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Can UK green hydrogen contract for difference (CfD) match the cost-saving success of renewable electricity?

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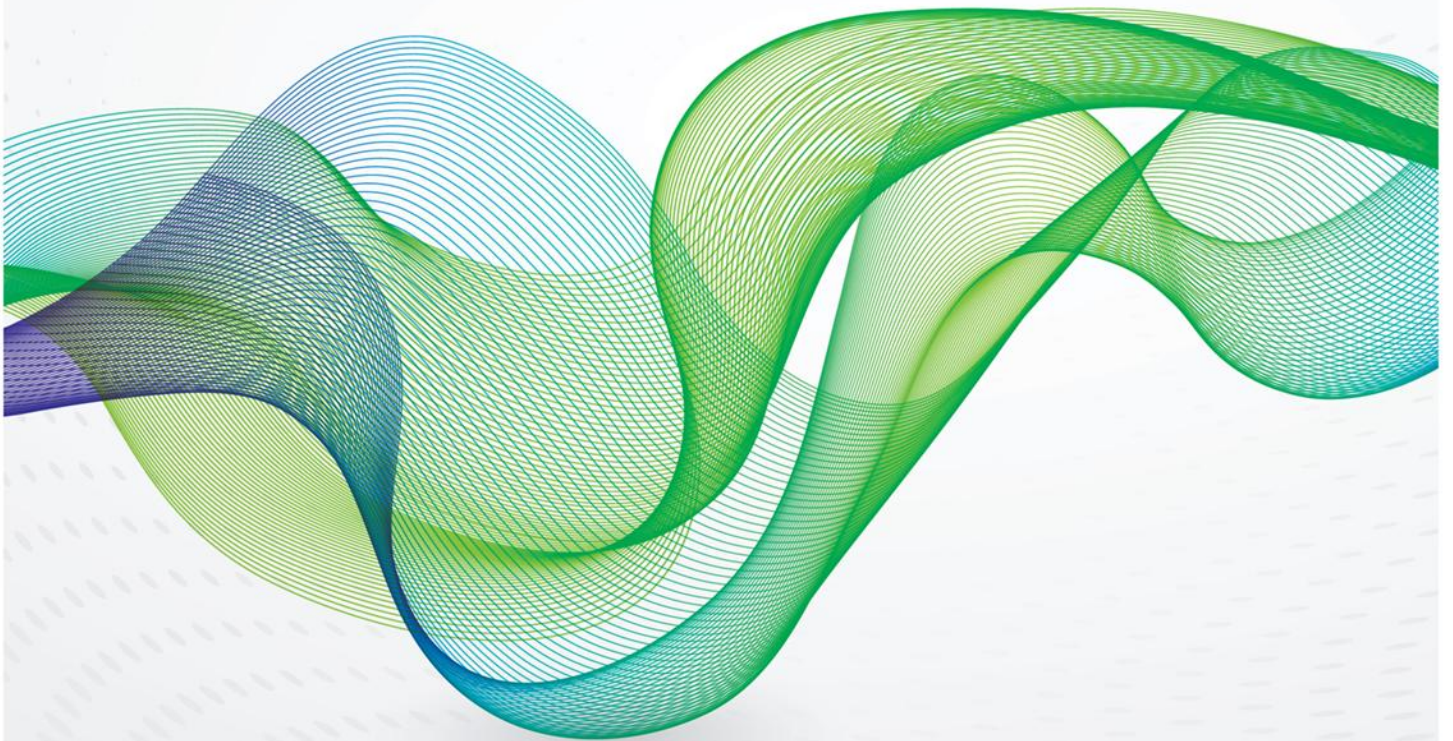
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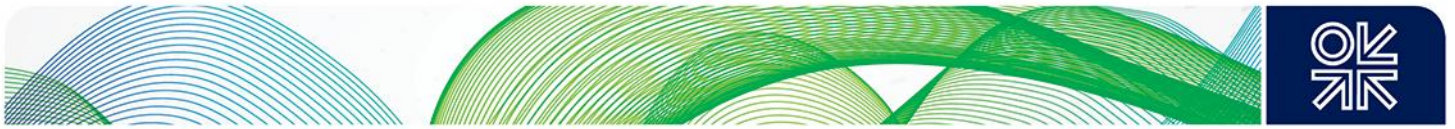
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October 2024

Can UK green hydrogen contract for difference (CfD) match the cost-saving success of renewable electricity?



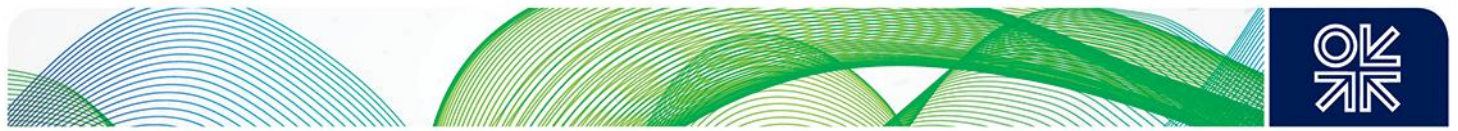


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Abstract

Contract for difference (CfD) entered the hydrogen sector as a natural extension of their successful application in the electricity sector. In the UK, low carbon hydrogen CfDs are primarily focused on two key objectives: reducing the costs of hydrogen production and scaling up production capacity. This raises the question of whether these contracts will be as effective as their counterparts in the electricity sector. We argue that Hydrogen CfDs face significant limitations compared to the more established renewable electricity CfDs, particularly in their ability to drive cost reductions and manage risk effectively. First, while renewable electricity projects benefit significantly from fixed-price contracts by reducing capital costs, this impact is less likely for green hydrogen, where operational costs are more dominant. Second, hydrogen CfDs place greater cost risks on producers due to the variability of electricity prices and immature supply chains. Offtakers also face higher risks given the uncertainty in green hydrogen market price development and the potential emergence of alternative, cheaper solutions. In contrast, renewable electricity CfDs provide a more balanced risk allocation with established markets and more predictable cost structures. Third, the uncertain and developing market for green hydrogen poses a significant challenge for fixed-price contracts. The potential for stranded assets is higher if demand does not materialise as expected. Renewable electricity, with its established demand, presents a more secure environment for long-term contracts. Finally, investors typically use fixed price long-term contracts as a way to hedge against price volatility. However, in presence of demand uncertainty, hedging strategies that focus on price stability offer little protection. Therefore, the unique challenges of the hydrogen sector—specifically around cost structures, risk distribution and uncertain market demand—indicate that the success seen with in renewable electricity CfDs may not be easily replicated in green hydrogen.



Contents

Abstract	ii
Contents	iii
Figures and Tables	iii
1. Introduction	1
2. Contract for difference under Hydrogen Allocation Round	2
3. Long term contracts in the electricity sector	6
4. The key economic properties of long term contracts and their implications for hydrogen 10	
4.1 Incentive structure vs cost structure	10
4.2 Risk allocation	12
4.3 Market demand.....	16
4.4 Unintended consequences.....	17
5. Conclusions.....	19
References	21

Figures and Tables

Figure 1: an overview of the successful HAR1 hydrogen projects.....	4
Figure 2: Average strike price in successive CfD auction allocation rounds.....	8
Table 1: key features of hydrogen CfDs versus renewable electricity CfDs.	9
Figure 3: Comparison of cost breakdown of green hydrogen LCOH versus renewable electricity LCOE	11
Figure 4: the share of long-term electricity products trading volume in Germany (2019–2021).....	14
Figure 5: Offshore wind CfD strike prices versus electricity spot prices (£/MWh) before 2021	15
Figure 6: Utility-scale solar PV PPA prices by region, contract size, and date of execution	15



1. Introduction

The UK has committed to achieving net-zero greenhouse gas emissions by 2050, as enshrined in law under the Climate Change Act 2008 (2050 Target Amendment) Order 2019. To meet this ambitious target, the UK government recognised the need to decarbonize various sectors of the economy, including heavy industry, transport, and heating, where direct electrification is challenging. Low-carbon hydrogen emerged as a solution, given its potential to replace fossil fuels in these sectors.

Certain industries, such as steel, cement, chemicals, and heavy transport (including shipping and aviation), are difficult to decarbonize through electrification alone. Hydrogen, particularly green hydrogen produced from renewable electricity via electrolysis, or blue hydrogen produced from natural gas with carbon capture and storage (CCS), offers a pathway to reduce emissions in these “hard-to-abate” sectors.

Despite the recognised potential of hydrogen, there are several barriers to its widespread adoption. Firstly, low-carbon hydrogen production, particularly green hydrogen, is currently more expensive than conventional hydrogen production (gray hydrogen) and fossil fuels. This cost differential poses a significant barrier to investment and market development. The nascent hydrogen market lacks the necessary infrastructure, regulatory frameworks, and demand certainty, making it risky for private sector investment. As a result, investors are hesitant to commit capital to hydrogen projects without assurance of long-term revenue streams and financial viability.

In response to these challenges, the UK government outlined its commitment to developing a hydrogen economy as part of its broader energy strategy. The publication of the UK Hydrogen Strategy in 2021 marked a significant step in this direction, setting out plans to create a thriving hydrogen sector (BEIS, 2021). The strategy envisioned low-carbon hydrogen as a key component of the UK’s energy transition, with a target to develop 5 GW of low-carbon hydrogen production capacity by 2030, which was later doubled to 10 GW.

The UK’s success in deploying renewable energy technologies, particularly through mechanisms like the Contracts for Difference (CfD) for renewable electricity, provided a valuable precedent. The CfD mechanism had proven effective in reducing costs, de-risking investments, and rapidly scaling up the deployment of offshore wind and other renewable technologies. Recognising the parallels, the government saw the need for a similar support mechanism tailored to hydrogen production. Given these challenges, the UK government developed the Hydrogen Production Business Model (HPBM) to address the financial and market barriers facing low-carbon hydrogen production. The HPBM is designed to provide revenue support to hydrogen producers, through hydrogen allocation rounds (HAR), similar to the CfD model used in the renewable electricity sector (Department for Energy Security and Net Zero, 2023e).

HPBM is part of a broader set of initiatives aimed at building a hydrogen economy in the UK, including the Net Zero Hydrogen Fund (NZHF), which provides capital funding for hydrogen projects, and the establishment of hydrogen hubs to foster regional development. The HPBM is also closely aligned with the UK’s Industrial Decarbonization Strategy, which seeks to reduce emissions from industrial sectors, and the British Energy Security Strategy, which aims to ensure energy security while transitioning to low-carbon sources.

