WORKING PAPER

MARKET INEFFICIENCIES IN RENEWABLE SUPPORT POLICIES: EVIDENCE FROM OFFSHORE WIND CONTRACTS FOR DIFFERENCE IN GREAT BRITAIN

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Market Inefficiencies in Renewable Support Policies: Evidence from Offshore Wind Contracts for Difference in Great Britain

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Abstract

Inefficient market responses to renewable support schemes can increase costs and undermine decarbonization efforts. We study two-way Contracts for Difference (CfDs), which stabilize generator revenues but may distort generation incentives. Exploiting variation across support schemes and CfD design rules for offshore wind farms in Great Britain, we apply difference-in-differences to hourly unit-level data to provide the first ex-post evidence on CfD-induced inefficiencies in day-ahead and balancing markets. Market-based wind farms reduced output by 69-83% during negative-price hours; CfD-backed units showed a similar reduction when payments were suspended after six or more consecutive negative-price hours. CfDs also distort the balancing market: generators curtail output by 28% less when they receive payments that cover the negative imbalance price; when they must repay, they curtail 19% more when the imbalance price drops below the payment. From 2019–2024, day-ahead market distortions resulted in 2.9 TWh excess generation, costing £176 million in support.

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1 Introduction

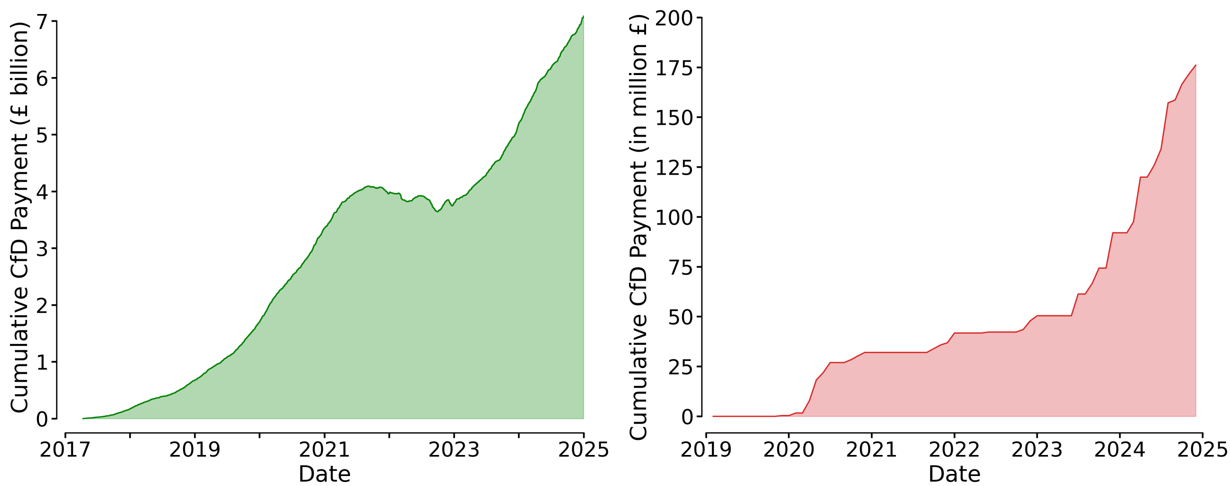
Governments around the world subsidize renewable generation to advance the clean-energy transition and meet climate targets. Yet the design of these renewable support schemes can introduce operational inefficiencies in electricity markets by distorting generators' response to price signals. A leading example is two-way Contracts for Difference (CfDs), which are long-term financial contracts between a government-owned entity and electricity generators. CfDs provide price stability for generators by guaranteeing a fixed "strike price" per MWh of electricity generated. In the standard design, if the market price falls below the strike price, the government pays the difference to the CfD-backed generators; if it rises above, the generators refund the difference. CfDs have been used for wind and solar, but also for nuclear plants (European Commission, 2023), and encourage investment by reducing price risk and lowering financing costs (Đukan and Kitzing, 2023; Beiter et al., 2024).

However, CfDs can give rise to inefficiencies on three levels. First, in the day-ahead (DA) market, CfDs can reduce generators' incentives to respond to price signals and produce when electricity is most needed (Schlecht et al., 2024). Since CfD payments are decoupled from wholesale prices, generators may continue producing even when negative prices indicate they should not (Huntington et al., 2017). Second, CfDs can introduce inefficiencies in the intraday and balancing market because once CfD payments are known to the generators, they consider these payments as an opportunity cost, leading to premature or delayed real-time curtailment decisions relative to what the imbalance price signals. Beyond these short-term effects, CfDs also shape long-term investment choices because the revenue security of long-term contracts influences projects' location and technology choices, favoring lower-cost, less flexible sites and technologies. As the energy transition accelerates, it is crucial to understand how CfDs influence generators' behavior in electricity markets, because these responses ultimately decide whether decarbonization, security of supply, and renewable integration are achieved efficiently. This illustrates a trade-off between market efficiency and investment certainty. Shielding generators from price volatility lowers financing costs and enables capital-intensive investment in renewables. Without such protection, the higher risk premium demanded by investors would raise discount rates and discourage projects. However, too much protection from volatile market prices weakens the role of the price signal, leading to market inefficiencies. While efficiency requires that generators react to volatile market prices, investment security requires generators to be shielded from that volatility. In this paper, we analyze the first two market inefficiencies: those in the DA market and in the intraday/balancing market. For the second, we focus on the balancing market due to data limitations on the intraday market. This is not a major restriction since the distortions are the same in both markets.

We apply our analysis to offshore wind farms in Great Britain (GB), which has been using CfD schemes since its Electricity Market Reform in 2014 and has offshore wind farms generating under CfDs since 2017. Furthermore, Great Britain has had wind farms that were market-based (MB) and wind farms under Renewable Obligation Certificates (ROCs). We study empirically how 65

CfD offshore wind farm units in GB, representing 88.4% of total installed offshore capacity in GB, respond to market signals, including negative-price periods, prolonged negative-price periods (lasting six hours or more), and the imbalance price. In total, the CfD-backed offshore wind farms in our sample received £7.09 billion in support payments between 2017 and 2024, as shown in Figure 1a. Of this, £6.50 billion was received during the studied 2019-2024 period.

To estimate the causal impact of CfD support in the DA market, we apply a two-way fixed effects difference-in-differences approach comparing offshore wind units with different types of support schemes. We find that when DA electricity prices are negative, market-based offshore wind units reduce their output by 69-83% compared to CfD- or ROC-supported units, which continue generating at near full capacity. This continued generation resulted in 2.9 TWh of excess generation, representing 1.29% of total offshore wind generation in Great Britain and -£19 million in market value. For this excess production, the GB government paid £176 million to CfD generators. Figure 1b presents the CfD payments during negative DA prices, showing that they have increased steadily over the sample period. However, generators awarded a CfD in Allocation Round (AR) 2 reduce generation by 77-92% when prices are negative for six or more consecutive hours, in response to the six-hour rule, which suspends CfD payments in such cases. This adjustment saved £15 million in CfD payments or £95,821 per negative-price hour. This is a 8.06% reduction in total CfD payments during negative price hours across all ARs and a 50.65% reduction in CfD payments to AR 2 units.



(a) Total cumulative CfD payments by month

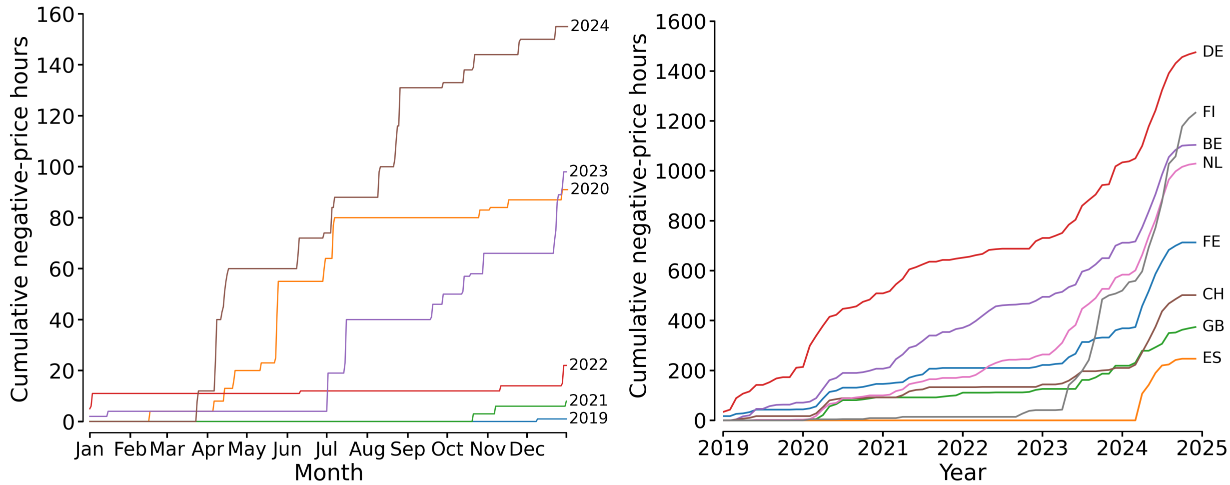
(b) CfD payments during negative DA prices by month

Figure 1. Total cumulative two-way Contract for Difference (CfD) payments for offshore wind generators in Great Britain (panel a) in billion pounds (£) by month (2017-2024) (Source: LCCC (2023d)) and payments during negative day-ahead (DA) prices (panel b) in million £ by month (2019 - 2024). CfD payments are the difference between the strike price and the DA price, multiplied by generation (MWh) (capped at the strike price).

To estimate the effect of CfD support in the balancing market, we employ a one-to-one nearest neighbor matching strategy. Instead of responding directly to the imbalance price -— by producing when prices are positive and curtailing when they are negative -— CfD-backed generators consider their CfD payments as an opportunity cost, using this as the reference point for deciding whether to produce or curtail. When generators need to make CfD repayments to the government and the imbalance price drops below their CfD payment, they decrease their generation capacity factor by 19% compared to generators with the same imbalance price but who receive CfD payments from the government. By curtailing generation, generators avoid the higher CfD repayment and thereby increase their revenues. Conversely, when CfD generators receive CfD payments, they curtail their capacity 27.7% less when imbalance prices are negative compared to generators facing the same imbalance price but who must repay the government. Curtailment only begins when the CfD payment no longer offsets the loss from negative imbalance prices. In both cases, this behavior is strongest when the distance between the imbalance price and the CfD (re)payment increases and financial risk declines.

Our results offer empirical lessons for policymakers that want to balance investment certainty with electricity market efficiency. Both Great Britain and the European Union (EU) have set ambitious offshore wind expansion targets, with CfDs expected to play a key role in achieving these goals (European Commission, 2014; Fabra, 2023). Consequently, the share of renewables operating under CfDs is expected to grow significantly in the coming years and many renewables today are supported by schemes that do not incentivize responding to market prices -— such as ROCs and CfDs. At the same time, negative DA prices are becoming more frequent across EU electricity markets (ACER, 2024). In Great Britain, the number of negative DA prices in 2024 was nearly double that of 2023 and more than seven times than in 2022 (Fig. 2a). At the EU level, negative price hours rose more than twelvefold between 2022 and 2023 (ACER, 2024). Without adjustment to the standard CfD design, this will result in inefficient market behavior -— generators producing when the market signals no need for energy -— and governments paying millions in CfD payments (Fig. 1a). Fortunately, our analysis shows that offshore wind farms are able to change their dispatch when facing market prices. Since offshore wind producers value predictable revenues more than exposure to volatile prices, policymakers will need to decide how to balance price stability with market efficiency in renewable support schemes. Our results suggest that embedding dispatch incentives directly into contract design (e.g. the six-hour rule) is successful in directly discouraging offshore wind farms to overproduce during negative DA prices, yielding savings for the government and more market efficient behavior. While a full suspension of payments for any negative-price hour would maximize market efficiency, it would also reintroduce revenue risk and thus investment uncertainty for investors as their revenue would depend on the frequency of negative prices.

This study contributes to three key areas in the economic literature. First, it adds to the literature on the efficiency implications of renewable support schemes. Prior work has used simulations or equilibrium models to examine how different subsidy designs affect electricity prices, dispatch



(a) Cumulative negative-price hours in Great Britain

(b) Cumulative negative-price hours in Germany, Finland, Belgium, The Netherlands, France, Switzerland, Great-Britain, Spain

Figure 2. Cumulative hours with negative day-ahead prices in Great Britain (GB) by month (panel a) (GB: February 2019 - December 2024) and in Germany (DE), Finland (FI), Belgium (BE), The Netherlands (NL), France (FR), Switzerland (CH), GB, and Spain (ES) by month (panel b) (January 2019 - December 2024). Source DE/FI/BE/NL/FR/CH/ES: ENTSO-E (2025).

incentives and welfare outcomes (e.g., Pahle et al. (2016); Winkler et al. (2016); Reguant (2019); Cook and Lin Lawell (2020); Meus et al. (2021); Veenstra and Mulder (2024)). While these studies provide valuable insights into theoretical trade-offs, there is little empirical evidence on how existing support mechanisms affect real-time operation. Exceptions include Aldy et al. (2023), who exploit the shift from output subsidies to investment subsidies in the United States to show empirically that output-based subsidies better align operating incentives with market signals, and Schmalensee (2016) who uses plant-level output and nodal-price data from multiple Independent System Operators in the United States to document generator's responses to negative-price and high-variability hours. Our paper complements this work by providing the first ex-post, data-driven evaluation of how two-way CfDs affect production decisions in both DA and balancing markets -— quantifying the occurrence, magnitude, and frequency of real-world inefficiencies.

Second, our study contributes to the growing CfD literature. A range of possible CfD inefficiencies have been identified in the literature (e.g., Bunn and Yusupov (2015), Savelli et al. (2022), Veenstra and Mulder (2024)) and multiple CfD design variants have been proposed, such as the six-hour rule, increasing the reference price period to monthly or yearly, or delinking CfD payments from actual generation and tying them instead to forecasts (yardstick-based CfDs) (Newbery, 2023), benchmarks (financial CfDs) (Schlecht et al., 2024), or fixed capacity payments (capacity-based contracts) (Huntington et al., 2017). However, these design variants are often introduced without empirical evidence of the distortions they aim to fix, leaving policymakers to rely on untested theory rather than measured outcomes.

A third area of relevant literature focuses on sequential markets and arbitrage, showing that prices in DA and subsequent markets often fail to converge due to market power and limits to arbitrage (Borenstein et al., 2008; Koichiro and Reguant, 2016; Birge et al., 2018). Our results contribute to this literature by empirically demonstrating how offshore wind farms change their behavior in the balancing market due to CfDs. By linking generators' decisions to contract payments rather than the price signal, CfDs block the usual arbitrage between markets.

The paper is structured as follows. Section 2 provides an overview of the design of CfDs, the potential distortions, their welfare effects, and their implementation in GB. Section 3 describes the data, including the sources, validation process, and key summary statistics. Section 4 outlines the empirical strategy of our analysis. Section 5 discusses the results and section 6 concludes.

2 Contracts for Differences: design and distortions

2.1 Design

A two-way Contract for Difference (CfD) is a long-term contract (typically 10-20 years) between a government-owned entity and a nuclear, dedicated biomass with combined heat and power (CHP), or renewable generator —– such as solar, onshore and offshore wind. CfDs are allocated through competitive auctions in which developers submit bids indicating the minimum strike price they are willing to accept. Contracts are awarded to generators with the lowest bid, until either a predefined budget or volume cap is reached. Once awarded, the generator under a CfD sells the generated electricity on the wholesale market but receives an additional financial settlement from the government-owned entity based on the difference between the agreed strike price and the reference price. In the standard design, the CfD payments for a renewable energy generator i at time t are calculated as follows:

$$\textit{CfD Payment}_{i,t} = (\textit{Strike Price}_{i,t} - \textit{Reference Price}_t) \times \textit{Generation}_{i,t} \tag{1}$$

That is, the CfD payment is computed as the difference between the $\textit{Strike Price}_{i,t}$ and the $\textit{Reference Price}_t$, multiplied by the actual volume of electricity ($\textit{Generation}_{i,t}$) that is generated. The $\textit{Strike Price}_{i,t}$ is generator specific and can be either fixed in nominal terms or adjusted for inflation. The $\textit{Reference Price}_t$ can be either the hourly day-ahead (DA) price or an average over a longer time period, such as daily, monthly, or yearly. When averaged, it is often weighted by the generation profile of the technology. A reference price tied to hourly DA prices insulates generators from short-term market signals. In contrast, using a longer-term average as the reference price tends to improve alignment with DA prices. The hourly reference price is typically floored at zero, making the maximum CfD payment from the government the strike price itself. When averaged, hours with negative prices are treated as zero-price hours. $\textit{Generation}_{i,t}$ can be the actual produced generation by generator i at time t, or a predefined reference generation profile (eurelectric, 2024).

2.2 Distortions

2.2.1 Day-ahead market

In an efficient electricity market, generators produce whenever market prices exceed their short-run marginal costs. Contracts for Difference (CfDs) can distort these incentives in the day-ahead (DA) market, as they guarantee a fixed strike price per MWh of actual generation, irrespective of timing. This design encourages producers to generate continuously, even during periods of oversupply -— a behavior often characterized as "produce and forget". As the CfD payment is equal to the strike price during hours with negative prices, CfD-backed renewable generators bid at prices equal to the negative of their strike price, well below their variable costs (Deng et al., 2014; Prokhorov and Dreisbach, 2022). Such bidding distorts the merit order of curtailment: when CfD-supported renewables with near-zero marginal costs continue to produce at negative prices, while plants with truly negative short-run marginal costs are curtailed instead, resulting in a productive inefficiency.

