European Commission

Economic and Financial Affairs

Evaluating the Cost-Competitiveness of Low-Carbon Energy in Future EU Power Markets

The Role of Flexibility and Contracts for Difference

Rafael Finck, Derck Koolen, Arnaud Mercier,
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EUROPEAN ECONOMY

DISCUSSION PAPER 236 | DECEMBER 2025

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PDF ISBN 978-92-68-31837-9 ISSN 2443-8022 doi:10.2765/9683407 KC-01-25-066-EN-N

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Abstract

The European Union's goal of achieving climate neutrality by 2050 requires substantial investments in low-carbon electricity generation, particularly wind, solar and nuclear power. By 2040, the EU aims for over 90% of electricity to come from low-carbon sources. This study examines the cost-competitiveness of various low-carbon technologies in different market environments and the influence of two key mechanims that support their investment and integration in the market: flexibility and long-term contacts.

Overall, the cost-competitiveness on a market basis of low-carbon electricity generation is possible but it is sensitive to the cost of capital and the commodity cost of price-setting technologies. Flexibility, which is the ability of assets to adjust energy consumption or production, plays an essential role in the integration of electricity from renewable sources. While flexibility has in general a positive effect on the profitability of low-carbon technologies and reduces price volatility, the analysis highlights the clear need to ensure coherence across policies supporting the integration of renewable energy and flexibility.

Contracts for Difference (CfDs) are long-term contracts between an electricity generator and a public entity, providing a stable revenue for the generator and protection for consumers from volatile and extreme prices. The strike price of a CfD contract is a key parameter determining the profitability for producers and the cost-effectiveness of the instrument for the public counterparty. The analysis shows that CfD revenues and cash flows largely depend on the potential for the technology to capture (high) market prices, and the level of the agreed strike prices per technology, indicating the importance of competitive auctions to allocate these CfDs.

JEL Classification: Q40, Q42, Q47, Q48.

Keywords: Low-carbon electricity, cost-competitiveness, renewable energy, flexibility, public support, Contracts-for-Difference, Power purchase agreements, cannibalisation.

Acknowledgements: Comments and suggestions by Géraldine Mahieu (Director, Investment, growth and structural reforms, ECFIN), Christina Jordan (Head of Unit, Economics of resilience and transition, ECFIN), Evangelos Tzimas (Head of Unit, Energy Transition Insights for Policy, JRC), Antonio Lopez-Nicolas (Head of Unit, Chief economist team, ENER), Bert Saveyn (Deputy Head of Unit, Chief economist team, ENER), Ivo Schmidt (Deputy Head of Unit, Energy Efficiency: Policy and Financing, ENER), Åsa Johannesson Lindén, (Senior expert, Economics of resilience and transition, ECFIN) and colleagues in the Directorate-General for Energy as well as by members of the Economic Policy Committee (EPC) Working Group on Energy and Climate Change are gratefully acknowledged.

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ABBREVIATIONS

COUNTRIES

AT	Austria
BE	Belgium
BG	Bulgaria
CY	Cyprus
CZ	Czechia
DE	Germany
DK	Denmark
EE	Estonia
EL	Greece
ES	Spain
FI	Finland
FR	France
HU	Hungary
IE	Ireland
IT	Italy
LT	Lithuania
LU	Luxembourg
LV	Latvia
MT	Malta
NL	Netherlands
PL	Poland
PT	Portugal
RO	Romania
SE	Sweden
SI	Slovenia
SK	Slovakia

UNITS

GW	Gigawatt
GWe	Gigawatt of electric energy
GWh	Gigawatt hour
kWh	Kilowatt hour
Mtoe	Million tonnes of oil equivalent
MWh	Megawatt-hour
TWh	Terawatt-hour

OTHER

bn	Billion
CfD	Contract for difference
CO2	Carbon dioxide emissions
ETS	Emissions trading scheme
EU	European Union
EUR	Euro
EV	Electric vehicle
FiP	Feed-in premium
FiT	Feed-in tariff
GHG	Greenhouse gas
IRENA	International Renewable Energy Agency
JRC	Joint Research Centre
LCOE	Levelised cost of electricity
MS	Member State
MV	Market value of the electricity
NECP	National Energy and Climate Plans
NRA	National regulatory authority
PPA	Power Purchasing Agreement
PV	Photovoltaic
REDIII	Renewable Energy Directive recast
RES	Renewable energy sources

CONTENTS

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EXECUTIVE SUMMARY

The European Union's ambition to electrify its economy is key for the EU to achieve climate neutrality and ensure the long-term competitiveness of the EU economy. To achieve this goal, significant investment in low-carbon electricity generation, such as wind and solar electricity sources, is necessary. In 2022, renewable energy sources accounted for 40% of the EU's electricity generation, while nuclear accounted for around 20%. By 2040, it is anticipated that over 90% of electricity production will be generated from low-carbon energy sources, primarily from renewables, complemented by nuclear energy. Within renewable energy, wind and solar energy will account for the largest shares of renewable capacity.

The increase in wind and solar generation, which is variable by nature, leads to an inherent volatility in production, posing challenges for investors. Investors must be able to recover their fixed costs and manage revenue risks to ensure the viability of their investments. If the risks associated with energy investments become too high or the potential returns are unattractive, public support may be needed to incentivise the investments needed to further decarbonise the electricity system. The EU has therefore reformed the design of its electricity market, focusing in particular on system flexibility and long-term contracts between generators and buyers.

This paper analyses the need for public support by examining the cost-competitiveness of various technologies in different market environments and with different levels of system flexibility and the functioning of two-way contracts for difference (CfDs) that are concluded between an electricity generator and a public entity.

Key take-aways are:

- **By 2030, low-carbon (renewable and nuclear) electricity generation is largely cost-competitive on a market basis but it is sensitive to the cost of capital and the commodity cost of price-setting technologies** such as natural gas fired power plants. High upfront capital expenditures coupled with low marginal price-setting technologies pose substantial challenges to the competitiveness of low-carbon technologies. This is particularly pronounced for offshore wind technologies and new nuclear power plants.
- **Flexibility, which is the ability of assets to adjust energy consumption or production, generally has a positive effect on the cost-competitiveness of low-carbon technologies** such as wind or solar photovoltaics and nuclear technologies.
- **Flexibility also lowers the volatility of wholesale electricity prices. However, the average price effect depends on the price distribution skewness.** This highlights the need for coherent planning and coordination in terms of investments planning and support mechanisms to ensure the cost-efficient combined integration of renewable energy and flexibility.
- **Batteries, as a source of flexibility, may experience a cannibalisation of revenues as they increase their market share for providing grid flexibility**, where wholesale spot market revenues are increasingly insufficient to cover fixed costs, and other market revenues are needed.
- **Contracts for Difference (CfDs) are a key instrument to stimulate investment**, when market risks hamper investment decisions in low-carbon technologies. CfDs provide stable revenues for the generator and protect consumers from volatile and extreme prices. The strike price of a CfD contract is a key parameter determining the profitability for producers and the cost-effectiveness of the instrument for the public counterparty. Competitive auctions should be used to allocate these CfDs.
- **Temporary changes in market conditions can result in CfDs producing positive or negative cash flows for the public budget**. Where these cash flows are positive, they should be used to further incentivise investments in clean energy as they represent an economic rent that drives investment decisions under market-based conditions.

1. INTRODUCTION

The integration of low-carbon energy sources and electrification of the economy is a key priority for the European Union to reach climate neutrality and decrease the exposure to volatile fossil fuel prices. In the impact assessment underpinning its recommendation for 2040 emissions reduction target[1], the Commission estimated that the share of electricity in the final energy consumption will double from 25% today to about 50% in 2040. The transition away from fossil fuels is crucial for ensuring the long-term competitiveness of the EU economy. Currently, natural gas retail and wholesale prices in the EU are substantially higher, ranging from three to five times the prices in the United States, which has implications for EU industrial competitiveness and household energy affordability[2].

Achieving this goal will require significant investment in low-carbon electricity generation such as wind and solar electricity sources. Renewable energy sources are the main source of electricity in the EU since 2020. In, 2022, 40% of the electricity generated in the EU was produced from renewable energy sources. By 2040, it is expected that the electricity system will be largely decarbonised[3]. More than 85% of the electricity production is expected to be generated by renewable energy sources, wind and solar accounting for the largest shares of renewable capacity. Meanwhile, nuclear energy is expected to contribute to about 10% of the electricity generation.

The dependency of wind and solar electricity sources on weather conditions requires a good coordination of the system investments and the way their investments and those of other generating assets are recovered[4]. Most electricity produced by renewable energy sources is inherently variable, which in combination with factors like limited storage capacity and price elasticity of demand puts power systems operations under pressure. Furthermore, as solar photovoltaic and wind power plants have low variable production costs, they are dispatched first, impacting the wholesale price and revenue of all generation technologies. As the magnitude of this effect increases with the market share, renewable technologies can erode their own market value over time. This is known as the cannibalisation effect of renewable energy. This cannibalisation can already be observed in many regions, the market value for electricity generated by solar panels keeps eroding compared to the average electricity price, potentially weakening investment incentives under the current market framework, at the same time signalling market saturation. This poses a challenge for capital intensive technologies such as renewable and nuclear energy, where the main driver for their cost of production is determined up-front during the investment period. While the availability of long-term hedging instruments such as Power Purchase Agreements[5] is growing, it is not available at the scale required for the transition today. Without such long-term contracts, the cost of capital would be higher or the risk too high to trigger the massive investment in renewable technologies needed to meet our EU climate and energy targets.

In response, the EU has adopted a reform of the European electricity market design[6]. It promotes, inter alia, two key options to enable the integration of renewable energy sources: enhancing non-fossil flexibility solutions and increasing the use of long-term contracts such as Power Purchase Agreements (PPAs) and Contracts for Difference (CfDs). The reform promotes the development of PPAs, which are commercial long-term contract between a generator and a buyer (off-taker) by removing key barriers to the PPA market such as the credit risks of buyers. Furthermore, where direct price support schemes are needed for investments, these should be in the form of two-way CfDs. The market reform further promotes the market integration of fossil-free flexible

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[1] European Commission (2024a). 2040 Climate Target Plan.

[2] Draghi (2024). The future of European competitiveness Part B | In-depth analysis and recommendations. September 2024

[3] European Commission (2024a). 2040 Climate Target Plan.

[4] Sebastian Busch, Ruben Kasdorp, Derck Koolen, Arnaud Mercier and Magdalena Spooner (2023). The Development of Renewable Energy in the Electricity Market European Commission. Directorate-General for Economic and Financial Affairs Discussion Paper 187, June 2023.

[5] Draghi (2024). Op. cit.

[6] European Commission (2024b). Directive (EU) 2024/1711 and Regulation (EU) 2024/1747.

technologies, such as demand side response, energy storage, and other non-fossil flexibility solutions that can complement variable energy production, reduce price volatility and support price convergence.

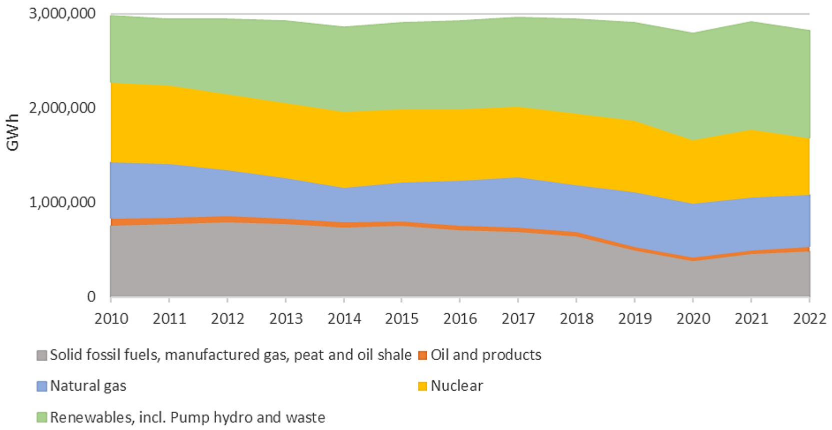
The aim of the reform is to create a sustainable investment environment on a market basis, thereby minimising reliance on public subsidies. Energy investment can only be sustainable over time if investors can expect revenues from these technologies to be sufficient to cover their total costs, while effectively managing key risks associated with energy investments, including price volatility, volume uncertainty, and regulatory uncertainties. If these risks remain excessively high or the potential returns on investment are not attractive enough, investors will be deterred, and public support will be necessary to stimulate investment. In contrast, if government support is directed towards technologies that are already competitive and can manage risk allocation on a market basis, this can lead to inefficiencies and place an undue burden on public finances.

This paper aims to analyse the need for public support by examining the cost-competitiveness of various technologies in different market environments and with different levels of system flexibility and the functioning of two-way contracts for differences (CfDs). Section 2 outlines the current integration of renewable and nuclear electricity, along with projections on their future deployment. It also provides information on the role of non-fossil flexibility solutions within the power system, as well as on the role of contracts for difference. Section 3 illustrates the impact of these two options on the cost-competitiveness of low-carbon technologies and on the evolution of the market value of electricity consumption from a wholesale perspective in different market environments. Section 4 concludes the paper.

2. STATE OF PLAY

2.1. RENEWABLE AND NUCLEAR ENERGY DEVELOPMENT

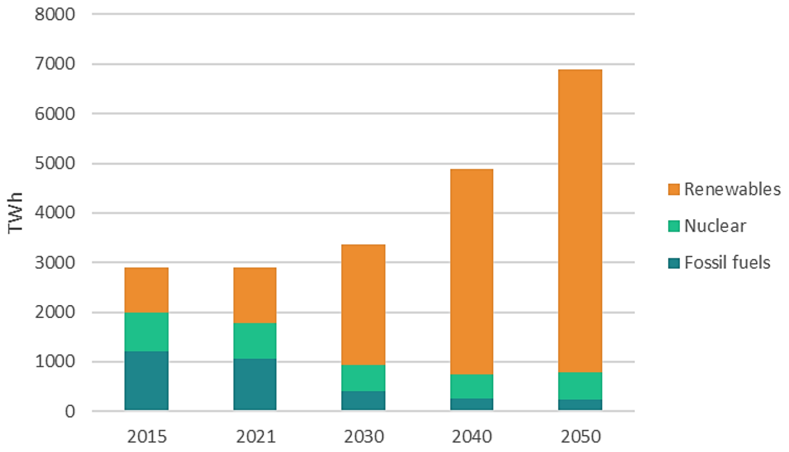
Graph 2.1. **Gross electricity production by type of fuels (EU-27)**



Source: Eurostat.

The production of electricity from renewable energy sources has become the dominant source of electricity in the EU, surpassing all other sources since 2020. As illustrated in Graph 2-1, in 2022, renewable energy sources accounted for 40% of the EU's total electricity generation, outpacing fossil fuels by 2 percentage points. A significant proportion of renewable electricity, over 55%, was generated by wind and solar power plants in 2022. Further breaking down the renewable energy sector, wind farms emerged as the largest contributor, producing 37.9% of the EU's renewable electricity in 2022. Hydropower followed closely. Solar photovoltaic ranked third, accounting for 18.5% of the renewable electricity generated in the EU during the same period.

Graph 2.2. **Electricity generation by energy carrier, 2015-2050**



Source: European Commission, based on the Impact Assessment of the 2040 Climate Target Plan[7].

Going forward, the decarbonisation of the electricity sector is expected to continue at a high pace with renewable electricity becoming the dominant source of supply. In the impact assessment carried out for the proposed 2040 climate target (Graph 2-2), the Commission estimated that the share of renewable energy in the electricity mix would continuously increase from 39 % in 2021 to around 70 % by 2030 and up to 85 % by 2040. Wind and solar electricity are expected to become the largest producers, amounting to more than 55% of the electricity production by 2030 and about 75% by 2040.

The share of nuclear energy in the EU power mix is expected to decline over time. Nuclear energy produced around 23% of the EU's total electricity production in 2023. There are currently 100 power reactor units (96 GW total installed net capacity) across the EU, located in twelve Member States[8, 9]. Based on the capacity assumptions in line with the Member State policies as described in the 2019 National Energy and Climate Plans, the EU's nuclear power capacity is projected to remain about stable in 2030 and decline thereafter to about 70 GW in 2040. These assumptions reflect the situation until March 2023. This result does not account recent announcements in the field of nuclear energy made by several Member States. For instance, in June 2023, France adopted a law removing the objective of reducing the share of nuclear power in the electricity mix and announced an additional 3.3 GWe nuclear capacity for deployment by the mid-2030s[10]. Further Member States have made announcements for new nuclear build in their updated National Energy and Climate Plans, among which Bulgaria, Czechia, Hungary, the Netherlands, Poland, Romania, Slovenia, Sweden[11]. The Commission has published a new Nuclear Illustrative Programme (PINC) in 2025[12].

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[7] For 2040 and 2050, average between the scenarios S2 and S3 of the 2040 Climate Target Impact Assessment.

[8] Belgium, Bulgaria, the Czech Republic, Finland, France, Hungary, the Netherlands, Romania, Slovakia, Slovenia, Spain and Sweden, with France responsible for almost 50% of the EU's total generation.

[9] Draghi (2024). Op. cit.

[10] European Commission (2024c). Commission staff working document - Impact assessment report accompanying the document communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee and the Committee of the Regions Securing our future Europe's 2040 climate target and path to climate neutrality by 2050 building a sustainable, just and prosperous society SWD(2024) 63 final.

