or establishment of an additional capacity market.
- **Cons:** Externality problem remains (no responsibility for overall system), danger of supply shortages due to lack of investment, danger of political intervention counteracting flexibility potential if spot prices are very high.

Policy option 2B: Energy-only market with strategic reserve (current model)

- **In brief:** Payment of power plants that do not participate in the regular electricity market to provide reserve capacity during supply shortages.
- **Pros:** Guarantees and increases security of supply, which can in principle be as high as desired; keeping this model only requires refinements rather than structural changes.
- **Cons:** Externality problem remains (no responsibility for overall system), comparatively poor cost efficiency, danger of politically motivated interventions if market prices are high, danger of free riding by neighbouring countries

Policy option 2C: Establishment of a central capacity market

- **In brief:** A second market is established to pay for (guaranteed) capacity.
- **Pros:** Guarantees high level of security of supply, incentive to maintain flexibility, cheaper and more efficient than current strategic reserve.
- **Cons:** Higher costs than energy-only market and decentralised capacity markets, danger of inc-dec gaming, less cost-efficient, susceptible to lobbying, flexibility potential of micro-consumers may not be leveraged.

Policy option 2D: Decentralised capacity markets with individual responsibility for security of supply

- **In brief:** Trading of certificates for flexible generation, providers have capacity obligation at peak demand times, security of supply level forms part of supply contracts.
- **Pros:** Resolves externality problem (transfers supply risk to providers), overcapacity less likely, better regional distribution, cost-efficient, promotes demand-side flexibility.
- **Cons:** Extensive technical and legal preparations required prior to implementation, lower-income households could suffer if badly designed.

Next steps

There is no fundamental question about the effective functioning of the current electricity market design. However, the current model will need to be reformed to ensure that the future electricity market design helps to meet the climate targets and reflects the fact that a high proportion of electricity will be generated from renewable sources. Regardless of which policy options are implemented, it will be essential to simultaneously leverage the **flexibility potential** in the current electricity system.

1. From both a climate effectiveness and a cost efficiency perspective, the long-term goal should be to move away from direct financial support of renewable energy and **focus** instead **on (cross-sectoral) carbon pricing**. This model should be implemented by 2030. During the transition period, the carbon price should increase gradually within a predictable **price corridor**. After weighing up the respective pros and cons, it will also be necessary to simultaneously implement an **appropriate market premium model** in order to achieve the massive expansion of renewables required by 2030. In the longer term, this market premium model should be phased out in favour of a focus on carbon pricing.

2. In view of the transition to a renewable electricity supply, it will be necessary to establish whether, in the future, a pure **energy-only market** will be able to guarantee the necessary **security of supply** and **flexibility**. Even today, it is necessary to maintain an additional strategic reserve outside of the market in order to guarantee the required capacity. By the same token, it will also be necessary to determine whether the establishment of a central or **decentralised capacity market** would be a better way of ensuring security of supply and increasing supply- and demand-side flexibility. If, after weighing up the pros and cons, the decision is taken to implement one of the capacity market models, extensive **technical and legal preparations** will be necessary, especially if the decentralised capacity market model is chosen. The design will also need to address the **social justice dimension**.

1 Introduction

Russia's invasion of Ukraine has combined with economic recovery effects after the COVID 19 pandemic to cause a temporarily sharp rise in energy prices in the EU since the end of 2021. This has heightened the debate among German and EU policymakers and experts about the need for a fundamental reform of the electricity market design. Even before the outbreak of the war, the German government's December 2021 coalition agreement contained a commitment to develop a new electricity market design that reflects the expansion of renewables. It is clear that tinkering with the current electricity market design will not be enough to enable the transformation of the energy system. The expansion of renewables continues to falter, not least due to protracted licensing procedures,0F[1] although numerous legislative proposals to improve these processes have been tabled in recent months. Despite this, if further progress is to be achieved it will be crucial to design a regulatory framework and market rules that enable a climate-neutral energy system with a high level of security of supply.

Notwithstanding the above, the current electricity market design has demonstrated its fundamental ability to function effectively in recent years. Market-based mechanisms have clear advantages – their cost efficiency ensures affordable electricity and they provide incentives to invest. Nevertheless, to overcome the challenges of the coming years and ensure that renewables are expanded fast enough to meet the climate targets in Germany, it will be necessary to systematically refine the electricity market design with these factors in mind.

Against this backdrop, a working group of the Academies' Project "Energy Systems of the Future" (ESYS) comprising 15 experts from the fields of economics, law and electrical engineering analysed the key problems with the current electricity market design and formulated a series of policy options for its medium-term development up to 2030. Rather than discussing short-term measures to tackle the current energy price crisis, the working group sought to identify the medium- to long-term changes needed to achieve the energy transition. The working group focused on the extent to which the different policy options support the market.[2] Their conclusions about the support they provide for the grid were drawn from previous ESYS studies, especially the position paper "Grid Congestion as a Challenge for the Electricity System".[3] The working group addresses two key questions in this position paper:

1 See acatech et al. 2022-2.
2 In the market, supply should meet demand as efficiently as possible.
3 See acatech et al. 2020-2.

1. What are the most effective and efficient ways of supporting renewable energy installations and how can the electricity market design help renewable energy to prevail in the market without financial support and a government safety net?

2. Is the current market design able to guarantee a high level of security of supply in the long term or are additional investment incentives required?

The position paper begins by explaining the principles of the current electricity market design and the main challenges in connection with the energy transition. First it focuses on the challenge of providing sufficient flexibility in the electricity system and on possible measures to improve this flexibility. It goes on to outline the criteria that the working group developed to compare the different policy options against each other. These criteria are used to evaluate the two sets of four policy options proposed by the working group for addressing the challenges associated with each of the two key questions.

2 Principles of the current electricity market design

Electricity is essentially a grid-based commodity. While it can be stored temporarily, doing so is (still) expensive and the options for storing it remain limited. A balance between supply and demand in the electricity system is thus particularly important. Any imbalance between the amount of electricity fed into and drawn from the grid, even if it only lasts a few seconds, causes a change in the grid frequency and, in the worst-case scenario, a power outage. Outages affect various parties who are connected to the grid, not just those responsible for the outage. Supply shortage scenarios pose an especially serious challenge for the system. Shortages can be triggered by problems with the procurement of feedstocks and raw materials (such as fossil fuels), failure to generate enough electricity and feed it into the system, or inadequate grid capacity.

Under the current market design, electricity is traded between suppliers and electricity providers and also some large consumers and other customers in one-hour or 15-minute intervals either through bilateral contracts or on the EPEX SPOT (European Power Exchange). All the bids are ranked by price in ascending order (the "merit order"). The generators with the lowest bid prices are scheduled to meet demand first, followed by the next generators above them in the merit order and so on until the demand for electricity is fully met.[4] The last accepted bid needed to meet demand determines the market or selling price. This price is paid to all the generators used for every unit of electricity that they sell (uniform pricing). This market mechanism seeks to ensure an efficient electricity price (see FOCUS ON Uniform Pricing versus Pay-as-Bid). Accordingly, the policy options discussed in this position paper are based on this underlying mechanism.[5]

In addition to day-ahead/intraday trading on the power exchange as described above, electricity can also be traded through other types of transactions on the power exchange or through over-the-counter transactions. These include forward transactions on the power exchange, long-term over-the-counter supply contracts known as Power Purchase Agreements, or other long-term agreements. These transactions are already established today and can be maintained in all of the policy options discussed in this paper. Nevertheless, the day-ahead price is a transparent reference price that provides a partial benchmark for the price of these other transactions, too.

In the ideal-typical case of a perfectly functioning competitive market, all the generators submit a bid price that is exactly the same as their marginal generation

4 It can be assumed that, in a competitive market, bid prices will correspond closely to the variable/marginal costs of generating electricity, so that the generators with the lowest variable costs will be the first to be scheduled.

5 Far from being unique to the electricity market, this mechanism is inherent to many organised wholesale markets where homogenous products are traded.

costs. Accordingly, generators with lower marginal costs (such as wind and solar installations, nuclear power plants and lignite-fired power plants) are scheduled more frequently than generators with comparatively high marginal costs which are not needed at times of low demand (such as hard-coal-fired and gas-fired power plants). On the other hand, generators with low marginal costs have relatively high investment costs that are not taken into account when calculating (short-term) marginal costs. Consequently, these generators rely on there being enough times with high selling prices for them to cover their investment costs in the long run.

While Germany's current electricity market is, in principle, based on the energy-only market model, this model is supplemented by various capacity mechanisms in order to guarantee security of supply. In addition to the grid reserve (to enable redispatch) grid operators can also draw on a strategic reserve. The strategic reserve only comprises power plants that do not regularly participate in the electricity market and thus have no influence on pricing and competition in the energy-only market. The strategic reserve (officially known as the "capacity reserve" in Germany) is used if supply cannot meet demand on the power exchange. The European Commission has sanctioned the establishment and use of a strategic reserve as a mechanism for dealing with a temporary problem. Germany's current strategic reserve was approved for a limited period, from February 2018 to 1 October 2025.[6]

Over the last 20 years, the financial support provided through the Renewable Energy Sources Act (EEG) of 2000 has enabled a steady increase in the proportion of renewable energy in the German electricity system. This now stands at almost fifty percent of all electricity generated. Market premiums are an established support mechanism that has been legally enshrined since 2012. At present, the main financial support model involves sliding market premiums (see policy option 1B) that are determined by auction and supplement the proceeds from direct marketing (EEG 2021). In addition, albeit to a much lesser extent, fixed market premiums have also been used in "innovation tenders". These are described under policy option 1A. However, the 2023 version of the Renewable Energy Sources Act steers clear of fixed market premiums and sliding market premiums have now also been used in innovation tenders since October 2022.

6 Commission Decision of 07.02.2018 on the Aid Scheme SA.45852 – 2017/C (ex 2017/N)), C(2018) 612 final, recital 114.

FOCUS ON Uniform Pricing versus Pay-as-Bid

The main advantage of the uniform pricing model is that it provides a transparent pricing mechanism that balances supply and demand. This enables high cost efficiency, since – under ideal conditions – it creates an incentive to submit a bid price in line with marginal production costs. This incentive is often lacking in alternative models such as the much-discussed pay-as-bid model, where power plants are paid the exact price of their individual bid. This is because it gives electricity generators an incentive to act strategically by submitting the highest possible bid that will still be accepted.[7] This means that electricity prices are unlikely to go down and there is no longer a transparent, easily interpreted price signal.[8] It could result in inefficiencies if the sequence in which power plants are scheduled to deliver power no longer reflects the marginal cost based merit order. The current electricity market model with its uniform pricing system has received public criticism because higher gas prices can lead to high spot prices. However, it remains a cost-efficient market model and its key features should therefore be retained under 'normal circumstances'.

7 See Oren 2014.
8 See Tierney et al 2008; Kahn 2001.

3 Challenges facing the current electricity market design

Variable renewable generation technologies such as wind and solar are expected to account for a significant proportion of Germany's future electricity supply. But these technologies have their own specific characteristics that must be taken into account. Firstly, the amount of electricity they generate depends on the weather. This means it varies over time and is rather difficult to control. And secondly, the investment costs make up a large part of the total cost, whereas the variable costs and thus the short-term marginal costs are virtually zero.[9] This gives rise to two key investment problems that are discussed in detail in this position paper. Firstly, the incentives to invest in renewables must be strong enough to ensure that the necessary investments are actually made (Key Question 1). And secondly, the investments that are made must ensure that enough flexible capacity is maintained to guarantee security of supply (Key Question 2). Appropriate mechanisms are required to resolve the partial conflict between these two goals.

Investments[10] in renewable energy must pay back within the installations' lifetime. However, the growing number of renewable installations being built affects spot prices, increasing uncertainty about future price levels.[11] The investment risks associated with renewable energy (Key Question 1) can be broken down into the following two effects:

1. **Merit order effect:** Renewables' very low marginal costs put them at the 'top' of the merit order. When renewable electricity is fed into the grid, it drives other forms of generation with higher marginal costs (for example gas) out of the market. This results in a lower spot price, since the spot price during a given period is determined by the marginal costs of the last power plant used. At least during times when electricity is being generated from renewable sources, the use of renewable energy thus causes a reduction in spot prices.[12] Known as the merit order effect, this phenomenon and the associated reduction in spot prices can already be observed in Germany and other countries.[13]

9 Some other types of renewable energy sources such as biomass do not share these characteristics, or only do so to a limited extent. However, wind and solar power will be responsible for the bulk of renewable electricity generation, and their market integration will be particularly challenging for the electricity system.

10 It is assumed that these will be private investments by companies or private individuals. Government investment is not considered here.

11 See Hirth 2015.

12 See acatech et al. 2022-1.

13 See Dillig et al. 2016; Cludius et al. 2014; Zipp 2017.

2. **Cannibalisation effect:** Because renewable energy generation is weather-dependent, the amount of electricity generated by different renewable installations is correlated at any given time. At times when there is a lot of sunshine, for example, solar installations push electricity prices down, since the fact that they are generating a lot of electricity leads to a particularly pronounced merit order effect. The cannibalisation effect describes this phenomenon, whereby variable renewable energy installations are disproportionately affected by the merit order effect. The cannibalisation effect gets stronger as the number of installations of the same variable generation technology increases. The construction of additional renewable energy installations thus leads to a reduction in the market returns of installations of the same technology in the form of "capture prices".[14] Consequently, there comes a point when it is no longer profitable to build more installations of this technology. The cannibalisation effect is especially pronounced for wind and solar installations.[15] In extreme cases when very high amounts of renewable electricity are being fed into the grid, it can cause the market value of this electricity to fall to almost zero.[16] In some situations, a temporal correlation between the amount of electricity being fed into the grid by two different technologies can also trigger a "cross-cannibalisation" effect. For instance, the construction of more solar PV installations can also push wind power capture prices down if there is a positive temporal feed-in correlation.[17] The cannibalisation effect can be mitigated by combining renewable energy generation with storage systems and by ensuring a broad geographical spread of new renewable energy installations. Increased sector coupling with flexible sectors can also lessen the cannibalisation effect by promoting greater demand-side flexibility.[18]

The challenges associated with renewables are by no means confined to the electricity market design – other barriers also exist. These should be at least partly addressed by the legislative changes adopted in 2022 (see FOCUS ON Legislative changes to accelerate the expansion of renewables).

14 Volume-weighted average price per unit of energy sold that a generation unit can earn in the market.

15 See Clò/D'Adamo 2015.

16 From 2015 to 2021, an increase in wind power feed-in caused an average fall in its market value of 3.7 percent, while a 10 percent increase in solar power feed-in caused a 1 percent fall in its market value. In extreme cases when very high amounts of renewable electricity (over 1,000 gigawatt hours) are being fed into the grid, the cannibalisation effect can cause the market value of this electricity to fall to almost zero, see Liebensteiner, M./Naumann 2022.

17 See López Prol et al. 2020.

18 See López/Schill 2021.

FOCUS ON

Legislative changes to accelerate the expansion of renewables

The immediate problems associated with the expansion of renewables are not confined to the creation of financial incentives – they also include protracted planning and licensing procedures, a growing shortage of skilled professionals and various other barriers. These barriers were addressed in a position paper by the ESYS working group “Development of Photovoltaics and Wind Energy”.[19] In 2022, a number of legislative changes were adopted with the aim of expediting planning and licensing procedures. The main reforms include amendments to the EEG, WIndSeeG, BNatSchG and Federal Building Code, and the adoption of the Wind Energy Area Requirements Act (WindBG).[20]

EEG: Under the amended Article 2 of the EEG, the construction and operation of renewable energy installations is deemed to be in the overriding public interest and in the interests of public security. When weighing up the priority of protected resources, renewable installations should therefore be given precedence, especially over nature conservation interests.[21]

WindSeeG: The 2023 version of the WindSeeG introduces a new, two-pillar financial support system. Developments must meet the requirements of the site development plan.[22] The amended Act stipulates that offshore wind installations in centrally pre-assessed areas will no longer receive any financial support. On the other hand, installations that are not in centrally pre-assessed areas are fundamentally eligible for financial support through the market premium.[23] For cases where there are several bids with a bid value of zero for a particular site, a dynamic bidding procedure replaces the previous system where the winning bid was decided by lot. From now on, the sites with a strike price of zero that are not in centrally pre-assessed areas[24] will be awarded via a process resembling an auction to the highest bidder.[25]

WindBG and Federal Building Code: The WindBG aims to accelerate the expansion of onshore wind by addressing the shortage of available land. To this end, it introduces binding land allocation targets (German: Flächenbeitragswerte) for Germany’s federal states.[26] These are based on the expansion targets in the EEG and the availability of suitable land in each state.[27] The amendment to the WindBG is reflected in changes to Article 249 of the Federal Building Code, which now contains additional special regulations for onshore wind installations.[28, 29]

19 See acatech et al. 2022c.
20 For more detail, see Harsch/Schäfer 2022; Schlacke et al. 2022; Zenke 2022.
21 See Harsch/Schäfer 2022; Parzefall, 2022; Schlacke et al. 2022; Zenke 2022.
22 Art. 2a(3), 4th WindSeeG 2023, see Harsch/Schäfer 2022.
23 Art. 19 EEG 2023 in conjunction with Art 24 (I)(2) WindSeeG 2023.
24 In the case of centrally pre-assessed areas, on the other hand, the winning bids are determined by a points system. In addition to the bid price, points are also awarded for contributions to decarbonisation and contributions to ensuring sufficient numbers of skilled professionals, for example, see Art. 53 (I) WindSeeG 2023.
25 Art. 21 WindSeeG, see Harsch/Schäfer 2022.
26 For the specific targets for each federal state, see Appendix 1 WindBG.
27 BT-Drs. 20/2355, 2f., see Harsch/Schäfer 2022.
28 Art. 2 WindBG, see Harsch/Schäfer 2022.
29 Other amendments have been introduced regarding the permissibility of developments in Art. 35 (3)(3) of the Federal Building Code, see Harsch/Schäfer 2022.