2.2.2 Intraday and balancing market

After the DA market auction closes, generators commit to producing a specific amount of electricity for each hour of the next day. In real time, their actual generation may differ from this commitment due to technical constraints, market signals, or strategic choices. Any such deviation is settled at the intraday or imbalance price on the intraday or imbalance market. If the deviation helps balance the system -— by generating more during shortages or less during oversupply -— the generator is paid the intraday or imbalance price. If it worsens the imbalance, they must pay that price instead.

However, once the DA price is known, CfD generators know their hourly CfD payment and treat it as an opportunity cost in subsequent markets (Schlecht et al., 2024). This means that the decision to deviate from their committed generation is influenced by the CfD payment rather than the intraday or imbalance price, as they aim to maximize net revenue. This distorts behavior in these markets: generators may curtail too early, when the intraday/imbalance price is still positive, or continue generating during periods of negative intraday/imbalance prices.

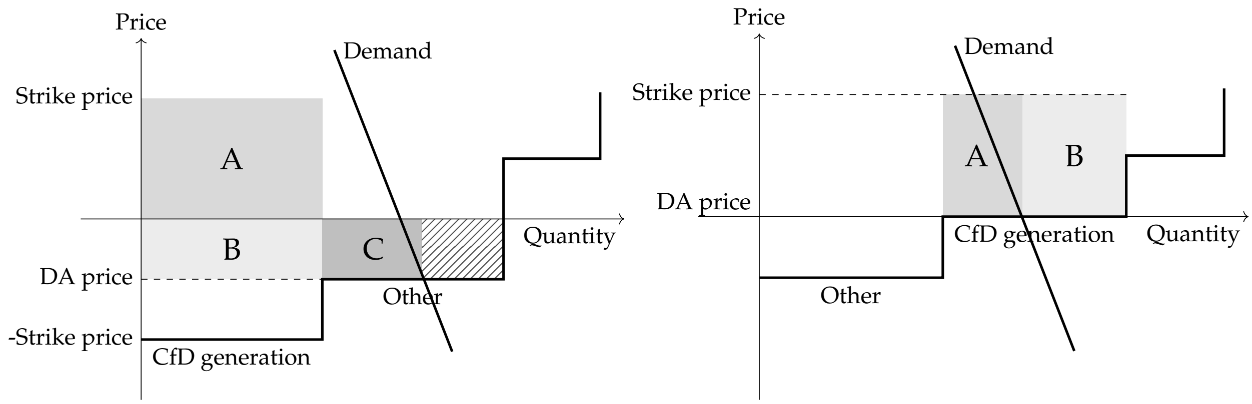
To illustrate this more concretely, consider two cases: one where the DA price exceeds the strike price, and one where it falls below it. First, when the DA price is higher than the strike price, generators know they will need to repay the difference to the government. Once the intraday/imbalance price is below the CfD payment, generators can choose to curtail their real-time generation and pay the intraday/imbalance price for this deviation to their committed generation. This increases the generators' revenue, as the intraday/imbalance price is lower than the CfD payments. Figure A.1a in Appendix A provides an example of this distortion in the balancing market. Such behavior is inefficient, as renewable curtailment at positive imbalance prices requires increased production by non-renewable generation with positive variable costs, such as gas or coal plants (Schlecht et al., 2024).

Second, when the DA price is lower than the strike price, the incentives reverse. In this case, generators are not immediately incentivized to curtail generation when the intraday/imbalance price becomes negative, as they continue to earn revenue from the CfD payment. Instead, they only curtail when the CfD payment is no longer sufficient to offset the negative intraday/imbalance price. This behavior can lead to inefficient generation at prices below their variable costs, while also further reducing already low prices (Newbery, 2023). Figure A.1b in Appendix A illustrates this case for the balancing market.

Even though the intraday and balancing market are subject to the same distortion, they differ in terms of uncertainty and risk. While the intraday market allows generators to adjust their committed generation with predictable intraday prices as they can observe market conditions, the imbalance market occurs in real-time with highly volatile imbalance prices, which are only known after real-time operations. This uncertainty makes imbalance exposure far riskier than intraday trading.

2.3 Welfare effects of CfD payments during hours with negative wholesale prices

CfD payments during hours with negative wholesale prices lead to surplus transfers between participants in the day-ahead (DA) market. Figure 3a illustrates. First, there is a transfer from consumers -— who pay the levies that fund the CfD payments -— to offshore wind farms receiving these payments. The net payment is $A - B$ because generators receive A but need to pay B to produce when the DA price is negative. Second, there is a transfer from other producers with negative-price bids -— e.g., CHP with heat obligations or costly partial curtailment of nuclear plants (Astier and Wolak, 2024) -— to consumers that benefit from lower DA electricity prices (area C).



(a) Welfare effects of CfD payments during hours with negative prices

(b) Welfare effects when there are no more negative-price bids by CfD-backed generators.

Figure 3. Welfare effects of two-way Contracts for Difference (CfDs) payments during hours with negative day-ahead (DA) prices. The stylized supply curve consists of generation under a CfD, other generation with negative-price bids (e.g. nuclear or combined heat and power), and generation with positive bids.

In addition to the transfers, the CfD design gives rise to several inefficiencies. The most immediate effect is a distortion in the merit order of curtailment: CfD generators keep producing at negative prices as long as the DA price remains above the negative of their strike price. This leads to curtailment of plants with truly negative short-run marginal costs while offshore wind with near-zero marginal cost remains in the system. This is indicated by the hatched rectangle in Figure 3a. The total market value of CfD generation during negative-price hours, estimated at about £19 million (see Section 5.1.3), provides an upper bound on the magnitude of this inefficiency, as it reflects the market's valuation of avoiding that excess production. Second, CfD payments to generation at negative wholesale prices increases consumer-funded levies. Because these levies are recovered on a per-kWh basis, they raise retail prices above marginal system cost, distorting electrification decisions, and generating deadweight loss (Borenstein and Bushnell, 2022). Third, in the long term, inefficient prices lead to dynamic misallocation of long-term investment for technologies such as storage and renewables (Lamp and Samano, 2023; Astier and Hatem, 2025).

When CfD-backed generators stop bidding at negative prices, the inefficiency in the merit order of curtailment disappears, as shown in Figure 3b. Negative DA prices can still occur when negative-price generation exceeds net demand (e.g. because of large amounts of price-insensitive residential rooftop solar), but renewable generation with near-zero marginal cost will then be curtailed before curtailment of generation with truly negative short-run marginal costs. However, this raises questions about how to deal with partial curtailment of CfD-supported renewables, as those producing receive CfD payments (area A) while curtailed generation would not (area B). In addition, any fiscal savings from suspending CfD payments at negative prices risk being offset if developers price the added risk into their bids and drive up strike prices in future auctions.

The central policy trade-off is therefore between welfare-enhancing efficiency gains -— more efficient curtailment, potentially lower distortionary levies and less distorted location decisions -— versus the higher risk premia and discount rates that offshore wind developers may require in future auctions, alongside the significant distributional consequences across consumers, CfD-backed producers, and non-CfD generators.

2.4 CfD design in Great Britain

2.4.1 Renewable Obligation Certificates (2002-2017)

Before 2014, Great Britain's main support scheme for large-scale renewables was the Renewables Obligation (RO). Under this scheme, generators receive Renewable Obligation Certificates (ROCs) for each MWh of renewable electricity produced, for up to 20 years. These certificates can be bundled with electricity sales or sold separately through energy trading platforms. Each year, licensed electricity suppliers are required to demonstrate compliance with the RO by submitting a sufficient number of ROCs proportional to their total electricity sales. Suppliers that fail to meet this requirement are obliged to pay a fixed buy-out price for each missing certificate.[1]

[1]Buy-out payments are pooled into a recycle fund and redistributed among suppliers that meet their obligation, in proportion to the number of ROCs they submit (Woodman and Mitchell, 2011). Because suppliers weigh the cost of

For generators, the RO scheme works as a variable feed-in premium, where they earn an extra income on top of the electricity price (Fig. 4a). This gives generators a "produce-and-forget" incentive because curtailment will only occur if the ROC price no longer covers the negative day-ahead (DA) price. On 31 March 2017, the ROC scheme closed to new projects[2]. In 2037, the scheme will end entirely (Department for Business Energy & Industrial Strategy, 2022).

2.4.2 Contracts for Difference (2014-...)

After 2014, Great Britain implemented two-way Contracts for Difference (CfDs) as part of its Electricity Market Reform to further stimulate investments in renewable energy (Department of Energy & Climate Change, 2014). Unlike under the RO scheme, where certificate prices reflected the administratively determined buy-out price, CfD strike prices were set through competitive auctions, known as allocation rounds (ARs), which allow for competition among technologies and help keep prices low. Successful bidders are granted a 15-year contract with the government-owned Low Carbon Contracts Company[3] (LCCC). The strike price is set through a uniform-price auction, where all winners in the same technology group for the relevant delivery year receive the clearing price, defined by the last successful bid before the budget cap is reached. However, each technology has an associated administrative strike price (reserve price), which sets a ceiling on what the government is willing to pay projects. If the clearing price exceeds this cap, the winning projects receive the administrative strike price instead. All strike prices are indexed annually to the consumer price index (CPI) (Garcia et al., 2019). To this date, their have been six ARs. The majority of the CfD portfolio consists of intermittent generators[4], with offshore wind making up 48% of awarded capacity -— 15.4 GW in total, of which 3.9 GW is currently operational.

CfDs in Great Britain are funded by the supplier obligation mechanism, which is a compulsory levy on electricity suppliers. In each quarter, suppliers pay a daily Interim Levy Rate (£/MWh) on eligible demand[5] and an up-front reserve payment (£). At the end of the quarter, payments from the suppliers are compared against the actual CfD costs to ensure suppliers pay exactly what is required (UK Government, 2014). This levy ensures that the LCCC has sufficient funds to meet its payment obligations under the CfD scheme. If the day-ahead (DA) price is lower than the strike price, LCCC covers the difference using funds from the levy. Conversely, if the DA price is higher than the strike price, the generator returns the difference and LCCC reimburses the suppliers. In both cases, the costs or repayments are passed on to end consumers through the per-KWh rate on their electricity bills. As a result, CfDs effectively reduce wholesale price risk for offshore wind

purchasing ROCs against paying the buy-out price and forfeiting the recycle payment, the market price of ROCs is generally close the expected sum of the buy-out price and the recycle value for that year.

[2] For some projects, the deadline was extended to January 2019.

[3] LCCC is owned by the Secretary of State for Business, Energy and Industrial Strategy (BEIS) and is responsible for signing CfD contracts with generators and managing the financial transactions associated with the CfD scheme.

[4] Technologies in GB's CfD portfolio AR 1 - AR 6: onshore wind, offshore wind, floating offshore wind, remote island wind, solar PV, tidal stream, advanced conversion technologies, energy from waste with combined heat and power (CHP), dedicated biomass with CHP and, geothermal.

[5] Energy-intensive industries and green excluded electricity (up to March 2023) are exempt.

investors and consumers. The CfD payments in Great Britain are calculated according to Equation 1, with as reference price the GB hourly DA price, referred to as the intermittent market reference price (IMRP). Payments are based on each project's actual metered output (in MWh) for every hour. CfD payments are settled hourly and disbursed on a daily basis (Fig. 4b).

2.4.3 Pre-Contracts for Difference or Investment Contracts (2014)

To ease the transition from ROCs to CfDs, Great Britain initially awarded Investment Contracts (IVCs) to renewable projects in 2014. These IVCs were "pre-CfDs" or "early CfDs" where the strike price was determined administratively (Fig. 4b). During this transitional phase, eight projects were supported, including five offshore wind projects and three biomass conversion projects.

2.4.4 Adjustments to Contracts for Difference (2017-2022)

Great Britain's CfD support scheme has gradually introduced safeguards to limit distortions from negative DA prices. For all CfDs, regardless of the AR, payments are capped to the strike price when the DA price drops below zero (EMRS, 2025). In addition, for the support contracts awarded in AR 2 and AR 3, GB implemented the "six-hour rule" rule, which states that when prices are negative for six or more consecutive hours, no CfD payment from LCCC will be made from the first negative hour (Fig. 4c). This policy was introduced to align with the EU requirement to limit support when prices are negative for new support schemes from 2016 onward (European Commission, 2014).[6] Its aim was to increase renewable generators' exposure to market price signals, discouraging unnecessary generation during negative prices and thereby protecting the levy payer. From AR 4 onward, the policy was tightened further -— no CfD payments are made for any hour with a negative DA price, regardless of duration. As of 2024 (the end of our sample), only offshore wind generators from IVCs, AR 1, and AR 2 are operational.

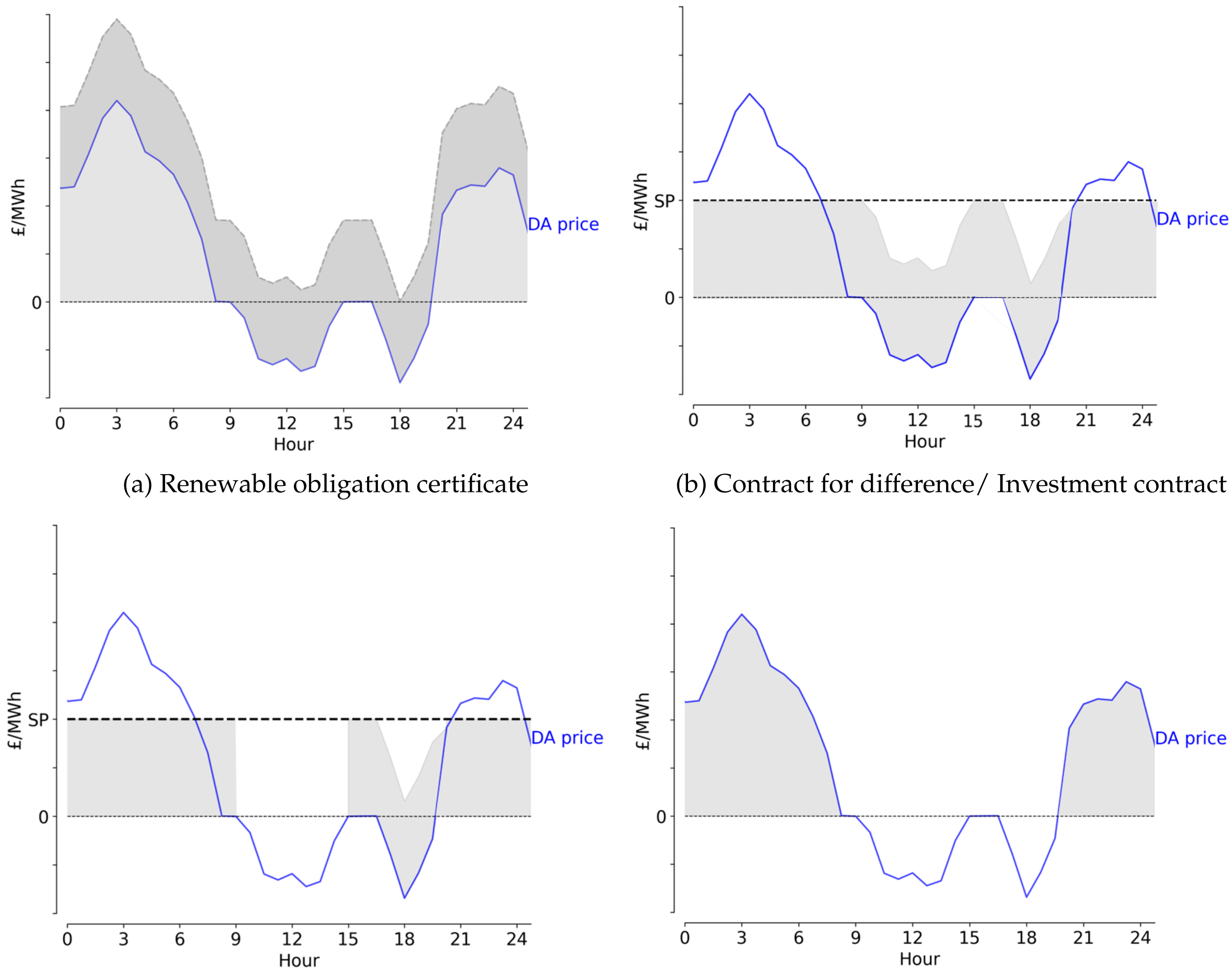
2.4.5 Market-Based

Some offshore wind farms in Great Britain were Market-Based (MB) or merchant -— meaning they were fully exposed to market prices without receiving any subsidy -— before activating their CfD (Fig. 4d). These are projects that had already secured a CfD but chose to delay the official start date. After being awarded a CfD and once operational conditions are met, generators are given a target commissioning window of 12 months[7], within which they can choose when to start the contract. The 15-year CfD begins once the generator submits the start date notice to LCCC, allowing them to time their entry into the support scheme strategically (BEIS, 2017). However,

[6] Under the EU State Aid Guidelines, member states must suspend support during negative-price hours for new support schemes from 2016 onward, but they retain discretion over the precise conditions -— such as applying the suspension only after a certain amount of consecutive hours (European Commission, 2014). In 2022, this rule was extended to existing schemes, which were due to align by end-2023 (European Commission, 2022). The EU further envisages a gradual phase-out of distortive subsidies by 2030 (European Commission, 2014).

[7] A target commissioning window exists to accommodate uncertainty in construction, testing/commissioning, and grid connection.

from AR 5 onward this possibility to delay the start date has been limited as the LCCC can issue an Unilateral Commercial Operations Notice (UCON) once at least 80% of commissioning tests are complete, thereby fixing the contract start unilaterally (Department for Energy Security & Net Zero, 2023). Figure B.1 in Appendix B represents a timeline of the different support schemes leading up to CfDs and the different ARs in GB.