The Hydrogen Allocation Rounds (HAR) is a competitive process designed to allocate government support to hydrogen production projects under the UK’s hydrogen business model. The HAR is primarily focused on two key objectives: reducing the costs of low-carbon hydrogen production and scaling up production capacity across the country. These rounds aim to make hydrogen more competitive in the energy market by driving down production costs through each allocation cycle. Additionally, HARs are designed to support the large-scale deployment of hydrogen production facilities, aligning with the UK government’s broader ambition to meet its net-zero emissions targets (Department for Energy Security and Net Zero, 2023c).

Beyond these core goals, HARs also seek to achieve broader outcomes that extend beyond cost and scale. These include, for example, electrolytic hydrogen producers contribute positively to the functioning of the UK’s electricity system, fostering economic growth by promoting the development of a robust hydrogen supply chain, and securing a reliable and continuous supply of hydrogen from various



production technologies which is essential for the stability of the hydrogen market and its various applications (Department for Energy Security and Net Zero, 2023c).

This paper examines hydrogen CfDs in relation to their two primary objectives, drawing a comparison with CfDs in the renewable electricity sector. By conducting this analysis, we aim to assess the effectiveness of the UK CfD framework in making hydrogen production more affordable and attractive to investors by mitigating investment risks. Insights from the UK's experience with hydrogen CfD can be valuable for other countries too, such as those in the EU or Japan, that are considering or implementing similar mechanisms.

The outline of this paper is as follows. The next section discusses the hydrogen allocation round in the UK and highlights its key features. Section 3 provides an analysis of long-term contracts in the electricity sector, with a specific focus on the CfD mechanism. Section 4 outlines the key features of long-term contracts and analyses their implications for the hydrogen sector. Finally, Section 5 offers the concluding remarks.

2. Contract for difference under Hydrogen Allocation Round

The Hydrogen Allocation Round (HAR) plays a pivotal role in the UK's efforts to boost the production of low-carbon hydrogen, which is a key part of its strategy to reduce carbon emissions (Department for Energy Security & Net Zero, 2023b). Launched in July 2022, the first round of HAR (HAR1) was specifically created to encourage the growth of hydrogen production using electrolysis. This is part of the UK government's larger objective, as outlined in the British Energy Security Strategy, which aims to expand the country's low-carbon hydrogen production capacity to 10 GW by 2030, with a significant portion of this capacity being generated through electrolytic methods.

The purpose of HAR is to mitigate the challenges and risks faced by the emerging hydrogen production sector. These risks include the possibility that producers might struggle to sell hydrogen at prices that are profitable or to generate sufficient sales volumes to cover their costs.

In HAR1, projects had the option to seek financial support either through the Hydrogen Production Business Model (HPBM) for revenue assistance or through a combination of revenue and capital expenditure support from the Net Zero Hydrogen Fund (NZHF). This structure was intended to provide the financial stability necessary for projects to reach the Final Investment Decision (FID) stage and begin construction.

The HAR uses a competitive process to determine which hydrogen production projects receive government support. This system is designed to select projects that can deliver hydrogen at the lowest cost while meeting essential technical and commercial requirements. In this process, projects submit bids that include their proposed strike prices and the volume of hydrogen they plan to produce. The government then evaluates these bids according to specific criteria to decide which projects will be awarded support.

The contracts issued through HAR are structured around a revenue support model, which bears similarities to the Contracts for Difference (CfD) used in the renewable energy sector. These agreements are long-term commitments between the government and hydrogen producers, ensuring financial stability by guaranteeing a predetermined strike price for the hydrogen produced.

The strike price is essentially the price per megawatt-hour (MWh) that a producer needs to cover the costs of low-carbon hydrogen production and earn a reasonable return on investment. This price is determined through negotiations on a project-by-project basis, taking into account certain eligible costs, and is expected to differ depending on the specific hydrogen production technology used.

The subsidy model is designed such that it provides financial support to successful producers by covering the gap between the strike price and a reference price. The reference price, in this context, is based on the market price at which the producer sells their hydrogen, with a minimum set at the natural gas price, which serves as the closest fossil fuel alternative. The gas reference price is calculated as the average end-of-day price for natural gas contracts in the month preceding the billing period.

The reference prices, expressed in pounds per MWh, are intended to reflect the market value received by the producer for hydrogen sold for specific qualifying purposes, such as power generation,



transportation, or industrial use, but excluding exports or blending into the natural gas grid. The support is provided only if hydrogen meets the Low Carbon Hydrogen Standard and is sold for these qualifying uses.

The floor price, which serves as a minimum benchmark for the reference price when calculating the difference amount, is set as the lower of the strike price or the gas reference price for the relevant billing period (BEIS, 2022). The floor price ensures that the reference price cannot fall below a certain level (the floor), even if the achieved sales price is very low. This prevents the government from having to pay excessively high subsidies in situations where market conditions cause the achieved sales price to drop significantly.

When achieved sales price > floor price, the reference price is determined by the achieved sales price. When achieved sales price < floor price, the reference price is set to the floor price, not the lower achieved sales price. This mechanism ensures that the producer is incentivized to achieve higher sales prices, and that the government subsidy is used effectively to support market development, rather than simply covering losses in an unsustainable market¹.

To ensure that the government's support achieves maximum value for money and contributes effectively to the UK's decarbonization goals, the Low Carbon Hydrogen Agreement (LCHA) does not subsidise hydrogen volumes sold to non-qualifying buyers. This approach ensures that intermediaries who take on market risks do not directly benefit from the subsidies, which aligns with the government's objective to support the early development of the hydrogen economy in a cost-effective manner.

Non-qualifying volumes will also play a role in determining the difference amount, but only when the reference price for these volumes surpasses the Strike Price²(BEIS, 2022). In such cases, the producer is required to make a payment to the LCHA Counterparty. This payment is calculated by subtracting the strike price from the reference price for non-qualifying volumes and then multiplying the difference by the relevant non-qualifying volumes (BEIS, 2022). The rationale behind this is that the government believes it is fair for the producer to compensate the LCHA counterparty in these instances, as it is unlikely the hydrogen would have been produced without the support provided under the LCHA.

Volume support is also offered to producers through a sliding scale mechanism. If a producer's hydrogen sales volumes decline, the producer will receive a top-up amount for each unit of qualifying volume sold, effectively offering a higher strike price for lower sales volumes, even though the strike Price itself remains unchanged. However, if sales volumes drop to zero, no additional volume support will be provided.

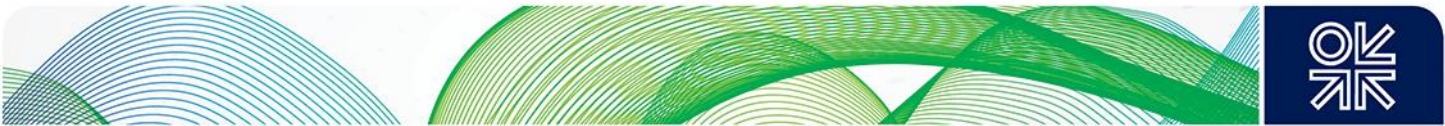
For each fiscal year, the hydrogen production and sales volumes from the facility must not surpass the "permitted annual volume cap," which is calculated as 125% of the annual volume cap (itself equal to the LCHA production cap divided by 15). Any hydrogen volumes exceeding this cap will be classified as non-qualifying volumes when calculating the difference amount. Conversely, if the production volumes fall below 75% of the annual volume cap, known as the "annual volume floor," they will be treated as equal to the annual volume floor for the purpose of calculating the total aggregate volume (BEIS, 2022).

In situations where excess volumes occur, these will be weighted at 50% for the calculation of the total aggregate volume, which will hasten the reduction of volumes remaining under the LCHA production cap. This structure incentivizes producers to keep their hydrogen production within the permitted annual volume cap to avoid penalties.

In December 2023, the UK government announced the results of the first Hydrogen Allocation Round (HAR1) under the Hydrogen Production Business Model (HPBM) and the Net Zero Hydrogen Fund (NZHF) (Department for Energy Security & Net Zero, 2023d). A total of 11 projects have been

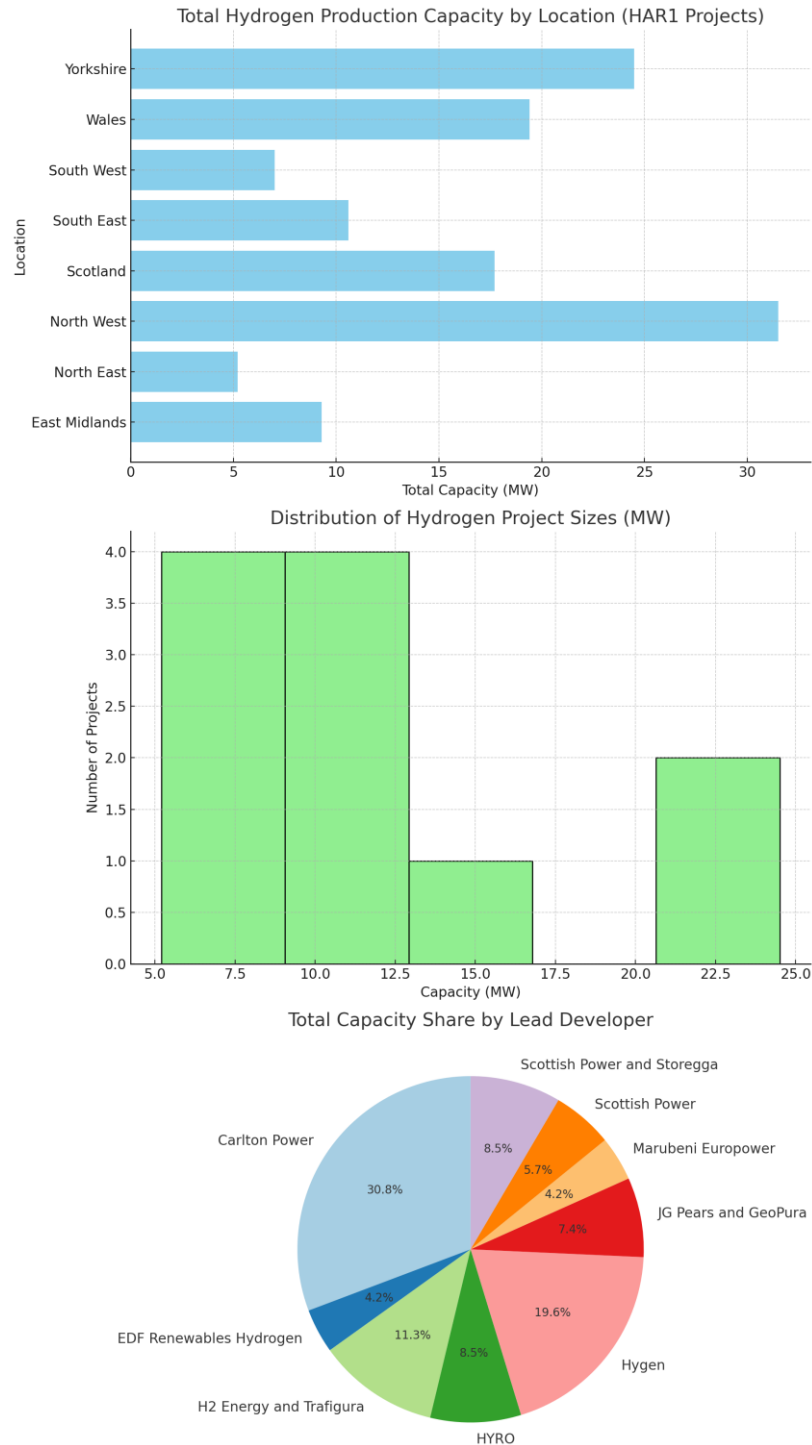
¹ Additionally, the HPBM includes an incentive mechanism aimed at encouraging producers to secure higher sales prices for qualifying volumes above the floor price. When the reference price for qualifying volumes exceeds the floor price, the producer will receive a reward linked to this price difference, which in turn reduces the overall support payment required under the LCHA.