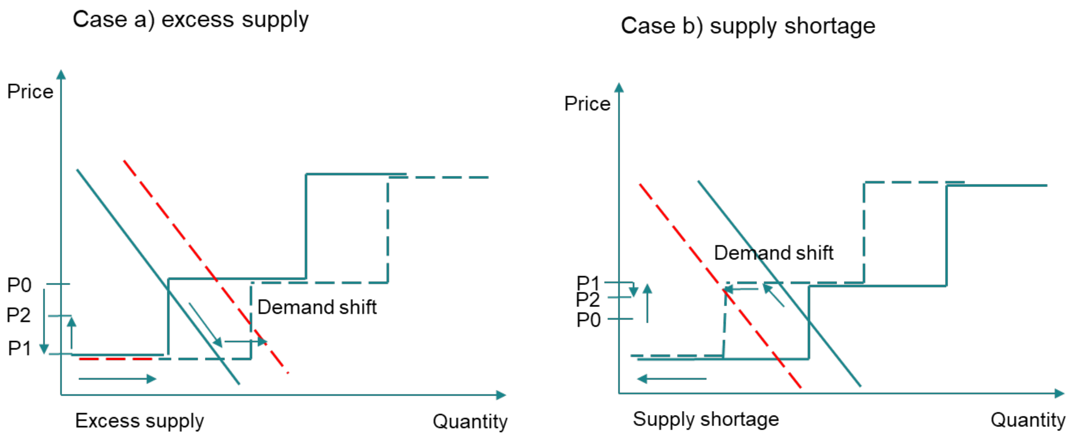
[11] https://commission.europa.eu/energy-climate-change-environment/implementation-eu-countries/energy-and-climate-governance-and-reporting/national-energy-and-climate-plans_en#national-energy-and-climate-plans-2021-2030.

[12]. The PINC is set out in Art. 40 of the Euratom Treaty, whereby the Commission shall periodically publish the PINC and obtain the opinion of the Economic and Social Committee (EESC). European Commission (2025). Communication on the Nuclear Illustrative Programme PINC (COM/2025/315 final).

2.2. FLEXIBILITY OF ELECTRICITY SYSTEMS

2.2.1 Basic principles of flexibility

Graph 2.3. **Basic principles of demand flexibility**



Source: European Commission.

Flexible assets are able to adjust their energy consumption or production in response to price changes or the intervention by system operators. On the electricity market, they can take advantage of low prices by increasing demand or reducing energy consumption during high prices. Graph 2-3 illustrates this graphically by looking at supply and demand adjustments for a one-hour period. In periods with excess wind or solar production (case a), prices decrease due to oversupply (shift along the demand curve to P1). If the supply of wind and solar energy exceeds demand, the market price will drop to the marginal production cost of these technologies, resulting in low, zero or even negative prices[13]. However, if sufficient flexible demand is in the system, the low-price environment due to oversupply will trigger additional demand from flexible assets, which will shift the demand curve to the right. Consequently, the reduction in prices due to excess supply of wind and solar energy may be mitigated (e.g. price may reach P2 in case a) and the number of hours with zero or negative prices will likely be significantly reduced. In contrast, during periods of shortage, the opposite effect may occur. The shortage of supply will require very costly technologies to cover the supply gap, leading to higher prices (shift along the demand curve to P1 in case b). With flexible demand, this price increase may be mitigated (shift the demand curve to the right to P2). The magnitude of the price effect from P1 to P2 of flexibility thereby depends on the amount of flexibility added to the system.

2.2.2 The need for non-fossil flexibility

The growing share of production of electricity from variable renewable energy sources increases the need for non-fossil flexibility in the power system. Renewable energy sources such as wind and solar energy have production profiles that depend on spatio-temporally varying weather conditions. This means that the generation of electricity from these renewable energy sources correlates over geographic areas up to a certain size and varies according to the change of weather conditions at

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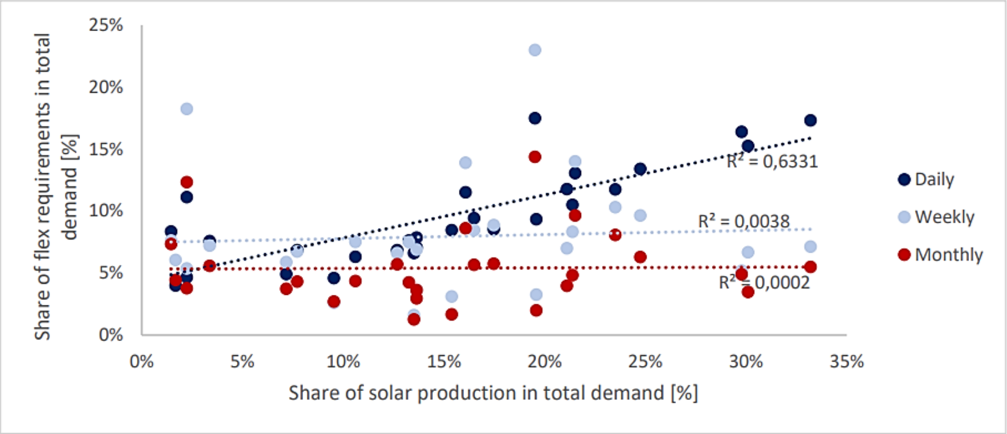
[13] If power stations with minimum load requirements are paying money to stay online for hours during which renewables operating under non-market based subsidy schemes such as Feed-in Tariffs do not react to price signals and no additional demand is available.

different timescales from minutes and hours to days, seasons and years [14]. Flexibility solutions allow demand and supply to be shifted over time according to system needs and price signals.

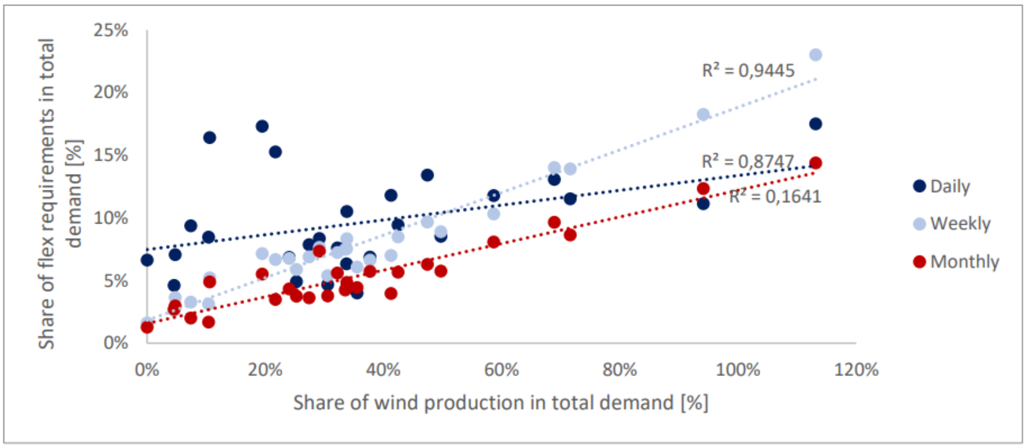
Graph 2.4. **Share of daily, weekly and monthly flexibility requirements in total demand in relation to share of solar production in 2030. Dots represent EU Member States; dotted lines are timescale trend lines.**



Note: Flexibility requirements determined by variation in the residual load curve, per timescale. See original paper for full elaboration.

Source: Joint Research Centre[15].

Graph 2.5. **Share of daily, weekly and monthly flexibility requirements in total demand in relation to share of wind production in 2030. Dots represent EU Member States; dotted lines are timescale trend lines.**



Note: Flexibility requirements determined by variation in the residual load curve, per timescale. See original paper for full elaboration.

Source: Joint Research Centre[16].

The JRC estimated that the need for flexible solutions will more than double by 2030 and will increase by a factor of 7 by 2050[17]. Flexibility requirements are thereby estimated based on variations in the residual load curve, defined as the load that can be served by dispatchable technologies, and are shown to require a variety of flexibility technologies and storage solutions to

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[14] De Felice, M., Koolen, D., Kanellopoulos, K., Busch, S., & Zucker, A. (2023). Climate variability on Fit for 55 European power systems. Plos one, 18(12).

[15] Koolen, D., De Felice, M. and Busch, S. (2023). Flexibility requirements and the role of storage in future European power systems, Publications Office of the European Union, Luxembourg, 2023, doi:10.2760/384443, JRC130519.

[16] Ibid.

[17] Ibid.

address the flexibility needs at different timescales[18]. Short-term flexibility represents the need for flexibility at hourly or even shorter time steps, reflecting flexibility needs to balance the system within the day. More long-term or seasonal flexibility requirements capture the needs for flexibility on a weekly or monthly basis that are not already captured by the short-term flexibility requirements such as seasonal changes or to compensate for long events where there would be a shortage of wind, solar or hydropower generation (e.g. so-called "Dunkelflaute"). As can be seen in Graph 2-4 and Graph 2-5, overall flexibility requirements increase with an increased generation of renewable technologies such as wind or solar. However, the timescale where flexibility is needed depends on the technology, or more specifically on the characteristics of its resource. There is a linear relationship between the installed capacity for solar PV and the daily flexibility requirement, while for wind, the relationship is more pronounced for a monthly and weekly timescale.

Flexibility solutions exist in all parts of the electricity value chain, from generation, transmission and distribution to consumption. Production assets such as dispatchable power plants or hydro-pump storage and grid interconnections are currently the main sources of flexibility of the European power system. While the contribution of interconnections and hydropower is expected to remain important in the future, the Electricity Market Design reform highlights the need to increase the share of non-fossil flexible solutions. Short-term storage technologies such as batteries or flexible demand response by industrial consumers or households, electrolysers, the charging of and injection from electric vehicles, heat pumps with storage, thermal storage, or other non-fossil flexibility solutions are key solutions to further increase the flexibility of the electricity system. Moreover, flexible technologies may be used to relieve congestion and improve grid reliability and flexibility.

Increasing the non-fossil flexibility of the power system is a long-standing priority for the EU. With the Electricity Market Design reform, the EU has expanded the tools to support the development of own sources of flexibility. This includes defining indicative national objectives for non-fossil flexibility, accelerating the development of the framework for non-fossil flexibility schemes (storage and demand side response) as well as the development of a common European methodology for non-fossil flexibility needs assessment by Member States (MS) and assessing EU flexibility needs. The reform also addresses the use of flexibility services by network operators, for example by allowing them to purchase peak shaving products, but also by introducing incentives linked to the remuneration of network operators through network tariffs that encourage grid investments as well as their smart operation.

2.2.3 Two-way Contracts for difference

BOX 1: TWO-WAY CONTRACTS FOR DIFFERENCE

A two-way Contract for difference (CfD) is a contract between an electricity generator and a public entity that aims at supporting investments in energy supply. The electricity generator sells the electricity in the market and then settles the difference between the market price and a strike price agreed in advance with the public entity, which can be positive or negative. This way, the contract helps providing stable prices and thus stable renumeration to investors over a long period and protecting consumers from high electricity price shocks.

The financial dynamics of CfDs revolve around the relationship between a strike price and a market reference price. The strike price is typically determined through a competitive bidding process and is based on market expectations of revenues. The reference price is a market-based price per unit of output produced or a reference production volume. It is typically the hourly price or an average of market prices over specific periods. If the market price is below the strike price, the generator receives the difference; if the market price is above the strike price, the generator pays back the difference. Graph 2-6

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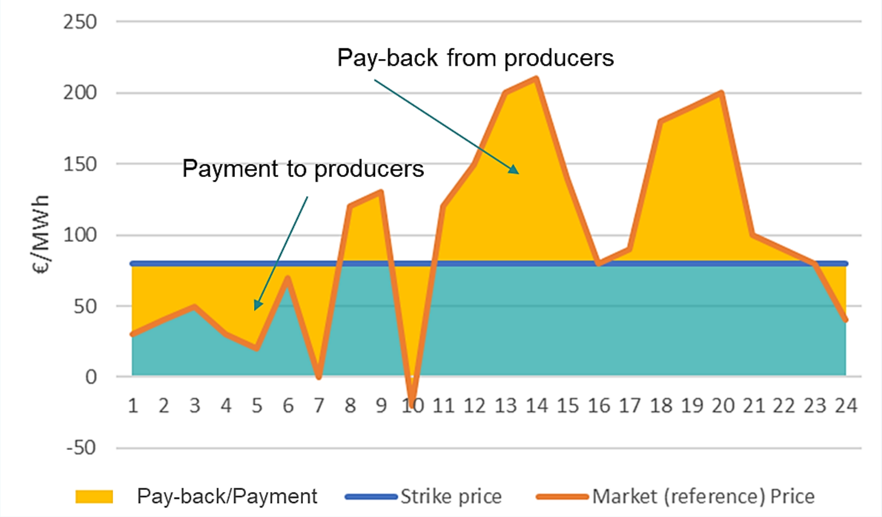
[18] European Commission (2019). Directorate-General Energy, Bardet, R., Khallouf, P., Fournié, L., et al., Mainstreaming RES : flexibility portfolios : design of flexibility portfolios at Member State level to facilitate a cost-efficient integration of high shares of renewables, Publications Office, 2019.

provides a general schematic representation of how Cfds work for the case where the market reference price is hourly based[19].

Graph 2.6. ***Schematic representation of a traditional hourly production based CfD***



Source: Reproduced from RAP (Regulatory Assistance Project).

The design of CfDs varies, including production-based and production-independent models. Production-based CfDs link cash flows with the actual output of the installation. This may lead to inefficiencies by incentivising production regardless of market conditions and can result in excessive generation when demand is low, or prices are below marginal cost. In contrast, production-independent CfDs align incentives better with market behaviour by decoupling payments from actual production levels, though they typically require more complex modelling to establish accurate reference volumes.

Two-sided CfDs have to date been used in 11 EU Member States [20,21]. The reform of the electricity market will make CfDs the reference model for investments in new capacities where public support is needed. The Reform of the electricity market Regulation[22] requires that three years after the enforcement of this law (by 2027), direct price support to new power-generating facilities based on wind energy[23], solar energy, geothermal energy, hydropower (without reservoir) and nuclear energy will need to be made in the form of two-way CfDs or equivalent schemes with the same effects. The legal text does not prescribe a specific design but includes a set of principles that would need to be respected in their design[24], in particular the need to preserve market incentives for the power-generating facility to operate and participate efficiently in the electricity markets, prevent any distortive effect of the support scheme on the operation, dispatch and maintenance decisions of the power-generating facility and avoid distortions to competition and trade.

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[19] Lena Kitzing, Anne Held, Malte Gephart, Fabian Wagner, Vasilios Anatolitis, Corinna Klessmann (2024). Contracts-for-Difference to support renewable energy technologies: Considerations for design and implementation. Research Report RSC/FSR March 2024.

[20] Belgium, the Czech Republic, Denmark, France, Greece, Hungary, Ireland, Italy, Poland, Portugal, Spain, and the United Kingdom

[21] Based on Lena Kitzing, Anne Held, Malte Gephart, Fabian Wagner, Vasilios Anatolitis, Corinna Klessmann (2024). Contracts-for-Difference to support renewable energy technologies: Considerations for design and implementation. Research Report RSC/FSR March 2024 and State aid cases: SA.58207 and SA.107336.

[22] Article 19 Direct price support schemes in the form of two-way contracts for difference for Investment of the Regulation of the European Parliament and of the Council amending Regulations (EU) 2019/942 and (EU) 2019/943 as regards improving the Union's electricity market design pdf (europa.eu).

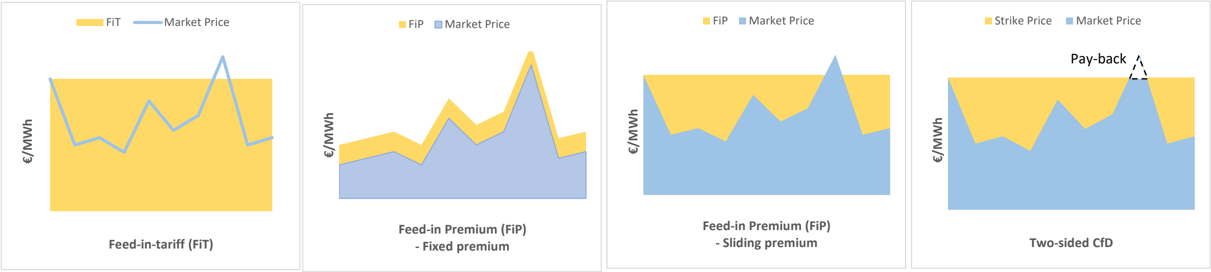
[23] Support for new capacity will need to be in the form of two-way contracts for difference or equivalent schemes with the same effects as of 17 July 2027 for wind energy, solar energy, geothermal energy, hydropower (without reservoir) and nuclear energy or in the case of offshore hybrid asset projects connected to two or more bidding zones, 17 July 2029.

[24] Also see the forthcoming Commission Guidance on CfD Design.

2.2.3.1 Concept and state of play

Renewable energy support schemes have changed significantly in the past few decades, in response to technological advancements, market dynamics, and policy imperatives. Lower costs for renewable energy have increasingly shifted renewable energy policy design, from covering incremental costs to facilitating risk-hedging and ensuring predictable investment frameworks. Graph 2-7 portrays the main types of renewable energy source (RES) support mechanisms used in EU Member States. Feed-in-tariffs have been a popular type of support over the years, where a regulator would set a fixed price for the entire generation volume, usually above the market price. These were deployed in times when renewables were still a nascent technology and needed financial support and full de-risking. However, due to inefficiencies such as limited incentives for market integration and often delayed alignment to decreasing investment costs due to technological advancement, Feed-in premiums (FiPs) have gradually increased in popularity over the years. FiPs guarantee a fixed or variable (sliding) premium on top of the captured market price, thereby mitigating downside price risk for investors and incentivising efficient dispatch through improved price signals. However, with the increase in electricity prices during the energy crisis the possibility to contain prices has become a priority to ensure affordable electricity prices for consumers. The uptake of long-term contracts, including PPAs and CfDs, as well as revising rules on forward markets to increase hedging opportunities, emerge as solutions to ensure long-term revenue stability for producers while protecting consumers.