(a) Renewable obligation certificate

(b) Contract for difference/ Investment contract

(c) Contract for difference with six-hour rule

(d) Market-based

Figure 4. Revenue (£/MWh) under different support schemes in Great-Britain: Renewable Obligation Certificates (ROC revenue in dark gray) (panel a), two-way Contract for Difference or Investment Contracts (panel b), two-way Contract for Difference with the six-hour rule (panel c), and Market-Based (panel d). Day-ahead (DA) price in blue. SP denotes the strike price.

3 Data

In this section, we introduce the datasets used in this study. These datasets include day-ahead (DA) price data, imbalance price data, and actual generation data from offshore wind farms in Great Britain (GB). We combine these datasets to create an hourly unit-level panel dataset, covering the period from 2019 to 2024. Subsequently, we provide descriptive statistics to summarize the key characteristics of the dataset.

Day-ahead price data. Day-ahead (DA) price data is obtained from the Low Carbon Contracts Company (LCCC) (LCCC, 2023d). This dataset contains hourly data of the actual Intermittent Market Reference Price (IMRP) in £/MWh from 30 June 2016 to 31 December 2024. The IMRP refers to the GB DA hourly price provided by the Intermittent Day Ahead Indices (EPEX and N2EX) and is computed as a weighted average of these Indices.

Imbalance price data. Half-hourly imbalance price data is obtained from Elexon[8] (£/MWh) (Elexon BMRS, 2024b). To align with the hourly resolution of DA prices, we convert the imbalance data to hourly values by averaging the two half-hourly prices within each hour.

Generation data. By the end of 2024, there were 17 offshore wind projects that won a Contract for Difference (CfD). Nine of these projects are live and fully operating (Department for Business, Energy & Industrial Strategy, 2023). Five of these projects received a CfD through an Investment Contract (IVC), one through Allocation Round 1 (AR 1), and three through Allocation Round 2 (AR 2). Other operating offshore wind farms (30 projects) in GB receive Renewable Obligation Certificates (ROCs) as subsidy mechanism (Ofgem, 2024a). We link the CfD and ROC projects to their Balancing Mechanism Unit (BMU) IDs (LCCC, 2023c; Elexon BMRS, n.d.b).[9] For all nine CfD projects this link could be made, however, for the 30 ROC projects only 23 projects could be linked to a unit ID. For each unit, either receiving CfDs or ROCs, we obtain unit-level half-hourly generation data (£/MWh) from Elexon (Elexon BMRS, n.d.a) from February 2019 to December 2024. We convert this to hourly data (£/MWh) by summing per unit the generation of two half hours of the same hour, to comply with the hourly DA prices. Generation data are available for all nine CfD projects (14 units), and for 20 ROC projects (41 units). We further add data on capacity (MW), commissioning year, and region (Scotland, England, or Wales) (Ofgem, 2024a; 4C Offshore, n.d.). Capacity data for CfD units is obtained from LCCC (LCCC, 2023b). For ROC units we first obtain capacity data from Elexon (Elexon BMRS, 2023), and where unavailable, we proxy capacity by the unit's maximum generation in our sample.[10] In terms of Market-Based (MB) projects, we restrict the sample to projects for which the commissioning year was prior to the date of their

[8]Elexon is a non-profit company funded by electricity market participants, responsible for managing the balancing and settlement code (BSC). The BSC sets out the rules and commercial arrangements that enable trading within the electricity balancing market. (Elexon BMRS, 2024a).

[9]According to Elexon, "Balancing Mechanism (BM) Units are used as units of trade within the Balancing Mechanism. Each BM Unit accounts for a collection of plant and/or apparatus, and is considered the smallest grouping that can be independently controlled." https://www.elexon.co.uk/bsc/operational/balancing-mechanism-units/. Throughout the paper, "unit" refers to a BMU.

[10]We compared the maximum generation as a proxy for installed capacity to the units for which we know installed capacity in our data, and those two closely align.

first CfD payment and for which online news articles confirm a market-based period (two projects linked to six units). After applying the restrictions, we are left with 29 projects linked to 65 units (Appendix C Table C.1 presents an overview of the data selection process). For the CfD units, we include the strike price (£/MWh), the AR and the date of first CfD payments (first settlement date), obtained from LCCC (LCCC, 2023a). We validate our generation data by comparing it with daily LCCC generation data (Appendix D).

Table 1: Descriptive statistics of offshore wind units by support mechanisms in Great Britain.

	CfD			ROC	MB
	IVC	AR 1	AR 2		
Projects	5	1	3	20	2
Units	14	2	8	41	6
Observations	690,413	84,792	105,506	2,124,697	83,235
Total capacity (MW)	3,122	650	2,891	6,053	2,270
Average capacity per unit (MW)	223	325	361	148	378
	(127)	(3)	(65)	(62)	(68)
Average generation capacity factor per unit (%)	0.44	0.48	0.33	0.39	0.37
	(0.03)	(0.06)	(0.09)	(0.07)	(0.13)
Average strike price per unit (£/MWh)	180	148	82		
	(6)	(2)	(8)		
Commissioning year (Minimum - Maximum)	2017-2021	2019	2021-2022	2006-2021	2022
Region					
England	0.80	1.00	0.67	0.74	0.50
Scotland	0.20	0.00	0.33	0.22	0.50
Wales	0.00	0.00	0.00	0.04	0.00

Notes: Unit of observation: unit-by-hourly generation. A unit is the smallest grouping of wind turbines that can be independently controlled. Support schemes are either Renewable Obligation Certificates (ROCs), Market-Based (MB), or two-way contract for difference (CfD) obtained via either Investment Contracts (IVCs), in Allocation Round 1 (AR 1), or in Allocation Round 2 (AR 2). Contracts for MB units also appear under AR 2, since those units are ultimately supported through AR 2. The average generation capacity factor is calculated as the hourly generation (MWh) divided by installed capacity (MW). The commissioning year is shown as a range and corresponds to the earliest and latest commissioning years observed within each support scheme. Standard errors in parentheses.

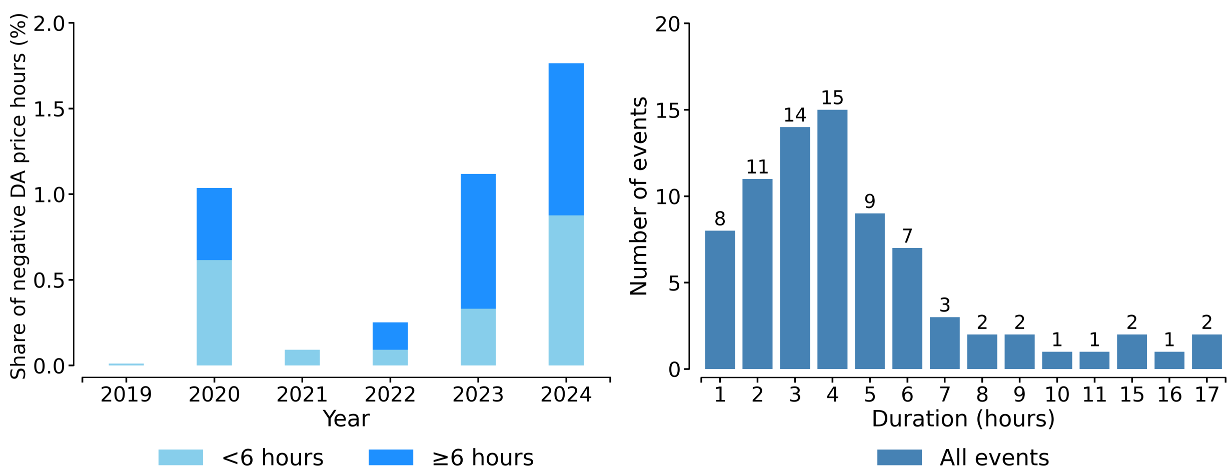
Table 1 reports the descriptive statistics for offshore wind units under the different support mechanisms. In total we have 3,088,643 observations at the hourly unit-level, covering February 2019 to December 2024. During that period, the IVC and the ROC scheme are the most represented, with 14 units related to five projects and 41 units related to 20 projects, while AR 1 has the lowest amount of units and projects (two units related to one project). This is expected, since ROCs were the sole support scheme between 2002 and 2016. By contrast the CfD ARs are more recent, beginning with AR 1 in 2014-2015, where one offshore project was awarded, and AR 2 in 2017, where three offshore projects won the auction. The average installed capacity per unit increases slightly across IVC (223 MW), AR 1 (325 MW), AR 2 (361 MW), and MB units (378 MW), while the installed capacity of ROC units is less than half that (148 MW). The average generation capacity factor per unit ranges from 0.33 (AR 2) to 0.48 (AR 1). Strike prices show a declining trend across ARs (IVC: 180 £/MWh, AR 1: 148 £/MWh, AR 2: 82 £/MWh).

4 Empirical strategy

4.1 Day-ahead market

Our identification strategy exploits a unique policy environment with multiple coexisting subsidy schemes: Renewable Obligation Certificates (ROCs), early Contracts for Difference (CfDs) obtained through Investment Contracts (IVCs), CfDs in Allocation Round 1 (AR 1), and later CfDs in Allocation Round 2 (AR 2) with a built-in "six-hour rule". We also include market-based (MB) generators that operated without subsidy support before activating a CfD. This policy variation offers a natural experiment to test whether subsidy design influences generator behavior. We focus on how offshore wind units adjust output during negative price periods, and in particular during events lasting six or more consecutive hours.

Between 2019 and 2024, we identify 78 negative price events, defined as consecutive periods of negative day-ahead (DA) prices, with durations ranging from one to 17 hours (Fig. 5b). Among these, 21 events lasted six hours or longer (Fig. 5a). For each negative price event, we construct an event window covering the 12 hours preceding and the 12 hours following the negative price event, and as a robustness check, we also test alternative windows of six and 24 hours.



(a) Share of negative DA price hours per year

(b) Negative DA price event durations

Figure 5. Share of negative day-ahead (DA) price hours per year (%), broken down by event duration (< 6 hours vs. ≥ 6 hours) (panel a) and distribution of negative DA price event durations (panel b) in Great Britain (2019 - 2024). An event is defined as a sequence of consecutive hours with negative DA prices.

We analyze all negative price events in general and long negative price events (≥ 6 hours) separately, using a two-way fixed effects difference-in-differences (DiD) approach (Imbens and Wooldridge, 2007), where treatment is unit-specific, and the "shock" -— negative prices (of six hours or longer) -— occurs repeatedly across time and varies in duration. We estimate the following model:

$$
\begin{aligned}
y_{i,t} = \beta_0 + \beta_1 \text{Treated}_i &+ \beta_2 \text{NegPriceEvent}_t \\
&+ \beta_3 (\text{Treated}_i \cdot \text{NegPriceEvent}_t) + \alpha_i + \gamma_t + \epsilon_{i,t}
\end{aligned} \tag{2}
$$

where $y_{i,t}$ represents the dependent variable of interest, i.e. the ratio of actual generation (MWh) in hour t to the average generation (MWh) in the periods before and after the event for unit i.[11] $Treated_i$ is a dummy equal to 1 for the treated units, and 0 for the control group(s). $NegPriceEvent_t$ equals 1 if hour t falls within a negative price event of interest, and 0 otherwise. β_0 is a constant representing the baseline level of the dependent variable. β_1, β_2, β_3 are estimated coefficients, with β_3 being the coefficient of interest, capturing the causal effect of the treatment — the average treatment effect on the treated (ATT). α_i are unit fixed effects, controlling for differences between units such as location or turbine type, γ_t are date $\times$ hour fixed effects, which absorb any hour-specific shocks common to all units, such as national demand or weather conditions. $\epsilon_{i,t}$ is the error term.

The average generation in the periods before and after each event serves as a benchmark for the unit's potential output during negative-price hours. The estimated coefficients therefore measure the percentage change in actual generation relative to the counterfactual of generation during hours of non-negative prices right around the event. Appendix E reports results using an alternative normalization, where generation (MWh) is divided by installed capacity (MW). In that specification, coefficients represent percentage-point changes relative to rated capacity. Because offshore wind farms rarely operate at full capacity, the regression constant drops from one to roughly 0.7, indicating that units in our sample produced about 70% of their rated capacity in the hours surrounding negative-price events.

We estimate Equation (2) on two separate samples. First, we examine how market-based (MB) units respond to negative prices, using all 25 negative-price events between 1 May 2022 and 27 March 2024, when MB units were operational. MB units are treated, while subsidized units (ROCs, IVCs, and AR 1) serve as controls. Because MB units are fully exposed to DA prices, they are expected to curtail production once prices turn negative. In contrast, subsidized units receive per-MWh support payments that offset negative wholesale prices, eliminating the financial incentive to reduce output.[12] Second, we analyze how AR 2 units respond to extended negative-price events lasting six hours or longer, restricting the sample to 18 such events between 30 December 2021 and 31 December 2024. In this specification, AR 2 units constitute the treated group and are compared to IVC, AR 1, and ROC units. We pool all negative-price events and estimate a unit-hour-weighted average treatment effect across events, allowing events with more treated units or longer events to weight more in the estimation.

[11] We winsorize the dependent variable of ROC units at the 99th percentile to reduce the influence of extreme outliers.

[12] For ROC units, the average buy-out ROC price (Ofgem, 2024b) is large enough to cover the most negative DA price observed in our dataset, implying no incentive to curtail in those hours. We use the buy-out price as a proxy for the ROC price due to data limitations.

To assess the validity of the parallel trends assumption underlying our DiD approach, we estimate an event-study specification (Appendix F). When comparing MB units with the control group(s) (IVC, AR 1, and ROC) across all negative-price events (Fig. F.1a; Appendix F), the estimated coefficients are close to zero, indicating the absence of pre-trends. This supports the parallel trends assumption and the validity of the DiD design (Lechner, 2011). For the long negative-price events ($\geq$ 6 hours) (Fig. F.2; Appendix F), we likewise find no significant pre-trends when comparing AR 2 units with ROC, AR 1, and IVC units.

4.2 Balancing market

To investigate whether offshore wind farms in Great Britain treat their CfD (re)payment as an opportunity cost in their response to the imbalance price, we exploit quasi-experimental variation in the relationship between the day-ahead (DA) price, strike price, and imbalance price. When the DA price is above the strike price, CfD generators must repay the difference; when it is below, they receive a top-up payment. This difference (i.e. the CfD (re)payment) can change their incentive to curtail. Figure 6 describes the balancing market, with on the x-axis the imbalance price. When the imbalance price is positive (i.e. to the right of zero), the system is short in energy, so generators should not curtail but those who are able to increase generation should. When the imbalance price is negative (i.e. to the left of zero), the system is long and has too much energy. As a generator you can help to restore balance on the energy market by curtailing generation. By helping the market in the correct direction, generators receive the imbalance price. By adding to the imbalance, generators pay the imbalance price. However, as explained earlier, the CfD payment can distort generators' response to imbalance prices. We test whether CfD-backed units adjust output inconsistently with imbalance prices -— starting curtailing already at positive imbalance prices when repayments are due (DA price > strike price) and only at negative imbalance prices when the received payments (DA price < strike price) no longer cover the negative imbalance price.

Imbalance price > 0. When the DA price exceeds the strike price, CfD generators know that they must return the difference to the government. This creates an incentive to curtail as soon as the imbalance price falls below that refund. In that case, the imbalance price paid for the deviation from their committed generation is lower than the CfD repayment, increasing net revenues. To capture this behavior, we divide the CfD unit-hour observations in our dataset into two groups that face the same positive imbalance price but have different curtailment incentives:

$$\text{Imbalance price} > 0 \quad \begin{cases} H_{\text{treated}} = 1, & \text{if (DA price} - \text{Strike price)} > \text{Imbalance price} \\ H_{\text{control}} = 1, & \text{if (DA price} - \text{Strike price)} < 0 \end{cases} \tag{3}$$

The treated group ($H_{treated} = 1$, 1.02% of the CfD observations) consists of observations where the difference between the DA price and the strike price is positive (DA > strike price) and exceeds the positive imbalance price. These are the observations in the dark gray area in Figure 6a. The control group ($H_{control} = 1$, 78.47% of the CfD observations) are observations where the imbalance price is also positive but the generator receives CfD payments from the government (DA $<$ strike price), represented by the light gray area in Figure 6b. While generators in the control group face the same imbalance price as the treated group, their incentive regarding curtailment differs.