² The reference price for non-qualifying volumes is defined as the greater of the producer's actual sales price for these volumes or the Strike Price (BEIS, 2022). This approach helps to establish a market benchmark in the absence of a well-established market price for hydrogen, thereby supporting the market's development over time.

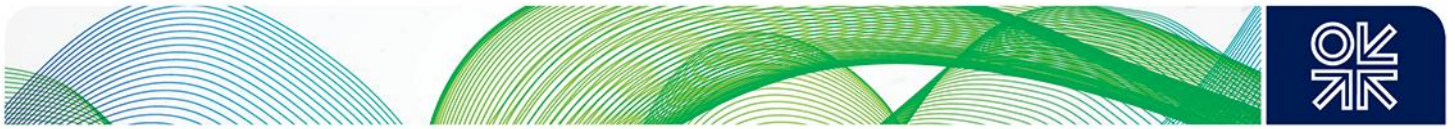


successfully awarded contracts with a weighted average strike price of £241/MWh (£175/MWh in 2012 prices), representing a combined potential to produce over 125 MW of low-carbon hydrogen. These projects are spread across various regions of the UK, including Scotland, Wales, and England, and encompass a range of hydrogen production methods, including both green hydrogen (produced through electrolysis using renewable electricity) and blue hydrogen (produced from natural gas with carbon capture and storage). Figure 1 provides a graphical representation of the successful projects and their features under HAR1.

Figure 1: an overview of the successful HAR1 hydrogen projects



Source: author based on the information in Department for Energy Security & Net Zero (2023d)



As the figure shows, early projects are mainly located in regions that are either historically industrial (e.g., Yorkshire, North West, and Wales) or have significant renewable energy potential (e.g., Scotland). Also, while some projects are relatively large (e.g., Bradford Low Carbon Hydrogen with 24.5 MW), majority are much smaller which may indicate that at this stage industry is still not confident with undertaking high scale projects. Furthermore, as seen from the pie chart in Figure 1, the list of successful projects includes a wide range of developers, from established energy giants like Scottish Power and EDF Renewables, to smaller or niche players such as HYRO and GeoPura.

HAR2 was launched in December 2023 and is significantly larger than HAR1, aiming to support up to 875 MW of hydrogen production capacity, with projects expected to become operational between 2026 and 2029. Unlike HAR1, which included capital support through the Net Zero Hydrogen Fund, HAR2 focuses solely on providing revenue support through the HPBM. The deadline for expressions of interest for HAR2 was February 2024, with final applications due in April 2024. The results for the Hydrogen Allocation Round 2 (HAR2) are expected to be announced in 2024, following the completion of the application process.

The Hydrogen CfD model is more complex compared with traditional CfDs in the renewable electricity. This is because it is designed with the aim of addressing the unique challenges of a developing hydrogen market.

First, the hydrogen market is still emerging, meaning there isn't a well-established or liquid market where prices are determined by supply and demand forces. Without a liquid market, price signals can be weak or distorted, making it difficult for hydrogen producers to predict and plan their production economically. The hydrogen CfD thus incorporates mechanisms such as the reference price and floor price to provide a proxy for market pricing where actual market prices are still undeveloped. This approach aims to mitigate the risks associated with selling hydrogen in an underdeveloped market by ensuring that producers are compensated based on a minimum benchmark.

Second, hydrogen can be used in a variety of applications, some of which are more valuable from a policy perspective (e.g., decarbonising heavy industry or transportation) than others (e.g., blending into natural gas networks where the decarbonisation impact might be lower). By offering financial support primarily for qualifying volumes, the CfD encourages producers to focus on these strategic industries from a decarbonisation policy perspective.

Third, subsidising hydrogen production through government support can be costly, and these costs are often passed on to consumers. Therefore, it's crucial to design the CfD in a way that minimises the need for subsidies while still supporting the hydrogen market. The design of the CfD includes various incentives for producers to sell at higher prices, thereby reducing the need for government payouts. The expectation is that, over time, as the market matures, these payments will decrease, leading to lower overall subsidy costs.

In conclusion, the Hydrogen CfD model's complexity is a direct response to the challenges inherent in a nascent and evolving market including the lack of market liquidity, the need to prioritise strategic applications, and the imperative to manage subsidy costs effectively. This is why hydrogen CfD framework incorporates multiple mechanisms to ensure that hydrogen production can progress steadily, even as the market is still non-existent. However, the extent to which it can achieve its primary objectives related to hydrogen scale up and cost reduction is highly affected by these challenges as well as unique economic features of hydrogen production. Specifically, as we show later in the paper, in comparison with renewable electricity, the current hydrogen CfD framework provides insufficient levels of risk mitigation. This is a critical issue, as risk mitigation has been a key factor in the rapid scale-up of renewable energy technologies and their substantial cost reductions over time.



3. Long term contracts in the electricity sector

Given that hydrogen CfDs are designed based on the similar long-term contracts in the electricity sector, it is useful to review the context that led to their introduction and key elements of these supporting frameworks.

Long-term contracts were introduced as part of the electricity market reforms that occurred in various jurisdictions during the late 20th and early 21st centuries. These reforms were driven by the need to transition from vertically integrated, state-owned or regulated monopolies to competitive electricity markets³. The deregulation of electricity markets shifted the responsibility of investment to competitive market participants, creating a need for mechanisms that could encourage private investment in generation capacity. Long term contracts between market participants was a way to overcome market related risks.

Initially, there were some reservations on the part of competition authorities about long term contracts by incumbent utility companies. The European Commission, for example, viewed these contracts as a problem, particularly in the early 2000s. In its 2007 Energy Sector Inquiry, the Commission identified long-term contracts as one of the key factors hindering the development of competitive electricity markets (European Commission, 2007). The concern was that long-term contracts could replicate the effects of vertical integration, allowing incumbent firms to dominate the market and stifle competition.

However, the Commission's position on long term contracts evolved as the electricity market matured and the need for investment in decarbonization grew. The potential anti-competitive effects of long-term contracts diminished in the context of more competitive and integrated electricity markets, and the benefits became clearer. Long-term contracts began to be seen as essential for supporting investments in clean energy infrastructure and ensuring price stability in a volatile market. The Commission eventually acknowledged that these contracts could help facilitate investments required for decarbonization by providing stable revenue streams, reducing financing costs, and promoting coordinated investment along the energy value chain (European Commission, 2023).

Beyond decarbonisation, there were also other reasons that reinforced the need for long term contracts. In some countries, such as the UK, there was a growing concern about the adequacy of generation capacity to maintain a reliable electricity supply. Long-term contracts needed to ensure that sufficient capacity would be built to meet future demand, despite the uncertainties and risks associated with competitive markets (Roques and Finon, 2017; Bhagwat et al., 2017). The uncertainty of future prices and demand make it difficult for investors to justify large capital expenditures for new generation facilities in absence of a long-term contract with a credible counter party.

Apart from providing a guaranteed revenue stream and thus reducing the risk associated with price volatility and uncertain future returns (Neuhoff & Vries, 2004), long term contracts also provide a mechanism to stabilise electricity prices for consumers by locking in prices over a longer period (Green, 2004). This was particularly important in markets with significant price volatility, which could lead to spikes in electricity costs for consumers (Moreno et al., 2010).

Independent Power Producers (IPPs) and other generation companies were typically one party to these contracts. On the other side of the contract were utilities or electricity suppliers. In some cases, governments or regulatory bodies acted as intermediaries or guarantors for these contracts, particularly in markets where the electricity sector was undergoing significant reforms. This was done to ensure that the contracts were honoured and to provide additional security to investors (Woolf and Halpern, 2001).

Long-term contracts come in various forms, each tailored to address specific risks and requirements in the energy market. Power Purchase Agreements (PPAs) are among the most common types. These

³ Before the introduction of long-term contracts, the electricity industry was typically structured as a regulated monopoly. In this model, a single utility company was responsible for generating, transmitting, and distributing electricity within a specific geographic area.

These utilities operated under a form of economic regulation such as cost-based regulation, where their rates were set by regulators to cover their costs plus a reasonable return on investment. This model ensured that utilities could recover their costs and earn a profit, which provided them with the financial security needed to invest in new infrastructure.



are contracts between electricity generators (such as IPPs) and buyers (such as utilities, large consumers, or electricity suppliers). PPAs lock in a fixed or indexed price for electricity over a long period (usually 10-25 years), providing price certainty for both sides.

The terms of PPAs, including price, duration, and volume, are negotiated directly between the two parties and are reflecting market conditions and the perceived risks by both parties. In liberalised markets PPAs are typically private agreements and do not involve direct government intervention, although regulatory frameworks might govern certain aspects of these contracts (e.g., grid access, renewable energy standards). They usually are either in the form of corporate PPAs (where companies like Google or Amazon sign agreements directly with renewable energy developers) or utility PPAs where Utilities enter into contracts with renewable energy developers to meet their renewable portfolio standards or to secure long-term supply. In non-liberalised markets however the state utility is often the counter party to these contracts.

Although PPAs are often physical where the buyer takes physical delivery of the electricity generated by the project, we have also virtual PPA where the buyer only settles the difference between the fixed price in the contract and the market price.