BNAtSchG: The Fourth Act amending the Federal Nature Conservation Act (BNatSchG) introduces a concrete significance test for breeding birds at risk of collision under Article 44 (5)(2) BNatSchG, as well as approximations and legal presumptions under Article 44 b in conjunction with Annex 1 BNatSchG.[30, 31] These changes aim to enable better and faster resolution of problems relating to species conservation law, improve transparency, and achieve an alignment of interests – all factors that have previously been a major cause of delays.

These changes should facilitate the expansion of renewables and the achievement of the energy transition. It will now be essential to ensure that the measures are properly implemented by the federal and state governments and industry. It will also be necessary to successfully and promptly accelerate the expansion of renewables as set out in the EEG and WindSeeG 2023, and to appropriately address the external challenges such as the shortage of skilled professionals and supply chain issues.[32]

The transition to more decentralised, primarily renewable energy generation poses new challenges for ensuring security of supply in the overall system (Key Question 2). These challenges must be addressed, since they will become increasingly acute as the transition progresses:

1. **Changes in Germany's electricity supply (coal and nuclear phase-out):** Germany completed its phase-out of nuclear power in mid-April 2023. It also plans to eventually phase out coal-fired power plants, which are also capable of providing base load power (the current deadline is 2038). As a result, a large percentage of the capacity that previously covered the base load will be lost and will need to be replaced by other energy sources. Weather-dependent renewable energy is not a perfect replacement. Gas-fired power stations will initially play a more important role until other solutions are found, since as well as covering peak loads (as in the past), it will also be necessary to balance out the fluctuations in the amount of electricity fed into the grid from variable renewable installations. If some parts of the gas supply are lost due to the war in Ukraine, renewables will have to cover most of the shortfall and the electricity system will need to be supported by additional flexibility solutions such as storage systems. Gas is a transition technology, and it seems unlikely that renewables will be able to replace it, at least in the next few years.

2. **Providing flexibility in a system with a high percentage of renewables**. Power plants that are fundamentally able to control how much electricity they generate and match their output to demand (for example hard-coal-fired, oil-fired and gas-fired plants) are increasingly being driven out of the market by weather-dependent renewables such as wind and solar. As a result, the electricity generation side is becoming harder to control overall, and thus less flexible. Consequently, the question of how to maintain an adequate degree of controllable flexibility in the electricity supply is becoming ever more pressing as the proportion of variable renewable electricity generation increases. Unless adequate incentives are implemented to compensate for this less flexible way of generating electricity (for

30 See Harsch/Schäfer 2022.
31 For the Banking Act (KWG) and WindSeeG 2023, see Harsch/Schäfer 2022.
32 See Harsch/Schäfer 2022.

example by storing it, converting it into synthetic fuels, increasing demand-side flexibility or using flexible renewables such as bioenergy), there is a danger that it may eventually no longer be technically possible to meet demand for electricity at all times (for instance during prolonged dunkelflautes). This would leave consumers facing load curtailments, temporary power cut-offs and blackouts.[33]

3. **Responsibility for security of supply.** German constitutional jurisprudence regards a secure energy supply as a public service.[34] It calls for both stable grid operation and functioning electricity trading (where supply meets demand). The grid operators are responsible for the stable and safe technical operation of the grid. Consequently, the grid has always been designed to cope with all foreseeable situations in order to prevent grid overload caused by situations where too much electricity is being fed into and drawn from the grid at the same time. The need to significantly expand the grid means that, in the future, it will be designed to cope with normal and probable situations rather than every conceivable extreme scenario.[35] This will require more curtailment and capping at peak demand times.[36] Responsibility for maintaining a basic balance between electricity supply and demand rests with the balance responsible parties, such as electricity traders and providers. From an economic perspective, this gives rise to an externality problem in the current energy-only market[37] model. It is not technically possible to ensure that the detrimental impacts of a power outage are borne solely by the responsible party – outages and their impacts also affect a wide range of third parties. The costs associated with increasing security of supply (for example the cost of maintaining reserve capacity for demand peaks) create an incentive to 'rely' on the investments made by everyone else. After all, the 'emergency backup' that these investments provide will benefit the whole system anyway. The fact that the costs are borne by individual parties, whereas the benefits are collective, leads to systematic underinvestment in the reserve capacity needed by the economy as a whole. The more competitive an electricity market's design, the less incentive there is for individual actors to contribute to security of supply. In order to address the growing challenge of security of supply, it will be vital to clarify which actors are fundamentally responsible for maintaining it and establish which methods the responsible parties can use to guarantee it in extreme situations. The options include supply and demand curtailment or maintaining reserve capacity.

33 See Kozlova/Overland 2022.

34 BGHZ 89, 226 (230); BVerfGE 134, 242 (338) – Garzweiler; see also BVerfGE 66, 248 (258) – Enteignung zugunsten Energieversorgung and BVerfGE 30, 292 (324).

35 See Deutsche Energie-Agentur (dena), 2012.

36 See Wagner 2018.

37 Although the energy-only market in Germany is supported by various supplementary mechanisms (not least the strategic reserve), these mechanisms at best only mitigate the effects of the externality problem and do nothing to resolve the underlying problem itself.

In overall terms, the locations chosen for renewable installations can increasingly cause conflicts between market support and grid support in the expansion of renewable energy. From a market perspective, it is efficient and desirable to focus on the locations with the most lucrative weather for renewable installations and make full and immediate use of the renewably generated electricity (without excessive curtailment and temporary storage). However, this approach requires a bigger increase in grid capacity. While a stronger focus on the expansion and use of renewable energy in ways that support the grid could reduce the grid expansion requirements, it may mean building new installations in locations with lower generation potential (in order to enable a wider geographical distribution of renewable installations). Furthermore, some of the renewable energy produced may not be optimally utilised (for instance because of curtailments due to grid congestion). This paper focuses on the use of renewable energy to support the market, while its use to support the grid is addressed in a previous ESYS working group position paper on “Grid Congestion as a Challenge for the Electricity System”.[38] Ultimately, it will be necessary to find the optimal balance between these two requirements.

38 See acatech et al. 2020-2.

4 Enabling adequate flexibility in the electricity system

Enabling an adequate level of flexibility is crucial for both of the key questions. The flexibility that is essential for guaranteeing security of supply (see Key Question 2, p. 53) is continuously declining due to the ongoing expansion of variable renewable energy (see Key Question 1, p. 35). However, electricity generation is not the only area where flexibility can be provided – it can also be achieved on the demand side or by using energy storage systems. In addition to the establishment of underlying market mechanisms, it is necessary to ensure that the available flexibility potential can actually be fully leveraged and utilised in every individual part of the electricity supply chain.

In general terms, flexibility refers to the electricity system's ability to balance supply and demand at all times, even in extreme situations. The serious consequences (for example a widespread blackout) of even a brief, temporary power imbalance highlight the importance of maintaining sufficient flexible capacity to ensure security of supply in the system as a whole. It should be borne in mind that different flexibility options have to meet different requirements. It should be easy enough to manage an oversupply of electrical energy, for example through curtailment of renewable generation. Shortages of electricity, meanwhile, can be categorised as either short-term (lasting a few hours) or longer-term (lasting several days, for example due to dunkelflautes). While short-term electricity shortages are technically and economically manageable, longer-term shortages pose far more serious challenges. For example, while a reduction or deferral of demand by private households and certain commercial electricity consumers can help to deal with short-term electricity shortages without any major disruption for the consumers in question, the impacts could be more serious if private households and other consumers are required to reduce their demand over a longer period. Ultimately, a combination of various measures at different levels will probably be necessary to achieve an adequate level of flexibility. Consequently, this chapter provides an in-depth discussion of how flexibility can be enabled in the individual supply chain areas of electricity generation, electricity trading, and electricity demand. A combination of measures across all of these areas can help to strengthen the flexibility of the overall system.

4.1 Electricity generation and storage systems

Targeted promotion of a more flexible electricity supply supported by storage systems is of central importance. There are various ways of ensuring a degree of supply-side flexibility despite the rising proportion of variable renewable generation. One possible approach is to deploy reserve capacity or additional energy storage systems. Another is the targeted promotion of more flexible renewable installations.

Additional **available generation capacity that is not weather-dependent** (reserve capacity) would support system flexibility and help to balance the electricity fed into the grid from variable renewable sources. State-of-the-art gas-fired power plants would currently be the best option for providing this capacity. However, (conventionally operated) gas-fired plants are also associated with major problems, including reliance on gas imports and additional greenhouse gas emissions. One possible renewable alternative would be the use of bioenergy. Bioenergy can provide the needs-based, flexible energy production to partly replace fossil fuels as a flexible energy carrier. However, the potential of biomass is limited and it should therefore only be used under optimal conditions.[39] Green hydrogen could also potentially be used in the longer term, although in this case, too, it would be necessary to address possible competition with industry and the danger of import dependency.

Another option is the deployment of additional **energy storage systems**, establishing them as standalone actors within the system. Tenders could be used to drive initial growth in this area. Boosting energy storage capacity could help to increasingly decouple electricity supply and demand in time. Although there are several different technologies for storing electricity (for example flywheels, electrochemical storage systems like Li-ion and redox flow batteries, chemical storage systems such as hydrogen cells and thermal storage systems), pumped-storage plants currently account for almost the entire global energy storage capacity.[40] However, it is becoming increasingly difficult to build further pumped-storage capacity due to the high fixed costs and the geographical requirements (two reservoirs at different elevations). Alternative storage media such as power-to-gas are not yet ready for market. In short, while energy storage systems are a promising means of providing flexibility, the availability of many storage technologies is currently very limited.

Simple, weather-dependent forms of renewable energy can also be controlled in at least one respect – if there is a surplus of renewable energy, renewable generation may need to be **curtailed**. In order to prevent a critical oversupply, it is vital to ensure that, when spot prices are negative, feed-in is curtailed as quickly as possible (or, ideally, that the surplus electricity is used elsewhere). At these times, any direct premium payments should be reduced to zero as soon as possible in order to give producers a direct incentive to cut back production (see the “4-hour rule” described under policy option 1B). As well as stabilising the electricity system, this provides renewable energy producers with additional incentives to minimise the amount of

39 See acatech et al. 2019.
40 See IRENA 2017.

surplus electricity that they feed into the grid (for example by storing it in the extra energy storage systems that have been installed or selling it in other submarkets).

Innovation tenders (see policy option 1A) provide an established, explicit means of promoting more flexible, low-emission power generation. Innovation tenders are only used to promote combinations of technologies (for instance wind/solar in conjunction with a connected storage technology or wind/solar combined with a flexible alternative generation technology such as gas). As a result, the installations promoted by innovation tenders are more flexible than renewable energy carriers used 'in isolation'. Sufficiently high tender volumes for EEG innovation tenders would result in the type of technology combinations described above accounting for a certain proportion of new renewable energy installations. It would be important to ensure that the additional technology used in conjunction with wind or solar power was a technologically appropriate means of delivering flexibility.[41]

In order to strengthen flexible electricity generation, the support mechanisms should ideally include as many solutions as possible (reserve capacity, energy storage systems, combinations of technologies) in a common system, so that the most efficient technologies can emerge and prevail in a technology-neutral setting. Indirect support through carbon pricing (see policy option 1D) must also be included, since its effectiveness at transmitting price signals provides a direct incentive for flexibility (or feeding more electricity into the grid in the event of a supply shortage). One explicit support option would involve stricter separation of support for renewable generation and support for flexibility in a central or decentralised capacity market (see policy options 2C and 2D). This would mean that energy storage systems and reserve capacity could benefit from flexibility premiums and there would be two complementary payment systems to incentivise flexible renewable installations (such as biomass plants). The effect would be to support the macroeconomically desirable goal of promoting more flexible forms of renewable generation over less flexible renewable installations.

4.2 Power trading (smart meters and real-time pricing)

The widespread installation of smart meters is key to enabling the first step of meeting the technical and legal requirements for providing flexibility on the electricity consumption side and allowing consumers to engage in power trading. While smart metering systems are already the norm in large industrial and commercial enterprises that consume a lot of electricity, they have yet to be installed in many smaller companies and private households. Without smart metering, there is little point even discussing the possibility of accessing demand-side flexibility, since it would not be technically possible to implement variable electricity tariffs based on real-time pricing (prices that reflect electricity supply costs with minimal distortion). Complex

41 Ideally, the technology should temporarily store surplus electricity, for example in a battery or in the form of syngas or hydrogen. At the very least, however, the additional technology (for example a connected gas-fired power plant) must be able to step in when the primary generation technology is unable to produce electricity due to the weather conditions.

processes that could help to increase flexibility (for example smart cities[42]) also rely on a fast, nationwide 5G network.[43]

In addition to installing the necessary hardware, the relevant legal requirements must also be met. As well as the provisions of the Act on Metering Point Operation (German: Messstellenbetriebsgesetz), it is also necessary to comply with data protection regulations if personal data is processed. Consequently, the design of the data processing processes required to enable digitalisation must meet high overall legal standards, making it harder to successfully roll out the relevant business models.

On 20 April 2023, the German Bundestag passed an Act to relaunch the digitalisation of the energy transition.[44] The Act sets out a roadmap for establishing the digital infrastructure for a climate-neutral energy system by 2030. The German government wishes to accelerate the rollout of smart meters by relaxing the "three manufacturers rule". Until now, this rule required three independent manufacturers to be certified for each development stage. It also aims to enable an "agile rollout". This means that certified devices can be installed immediately, with additional functionality being added at a later date via a software upgrade. From 2025, suppliers will also be required to offer dynamic electricity tariffs.

Once the technical and legal requirements have been met, the second step is to ensure that the **design of the electricity wholesale markets** allows electricity supply costs to be reflected in the price with minimal distortion (real-time pricing). This provides the basis for the 'right' (i.e. undistorted) market signals and corresponding incentives. It is already partly the case[45], although some distortions do still exist in the wholesale market. These include excessively large bidding zones (and the associated necessary price signals in redispatch), or excessively long trading intervals.[46] However, since the elimination of these distortions entails major (policy) challenges, it will be necessary to weigh up the respective pros and cons.

Finally, the third step is to enable direct **market access for consumers** so that wholesale prices can be passed on to them with as little distortion as possible. While large consumption points (for example in industry) can to some extent already respond to price signals, small consumers (such as private households and small businesses) have very limited access to the market. However, this access is vital in order to create incentives for end consumers to provide flexibility (for example prosumers like electric vehicle owners with suitable bidirectional grid connections). Participation in power trading could be enabled either through central management by aggregators or through a decentralised approach using decision-making algorithms, for example. If

42 In an integrated smart city model, for example, a complex process such as autonomous driving could enable innovative carsharing services. As well as providing a mobility service, the cars in an electric car fleet could be coordinated to provide a decentralised (mobile) energy storage system and source of flexibility.

43 It should also be possible to adapt the hardware to advances in software development. This means maximising interoperability and providing a wide range of interfaces. See acatech et al. 2021.

44 See Bundesrat 2023.

45 See Bichler et al. 2022; Ketter et al. 2018; Cramton 2017; Ketter et al. 2016.

46 One possible solution might be to reduce the trading interval on the power exchange from 15 to 5 minutes. While this would bring trading intervals a step closer to real-time pricing, it would triple the number of separate bidding intervals. It would only make sense if it was not detrimental to liquidity in the individual auctions, thereby weakening competition.

demand-side flexibility is to be used in a manner that supports the market, it must be included in the regular pricing system.

More complex energy markets can enable more targeted coordination of the balance between production and demand and facilitate the integration of less flexible renewables like wind and solar – greater demand-side flexibility means that the flexibility of the electricity generation side becomes less important. Demand-side flexibility also reduces reliance on flexible fossil fuels. For small consumption points, however, it may be more cost-effective to use less energy-intensive control systems instead of complex, energy-intensive decision-making algorithms.

4.3 Increasing demand-side flexibility

It is also possible to increase the flexibility of electricity demand. One means of doing so is through energy-saving (energy efficiency) measures that are effective regardless of when the electricity is consumed. New tariff options for electricity customers can also help to reduce demand during shortages caused by high demand at times when less electricity is being generated. This can help to match electricity demand more closely to (increasingly weather-dependent) electricity generation and smooth demand peaks at times when less electricity is being generated, thereby stabilising the electricity system and reducing the likelihood of shortages. In order to enable demand-side flexibility, it is necessary to fulfil the relevant technical and legal requirements and provide adequate economic incentives to ensure that flexibility is used in a manner that supports the system.