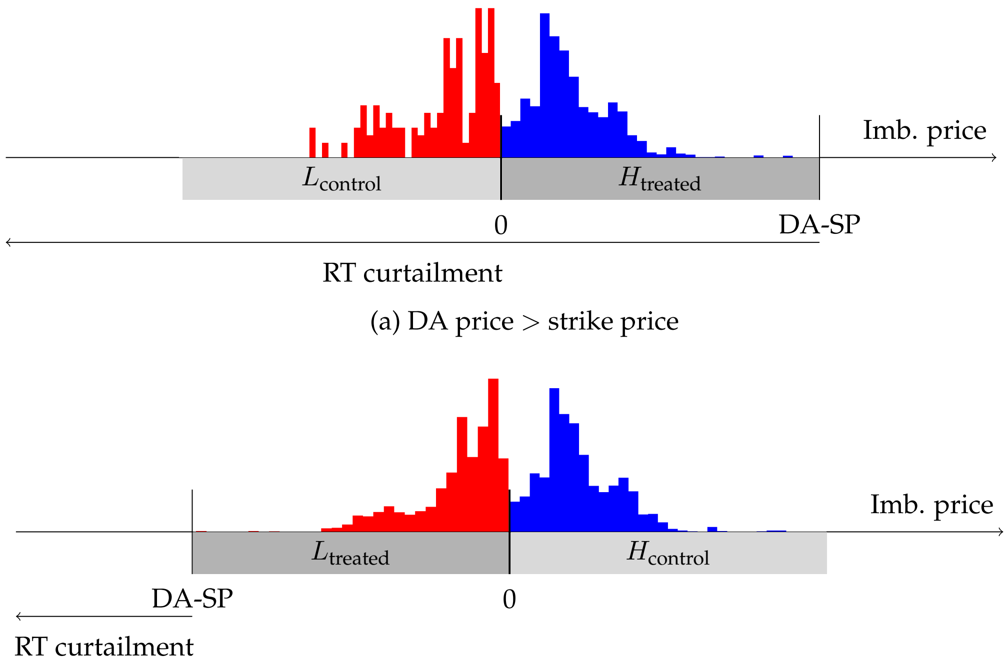
Imbalance price $<$ 0. When generators receive CfD payments from the government (DA price $<$ strike price), generators have the incentive to continue generating at negative imbalance prices as long as the CfD payment offsets the imbalance price. To analyze this behavior, we separate our CfD unit-hour observations in our dataset accordingly:

$$\text{Imbalance price} < 0 \quad \begin{cases} L_{\text{treated}} = 1, & \text{if (DA price} - \text{Strike price)} < \text{Imbalance price} \\ L_{\text{control}} = 1, & \text{if (DA price} - \text{Strike price)} > 0 \end{cases} \tag{4}$$

The treated group ($L_{treated} = 1$, 2.82% of the CfD observations) consists of observations where the difference between the DA price and the strike price covers the negative imbalance price, shown as the dark gray area in Figure 6b. The control group ($L_{control} = 1$, 0.06% of CfD observations) includes cases with the same negative imbalance price, but where generators make CfD repayments to the government (DA price $>$ strike price), shown as the light gray area in Figure 6a. This contrast between treated and control observations allows us to empirically estimate how CfD payments influence curtailment decisions.

For both cases, we use one-to-one nearest neighbor (NN) matching with and without replacement to match each treated observation with a control observation with approximately the same imbalance price.[13] Matching without replacement uses each control observation only once, reducing the risk of overfitting, whereas matching with replacement allows controls to be reused, which is useful when few comparable controls are available (Stuart, 2010) -— as occurs when the imbalance price is below zero. In the case of NN matching with replacement, we use matching weights in all post-matching analyses to account for multiple reuse of control units. Summary statistics before and after matching (Table 2) show that, for both positive and negative imbalance prices, the two matching methods lead to almost equal average imbalance prices between treated and control groups. The standardized mean difference (SMD) is well below the 0.25 threshold in both cases, indicating well balanced groups. Figure 6 illustrates the post-matching imbalance price histograms for treated and control groups. Additional descriptive statistics before matching and alternative matching approaches are described in Appendix G.

[13] The distance between treated and control units is the Mahalanobis distance on the imbalance price, i.e. $|\text{Imbalance price}_{treated} - \text{Imbalance price}_{control}| / \,\text{sd}(\text{Imbalance price})$. The imbalance price histograms for each treated and control group before matching can be found in Appendix G Figure G.1a when imbalance price $>$ 0 and Figure G.2a when imbalance price $<$ 0.



(a) DA price > strike price

(b) DA price < strike price

Figure 6. Distortions in the balancing market due to two-way Contracts for Difference. Panel a represents the imbalance price (Imb. price) histogram of unit-hours with the day-ahead (DA) price above the strike price (SP). Panel b represents the imbalance price histogram of unit-hours with the DA price below the SP. H_{treated} in panel a are unit-hours with a positive imbalance price below (DA price - SP), while L_{control} are unit-hours with a negative imbalance price. The treated group (L_{treated}) in panel b are unit-hours with a negative imbalance price smaller in magnitude than (DA price - SP), while H_{control} are unit-hours with a positive imbalance price. Arrows indicate the direction of real-time (RT) curtailment incentives. The histograms are shown post-matching, with 1:1 nearest neighbor (NN) without replacement for the H_{treated}-H_{control} pairs (capped at an imbalance price of 750 £/MWh) and with replacement for the L_{treated}-L_{control} (capped at -150 £/MWh). The histograms are plotted separately for each of the four groups.

Table 2: Balance of imbalance prices between treated and control groups before and after one-to-one nearest neighbor matching (with and without replacement).

	Imbalance price > 0				Imbalance price < 0			
Matching method	H_{treated} (1)	H_{control} (2)	t-stat (3)	SMD (4)	L_{treated} (5)	L_{control} (6)	t-stat (7)	SMD (8)
Before matching								
Observations	8,962	691,011			24,864	559		
Imbalance price (£)	164.17	75.24	66.28	0.91	-23.40	-30.63	8.16	0.34
	(126.86)	(54.75)			(21.59)	(20.71)		
NN without replacement								
Observations	8,962	8,962			559	559		
Imbalance price (£)	164.17	163.72	6.96	0.01	-26.73	-30.63	6.31	0.18
	(126.86)	(126.40)			(24.35)	(20.71)		
NN with replacement								
Observations	8,962	2,026			24,864	186		
Effective sample size	8,962	672			24,864	80		
Imbalance price (£/MWh)	164.19	164.19	-0.01	0.00	-23.40	-23.30	-0.05	-0.01
	(126.86)	(127.17)			(21.59)	(21.17)		

Notes: Unit of observation: unit-by-hour generation (MWh). The matching methods employed include: 1:1 nearest neighbor (NN) without replacement and 1:1 NN with replacement (using weights for the controls to account for reuse). Effective sample size accounts for the reuse of control units and reports the number of independent observations that the weighted control group is equivalent to. In columns (1)-(4), H_{treated} consists of unit-hours where the (day-ahead (DA) price > strike price) < imbalance price, and H_{control} consists of unit-hours where the DA price < strike price. In columns (5)-(8), L_{treated} consists of unit-hours where the DA price < strike price < imbalance price, L_{control} consists of unit-hours where the DA price > strike price. Both groups are restricted to hours with a negative imbalance price. Standard deviations in parentheses. The reported t-statistic is a paired t-test on within-pair differences for NN without replacement, and a weighted Welch t-test for NN with replacement. The Standardized Mean Difference (SMD) estimates the covariate balance between the treated and control group and is calculated as the difference in treated and control means divided by the pooled standard deviation (after matching with replacement it is computed using matching weights). Well balanced: SMD < 0.1, moderate imbalance 0.1 < SMD < 0.25, large imbalance: SMD > 0.25 (Stuart, 2010). Analysis period: 17 May 2021 - 31 December 2024.

We estimate the following regression model to determine the effect of treatment on generation output:

$$y_{i,t} = \beta_0 + \beta_1 \text{Treated}_{i,t} + \epsilon_{i,t} \tag{5}$$

where $y_{i,t}$ is generation (MWh) divided by installed capacity (MW) for unit i at time t (i.e., generation capacity factor). Treated$_{i,t}$ is a dummy equal to 1 if unit i in hour t is in the treated group -— either H_{treated} ((DA price > strike price) > positive imbalance price) or L_{treated} ((DA price < strike price) < negative imbalance price) -— and 0 if unit i in hour t is in the control group – either H_{control} (DA price < strike price, and positive imbalance price) or L_{control} (DA price > strike price, and negative imbalance price). $\epsilon_{i,t}$ is the error term and β_0 is a constant. β_1 captures the average treatment effect on the treated (ATT) (i.e. the difference in generation between treated and control units after matching).

To examine whether treatment effects vary by the difference in magnitude between the imbalance price and the CfD (re)payments, we extend the baseline model (Eg. 5) by replacing the binary treatment variable Treated$_{i,t}$ with a continuous treatment intensity variable (Treated intensity). The treatment intensity captures the financial incentive to deviate from committed generation: the larger the distance between the imbalance price and the CfD (re)payment, the greater the potential financial gain and the lower the risk, since the imbalance price is less likely to exceed the CfD payment and reduce revenues. For example in the case of positive imbalance prices, when the CfD repayment is £50/MWh and the imbalance price is low (e.g. £1/MWh), the treatment intensity is £49/MWh, creating a strong incentive to reduce generation. Conversely, when the imbalance price is £49/MWh the treatment intensity is low as the distance between the repayment and the imbalance price is small (£1/MWh), making arbitrage financially unattractive.

Unlike the DA price, which is fixed and known ex ante, the real-time imbalance price remains uncertain until the final settlement. Generators must therefor forecast whether the imbalance price will be positive or negative and the magnitude. Generators would prefer a larger imbalance price as small magnitudes carry substantial risk: a small revision in the final settlement can flip the sign, turning a receive in payment into an unexpected charge.

5 Results

5.1 Day-ahead market

5.1.1 Market-based offshore wind farms

Table 3 shows the impact of 25 negative day-ahead (DA) price events -— of any duration -— on marked-based (MB) offshore wind farms' generation, obtained from the Difference-in-Differences (DiD) model (Eq. 2). Columns (1)–(3) compare MB units with the pooled control units subsidized by either Investment Contracts (IVCs), Allocation Round (AR 1), or Renewable Obligation Certificates (ROCs) across three different event windows (six, 12, and 24 hours). Columns (4)–(6) provide pairwise comparisons -— MB vs. AR 1, MB vs. IVCs, and MB vs. ROCs -— for the 12-hour event window. The dependent variable is the ratio of a unit's actual average generation (MWh) in hour t to its average generation (MWh) before and after the negative price event (i.e. potential generation). Across columns (1)-(3), $MB \cdot NegPriceEvent$ is negative and highly statistically significant, ranging from -0.693 to -0.828, indicating that MB units generate 70-83% less during negative price events than their potential generation output. Columns (4)-(6) indicate that the size of reduction in generation varies somewhat across different control groups, but are all highly significant. These results are consistent with the fact that MB units are exposed to market prices, which gives them a strong incentive to reduce generation during periods of negative DA prices. In contrast, subsidized units keep producing because they receive a stable revenue regardless of the market price. The results are robust across all three event windows (Table H.1 Appendix H). Appendix E Table E.1 re-estimates the model using generation (MWh) normalized by installed capacity (MW) as an alternative dependent variable. Results indicate that MB units reduce output by 30-35 percentage points compared to the pooled control group who operates at 67-74% of installed capacity, during negative prices.

Table 3: Impact of all negative day-ahead price events on generation of Marked-Based offshore wind farms in Great Britain (2022-05-01 - 2024-03-27).

	Control group					
	AR 1 + IVC + ROC			AR 1	IVC	ROC
	(1)	(2)	(3)	(4)	(5)	(6)
MB · NegPriceEvent	-0.693^{***}	-0.744^{***}	-0.828^{***}	-0.772^{***}	-0.597^{***}	-0.792^{***}
	(0.0.069)	(0.076)	(0.085)	(0.069)	(0.105)	(0.072)
Fixed-effects						
Time FE	Yes	Yes	Yes	Yes	Yes	Yes
Unit FE	Yes	Yes	Yes	Yes	Yes	Yes
Window (hours)	6	12	24	12	12	12
Negative price events	25	25	25	25	25	25
Units	63	63	63	8	20	47
Constant	0.989	1.001	1.009	1.012	0.975	1.010
	(0.002)	(0.001)	(0.001)	(0.010)	(0.005)	(0.002)
Observations	22,748	34,999	57,212	3,536	10,524	25,859

Notes: Unit of observation: unit-by-hourly generation. The dependent variable is the ratio of actual generation (MWh) in hour t to the average generation (MWh) in the periods before and after the negative price event (NegPriceEvent). An event is defined as a sequence of consecutive hours with negative day-ahead prices. The event window in hours represents the number of hours before and after the event (either six, 12, or 24 hours). The control group includes units under the support schemes: Investment Contract (IVCs) and Allocation Round 1 (AR 1), which are under the two-way Contract for Difference (CfD) scheme, as well as Renewable Obligation Certificates (ROCs). The treated group includes market-based (MB) units. Analysis period: 1 May 2022 - 27 March 2024. Standard errors in parentheses, clustered at the unit level. $^{*}p < 0.1$, $^{**}p < 0.05$, $^{***}p < 0.01$.

5.1.2 Offshore wind farms under the six-hour rule

Table 4 reports the impact of the six-hour rule on AR 2 offshore wind farms' generation, obtained from the DiD estimates (Eq. 2). Columns (1)–(3) compare AR 2 units with the pooled control units (AR 1, IVC, and ROC) using event windows of six, 12, and 24 hours, respectively. Columns (4)–(6) provide pairwise comparisons -— AR 2 vs. AR 1, AR 2 vs. IVCs, and AR 2 vs. ROCs -— for the 12-hour event window. The dependent variable is the ratio of a unit's actual average generation (MWh) in hour t to its average generation (MWh) before and after the negative price event (i.e. potential generation). Across columns (1)–(3), AR 2 units curtail 77–92 % relative to the pooled controls during negative price events lasting six hours or longer. This level of curtailment is similar to but somewhat higher than the curtailment response of the MB units (Table 3). Columns (4)–(6) compare AR 2 units separately with AR 1, IVC, and ROC units. The results mirror those in columns (1)–(3): AR 2 units significantly reduce generation during prolonged negative DA price events relative to each control group. The size of the reduction varies, ranging from 62.7% (AR 2 vs. IVC units) to 89.5% (AR 2 vs. ROC units). These findings remain robust when the event window is changed to six or 24 hours (Table H.2 Appendix H). Appendix E Table E.2 reports estimates based on generation (MWh) normalized by installed capacity (MW). The results indicate that AR 2 units generate 41-45 percentage points less than the pooled control group, who operate at 66-73% of installed capacity, during negative price events.

Full curtailment is difficult to achieve for several reasons, which helps explain why the observed reduction in generation does not reach zero. First, shutting down an entire wind farm in real time is technically challenging due to wind variability, turbine-specific behavior, and park-level control limitations (Tong, 2010). Second, generators may be required to maintain a minimum output to provide reactive-power support, and contractual terms can even restrict curtailment during certain periods or limit the total amount allowed over a given time frame. Finally, complete shutdowns can increase turbine wear and tear (Orlando et al., 2021) and delay ramp-up when prices turn positive again, making operators weight these costs against potential financial gains. Together, these factors explain why generation drops sharply during prolonged negative price events but rarely all the way to zero.

Figure 7 illustrates two negative price events: one on 24 December 2023 lasting 10 hours, and another on 22 December 2023 lasting 5 hours. During the negative price event of 10 hours, the six-hour rule is triggered for AR 2 units (Fig. 7a). This makes them decrease generation significantly, while AR 1 and ROC units keep generation output relatively stable. IVC units reduce generation output slightly.[14] In contrast, during the shorter five-hour negative-price event, the six-hour rule is not triggered, AR 2 units do not react to the negative prices and continue producing electricity (Fig. 7b). This figure is in line with the results in Table 4.

[14]The 19 other negative DA-price events lasting six hours or longer are shown in Appendix I.

Table 4: Impact of the six-hour rule -— which excludes support payments during negative price events with six or more consecutive hours of negative day-ahead prices -— on two-way Contracts for Difference (Allocation Round 2 units) offshore wind farms' generation in Great Britain (2021-12-30 - 2024-12-31).

	Control group					
	AR 1 + IVC + ROC			AR 1	IVC	ROC
	(1)	(2)	(3)	(4)	(5)	(6)
AR 2 · NegPriceEvent	-0.769^{***}	-0.827^{***}	-0.918	-0.849^{***}	-0.627^{***}	-0.895^{***}
	(0.064)	(0.070)	(0.076)	(0.046)	(0.105)	(0.066)
Fixed-effects (FE)						
Time FE	Yes	Yes	Yes	Yes	Yes	Yes
Unit FE	Yes	Yes	Yes	Yes	Yes	Yes
Window (hours)	6	12	24	12	12	12
Negative price events	18	18	18	18	18	18
Units	65	65	65	10	22	49
Constant	0.993	1.008	1.022	1.026	0.954	1.027
	(0.002)	(0.002)	(0.001)	(0.010)	(0.008)	(0.002)
Observations	22,161	33,573	55,810	3,321	10,227	24,961

Notes: Unit of observation: unit-by-hourly generation. The dependent variable is the ratio of actual generation (MWh) in hour t to the average generation (MWh) in the periods before and after the negative price event (NegPriceEvent) for unit i. An event is defined as a sequence of consecutive hours with negative day-ahead (DA) prices, lasting six hours or longer. The window in hours represents the number of hours before and after the event (either six or 12). Support schemes include Investment Contracts (IVCs), Allocation Round 1 (AR 1), and Allocation Round 2 (AR 2), which are under the two-way Contract for Difference (CfD) scheme, as well as Renewable Obligation Certificates (ROCs). The control group in columns (1)-(3) are units under AR 1, IVC, or ROCs, in column (4) units under AR 1, column (5) units under IVC, and in column (6) units under ROC. The treated group in each column are units under AR 2. For the offshore wind farms under AR 2, Great Britain implemented the six-hour rule policy, which states that when prices are negative for six or more consecutive hours, no CfD payment from the government will be made from the first hour with a negative DA price. Analysis period in columns (1)-(6): 30 December 2021 - 31 December 2024. Standard errors in parentheses, clustered at the unit level. $^{*}p < 0.1$, $^{**}p < 0.05$, $^{***}p < 0.01$.