Overall, PPAs allow generators to secure financing for new projects by providing a guaranteed revenue stream, which reduces the perceived investment risk. Buyers benefit by securing a stable supply of electricity at predictable prices.

Contracts for Difference (CfDs) are another form of long-term contracts. They are often between electricity generators and a government-backed entity (in the UK, this is the Low Carbon Contracts Company)⁴. The concept of CfDs in the electricity sector was formalised as part of the UK's Electricity Market Reform (EMR) package, which was introduced in 2010 and became fully operational in 2014. The primary reasons for introducing CfDs were to support the UK's transition to a low-carbon energy system, ensure energy security, and keep electricity prices affordable for consumers. The UK government recognised the need for substantial investment in renewable energy and low-carbon technologies to meet its climate change targets, particularly its legally binding carbon budgets under the Climate Change Act of 2008.

Before CfDs, the UK's renewable energy sector relied heavily on the Renewable Obligation (RO) scheme, which provided revenue based on Renewable Obligation Certificates (ROCs) (Newbery, 2012). However, the value of ROCs was subject to market fluctuations, creating uncertainty for investors. CfDs were introduced to replace ROCs with a more predictable and secure revenue model.

The introduction of CfDs in the UK has been considered highly successful in mitigating the risk and driving investment in renewable energy although there has been a lot of debate about their market efficiency (Khodadadi and Poudineh, 2024). The mechanism has supported the development of a wide range of low-carbon technologies, including offshore wind, onshore wind, solar PV, and nuclear power.

The success of CfDs in the UK has led to their adoption in various forms in other countries, including Denmark, France, and Poland. Each country has adapted the CfD model to fit its specific regulatory and market context, but the core principle of providing revenue stability to incentivise low-carbon investment remains central.

CfDs in the electricity sector operate on a "strike price" mechanism, where the generator is guaranteed a certain price for their electricity (the strike price). If the market price (reference price) is below the strike price, the government compensates the generator for the difference. If the market price is above the strike price, the generator pays the difference back to the government. The terms of CfDs, including strike prices, are often set through competitive auctions, and the contracts are generally public, with significant government oversight.

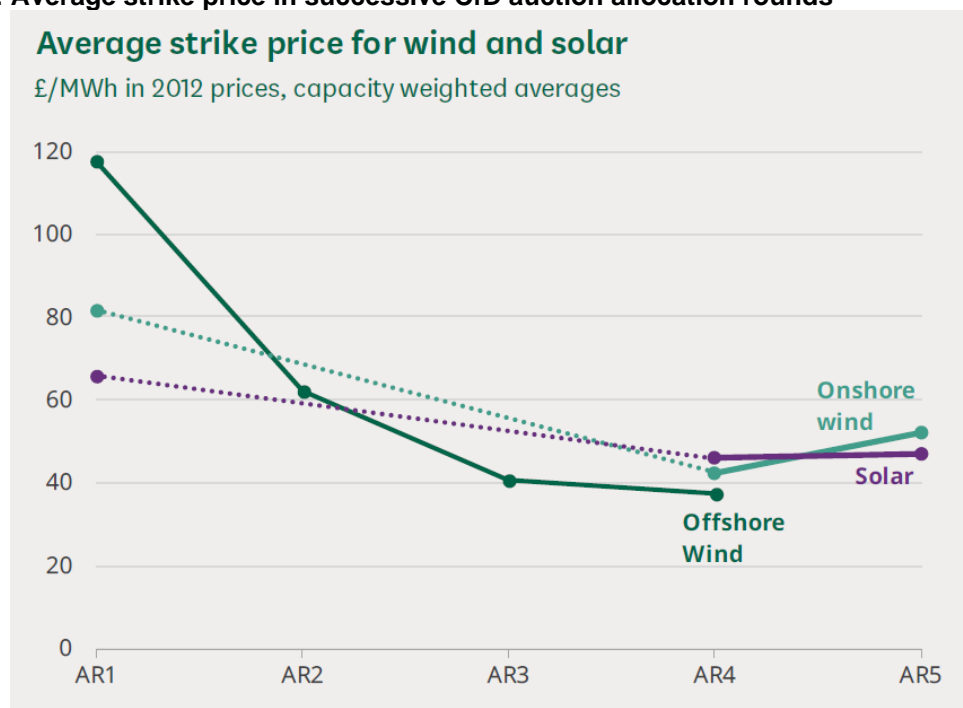
⁴ Although PPAs and CfDs share some features, there are differences between them. PPAs are typically signed between private parties (generators and utilities/companies), while CfDs involve a government-backed entity as a counterparty. In PPAs, the price risk is borne by the buyer, whereas in CfDs, the government (or its agent) takes on the price risk, stabilising revenues for the generator. PPAs are market-driven and primarily aimed at securing long-term electricity supply at a predictable price. CfDs, on the other hand, are policy-driven, designed to support specific types of generation and meet broader policy goals.



As CfDs are backed by the government, it reduces the cost of capital for projects and encourages investment in technologies that might otherwise be considered too risky or expensive.

Risk mitigation along with competitive auctions for allocation of these contracts have resulted in significant cost reductions, particularly in offshore wind, where prices have fallen dramatically over successive auction rounds in the UK (see Figure 2).

Figure 2: Average strike price in successive CfD auction allocation rounds



Source: (Watson & Bolton, 2023)

CfDs entered the hydrogen sector as a natural extension of their successful application in the electricity sector. As discussed in the previous section, the CfD model used in the hydrogen sector is similar to that in the electricity sector but tailored to the specific needs of hydrogen production.

The structure of the Hydrogen CfD reflects its role in supporting an emerging market characterised by high uncertainty and risk. Unlike the renewable electricity CfD, which relies on standardised, competitive auctions to drive cost reductions in a mature market, the Hydrogen CfD incorporates project-specific strike prices, volume caps, and a sliding scale support mechanism. This design demonstrates a nuanced approach to addressing the unique challenges faced by the nascent hydrogen sector.

Furthermore, basis risk (i.e., the risk of reduced subsidy payouts because of deviation between achieved sales price and reference price) for hydrogen producers increases when the achieved sales price for hydrogen is lower than the gas reference price. This is especially relevant in a market with limited liquidity and underdeveloped price signals. In a nascent hydrogen market, where there is no established benchmark or liquid trading platform, producers often have limited power to negotiate higher prices. Basis risk can also be magnified by regulatory uncertainty and volatility in the pricing of natural gas. If natural gas prices fluctuate significantly, especially upward, the gas reference price in the hydrogen CfD will adjust accordingly. Hydrogen CfD producers may face situations where their achieved sales price is lower than the gas reference price, resulting in financial shortfalls despite CfD protection. This risk is less of a concern in traditional renewable electricity CfDs, where established market prices offer more predictability and stability. Nonetheless, alternative CfD designs that have been proposed for the electricity sector in recent years to improve market efficiency of these contracts may lead to increased basis risk.

Although the inclusion of a reward mechanism for achieving higher sales prices above the floor price, and linking payments to market-based reference prices, suggest an intent to drive market creation and price discovery in the hydrogen sector, When the market is immature, producers may be limited to selling



to off-takers who have higher price elasticity or bargaining power, further increasing the likelihood of basis risk.

Table 1 compares key features of hydrogen CfDs with renewable electricity CfDs.

Table 1: key features of hydrogen CfDs versus renewable electricity CfDs.

Feature	Hydrogen CfD	Renewable Electricity CfD
Purpose	Supports low-carbon hydrogen production	Supports renewable electricity generation
Strike price	Negotiated on a project-by-project basis, accounting for eligible costs	Determined through competitive auction process
Reference price	Linked to either the achieved sales price or a defined floor price, acting as a proxy for market pricing	Typically based on wholesale electricity market price
Qualifying volumes	Only applies to hydrogen used in strategic applications (e.g., heavy industry, transportation), incentivising decarbonization in valuable sectors	Not applicable; all generation under the CfD is considered qualifying if it meets contractual obligations
Payment mechanism	Producers receive payments if the strike price exceeds the reference price and pay back when it falls short; no payment for non-qualifying volumes but producers may have to pay back if non-qualifying volumes are sold above the strike price	Generators receive payments when the reference price (wholesale market price) is below the strike price, and pay back when it's above
Eligible technologies	Focus on low-carbon hydrogen production methods, such as electrolysis	Includes a wide range of renewable energy technologies, like wind, solar, and biomass
Contract length	Long-term, similar to renewable electricity CfDs	Typically, 15 years
Volume caps	Includes permitted annual volume cap and annual volume floor to regulate production volumes	Generally, it does not include specific volume caps; generation is based on installed capacity
Basis risk	There is risk of deviation between achieved sales price and reference price specifically when the achieved sales price is lower than the gas price	Basis is risk low under conventional renewable electricity CfD but in recent years new models have been proposed that may increase the basis risk
Flexibility	Includes provisions for sliding scale support based on production volumes	Standard CfD contracts, with no volume-based sliding scale support
Sector development	Aims to establish benchmarks in an emerging hydrogen market and support early market development	Supports mature renewable energy markets with established benchmarks
Application complexity	More complex due to the underdeveloped market and varied applications of hydrogen.	Simpler, as renewable electricity CfDs are standardised for a well-established market.



4. The key economic properties of long-term contracts and their implications for hydrogen

4.1 Incentive structure vs cost structure

Long-term contracts, particularly in the renewable energy sector, have played a significant role in driving down the costs of generation technologies. This has been largely due to their impact on financing costs. These contracts align well with the capital cost nature of renewable electricity projects. Wind and solar power generation are heavily capital-intensive. The majority of the costs are upfront, related to the construction, installation, and commissioning of the infrastructure (e.g., turbines, solar panels). Once these assets are in place, the ongoing operational and maintenance costs are relatively low, and the primary inputs (sunlight and wind) are free. Therefore, long-term fixed-price contracts, such as PPAs and CfDs, are particularly effective in this context because they provide certainty about future revenue streams. This certainty lowers the perceived financial risk for investors, which in turn reduces the cost of capital. With lower financing costs, developers can optimise capital investments more effectively, resulting in lower overall project costs and reduced electricity prices over time.

There is evidence on the positive impact of long-term contract on the cost of renewable electricity. Specifically, mechanisms such as PPAs, Feed-in Tariffs (FiTs), and CfDs have proven instrumental in reducing financial risks for investors, stimulating technological innovation, and ultimately achieving significant cost reductions across various renewable energy technologies.