Large consumers (such as energy-intensive industries) already have relatively good **access** to the spot market. They can already trade at spot prices on the spot market using alternative transaction types (for example forward contracts or OTC transactions). In principle, this opens up the prospect of real-time pricing, which creates an incentive for them to flexibly adjust their demand in response to fluctuating bid prices. In this context, it is important to ensure that price signals are not too strongly distorted by additional grid tariffs. If (as is currently possible) these depend on the consumption point's peak demand, demand will potentially not increase as much at peak production times as would be desirable from a macroeconomic perspective.[47]

More flexible demand among small consumers (such as private households and small businesses) is also already possible to some extent. Large domestic appliances, for example, can enable a limited degree of flexibility with regard to electricity demand times. In the longer term, increased sector coupling in the heating (heat pumps) and mobility (electric vehicles) sectors and the use of private energy storage systems hold huge potential for increasing demand-side flexibility in the private sector (see Chapter 5.2 for the potential of sector coupling).

At present, however, the retail price for small consumers such as private households is usually fixed for a long period of time (often twelve months for customers who are not with the default provider). It remains the same throughout this period and

47 See SynErgie 2020.

does not reflect daily or annual spot price volatility. A significant proportion of the price is consumption-based, that is calculated on a per kilowatt hour basis. Moreover, the retail price is made up of several components – at times when prices are normal, only around a quarter to a third of the price relates to supply costs and margins. Grid tariffs and electricity tax are additional fixed components that do nothing to encourage consumers to support the system through demand-side flexibility. But as components of consumption-based prices, they have two problems. Firstly, fixed grid tariffs do not reflect actual grid costs, which are much more closely related to annual peak load than total energy consumption. And secondly, these fixed components increase the difference between the electricity purchase and sale prices, creating a stronger incentive for behind-the-meter consumption. This can actually discourage behaviours that support the system. Electricity demand – and thus spot prices – are typically higher during the day than at night. Take the example of a household with its own solar panels that generate electricity during the day and with completely flexible demand for a consumer such as an electric car that can be charged at any time. The best way of supporting the system would currently be to feed the electricity generated during the day into the grid and charge the car battery at night (when demand for electricity is lower). However, the incentive for behind-the-meter consumption encourages the household to charge the battery directly with the electricity generated during the day. In other words, the electricity price structure does not incentivise behaviours that support the system or grid. A flexible system would be able to respond appropriately to changes in the relevant parameters.

Once the technical requirements (smart meters) for participation in power trading have been met, it is also necessary to provide an adequate **(financial) incentive** to respond to price signals. For instance, new contract structures should provide financial compensation for consumers who reduce or defer demand. Smart meters could influence electricity customers' demand patterns by displaying real-time prices. Cheaper tariffs could also be offered to customers willing to accept a certain risk of supply interruptions. These consumers' electricity supply could be interrupted for a short while at times of high system stress in order to reduce the pressure on the system. In the immediate future, this approach could be particularly effective in the industrial sector.[48] Small consumers who are sometimes able to meet their own electricity demand could be allowed to opt in (for example if they have solar panels and storage batteries, see policy option 2D). Households with heat pumps or heat storage systems could also voluntarily accept temporary demand curtailments without suffering any negative impacts.

It is also vital to ensure that providing demand-side flexibility is simple (for example fully automated) and cheap (i.e. the investment costs must not be too high). Smaller consumption points in particular can also engage indirectly in regular spot market trading via aggregators. Appropriate contract structures could be employed to increase acceptance of volatile electricity tariffs (and the removal of price guarantees). For instance, consumer risks could be covered by basing prices on an average historical

48 The potential in industry is explored e.g. in the Kopernikus project SynErgie: https://synergie-projekt.de/ergebnis/flexpotenzial-industrie.

demand profile with predictable prices and – where relevant – providing a risk premium for one year.[49]

It is also important to bear in mind that, although greater demand-side flexibility can play an important role in coping with short-term shortages, significant reductions in demand over a prolonged period (for instance in the case of dunkelflautes lasting several days) can be problematic, especially for small consumers.

4.4 European grid integration

The final measure to strengthen power grid flexibility involves the expansion of the German grid and close international integration, especially within Europe. Closer international integration and increased cross-border electricity trading can mitigate the variable nature of renewables by providing access to electricity from generators over a wider geographical area whose feed-in profiles partly balance each other out.[50] Exporting electricity could prevent the need for curtailment of renewable installations, while electricity imports could help during periods when there is little wind or daylight. This approach could also prevent grid congestion and reduce the need for regional proximity of generation and consumption. In other words, more renewable installations could be built in locations with the greatest generation potential. A significant expansion of the grid can thus reduce generation and reserve capacity requirements across the system as a whole.

The benefits of expanding the grid and interconnection capacity must be weighed up against the high levels of investment in the power grid that this would entail. However, the rising proportion of electricity generated from variable renewable sources means that a major expansion of the grid will be required anyway to enable efficient use of the electricity generated.[51] The cost of expanding the grid is relatively low compared to the benefits, and it should also reduce additional costs such as the cost of reserve capacity.[52]

Lastly, sufficient grid capacity must be available to enable the provision of flexibility from lower grid levels. In this context, there is a conflict between the market and system support provided by flexibility and its support for the grid. It will nevertheless be necessary to expand and provide access to sufficient distribution grid capacity to ensure the economically rational use of flexibility from the lower grid levels.

49 See Agrawal/Yücel 2022
50 See Schaber et al. 2012.
51 Ringler et al. (2017) show how increasing interconnection capacity can help to improve the utilisation of power generated from variable sources and improve welfare.
52 For further details, see Schaber et al. 2012 and Frontier Economics/IAEW 2020.

5 Criteria for evaluating the policy options

Adapting the electricity market design to a market dominated by renewables will not just require solutions to the challenges outlined above. The new system will also need to fulfil a number of other requirements. The working group defined these requirements as criteria for evaluating the policy options discussed under Key Questions 1 and 2.

The new electricity market design will need to be **effective** in terms of meeting the climate targets, i.e. reducing greenhouse gas emissions (Key Question 1) and in terms of guaranteeing security of supply (Key Question 2). It must also **ensure** the desired **expansion** of renewable energy and meet the relevant requirements (for example regional and technological differentiation, generating electricity as near as possible to the point of consumption). Ensuring the expansion of renewables will also mean addressing the associated **financing risks**.

As well as the financing volume required for the energy transition, it will also be increasingly important to take **macroeconomic cost efficiency** into account. This will ensure that the overall cost of the energy transition is kept as low as possible and make renewables more competitive. This criterion is primarily evaluated from a market support perspective. While the location- and technology-neutral implementation of the policy options can be evaluated as promoting macroeconomic cost efficiency and thus supporting the market, location-neutral implementation can also increase grid capacity requirements (see Chapter 3).[53] This position paper therefore recommends location neutrality that is compatible with existing or planned grid capacity.

Cost efficiency is also extremely important for the energy transition since it supports **public acceptance** by keeping electricity prices as low as possible. Lower costs for the general public can be key to achieving widespread public support for the energy transition as a whole. Given the high projected cost of the transition and the growing proportion of renewable energy, it will be increasingly important for the future electricity market design to ensure cost efficiency, albeit without jeopardising the necessary expansion of renewables and security of supply.

It will also be necessary to ensure that the relevant policy measures can be **legally implemented**. It will be especially important to address the measures' compliance with EU state aid rules and the constitutional law provisions relating to security of supply. When developing the model, it is also important not to overlook its general **compatibility** with international and European regulations. The chosen financial support model will furthermore need to be compatible with other existing and

53 This dilemma could be resolved by introducing grid tariffs and smart connection agreements that strengthen resilience, for example; See acatech 2021.

planned regulations so that it can be integrated with international (European or global) financial support systems, for example.

It will also be important to be aware of the factors affecting the **political viability** of the policy options at both the EU and German federal government levels. This criterion includes the fact that policymakers must be able to push through the chosen instruments for meeting the climate targets (for instance a high carbon price) without watering them down due to public pressure. A realistic assessment of any barriers in the policy process will make it easier to implement the policy options proposed in this position paper.

Finally, the **timescale for implementing** the measures is also important. Since many of the challenges already exist today and are likely to get even tougher, the measures to tackle them must be implemented as soon as possible. Consequently, the evaluation should consider how quickly each policy option can be implemented.

The development and evaluation of the policy options in this paper can largely be addressed independently of the distributional questions that must also be resolved. These questions are also key to the success of the energy transition – the environmental dimension must always take the social dimension into account. For example, advocating a higher carbon price raises the question of how the extra costs will be covered, especially by low-income households. The same applies to a model where individual private households assume more of the risks associated with security of supply. While this paper does highlight the importance of the accompanying social policy measures, their exact nature is a path-dependent question that follows on from the mix of options chosen in each particular situation. This is not so much an energy policy question as a social policy question that should be the subject of ongoing analysis. However, this analysis lies outside the scope of this paper. (Targeted) redistribution measures based on market outcomes are fundamentally possible in all of the following policy options without the need for direct market intervention.

6 Key Question 1: Financial support models for the expansion of renewables

6.1 Policy options

The working group analysed four options for market-based compensation of renewable electricity generation in the future electricity market. These options have been widely discussed in the current debate. The market premium models include fixed market premiums (policy option 1A), sliding market premiums (policy option 1B) and Contracts for Difference (policy option 1C). The premiums are usually determined by auction (tender). Accordingly, the following sections assume the use of tender instruments to promote a pre-defined level of expansion. These premium models supplement the returns achieved through direct marketing. A significant departure from these models would be to dispense with their targeted financial support for renewable energy in favour of 'indirect support' through a sufficiently high carbon price (policy option 1D).

6.1.1 Policy option 1A: Fixed market premiums

In fixed market premium models, renewable electricity is sold directly on the power exchange (or through bilateral contracts), but is also subsidised via a fixed (sometimes technology-dependent) premium (paid in cents per kilowatt hour of electricity fed into the grid, for example).[54] The level of the **fixed market premium** is constant and does not depend on the return or capture prices achieved by a generator during a given period. Consequently, the variation over time in renewable energy returns is the same as the variation in the capture prices that generators would be able to achieve in the market without any financial support. At the same time, renewable energy installations are subject to all the market rules (such as forecast and balancing risk), resulting in a focus on market and system requirements. However, with fixed market premiums, the returns from market sales only need to cover a smaller part of the cost in order for renewable energy installations to be profitable and become established in the electricity market in the desired numbers.

54 See Flues et al. 2013.

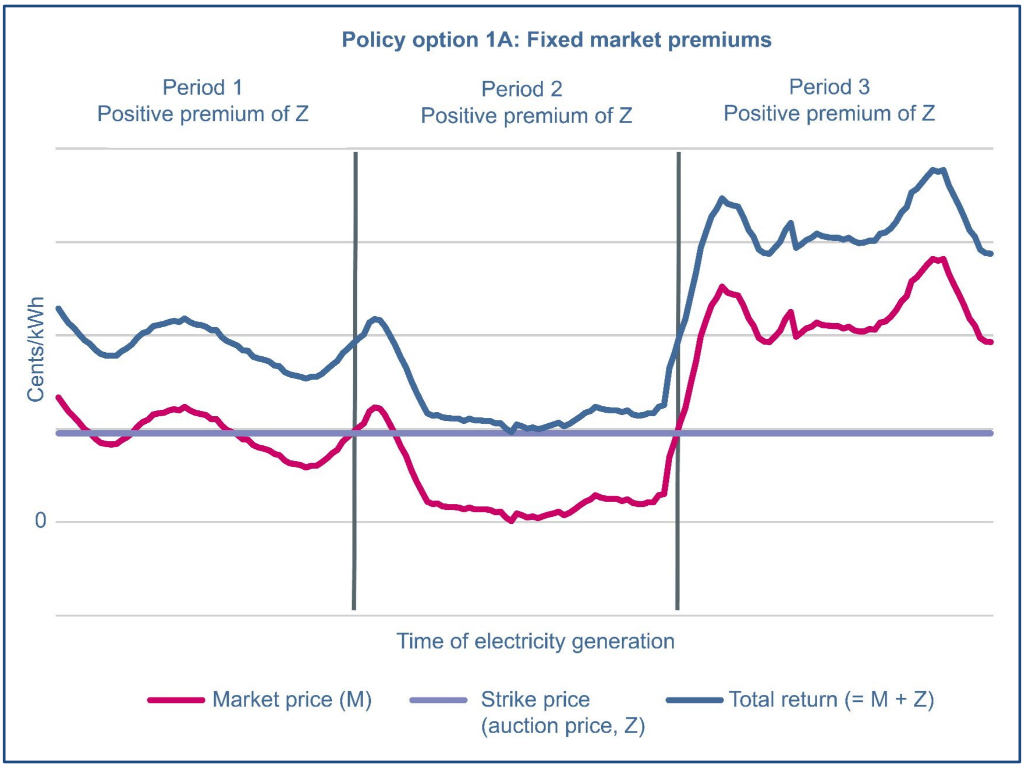

Figure 1: How fixed market premiums work (Source: authors' own illustration)

Figure 1 illustrates the returns of a renewable installation over time. The market price is the price that an installation can achieve on the regular spot market. On average, it achieves a moderate market price in Period 1, a low market price in Period 2 and a high market price in Period 3. The strike price in the auction is the negotiated fixed market premium. Its level is not connected to the achieved market price and thus remains the same across all three periods. In all three periods, the total return from the installation is therefore the sum of the achieved market price and the market premium.

6.1.2 Policy option 1B: Sliding market premiums

Sliding market premiums are an alternative way of providing financial support for renewable energy. In this model, the strike price is typically determined by auction. If an installation's reference market price (i.e. the expected market price) is lower than this strike price during a given period (for example one month), the difference is made up by a positive premium. The reference market price is the hypothetical average price that a similar installation could have achieved in a given period (the reference period) and is not linked to the actual prices achieved by a given installation. If the reference market price is higher than the strike price during a given period, the installation operators only earn the achieved market price and are not paid an additional premium. This model reduces price fluctuations over time compared to fixed market premiums (policy option 1A) and models without direct financial support in the form of premiums (policy option 1D). Sliding market premiums prevent returns from getting too low by acting as a kind of guaranteed minimum payment or lower limit on the market price. As well as straight financial support, they thus also include a price guarantee component.

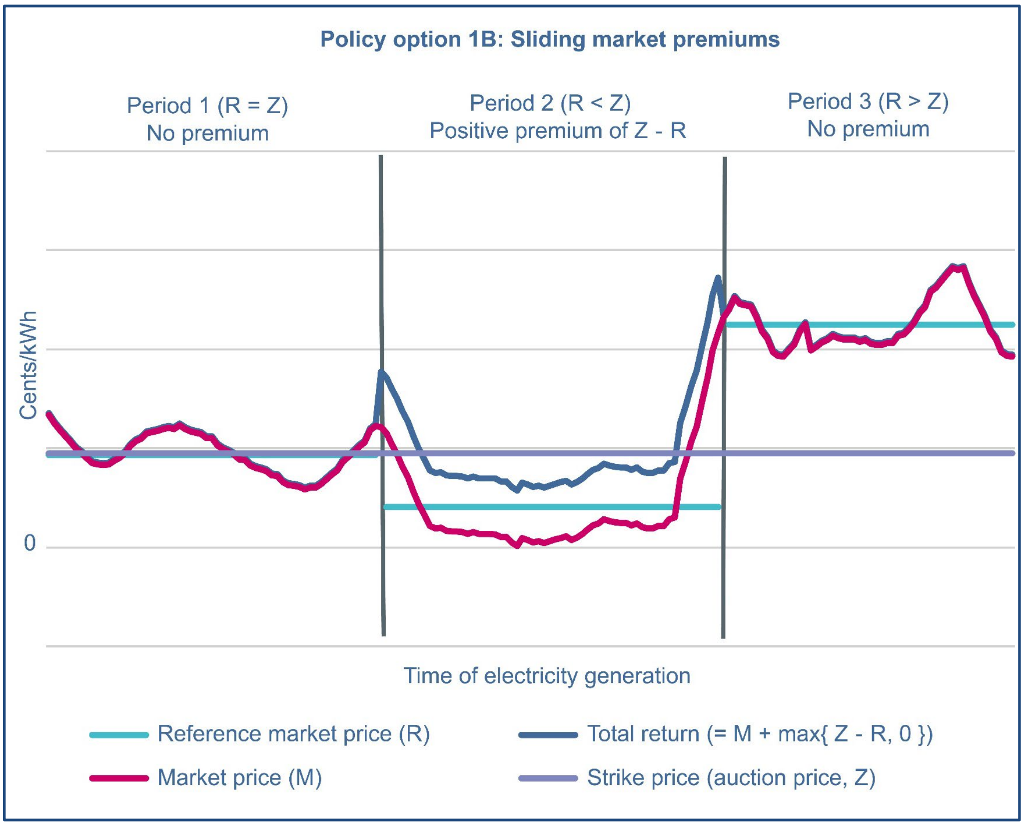

Figure 2: How sliding market premiums work (Source: authors' own illustration)

Like Figure 1, Figure 2 also illustrates the returns of a renewable installation during periods with average (Period 1), low (Period 2) and high (Period 3) market prices. The reference market price is the average market price that a renewable installation of this type could have achieved during a given period. The strike price in the auction denotes the level of the sliding market premium, i.e. the average minimum payment for each period. In Figure 2, the strike price is exactly the same as the reference market price in Period 1. As a result, no additional premium is paid during this period. In Period 2, the reference market price is lower than the agreed strike price. In this period, a premium is paid that makes up the exact difference between the two. The total return from the installation is thus increased by the exact amount of this premium. In Period 3, the reference market price is higher than the strike price, and no premium is paid.