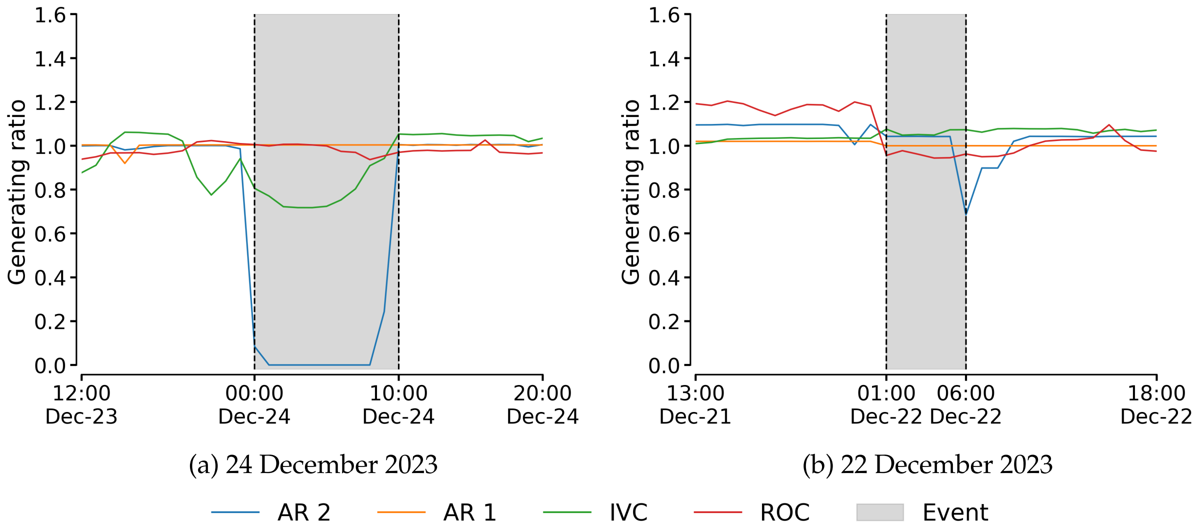


Figure 7. Illustration of two negative day-ahead (DA) price events for offshore wind units in Great Britain, supported by either Renewable Obligation Certificates (ROCs), or two-way Contract for Difference (CfD) obtained via either Investment Contracts (IVCs), in Allocation Round 1 (AR 1), or in Allocation Round 2 (AR 2). An event is defined as a sequence of consecutive hours with negative DA prices. Panel (a) presents the DA price event on 2023-12-24 (00:00-06:00), triggering the six-hour rule for AR 2 units that suspends support payments during events with six or more consecutive hours of negative (DA) prices. Panels (b) presents the negative DA price event in 2023-12-22 (01:00-05:00). The generation ratio is the ratio of actual generation (MWh) during a negative price event hour to the average generation (MWh) in the periods before and after the event.

5.1.3 Generation and CfD payments during negative day-ahead price hours

In this section, we examine how the findings of Section 5.1.1 and 5.1.2 translate into the amount of electricity still generated during negative prices and the corresponding payments made by the government to CfD generators for this excess generation. Table 5 provides a breakdown per support scheme. Between February 2019 and December 2024, a total of 375 negative DA price hours occurred. Despite market prices being below zero during these hours, offshore wind farms in our sample generated 2.9 TWh of electricity combined, representing 1.29% of their total generation and -£19 million in market value. The excess generation capacity factor, which represents the ratio of excess generation to capacity during negative price hours, shows that CfD units not subject to the six-hour rule (IVCs and AR 1) continue to generate almost at full capacity (0.76 and 0.83), while AR 2 units reduce generation capacity significantly (0.51). The lower generation capacity of AR 2 units reflects the six-hour rule, which suspends payments during negative-price events lasting six hours or longer. However, AR 2 units generate more than MB units (0.21) because they continue producing during shorter negative price events, to which the six-hour rule does not apply. Across all support schemes, CfD payments from the government during negative price hours totaled over £176 million -— although they only represent a small amount in total revenues of generators (AR 2: 1.35%; AR 1: 1.36%; IVC: 1.15%). When averaged per unit and per negative price hour, AR 1 units receive the most (£35,547), followed by IVC units (£25,598), while AR 2 units received substantially less due to the six-hour rule (£6,640). To quantify the exact impact of the six-hour rule, we estimate the avoided subsidy for AR 2 units during prolonged negative-price events of six hours or more by comparing actual generation to expected generation, calculated as the average generation in the 12 hours before and after each event. The avoided subsidy is then computed as the difference in generation multiplied by the strike price minus the negative DA price. This results in approximately £15 million (£95,821 per negative hour) in avoided CfD payments to AR 2 units, cutting negative-price payments by 8.06% overall and by 50.65% for AR 2 units. This illustrates the substantial effect of the six-hour rule. Even though suspending payments during negative prices reduces government spending and increases market efficiency, it also reduces revenues for generators.

In Table 6 we examine the impact of tightening the negative price rule from the six-hour rule to shorter durations (five to one hour) on generation behavior and subsidy payments for AR 2 units between 2019 and 2024. Under the six-hour rule, AR 2 units reduced their generation on average by 84% (Section 5.1.2 Table 4). This led to 113.05 GWh less generation, which saved the government £15 million in CfD support payments. Introducing a five-hour rule would have triggered curtailment one hour earlier, assuming AR 2 units would also have reduced their generation in this extra hour by 84%, this would have resulted, on top of the six-hour rule, in an additional 104 GWh of excess generation avoided and £5.50 million in further CfD savings (totals: 217 GWh and £20.93 million). If one would have introduced the one-hour rule, 310 GWh of excess generation would have been avoided and 30.46 million in CfD payments would have been saved compared to no rule. In terms of market value, the six-hour rule gained £933 thousand in market value.

Table 5: Excess generation and two-way Contract for Difference payments during negative day-ahead price hours -— of any duration -— by offshore wind support schemes in Great Britain (2019-2024).

	CfD			ROC	MB	Total
	IVC	AR 1	AR 2			
Number of negative hours	375	375	283	375	121	375
Actual generation during negative prices						
Excess generation (GWh)	713	171	233	1,703	53	2,874
% of scheme's generation	1.09	1.31	1.86	1.42	0.47	1.29
Excess/capacity per unit and negative hour	0.76	0.83	0.51	0.76	0.21	0.66
Market value (£k)	-4,250	-1,284	-789	-12,290	-339	-18,951
CfD payments during negative prices						
CfD payments (£m)	134	27	15			176
CfD payments per unit and negative hour (£k)	25.6	35.5	6.6			67.8
Avoided subsidy (£m)			15			15

Notes: Unit of observation: offshore wind unit-by-hourly generation. All metrics are first computed at the month-support scheme level, and then aggregated by support scheme (IVC: Investment Contract (two-sided Contract for Difference (CfD)), AR 1: Allocation Round 1 (CfD), AR 2: Allocation Round 2 (CfD), ROCs: Renewable Obligation Certificates, and MB: market-based). Excess generation (GWh) is defined as actual generation during negative day-ahead (DA) prices. The percentage (%) of scheme's generation is the ratio of excess generation to total generation for that support scheme. Average excess/capacity per unit and negative hour is computed as actual generation (MWh) divided by capacity (MW) during negative price hours, averaged per unit and per negative price hour. The market value (£k) is the excess generation times the DA price. CfD payments during negative prices (£m) are the difference between the strike price and DA price, multiplied by actual generation during negative DA price hours (capped at the strike price). The CfD payment per unit and per negative hour (£k) is defined as the CfD payments divided by the the number of units times the number of negative price hours. Avoided subsidy (£m) is estimated only for units who obtained a CfD in AR 2, during prolonged negative-price events ($\geq$ 6 hours), as the expected generation times the strike-minus-DA price gap (capped at the strike price), with the expected generation as the average generation in the 12 hours before and after the event. An event is defined as a sequence of consecutive hours with negative DA prices.

Restricting the six-hour rule to a one-hour rule would have an added market value gain of £662 million, totaling to £1,594 in market value saved compared to no rule. However, restricting the negative-price rule to a lower hour brings loss of revenue for generators. Compared to a situation without any rules for negative prices, the six-hour rule reduces revenue by 1.39%. Restricting to a one-hour rule reduces revenue by 1.31 percentage points extra compared to the six-hour rule reduction, leading to 2.74% in total revenue reduction.

Table 6: Impact of stricter negative-price rules on generation, two-way Contract for Difference payments, market value, and revenue for Allocation Round 2 units (2021-05-17-2024-12-31).

Rule (hours)	Excess generation avoided (GWh)		CfD savings (£m)		Market value gain (£k)		Revenue reduction for generators (%)	
	Added	Total	Added	Total	Added	Total	Added	Total
6	113	113	15.43	15.43	933	933	1.39	1.39
5	104	217	5.50	20.93	401	1,334	0.49	1.88
4	36	253	3.75	24.68	139	1,473	0.34	2.22
3	32	285	3.30	27.98	71	1,544	0.30	2.52
2	20	305	2.00	29.98	48	1,592	0.18	2.70
1	5	310	0.48	30.46	3	1,595	0.04	2.74

Notes: Unit of observation: offshore wind unit-by-hourly generation. Rule (hours) indicates the minimum duration threshold for two-way Contract for Difference (CfD) payment suspension: once negative prices persist for at least this many consecutive hours, CfD payments are suspended for all hours within this negative-price event. Added columns report the incremental change when moving from one rule to the next. Total columns show the cumulative change compared with having no rule. Excess generation avoided (GWh) is the difference between actual generation and counterfactual generation under the given rule, compared to the previous rule. For counterfactual generation, we assume that generation reduces by 84%, as estimated under the six-hour rule for windows of six, 12, and 24 hours for Allocation Round 2 (AR 2) units. For the six-hour rule, the counterfactual generation is the average generation in the 12 hours before and after the negative-price event. CfD savings (million £) indicates the savings in CfD payments due to counterfactual generation levels, relative to the rule one hour before. CfD payments are the difference between the strike price and day-ahead (DA) price, multiplied by actual or counterfactual generation (capped at the strike price). Market value gain (thousand £) indicates the gain in DA market value resulting from counterfactual generation levels, relative to the rule one hour before. Revenue reduction for generators (%) is the loss in revenue under each rule relative to the rule one hour before. Analysis period: 17 May 2021 - 31 December 2024.

Even though Great Britain will suspend payments entirely during any negative DA-price hour from AR 4 onward, generators operating under earlier ARs with no such rule will continue to generate during all negative price periods and thus receive CfD payments. In addition, many AR 3 generators expected to become operational in the coming years will remain subject to only the six-hour rule (5,466 MW). Since 73.1% of negative-price events between 2019 and 2024 lasted less than six hours, those CfD generators will continue to receive CfD payments and produce unnecessary electricity during short negative-price events. This could result, on average, in an extra of £3.40 million per year in CfD payments during negative prices[15].

[15]Estimated using AR 2 generation data for 2021-05-17 - 2024-12-31 during hours with negative DA prices. Payments were calculated using the average AR 3 strike price (£40.63/MWh) and scaled to the total planned AR 3 capacity of

5.2 Balancing market

Table 7 presents the results on possible balancing market distortions caused by two-way Contract for Difference (CfD) offshore wind generators. First, when the imbalance price is above zero (columns (1)-(2) and (5)-(6)), and second, when the imbalance price is below zero (columns (3)-(4) and (7)-(8)). The average treatment effect on the treated is estimated in columns (1), (3), (5) and (7) (Eq. 5), while the treatment intensity -— defined as the difference between the CfD (re)payment and the imbalance price -— is estimated in columns (2), (4), (6) and (8). Columns (1)-(4) present the results of one-to-one nearest neighbor (NN) matching without replacement, while columns (5)-(8) show the results of one-to-one NN matching with replacement. The dependent variable is the generation capacity factor, defined as the ratio of generation (MWh) to installed capacity (MW).

5.2.1 Imbalance price above zero

When the day-ahead (DA) price exceeds the strike price, CfD units have to return the difference to the government for each MWh produced. However, as soon a the imbalance price drops below this repayment, CfD generators can increase their revenue by curtailing generation and buying back shortfalls at the lower imbalance price. Column (1) shows that CfD generators facing this arbitrage opportunity reduce their generation capacity by 19.0% compared to control units with the same imbalance price but a different incentive (DA price $<$ strike price), even when the market signals a need for electricity. This strategic curtailment could lead to upward pressure on imbalance prices and reduced market efficiency.

Column (2) indicates how the treatment effect varies with the difference in magnitude between the imbalance price and the CfD repayment (DA price - strike price), i.e., the treatment intensity. When the treatment intensity is low, the imbalance price lies close to the CfD repayment, reflecting higher risk and less financial benefit, while a high treatment intensity indicates a large distance between the two, reflecting lower risk and higher financial benefit. The coefficient on treatment intensity ($H_{treated}$ intensity) indicates that for each additional £1/MWh increase in the price distance between the imbalance price and the CfD repayment, treated units reduce their output by 0.033 percentage points. At treatment intensity levels of £50-100/MWh, this translates to reductions of 1.7-3.3 percentage points relative to the control group baseline. Appendix J Figure J.1a confirms this relationship. The results are robust to alternative matching methods; columns (5)-(6) reports estimates using NN with replacement. Additional estimates using other matching methods are provided in Appendix K, Table K.1.

5.2.2 Imbalance price below zero

If the CfD payment covers the negative imbalance price, generators show a significantly higher generation capacity factor of 27.7% compared to the control units, which face the same imbalance

5,466 MW. The estimate assumes unchanged DA prices and negative-hour frequency in the future.

Table 7: Balancing market distortion of two-way Contracts for Difference on generation of offshore wind units in Great Britain.

	NN without replacement				NN with replacement			
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Imbalance price > 0								
$H_{treated}$	-0.190^{***}				-0.151^{***}			
	(0.025)				(0.008)			
$H_{treated}$ intensity		-0.000331^{***}				-0.00212^{***}		
		(0.000)				(0.000)		
Imbalance price < 0								
$L_{treated}$			0.277^{***}				0.203^{***}	
			(0.064)				(0.024)	
$L_{treated}$ intensity				0.002294^{***}				0.001105^{***}
				(0.001)				(0.000)
Constant	0.468	0.393	0.462	0.478	0.429	0.327	0.469	
	(0.012)	(0.019)	(0.064)	(0.059)	(0.007)	(0.025)	(0.024)	()
N treated observations	8,962	8,962	559	559	8,962	8,962	24,865	
N control observations	8,962	8,962	559	559	2,026	2,026	186	

Notes: Unit of observation: unit-by-hourly generation (MWh). The matching methods employed include: 1:1 nearest neighbor (NN) without replacement (columns (1)-(4)) and NN with replacement (columns (5)-(6)). Included offshore wind farm units are units who obtained a two-way Contract for Difference (CfD) either via Investment Contracts, in Allocation Round 1 or in Allocation Round 2. The dependent variable is generation (MWh) divided by installed capacity (MW). $H_{treated}$ are observations with (day-ahead (DA) price > strike price) > the positive imbalance price. $L_{treated}$ are observations with (DA price < strike price) < the negative imbalance price. The intensity measures the effect of the distance between the CfD (re)payment and the imbalance price. Standard errors in parentheses, clustered on matched group and unit level for NN without replacement and on unit level for NN with replacement. *$p < 0.1$, **$p < 0.05$, $^{***}p < 0.01$. Analysis period: 17 May 2021 - 31 December 2024.

price but make repayments (DA price > strike price) to the government (column (3)). This suggests that rather than curtailing generation when imbalance prices are negative, CfD units only curtail if the CfD payment no longer covers the negative imbalance price. By disregarding balancing price signals and prioritizing the CfD payment, CfD generators contribute to inefficient price formation in the market. This behavior could lead to even lower imbalance prices as they may be willing to produce at prices below their variable costs.

Column (4) indicates how the treatment effect varies with the price difference between the imbalance price and the CfD payment (DA price - strike price), i.e., the treatment intensity. The $L_{treatment}$ intensity coefficient shows that each additional £1/MWh increase in the gap between the imbalance price and the CfD payment is associated with 0.0023 percentage point increase in output for treated units. Appendix J Figure J.1b illustrates this positive relationship. The results are robust to alternative matching methods (NN with replacement (columns (7)-(8)) and other matching methods (Appendix K, Table K.2)).

6 Conclusion

This study provides empirical evidence of the impact of two-way Contract for Difference (CfD) subsidy schemes on the market behavior of 65 offshore wind farm units in Great Britain (GB) using a panel dataset from 2019 to 2024. We examine two markets where inefficiencies can occur; the day-ahead (DA) market and the balancing market. Our results show that production-based support of renewables makes generators unresponsive to market signals. This led to 2.7 TWh of production during negative DA prices between 2019 and 2024, representing 1.36% of total generation and -£19 million in market value. For this excess production, the GB government paid £176 million to CfD generators. Fortunately, we find that market-based units and AR 2 units under the six-hour rule reduce their generation by around 70-92% when exposed to negative DA prices – despite technical, contractual, and wear-and-tear constraints that could prevent large reductions. The six-hour rule led to a saving of £15 million in CfD payments, cutting negative-price payments by 50.65% for AR 2 units. In the balancing market, CfD generators use their CfD payment as an opportunity cost, distorting the market: generators curtail output by 27.7% less when they receive payments that cover the negative imbalance price, and they curtail by 19.0% more when the imbalance price drops below the payment. When the treatment intensity increases, generators react more strongly as potential financial benefits increase.

Our research highlights that policymakers should carefully make the trade-off between improving market efficiency and maintaining price and revenue stability, particularly as negative prices become increasingly frequent across Europe. Several European countries have already adopted such measures in their newest CfD auctions, e.g. prohibiting negative bids in the DA market (e.g. Ireland), suspending CfD payments after six hours of negative prices (e.g. Great Britain, Hungary, Italy), suspending CfD payments entirely during any negative DA-price hour (e.g. Denmark, France, Poland, Portugal), using a capability-based scheme with a monthly reference price that treats any negative-price hour as a zero-price hour (e.g. Belgium) (Kitzing et al., 2024), or proposals to add hours where CfD payments are suspended to the end of the contract term to preserve overall revenue certainty for investors (e.g. the Netherlands) (Moerenhout et al., 2024). The design principle is to expose output to prices while providing some level of revenue insurance over time, balancing efficient dispatch with investment risk.