In Germany, for example, FiTs led to a decline in the installation costs for photovoltaic systems by 70% from 2000 to 2007 (FuturePolicy.org, 2019). Following this, average costs declined further, from €5/kWp in 2006 to €1.60/kWp by 2014 (FuturePolicy.org, 2019). Similarly, wind turbine costs saw a 25% reduction between 2000 and 2012 (ibid). Also, in Italy, where solar PV installations expanded rapidly under the Conto Energia FiT scheme, solar module prices decreased by over 50% between 2000 and 2011 (Ameli & Kammen, 2014). The UK's experience with CfDs for wind power further highlights the benefits of long-term contracts. The levelized cost of energy (LCOE) for offshore wind plummeted from £140/MWh in 2015 to around £44/MWh (2012 prices) in allocation Round 5 (AR5), which concluded in 2023, largely due to the price stability provided by CfDs.

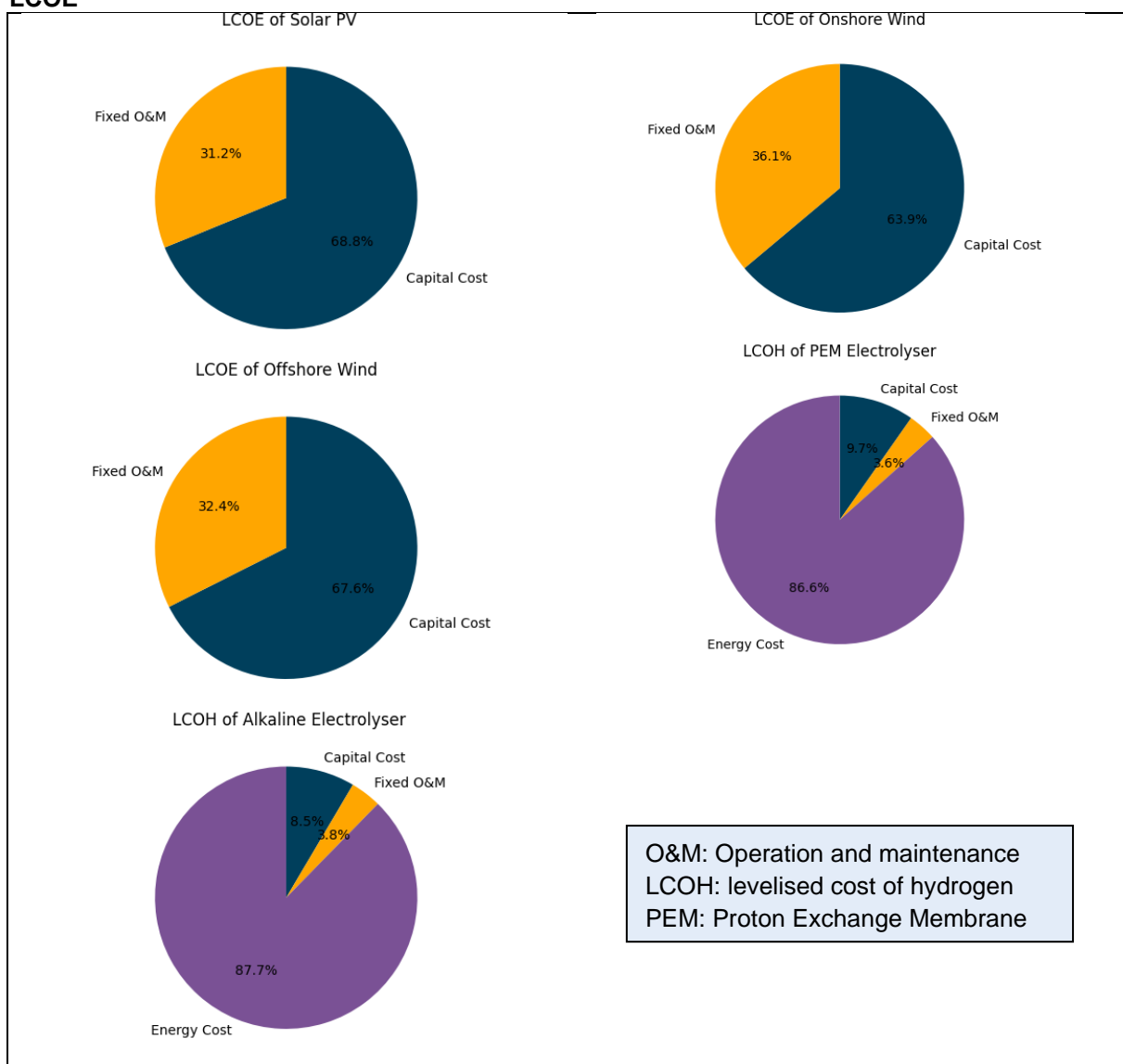
The positive impact of long-term contracts in the electricity sector extends beyond Europe. In the United States, PPAs have played a key role in reducing the LCOE for wind power. Brazil's renewable energy expansion has also benefited from long-term contracts. These contracts have minimised regulatory risks and provided stable revenue streams, leading to significant cost reductions in technologies like wind and hydroelectric power (Hochberg and Poudineh, 2018). These all highlight the importance of stable, long-term price signal in reducing generation costs (Genoese et al., 2016).

A key question however is that will fixed-price long-term contracts have the same cost reduction effect for green hydrogen? There are reasons to think that they might not.

Unlike renewable electricity, green hydrogen production is less capital-intensive but more operationally expensive, particularly because it relies heavily on electricity as a feedstock (see Figure 3). This means that the ongoing operational costs are a significant portion of the total cost structure. Long-term fixed-price contracts may be less effective in this context because they do not directly address the variable and significant operational costs. Even if capital investments in electrolysis technology can be optimised under a long-term contract, the fluctuating price of electricity introduces a level of cost unpredictability that such contracts may not mitigate. This may necessitate more complex financial instruments, such as hedging strategies, to manage the risk of input price variability, which can erode the benefits of reduced financing costs. The variable nature of input costs thus makes it difficult to achieve the same degree of cost stability and reduction for green hydrogen that long-term contracts can deliver in the capital-intensive renewable electricity sector.



Figure 3: Comparison of cost breakdown of green hydrogen LCOH versus renewable electricity LCOE



Source: author's illustration based on data in Lazard (2024)

Combining a long-term contract for hydrogen production with a corresponding long-term contract for electricity could, in theory, stabilise the operational costs of hydrogen producers, creating a more predictable environment akin to the renewable electricity sector. This would provide green hydrogen producers with the financial security needed to manage the significant operational costs associated with their reliance on electricity as a feedstock. However, in practice, securing such a long-term electricity contract remains challenging. One key reason is the illiquidity of the forward electricity market, where duration of contracts is typically far shorter than the long-term horizons required for hydrogen production, where contracts typically extend to 10 or 15 years. Additionally, market volatility in electricity prices, driven by fluctuations in renewable energy generation, can make it difficult to secure a fixed-price contract that aligns with the operational needs of hydrogen producers. Moreover, the uncertain future of electricity prices due to evolving policies and carbon pricing schemes adds another layer of complexity, making long-term agreements for electricity input difficult to negotiate. As a result, green hydrogen producers can be left vulnerable to operational cost variability, which undermines the potential stability offered by long-term contracts for hydrogen.



As with regard to scale efficiency, large-scale deployment of renewable technologies has led to significant economies of scale, which has driven down costs. While economies of scale are possible for electrolyzers, the scale required to make low-carbon hydrogen cost-competitive is immense and may not be achievable in the near term. Globally, the scale efficiency and cost reductions for electrolyzers are unlikely to match those seen in renewable technologies. For example, China has made notable progress in lowering electrolyser costs, largely driven by government support and advancements in manufacturing, but it is unlikely to achieve the same significant cost reductions and global dominance seen in the solar PV industry. This is primarily due to the greater complexity of electrolysis systems, the challenges related to technology transfer, and the external factors affecting exports. In particular, electrolyzers involve more intricate systems than solar PV, which reduces the advantages of standardisation and large-scale production. Moreover, global overcapacity and increasing trade protectionism further complicate China's ability to expand its electrolyser exports.

Another point is that renewable electricity technologies (e.g., wind and solar) were already on a learning curve when long-term contracts like PPAs, FiTs, and CfDs were introduced—i.e., they had reached a stage where economies of scale and ongoing innovations could significantly reduce costs. On the other hand, the technology for low-carbon hydrogen, such as green hydrogen produced via electrolysis or blue hydrogen from natural gas with carbon capture and storage (CCS) have not yet reached the same point in their learning curve as renewable electricity technologies.

Furthermore, the infrastructure for renewable electricity (e.g., grids, turbines, and panels) was relatively well-developed and benefited from decades of incremental improvements and a well-established global supply chain. The infrastructure for hydrogen production, storage, and distribution is less developed. For example, there is limited infrastructure for transporting hydrogen, and retrofitting or building new pipelines is costly. The immature supply chain and high initial costs could limit the effectiveness of long-term contracts in driving down production costs.

In a nutshell, due to mismatch between the cost structure of green hydrogen and the incentive structure offered by long-term contracts, the same level of cost reduction driven by long-term contracts seen in the renewable electricity sector is unlikely to materialise for low-carbon hydrogen, since these contracts do not address the volatile operational expenses that are critical to hydrogen's overall cost competitiveness.

4.2 Risk allocation

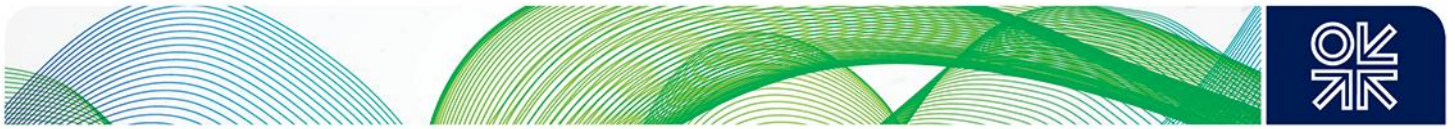
The risk allocation in fixed price long term contracts is such that the producers bear the cost risk whereas the offtakers bear the profit risk. The cost risk is related to increases in production costs (e.g., materials, labour, inflation) beyond what was anticipated. The profit risk is about the buyer paying more than the market price if production costs decrease over time, but they avoid the risk of price spikes.

Although the issue of cost risk for producers and profit risk for offtaker also exist in electricity sector, this issue can be even more problematic for hydrogen market participants as we explain in this section.

4.2.1 Cost risk

There have been instances in the electricity sector, particularly in offshore wind projects, where developers have faced significant cost risks that have led to reconsiderations or even withdrawals from long-term contracts such as CfDs.