6.1.3 Policy option 1C: Contracts for Difference (CfDs)

As in the sliding market premium model, in the **Contracts for Difference** (CfDs) model, a strike price is determined (by auction). However, unlike the sliding market premium model, any upward or downward variation in the reference market price from the agreed strike price over a given reference period is offset by either positive or negative premiums. This means that prices are closely tied to the strike price. In the sliding market premium model, extra profits can be achieved at times of higher electricity prices. As a result, operators can build these projected extra profits into their calculations for recouping their investment. Since these extra profits cannot be achieved with Contracts for Difference, it can be assumed that the strike prices determined by auction will be significantly higher in this model than in the sliding market premium model. Especially if short reference periods are used, this financial support model is very similar to fixed feed-in tariffs, the main difference being that the premiums are determined by competitive tender.[55]

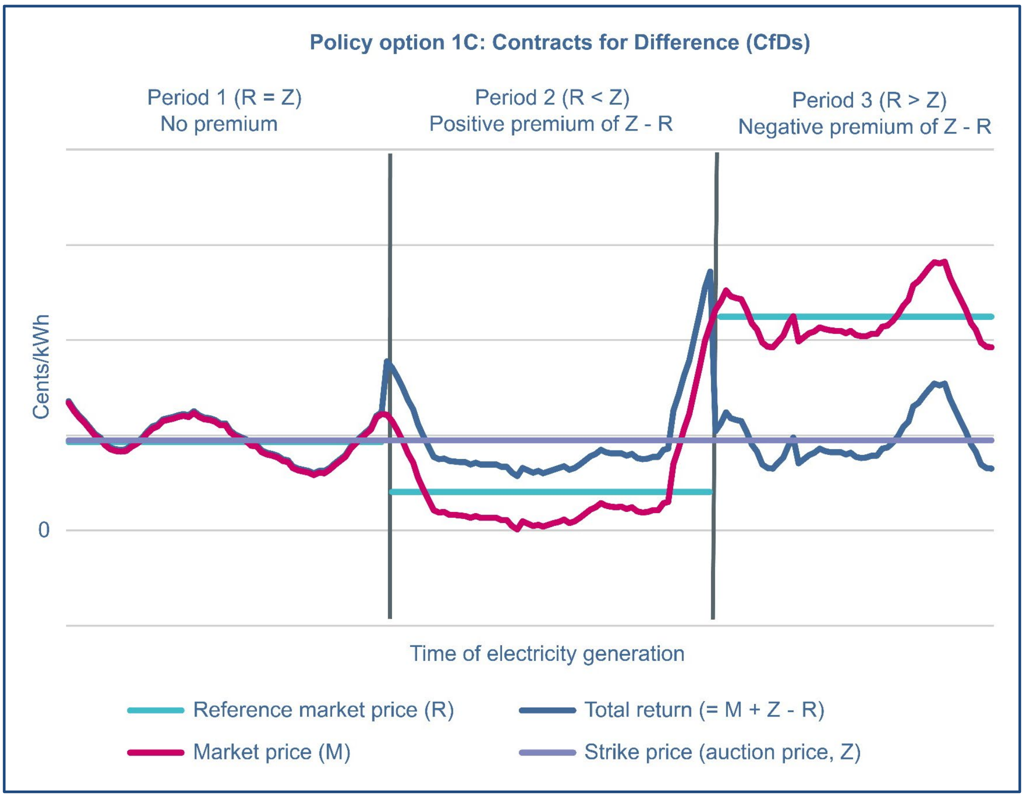

Figure 3: How CfDs work (Source: authors' own illustration)

Figure 3 shows the same market price trends for a renewable installation as in Figures 1 and 2. The strike price denotes the negotiated CfD price. As in Figure 2, no premium is paid in Period 1 (strike price = reference market price). In Period 2, the difference between the strike price and the reference market price is made up by a premium exactly equivalent to this difference, again as in Figure 2. In Period 3, the reference market price is higher than the strike price and a negative premium applies. This offsets the difference between the high reference market price and the strike price, reducing the average achievable capture price to the level of the strike price. As a result, the total return from the renewable installation during Period 3 is reduced by the amount of this negative premium.

6.1.4 Policy option 1D: Focus on carbon pricing

Carbon pricing is an indirect means of supporting[56] renewables, since it increases the levelised cost of electricity of all competing (fossil) fuels based on their emission intensity. Since the electricity sector is covered by the EU ETS, electricity generation is already subject to a current carbon price of 85 euros per tonne (as of 27.04.2023). This significantly increases the cost of fuels with high emissions such as lignite, while at the same time making lower-emission technologies, especially renewable energy technologies, more competitive. The aim is to allow these technologies to compete in

55 While fixed feed-in tariffs can also theoretically be determined by tender, this does not usually happen in practice.

56 It would be somewhat misleading to talk of "financial support" in this context, since carbon pricing aims to reflect the external costs of CO_2 emissions. Instead, the failure to internalise these costs in systems that do not use carbon pricing should be regarded as providing "financial support" for generation technologies that are harmful to the climate.

the electricity market as regular, unsubsidised players. At present, carbon pricing is already employed alongside direct financial support models and can thus also supplement policy options 1 to 3. However, a decision to focus on this fourth policy option would mean relying on carbon pricing – which works by influencing how electricity is generated – as the main support model (without any significant direct financial support). Ideally, this model would apply throughout Europe and be implemented directly through the EU ETS.

6.2 Policy option pros and cons

The following table provides an overview of how well the different policy options fulfil the requirements identified by the working group for the electricity market design in 2030. The table is followed by an in-depth evaluation and discussion of the different options' pros and cons.

	Policy option 1A: Fixed market premiums	Policy option 1B: Sliding market premiums	Policy option 1C: Contracts for Difference (CfDs)	Policy option 1D: Carbon pricing
Effectiveness (in terms of meeting climate targets)	O	O	O	+
Compatibility with international systems and EU mechanisms	O	O	-	++
Macroeconomic cost efficiency	+	O	-	++
Minimises financing risks for renewables	O	+	++	-
Ensures renewable expansion targets are met	+	++	++	O
Political viability	+	+	+	O
Legal implementation	O	O	O	+
Implementation timescale	Short-term	Immediate	Short-term	Longer-term

Table 1: Comparison of policy option pros and cons (- requirement not met; O requirement partly met; + requirement met; ++ requirement particularly well met)

6.2.1 Policy option 1A: Fixed market premiums

+ Pros: Fixed market premiums provide incentives to act in a way that supports the market, since a significant proportion of an installation's revenue depends on the success of direct marketing rather than only on the premium payments. Market incentives (in the form of price fluctuations) are passed on to the market players without distortion since the returns fluctuate by the same amount as the purely market-driven capture prices. This creates incentives to respond to price signals, for example by using technologies particularly suited to feeding in electricity at times of high demand and high spot prices.[57] Fixed market premiums are thus especially suitable for promoting more flexible assets that can respond to low spot prices by 'delaying' the time when they feed in electricity. By providing a guaranteed component of the total return, they can also help to reduce investment risks. However, because they are good at passing on price signals, they also provide less protection against a sharp drop in individual capture prices.

In principle, fixed market premiums can also be adjusted as required. If necessary, certain regions (for example to reduce grid congestion) or technologies can receive extra support in the shape of a higher premium without simultaneously creating a strong price guarantee component (as in policy options 1B and 1C). As a relatively simple mechanism, market premiums can also be used for over-the-counter transactions such as Power Purchase Agreements (PPAs), which often involve long-term contracts to supply electricity at certain prices, meaning that the electricity is not traded on a power exchange.

As a support mechanism established by the Renewable Energy Sources Act, market premiums have been recognised and legally sanctioned since 2012, especially in the form of sliding market premiums. Fixed market premiums have hitherto only been used in the specific case of innovation tenders. Any amendments or updates to these measures would need to be approved as being compatible with EU state aid rules. However, provided that the market premiums are properly designed and reflect the European Commission's most recent Climate, Energy and Environmental State Aid Guidelines, there is no reason why they shouldn't obtain this approval, as they have in the past. Accordingly, this requirement is deemed to be partly met in Table 1. Against the backdrop of its more ambitious climate targets, the EU has recently adopted a more flexible, less stringent approach to the compliance of financial support schemes with the state aid rules. Problems are most likely to occur if the support is not extended to foreign-owned assets or if technology neutrality is not ensured. In the medium term, these two factors could jeopardise the approval of market premiums.

- Cons: Because this model includes direct marketing and is affected by spot prices, some investment risk still remains. There is also a relatively high danger of installations receiving too much or too little financial support. Existing installations could encounter financial difficulties if spot prices remain unexpectedly low for a prolonged period. This means that their financing may need to be privately insured. On the other hand, since the premiums are still paid when spot prices are (unexpectedly) high, windfall profits are also likeliest to occur in this model (see FOCUS ON Windfall Taxes). In other words, companies can benefit from extra profits if capture prices reach an unexpectedly high level that was not taken into account in their investment decisions or business operations. This can lead to undesired deadweight effects due to the provision of financial support that would not actually have been necessary to finance the

57 One example is the use of east-west rather than south facing solar panels. While this orientation means the panels generate less electricity overall, they generate more in the morning and evening, enabling a better response to the typical morning and evening demand and price peaks.

installations. Both macroeconomic cost efficiency and public acceptance of the financial support measures can suffer as a result.

In addition, individually differentiated fixed market premiums are neither technology- nor location-neutral. Differentiated premiums can thus result in suboptimal location and technology choices, to the detriment of cost efficiency. However, market premiums can in principle be technology- and location-neutral if a single premium is used instead of differentiated ones – as in all the other premium models discussed here. In the event of negative electricity prices, there is only a limited incentive for voluntary curtailment. The incentive only occurs if the negative return in the electricity market is higher than the premium payment.

FOCUS ON
Windfall Taxes

In the merit order, gas-fired power plants are often key to determining electricity prices. Consequently, the temporary hike in gas prices caused mainly by Russia's illegal invasion of Ukraine has led to a pronounced overall rise in electricity prices. As a result, the inframarginal electricity generation technologies that do not determine prices, such as wind and solar, have profited from the price hikes even though their costs have not risen (to the same extent). In 2022, this prompted an extensive debate about whether these windfall profits should be taxed.[58] This could be done through a direct market intervention to tax one hundred percent or, as proposed in Germany, ninety percent of the profits of inframarginal electricity generation above a certain threshold. Alternatively, the use of gas to generate electricity could be subsidised, thereby lowering the marginal costs of the gas-fired power plants that determine electricity prices.[59]

The steep rise in electricity prices is the result of a one-off situation – no-one could have predicted that prices would go up so sharply. Moreover, investments in new production assets such as renewable energy installations take time. This means that they will have little short-term impact in terms of increasing generation capacity and bringing electricity prices back down. A short-term market intervention and partial taxation of windfall profits would therefore appear to be justified in the current context. A "price cap" for inframarginal power generation technologies would also provide direct relief for electricity consumers.[60]

On the other hand, the long-term impacts must also always be considered. For instance, high electricity prices can significantly increase the incentive to invest in technologies with lower marginal costs, especially renewable energy technologies. The high gas prices provide a particularly strong incentive to invest in power plants capable of supplying electricity at peak load times and thus replacing gas-fired power plants during periods when gas is currently needed to produce electricity. A windfall tax would reduce the incentive to invest in these technologies. Overly restrictive tax measures would thus waste the opportunity for more and faster investment. In the worst-case scenario, they could actually slow down the expansion of renewables and prolong dependency on fossil fuels like gas and their commodity prices.[61] On the consumption side, it is important to recognise that a fall in electricity prices would lead to an increase in electricity consumption, which would also affect the level of gas-fired power generation. It would furthermore encourage producers to export the cheaper electricity to third countries (such as Switzerland). These factors would counteract the effectiveness of the necessary energy-saving measures.

In short, windfall taxes must strike a balance by enabling the necessary short-term reduction in electricity prices and providing relief for consumers without wasting the long-term opportunities. Additional relief measures could be taken as a second step (after the market outcome) rather than as a direct market intervention. To avoid distorting price signals and incentives to save electricity, these relief measures should not be tied to actual electricity consumption. The relief measures should also be targeted at those most in need.

58 At EU level, see also Council Regulation (EU) 2022/1854 of 06.10.2022 on an emergency intervention to address high energy prices.
59 See Haucap et al. (2022).
60 See Monopolkommission (2022).
61 It is also important to ensure that market interventions do not undermine confidence in the legal framework, resulting in new investment barriers and risks. Retroactive measures that would cause a massive loss of confidence should therefore be avoided.

6.2.2 Policy option 1B: Sliding market premiums

+ **Pros:** Sliding market premiums provide a high level of confidence with regard to the minimum selling price and thus – in addition to the premium payments themselves – also have a strong price guarantee component compared to policy option 1A. Since the premium payments protect total returns when capture prices are low, investments are safeguarded against declines in revenue due to the merit order or cannibalisation effects. This offers (partial) protection for up-front investment costs, reduces the risks for investors and can thus lead to lower financing risk premiums. Reduced investment risks can be particularly important for promoting private investments (for example community wind farms) where environmental considerations may be the main reason for the investment rather than financial gain (provided that the financial risk is not too great).

Sliding market premiums that are determined by tender can enable targeted delivery of renewable energy expansion targets.[62] This is especially true at times of uncertain price trends, when a guaranteed minimum payment can be pivotal. Sliding market premiums can cover some of investors' costs even if the capture prices frequently fall to almost zero (for instance due to a strong cannibalisation effect). They also provide an incentive to act in a manner that supports the market when the capture prices are higher than the agreed strike price, since at these times the returns depend solely on the achieved market prices. The longer the chosen reference periods, the easier it is to promote behaviour that supports the market even when market prices are low. Unnecessary premium payments are avoided at times when spot prices are (unexpectedly) high. The sliding market premium model also allows for alternative (typically longer-term) supply contracts such as forward contracts or PPAs. In the form of bilateral contracts, for example, these can be used to provide reliable, long-term mutual risk mitigation. Sliding market premiums support a diverse range of financing options by also permitting the coexistence of other contract types.[63]

Sliding market premiums in conjunction with direct marketing are the prevailing model for supporting renewable energy under Germany's Renewable Energy Sources Act (EEG).[64] They are already supported by a carbon price. As with fixed market premiums, sliding market premiums must reflect developments in the EU state aid rules. They thus also satisfy the legal implementation criterion as long as they comply with these rules. As things currently stand, this model for promoting renewable energy could therefore be retained as long as it has an appropriate design. Another advantage of doing so would be that no major changes to the current EEG would be required.

62 In order to prevent tenders from being undersubscribed and make sure that projects are delivered, it is important to have an appropriate tender system and ensure that other barriers and factors do not counteract the tenders.

63 See EWK 2023.

64 Arts. 19 (1), 20, 23a, in conjunction with Appendix 1 EEG 2021.

- Cons: Sliding market premiums generally offer less incentive than fixed market premiums to respond to market price fluctuations, since falls in the market price are mitigated. When spot prices are low, the price guarantee effect also inevitably reduces the incentive to respond to market price trends. This is particularly true when shorter reference periods are used, whereas longer reference periods tend to strengthen market incentives (at the expense of investment security) (see FOCUS ON Reference period length in sliding premium and CfD models). As with fixed market premiums, there is only an incentive for voluntary curtailment at times when electricity prices are negative if the negative spot price exceeds the (expected) premium payment. Additional regulations to suspend the premium are required so that macroeconomically desirable voluntary curtailments can be achieved sooner. One initial attempt is the 4-hour rule introduced in the 2021 version of the EEG. This rule reduces the premium for new installations to zero if the spot price is negative for at least four hours.64F[65] Since sliding market premiums do not pass on the full spectrum of fluctuating market prices, they are less compatible with instruments such as the EU ETS than fixed market premiums. A potential switch to a market price system would thus involve a harder break, since the scrapping of sliding market premiums will inevitably result in the loss of the price guarantee effect. The existence of differentiated premiums for specific locations and technologies (as in the current system) means that the construction of additional installations does not support the market as effectively, reducing macroeconomic cost efficiency. However, as with fixed market premiums, this model can in principle have a location- and technology-neutral design.

6.2.3 Policy option 1C: Contracts for Difference (CfDs)

+ Pros: Contracts for Difference offset any upward or downward difference between the capture prices achieved in the market and the agreed strike price. This means that, in the long run, the payments received are very close to the pre-agreed strike price. Investments are mainly recouped on the basis of this pre-agreed strike price. Since CfDs offer the greatest reliability regarding payments for renewable energy, they provide the highest degree of investment security out of the policy options discussed in this paper. This reduced price risk results in the lowest project investment costs.65F[66]

The low investment risk makes CfDs especially attractive as a means of providing targeted financial support, for example for “infant industries”[67], capacity markets or system services – in other words, for investments in particularly new and risky projects or investments that are especially important for society as a whole. However, renewable energy technologies like wind and solar are already so well-established that they are not classified as infant industries in this context. High investment security can also be attractive to private investors (see policy option 1B).