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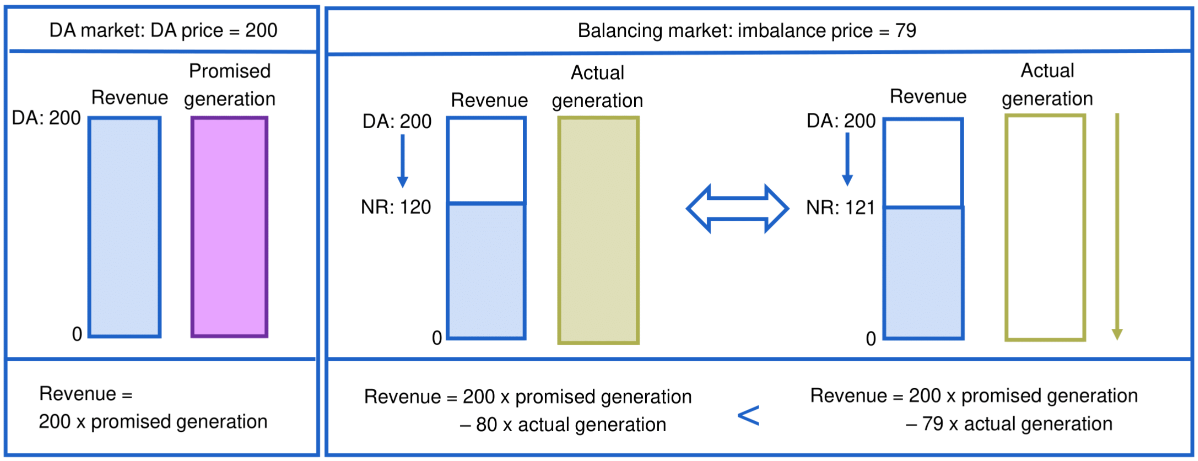
Appendix A Balancing market distortion examples

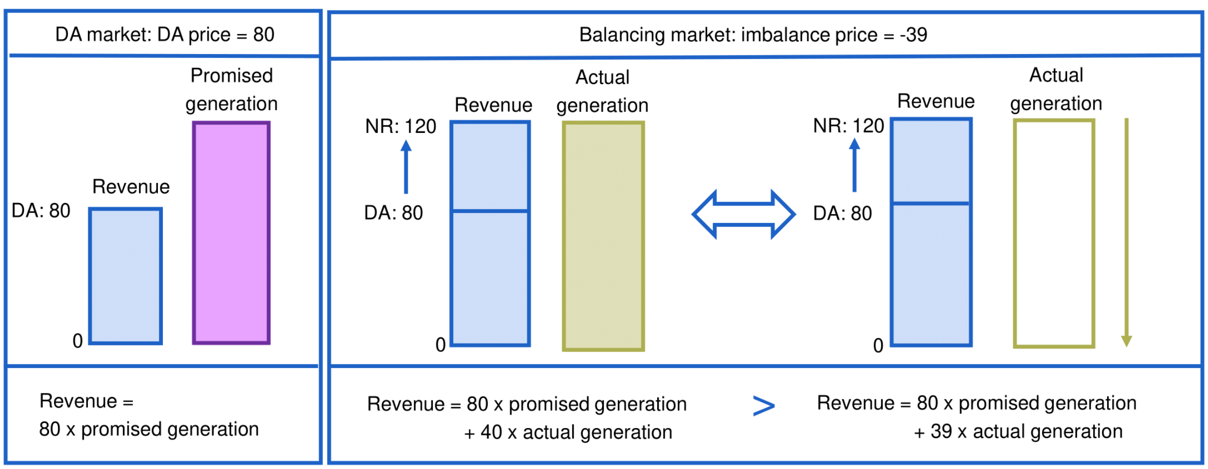
Figure A.1 shows two examples of the distortions in the balancing market due to Contracts for Difference (CfDs). The first one when the imbalance price is positive (Fig. 6a) and the second one when the imbalance price is negative (Fig. 6b). In both examples, the generators has a strike price (SP) of £120/MWh.

Imbalance price > 0 In the day-ahead (DA) market the promised generation is sold at £200/MWh while the SP is £120/MWh. Under the CfD, the generator must pay back £80/MWh to the government if their committed generation would be equal to their actual generation. This results in a net revenue (NR) of £120/MWh. However, when the imbalance price turns out to be £79/MWh, which is £1 less than the difference between the DA price and the SP, the generator would have a higher NR if he would curtail generation in real time, even though the system is short of supply. This is because the generator would not need to repay the difference to the government because he has 0 actual generation, and he only needs to pay the imbalance price for being out of balance.

Imbalance price < 0 In the DA market the promised generation is sold at £8O/MWh, while the SP is £120/MWh. Under the CfD, the generation would receive an extra £40/MWh from the government. In real time, the imbalance price of -£39/MWh signals an oversupplied system and thus signals to generators to curtail output and receive £39/MWh. However, a CfD generator would not comply since he would earn less than the £40/MWh he would receive from the CfD payment. That is, the generator keeps producing as long as the CfD payment covers the negative imbalance price.



(a) Imbalance price > 0



(b) Imbalance price < 0

Figure A.1. Examples of the distortion in the balancing market due to two-way Contracts for Difference (CfD). In both examples the offshore wind generator has a strike price of £120/MWh. Panel (a) shows the balancing distortion when the imbalance price is positive (£79/MWh) and the day-ahead (DA) price is £200/MWh. Panel (b) shows the balancing distortion when the imbalance price is negative (£-39/MWh) and the DA price is £80/MWh. NR: net revenue.

Appendix B Timeline of the different support schemes in Great Britain

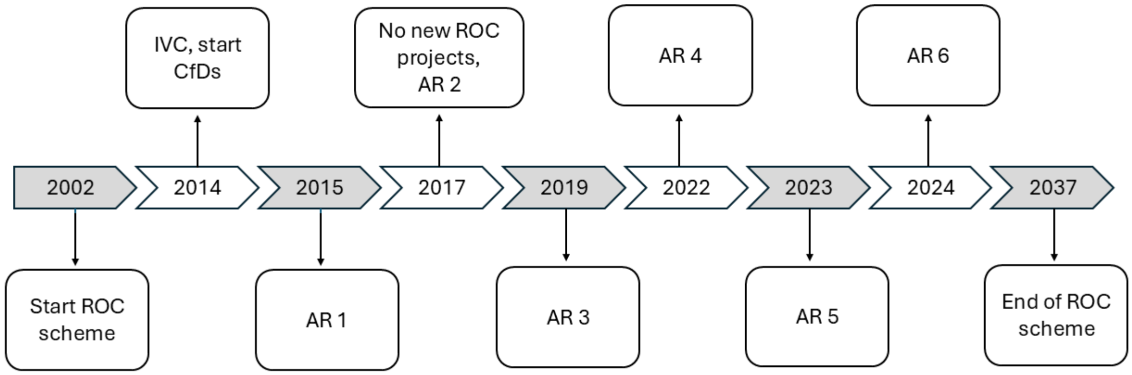


Figure B.1. Timeline of the different support schemes in Great Britain; Renewable Obligation Certificates (ROC), Investment Contracts (IVC), and Contracts for Difference (CfDs) (allocation rounds (AR 1- AR 6)).

Appendix C Data selection

Table C.1: Data selection process of offshore wind units in Great Britain (2019-2024).

	CfD			ROC	MB	Total
	IVC	AR 1	AR 2			
Projects	5	2	3	30	2	40
Operational projects	5	1	3	30	2	39
Projects with link to unit	5	1	3	23	2	32
Projects with Elexon generation data	5	1	3	20	2	29
Units	14	2	8	41	6	65
Start date	2019-02-01	2019-10-30	2021-05-17	2019-02-01	2022-05-01	
End date	2024-12-31	2024-12-31	2024-12-31	2024-12-31	2024-03-27	

Notes: A unit is the smallest grouping of wind turbines that can be independently controlled. Support schemes are either Renewable Obligation Certificates (ROCs), Market-Based (MB), or two-way Contract for Difference (CfD) obtained via either Investment Contracts (IVCs), in Allocation Round 1 (AR 1), or in Allocation Round 2 (AR 2). The total is the sum of columns CfD (IVC, AR 1, AR 2), and ROC. MB projects are also represented in the AR 2 projects as the MB projects will eventually be supported under AR 2. Source CfD projects: Department for Business, Energy & Industrial Strategy (2023). Source ROC projects (Ofgem, 2024a). Source projects link to unit (LCCC, 2023c; Elexon BMRS, n.d.b). Source generation data: (Elexon BMRS, n.d.a).

Appendix D Check with LCCC data

To make sure that our data is representative, we compare our data with data from the low carbon contracts company (LCCC), who manages the two-way Contracts for Difference (CfDs) in Great Britain (GB). The LCCC dataset provides daily data from January 2016 to December 2024, including actual generation from CfD-backed offshore wind farms and the corresponding payments they received. The dataset also includes daily averages of the intermittent market reference price (IMRP) as well as the weighted IMRP, which is calculated as a generation-weighted IMRP based on intermittent generation. LCCC publishes this data on the CfD_ID level, referring to the identifier associated with a specific contracted unit or project phase. This check is limited to offshore wind farms supported by CfDs, excluding the ones operating under ROCs or the ones that are MB. In total, our check covers 9 projects, representing 24 Balancing Mechanism Units (BMUs).

Generation data We compare our generation data obtained from Elexon (Elexon BMRS, n.d.a) (Section 3) with the generation data reported by LCCC (LCCC, 2023a). Since our data is at the hourly level per BMU, we aggregate it to daily totals at the project level. In terms of the LCCC data, we also aggregate it at the project level, as there is not always a clear one-to-one mapping between BMUs and CfD_IDs. Figure D.1a shows the correlation between Elexon's generation data and LCCC's generation data. Even though the correlation is high (0.99), we notice a discrepancy between Elexon's data and LCCC's data. Specifically, the daily generation reported by Elexon is higher for some project-days than the daily generation published by LCCC. After looking into each project separately, we notice that the projects Triton Knoll Offshore Wind Farm (2021-2024) and East Anglia 1 (2020) are leading to the discrepancy. To correct for this, we computed a daily correction factor as the ratio of LCCC generation to Elexon generation data for both projects and each day. Figure D.1b shows the improved correlation (1.00) after applying the daily correction factor to the Elexon generation data. We apply the daily correction factor to each hour of our Elexon generation data for the two projects. The adjusted hourly generation data is used throughout the paper.

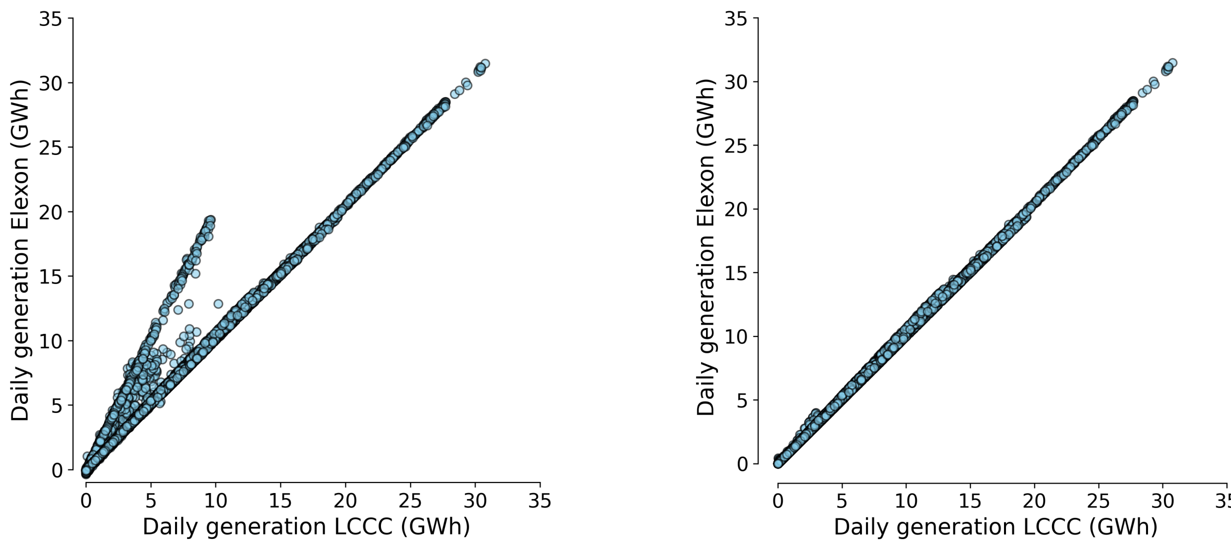
Day-ahead price In terms of the day-ahead (DA) price data, we use the hourly data published by LCCC (IMRP) (LCCC, 2023d) (Section 3). However, for the calculation of the daily CfD payments, LCCC uses the weighted IMRP. We calculate the daily (t) weighted IMRP per project (k) by weighting each hourly (h) IMRP by the corresponding generation volume and dividing by total daily generation. The correlation between our weighted IMRP and the weighted IMRP of LCCC is 1.0.

$$\text{Weighted IMRP}_{tk} = \frac{\sum_h (\text{IMRP}_h \cdot \text{Actual generation}_{tkh})}{\sum_h \text{Actual generation}_{tkh}} \tag{D.1}$$

CfD payments LCCC calculates the daily (t) CfD payments per project (k) as follows:

$$\text{CfD Payment}_{tk} = (\text{Strike Price}_{tk} - \text{Weighted IMRP}_{tk}) \cdot \text{Actual Generation}_{tk} \tag{D.2}$$

We use the adjusted Elexon generation data (corrected as described above) for each contract and day, along with the weighted IMRP as calculated above. The corresponding strike prices are obtained directly from the LCCC dataset. By calculating the correlation between our CfD payments and the LCCC CfD payments, we obtain a correlation of 1.00, confirming the consistency between our dataset and the LCCC data.



(a) Before adjustment

(b) After adjustment

Figure D.1. Unit of observation: project-by-daily generation. Correlation between Elexon generation data and LCCC generation data before and after adjusting the data for 9 two-way Contracts for difference projects (24 units). Panel a and b display the daily generation data per contract (MWh) correlation between the generation data from Elexon (Elexon BMRS, n.d.a) on the y-axis and the generation data from the low carbon contracts company (LCCC) (LCCC, 2023a) on the x-axis. Panel a displays the correlation between both datasets before adjusting any generation data. Panel b displays the correlation between both datasets after adjusting the Elexon generation data for two projects with a correction factor, calculated as the ratio between the generation from both datasets.

Appendix E Robustness check capacity-normalized dependent variable

Table E.1: Impact of all negative day-ahead price events on generation of offshore wind farms under different support schemes in Great Britain (2022-05-01 - 2024-03-27): robustness check.

	Control group					
	AR 1 + IVC + ROC			AR 1	IVC	ROC
	(1)	(2)	(3)	(4)	(5)	(6)
MB · NegPriceEvent	-0.301^{***}	-0.328^{***}	-0.347^{***}	-0.373^{***}	-0.212^{**}	-0.365^{***}
	(0.072)	(0.073)	(0.056)	(0.071)	(0.089)	(0.071)
Fixed-effects						
Time FE	Yes	Yes	Yes	Yes	Yes	Yes
Unit FE	Yes	Yes	Yes	Yes	Yes	Yes
Window (hours)	6	12	24	12	12	12
Negative price events	25	25	25	25	25	25
Units	63	63	63	8	20	47
Constant	0.744	0.723	0.668	0.603	0.658	0.716
	(0.002)	(0.001)	(0.001)	(0.011)	(0.006)	(0.002)
Observations	23,349	35,880	58,296	4,251	11,214	26,715

Notes: Unit of observation: unit-by-hourly generation. The dependent variable is the ratio of actual generation (MWh) in hour t to the installed capacity (MW) for unit i. A negative price event (NegPriceEvent) is defined as a sequence of consecutive hours with negative day-ahead (DA) prices. The event window in hours represents the number of hours before and after the event (either six, 12, or 24 hours). The control group in columns (1)-(3) are units under Allocation Round (AR 1), Investment Contracts (IVCs), or Renewable Obligation Certificates (ROCs), in column (4) units under AR 1, column (5) units under IVCs, and in column (6) units under ROCs. The treated group in each column are units who are Market-based (MB). Analysis period: 1 May 2022 - 27 March 2024. Standard errors in parentheses, clustered at the unit level. $^{*}p < 0.1$, $^{**}p < 0.05$, $^{***}p < 0.01$.

Table E.2: Impact of the six-hour rule - which excludes support payments during events with six or more consecutive hours of negative day-ahead prices - on two-way Contracts for Difference (Allocation Round 2 units) offshore wind farms' generation in Great Britain (2021-12-30 - 2024-12-31): robustness check.

	Control group					
	AR 1 + IVC + ROC			AR 1	IVC	ROC
	(1)	(2)	(3)	(4)	(5)	(6)
AR 2 · NegPriceEvent	-0.414^{***}	-0.438^{***}	-0.447^{***}	-0.553^{***}	-0.315^{***}	-0.459^{***}
	(0.040)	(0.033)	(0.028)	(0.059)	(0.069)	(0.022)
Fixed-effects (FE)						
Time FE	Yes	Yes	Yes	Yes	Yes	Yes
Unit FE	Yes	Yes	Yes	Yes	Yes	Yes
Window (hours)	6	12	24	12	12	12
Negative price events	18	18	18	18	18	18
Units	65	65	65	10	22	49
Constant	0.725	0.712	0.662	0.705	0.670	0.696
	(0.001)	(0.001)	(0.000)	(0.013)	(0.005)	(0.001)
Observations	22,161	33,573	55,810	3,321	10,227	25,460

Notes: Unit of observation: unit-by-hourly generation. The dependent variable is the ratio of actual generation (MWh) in hour t to the installed capacity (MW) for unit i. A negative price event (NegPriceEvent) is defined as a sequence of consecutive hours with negative day-ahead (DA) prices, lasting six hours or longer. The window in hours represents the number of hours before and after the event (either six, 12, or 24). The control group in columns (1)-(3) are units under Allocation Round 1 (AR 1), Investment Contract (IVCs), or Renewable Obligation Certificates (ROCs), in column (4) units under AR 1, column (5) units under IVC, and in column (6) units under ROC. The treated group in each column are units under Allocation Round 2 (AR 2). Great Britain implemented the six-hour rule policy from AR 2 onward, which states that when prices are negative for six or more consecutive hours, no CfD payment from the government will be made from the first hour with a negative DA price. Analysis period in columns (1)-(6): 30 December 2021 - 31 December 2024. Standard errors in parentheses, clustered at the unit level. $^{*}p < 0.1$, $^{**}p < 0.05$, $^{***}p < 0.01$.