The offshore wind industry has been significantly impacted by cost inflation since 2021, with price increases ranging from 11-20%, and some companies reporting rises of over 30% (Westwood Global Energy Group, 2023). Key drivers include soaring material costs—particularly for steel and copper—rising financing expenses, and higher vessel charter rates, all exacerbated by global supply chain disruptions. As a result, nearly 75% of developers have had to reassess project viability, leading to delays, renegotiations, and in some cases, project cancellations. These risks are compounded by the fact that the contracts were agreed upon with the expectation of falling costs, but unexpected increases in input prices have threatened profitability. Westwood estimates that this inflation could add around \$280 billion to offshore wind capital expenditures over the next decade, representing a 19.6% increase,



potentially requiring greater consumer prices or increased government support (Westwood Global Energy Group, 2023).

Another example is Hinkley Point C nuclear power plant project in the UK which is developed under a long-term CfD agreement. The project has been plagued by significant cost overruns and delays. Initially, the project was expected to cost £18 billion (and complete by 2017), but the most recent estimates place the cost between £31 billion and £35 billion (Carbon Brief, 2024). The delays, partly caused by inflation, COVID-19, Brexit, and changes in safety requirements, have pushed the expected completion date to 2029 or even 2031 in the worst-case scenario. The rising costs have created financial strain on EDF who bears the cost risks under the CfD agreement.

In India, several large-scale solar PV projects have been awarded through competitive bidding processes, where developers commit to supplying electricity at very low fixed prices under long-term PPAs. Solar PV developers in India have faced significant challenges due to rising costs of solar panels, tariffs on imported solar equipment, and currency fluctuations. These factors have increased the costs of project development beyond what was initially anticipated when bidding for PPAs. Some developers have struggled to honour their PPAs at the contracted prices, leading to delays in project execution, renegotiation of contracts, or even project cancellations. For example, in 2018, several Indian solar developers sought to renegotiate PPAs after a sudden increase in module prices and the imposition of safeguard duties on imported solar panels (PV magazine, 2018; IJPIEL, 2022).

When it comes to green hydrogen, cost risk is even more critical than for renewable electricity generators. This is due to several factors such as the high dependence on variable electricity prices, the focus on operational rather than capital costs, the immaturity of the supply chain, and the lack of established economies of scale. Unlike renewable electricity generators, where the majority of costs are capital expenditures incurred upfront, green hydrogen producers face continuous exposure to variable operational costs. These factors make green hydrogen production particularly vulnerable to cost fluctuations, and long-term contracts for outputs, which have been effective in stabilising costs for renewable electricity, may not offer the same level of protection for green hydrogen projects.

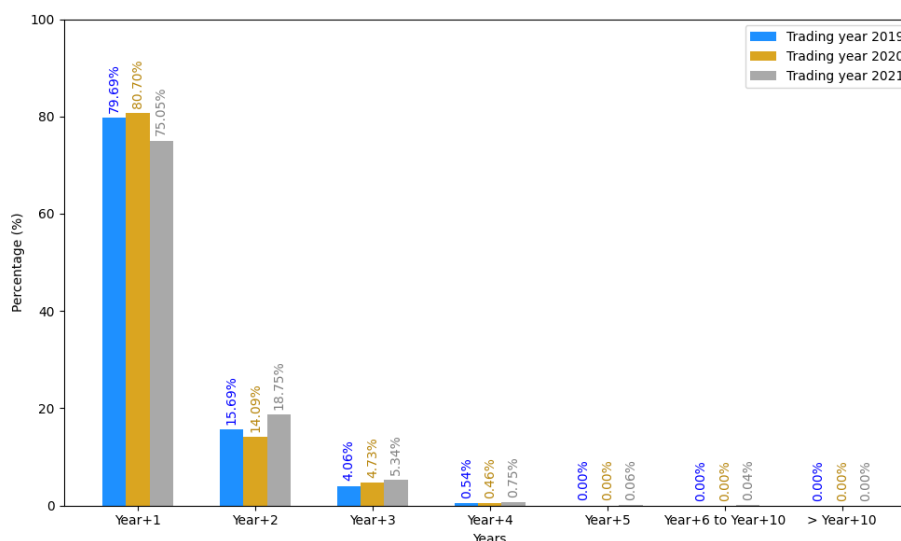
While, in theory, there are financial derivatives (such as forwards, futures, and options) available to hedge electricity input costs for electrolyzers, the availability and sophistication of these instruments can be limited, particularly when they need to align with the long-term contracts for hydrogen production. Electrolyser projects are long-term investments, typically spanning 15 to 20 years or more. However, renewable electricity forward contracts often have shorter durations than the lifespan of electrolyzers. This mismatch creates uncertainty in terms of long-term electricity supply and pricing, which affects the financial predictability of these projects.

According to the Agency for the Cooperation of Energy Regulators (ACER), Germany has one of the most liquid forward electricity markets in Europe (ACER, 2022). However, even in this market, most contracts are traded with a horizon of up to two years (see Figure 4). The situation is not much better in the UK's electricity market. One key reason for this is that many renewable energy projects in the UK are supported by government-backed mechanisms such as CfDs. These mechanisms often guarantee fixed prices for renewable energy generation over extended periods, reducing the need for generators to hedge their electricity prices in the forward market. This has also contributed to the underdevelopment of the market for PPAs in many European countries, including the UK.

Moreover, electricity markets in Europe (including the UK) are heavily regulated, and ongoing policy changes—such as capacity market reforms, carbon pricing adjustments, or renewable energy support schemes—can significantly impact electricity prices. Regulatory uncertainty discourages market participants from entering into long-term forward contracts because future policy changes could drastically alter the economic landscape. As a result, market players tend to trade in shorter-term contracts (1 to 3 years), where there is more regulatory clarity and less risk of policy shifts. Additionally, long-term forward contracts typically require more credit and collateral due to the higher levels of uncertainty and risk. Many market participants, particularly smaller companies, may lack the financial resources or risk appetite to engage in long-term forward electricity contracts.



Figure 4: the share of long-term electricity products trading volume in Germany (2019–2021)



Source: ACER (2022)

Co-locating electrolyzers with renewable energy projects, such as wind or solar farms, could allow direct access to low-cost electricity without relying heavily on the grid. This may require revising the terms of existing hydrogen CfDs to allow for the inclusion of renewable electricity. However, a critical consideration is that if electrolyzers operate primarily when renewable electricity is abundant (e.g., during periods of high wind or solar generation), the economics of such projects may not always be favourable due to the lower capacity factor under intermittent conditions. Therefore, co-located projects may need to be combined with storage or backup generation to ensure continuous hydrogen production.

In essence, it is not possible to decouple long-term contracts for green hydrogen from the conditions of the electricity market. In other words, an effective green hydrogen CfD cannot function in the presence of significant challenges in securing long-term contracts for electrolyzers in the electricity sector. These two elements must be addressed simultaneously. Currently, there are plans to reform the UK electricity market under the Review of Electricity Market Arrangements (REMA) (Department for Energy Security and Net Zero, 2024). The main objective of this reform is to ensure that the market design supports decarbonization, energy security, and affordability. However, it remains to be seen to what extent the planned reforms will address the specific challenges green hydrogen producers face in managing the cost and intermittency of their renewable electricity inputs.

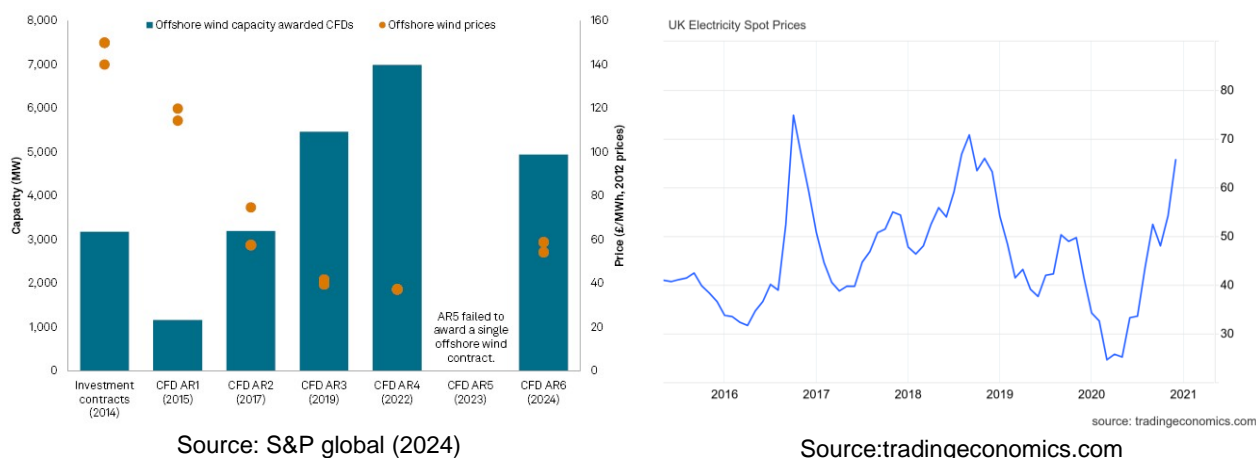
4.2.2 Profit risk

There have been examples in the electricity sector where buyers (offtakers) have faced profit risk under long-term contracts. This typically occurs when market prices for electricity fall below the fixed prices agreed upon in contracts like PPAs or CfDs.

Several offshore wind projects in the UK have secured CfDs with strike prices that, over time, became higher than the prevailing market prices for electricity. In recent years, wholesale electricity prices in the UK have fluctuated significantly. During 2020 wholesale electricity prices fell below £40 per MWh due to reduced demand, oversupply, and the impact of the COVID-19 pandemic on the economy (Figure 5). The government (through the Low Carbon Contracts Company) faced the risk of paying more than the market rate for electricity, leading to increased costs for the government and, by extension, electricity consumers. Although the prices raised again after 2021, this was particularly a problem with respect to earlier CfDs that had been awarded with high strike prices.