Compared to fixed and sliding market premiums, there is also no immediate danger of windfall profits, since unexpectedly high capture prices are offset by negative premium payments.[68] Just as with sliding market premiums, the expansion pathway for renewables can be very precisely controlled through tender volumes, and the

65 Art. 51 (1) EEG 2021.
66 See Neuhoff et al. 2022.
67 Infant industries are technologies that are not yet ready for market. The market structures do not (yet) provide sufficient incentives to invest in the expansion of these technologies.
68 See Deutsches Institut für Wirtschaftsforschung (DIW) 2022.

expected costs to society as a whole can be accurately calculated. Consequently, it should be relatively easy for policymakers to implement this policy option.

- Cons: Being so closely tied to the strike price is also a major problem for CfDs, since this payment model severely dampens price signals, meaning that there is little incentive to act in a way that supports the market. In other words, there is no incentive to invest in more flexible technologies that are more beneficial to the market. Strongly differentiated tenders would be needed in order to counteract this problem – tender volumes could increase in line with the level of flexibility, for example. Moreover, in addition to the CfD payment, there needs to be an incentive to actually use the available flexibility in a way that supports the market and the grid. Once the strike price has been fixed, there is also very little incentive to respond to changes in the electricity market.[69] This means there is a danger of inefficiencies (for example due to inefficient dispatch decisions).[70] The drawbacks of inadequate dispatch incentives can at least be mitigated by choosing long reference periods (albeit at the expense of investment security) (see FOCUS ON Reference period length in sliding premium and CfD models). Depending on their design, CfDs can have some similarities to bilateral contracts (such as PPAs) or forward contracts. The difference is that the risk is mitigated by the premium rather than mutually by the parties to the contract. This could result in competition, with CfDs partially driving out alternative business models like forward contracts or PPAs.[71]

CfDs are not currently used in Germany. The government's April 2022 draft of the 2023 EEG included a power to issue statutory instruments. This would have made it possible to make changes to the financial support system, and the introduction of CfDs was cited as an example. However, this power to issue statutory instruments was dropped from the final version of the 2023 EEG adopted on 8 July 2022. As a result, there is currently no legal basis for the introduction of CfDs. This also makes their incorporation into international systems such as the EU ETS significantly harder and, for example, raises the prospect of a waterbed effect.

69 See Newbery 2021.
70 See Bundesverband für erneuerbare Energien e.V. (BEE) 2022 and EWK 2023.
71 See also EWK 2023.

FOCUS ON

Reference period length in sliding premium and CfD models

The chosen reference period length plays an important role in sliding premium and CfD models (policy options 1B and 1C). The key is to find the right compromise between covering price and investment risks and (at least partly) maintaining incentives to act in a manner that supports the market. While choosing shorter reference periods reduces investment risks, it also weakens incentives for behaviour that supports the market. Longer reference periods offer installation operators more opportunities to earn above-average prices from time to time (compared to the established reference market price), thereby strengthening their dispatch incentives. However, they also increase revenue uncertainty and thus investment risk. This is a particularly important consideration in the design of CfDs (policy option 1C), since positive or negative premium payments always apply in this model, unlike sliding market premiums (policy option 1B) where they only apply at times of low market prices.

This effect is illustrated by the orientation of a hypothetical solar installation. The amount of electricity generated is greatest if the installation is south-facing. Although an east-west facing installation generates less electricity overall, it can feed more electricity into the grid during the morning and evening. This means that an east-west facing installation can support the market more effectively, since its feed-in profile more closely matches the traditional morning and evening peaks in electricity demand (and market prices). On the other hand, demand and market prices are typically lower during the middle of the day. In other words, the electricity generated by an east-west facing installation can be utilised more effectively in this scenario. The choice of an hourly reference period for market premiums reduces the market price peaks during the morning and evening through low or negative premiums. Meanwhile, the premium payments in the middle of the day are relatively high in order to compensate for the low market prices. In this scenario, the level of the premium payments is varied in order to offset market price fluctuations throughout the day, meaning that the incentive provided by market price fluctuations for east-west facing installations is lost. On the other hand, if the reference period is one day rather than one hour, the level of the premium remains the same throughout the day. In this scenario, the market price for the solar installation's electricity fluctuates depending on the time of day and the incentive for an east-west orientation is preserved. However, since the solar installation is now subject to daily market price fluctuations that are no longer offset on an hourly basis, there is greater uncertainty about the revenue that the installation will generate.

6.2.4 Policy option 1D: Focus on carbon pricing

+ Pros: Indirect support through carbon pricing has two key advantages: it is highly cost-efficient and is also a very effective means of achieving the climate targets. While direct financial support measures for renewables tend to be tailored to the technology in question (which can distort price signals), carbon pricing has the benefit of being technology- and location-neutral. Moreover, carbon pricing applies to all the installations that are active in the market, not just renewable installations. As a result, higher-carbon technologies (such as coal-fired power plants) tend to be replaced by lower-carbon technologies (such as gas-fired power plants). Furthermore, Gugler et al. (2021) show that a high carbon price can also incentivise the construction of additional wind and solar installations at a lower cost than direct subsidies.[72] Carbon pricing thus

72 When comparing the financial support systems in Germany and the UK, see Gugler et al. 2021.

offers stronger market-based incentives and better cost efficiency than the financial support mechanisms described in policy options 1A to 1C.[73]

Strong political commitment to a sufficiently high carbon price (or low number of carbon credits) is key to maximising the effectiveness of this model and enabling reliable enough incentives to invest in renewables.[74,F75] This commitment would make the carbon price less susceptible to lobbying than a financial support package comprising several individual measures (all of which could be influenced by lobbyists). A permanently high carbon price can thus also promote structural changes.

In the electricity sector, carbon pricing is already implemented through the Europe-wide EU ETS. A stronger focus on carbon pricing can therefore be achieved by strengthening and expanding this mechanism. Since carbon pricing is increasingly being introduced around the globe, this model is highly compatible with systems in other parts of the world. An internationally coordinated emission trading system also prevents the waterbed effect, since it directly limits CO_2 emissions, ensuring that they are not simply displaced as can happen in direct financial support models. The prevention of these perverse incentives further increases the efficiency of carbon pricing compared to direct financial support mechanisms. Carbon pricing can still be combined with additional (direct) support instruments (such as specific premiums) in order to provide extra support for particular technologies or regions.

Lastly, the fact that this model is closely tied to the spot price weakens the merit order and cannibalisation effects by providing direct price incentives.[76] Installation operators have a strong incentive to sell electricity when prices are high in order to earn higher revenues. For example, it becomes less attractive to sell electricity at times when there is a lot of sunshine and a lot of PV installations are already feeding electricity into the grid, depressing the selling price. The greater the existing cannibalisation effect, the stronger the incentive to invest in alternative technologies or use storage systems to ‘save’ the electricity so it can be sold when prices are higher. The price smoothing enabled by storage systems or by deferring demand benefits both new and existing installations. As well as (short-term) power exchange trading, in principle this policy option also allows for alternative (long-term) contracts such as forward contracts and PPAs. The contracting parties can reduce their investment and price risks through mutual risk mitigation.

If specific direct financial support for renewables in the form of an additional payment model as provided for by the EEG were completely abandoned, the corresponding statutory regulations and the need to ensure compliance with the EU state aid rules would become obsolete. In principle, this would make the system significantly simpler to implement from a legal point of view.

- Cons: On the other hand, dispensing with direct financial support makes investments riskier and thus increases their cost. This could impede the construction of additional new installations, causing the targets for the expansion of renewable energy to be

73 See Freebairn 2014.
74 See Sachverständigenrat zur Begutachtung der Gesamtwirtschaftlichen Entwicklung (SVR) 2019.
75 See Boyce (2018).
76 See Brown/Reichenberg 2021; Liebensteiner/Naumann 2022.

missed.[77] High investment risks could also be detrimental to investor diversity, since some investors could be put off by the high financial risks. The reason for this risk is that returns are strongly linked to an uncertain spot price. Unlike in direct financial support models, renewables do not receive an extra payment that guarantees a minimum return in the event of low spot prices. The risk is particularly pronounced because a high proportion of weather-dependent renewable energy in the system can result in a high number of hours with low spot prices (caused by an inflexible oversupply).[78] If an emission trading system is employed, the carbon prices themselves can also be very volatile, causing further price fluctuations and uncertainty with regard to revenues (assuming that prices are determined by carbon-intensive power plants). However, this can be addressed by setting a minimum (and potentially also maximum) carbon price.

There is no doubt that carbon pricing, especially in an emission trading system, can be an extremely effective means of achieving the climate targets. However, its effectiveness is highly dependent on its sustained political viability and the variables determined by policymakers (quantity of carbon credits/carbon tax), all of which can change over time. Indirect support through carbon pricing leads to higher spot prices, which are reflected in higher prices for consumers and businesses. Its impact is thus felt more directly than tax-funded financial support models. High carbon prices could even undermine public acceptance, creating political pressure to water the instrument down (for instance by flattening the decarbonisation pathway). In this context, it is especially vital to consider the distributional implications and implement appropriate measures to mitigate the impact on low-income households in particular. While this is important for all the policy options, it has already been implemented for some of the individual options described above in the shape of complementary measures, for example where the renewable energy reallocation charge is wholly or partly paid by the public purse. Overall, it is essential to address the social policy implications for all the options, not just to maintain public acceptance but also to prevent social problems. As far as the corporate sector and especially energy-intensive industry is concerned, it is also important to ensure that the rise in electricity prices due to carbon pricing does not excessively undermine competitiveness or the attractiveness of locations covered by this model. Failure to address this issue could lead to a danger of carbon leakage to third countries with lower energy prices.

6.3 Suitability for a new electricity market design for 2030

The comparison of the different models' pros and cons indicates that, in many respects, the requirements of a new electricity market design for 2030 are best met by carbon pricing. One particular advantage of the **carbon pricing** model is its **cost efficiency**. Carbon pricing is also the only policy option that does not rely on direct subsidies. This prevents a scenario where most electricity generation (eighty percent in 2030 based on the current targets) is permanently subsidised. At the same time, the EU ETS provides a clear pathway for reducing harmful emissions. Provided that it remains politically viable, the EU ETS is thus an extremely **effective** instrument for meeting the climate targets. A model that focuses on a strong carbon price without supplementary financial

77 In this context, Hirth (2015) shows that a high carbon price can cause the growth in solar and wind power to stagnate or even contract as they are replaced by other (carbon-neutral) technologies.

78 See Bundesverband Erneuerbare Energien e. V. (BEE) 2022.

support mechanisms can ensure that the climate targets are achieved through the progressive replacement of high-emission electricity generation by renewable electricity generation.[79] Consequently, this should become the main instrument for supporting renewables by 2030.

However, the switch to indirect support driven by carbon pricing would involve major changes and constitute a hard break with the current system based on guaranteed premiums and managed expansion of renewables. This could result in volatile carbon price increases and pronounced price fluctuations, creating a very volatile market and uncertainty for investment projects. Accordingly, it would be inadvisable to abruptly switch to a carbon pricing model without any other form of support. That said, work should begin on the transition to this model, since in the long run it can provide efficient, technology-neutral support. Unless the prices are set at a very high level, a pure carbon pricing model would also be unable to guarantee that specific expansion targets will be met (in the short term). If policymakers wish to ensure that the relevant targets are achieved by 2030, an additional financial support mechanism will be required during a transition period. In any case, the aim should be for a significant percentage of support for renewable energy to be delivered through carbon pricing by 2030.

Fixed market premiums, on the other hand, are not an efficient long-term support model. Even if the market premiums were designed to be technology-neutral, this option would still be less efficient than carbon pricing. This is because, although it would support renewables, it would not help to force carbon-intensive electricity from conventional power plants out of the market sooner by significantly increasing its price. In the short term, however, fixed market premiums can be a flexible instrument for providing targeted support for certain technologies.

Sliding market premiums are also not a suitable long-term support model. Unlike CfDs, at least sliding market premiums create dispatch incentives when spot prices are high. They also offer protection against investment risks, since the payments cannot fall below the pre-established minimum price. However, it is necessary to guard against possible perverse incentives in the event of low or even negative spot prices, for instance by applying the 4-hour rule or even reducing its duration.

CfDs are not an appropriate model for supporting the further expansion of renewables, except in specific instances such as infant industries, capacity markets and system services. Because they are so closely tied to the strike price, they constitute a move away from a market-based model. Accordingly, sliding or fixed market premiums are a better option for the transition period. The widespread introduction of CfDs would therefore be inadvisable – if at all, they should only be used in individual cases where there are good reasons for doing so.

79 See Grimm et al. 2022.

6.4 The transition to a new model in 2030

Because it is both technology-neutral and the most cost-efficient option, the long-term aim should be to move to a **carbon pricing model**. However, in order to ensure that the relevant expansion targets are met by 2030 and avoid an abrupt change of support regime, the introduction of carbon pricing as the main instrument should take the form of a gradual, planned transition rather than a sudden switch.

6.4.1 Transition period

Regardless of whether fixed or sliding premiums are used during the transition to a model based mainly on carbon pricing, the premium payments should be progressively reduced to zero over time. Since the level of the premiums is determined by tender, their progressive reduction can be indirectly supported by a steadily increasing carbon price. In order to ensure greater price certainty, this rising price trajectory could be kept within a defined corridor by establishing a minimum price and price cap for carbon credits.[80] A relatively narrow price corridor could provide confidence about the EU ETS carbon price, making indirect support through carbon pricing more reliable and predictable. This would make it possible to implement a gradual transition with a progressive reduction of direct financial support.[81] The transition to indirect support through carbon pricing would be complete once the market premium or strike price reached zero.

Sliding market premiums are fundamentally suitable as a model for transitioning to indirect support through carbon pricing. As the main model currently used under the Renewable Energy Sources Act, their retention would avoid the need for extensive legislative amendments. It is important to remember that, as well as reducing the financial payments, reducing the premium also diminishes the price guarantee effect provided by a guaranteed minimum payment. Regular bid values of zero would be an indication that direct financial support measures were no longer necessary and renewables had been fully integrated into the market.

Fixed market premiums are in principle also suitable as a model for transitioning to indirect support through carbon pricing. In fact, they would initially be somewhat “closer” to the target model because, unlike sliding market premiums, they pass on the full spectrum of potential spot prices with no price guarantee effect. However, the 2023 Renewable Energy Sources Act steers clear of this model, since a combination of fixed market premiums and rapidly rising electricity prices could easily result in windfall profits due to renewables receiving too much financial support. It is important to remember that the use of sliding market premiums instead of fixed market premiums in innovation tenders diminishes the incentives to use flexible generators and energy storage systems to restrict the amount of electricity fed into the grid at times of very low market prices.

There should be regular **monitoring** of the impacts of the electricity market design during the transition to a model based mainly on carbon pricing. This would allow specific problems identified during the transition period to be addressed, for

80 However, it would be important for the price cap to be high enough to ensure that the climate targets are met.

81 See Brown/Reichenberg 2021.

example if not enough new renewable installations were being built or if the carbon prices were too low. Individual premium-based models could then be used to provide targeted financial support in specific cases such as necessary infant industries, system services or capacity markets.

Another possible design for the support model during the transition period would be to switch from time-based support to **quantity-based support** for future new installations. Instead of being based on a fixed support period (for example twenty years), a quantity-based support model would pay a premium for an agreed total volume of supplied electricity. The support would thus end once this agreed volume of electricity had been supplied. This would remove the incentive to feed in as much electricity as possible during the fixed support period.[82] It would help to prevent negative electricity prices if combined with fixed market premiums, since there would be an incentive for curtailment at times of negative spot prices and, instead of being lost, the premium payments would simply be deferred until a later time.

In the current system, Article 51a of the Renewable Energy Sources Act already allows for times without financial support due to negative prices to be deferred beyond the end of the fixed support period. However, switching to quantity-based support would mean that payments were no longer tied to a fixed support period. If quantity-based support was combined with sliding market premiums, an additional regulation would be required to ensure that generators were shut down at times of negative electricity prices. The investment risk would also be lower because it would be easier to predict the total amount of financial support. For example, there would no longer be a risk that the agreed support period might coincide with a period of lower-than-average winds.

6.4.2 Carbon price design

In principle, a carbon price established within the EU ETS is a functioning and efficient model for achieving the desired emission reductions in the electricity sector. That said, it is also necessary to look beyond the integration of renewables into the electricity market. In order to strengthen its effectiveness at meeting the overall climate targets rather than just those of the electricity sector, carbon pricing in Europe should be extended to all sectors by 2030, when the EU Effort Sharing Regulation is due to expire.[83] The introduction of a separate ETS II for road transport and buildings is currently planned for 2027.[84] ETS II will cap the carbon price at €45/tonne.[85]

In the long term, however, the aim should be to have a single carbon price for all sectors under a common, cross-sectoral emission trading system. A single emission trading system would leverage additional efficiency opportunities by ensuring that emissions were reduced in the most cost-effective manner across the economy as a whole.[86] The increasing electrification of the heating and transport sectors (for example in the shape of electric vehicles) means that these sectors are becoming more and more

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82 See Bundesverband Erneuerbarer Energien e. V. (Ed.)/Fraunhofer IEE/Fraunhofer ISE/BBH 2021; EWK 2023; Newbery 2021.
83 See acatech et al. 2020-1.
84 However, its introduction could be postponed until 2028 if oil and gas prices exceed 99 euros per megawatt hour.
85 See Europäisches Parlament 2022.
86 See Abrell/Rausch 2021.

closely integrated with the electricity sector. In the medium term, therefore, the boundaries between rival carbon pricing systems for different sectors will in any case be blurred, potentially creating uncertainty. However, it should be noted that a cross-sectoral emission trading system would probably push up the carbon price in the electricity sector, since emission reductions can be achieved more cheaply here than in the transport and heating sectors. Emission reductions in the electricity sector would increase as a result.[87] While this additional pressure on the carbon price could contribute to a faster phase-out of direct financial support measures, it could also threaten public acceptance. Moreover, it could increase the burden on energy-intensive industries if adequate relief measures are not taken elsewhere.