Graph 2.7. **Schematic representation of main types of RES support mechanisms**



Source: Reproduced from RAP (Regulatory Assistance Project).

For mature technologies, PPAs allow the derisking of investments on a market basis. A PPA is a commercial long-term contract between a generator and a buyer (off-taker), whereby the latter purchases a specific volume of electricity from the former at an agreed pricing, such as a predetermined price, a price reference formula or a combination of both over a certain period. The electricity can be delivered physically or virtually as a financial market product. PPAs have been used for a long time in the electricity sector, preceding the deregulation that started in the late 1990s. Today, the instrument gains popularity as a tool to trade renewable electricity over longer time periods. There currently are, however, several barriers preventing a more rapid uptake of the market for renewable PPAs. These include, without being exhaustive, the creditworthiness of the off-taker i.e. its ability to meet its payment obligations, a mismatch between the off-taker's demand and the renewable production profile, increasing the risk and cost of capital. Public support can play a crucial role to overcome such barriers. National promotional banks can establish, for instance, guarantee schemes or insurance products to mitigate off-taker credit risk. Governments can also promote pooling mechanisms, such as aggregation platforms to address the demand-production mismatch[25].

Contracts-for-difference have an important role to make these projects bankable or provide the stability lenders demand. As explained in Box 1, the goal of a two-way CfD is to support investment in energy supply, by providing stable prices and thus renumeration to investors over a long period and protecting consumers from high electricity price shocks. There are two main categories of CfD designs: *production-based and non-production-based (capability-based and financial RES) CfDs.*

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[25] Draghi, (2024). The future of European competitiveness - Part B | In-depth analysis and recommendations.

Production based CfDs are linked to the actual energy production of an asset. Payments are calculated based on the quantity of energy they generate. If they do not produce, they do not earn any revenues. The reference price can be set at different time levels, e.g. hourly, as illustrated in Graph 2-6 below, or a yearly reference price. When set at hourly level, no incentive is however given to produce high-value electricity or enhance system efficiency (e.g. maintenance planning, system-optimised asset design) but rather maximise production ("produce-and-forget" effect). Some of these issues are circumvented with a longer reference price (i.e. the hourly price averaged over an entire year), leading to more efficient dispatch incentives, but market distortions may still occur in relation to market parties knowing or predicting the actual premium.

It is important to ensure the short-term efficiency when designing and implementing CfDs. Efficiency is achieved when dispatch decisions are driven by short-term market prices that exceed their marginal cost of production within a given market and the arbitrage between short-term markets is not distorted by subsidies[26]. CfDs can lead to a distortion of the production incentivisation in the short-term, depending on their design. In particular, CfDs that link the renumeration received from the CfDs to the actual generation leads to inefficiency. For instance, if a producer receives a fixed price irrespective of the market price, it has no incentive to modulate its production according to the system value. Furthermore, the price differential between the market price and strike price acts as an opportunity cost when it is linked to actual generation. Other distortions occur at the interplay between the day-ahead market and the intra-day or balancing market. The potential revenue from the CfDs on the day-ahead market distort the bidding incentives on both intra-day and balancing markets. For instance, if the spot price is high and the strike price is low, i.e. the producer would have to give money back if it produces according to its agreement under the day-ahead market; then, if the intra-day price were to turn out lower than the potential payback amount, the producer would aim to stop production and buy back its day-ahead commitment in the intra-day market. This means that the subsidy distorts the production incentive as valuable electricity would be curtailed to avoid payment in the day-head market[27].

A solution to address short-term inefficiency is to decouple the subsidy renumeration from the production incentive. Non-production based CfDs allow to minimise dispatch distortions by de-coupling production and subsidy-level. By decoupling the payment from the actual production of the generation, the goal is to avoid distorting the production incentive that the generator faces. Under these models, a generator would continue bidding in the different markets (day-ahead, intraday or balancing) based on the price signal. These concepts are quite new. Two designs have become prominent in literature:

- **Capability-Based CfDs** are linked to the performance of a reference plant, reflecting production potential, and not the actual energy output of the plant. Graph 2-8 below illustrates the functioning of this model in case spot prices exceed the strike price. If the asset performs as the reference plant, the outcome will be the same as for the production-based CfD. If however, the asset produces less than the reference plant, it will still have to pay the same amount of money based on the production of the reference plant. It will thereby generate less revenue on the market, shown by area A and B, resulting in a net loss defined by area A. In contrast, if the asset produces more than the reference plant, it will gain the revenue linked to this extra production (areas C+D). Under this scheme the asset owner will be incentivised again to optimise profits, in that deviations between potential and actual production can for example reflect curtailment or scheduled maintenance. This capability-based CfD model has been used and approved by the Commission under State Aids regarding the construction of the Nuclear Power Plant in Dukovany in Czechia and of the offshore windfarm in the Princess Elisabeth Zone in the North Sea in Belgium.

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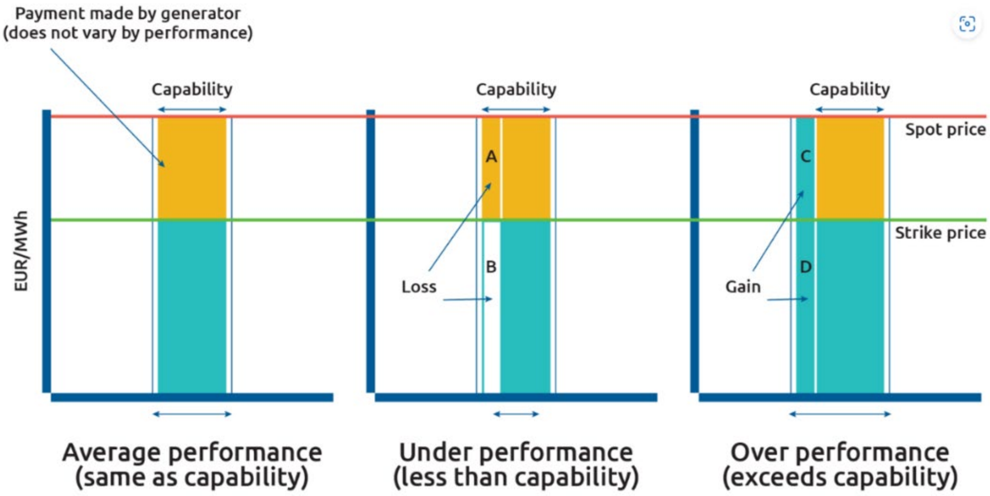
[26] Lena Kitzing, Anne Held, Malte Gephart, Fabian Wagner, Vasilios Anatolitis, Corinna Klessmann (2024). Contracts-for-Difference to support renewable energy technologies: Considerations for design and implementation. Research Report RSC/FSR March 2024.

[27] Schlecht I., Maurer C. and Hirth L. (2024). Financial contracts for differences: The problems with conventional CfDs in electricity markets and how forward contracts can help solve them Author links open overlay panel. Energy Policy. Volume 186 , March 2024.

Graph 2.8 **Capability-based CfD — spot price exceeds strike price scenario**

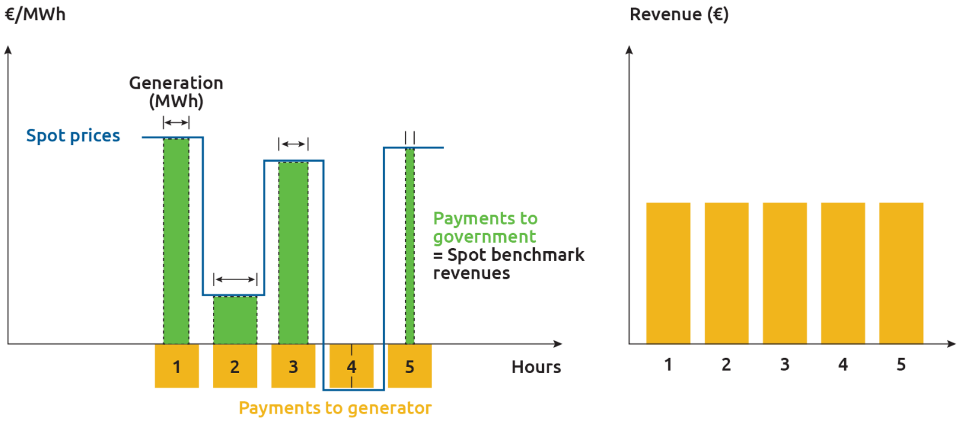


Source: RAP (Regulatory Assistance Project).

- **Financial RES CfDs**[28], which have not yet been used in real market environment, are similar to the capability-based CfDs. However, this contract model involves a dual payment system (see Graph 2-9 below).
    - The government pays a fixed hourly remuneration to the generator for each installed MW, irrespective of the level of production and for the duration of the contract. This payment is determined through a competitive auction.
    - The generator, in turn, pays the government the hourly revenue that would be generated by a reference generator and not the subsidised asset. This may exclude pay-backs when prices are negative.

The abstraction from real asset revenues increases risk under this model compared to the capability-based CfD.

Graph 2.9. **Concept of financial CfD**



Source: Schlecht, I., Hirth, L., & Maurer, C. (2022).

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[28] Schlecht, I., Hirth, L., & Maurer, C. (2022). Financial Wind CfDs. EconStor. ZBW — Leibniz Information Centre for Economics. RAP (Regulatory Assistance Project) (2023). Search for two-sided CfD design efficiency — a Shakespearean history - Dominic Scott and Monika Morawiecka. ENTSO-E (2024). Position Paper Sustainable Contracts for Difference (CfDs) Design February 2024.

Different variations of these designs exist[29]. **Cap-and-Floor mechanisms** can be introduced to establish a "revenue band" where the generator is fully exposed to the market price. Under such configurations, the net revenue for producers will be the market price as long as the price is within the cap and floor range. If the price falls below the floor, producers receive the difference between the floor price and the market price, while when the price exceeds the latter, they pay back the difference between the cap price and the market price. The width of the band determines the incentives for generators to optimise dispatch decisions and maximise market value. Further variations depend, in particular, on the **definition of the reference market price** against which the strike price is compared, the **duration of the contract**, i.e. the number of years for which the contract is concluded, or whether it can be **volume-based** i.e. determined based on a number of full load hours (MWh/MW) over the lifetime of the project. The latter concept was proposed by Newberry et al. (2023) as a locational signal[30]. The goal of limiting the number of MWh eligible for payment is to incentivise operators to locate the asset where the market value of these MWhs would be the highest, e.g. penalising high production areas with transmission bottlenecks as there would be excess supply and a low price. Defining or recommending a specific design goes beyond the scope of this note.

3. ANALYSIS

3.1. SCENARIOS AND METHODOLOGY

A scenario-based approach is used building on the scenario developed by the European Commission for the 2040 Climate Target Plan. Five European electricity markets that are deemed relevant in terms of different market and climatic conditions for this study are analysed. These are the Czech Republic, France, Germany, Spain, and Sweden. The study makes use of the METIS model, a mathematical model simulating the operation of the European electricity system, to simulate the dispatch of the electricity system in the year 2030. The analysis focuses on five key technologies: onshore and offshore wind, utility-scale solar PV, nuclear[31], and batteries[32]. Note that residential and commercial solar PV are not included in this study as these technologies are less exposed to the wholesale market directly. In addition, geothermal energy and run of river hydropower are also not covered due to the limited additional capacity expected by 2030. It is important to emphasise that this study does not provide a forecast for 2030, but rather seeks to project short-term power system dynamics based on the long-term energy system scenario from the 2040 Climate Target Plan for the year 2030. The results are based on a simplification of the market functioning that does not consider strategic behaviours. In addition, as the model considers MS to be represented by single nodes, grid bottlenecks within bidding zones are not modelled. The results should as such be interpreted in terms of possible trends in market conditions represented by the presented group of Member States.

The reference market environment analysed in this section is consistent with achieving the climate and energy objectives, as stipulated in the 2040 Climate Target Plan. **The reference scenario assumes a certain level of flexibility and storage solutions on both the supply and demand sides.** Graph 3-1 shows the estimated contribution in addressing the flexibility requirements by some key flexibility technologies, based on work by the JRC[33] for a 2030 power system set-up similar to our context. As can be seen, flexibility is provided by batteries, interconnectors, pumped hydro storage, other hydro generation, and electrolysers. Smaller contributions in 2030 also include the flexibility provided by

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[29] ENTSO-E (2024). Position Paper Sustainable Contracts for Difference (CfDs) Design February 2024.

[30] Newberry, D. (2023). Efficient Renewable Electricity Support: Designing an Incentive-compatible Support Scheme. The Energy Journal, Vol. 44, No. 3.

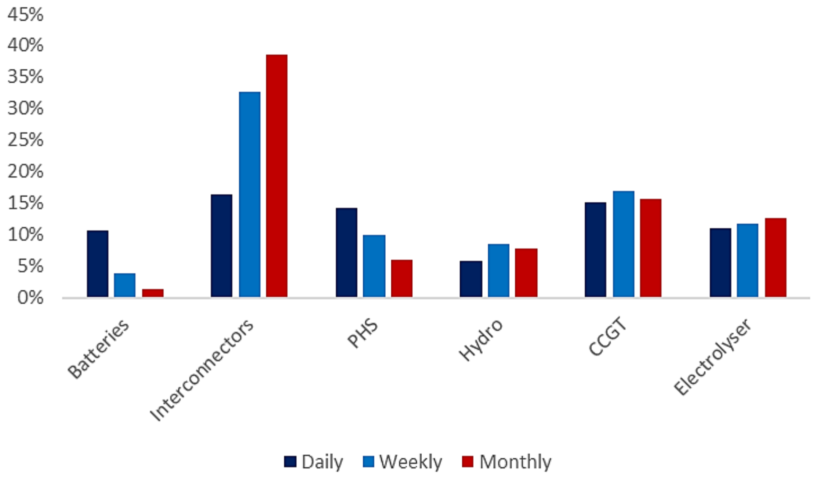
[31] New and life-time operation (LTO).

[32] Stand-alone and electric vehicles.

[33] Koolen, D., De Felice, M. and Busch, S. (2023). Flexibility requirements and the role of storage in future European power systems, Publications Office of the European Union, Luxembourg, 2023, doi:10.2760/384443, JRC130519.

nuclear, demand side management (incl. EVs and heat pumps), coal and biofuels. In the reference scenario, electric vehicles and heat pumps are assumed to be non-price-responsive, meaning their consumption or discharge behaviour do not adjust according to changes in prices.

Graph 3.1. **Technological contribution to flexibility requirements in the EU, 2030.**



Source: European Commission (based on Koolen, D., De Felice, M. and Busch, S., Flexibility requirements and the role of storage in future European power systems, Joint Research Centre).

In this study, we run two sensitivity analyses on the impact of non-fossil flexibility in the power system, developing scenarios by varying the level of flexibility provided by electric vehicles and batteries compared to the baseline scenario. In the first sensitivity analysis, we assume that electric vehicles become fully price responsive as opposed to being non-price responsive in the reference case, while keeping the installed capacity of all other flexibility and storage solutions as in the reference scenario. The second set of scenarios explore the impact of battery flexibility with battery capacity varying from 0 to 100 GW on top of having electric vehicles being fully price responsive, with the reference case set at 25 GW at EU level. The energy/power ratio is assumed constant. The maximum battery capacity considered in the study is aligned with the installed capacity of batteries foreseen in the scenarios underpinning the European Commission for the 2040 Climate Target Plan.

A sensitivity analysis is also conducted on gas prices, as the main marginal price-setting technology in EU power markets[34]. The reference gas price is set at 35 EUR/MWh in line with the assumption in the 2040 climate target scenario by 2030, and two alternative scenarios with lower prices at 20 EUR/MWh and higher gas prices at 105 EUR/MWh. The price of CO2 is assumed at EUR 80/tCO2. Two values are chosen for the weighted average cost of capital (WACC): 4% assuming the possibility to project finance derisked investments and 8% representing typical WACC of balance sheet financed projects.

More details on the scenarios and methodology used in this study are available in Annex I.

3.2. RESULTS

3.2.1 Cost-competitiveness of low-carbon energy technologies

In this section, the cost-competitiveness of low-carbon energy technologies and evolution of the wholesale electricity price is assessed based on three key indicators. Unless discussed otherwise, the results thereby follow the reference scenario.

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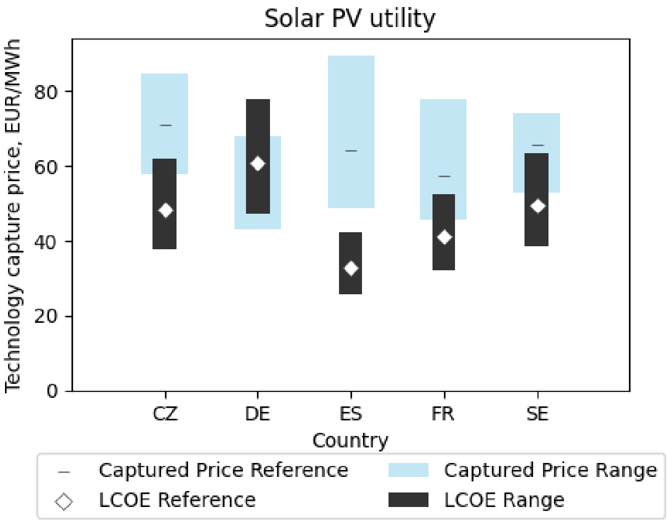
[34] Gasparella, A., Koolen, D. and Zucker, A. (2023). The Merit Order and Price-Setting Dynamics in European Electricity Markets, JRC European Commission, JRC134300.

- Technology cost-competitiveness, assessed by comparing the Levelised Cost of Electricity (LCOE) and the captured price. The LCOE represents the average revenue per unit of electricity generated that would be required to recover the investment and operating costs during the technical life of the project. The captured price is calculated as the ratio of the annual revenue generated by the project over its yearly electricity production.
- Renewable cannibalisation effect, analysed through the market value ratio, which represents the fraction of revenues captured by a given project if the entire production was sold to the spot market.
- The electricity consumption market value calculated as a demand-weighted average price of electricity.