Appendix F Tests for parallel trends assumption

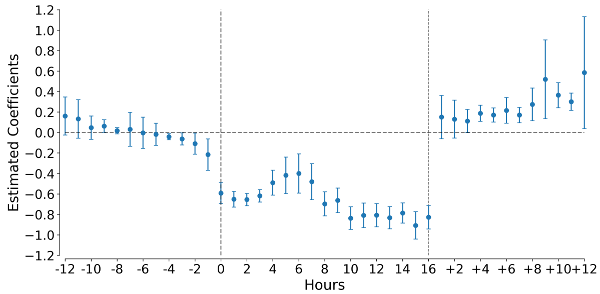
To test the underlying parallel trend assumption, we estimate an event study specification. Instead of the single treatment interaction ($Treated_i * NegPriceEvent_t$) from Equation 2, we use a series of interaction terms between the treatment group and event-time dummies. We estimate the following specification:

$$y_{it} = \sum_{k \neq -1} \beta_k \cdot \text{Treated}_i \cdot D_{kt} + \alpha_i + \gamma_t + \epsilon_{it} \tag{F.1}$$

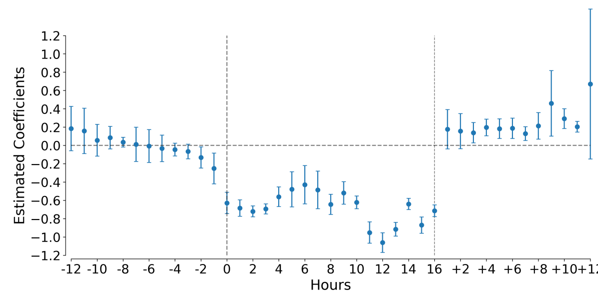
where y_{it} is the ratio of actual generation (MWh) in hour t to the average generation (MWh) in the periods before and after the event for unit i. Treated$_i$ is a dummy for the treatment group, 1 for market-based (MB) units for all negative price events and two-way Contracts for Difference (CfD) obtained in Allocation Round 2 (AR 2) for long negative events (six hours or longer), 0 for the control group (Renewable Obligation Certificates (ROCs), Allocation Round 1 (AR 1), or Investment Contracts (IVC)). D_{kt} is a dummy variable that is 1 if time t corresponds to hour k relative to the start of a negative price event, and 0 otherwise. We omit the dummy for $k = -1$ so that the negative price period effects are relative to the hour before the start. We further normalize the estimated coefficients by subtracting the mean of all 12 pre-event period coefficients (treating the omitted $k = -1$ coefficient as zero). α_i are unit fixed effects and γ_t are time fixed effects. The parameter of interest β_k estimates the effect of being a treated unit. ϵ_{it} is the error term. We estimate the regression separately for each control group (ROCs, AR 1, or IVC) in both all negative price events and long negative price events.

Figure F.1a presents the results for all negative price events, where we compare MB units with those who receive a fixed strike price per MWh produced (IVC, and AR 1 units) and those receiving certificates (ROCs units). Each panel compares MB units with a different control group – the pooled group of AR 1, IVC, and ROC units (panel a), AR 1 (panel b), IVC (panel c), and ROCs(panel d). The estimated coefficients in the 12 hours before the negative price event hours are close to zero, indicating that MB units and the control groups display similar generation patterns before negative prices occur. During negative price event hours, the coefficients drop below zero, suggesting that MB units tend to reduce their generation relative to the control groups. Following the negative price event hours, the estimated coefficients return to values close to zero.

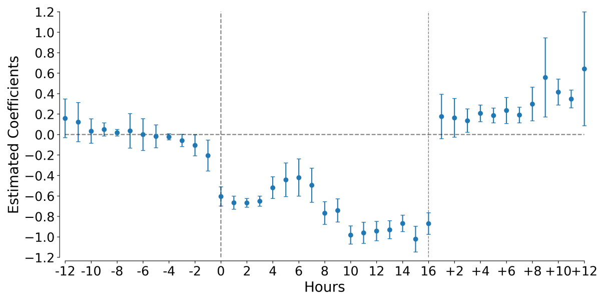
The results for long negative price events (six hours or longer) are shown in Figure F.2. We do not observe significant differences in generation between AR 2 units and their control groups – the pooled control group (AR 1, IVC, and ROC) (panel a), AR 1 (panel b), IVCs (panel C), and ROCs (panel d) in the 12 hours before the negative price events. The estimated coefficients are close to zero, indicating the absence of pre-trends and supporting the parallel trends assumption. This suggests that before the start of a negative price event, treated and control units display similar generation behavior. For all control groups, the trend breaks after the start of the negative price event, as the estimated coefficients become negative.



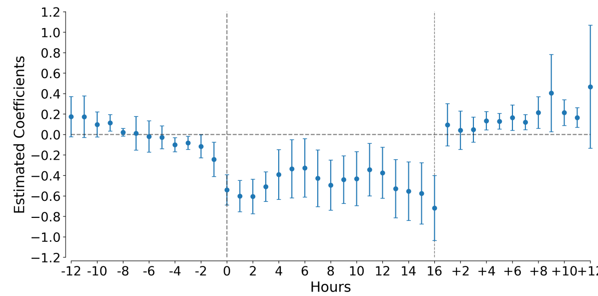
(a) MB vs AR 1, IVC, and ROC



(b) MB vs AR1

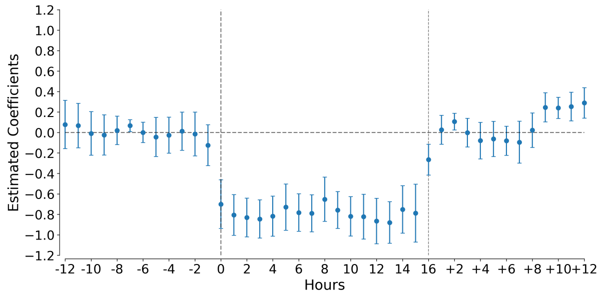


(c) MB vs ROC

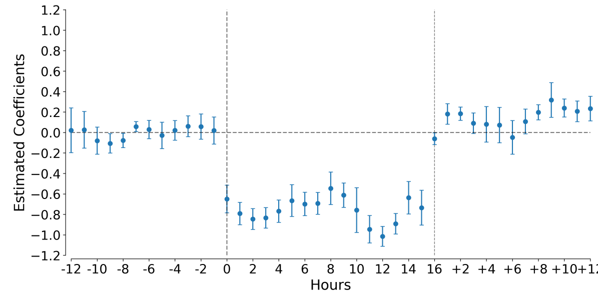


(d) MB vs IVC

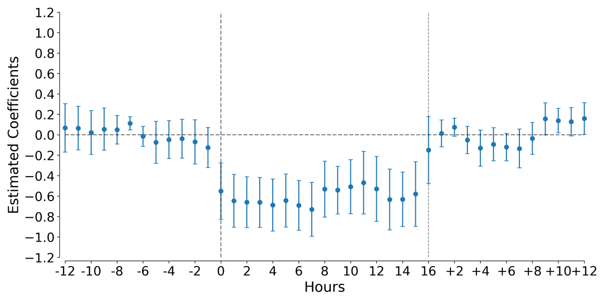
Figure F.1. Event-study estimates to assess the parallel trends assumption across different support schemes. Each panel shows estimated coefficients from the event-study specification (Eq. F.1), where k indexes event time (hours relative to the start of a negative-price event). Panel a compares market-based (MB) units with a control group (Allocation Round 1 (AR 1), Investment Contracts (IVCs), or Renewable Obligation Certificates (ROCs) (panel a)). Panel b compares MB with AR 1. Panel c compares MB with IVC. Panel d compares MB with ROC. The coefficients reflect the ratio of actual generation (MWh) in hour t to the expected generation in the pre- and post-event periods for unit i. Coefficients are normalized by subtracting the mean of all 12 pre-event period coefficients (treating the omitted $k = -1$ coefficient as zero). Error bars represent the 95% confidence intervals, clustered at the unit level. Vertical dotted lines mark the negative-price event start and end.



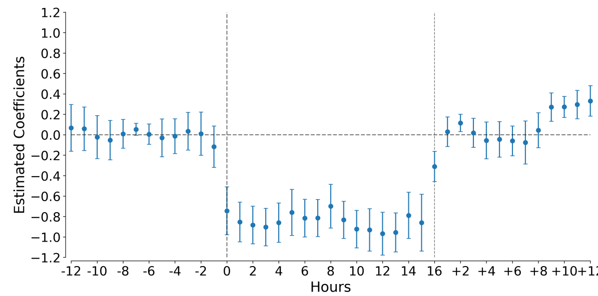
(a) AR 2 vs AR 1, IVC, and ROC



(b) AR 2 vs AR 1



(c) AR 2 vs IVC



(d) AR 2 vs ROC

Figure F.2. Event-study estimates to assess the parallel trends assumption for different support schemes. Each panel shows the estimated coefficients from the event-study specification (Eq. F.1), where k indexes event time (hours relative to the start of a negative-price event). Panel a compares Allocation Round 2 (AR 2) units with a control group (Allocation Round 1 (AR 1), Investment Contracts (IVCs), or Renewable Obligation Certificates (ROCs) (panel a)). Panel b compares AR 2 with AR 1. Panel c compares AR 2 with IVC. Panel d compares AR 2 with ROC. The estimated coefficients reflect the ratio of actual generation (MWh) in hour t to the average generation (MWh) in the periods before and after the event for unit i. Coefficients are normalized by subtracting the mean of all 12 pre-event period coefficients (treating the omitted $k = -1$ coefficient as zero). The error bars represents the 95% confidence intervals, clustered at the unit level. Vertical dotted lines mark the negative price event start and end.

Appendix G Matching procedure

Table G.1: Occurrence and characteristics of treated and control groups when the imbalance price is positive or negative.

	Imbalance price > 0		Imbalance price < 0	
	Treated	Control	Treated	Control
Total hours	8,962	691,011	24,864	559
% of total CfD hours	1.02	78.47	2.82	0.06
Units	24	24	24	24
Total generation (MWh)	615,531	71,144,307	4,400,527	69,818
Total generation per hour (MWh)	68.68	102.96	176.98	124.90
	(0.93)	(0.13)	(0.82)	(5.12)
Total CfD payment (£)	-145,088,886	6,810,242,610	609,957,610	-2,723,474
CfD payment per hour (£/hour)	-16,189	9,855	24,532	-4,872
	(292.11)	(14.45)	(122.84)	(459.98)
CfD payment per MWh (£/MWh)	-235.71	95.72	138.61	-39.01
	(2.74)	(0.05)	(0.30)	(2.17)
Mean strike price (£/MWh)	142.11	170.88	168.26	130.57
	(39.55)	(27.92)	(40.54)	(40.22)

Notes: Unit of observation: unit-by-hourly generation (MWh). A unit is the smallest grouping of wind turbines that can be independently controlled. Imbalance > 0: the treated group consists of offshore wind unit-hours where the day-ahead (DA) price $>$ strike price, and the control group consists of unit-hours where the DA price $<$ strike price. Imbalance price < 0: the treated group consists of unit-hours where the DA price $<$ strike price, the control group consists of unit-hours where the DA price $>$ strike price. Two-way Contracts for Difference (CfDs) payments are calculated as (strike price (SP)$-$day-ahead (DA) price)$\times$actual generation (capped at the strike price). Standard errors in parentheses.

Table G.2: Summary statistics before and after matching when the imbalance price is positive.

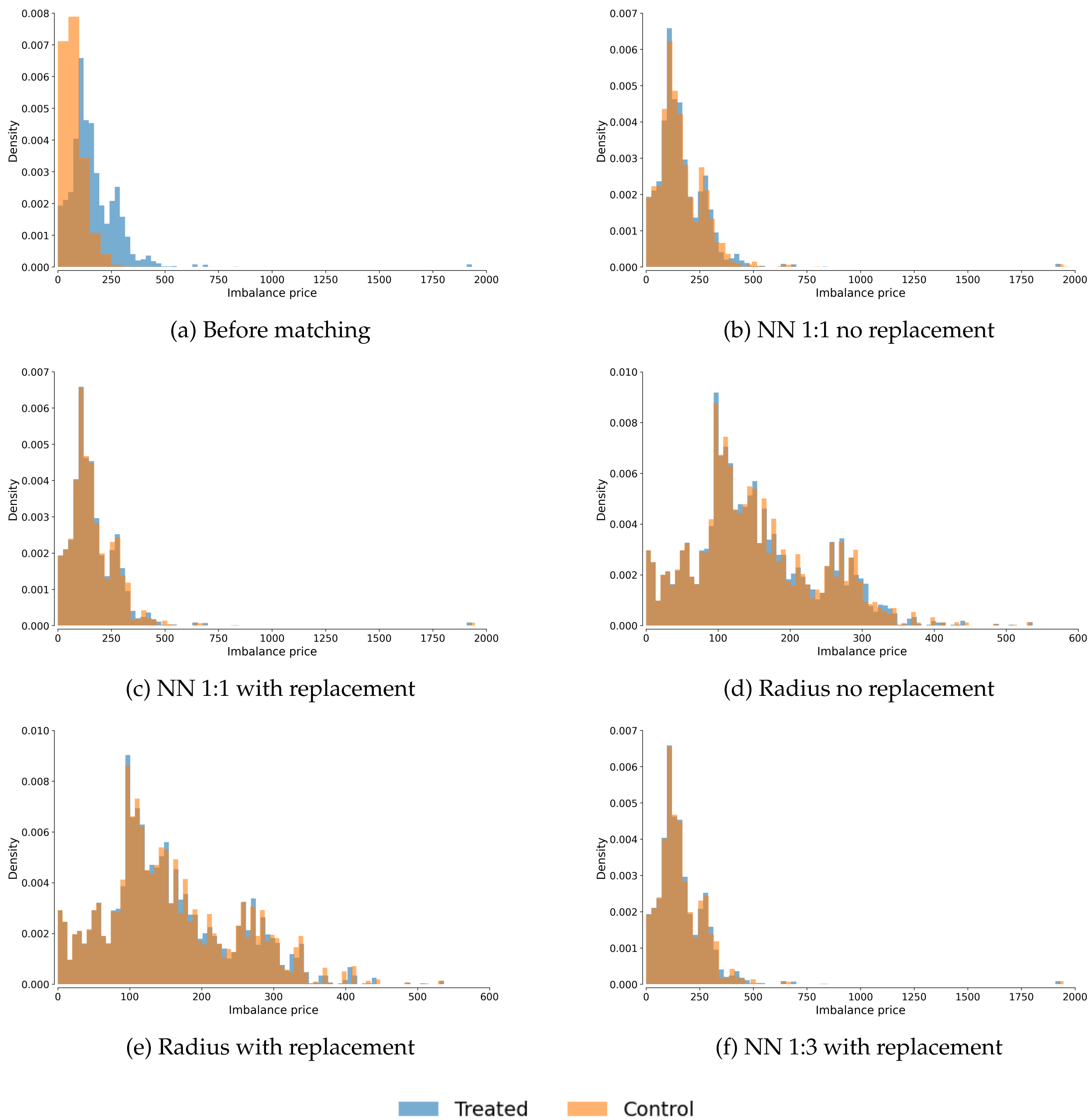
Imbalance price > 0	Treated	Control	t-stat	SMD
Before matching				
Observations	8,962	691,011		
Imbalance price (£)	164.17	75.24	66.28	0.91
	(126.86)	(54.75)		
After matching				
NN 1:1 without replacement				
Observations	8,962	8,962		
Imbalance price (£)	164.17	163.72	6.96	0.01
	(126.86)	(126.40)		
Radius 1:1 without replacement				
Observations	8,660	8,660		
Imbalance price (£)	151.84	151.66	20.37	0.00
	(85.76)	(85.44)		
Radius 1:1 with replacement				
Observations	8,807	2,021		
Observations (ESS)	8,807	670		
Imbalance price (£)	155.33	155.33	0.00	0.00
	(89.27)	(89.31)		
NN 1:3 with replacement				
Observations	8,962	5,059		
Observations (ESS)	8,962	1,996		
Imbalance price (£)	164.17	127.15	-0.01	0.00
	(130.06)	(130.45)		

Notes: NN: nearest neighbor matching. The treated group consists of offshore wind unit-hours where the day-ahead (DA) price $>$ strike price, and the control group consists of unit-hours where the DA price $<$ strike price. The reported t-statistic is a paired t-test on within-pair differences for matching without replacement, and a weighted Welch t-test for matching with replacement. The Standardized Mean Difference (SMD) estimates the covariate balance between the treated and control group and is calculated as the difference in treated and control means divided by the pooled standard deviation (after matching with replacement it is computed using matching weights). Well balanced: SMD < 0.10, moderate imbalance $0.10 <$ SMD < 0.25, large imbalance: SMD > 0.25. Standard errors in parentheses.

Table G.3: Summary statistics before and after matching when imbalance price is negative.