In order to minimise investment risks due to spot price and carbon price fluctuations, it is vital to ensure a reliable **minimum price** for CO_2 emissions. Ideally, this minimum price would be introduced throughout Europe under the EU ETS and apply to all the sectors that it covers. Failing that, it would in principle still be possible to introduce a minimum price just for Germany within the current EU ETS. In this case, German electricity producers would have to pay an additional levy on CO_2 emissions to make up the difference if the trading price fell below the fixed minimum price. However, a national solution like this would be less efficient than a European system and should therefore at most be considered as a stopgap measure until the transition to a Europe-wide minimum price is completed.[88]

Another possibility would be a **price cap** for CO_2 emissions that also increases over time. Since a high carbon price translates into high electricity prices for consumers, public acceptance of systematic carbon pricing could decline over time. This could put more pressure on policymakers to water the instrument down, potentially making the current emissions corridor politically infeasible. A price cap could strengthen public acceptance by limiting carbon prices and the associated rises in electricity prices. Since a price cap would make it possible to exceed the prescribed volume of emissions, any excess emissions would have to be deducted from the future carbon budget in order to ensure that the emission targets were not permanently missed.

As the transition to a carbon pricing model progresses the Renewable Energy Sources Act will become increasingly redundant. However, it will probably still play a long-term transitional role for existing installations covered by grandfather clauses. With different clauses expiring at different times, it will be a long time before the complexity of the regulatory framework is reduced. Other forms of preferential treatment, such as priority dispatch for renewables (which is already occurring less frequently), should end as soon as possible.

87 See Abrell/Rausch, 2021.
88 See acatech et al. 2020-1.

7 Key Question 2: Security of supply

The power grid needs to be robust and flexible enough to guarantee security of supply at all times. The increasing proportion of variable renewable electricity means that more flexible capacity will be required in years to come in order to prevent shortages and outages.

7.1 Policy options

When it comes to incentivising and delivering sufficient flexibility to guarantee security of supply, a fundamental distinction can be drawn between explicit and implicit flexibility.[89] **Explicit flexibility** means that the amount of flexibility and the time when it is delivered can be quantified in advance, for example through quantity tenders for flexible generation capacity, guaranteed voluntary demand curtailment (or a strategic reserve) or capacity markets, see policy options 2B, 2C and 2D.[90] **Implicit flexibility**, on the other hand, is achieved through indirect incentives such as high price signals (as in an energy-only market, see policy option 2A). In both instances, it is important to make sure that the technical and regulatory requirements needed to leverage the relevant flexibility potential have been met (see Chapter 4).

Policy options 2A-2D outline possible designs for a future electricity market that can provide adequate security of supply despite a growing proportion of (inflexible) renewable electricity.

7.1.1 Policy option 2A: Pure energy-only market (without supplementary measures)

In principle, it is possible to design an energy-only market[91] without supplementary capacity mechanisms. To do this, the electricity market must have a price-setting mechanism that balances supply and demand at all times. This means meeting two key requirements. From an economic perspective, spot price signals must provide a strong enough incentive. In other words, the fluctuations over time in the spot prices for electricity fed into the grid must be sufficient on their own to make the market players willing to adjust their supply of or demand for electricity by enough to ensure that supply meets demand at all times. The second requirement involves ensuring the necessary technical flexibility for these balancing adjustments to be made fast enough.

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89 See also the study on “Electric Mobility in the Future Energy System” undertaken as part of the E-Mobility Lab Hessen project, and Lehmann et al. 2019.

90 See Kozlova/Overland 2022 for an international overview of different capacity mechanisms for providing explicit flexibility.

91 The energy-only market still allows for forward markets and the option of over-the-counter electricity contracts alongside the spot market.

Consequently, the implementation of complementary measures to increase the flexibility of electricity supply and demand is of paramount importance.

The model must also fit within the framework of constitutional, European and national law. In this context, it will be necessary to monitor whether a sufficient level of security of supply is maintained.

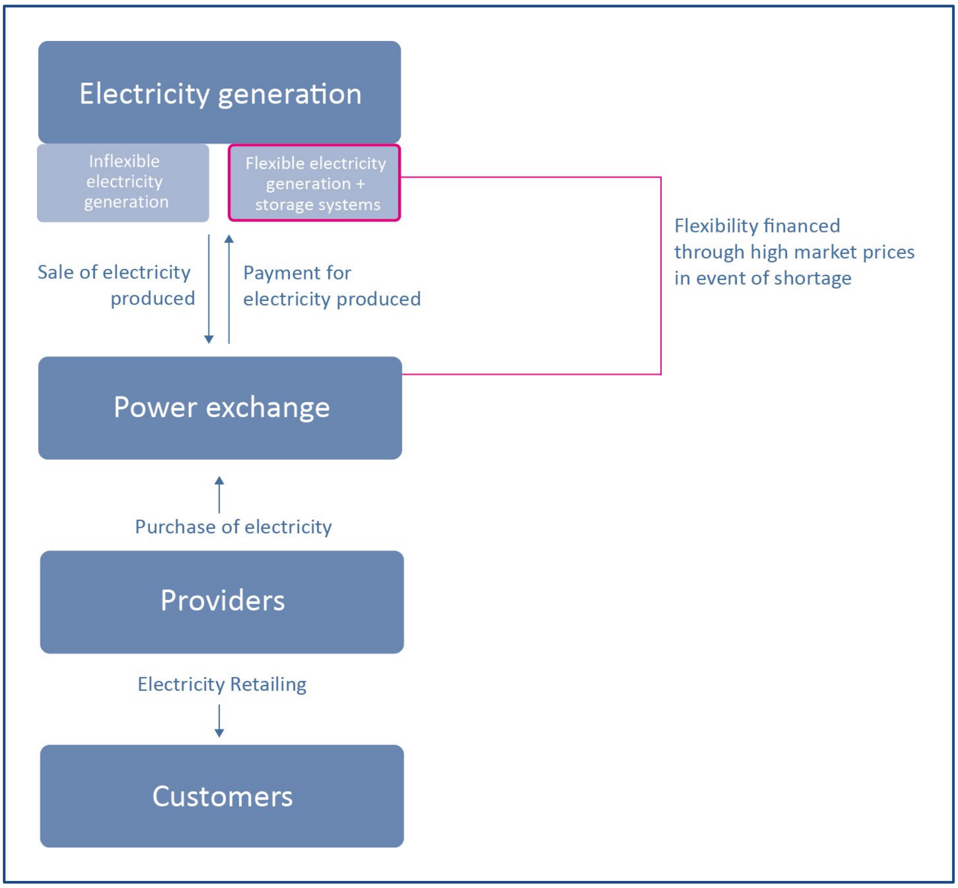

Figure 4: Energy-only market (Source: authors' own illustration)

7.1.2 Policy option 2B: Energy-only market with strategic reserve

An energy-only market can also be supplemented by a strategic reserve. The strategic reserve comprises backup capacity for times when the market supply is temporarily unable to meet demand. At these times, the temporary supply shortage is covered by the strategic reserve.

This policy option reflects the current market design in Germany, except that it retains the current strategic reserve on a long-term basis. The strategic reserve was introduced in 2019 as a temporary instrument to reduce the risk to the electricity system of a short-term electricity supply shortfall. Regulated by the Capacity Reserve Ordinance (KapResV) this instrument is designed to ensure that the constitutional requirements are met and is due to remain in force until 1 October 2025. However, it is debatable whether the fundamental problem – which is only being exacerbated as a result of the growing proportion of renewables in the electricity mix – can be solved without such a mechanism in the long run. Were the strategic reserve to be made into a permanent instrument, it would need to comply with the EU state aid rules.

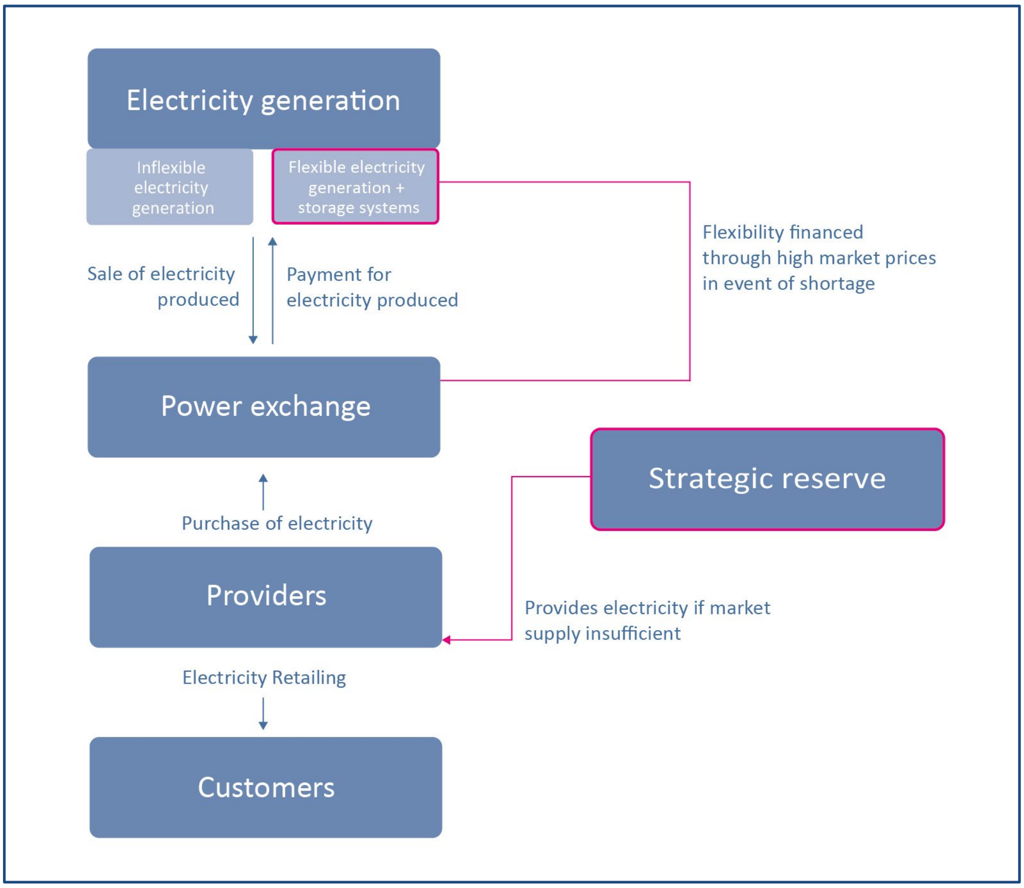

Figure 5: Energy-only market with strategic reserve (Source: authors' own illustration)

7.1.3 Policy option 2C: Establishment of a central capacity market

The third policy option involves the establishment of a central market for capacity/flexibility. In this context, 'flexibility' means a guaranteed contribution to load coverage at peak demand times. A capacity market ensures that sufficient flexibility (also referred to as "guaranteed capacity") is available to cope even with extreme situations so that shortages cannot occur. In this model, in addition to the return from the electricity sold on the market, electricity generators (and storage systems) could earn an additional payment for providing a certain amount of flexibility.

Unlike the strategic reserve, this model does not maintain a separate power plant fleet to supply the system with extra electricity at times of high demand. Power plants that participate in the capacity market can continue to operate in the regular electricity market but receive an additional 'flexibility premium'. The level of flexibility provided thus becomes a second variable in the electricity market and earns additional revenue that is not linked to the amount of electricity actually supplied. In a central capacity market, the exact amount of flexibility that needs to be maintained is determined by the responsible regulatory authority and auctioned in a centrally organised tender process. The cost of paying for this capacity (equivalent to the payments for interruptible loads under the Ordinance on Agreements on Interruptible Loads – AbLaV) could be passed on to consumers via electricity prices. In addition to the central design described here, decentralised capacity mechanisms are also possible. These are described in detail under policy option 2D.

Capacity markets are a fundamentally suitable means of compensating flexibility and the contribution it makes to security of supply at different levels of the electricity market. Payments for providing flexibility can be an important additional source of revenue for flexible generation capacity with high production costs (such as gas-fired power plants). Although this type of capacity provides important flexibility for the electricity system, the merit order means that it is infrequently used due to its high marginal costs. Flexibility can also be achieved through flexible demand, for example in the form of guaranteed voluntary load curtailment. In this instance, electricity shortages would be addressed by reducing demand rather than increasing supply. Moreover, the use of electricity storage systems as a standalone technology may only be profitable if additional payments are earned for providing flexibility. It is important for the capacity market players to have the technical capability and economic incentives to actually deliver the promised flexibility, even at short notice. In the interests of meeting the climate targets, an emissions cap can be established for participants in the flexibility market.[92]

In terms of constitutional law, capacity markets are a substantive instrument for guaranteeing security of supply. Before introducing a capacity market, it would be necessary to determine how much its specific design would actually contribute to guaranteeing security of supply. The corresponding projections should be scientifically substantiated in order to significantly reduce any risks from a constitutional law perspective. However, it is also vital to ensure that capacity markets comply with European Union law, especially Arts. 20-27 of the Regulation on the Internal Market for Electricity and the EU state aid rules. If the payments are classified as state aid under Art. 107 of the Treaty on the Functioning of the European Union (TFEU), the capacity market model cannot be implemented unless it has first been examined and approved by the European Commission in accordance with TFEU Articles 108 and 107 (3). Payments are classified as state aid if they favour certain producer groups and are at least partly funded by the state. The Guidelines on State aid for climate, environmental protection and energy 2022 are the main benchmark for making this assessment.[93]

92 Art. 22(4) of the Regulation on the Internal Market for Electricity establishes a CO2 emissions cap of 550 grammes/kilowatt hour for new generation capacity to participate in a capacity mechanism; this rule applies from 01.07.2025 for capacity that has already started commercial production.

93 Guidelines on State aid for climate, environmental protection and energy 2022l.

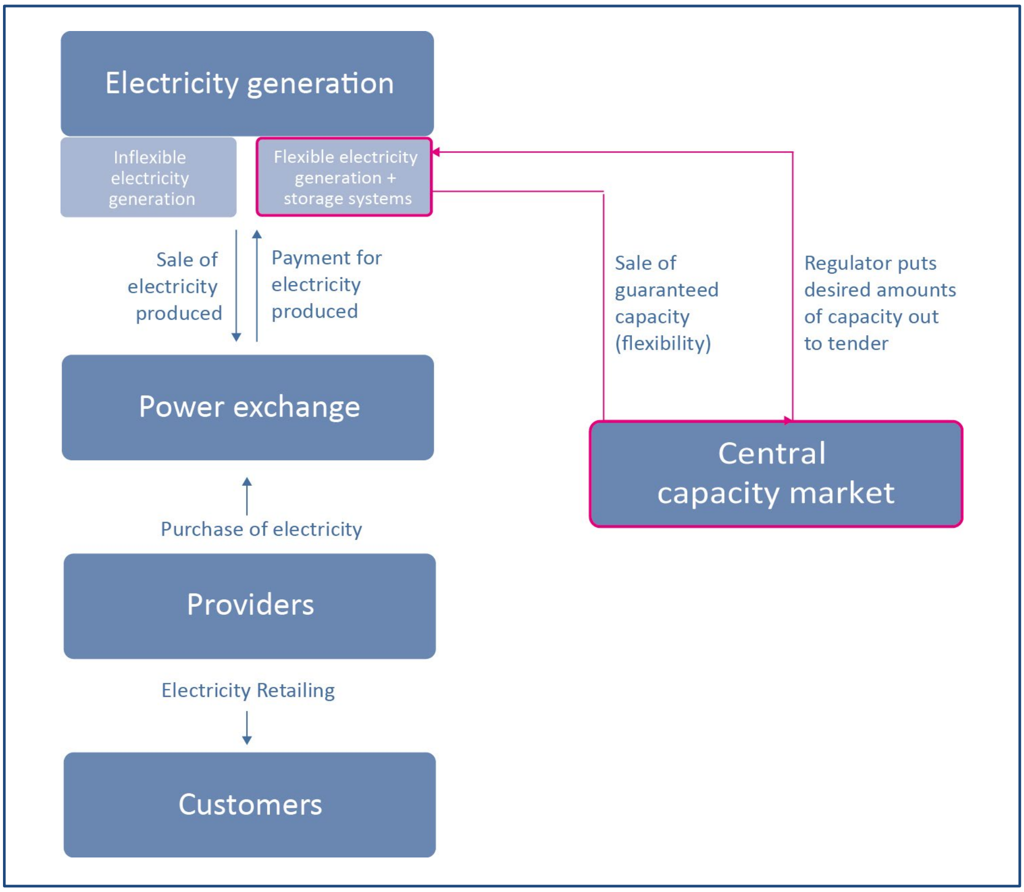

Figure 6: Central capacity market (Source: authors' own illustration)

7.1.4 Policy option 2D: Decentralised capacity markets with individual responsibility for security of supply

Capacity markets do not have to be central – they can also be decentralised. As with the central model, decentralised capacity markets are a mechanism that offers separate payments for providing flexibility – but without a central market. In a decentralised capacity market, all qualifying generation capacity receives capacity certificates that reflect the calculated amount of flexibility it is capable of providing. For their part, providers are assigned capacity obligations. This means they must produce certificates equivalent to their end customers' projected demand at peak load times. This internalises the responsibility for meeting supply obligations and thus for guaranteeing security of supply, making the provider directly responsible. The providers thus also directly bear the cost of ensuring the necessary flexibility and must cover these costs through the supply contracts with their own customers. The certificate system allows providers to meet their individual capacity obligations through decentralised certificate trading.[94]

The key point in this context is that providers can reduce their own projected load at peak load times through increased demand-side flexibility on the part of their end customers. This reduces the level of their capacity obligations and the number of corresponding certificates. It creates an incentive for providers to conclude individually customised supply contracts with their customers. In addition to the electricity price

94 See EnBW/A.T. Kearney 2014.

itself, supply contracts could also specify the level of "guaranteed supply". This would presumably result in a trade-off between electricity price and guaranteed supply level in electricity supply contracts. End customers able to cope with temporary curtailments, for example because they have their own electricity storage systems, could benefit from contracts offering lower prices in return for a lower level of guaranteed supply. Customers who need a high level of guaranteed supply would pay correspondingly higher prices. This would reduce the provider's capacity obligations and establish a clear sequence for capacity utilisation/curtailment in the event of a shortage. However, the providers would need to be technically capable of actually curtailing the supply to the relevant customers during a shortage.