3.2.1.1 Cost-competitiveness for new low-carbon energy investments

Graph 3.2. **Comparison between the LCOE and the captured price of utility scale solar photovoltaic (PV) electricity generation in representative European market environments by 2030**



Source: European Commission.

Overall, utility scale solar photovoltaic electricity production is expected to be cost-competitive by 2030 in most market environments. Cost competitiveness is defined as a market situation where the revenue generated by a given technology on the day-ahead electricity market[35], i.e. its captured price, is higher than its production cost. The range of the production cost is obtained by varying the WACC from 4% and 8% and considering different sub-technologies that have different techno-economic characteristics. The range of captured prices results from the different gas price scenarios ranging from 20 EUR/MWh to 105 EUR/MWh. As shown in Graph 3-2, the price captured by utility scale solar photovoltaic technologies at the reference gas price is expected to be higher than the median cost of production, meaning that they achieve cost competitiveness in most of the market environments analysed under such gas price, except for the case of Germany. In Germany, the captured price at the reference gas price is slightly lower than the production cost, meaning that its cost-competitiveness is challenging under such market conditions. For most Member States, except Spain, it may be challenging for utility scale solar photovoltaic technologies to be profitable when the cost of capital is high and the price of gas is low.

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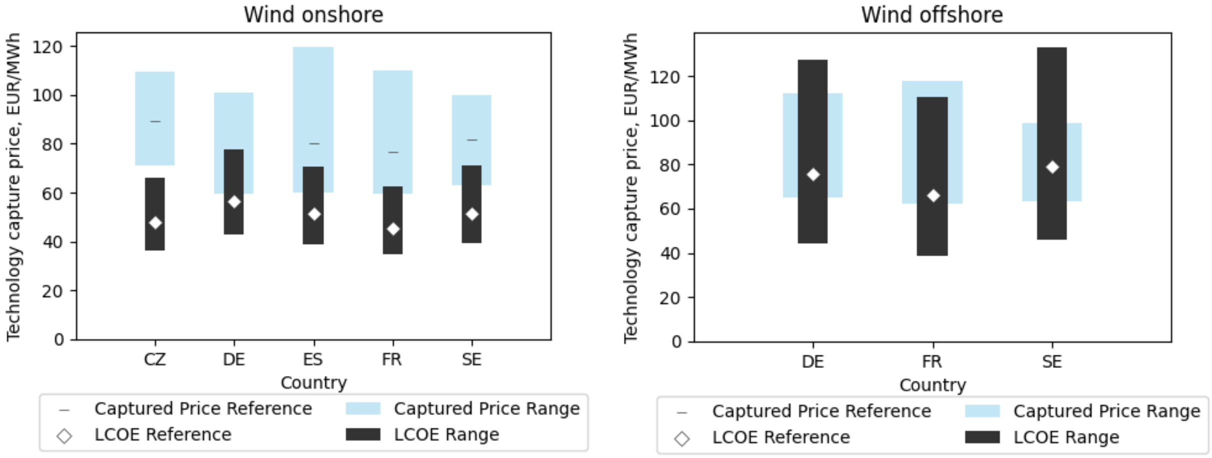
[35] The captured price calculated can be considered to represent a modelling of the day-ahead market prices. The revenue generated does not account for balancing costs nor possible revenues from the balancing and other ancillary services. This represents therefore an approximation.

Graph 3.3. **Comparison between the LCOE and the captured price of onshore and offshore wind electricity generation in representative European market environment by 2030**

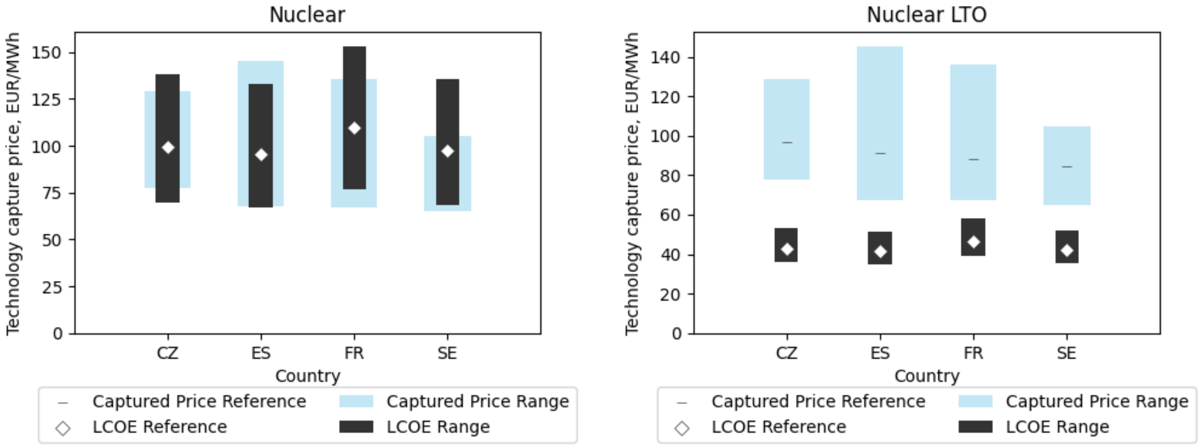


Source: European Commission.

Onshore wind electricity production is also expected to be largely cost-competitive in all analysed market environments by 2030. As shown in Graph 3-3 above, the captured price by onshore wind technologies at the reference gas price is expected to be higher than the median cost of production in all market environments analysed. However, it may be challenging for onshore wind technologies to be profitable when the cost of capital is high and the price of gas is low, for instance, in Germany, Spain and Sweden.

The cost-competitiveness of offshore wind technologies may be challenging in all relevant analysed market environments by 2030. As shown in Graph 3-3, the range of the cost of electricity production from offshore wind turbines is wide as the investment costs of these technologies is quite project-specific and dependent on maritime deployment settings such as distance from shore, water depth etc. Offshore wind technologies are expected to be profitable for all gas prices analysed when the cost of capital is low. At the reference gas price, it is expected that offshore technologies are cost-competitive as the captured price by offshore wind technologies at this gas price is expected to be at about the same level as the median cost of production in all market environments analysed. However, the upper range of production costs would require higher gas prices for these technologies to break even than the gas prices assumed in this study for Germany and Sweden, while it may be sufficient for France.

Graph 3.4. **Comparison between the LCOE and the captured price of nuclear electricity generation (new and long-term operation (LTO)) in representative European market environment by 2030**



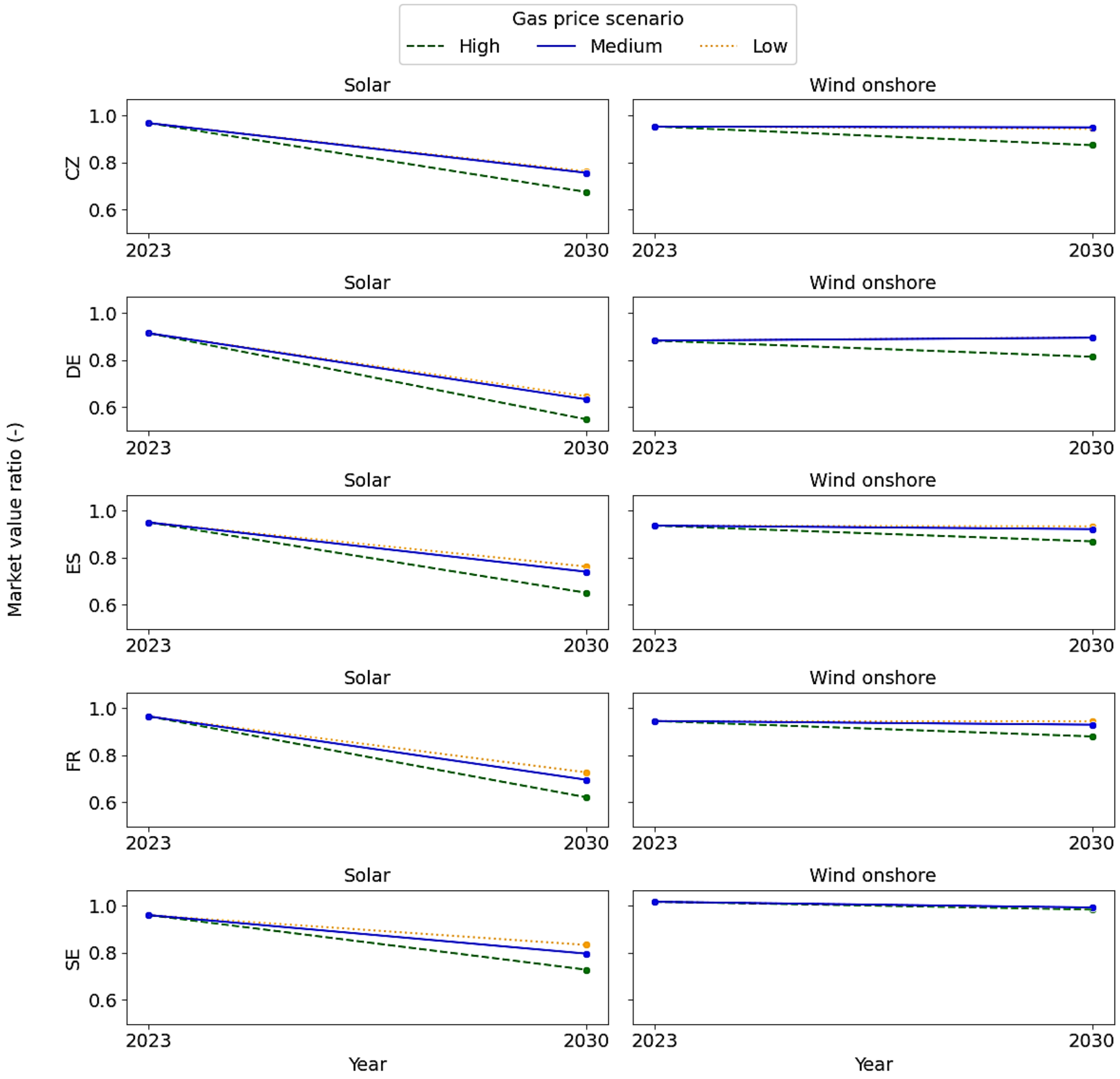
Source: European Commission.

Extending the lifetime of existing nuclear power plants (LTO) in Europe is cost-competitive in those analysed EU Member States that decide to make such investments. As shown in Graph 3-4, these investments would result in a cost of production well below the price they can capture on the market.

The cost-competitiveness of new nuclear power plants may be challenging in market environments where these technologies are deployed. The cost of capital and the price of natural gas play an important role in cost-competitiveness. Graph 3-4 shows that the median cost of production of new built nuclear energy is of the same order of magnitude, yet higher, than the electricity market prices captured by these technologies under a reference gas price. For cost-competitiveness to be ensured, there is a need for a low cost of capital. Higher cost of production, for instance due to higher cost of capital, would require higher gas prices to break even, even higher than the prices assumed in this study in the Czech Republic, France and Sweden. This shows the high sensitivity of these technologies to the cost of capital. Due to the very limited recent experience with nuclear new built in the EU, there remains an uncertainty in the estimated LCOE for this technology.

3.2.1.2 The cannibalisation effect

Graph 3.5. **Evolution of the market value ratios of solar, onshore wind between 2023 and 2030 in the selected Member States**

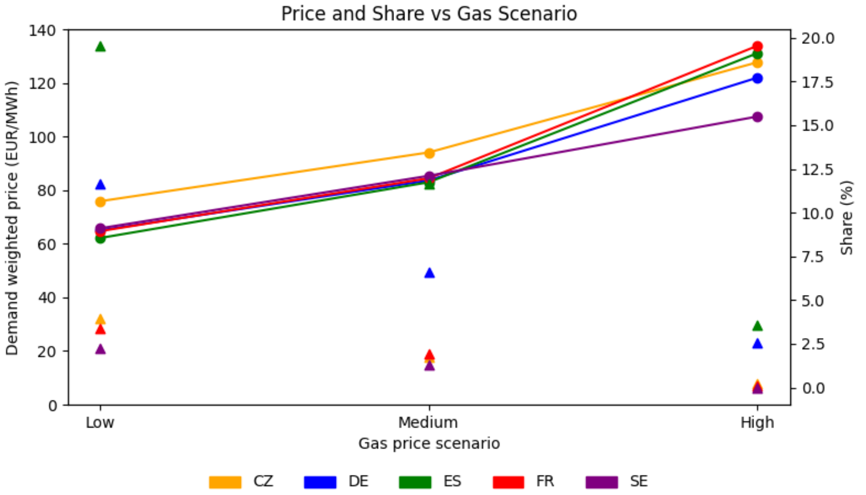


Source: European Commission.

The modelling results presented in Graph 3-5 reveal a much more pronounced cannibalisation effect for solar photovoltaic electricity, in contrast to onshore wind technologies. A cannibalisation effect occurs when the market value ratio, capturing the actual market price received, of renewable energy sources decreases as their capacity increases[36]. The evolution of market value ratios for solar PV and onshore wind electricity from 2023 to 2030 is shown in Graph 3-5 for each of the Member States analysed. The market value ratio of solar photovoltaic electricity in 2030 is consistently lower than its 2023 value across all selected member states, regardless of the gas price scenario. A higher gas price further leads to a more pronounced relative cannibalisation effect. In contrast, the market value ratio of onshore wind energy in 2030 shows a stable and uniform trend relative to their 2023 values. This suggests that wind electricity production is more evenly distributed throughout the year. Under high gas price scenarios, the relative effect of cannibalisation is more pronounced, indicating that gas fired power plants are used to balance the market during periods when onshore wind turbines, similarly to solar, are not generating electricity.

3.2.1.3 Evolution of demand weighted average electricity prices

Graph 3.6 **Evolution of the demand weighted average electricity price and share of the natural gas in the production of electricity as a function of the gas price by 2030.**



Source: European Commission. Prices are represented by the line curves, while the shares are plotted as individual data points.

Rising natural gas prices would lead to increased electricity prices across the countries analysed, as depicted in Graph 3-6. The modelling results indicate that increased natural gas prices would lead to higher demand-weighted electricity prices and a decreased share of natural gas in the electricity generation mix by 2030. In a scenario with low gas prices, natural gas is projected to contribute approximately 19.5% to Spain's annual electricity production by 2030, 12% in Germany, 5% in the Czech Republic and around 3% in both France and Sweden. However, in a high gas price scenario, the share of natural gas in electricity production drops to about 5% in Spain, 3% in Germany, and falls below 1% in the Czech Republic, France and Sweden. Note that this does not directly imply a direct relation between the share of gas production and their role in setting the electricity price. In fact, gas power plants are projected to set the price an almost equal amount of the time (around 55%), with their share in the generation mix projected to half from 20% to 10%[37]. This highlights a continued importance

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[36] Lannhard Fredrik (2023). Cannibalization of Renewable Energy in Spain: Market Implications and Mitigation Strategies through Carbon Pricing and Guarantees of Origin. KTH Master Thesis Report. 2023.

[37] Gasparella, A., Koolen, D. and Zucker, A. (2023). The Merit Order and Price-Setting Dynamics in European Electricity Markets, JRC European Commission, JRC134300.

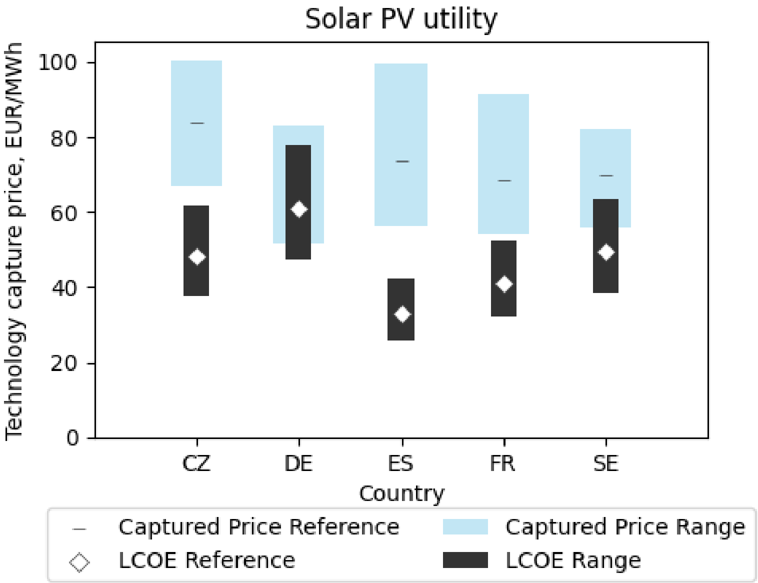
of natural gas in setting electricity prices by 2030, strengthened by natural gas role in balancing market demand and the interconnected nature of the European electricity system, even as its role in the electricity generation mix declines.

3.2.2 THE IMPACT OF AN INCREASE IN ELECTRIC VEHICLE FLEXIBILITY

In this section, the impact of increasing electric vehicle flexibility on electricity systems is analysed. This is achieved by imposing the condition that the whole fleet of electric vehicles become price responsive.