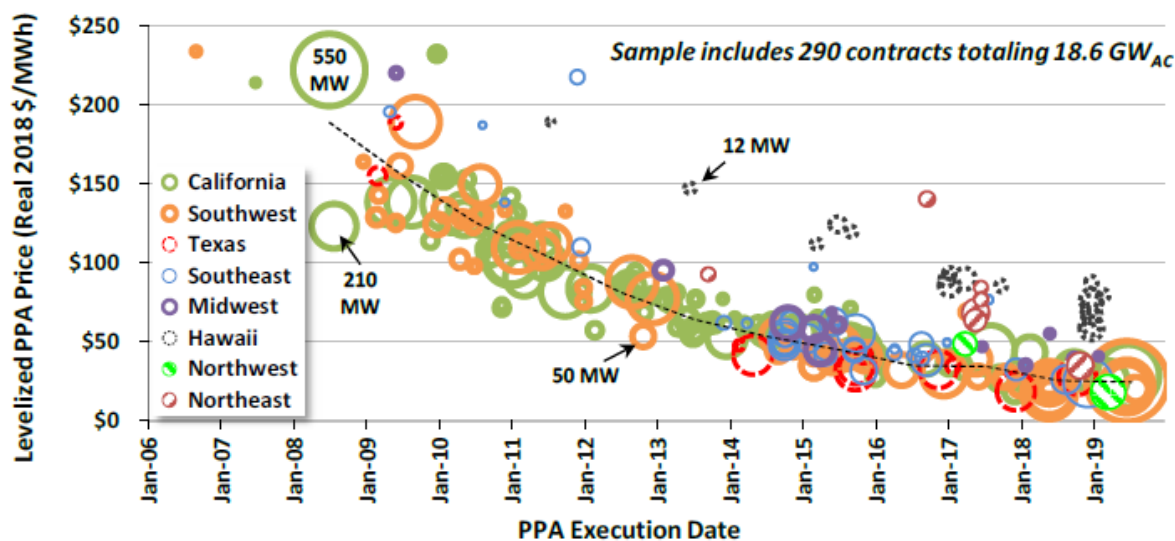


Figure 5: Offshore wind CfD strike prices versus electricity spot prices (£/MWh) before 2021



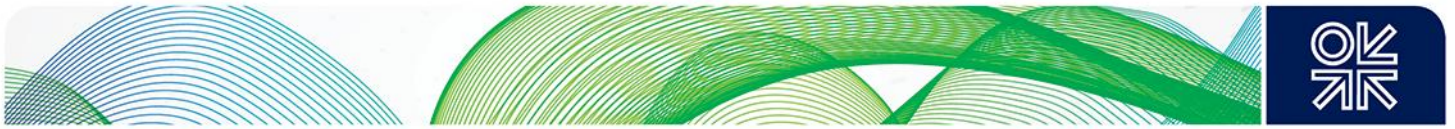
In California, many solar energy projects were developed in the early 2000s under long-term PPAs with utilities like Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E). These PPAs typically featured fixed prices to provide financial stability for the solar developers. As solar technology costs declined rapidly, the market price of solar electricity also decreased (see Figure 6). However, utilities locked into older PPAs continued to pay the higher fixed prices, even as new solar projects were offering electricity at much lower prices.

Figure 6: Utility-scale solar PV PPA prices by region, contract size, and date of execution



Source: Bolinger et al. (2019)

Another example is Germany's Feed-in Tariff (FiT) system which guaranteed renewable energy producers a fixed payment for the electricity they generated over a long-term period, typically 20 years. The payments were set above market prices to encourage investment in renewable energy. Over time, the cost of solar PV had dropped significantly, but many producers were still receiving high FiT rates set years earlier. For instance, although PV systems made up only about 14% of electricity generation from non-hydro renewable sources in Germany in 2010, the total committed payments (discounted over a 20-year period) amounted to approximately €100 billion by 2011, with annual payments representing more than 40% of the total under the Renewable Energy Sources Act (EEG) (Huenteler et al., 2012). As a result, the German government and electricity consumers faced higher costs, paying more for electricity under the FiT scheme than the prevailing market prices. This led to growing concerns about the financial sustainability of the FiT system and ultimately resulted in reforms to reduce FiT rates for new projects.



Profit risk under long-term contracts is bigger for green hydrogen offtakers than for renewable electricity buyers. This is due to a number of factors including the higher volatility in input costs (e.g., electricity), the nascent and uncertain market for green hydrogen, rapid technological advancements, and the potential for significant demand and policy shifts. The technology for producing green hydrogen, particularly electrolysis, is rapidly advancing. As technology improves, production costs are expected to decrease. Furthermore, unlike renewable electricity, which has a relatively well-established market with historical data to guide pricing decisions, green hydrogen lacks extensive market history. On top of that the policy environment surrounding green hydrogen is still evolving. Government incentives, subsidies, electricity market structure and carbon pricing mechanisms could change, affecting the market price for green hydrogen. If policies shift in a way that reduces the cost of green hydrogen production, offtakers who are locked into long-term contracts may not be able to take advantage of prices that result from such policy changes. These issues make it harder for offtakers to accurately assess future price trends, increasing the likelihood of profit risk.

4.3 Market demand

Unlike electricity which has a very established demand, the future demand for hydrogen is subject to significant uncertainty due to a wide range of factors that influence its adoption, market development, and overall viability.

The current high cost of green hydrogen production, primarily due to the cost of renewable electricity and electrolyser technology, creates uncertainty about whether these costs can be reduced sufficiently to make hydrogen competitive with other energy carriers. If cost reductions do not materialise as expected, demand for hydrogen could be lower than anticipated.

While hydrogen is already used in certain industrial processes (e.g., ammonia production, refining), its expansion into other industries (e.g., steelmaking, cement production) depends on its ability to replace existing fuels or feedstocks. The pace and scale of this transition are uncertain. Also, the role of hydrogen in transportation (e.g., fuel cell vehicles, heavy-duty trucking, shipping, aviation) is still being defined. Competing technologies, such as electric vehicles and biofuels, could limit hydrogen's adoption in this sector, creating uncertainty about future demand. Furthermore, hydrogen's role in power generation (as a fuel for turbines or in combined cycle plants) and as a long-term energy storage solution depends on technological developments, cost reductions, and the availability of alternative storage solutions. Uncertainty in these areas contributes to the unpredictability of hydrogen demand.

The development and adoption of alternative technologies (e.g., battery storage, direct electrification) could reduce the need for hydrogen in sectors where it might otherwise have been used. If these alternatives become more cost-effective or technologically superior, demand for hydrogen could stagnate. This is not to say there is no possibility of breakthroughs in hydrogen production, storage, or distribution technology but the timing and likelihood of such breakthroughs are uncertain, making future demand difficult to predict.

The infrastructure for producing, transporting, and storing hydrogen is not yet fully developed. Significant investment is required to build the necessary infrastructure, and if this investment does not occur at the required scale or pace, it could limit the growth of the hydrogen market and, consequently, demand. Furthermore, the ability to integrate hydrogen into existing energy systems (e.g., blending hydrogen with natural gas in pipelines, converting existing fuel infrastructure to hydrogen) is uncertain. If integration proves challenging or costly, it could slow the adoption of hydrogen and reduce demand.

The future demand for hydrogen is also highly dependent on government policies and incentives designed to promote its use. Changes in government priorities, budgets, or political leadership could result in reduced support for hydrogen, leading to lower demand.

In a nutshell, demand for hydrogen is uncertain. In markets where demand is uncertain or potentially limited, fixing the price does not guarantee that all the produced output will be sold. If demand does not grow as expected, investors might not achieve the scale needed to make their projects financially viable, even with a fixed price. Fixed-price contracts without volume guarantees make producer's income variable and dependent on the buyer's needs. If demand is overestimated at the time of entering into a



long-term contract, investors may find themselves producing more than the market needs. This can result in excess supply, storage issues, and potentially lower returns if the surplus cannot be sold or if storage costs become prohibitive. Furthermore, the underutilisation of production capacity can lead to higher per-unit costs and reduce the overall profitability of the investment, as the fixed costs are spread over a smaller production volume. Even worse, if demand fails to grow as projected, assets tied to long-term contracts may become stranded, meaning they cannot be used to their full economic potential. This is particularly concerning in rapidly evolving markets where technology or policy shifts could make certain assets obsolete before they have paid for themselves.

Another point is that in markets characterised by rapid technological change fixed-price contracts do not account for the possibility that newer, cheaper decarbonising technologies could emerge, leading to a shift in market dynamics. If demand shifts towards these newer technologies, existing green hydrogen projects with fixed-price contracts might struggle to maintain market relevance and profitability.

External factors such as shifts in global energy prices, geopolitical tensions, or changes in government policies can significantly alter market dynamics, leading to higher demand uncertainty. This makes long-term contracts more vulnerable to external shocks that could impact demand and, consequently, the financial viability of these contracts. In comparison, renewable electricity has a broader market base, including grid power, distributed generation, and direct use in industrial, commercial, and residential sectors. This diversification reduces the impact of external shocks on demand compared to the more niche and developing market for green hydrogen.

Finally, investors typically use long-term contracts as a way to hedge against price volatility. However, if the primary uncertainty lies in demand rather than price, these contracts do not effectively hedge against the risk of insufficient revenue. In cases of low demand, hedging strategies that focus on price stability offer little protection.

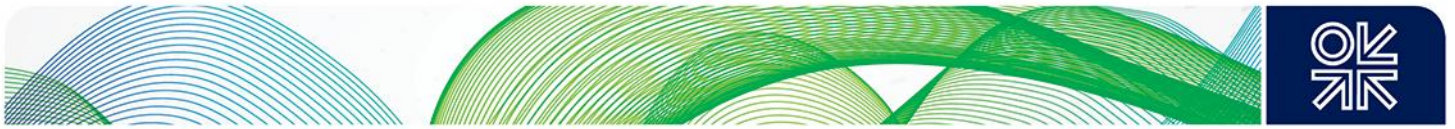
4.4 Unintended consequences

There are also a number of possible unintended consequences when deployment of a nascent energy source and associated infrastructure are incentivised through long term contracts.

First, when the costs of fixed-price contracts for green hydrogen are passed on to consumers, particularly through higher energy bills, this can result in cross-subsidisation or a financial burden exacerbated by potential overcapacity. On one hand, non-hydrogen users may find themselves indirectly funding the hydrogen industry, even though they may not directly benefit from it. On the other hand, in an energy system with limited storage capacity and uncertain demand, there is a risk of overproduction, which drives up the cost of hydrogen production per unit. This situation can lead to higher overall energy costs, especially if the infrastructure is underutilised. If the public perceives these rising costs as unfair or fails to see the tangible benefits of green hydrogen, such as emissions reductions, this could lead to public backlash, potentially eroding support for the broader energy transition.

Second, as fixed-price contracts tend to favour larger, established producers with the resources and infrastructure to meet the criteria for subsidies, this could result in market consolidation where a small number of large players dominate the hydrogen market. While this can create economies of scale, it also risks stifling innovation. Smaller companies, which are often more agile and open to experimenting with alternative or emerging technologies, might be crowded out. This reduction in competition can lead to a less dynamic market, where the incentive to explore innovative green hydrogen production methods diminishes. A market dominated by a few large players may focus on optimising existing processes rather than investing in groundbreaking technologies that could make hydrogen more cost-effective or sustainable in the long run.