The internalisation of the supply risk creates an incentive and an imperative for providers to hedge their own supply obligations. This creates two markets for hedging transactions. On the one hand, there is competition between installations and technologies capable of providing the necessary flexibility and selling the corresponding obligations to providers in the form of certificates. On the other hand, end customers can also offer demand-side flexibility that is rewarded in the terms of their individual contracts. Providers should coordinate their demand in both markets so they can meet their capacity obligations through the most cost-efficient allocation for their own particular circumstances.

This policy option also needs to meet the relevant statutory requirements. As with the energy-only model, its compliance with constitutional law depends on the extent to which this form of individual responsibility results in supply shortfalls.

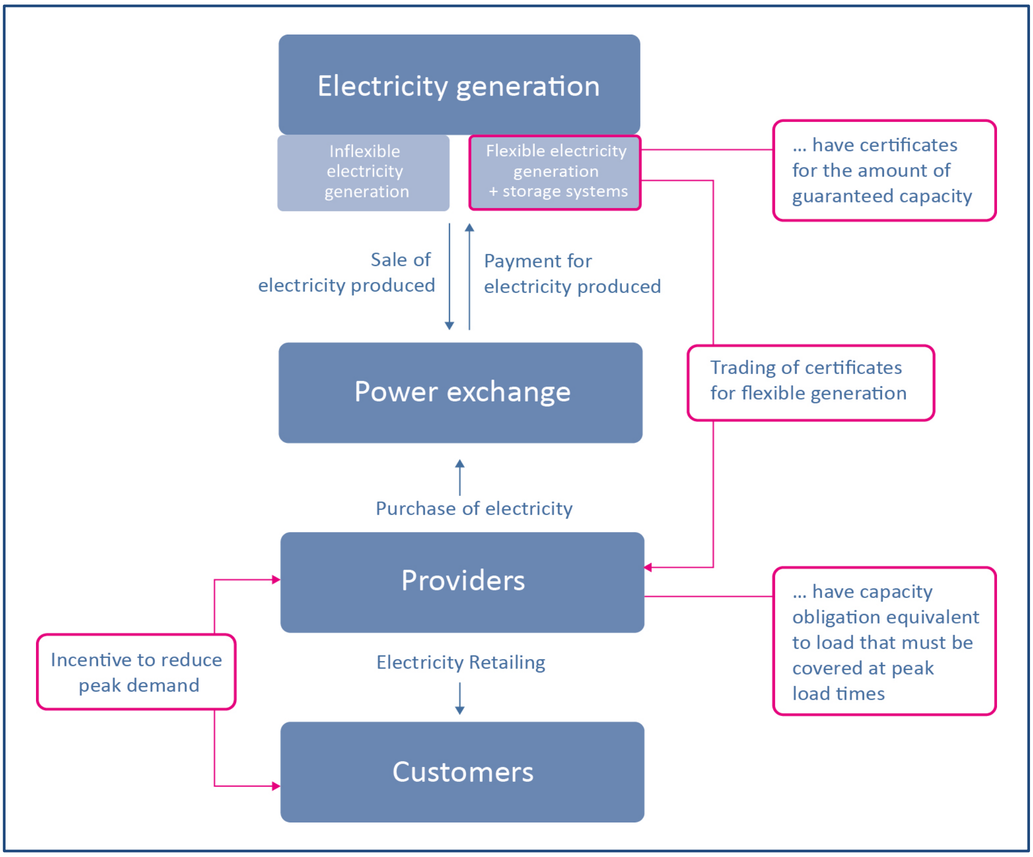

Figure 7: Functioning of decentralised capacity markets (Source: authors' own illustration)

7.2 Policy option pros and cons

Table 2 provides an overview of the four policy options for ensuring security of supply described above and their pros and cons.

	Policy option 2A: Energy-only market	Policy option 2B: Strategic reserve	Policy option 2C: Central capacity market	Policy option 2D: Decentralised capacity markets
Effectiveness (achievable level of security of supply)	-	++	++	+
Compatibility (with EU regulations)	++	O	O	O
Cost efficiency (prevention of overcapacity)	++	-	O	+
Political viability	O	+	++	O
Legal complexity and feasibility	O	O	O	O
Implementation timescale	short-term	immediate	longer-term	longer-term

Table 2: Comparison of policy option pros and cons (- requirement not met; O requirement partly met; + requirement met; ++ requirement particularly well met)

7.2.1 Policy option 2A: Pure energy-only market (without supplementary measures)

+ Pros: The main advantage of a more flexible energy-only market is that it is easy and cheap to implement. In this model, spot price fluctuations over time create a strong, market-based incentive to adjust electricity supply and demand to the current market situation. The spot price alone is thus able to ensure a cost-efficient level of flexibility and security of supply.

Moreover, this model does not call for major structural changes and thus avoids the extra costs potentially associated with the establishment of an additional capacity market, for example (policy options 2C and 2D). Provided that an adequate level of security of supply is achieved, this model can be highly cost-efficient. Market price fluctuations alone must be enough to ensure financially profitable implementation of sufficient flexibility, so that it is not necessary to resort to supplementary mechanisms (such as a strategic reserve).

- Cons: The drawbacks include the fact that the underlying externality problem would remain and the individual actors would not be sufficiently responsible for the overall system's security of supply. The incentive to provide the necessary flexibility is only created implicitly by spot price fluctuations over time. In contrast to the following three policy options, there is no explicit mechanism to guarantee a certain level of flexibility. There are thus two fundamental issues with this model. The first is that, because not enough responsibility is assumed for ensuring security of supply, the level provided is relatively low. It is doubtful whether such a low level of security of supply would be publicly acceptable or politically viable as a long-term model. The second is that there would always be a danger of political intervention in the event of very high spot prices, potentially jeopardising the returns for providing flexibility. The recent public discussion of and political interventions in price setting and profit taxing (that extend beyond the windfall profits due to the war) may have further eroded confidence in the prospects of actually earning the expected returns in extreme situations.[95] This could hold back the expansion of flexible capacity with low full-load hours intended primarily for use in extreme situations, further undermining the effectiveness of this policy option in terms of ensuring a high level of security of supply. In view of this limited effectiveness and the social problems and financial damage it could cause, it seems unlikely that an energy-only market would be sustainable for any length of time without supplementary measures.

In the absence of explicit incentives to provide a given level of flexibility in a pure energy-only market, it is extremely important to identify ways of implementing sufficient supply-side and demand-side flexibility. Accordingly, it is vital to systematically deploy supplementary measures such as programmes to explicitly promote electricity storage systems or measures to increase demand-side flexibility. Moreover, this policy option has the greatest risk of supply disruption, with all the damage that this entails.[96]

From a legal perspective, the danger of a pure energy-only market is that not enough electricity would be generated to guarantee security of supply. There is a risk that investor uncertainty (due to concern that legal interventions could prevent the necessary high price peaks, for example) could inhibit an adequate level of investment, eventually resulting in supply shortages. This raises doubts as to whether the adequate supply level required by the constitution could be guaranteed. There are two reasons why it is hard to evaluate this criterion. Firstly, it is difficult to precisely establish the level of security of supply required by the constitution, and secondly, it is also difficult to predict the risk to security of supply that would occur if a strict interpretation of this model were to be implemented. Consequently, it is possible that a breach of the constitution might only occur in the event of major supply disruption. However, if the constitutional requirement is met, the model would satisfy the legal implementation criterion. In procedural terms, the stricter the implementation of the energy-only model, the more important it becomes to define adequate security of supply and establish continuous monitoring obligations, including evidence-based forecasts about whether the required level of supply is guaranteed. Backup mechanisms such as the strategic reserve established until 1 October 2025 by the Capacity Reserve Ordinance (KapResV) are a substantive instrument for ensuring compliance with the constitutional requirements. However, to use instruments like this is to move away from a pure energy-only market. A pure energy-only model is

95 For more on the underlying problem, see also Hildmann et al (2015) and Newbery (2016).
96 See Coester et al. 2018.

thus constitutionally problematic – at least from a procedural perspective, supplementary backup mechanisms are necessary.

7.2.2 Policy option 2B: Energy-only market with strategic reserve

+ Pros: Supplementing the energy-only market with a strategic reserve provides backup capacity that increases security of supply, since the reserve can be drawn on in the event of a shortage. In principle, any desired level of security of supply can be implemented if a sufficiently large strategic reserve is built up. Moreover, no structural changes would be required, since this is largely the mechanism that is already in place today – it would simply be a case of refining the current system. From a legal perspective, the temporary approval granted for the current strategic reserve mechanism would need to be made permanent.

- Cons: The deployment of a strategic reserve does nothing to resolve the underlying externality problem encountered in a pure energy-only market, since it involves creating a backup mechanism outside of the market. Moreover, expanding the strategic reserve would be a comparatively costly means of providing reserve capacity. The reserve would exist outside of the market and would only be used in the event of a shortage. This would mean maintaining and financing capacity that would be used relatively infrequently and could not be financed in the market (unlike central capacity markets, for example, see policy option 2C). The fact that all of the additional finance required for the strategic reserve would need to come from outside the market would reduce its relative cost efficiency.

In addition, the strategic reserve mechanism is designed to deal with a market failure (where supply cannot meet demand) and close the supply gap. This differs from the other mechanisms, which are designed to maintain a functioning market at all times. As soon as the strategic reserve has to be used, prices can no longer be determined purely by the market, since there is no longer a balance between supply and demand. As a result, a market clearing price must also be established for all the power plants in the market. In this context, it is doubtful whether very high market prices would be politically acceptable, making it possible that the strategic reserve might also be used to prevent high market prices. This would mean that the strategic reserve had a direct influence on price formation in the electricity market, reducing incentives to invest (especially in flexible technologies for covering peak load) and thus necessitating further expansion of the strategic reserve. Lastly, there would also be a danger of free riding in the context of European grid integration. Free riding occurs when a country relies on the additional capacity installed by neighbouring countries while neglecting the flexibility of its own electricity system (and saving on the associated costs).[97]

Furthermore, a strategic reserve must comply with EU state aid rules insofar as its design must avoid overcompensation that distorts competition. Consequently, this model only partly satisfies the legal implementation criterion. The reserve must also be open to competition from other countries in the European single market provided that they can guarantee the same security of supply – on the grid side, too – as domestic reserve capacity.

97 Bhagwat et al. 2017.

7.2.3 Policy option 2C: Establishment of a central capacity market

+ Pros: In principle, the establishment of a central capacity market makes it possible to guarantee a very high level of security of supply. In a central capacity market, the state could essentially implement as high a level of security of supply as it wishes by organising tenders for the desired capacity.[98] Of the four policy options, central capacity markets are thus the most effective model for guaranteeing security of supply. Capacity payments also create a strong enough incentive to provide the desired degree of flexibility (on both the supply and the demand side),[99] although it is important to ensure that the agreed capacity is actually delivered in the event of a shortage.[100] Since this policy option generally has the fewest negative impacts at times when there is an acute shortage of electricity, its political viability and public acceptability are both high.

In the long run, central capacity markets should also be cheaper and thus more efficient than a strategic reserve, especially if there is a large increase in the proportion of variable renewable energy.[101] This is because the operators in the capacity market remain active in the regular electricity market rather than only stepping in 'in an emergency'. This means that the available capacity and the investments required to provide it can be permanently utilised. The extent of the necessary flexibility and the price needed to achieve it continue to be directly determined by the market, providing a more direct reflection of market conditions. For instance, in an extreme scenario where the electricity system is already providing enough flexibility on its own, the additional premium would fall to (nearly) zero. This contrasts with a strategic reserve, where the reserve capacity has to be paid for at all times, even if it isn't needed. The risk of additional costs due to pure deadweight effects is thus lower in a capacity market.

While additional financial support for a flexible electricity supply and flexible electricity demand in the primary market can still make sense in this scenario, it involves a certain trade-off with regard to the size of the capacity market. If financial support measures are already making the electricity system more flexible without capacity payments, the premiums paid in the capacity market will be lower. Conversely, if the premiums are high enough, the capacity market can provide a mechanism for promoting supply- and demand-side flexibility. Additional measures should therefore focus on enabling ways of promoting flexibility and ensuring that they can be used in the capacity market. The costs associated with the capacity market will fall as the number of technologies certified for providing flexibility in the capacity market increases.

- Cons: The cost of establishing a central capacity market would probably be higher than policy options 2A and 2D, since it offers additional payments for providing flexibility (although the cost would be negligible if the market was already providing the necessary capacity). There is a particular danger that the required capacity could be set at too high a level if the regulatory authorities over-prioritise minimisation of supply disruption.[102] It is also possible that the geographical distribution of the supported

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98 Decentralised capacity markets can also guarantee a very high level of security of supply by stipulating correspondingly high requirements for the amount of flexibility that must be maintained by providers.

99 However, demand-side flexibility can only be enabled if smart meter systems are implemented and consumers are willing to participate in capacity tenders (either directly, or indirectly through an aggregator).

100 Security of supply contracts are one means of ensuring this.

101 See Cramton et al. 2013, Elberg 2014 and Bhagwat 2016.

102 See Newbery 2016.

capacity could favour cheap locations over regional requirements for locally available capacity. Suboptimal siting of flexible capacity could unnecessarily increase grid expansion requirements, and regional differentiation of the mechanism may therefore be necessary.[103] It may also need to be differentiated on the basis of what it is used for (short-term flexibility versus the prevention of longer-term shortages for example during dunkelflautes).

Moreover, if individual actors behave strategically, there is a danger that the electricity market and the capacity market could influence each other, potentially reducing cost efficiency. Lastly, a central capacity market would probably not be able to leverage the full potential for demand-side flexibility as well as a decentralised system. While the capacity market design can and should make it possible for consumers to provide flexibility, very small consumers are unlikely to actively engage in a capacity market.[104]

Furthermore, international experience shows that capacity mechanisms are susceptible to lobbying if the desired level of security of supply is determined by policymakers. Frequent capacity mechanism rule changes can also result in investors holding back from making investments for strategic reasons, in a bid to provoke supply shortages so that they can influence the capacity mechanism rules and associated financial support. In order to ensure compatibility in the context of increased European grid integration, it will be important to take a coordinated approach to the establishment of capacity markets. Failure to do so could result in a free rider problem (as in policy option 2B), since extensive grid integration would allow individual nations to benefit from capacity markets in neighbouring countries and the flexibility they provide.

The capacity market design should ensure that it does not distort cross-border trade and competition. This is likelier to happen if the capacity mechanism is not sufficiently open to capacity from other EU countries and/or if it is not technology-neutral. Capacity mechanisms should therefore be combined with appropriate market reforms, be proportionate and fixed-term in nature, and be fundamentally open to all capacity providers and member states. Payments must be determined by a competitive process. The specific design must also comply with the principles established by Articles 22 and 26 of the Regulation on the Internal Market for Electricity. In accordance with Art. 25(1) of the Regulation on the Internal Market for Electricity, a reliability standard shall indicate the necessary level of security of supply in a transparent manner.

103 See Amprion GmbH 2022.

104 At most, they would do so through aggregators, who would then need extensive powers and technical capacity to enable load curtailment of very small consumers in practice.