3.2.2.1 Cost-competitiveness of low-carbon energy with increased flexibility

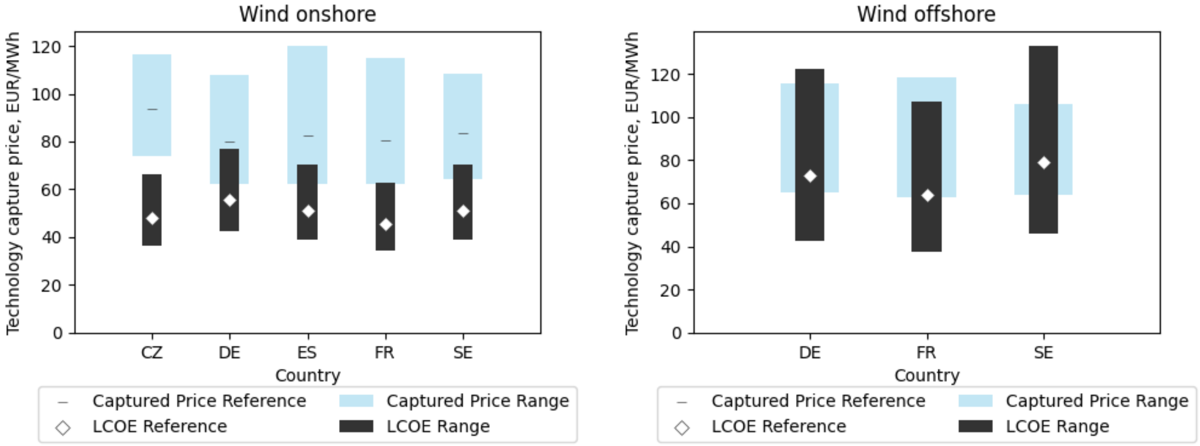
Graph 3.7. **Comparison between the LCOE and the captured price of utility scale solar photovoltaic (PV) electricity generation in representative European market environments by 2030**



Source: European Commission.

Overall, the increase in flexibility results in an improvement of the cost-competitiveness of utility scale solar photovoltaic electricity production by 2030. As shown in Graph 3-7, the price captured by utility scale solar photovoltaic technologies is expected to be higher than the median cost of production, meaning that they achieve cost competitiveness in most of the market environments analysed under the different gas price scenarios. Compared to the reference case, the electricity price captured by this technology increases by approximately 10% to 20%, depending on the market environment, while the production cost remains relatively stable between the two scenarios. Nevertheless, achieving profitability can still be challenging, particularly in Germany and, to a lesser extent, in Sweden, when the cost of capital is high, and the gas price is low.

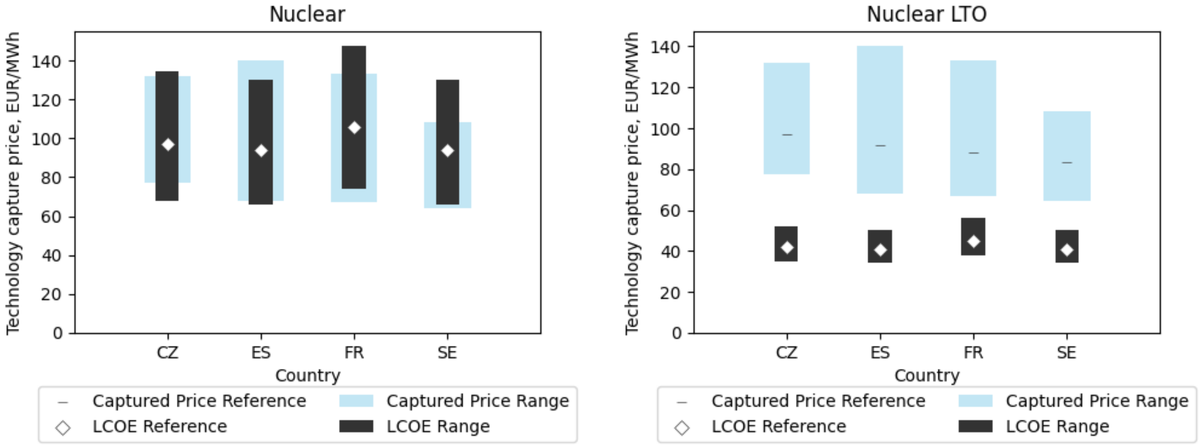
Graph 3.8. **Comparison between the LCOE and the captured price of onshore and offshore wind electricity generation in representative European market environment by 2030**



Source: European Commission.

An increase in flexibility also improves the cost-competitiveness of onshore and offshore wind electricity production in all analysed market environments by 2030. As shown in Graph 3-8 above, the price captured by onshore wind technologies at the reference gas price is expected to be higher than the median cost of production in all market environments analysed under the different gas price scenario. The improvement in cost competitiveness compared to the reference case is primarily driven by higher captured prices, which have increased by approximately 5%. For offshore wind technologies, compared to the reference case, the improvement in cost-competitiveness results from lower production costs due to higher production levels, while the price of electricity captured remains quite stable between the two scenarios. The upper range of production costs would still require high gas prices for these technologies to break even than the gas prices assumed in this study for Germany and Sweden.

Graph 3.9. **Comparison between the LCOE and the captured price of nuclear electricity generation (new and long-term operation (LTO)) in representative European market environment by 2030**



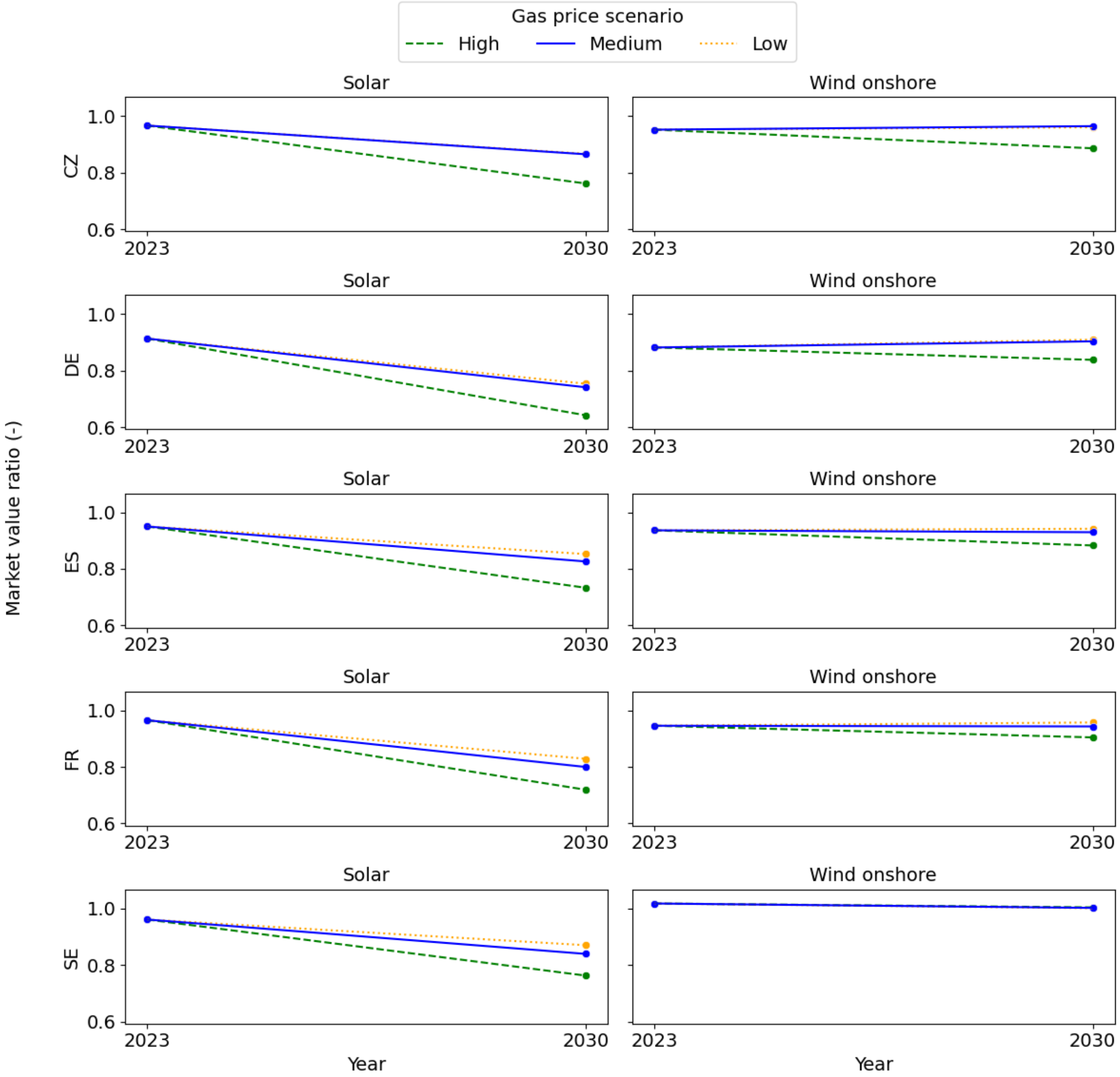
Source: European Commission.

A similar conclusion can be reached for nuclear technologies. Flexibility further consolidates the high profitability of extending the lifetime of existing nuclear power plants (LTO) in Europe in those analysed EU Member States that decide to make such investments. As shown in Graph 3-9, the positive gap between the price they can capture on the market and their costs of production is increasing compared to the base case. The cost-competitiveness for new nuclear power plants is also improved.

Compared to the reference case, the improvement in cost-competitiveness results from lower production costs due to higher production levels, while the price of electricity captured remains rather stable between the two scenarios.

3.2.2.2 The cannibalisation effect with increased flexibility

Graph 3.10. **Evolution of the market value ratios of solar, onshore wind between 2023 and 2030 in the selected Member States**



Source: European Commission.

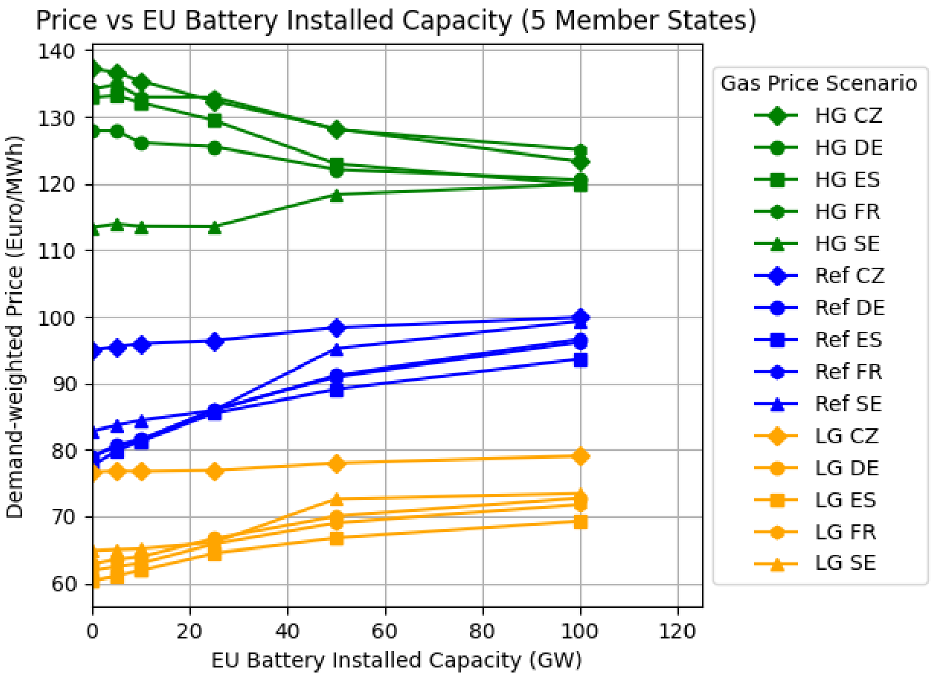
Flexibility reduces the cannibalisation effect for solar photovoltaic electricity and onshore wind technologies. While the same cannibalisation effect trend persists when flexibility is increased, the magnitude of this effect is lower. This reduction is more pronounced for solar PV than for onshore wind electricity. As shown in Graph 3-10, the market value ratio of solar photovoltaic electricity in 2030 is higher than in the reference case (see Graph 3-5), indicating a decrease of the cannibalisation effect. However, the market capture rate still remains consistently lower than its 2023 value across all selected member states, regardless of the gas price scenario, meaning the effect persists. The effect of an increase in flexibility is less pronounced for onshore wind energy, given that this technology was less exposed to cannibalisation in the reference case.

3.2.3 The impact of a further increase in flexibility through batteries

In this section, the impact of a further increase in flexibility on electricity systems is analysed. This is achieved building on the scenario with higher EV flexibility and varying the level of battery capacity from 0 GW to 100 GW at EU level. The storage duration is assumed to be 4h[38]. All other parameters are kept identical to the reference scenario.

3.2.3.1 Impact of battery capacity on average electricity prices

Graph 3.11. **Evolution of the demand weighted average electricity price as a function of the gas price and installed battery capacity in the four market environments analysed by 2030**



Source: European Commission.

The price impact of an increase in battery capacity in the power system depends on the overall price distribution across hours, affected by underlying fundamentals such as low and high gas prices. The presence of batteries narrows the range of prices, which is the result of two mechanisms at play. On the one hand, batteries push expensive generators out of the money, which in turns lowers electricity prices, while on the other hand, batteries leverage times of low demand or high renewable production to charge, which in turn raises electricity prices. The average result will depend on which effect is stronger, depending on the degree of high and low-price hours. As shown in Graph 3-11, for the low and reference gas prices, the demand-weighted average wholesale electricity price is 15% to 20 % higher in France, Germany, Spain and Sweden when the battery capacity at EU level is 100 GW as compared to when it is 0 GW (or around 10 €/MWh for the low gas price and above 15 €/MWh for the reference gas price) and about 5% higher in the Czech Republic (or around 5 €/MWh). At a high gas price, the trend is partially reversed. The electricity price is reduced by around 10% in the Czech Republic and Spain (or 13 €/MWh) and about 5% to 7% in Germany and France (about 7 to 9 €/MWh), but increases by about 5% in Sweden (about 7 €/MWh). For the latter, this can be explained by the high share of

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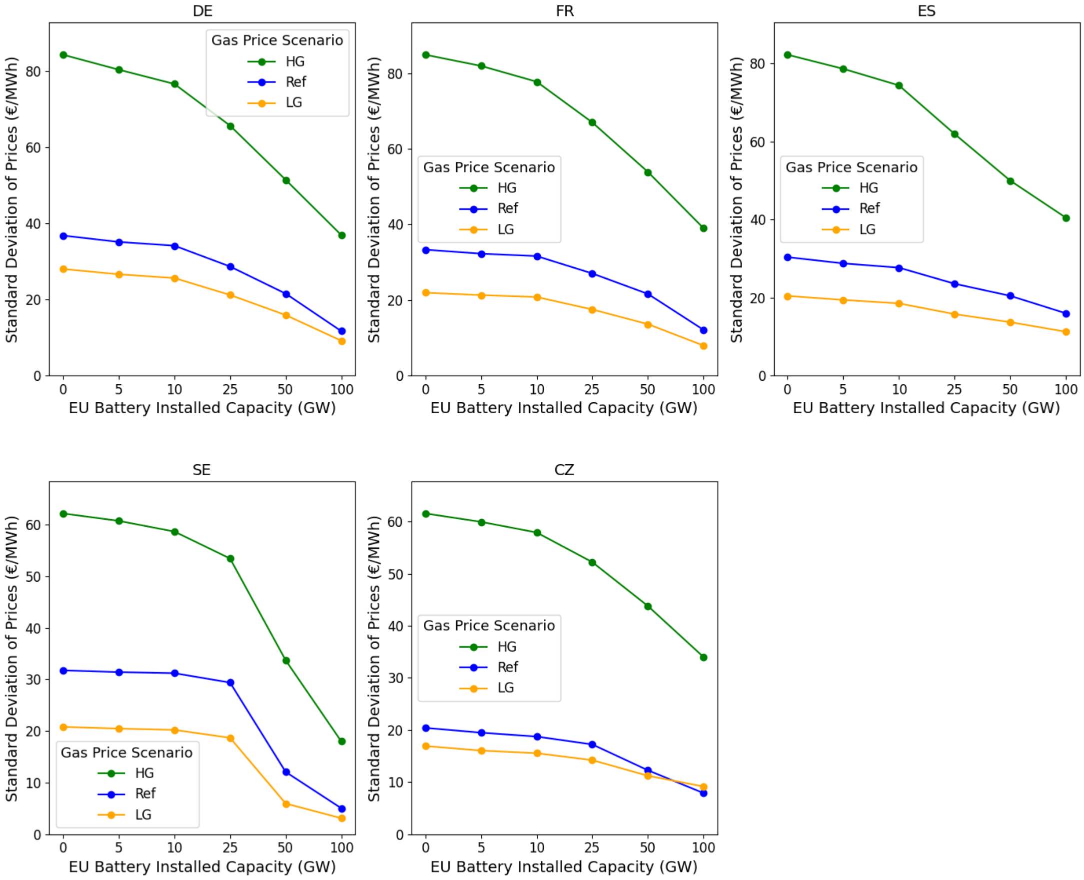
[38] Changing the storage capacity in hours downward (upward) could constrain (amplify) the magnitude of the results but not the direction.

hydropower in the Swedish power system in both scenario, which offers a substantial level of flexibility, minimising the relative impact between scenarios.