Finally, incentivizing hydrogen production through long-term contracts could also inadvertently lead to infrastructure lock-in. If subsidies are tied to specific technologies or production methods (such as blue hydrogen with carbon capture), it may limit the flexibility of the market to adapt to future advancements in green hydrogen technologies. As the market evolves, new technologies, such as more efficient electrolyzers or novel hydrogen production methods, may emerge, but long-term contracts could



discourage switching to these innovations due to sunk costs and the desire to avoid disrupting existing production. This lock-in effect may slow the overall pace of technological progress and reduce the adaptability of the hydrogen sector to future developments.

These are not just theoretical possibilities, there are example of these instances in the history of energy sector.

With regard to financial burden, a historical example can be found in Germany's Renewable Energy Act (EEG) and its feed-in tariff (FiT) system. Introduced in 2000, the EEG mandated that consumers pay a surcharge to fund renewable energy subsidies (Fronzel et al., 2008). This system guaranteed above-market prices for renewable energy producers, such as solar and wind, to drive investment in these sectors. However, this resulted in higher electricity costs for consumers, particularly residential users and small businesses (Fronzel et al., 2010). The financial burden on consumers led to significant public backlash, as the EEG surcharge continued to rise over years. Many viewed this as unfair, believing that ordinary consumers were disproportionately subsidising the renewable energy sector. This backlash eventually led to reforms in the EEG⁵.

An example of overcapacity and financial non-sustainability of subsidies can be seen during the early years of Spain's rapid solar energy expansion in the late 2000s. Spain implemented an ambitious feed-in tariff (FiT) program to promote solar energy production. However, the FiT rates were set too high, and coupled with declining technology costs and the government's failure to adjust to these changes, the program led to an unexpected and uncontrolled surge in solar PV installations in 2007 and 2008 (Del Río and Mir-Artigues, 2014). This surge resulted in a substantial increase in the cost of the program, with solar PV subsidies reaching €2.6 billion per year by 2009, representing about 50% of all renewable energy support despite only accounting for 10% of renewable electricity generation (ibid). As a result, Spain accumulated billions of euros in tariff deficits, as the government was paying far more for electricity production than the market value of the electricity consumed. The government responded with a series of measures to reduce costs, including capacity quotas, tariff reductions, caps on operating hours, and eventually, a complete moratorium on new installations in 2012. Some of these measures, particularly the cap on the duration of FiT payments and the changes to operating hours, were considered retroactive by the solar PV sector, causing significant backlash and damaging investor confidence.

With regard to market concentration and reduced innovation in the energy sector, the experience of the United Kingdom's electricity market during the early years of privatisation in the 1990s provides useful insights. After the privatisation of the UK's electricity sector in 1990, the market quickly became dominated by a few large companies. These companies held substantial market power over both generation and supply, leading to high market concentration (Green, 2006). As the dominant players controlled most of the infrastructure and had secured long-term contracts (Thomas, 2006), there was little incentive for them to innovate or explore new technologies, particularly in the renewable energy space. It wasn't until government intervention in the 2000s, through policies like New Electricity Trading Arrangements (NETA) and the Electricity Market Reform (EMR), that significant innovation began to re-emerge in the UK electricity market. These policies promoted competition and introduced support mechanisms for renewable energy, which helped to break the market concentration and encouraged the development of new technologies such as wind and solar power.

A notable example of infrastructure lock-in in the energy sector is the extensive investment in coal-fired power plants in China and the United States during the 20th and early 21st centuries. In both countries, coal became the dominant energy source for electricity generation due to large reserves and relatively low production costs. Significant infrastructure was built around coal mining, transportation, and power plants, locking both nations into coal-based energy systems. This lock-in created barriers to transitioning to cleaner energy sources, as the sunk costs in coal infrastructure and the economies of scale

⁵ Germany's Renewable Energy Act (EEG) has undergone several reforms since its introduction in 2000. These reforms were driven by a combination of factors, including rising costs, market integration, and evolving EU policies on renewable energy.



associated with coal-fired plants made it financially and politically difficult to shift to alternative energy systems (Erickson et al., 2015).

Even as environmental concerns and the need for decarbonization became more pressing, these coal investments led to resistance to policy changes and slower adoption of renewable energy. The existing coal infrastructure also had long lifespans, which further delayed the transition. This infrastructure lock-in effect underscores how early investments in certain energy systems can create long-term inertia that hinders transitions to more sustainable energy systems.

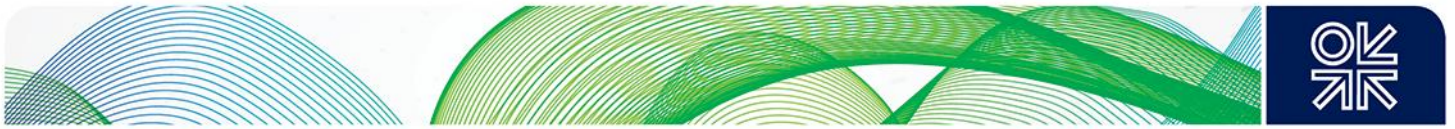
Overall, the above discussion points to a potential paradox between incentive to deploy necessary hydrogen infrastructure and long-term flexibility. While long-term contracts, such as fixed-price agreements, can provide financial stability and drive initial large-scale deployment, they can inadvertently create market rigidity that limits the ability of the sector to adapt to future technological advancements or demand shifts. This rigidity stems from infrastructure lock-in and market concentration, where dominant players benefit from economies of scale and lower costs, but at the expense of reducing diversity and innovation. Over time, the sector may become less agile, less capable of adopting more efficient, cost-effective, or environmentally sustainable technologies, such as future generations of electrolyzers or novel hydrogen production methods. Furthermore, the social equity implications, where certain users disproportionately bear the cost of supporting industries from which they do not directly benefit, can lead to broader economic and political resistance. Thus, while long term contracts are critical to incentivise investment, they risk creating a long-term structural inertia that may undermine the sector's ability to fully evolve, innovate, and democratise its benefits.

5. Conclusions

The comparative analysis of the UK Hydrogen CfD and renewable electricity CfDs reveals several critical insights, particularly in relation to the ability of these contracts to drive cost reductions and manage risk effectively across the two sectors. Renewable electricity projects, such as wind and solar, have benefited immensely from fixed-price, long-term contracts. These contracts have been instrumental in reducing capital costs, as they provide revenue certainty that lowers the cost of capital, enabling large-scale investments and economies of scale. Over the past decade, this approach has led to dramatic reductions in the levelized cost of electricity for renewable energy, making these technologies highly competitive. However, the same cost-reducing effects are less likely to materialise in the green hydrogen sector. Hydrogen production is characterised by high operational costs, largely due to its dependence on electricity as a feedstock, and long-term contracts for hydrogen production may not effectively mitigate these variable costs. While capital investments in electrolysis technology could potentially benefit from such contracts, the fluctuating price of electricity introduces a level of cost unpredictability that long-term, fixed-price agreements for hydrogen production alone may not address.

The allocation of risk between producers and offtakers differs significantly between the two CfDs, reflecting the distinct market environments in which they operate. In the hydrogen sector, producers are exposed to high cost risks due to the volatile nature of electricity prices and the immature state of the supply chain. This contrasts sharply with the renewable electricity sector, where the majority of costs are capital expenditures incurred upfront, allowing for more predictable financial planning. The Hydrogen CfD places a considerable burden on producers to manage these operational costs, which could hinder investment and slowdown the sector's growth. Additionally, offtakers in the hydrogen market face substantial profit risks, given the nascent and uncertain demand for green hydrogen. The rapid pace of technological advancements and the potential for significant policy shifts further exacerbate this risk, making long-term contracts a less stable foundation for planning. In contrast, the renewable electricity CfD offers a more balanced risk allocation, with well-established markets and predictable demand reducing the uncertainties for both producers and offtakers.

The future demand for green hydrogen remains highly uncertain, a stark contrast to the well-established demand for renewable electricity. The hydrogen market is still in its infancy, with its growth dependent on a complex interplay of technological advancements, policy support, and the successful integration of hydrogen into various sectors such as transportation, industry, and power generation. This uncertainty creates significant challenges for fixed-price contracts, which may not provide the security needed to



attract large-scale investment in hydrogen production. There is a real risk that hydrogen producers could face stranded assets if demand does not materialise as expected, leading to financial losses despite the presence of long-term contracts. Renewable electricity, on the other hand, benefits from a diversified and mature market, where the demand for electricity is well understood and stable, providing a solid foundation for long-term investment.

The Hydrogen CfD, while designed to promote the growth of green hydrogen, could inadvertently have adverse effects. While long-term contracts, like fixed-price agreements, offer financial stability and enable large-scale deployment of new technologies, they can also lead to market rigidity. This rigidity results from infrastructure lock-in and market concentration, where dominant players benefit from economies of scale but stifle competition and innovation. As a result, the sector may struggle to adopt newer, more efficient technologies over time. Additionally, the burden of supporting these industries can disproportionately fall on certain users sparking social and political resistance. Although crucial for attracting investment in nascent industries, paradoxically, long-term contracts risk creating structural inertia that could hinder future innovation and equitable growth.

In conclusion, while the hydrogen CfD and renewable electricity CfD share a common goal of promoting low-carbon energy production, their effectiveness is shaped by the distinct characteristics of the markets they serve. The challenges faced by the hydrogen sector, particularly in terms of cost structure, risk allocation, market demand, and potential unintended consequences, suggest the experience of renewable electricity with CfD might not be replicated in green hydrogen. Future research is needed to better understand how CfDs for green hydrogen should be designed or modified to effectively mitigate risks, not only related to hydrogen market price and demand but also to input costs, especially electricity. Without addressing these issues, the full potential of hydrogen CfDs to drive cost reductions and de-risk investment may not be realised.



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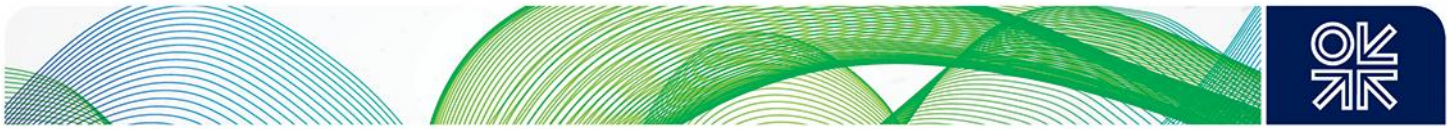
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