7.2.4 Policy option 2D: Decentralised capacity markets with individual responsibility for security of supply

+ Pros: This is the only policy option that can fundamentally resolve the underlying externality problem by fully transferring the supply risk to the providers. Moreover, in this model, flexibility requirements are closely determined by the actual market circumstances of the individual providers. This means that they are more strongly determined by the market than in a central system, where flexibility requirements are established by a public authority. A decentralised system is thus less prone to overcapacity and ensures that flexibility is also available regionally where providers have taken on the corresponding supply obligations.[105] Since providers also coordinate their end customers' contracts for flexible generation and demand-side flexibility or temporary curtailment, the market outcome in this model should be closest to the actual optimal level of security of supply.

The fact that providers can coordinate individually in order to deliver the necessary capacity can also offer cost efficiency benefits. Unlike in central capacity markets, the providers in a decentralised system have an incentive to encourage flexible demand on the part of their customers, since this allows them to reduce the flexible capacity they need to maintain themselves. The ability to increase demand-side flexibility in extreme situations is especially valuable, since it removes the need to maintain additional capacity that is almost never used. Additional financial support to ensure an adequate level of (regionally differentiated) supply- and demand-side flexibility is not necessarily required – providers should have a sufficiently strong intrinsic incentive to provide the necessary flexibility through hedging transactions.

However, it is vital to ensure the fundamental availability of the various technologies for enabling supply- and demand-side flexibility. The removal of technical and legal barriers should therefore be prioritised. One example is the systematic implementation of smart metering systems. The flexibility that they enable would reduce the need for capacity obligations (meaning, for instance, that the providers in a decentralised capacity market would need to buy fewer certificates). This would give providers a direct incentive to support the deployment of smart metering systems. The EU state aid rules do not apply to this policy option, since there is no state financing in the pure form of the model – generation capacity is agreed individually by contract and the desired level of security of supply is chosen and financed in supply contracts.

- Cons: This policy option calls for some preparation and interventions in the current electricity market. It requires the establishment of capacity obligations for all providers, the development of a certification system for all the different types of flexibility, and potentially also the creation of a low-threshold certificate trading system. Moreover, it is not just the amount of contractually agreed flexibility that matters – its geographical location in the electricity grid is also crucial. For example, it would be necessary to ensure that the contracts also guarantee adequate grid support so that, in the event of a shortage, grid congestion would not prevent individually contracted capacity from being fully available to the providers.

105 See Matthes et al. 2015. In this scenario, it is necessary to ensure that providers really are obliged to curtail their own customers' load if they are unable to meet the demand for electricity.

As for the use of demand-side flexibility to reduce the need for capacity obligations, it is important to ensure that the contractually stipulated level of flexibility or security of supply is technically feasible and can actually be implemented in the event of a shortage. Only then can providers actually meet their responsibility to deliver their guaranteed electricity supply and make appropriate provisions for shortages. It is also necessary to set contractual penalties high enough to ensure that providers do actually meet their capacity obligations, since they may fail to make the necessary provisions if the penalties are too low. However, the effect of contractual penalties can be nullified if a provider goes bankrupt. If the provisions include temporary load curtailment of a provider's own end customers, it must actually be possible to rapidly curtail the load of individual customers. Smart metering and remote control systems are key to making this possible.

The introduction of different levels of security of supply would also end the electricity system's grid neutrality. This inevitably raises the question of whether it would be necessary to regulate a market for hedging transactions. For instance, it is conceivable that only qualifying end customers would be allowed to engage in hedging transactions, with all other customers being excluded from providing demand-side flexibility. It is doubtful whether private households in particular would be capable of realistically estimating the consequences of possible curtailments (especially long-lasting ones). If they are unable to do so, private households' freedom of contract could be restricted, for instance because only households with private electricity storage systems would be allowed to enter voluntary curtailment agreements. Another option would be to define limited-duration and potentially fixed curtailment times, as is partly the case for heat pumps. Without interventions like this, there would be a danger that poorer households would be forced to choose cheaper tariffs offering a lower level of security of supply, meaning that they would be worst affected if curtailments were actually implemented. Consequently, regulation is key to the public acceptability and political viability of this mechanism. However, additional interventions like this would diminish the efficiency of this policy option, since they would restrict freedom of choice.

As with the energy-only model, the evaluation of how well this mechanism complies with constitutional law depends on the extent to which its reliance on demand-side flexibility results in supply shortfalls. A model lacking extensive protection mechanisms, especially for private households, would probably stretch the limits of constitutional law. This would be particularly true if low-income households ended up opting for cheaper tariffs with less security of supply that could result in their electricity supply being cut off for significant periods. This is already evident in the applicable German law, which stipulates that a customer's electricity supply may only be cut off if strictly defined conditions are met. These include significant payment arrears, the issuing of a warning to the customer that their supply will be cut off and a final warning before it is cut off, the proportionality of this action, and the provision of information about how to avoid being cut off. The details are regulated by the Basic Electricity Supply Ordinance (StromGVV), especially Article 19, which deals with cutting off a customer's electricity supply. It is thus important to draw a distinction between business and household customers. Consequently, on constitutional grounds alone, but also for sociopolitical reasons, rather than implementing a pure version of this model for all customers, it would be more appropriate to consider making it available to certain flexible customer groups. This approach would also ensure that there was no risk of contravening EU law.

7.3 Suitability for an electricity market design for 2030

The extent to which a refined version of the pure energy-only market described under policy option 2A can provide a secure, long-term solution depends on the technical and regulatory availability of sufficient supply and demand elasticity. There would need to be sufficient elasticity to prevent blackouts even in extreme situations. Moreover, the provision of this elasticity would need to be financially attractive enough to make it worthwhile purely on the basis of electricity price fluctuations over time. The discussion of political market interventions at times of high electricity prices has further undermined confidence in the idea that capacity reserves for extreme situations can be financed through market prices alone.

In addition, the pure energy-only market model only makes sense if it is not accompanied by the establishment of a permanent strategic reserve (policy option 2B), since this was only ever intended as a temporary instrument. The principal advantage of this model is its cost efficiency, and this advantage no longer applies if, in the long run, an energy-only market can only deliver the required level of security of supply if backed up by a large strategic reserve. In this case, it would be more cost-efficient to implement a capacity market instead of a strategic reserve. And yet, even today, a supplementary strategic reserve is already needed to maintain the necessary capacity outside of the market. Moreover, the problems associated with increasingly inflexible electricity generation due to the growing proportion of renewable energy (such as wind and solar power) are only going to get worse. Consequently, it is hard to see how an energy-only market without a strategic reserve can guarantee a sufficiently high level of security of supply in the medium term. Massive additional financial support for supply- and demand-side flexibility would certainly be essential. If a strategic reserve has to be maintained on a permanent basis, the energy-only market loses its cost advantage over other models, and the underlying security of supply externality problem remains unsolved. In the long run, it will therefore be necessary to transition to a different system.

The establishment of a central capacity market (policy option 2C) would be less reliant on supplementary measures and is a particularly robust mechanism for guaranteeing security of supply. Central capacity markets are able to independently incentivise supply- and demand-side flexibility by providing payments for this flexibility. However, it is vital to systematically enable the technical availability of this flexible capacity and ensure that it is eligible for inclusion in the capacity market. Consequently, supplementary measures should focus on the technical and legal enabling of the relevant technologies and on making them available to capacity markets. The establishment of capacity markets must also be closely coordinated at European level. Stronger European grid integration would allow cross-border access to capacity. This should reduce the total additional cost of flexibility, since less capacity would need to be maintained overall. The establishment of capacity markets must therefore be effectively coordinated in order to leverage efficiency benefits and prevent free riders. It is vital to ensure that the relevant capacity is actually delivered in the event of a shortage and that sufficient capacity is available for different scenarios (short-term shortages versus dunkelflautes).

Lastly, decentralised capacity markets with individual responsibility for security of supply (policy option 2D) are also an appropriate mechanism for guaranteeing long-term security of supply despite the increasing use of variable renewable energy. Decentralised capacity markets may in fact be a better option than central capacity markets, since the required amount of flexibility and the price paid for providing it are more strongly determined by the market. A particular benefit of this model is that it internalises the security of supply externality problem, enabling cost-efficient implementation of security of supply. Decentralised capacity markets would thus tend to be more cost-efficient and less susceptible to the influence of policymakers, public authorities and lobbyists (for example when it comes to establishing the amount of flexibility needed in the system). Appropriate contractual penalties are necessary to ensure that providers make adequate provisions. As with the central model, however, it is still necessary to maximise the range and availability of different technologies in order to leverage any cost reduction opportunities. This includes creating the conditions to increase demand-side flexibility (for example by deploying smart meters) and ensuring that different types of energy storage system can be used in the capacity mechanism.

Implementation of different levels of guaranteed supply in order to leverage the potential of demand-side flexibility would require the introduction of regulations to protect consumers. This would strengthen public acceptance by protecting private households in particular from uncomfortable curtailments. Without this regulation, there would be a danger that lower-income households without their own backup systems would choose cheaper tariffs, leaving them particularly exposed to curtailments and power cut-offs.

One possible compromise would be initially to promote demand-side flexibility opportunities and participation in hedging transactions primarily in the industrial and commercial sectors. An opt-in could be offered to private households that qualify to participate in these transactions (for example by virtue of having their own electricity storage systems). This would allow efficiency benefits in these sectors to be leveraged while at the same time ensuring that, in case of doubt, the first end consumers to be affected by any curtailments would be those who were most willing and able to cope with them. Excluding private households without storage systems from participation in these arrangements would ensure that they were guaranteed a high level of security of supply. The drawback of this approach is that the cost benefits cannot be leveraged due to the internalisation of the costs.

7.4 The transition to a new model by 2030

The current electricity market design comprising an energy-only market with a supplementary strategic reserve complies with the applicable EU and constitutional law. However, for both economic and legal reasons, it is only intended and approved as a temporary system. It is hard to see how the strategic reserve could be dispensed with in the short term. To manage without a strategic reserve, it would first be necessary to implement a much greater level of supply- and demand-side flexibility and meet the corresponding technical and legal requirements. These preparatory measures would also be required for the transition to any of the other policy options. In the short term, there is little prospect of a switch to an energy-only market without a strategic reserve or to a capacity market. Instead, it will be necessary to find a long-term solution (that looks beyond 2030) and gradually transition the system to this target model. To avoid jeopardising security of supply, whichever model is chosen will need to ensure sufficient supply- and demand-side flexibility and the deployment of storage systems.

As already explained, a pure energy-only market (policy option 2A) is a less attractive option in the long run, since this model tends to provide the lowest level of flexibility and security of supply. While policy options 2C and 2D represent a bigger departure from the current system, once implemented they would be able to independently incentivise the necessary flexibility, thereby guaranteeing security of supply in the system. Consequently, both of these policy options are better solutions in the medium to long term. However, it will be very difficult to change systems in the short term, since both policy options involve a relatively hard break with the current model and would require extensive preparations. The first step should thus be to identify and define the new target model. In particular, it will be necessary to analyse any drawbacks and determine whether they are acceptable in the long term.

The actual transition will involve the technological and legal enabling of the necessary flexibility. The success of whichever target model is chosen will depend on doing this as comprehensively as possible. Financial support to promote flexible supply and demand and the installation of additional storage systems is possible in all the models. Future amendments to the regulatory framework should focus on this aspect, which involves measures such as the widespread deployment of smart metering systems (without which it will be technically impossible to achieve the necessary elasticity of demand) and greater digitalisation of the electricity system (see Chapter 4).

Secondly, work on the transition to the target model must begin now. This includes defining the flexibility targets, implementing a certificate trading system if applicable, and (gradually) running down the strategic reserve while at the same time building the capacity market. A number of additional measures will be required to enable decentralised capacity markets and different tariffs for different levels of guaranteed supply. These include the establishment of a certificate system for providers and possibly also a certificate trading system. In order to guarantee the delivery of demand-side flexibility, it will be necessary to conclude appropriate new contracts and meet the relevant technical and legal requirements.

8 Conclusion

There is no fundamental question about the effective functioning of the current electricity market design. Consequently, it is not necessary to restructure the entire system from the ground up and, for example, abandon the tried-and-tested merit order model in response to the current energy crisis. However, that is not to say that the electricity market design does not need to be reformed at all. If climate neutrality is to be achieved as soon as possible in Germany and Europe, it will be necessary to ensure a rapid transition to renewable electricity generation. This transition is associated with a number of challenges for the electricity market design that will need to be addressed in the coming years. However, a significant number of these challenges fall outside the scope of the market design. For instance, the expansion of renewables has long been held back by overly complex licensing laws and other barriers.[106] Extensive new legislative measures designed to alleviate these problems were only announced a few months ago. Since most of them are still to come into force, they have not yet brought about any new trends.

In order to address the existing market design challenges, this position paper describes policy options for two key aspects. All of these policy options have their pros and cons. Consequently, rather than trying to find the perfect electricity market model, the aim should be to achieve the best possible model that can be realistically implemented and will stand the test of time.

When planning changes to the electricity market design, it is essential to carefully weigh up the pros and cons, since interventions in the electricity market design will always also be accompanied by negative repercussions and the danger of lock-in effects. To maintain a functioning electricity market, it is important to avoid abrupt or repeated switching between different models. Any reform should instead aim to create a lasting, politically sustainable model. It is thus vital to identify the opportunities and problems in advance and have a clear understanding of the chosen model's long-term suitability.

When making short-term interventions such as those needed to support households and industry during the current energy price crisis, it is also important to ensure that the instruments introduced will still contribute to a functioning electricity market once the crisis is over. Otherwise, there is a danger that these short-term instruments could jeopardise the functioning of the electricity market and undermine its potential contribution to meeting the climate targets.

106 See acatech et al. 2022-2.

Based on the key questions discussed in this position paper, the following options for a reform of the electricity market design should be considered by policymakers without delay:

Meeting the 2030 climate targets and achieving climate neutrality by 2045 is a matter of absolute priority. Taking this long-term view, the working group concluded that a carbon price that increases to an appropriate level is the most suitable primary market instrument in terms of both climate effectiveness and cost efficiency. Prescribing and staying on this pathway is thus key to providing the long-term investment incentives needed for a successful energy transition. Accordingly, it will be necessary to study and implement the continuation of carbon pricing and its extension to as many sectors as possible. The transition to climate neutrality will also rely heavily on the generation of electricity from renewable sources. In order to meet the ambitious targets for the expansion of renewables by 2030, it makes sense to keep providing financial support through market premium models during the migration phase over the next few years. There is no perfect model for this. Instead, it will be necessary to weigh up the pros and cons outlined in this paper and formulate clear policy guidelines for delivering an appropriate market premium model that can support the transition to a future unsubsidised system where carbon pricing constitutes the main market instrument.

The transition to a climate-neutral energy system makes it more challenging to maintain the high level of security of supply that people are accustomed to. A decision will need to be taken as to whether the existing system comprising an energy-only market potentially accompanied by a strategic reserve can still provide the necessary security of supply in an energy system dominated by renewables. The current energy-only market may need to be supplemented by a central capacity market or decentralised capacity markets with greater individual responsibility for security of supply. All the alternatives have a number of drawbacks. Regardless of whether the current system is retained or new mechanisms are introduced, the negative impacts of the chosen system will therefore need to be analysed in advance so that appropriate counter-measures can be taken. Clear long-term policy guidelines for a development pathway are once again key in this context.

Neither climate neutrality nor security of supply can be achieved unless the electricity system is sufficiently flexible. To enable this flexibility, it will be vital to move ahead as quickly as possible with the system's digitalisation. Without digital infrastructure such as smart meters and universal broadband coverage, many places will lack the basic requirements to create economic incentives for greater flexibility. This technical infrastructure will need to be accompanied by additional demand- and supply-side incentives to provide flexibility and install energy storage systems. A whole host of barriers will have to be overcome in order to enable the innovative, data-driven consumer applications that are necessary in this context. For example, it will be important to engage with data protection supervisory authorities from an early stage to ensure that these digital applications can be deployed. Increasing the flexibility of the electricity system will also call for the systematic expansion of the power grid, both within Germany and through further European grid integration.

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The Academies' Project

In the Energy Systems of the Future initiative, acatech – National Academy of Science and Engineering, the German National Academy of Sciences Leopoldina and the Union of the German Academies of Sciences and Humanities provide input for a fact-based debate on the challenges and opportunities of the German energy transition. Around 160 experts collaborate in interdisciplinary working groups to develop policy options for the transition to a sustainable, secure and affordable energy supply.

The "Electricity Market of the Future" working group

The expansion of renewable energy as part of the energy transition in Germany and the EU is creating a new dynamic on the electricity markets. Instead of being able to plan ahead with long-term forecasts and large power plants, in the future electricity markets will have to reflect short-term changes due to fluctuating renewable energy sources, multiple small market players and flexible usage patterns. The (planned) phase-out of nuclear and coal-fired power plants reinforces this dynamic. The ESYS working group "Electricity Market of the Future" investigated how the market design could be improved to guarantee a cost-effective and secure supply in the long term. Among other things, the working group addressed the following questions: What is the best financial support model for renewable energy installations, or will a high carbon price make financial support redundant? Can the power plants and storage systems that are crucial for security of supply be financed within the existing system? How can the electricity market become more flexible without jeopardising security of supply and cost efficiency?

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