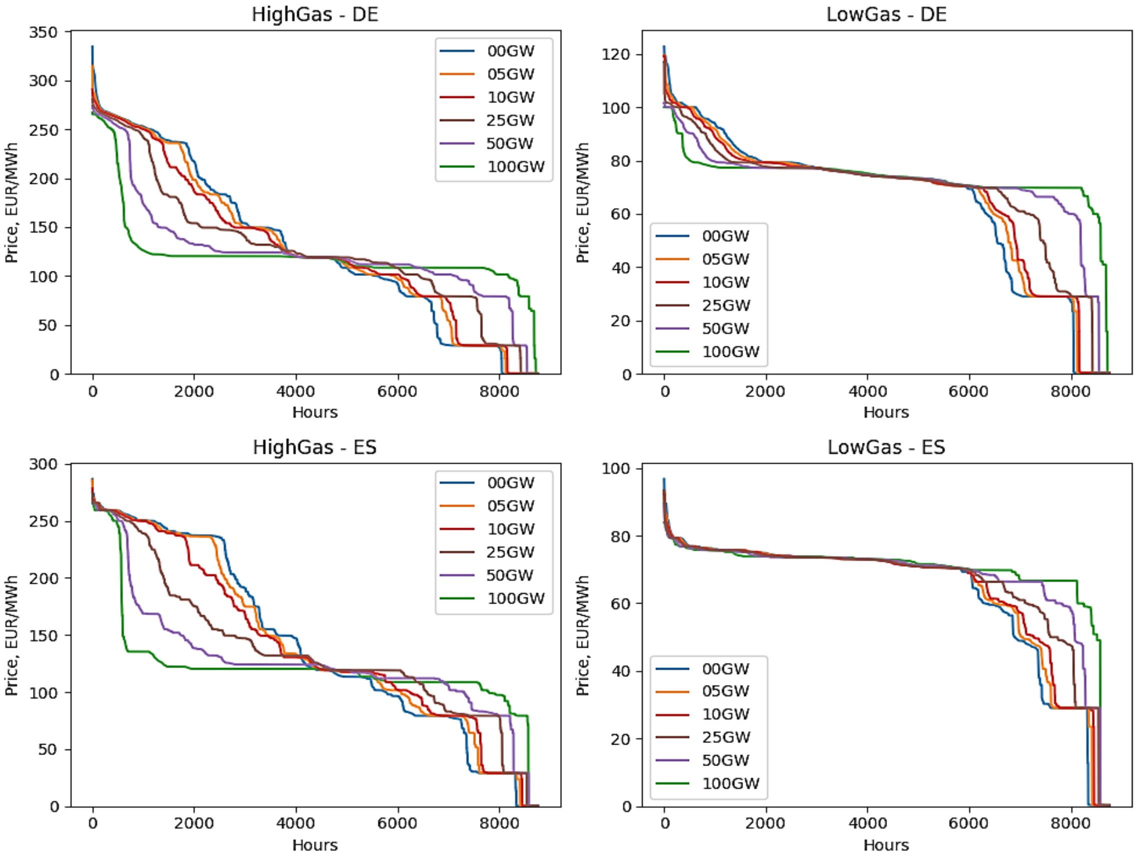
Graph 3.12. **Evolution of the standard deviation of the hourly electricity price as a function of the gas price in the four market environments analysed by 2030**



Source: European Commission.

Flexibility decreases the volatility of electricity prices. Graph 3-12 shows the evolution of the standard deviation of hourly electricity prices across various market environments and installed battery capacity scenarios. The data reveals that the standard deviation of electricity prices increases with increased gas price levels. This reflects the role of natural gas in setting electricity prices. However, higher installed battery capacity is associated with reduced price volatility compared to a system with limited flexibility, related to a smaller price spread by reducing the number of hours when the price of electricity is low or high. These beneficial effects may also roll-over in other short-term markets, decreasing volatility in prices overall and reducing balancing costs (e.g. the cost of ancillary services).

Graph 3.13. **Price duration curve for DE and ES by 2030 under a high and low gas price scenario and varying levels of installed battery capacity**



Source: European Commission.

The impact of installed battery capacity on the average and the standard deviation of electricity prices can be illustrated by price duration curves. Price duration curves show the proportion of time for which the price exceeds a certain value. Graph 3-13 presents the evolution of the price duration curves in Germany and Spain as a function of the EU battery capacity levels and natural gas price, for illustrative purposes. As can be seen, the flexibility of batteries has a substantial impact on the price distribution, particularly in two distinct regions: the low and high price regions. Increased flexibility in the system results in lower observed peak prices and a flattening of the price duration curves, leading to a reduction in both high and low electricity prices. The interplay between installed battery capacity and gas prices impacts the average price of the distribution. Notably, in a low gas price scenario, the number of hours with low electricity prices decreases, while the number with high prices remains relatively unchanged. Under a high gas price scenario, high price hours decrease much more profoundly as both high and low electricity price hours decrease in quantity.

The findings illustrate the need for policy makers to ensure, where support for either renewable energy or non-fossil flexibility is deemed necessary, integrated planning between the two to avoid adverse effect for the affordability of electricity prices. Increasing flexible capacity will steer prices across the year to move towards the median price of the year, i.e. the price level for which half of the prices during the year are more expensive and half are less expensive[39]. If prices are skewed upwards, in the case of high gas prices, the overall effect of increasing battery capacity will be a decrease of average prices, dominated by the lowered high price moments. However, when prices are skewed downwards, in the case of low gas prices, the opposite occurs and average prices may increase. Policy decisions on support for (battery) non-fossil flexibility to lower energy prices

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[39] Up to the point at which either the 50% most expensive hours or the 50% least expensive hours are equal to that median price. In that extreme case, adding additional flexible capacity could move the median price level.

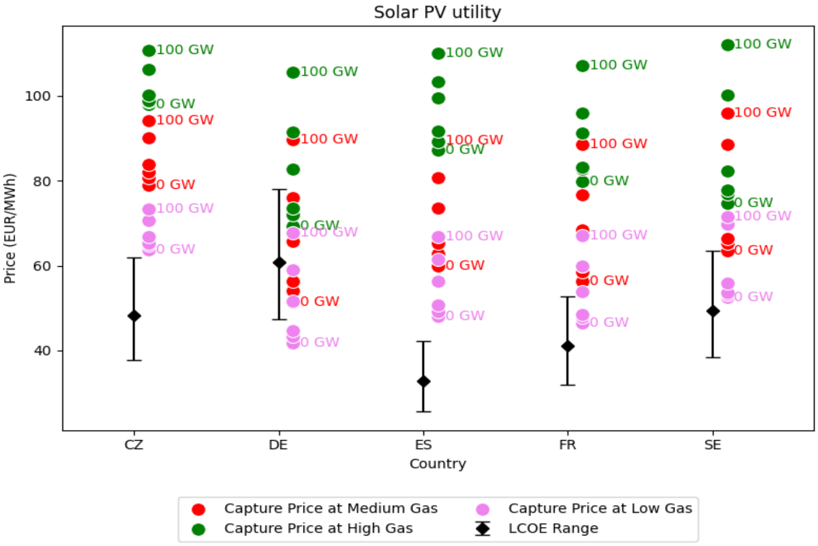
should thus be aligned with price-setting dynamics, specifically with regards the higher moments of the price distribution, in the respective market. It should thereby be coordinated with the uptake of low-cost marginal production (such as renewables) and avoid market support inefficiencies. Moreover, in the medium term, it is key to ensure that the median price is established at a relatively low or "affordable" level, with demand supplied by low-cost marginal production in more than half of the hours[40].

Support for the uptake of non-fossil flexibility should thus be planned and coordinated with other policy initiatives such as the support for renewable built-up to ensure lowering total system costs. As renewable energy variation is inherently variable, it does not represent firm power, requiring investments in networks and flexibility to accommodate an efficient integration in power systems. A decrease in the wholesale electricity price through adding more low-cost marginal production and flexibility may also not necessarily translate to a decrease in the cost of energy paid by consumers, unless the wholesale price is sufficient to cover the total cost of production for various generation technologies. Cost comparisons for policy decisions should be based on the total system costs based on equivalent firm power, promoting a balanced and resilient energy ecosystem while minimising overall system costs[41].

3.2.3.2 The impact of battery flexibility on the cost-competitiveness of low-carbon energy technologies

The effect of flexibility on the price distribution has a differentiated impact on the cost-competitiveness of the different technologies. Similar to the increase in EV flexibility, a further increase in battery flexibility will improve the cost-competitiveness of weather-dependent technology such as solar or wind. Overall, the increased flexibility reduces the number of hours with extreme prices, low and high. In this context, it can be expected that increasing the share of batteries has a net positive effect on the cost-competitiveness of weather-dependent renewable technologies. For revenues of nuclear power stations, the net effect of increasing flexibility can be positive or negative as flexibility reduces the number of hours both low and high electricity price periods. Nuclear power plants provide load following for a number of years[42] and European utilities have made the capability to perform daily load cycles a requirement for any new reactor[43].

Graph 3.14. **Evolution of the captured price for utility-scale solar electricity under different levels of flexibility by 2030**



Source: European Commission.

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[40] This does not withstand support for flexibility to deal with bottlenecks in the grid, to e.g. lower congestion costs, as these could lower the final retail price.

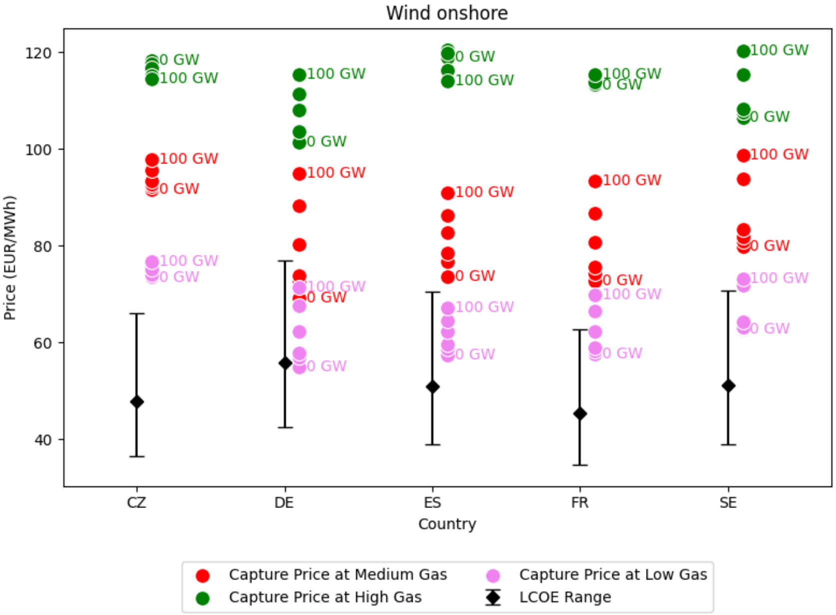
[41] Draghi (2024). The future of European competitiveness - Part B | In-depth analysis and recommendations.

[42] IAEA (2018). Non-Baseload Operation in Nuclear Power Plants, IAEA Nuclear Energy Series No. NP-T-3.23.

[43] EUR (2016). European Utility Requirements Document REV E Volume 2 – Chapter 2 – performance requirement section 2.2.

Overall, the cost competitiveness of utility scale solar technologies improves with increasing levels of battery capacity at all analysed gas price levels. As shown in Graph 3-14, solar technologies capture a higher price when the electricity system is more flexible. This is since solar power generation is concentrated during the day, so solar PV plants tend to produce at the same time, resulting in lower prices. Flexible assets take advantage of these low prices to shift demand over these periods, thus mitigating the decline in prices. The analysis shows that utility-scale solar electricity is already profitable at the lowest level of flexibility studied in this study in the Czech Republic and Spain. Indeed, in these market environments, the highest cost of production is lower than the lowest captured price obtained on the basis of the different gas price assumptions. Higher levels of installed battery capacity further improve the cost-competitiveness of solar electricity in these countries. Higher levels of installed battery capacity also improve the cost-competitiveness of utility scale solar electricity in France, Sweden and Germany. However, the cost-competitiveness gap is only closed if gas has a reference price of at least 35 EUR/MWh in France and Sweden and an even higher one in Germany.

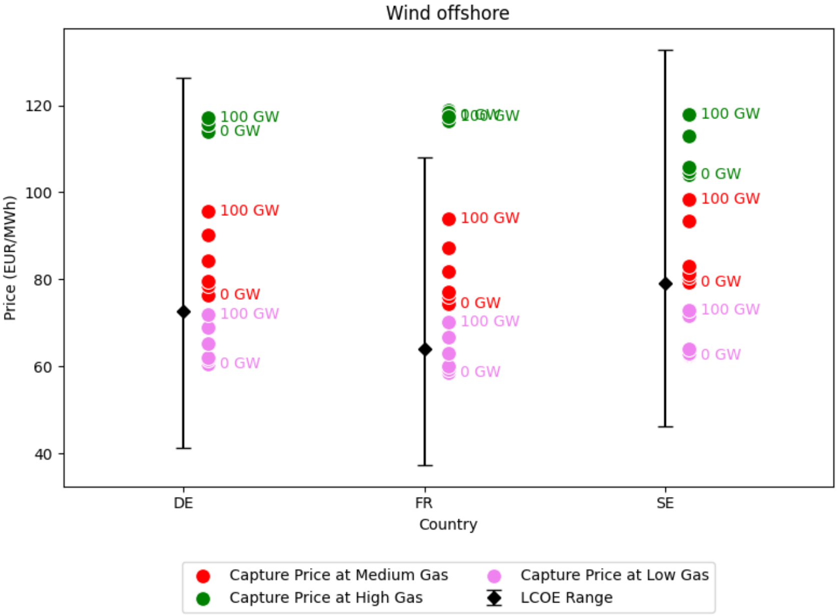
Graph 3.15. **Evolution of the captured price for onshore wind electricity under different levels of flexibility by 2030**



Source: European Commission.

Battery flexibility improves the cost-competitiveness of onshore wind electricity at all gas prices. As shown in Graph 3-15, the price captured by onshore wind technologies increases with higher levels of flexibility for each gas price level. Overall, a high level of flexibility can render the technology profitable even in a low gas price environment. However, in Spain and Germany, this may not be sufficient, and higher gas prices might be necessary to achieve cost competitiveness.

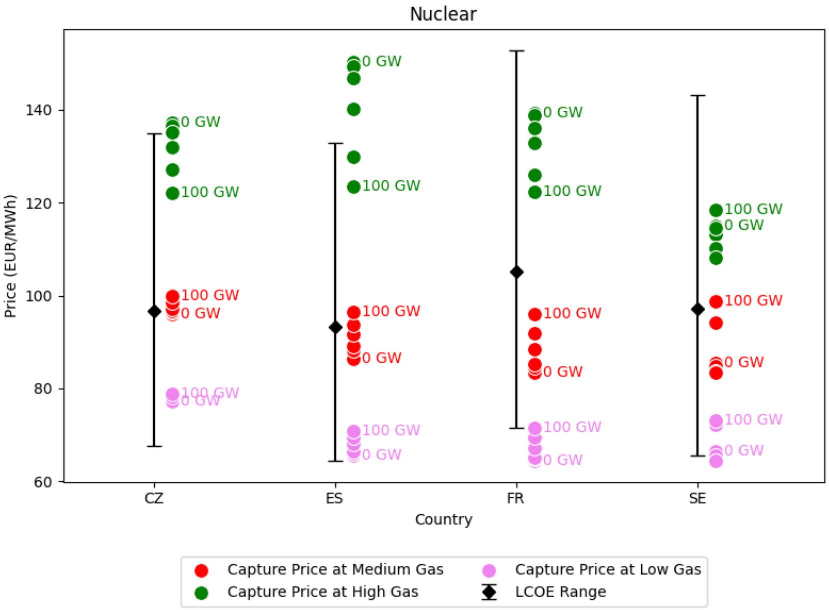
Graph 3.16. **Evolution of the captured price for offshore wind electricity under different levels of flexibility by 2030**



Source: European Commission.

Battery flexibility improves the price captured by offshore wind technologies at the different gas price levels. Graph 3-16 indicates that, based on the median cost of production, offshore technologies are not always profitable in a low gas price environment in Germany, France, and Sweden, regardless of installed battery capacity. Increasing the gas price and flexibility enhances their cost-competitiveness. However, this might not be sufficient to achieve cost-competitiveness if the cost of production is high due for instance to a high cost of capital.

Graph 3.17. **Evolution of the captured price for nuclear electricity based on new power plants under different levels of flexibility by 2030**

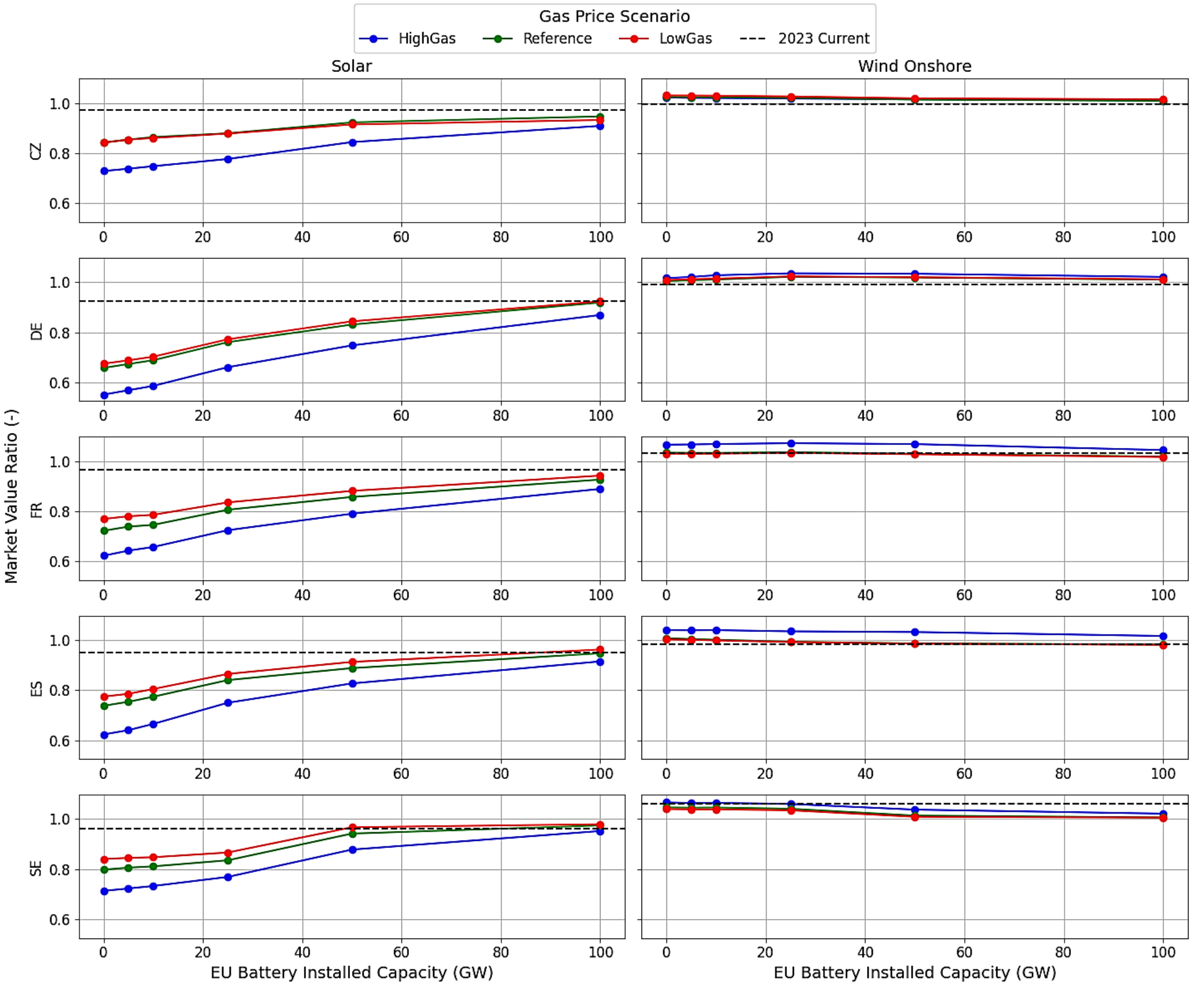


Source: European Commission.

Battery flexibility enhances the captured price by new nuclear technologies at low and reference prices. However, at high prices, flexibility has the opposite effect (Graph 3-17). Specifically, at low gas prices, higher levels of flexibility increase the market value captured by nuclear technologies, although this still falls short of covering the median production costs. At reference gas prices, increased flexibility further improves the cost-competitiveness of nuclear technologies, with captured prices in the range of the median production costs at high levels of flexibility. Conversely, at high gas prices, the trend is reversed, and nuclear technologies capture lower prices as flexibility increases. This is due to batteries lowering electricity prices in the case of high gas prices as nuclear typically captures hours with both high and low electricity prices.

3.2.3.3 The cannibalisation effect

Graph 3.18. **Evolution of the market value ratios of solar, onshore and offshore wind between 2023 and 2030 in the selected Member States as a function of the installed battery capacity at EU level**



Source: European Commission.

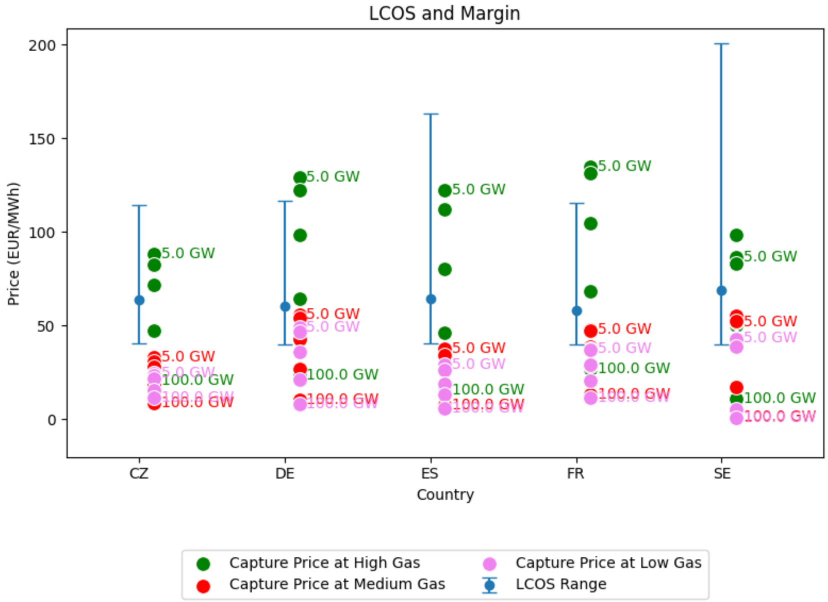
The impact of battery flexibility on the cannibalisation effect varies between solar and wind technologies. As can be seen in Graph 3-18, higher levels of installed battery capacities result in an increase in the market value ratio of solar power, suggesting that flexibility can enhance its business case. In contrast, battery flexibility has a relatively minor impact on wind technologies, with flat-to-moderate increases in market value ratio observed in the Czech Republic, Germany and France, and flat-to-moderate decreases in Spain and Sweden. It is noted that even under the 0 GW battery assumption, the electricity system has already price responsive demand technologies such as electric vehicles and heat pumps and supply technologies such as gas turbines.

3.2.3.4 Perspectives on the spot market cost-competitiveness of batteries

The objective of this section is to evaluate the spot market cost-competitiveness of battery systems across the different scenarios analysed. We emphasise that the analysis only includes modelled spot market revenues, and excludes revenues from providing services in addition to spot market price arbitrage such as revenue-stacking across a range of forward and spot markets (e.g. day-ahead, intraday or balancing markets) or benefit from capacity payments.

Two key indicators are used: unit revenue margin and levelised cost of storage, which are described in detail in Annex I. The unit revenue margin, calculated as the difference between revenue from electricity sales and the cost of electricity purchase, is directly derived from scenario simulations. The levelised cost of storage is computed based on an assumed four-hour discharge time per cycle, constant across all scenarios. For the purpose of this study, it is assumed a maximum of 7,300 cycles over the battery's lifetime, or an economic lifespan of 15 years, whichever is reached first, taking into account the cycling behaviour of the battery in each scenario.

Graph 3.19. **Evolution of the captured price for batteries under different levels of flexibility by 2030**



Source: European Commission.

Overall, revenues from only the spot market can account for a significant, but not the full, share of the revenues necessary to make batteries profitable. As illustrated in Graph 3-19, the unit revenue margin, based on spot revenues alone, falls short of the levelised cost of storage at low and reference natural gas prices, indicating that revenues from the spot market are inadequate to recover capital costs under these market conditions. However, when natural gas prices are high, revenue may approach or even exceed the levelised cost of storage, suggesting potential cost-competitiveness from spot markets alone in such market contexts. In both France and Germany, unit revenues would surpass the levelised cost of storage where battery capacities are in the range of 5 to 10 GW at EU level.

Batteries derive market revenue from exploiting price spreads in the electricity market. To turn a profit, a sufficient price spread is essential, but an increasing battery capacity lowers the price spread and cannibalises profits. As overall battery capacity increases, the price spread decreases, which diminishes the opportunities for batteries to capitalise on price arbitrage - the key mechanism by which they generate profits. Graph 3-19 illustrates this phenomenon, with unit revenues declining as capacity scales from 5 GW to 100 GW.

To achieve cost-competitiveness, batteries will need to diversify their revenue streams by exploring opportunities in other markets and services. For example, by bidding on frequency containment reserve (FCR) and frequency restoration reserve (FRR) services in the balancing market, batteries can earn revenues for their ability to rapidly respond to changes in grid frequency. Additionally, batteries can also participate in the capacity market, where they can earn revenues for their availability. Additionally, the reform of electricity has expanded the toolbox available to Member States to support non-fossil flexibility solutions when the level of flexibility of the national power system is not sufficient to meet its indicative national target for non-fossil flexibility (see section 2.2).

3.2.4 The functioning of CfDs

CfDs aim by design to ensure stable prices to producers over a long period. As explained in section 2.2.3, a two-way contract for difference is a contract signed between an electricity generator and a public entity, which sets a strike price. If the market price is below the strike price, the generator receives the difference; if the market price is above the strike price, the generator pays back the difference.

The strike price as such plays a pivotal role in determining the profitability for producers and the cost-effectiveness of the instrument for the public counterparty. Setting the strike price too high can lead to excessive profits for the producer and negatively impact public finances. Conversely, a strike price set too low may discourage investment, as it fails to cover the producer's fixed costs.

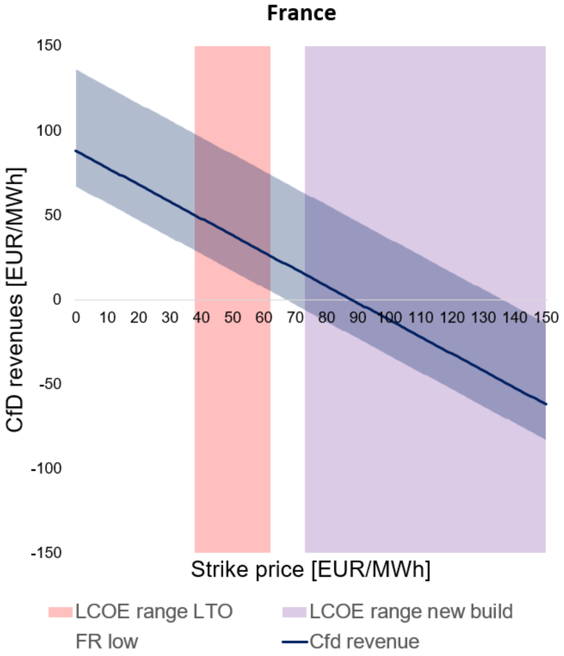
In the long run, electricity market prices should in principle converge to the Levelised Cost of Electricity (LCOEs), resulting in net-zero revenues from CfDs. Indeed, in a competitive market with free entry and exit, constant return to scale production would lead to new capacities being added or retired until the captured revenues are close to the long run marginal cost of the investment. This means that as market capture prices move closer to production costs, expected revenues from CfDs move closer to net-zero.

CfD strike prices should be set through competitive tenders. This would be a natural choice for CfDs with price bids reflecting market price expectations and risk preferences of the generator. Where price expectations lead to revenues that are above the long run marginal production costs, in cost-competitive markets, winning auction bids may further be below expected market value to reflect costs associated with mitigated revenue risks.

However, even if the strike price matches production costs, CfDs can still generate positive or negative cash flows over shorter-term periods due to various factors such as market disruptions, commodity price fluctuations, climate variability, or political interventions. In a competitive electricity system, capacities are determined so that power plants generate enough revenues to cover their long run costs. However, the optimal capacity cannot be achieved instantaneously due to investment inertia, as it takes time to build new capacities or decommission existing ones. This implies that the capacity mix is not always adjusted to short-run disruptions such as commodity price fluctuations, climate variability, or political interventions, leading to situation where revenues exceed or fall shorts of the revenues needed to cover the long-run cost of energy production. This imbalance generates positive or negative cash flows for capacities under CfDs.

Graph 3.20 to 3.22 present the relative CfD revenues in EUR/MWh from a set of low carbon technologies in selected market environment in 2030 in relation to the LCOE, for the reference scenario with low EV flexibility and 25GW of battery capacity installed.

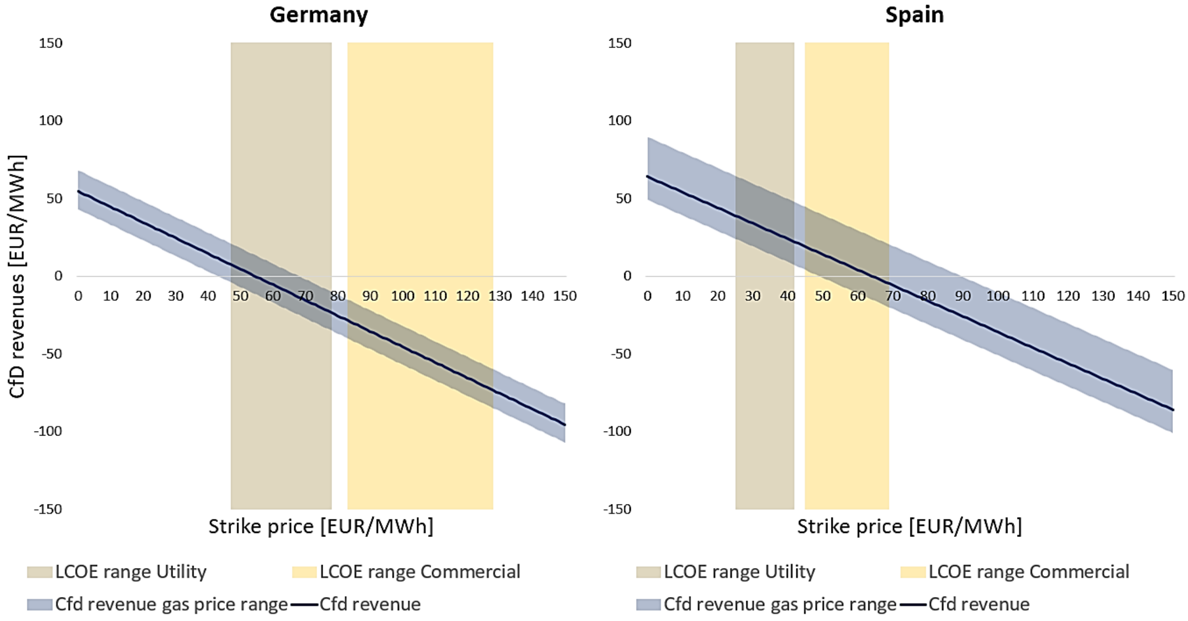
Graph 3.20. **Modelled CfD revenues in EUR/MWh as a function of the strike price for French nuclear electricity production in 2030, in relation to the gas price and LCOE**



Source: European Commission.

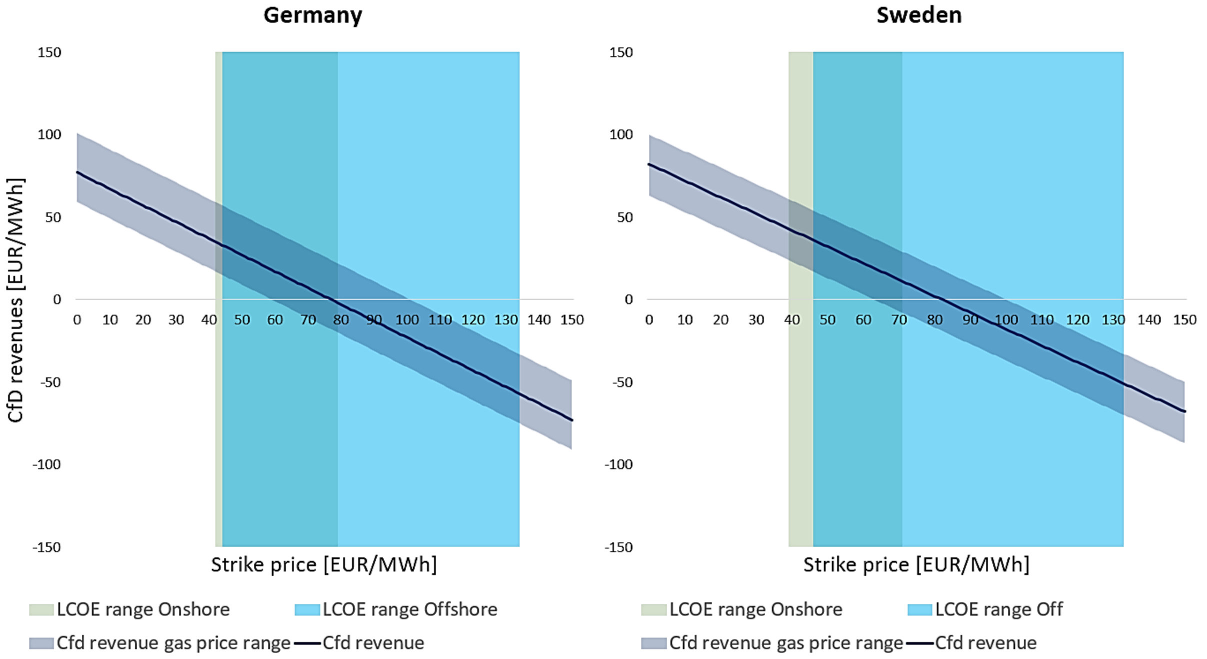
For nuclear LTO, the government would receive payments from nuclear generators in 2030 if the strike price is set within the LCOE range of nuclear LTO, regardless of the gas price. **New nuclear projects present a much larger LCOE** uncertainty range and market revenues might not be necessarily sufficient to cover its cost of production, **leading to possible State support under such CfD schemes**.

Graph 3.21. **Modelled CfD revenues in EUR/MWh as a function of the strike price for German and Spanish solar electricity production in 2030, in relation to the gas price and LCOE**



Source: European Commission.

Graph 3.22. **Modelled CfD revenues in EUR/MWh as a function of the strike price for German and Swedish wind electricity production in 2030, in relation to the gas price and LCOE**



Source: European Commission.

Graph 3-21 and Graph 3-22 present a similar analysis for selected countries for solar and wind generation. **Most onshore wind and Spanish solar CfDs where a strike price would be negotiated within the respective LCOE range would result in net positive cash flows to the government.** CfDs for solar generation in Germany on the other hand would most likely result in support from the State, driven by relatively high LCOE in combination with a low capability to capture high market prices. Offshore wind finally presents a large uncertainty range in terms of LCOE, and with strike prices set in this range, net cash flow effects of potential CfDs for governments remain uncertain.

The analysis shows that CfD revenues and cash flows largely depend on the agreed strike prices per technology, as well as the potential for the technology to capture (high) market prices. A decline in the gas price combined with a high cost of capital, supply chain constraints or slower than expected technology improvements would imply a higher need for public support. Whether investment decisions will be made in the absence of support depends further on the risk appetite of the project developer. This risk can be shared between or mitigated from project developers to off-takers if and depending on the form of long-term contract. For example, Power Purchase Agreements (PPAs) can be designed such that associated risks (e.g. price, volume or profile risk) remains either with the producer, shared between both or is mitigated to the off-taker[44].

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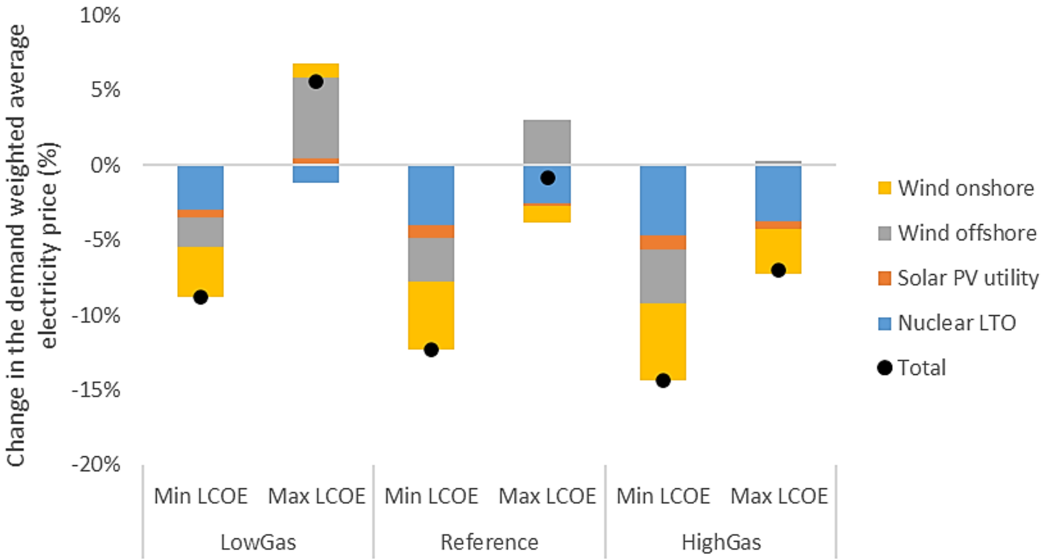
[44] Note that PPA prices typically depend on market price expectations rather than on the levelised cost of electricity (LCOE).

Graph 3.23. **Upper bound of impact of CfD on the Weighted Demand Average Electricity Price in the Reference Scenario by 2030**



Source: European Commission (Reference Case 25 GW EU battery capacity).

When consolidating at the level of the portfolio of technologies under Cfds, substantial cash flows can be observed. However, their sign depends on the level of gas prices and cost of production. Graph 3-23 presents a sensitivity analysis of the potential cash flows, expressed as a percentage of the demand weighted average wholesale electricity price at the EU level, resulting from the installation of additional capacity from 2026 to 2030 using technologies related to CfDs in the electricity market reform[45]. The percentage figure indicates by how much the demand weighted average electricity price as a stylised proxy of the procurement cost of electricity for consumers could decrease or increase as a result of selling electricity under CfDs. The capacity additions considered are based on the baseline scenario. It should be noted that, based on the final updated NECPs, no new nuclear power plants are expected to enter into service during the time period considered. However, significant investments into long term operation of existing facilities are planned and taken into account in the present analysis [46].

In general, public support will be needed when technological costs remain high and commodity prices for the marginal producer are low. Under a low gas price scenario and with low production costs, driven by a low cost of capital or technology improvements, the demand-weighted average electricity price can decrease by approximately 10% at the EU level. Conversely, if the production costs of these technologies remain high, the average electricity price may increase by about 5%, primarily due to the lack of cost-competitiveness of offshore wind technologies under low gas price conditions and, to a lesser extent, of other renewable technologies. Under a high gas price scenario, inframarginal rent for low-carbon technologies increases and reduces the need for public support for these technologies**,** although the magnitude varies by technology. The transfer from producers to the public entity can lead to a price decrease ranging from 5% to 15%, depending on the production costs. At the reference price and under a high cost of capital, the use of CfDs may result in a limited impact on the average electricity price as the profitability of nuclear LTO, onshore wind and solar PV would balance out the need for public support of offshore technologies. Improvements in the cost-competitiveness of offshore wind technologies through low cost of capital or technology advancements could lead to a net decrease in the average electricity price when using Cfds.

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[45] It is assumed that Cfds are not used for residential and commercial solar photovoltaics are these are small-scale projects, for which the business model is linked to self-consumptions.

[46] It is expected that LTOs will take place in the following MS: Czechia, France, Hungary, Romania, Slovakia and Sweden.

It is important to note that the cash flow figures presented are illustrative and not intended to be forecasts. Several modelling simplifications have been applied, which may influence the results. First, the analysis is based on a one-year simulation during which the electricity system may not be fully optimised. A more stable market with unrestricted entry and exit could theoretically enable capacity optimisation, align electricity prices with costs, and potentially eliminate cash flows. Additionally, the analysis assumes the absence of grid constraints within bidding zones, ignoring the potential locational impacts of new investments within a zone. In reality, grid constraints are likely to lead to increased curtailments if adequate investments in the network are not made.

Given that these cash flows are the result of a scenario where market prices diverge from LCOEs due to inertia in the transition to a clean power system, it is preferable that they are used to further incentivise investments in clean energy. Based on economic principles, in the long run, because of ongoing investments or disinvestments, electricity market prices should converge, or move close, to levelised costs of production. The results should therefore be interpreted as driven by inertia inherent to building new generation capacity which may, next to short-term market shocks, cause variations in the overall revenue generated by CfDs.

4. CONCLUDING REMARKS

Market based cost-competitiveness of low-carbon electricity generation is possible by 2030 but remains dependent on the evolution of technological costs and market prices. Specifically, we find that the cost-competitiveness is influenced by two primary factors: upfront capital costs and commodity costs for price-setting technologies. As shown in the analysis, the cost of capital can significantly impact the cost-competitiveness of off-shore wind technologies and new nuclear power plants, with higher costs of capital requiring higher electricity prices to break even.

Non-fossil flexibility is essential for the integration of electricity from renewable sources. Increasing flexibility through installed battery capacity or price-responsive electric vehicles generally improves the cost competitiveness of inframarginal technologies. This is more prominently the case for those technologies which are more exposed to cannibalisation risks.

However, the study reveals that relying solely on day-ahead market revenues may not be sufficient for batteries to achieve cost-competitiveness. To ensure viability, batteries likely require a diversified revenue stream, combining day-ahead market revenues with additional sources of income from other markets such as balancing market or ancillary services. It is therefore essential to remove remaining regulatory (national) barriers to the participation of non-fossil flexibility that hinder the uptake of storage solutions such as electrical storage and demand response across markets, such as wholesale markets or ancillary and congestion management services.

The findings show that increasing flexible battery capacity alone does not necessarily lower wholesale electricity prices, depending on the asymmetry of the distribution of market prices and whether there is adequate low-cost generation in the system it can benefit from. It is important to ensure integrated planning among renewables, batteries and other non-fossil flexibility solutions to prevent inefficient investment and minimise overall system costs. Support decisions for low-carbon generation, flexibility and networks should be based on the equivalent firm power, minimising system costs.

CfDs are a key instrument to stimulate investment, while protecting consumers from extreme prices. The Reform of the Electricity Market Design lays out a structural response to the high and volatile energy prices and secure clean and affordable energy into the future. While the current electricity market design for short term markets ensures an efficient and well-integrated market, the energy crisis highlighted the need for long-term markets and price contracts to guarantee predictable and stable prices for customers and secure predictable revenue streams for investors. CfDs have been proposed to mitigate the impact of short-term markets on electricity prices, for example due to variations in underlying commodity prices or intermittent production profiles, and to support investments in new capacity, where investments are not forthcoming on a market basis. While the analysis highlights that inframarginal technologies may be profitable under specific market conditions, CfD schemes may still be preferred by investors as a means of risk mitigation. In this case but also where public support is needed, government should carefully assess the design of the CfD in relation to associated risk sharing and necessary investment costs. It is further important that resulting cash flows for the public budget should be used to further incentivise investments in clean energy.

The 2024 electricity market reform has significantly strengthened the EU's electricity market design in these two key areas: non-fossil flexibility and Contracts-for-Difference. Given the anticipated steady growth in the share of renewables in the electricity mix, from 39% in 2021 to around 70% by 2030 and 85% by 2040, the swift implementation of these reforms is crucial. This will stimulate the necessary investments, support more stable prices, and ultimately enhance the competitiveness of European industry on the global stage.

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ANNEX I – SCENARIOS AND METHODOLOGY

A. Scenarios

Five European electricity markets that are deemed representative of different market and climatic conditions in Europe are analysed in this study. These are the Czechia, France, Germany, Spain, and Sweden. The study makes use of the METIS model[47] for simulating the dispatch of the electricity system in the year 2030. The METIS energy model simulates, for each Member State of the EU and relevant neighbouring countries, the clearing of the short-term power market, using input data on installed capacities, weather variability and commodity price costs, on an hourly basis over a given year. It is important to emphasise that this study does not provide a forecast for this year. The results should be interpreted in terms of possible trends in market conditions represented by this group of Member States.

The scenario used for this study builds on the PRIMES scenario developed by the European Commission in the context of the recommendation for a 2040 Climate target Plan[48]. The installed capacities for the different generation technologies are derived from this scenario. The underlying PRIMES scenario achieves the EU's commitment to reduce net GHG emissions by at least 55% in 2030 relative to 1990 and the sectoral objectives adopted by the EU in the relevant Fit For 55 and REPowerEU policies. This includes a binding renewable energy target for 2030 of at least 42.5% of the gross final energy consumption and an additional 11.7% reduction of energy consumption by 2030, compared to the 2020 Reference Scenario projections. The PRIMES scenario provides data on the 27 EU member states. As the METIS model also represents non-EU countries of the larger European electricity system, the data for the countries not reported by the PRIMES scenario are substituted from the ENTSO-E 2023 European Resource Adequacy Assessment[49] for the year 2030. The renewable energy production is modelled using a median climatic year from the Pan-European Climatic Database v3.1.

A sensitivity analysis is conducted on gas prices, using a reference gas price based on the 2030 assumption in the 2040 climate target scenario, which approximates €35/MWh. The low gas price scenario assumes 20 EUR/MWh, while in the high gas price scenario, the price reaches three times the reference price i.e. 105 EUR/MWh. These lower and higher bounds are consistent with the gas price developments experienced in the European Union before the COVID-19 crisis and in the months and years following Russia's invasion of Ukraine.

The **price of CO2** is assumed at EUR 80/tCO2.

The impact of non-fossil flexibility in the power system is analysed by developing two sensitivity analyses, varying the level of flexibility provided by electric vehicles and batteries compared to the baseline scenario. In the first sensitivity analysis, electric vehicles are assumed to be fully price responsive as opposed to being non-price responsive in the reference case, while keeping the installed capacity of all other flexibility and storage solutions as in the reference scenario. In the second set of scenarios that explore the impact of battery flexibility, the battery capacity varies from 0 to 100 GW on top of having electric vehicles being fully price responsive, with the reference case set at 25 GW at EU level. The energy/power ratio is assumed constant.

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[47] https://energy.ec.europa.eu/data-and-analysis/energy-modelling/metis_en.

[48] European Commission (2024c). Commission Staff Working Document - Impact Assessment Report Accompanying the document Communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee and the Committee of the Regions Securing our future Europe's 2040 climate target and path to climate neutrality by 2050 building a sustainable, just and prosperous society SWD(2024) 63 final.

[49] https://www.entsoe.eu/outlooks/eraa/2023/.

B. Technologies

The technologies analysed in this study are in line with those covered by the provisions for CfDs under the revised Electricity Market Design Regulation:

- onshore wind,
- offshore wind,
- solar PV,
- nuclear (new and long-term operation (LTO[50])).

In addition, batteries are also analysed as a non-fossil technology to enhance the flexibility of the electricity system. For solar PV, only utility scale systems are analysed as the wholesale market revenue does not constitute the benchmark for the cost-competitiveness of residential and commercial photovoltaics. Geothermal energy and run of river hydropower are also not covered in this study due to the limited additional capacity expected by 2030. The techno-economic parameters to calculate the cost of electricity generation are based on both proposals presented at the stakeholder workshop for the development of the upcoming EU Reference scenario and technology cost data shared by the European Network of Transmission System Operators for Electricity (ENTSO-E) in the context of the development of the 2026 Ten-year Network Development Plan[51].

Two values are chosen for the weighted average cost of capital (WACC): 4% assuming the possibility to project finance derisked investments and 8% representing typical WACC of balance sheet financed projects.

C. Key indicators and formulas

In line with the objective of this study, three key performance indicators are defined to illustrate quantitatively the impact of flexibility and CfDs on producers and consumers from a wholesale perspective in different market environments:

The **technology cost-competitiveness** is analysed for generation technologies through the comparison of the Levelised Cost of Electricity (LCOE) and the captured price. The captured price is calculated as the ratio of the annual revenue generated by the project over its yearly electricity production. For batteries, the technology's cost-competitiveness is assessed by comparing the Levelised Cost of Storage (LCOS) to the unit revenue margin. The unit revenue margin is calculated as the difference between the annual revenue generated from selling electricity on the market during discharge cycles and the annual expenditure incurred when purchasing electricity to charge the batteries. Revenues are assumed to be derived from the day-ahead wholesale electricity market only. Additional revenues that batteries might capture on intraday markets or reserve markets are not considered. The total size of batteries installed (0-100 GW) would only allow a fraction of those to obtain revenues from the reserve market which has a current size of 3 GW for continental Europe[52]. Possible revenues from capacity payments are not considered in this paper, yet the analysis performed could give an indication for the level of payments that could be required to compensate the gap between revenues and capital expenditure.

These indicators are calculated as follows:

$LCOE_i \;=\; \frac{INV_{ref} * CRF + FC_i^y + VQ_i^y}{\sum_{t=1}^{n} \mathrm{Q}_\mathrm{t}^{\mathrm{i,y}}}$, levelised cost of electricity of technology i

$CP_i^y = \frac{\sum_{t=1}^{n} P_t^y \mathrm{Q}_\mathrm{t}^{\mathrm{i,y}}}{\sum_{t=1}^{n} \mathrm{Q}_\mathrm{t}^{\mathrm{i,y}}}$, annual average of the captured price of the electricity produced by technology *i* during the year *y*.

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[50] Long-term operation.

[51] https://www.entsos-tyndp-scenarios.eu/.

[52] https://www.entsoe.eu/network_codes/eb/fcr/.

$LCOS_i \;=\; \frac{INV_{ref} * CRF + FC_i^y}{\sum_{t=1}^{n} \mathrm{Q}_{,\mathrm{dis,t}}^{\mathrm{i,y}}}$, levelised cost of electricity storage

$SRM_i^y = \frac{\sum_{t=1}^{n} P_t^y \mathrm{Q}_{\mathrm{dis,t}}^{\mathrm{i,y}} - P_t^y \mathrm{Q}_{\mathrm{charg,t}}^{\mathrm{i,y}}}{\sum_{t=1}^{n} \mathrm{Q}_{\mathrm{dis,t}}^{\mathrm{i,y}}}$, unit revenue margin for batteries

Where the following notation applies

- REF: reference year. 2030 in this study
- INV_{ref}: investment cost and annual production in the reference year
- CRF (Capital recovery factor): $\frac{d(1+d)^{PLT}}{(1+d)^{PLT}-1}$
- *PLT* : project lifetime (in year)
- *i*: technology – onshore wind or solar photovoltaic
- *d*: discount rate
- *t*: time increments (hours) for a year, *n* total number of hours per year
- *y*: year
- *h*: hour
- P_t^y is the equilibrium price for demand t (in $\frac{EUR}{MWh_{el}}$) and $Q_t^{i,y}$ is the electricity quantity generated by technology *i* during the demand period *t* in MWh_{el} and in year *y*.
- $Q_t^{i,y}$hourly electricity generated by technology in a given year *y*.
- $Q_{dis,t}^{i,y}$hourly electricity discharged by batteries in a given year *y*.
- $Q_{charg,t}^{i,y}$hourly electricity charged by batteries in a given year *y*.
- FC_i^y Annual fixed cost of technology, in EUR/yr, in year *y*.
- VQ_i^y Annual variable cost of technology, in EUR/yr, in year y.

The **renewable cannibalisation effect** is analysed through the market value ratio which represents the fraction of revenues captured by a given project if the entire production was sold to the spot market on an hourly basis as compared to the average wholesale price during the same time period. This base price is calculated as the arithmetic average of all hourly prices in the year:

$$MVR_i^y = \frac{CP_i^y}{BP^y}$$

$\mathrm{BP}^{\mathrm{y}} = \frac{\sum_{\mathrm{t=1}}^{\mathrm{n}} \mathrm{P}_{\mathrm{t}}^{\mathrm{y}}}{n}$, base price in year y

The **electricity consumption** market value is analysed through a demand weighted average price of electricity. It is calculated as follows:

$MVC^y = \frac{\sum_{t=1}^{n} P_t^y \mathrm{QC}_{\mathrm{t}}^{\mathrm{y}}}{\sum_{t=1}^{n} \mathrm{QC}_{\mathrm{t}}^{\mathrm{y}}}$, annual average of the market value of the electricity consumed in a given Member State during the year *y*, where,

- P_t^y is the equilibrium price for demand t (in $\frac{EUR}{MWh_{el}}$) and $Q_t^{i,y}$ is the electricity quantity generated by technology *i* during the demand period *t* in MWh_{el} and in year *y*.
- QC_t^yhourly electricity consumed at Country level in a given year *y*.

The Cfds are modelled through this generic mathematical formulation for the pay-out or claw-back for the asset in the case of an hourly production.

$$R(h) = \big(s - p(h)\big) * CF(h) * K$$

With R(h): pay-out or clawback cash flow for the asset in EUR

h: hours

s: strike price in EUR/MWh

p(h): reference market price (h) e.g. the hourly wholesale day-head price in EUR/MWh

CF(h): hourly capacity factor (% of the installed capacity of the assets)

K: installed capacity of the asset in MW

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