Imbalance price < 0	Treated	Control	t-stat	SMD
Before matching				
Observations	24,864	559		
Imbalance price (£)	-23.40	-30.63	8.16	0.34
	(21.59)	(20.71)		
After matching				
NN 1:1 without replacement				
Observations	559	559		
Imbalance price (£)	-26.73	-30.63	6.31	0.18
	(24.35)	(20.71)		
Radius 1:1 without replacement				
Observations	559	559		
Imbalance price (£)	-28.60	-30.63	187.32	0.10
	(20.82)	(20.71)		
Radius 1:1 with replacement				
Observations	24,265	185		
Observations ESS	24,265	78		
Imbalance price (£)	-21.96	-21.96	0.00	0.00
	(19.50)	(19.55)		
NN 1:3 with replacement				
Observations	24,864	338		
Observations ESS	24,864	160		
Imbalance price (£)	-23.40	-23.24	-0.10	-0.01
	(21.59)	(21.02)		

Notes: NN: 1:1 nearest neighbor matching. The treated group consists of unit-hours where the DA price $<$ strike price, the control group consists of unit-hours where the DA price $>$ strike price. The reported t-statistic is a paired t-test on within-pair differences for NN without replacement, and a weighted Welch t-test for NN with replacement. The Standardized Mean Difference (SMD) estimates the covariate balance between the treated and control group and is calculated as the difference in treated and control means divided by the pooled standard deviation (after matching with replacement it is computed using matching weights). Well balanced: SMD < 0.10, moderate imbalance $0.10 <$ SMD < 0.25, large imbalance: SMD > 0.25. Standard errors in parentheses.



(a) Before matching

(b) NN 1:1 no replacement

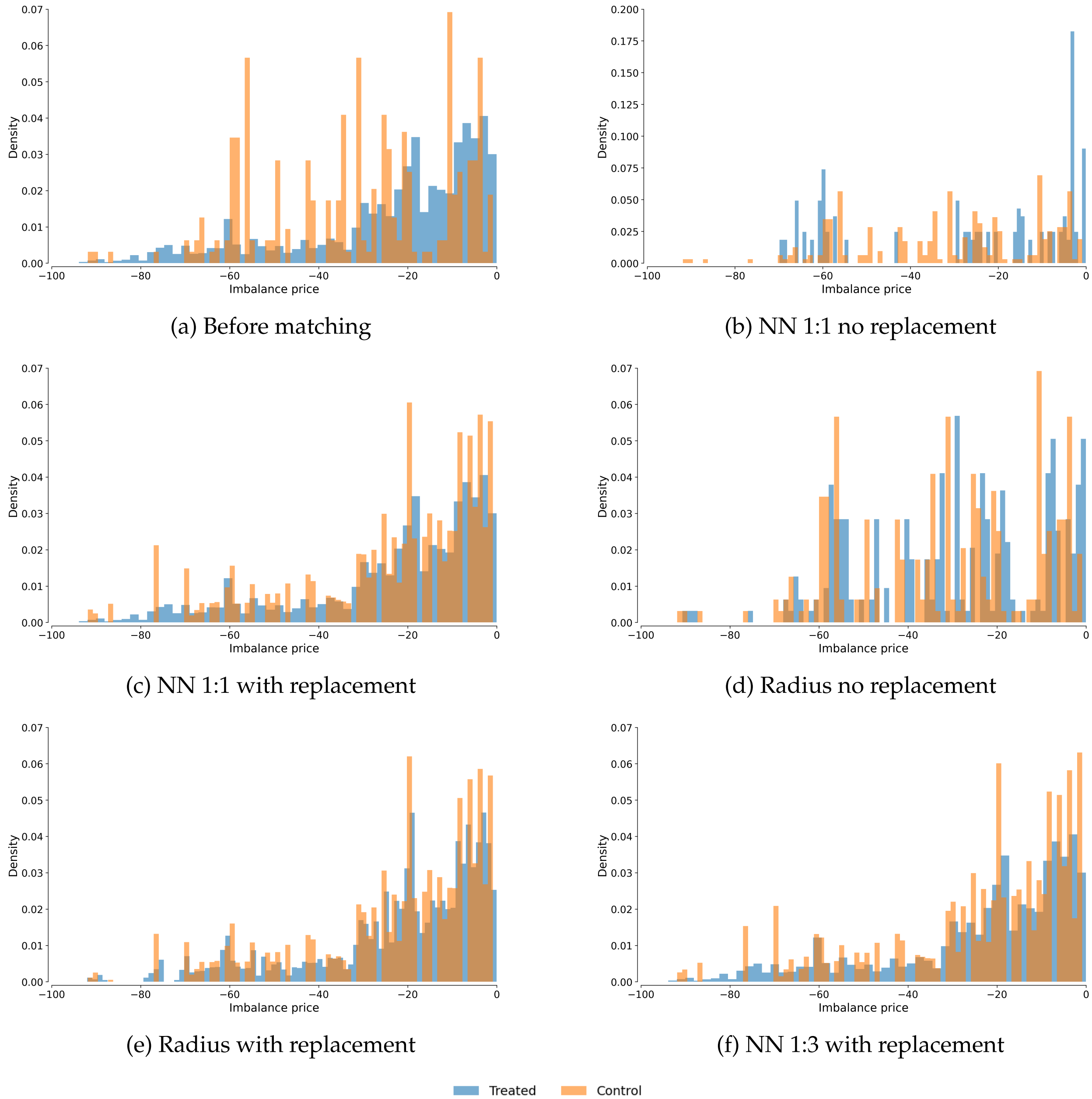
(c) NN 1:1 with replacement

(d) Radius no replacement

(e) Radius with replacement

(f) NN 1:3 with replacement

Figure G.1. Distribution of imbalance prices by matching design (positive-price hours only). Panels show histograms for: (a) before matching, (b) nearest-neighbor (NN) 1:1 without replacement, (c) NN 1:1 with replacement, (d) radius (caliper) without replacement, (e) radius (caliper) with replacement, and (f) nearest-neighbor 1:3 with replacement. The treated group consists of offshore wind unit-hours with day-ahead (DA) price > strike price, the control group consists of unit-hours with DA price < strike price. For designs with replacement, histograms use observation weights from the match (so reused controls contribute proportionally).



(a) Before matching

(b) NN 1:1 no replacement

(c) NN 1:1 with replacement

(d) Radius no replacement

(e) Radius with replacement

(f) NN 1:3 with replacement

Figure G.2. Distribution of imbalance prices by matching design (negative-price hours only). Panels show histograms for: (a) before matching, (b) nearest-neighbor (NN) 1:1 without replacement, (c) NN 1:1 with replacement, (d) radius (caliper) without replacement, (e) radius (caliper) with replacement, and (f) nearest-neighbor 1:3 with replacement. The treated group consists of unit-hours where the day-ahead (DA) price $<$ strike price, the control group consists of unit-hours where the DA price $>$ strike price. For designs with replacement, histograms use observation weights from the match (so reused controls contribute proportionally).

Appendix H Robustness checks: different event windows

Table H.1: Impact of all negative price events on Market-Based offshore wind units' generation in Great Britain (2022-05-01 - 2024-03-27): robustness check.

	AR 1		IVC		ROC	
	(1)	(2)	(3)	(4)	(5)	(6)
MB * NegPriceEvent	-0.760^{***}	-0.804^{***}	-0.554^{***}	-628^{***}	-0.737^{***}	-0.896^{***}
	(0.060)	(0.082)	(0.095)	(0.109)	(0.065)	(0.082)
Fixed-effects (FE)						
Time FE	Yes	Yes	Yes	Yes	Yes	Yes
Unit FE	Yes	Yes	Yes	Yes	Yes	Yes
Event window (Hours)	6	24	6	24	6	24
Negative price events	25	25	25	25	25	25
Units	8	8	20	20	47	47
Constant	1.017	1.013	0.948	0.990	1.002	1.016
	(0.014)	(0.007)	(0.008)	(0.004)	(0.002)	(0.001)
Observations	2,281	5,921	6,833	17,277	16,800	42,360

Notes: Unit of observation: unit-by-hourly generation. The dependent variable is the ratio of actual generation (MWh) in hour t to the average generation (MWh) in the periods before and after the negative-price event (NegPriceEvent) for unit i. A negative-price event is defined as a sequence of consecutive hours with negative day-ahead (DA) prices, lasting six hours or longer. The event window in hours represents the number of hours before and after the negative DA price event. The control group in columns (1)-(2) are units under Allocation Round 1 (AR 1), in columns (3)-(4) under under Investment Contracts (IVC), and in columns (5)-(6) units under the Renewable Obligation Certificates (ROCs) scheme. The treated group in each column are Allocation Round 2 (AR 2) units. For the offshore wind farms under AR 2, Great Britain implemented the six-hour rule policy, which states that when prices are negative for six or more consecutive hours, no CfD payment from the government will be made from the first hour with a negative DA price. Analysis period in columns (1)-(6): 30 December 2021 - 31 December 2024. Standard errors in parentheses, clustered at the unit level. $^{*}p < 0.1$, $^{**}p < 0.05$, $^{***}p < 0.01$.

Table H.2: Impact of the six-hour rule – which excludes support payments during events with six or more consecutive hours of negative day-ahead prices – on two-way Contract for Difference offshore wind units' generation in Great Britain (2021-12-30 - 2024-12-31): robustness check.

	AR 1		IVC		ROC	
	(1)	(2)	(3)	(4)	(5)	(6)
AR 2 * NegPriceEvent	-0.819^{***}	-0.884^{***}	-0.60^{***}	-0.672^{***}	-0.826^{***}	-1.000^{***}
	(0.049)	(0.051)	(0.100)	(0.114)	(0.060)	(0.072)
Fixed-effects (FE)						
Time FE	Yes	Yes	Yes	Yes	Yes	Yes
Unit FE	Yes	Yes	Yes	Yes	Yes	Yes
Event window (Hours)	6	24	6	24	6	24
Negative price events	18	18	18	18	18	18
Units	10	10	22	22	46	46
Constant	1.024	1.024	0.919	0.982	1.019	1.036
	(0.016)	(0.007)	(0.011)	(0.005)	(0.003)	(0.001)
Observations	2,217	5,480	6,769	16,955	16,491	41,483

Notes: Unit of observation: unit-by-hourly generation. The dependent variable is the ratio of actual generation (MWh) in hour t to the average generation (MWh) in the periods before and after the negative-price event (NegPriceEvent) for unit i. A negative-price event (NegPriceEvent) is defined as a sequence of consecutive hours with negative day-ahead (DA) prices, lasting six hours or longer. The event window in hours represents the number of hours before and after the negative DA price event. The control group in columns (1)-(2) are units under Allocation Round 1 (AR 1), in columns (3)-(4) under under Investment Contracts (IVC), and in columns (5)-(6) units under the Renewable Obligation Certificates (ROCs) scheme. The treated group in each column are Allocation Round 2 (AR 2) units. For the AR 2 offshore wind farms, Great Britain implemented the six-hour rule policy, which states that when prices are negative for six or more consecutive hours, no CfD payment from the government will be made from the first hour with a negative DA price. Analysis period in columns (1)-(6): 30 December 2021 - 31 December 2024. Standard errors in parentheses, clustered at the unit level. $^{*}p < 0.1$, $^{**}p < 0.05$, $^{***}p < 0.01$.

Appendix I Negative day-ahead price events lasting six consecutive hours or longer

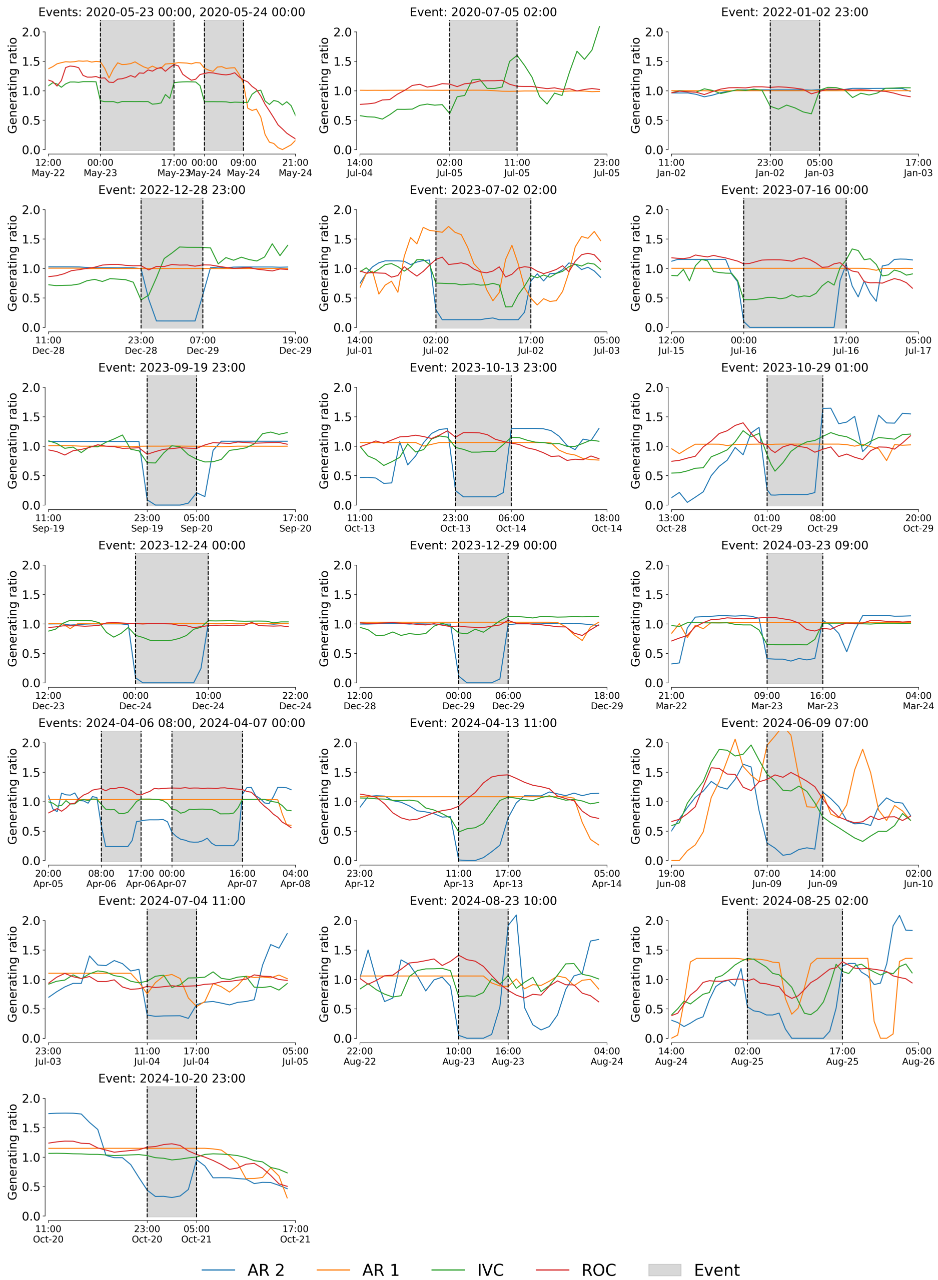
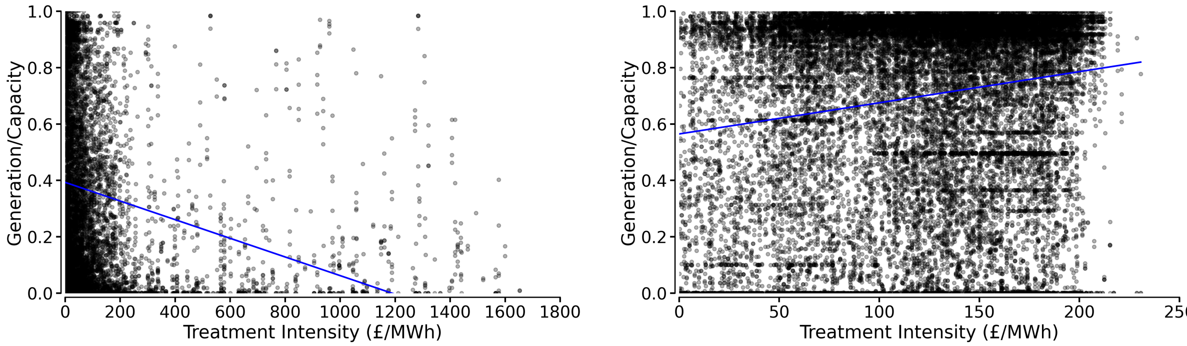


Figure I.1. Generation (MWh) in hour t to the average generation (MWh) in the 12 hours before and after the negative price event lasting six consecutive hours or longer per support scheme. Support schemes include; Investment Contract (IVCs), two-way Contract for Difference (CfD) Allocation Round 1 (AR 1), and CfD Allocation Round 2 (AR 2), Renewable Obligation Certificates (ROCs), and Market-Based (MB).

Appendix J Treatment intensity plots



(a) Imbalance price > 0

(b) Imbalance price < 0

Figure J.1. Unit of observation: unit-by-hourly generation. Scatter plots showing the relationship between treatment intensity (absolute difference between CfD (re)payment and the imbalance price) and the generation capacity factor. Panel (a) represents $H_{treated}$ observations with (day-ahead (DA) price $>$ strike price) $>$ the positive imbalance price. Panel (b) represents $L_{treated}$ observations with (DA price $<$ strike price) $>$ the negative imbalance price. Blue lines represent linear fits. Each point represents a matched treated (unit-hour) observation.

Appendix K Robustness check balancing market distortion

Table K.1: Matching estimates under different methods when the imbalance price is positive.

	Radius 1:1 NR		Radius 1:1 WR		NN 1:3 WR	
	(1)	(2)	(3)	(4)	(5)	(6)
$H_{treated}$	-0.193^{***}		-0.154^{***}		-0.172^{***}	
	(0.026)		(0.008)		(0.006)	
$H_{treated}$ intensity		-0.000331^{***}		-0.000213^{***}		-0.000274^{***}
		(0.000)		(0.000)		(0.000)
Constant	0.473	0.397	0.433	0.330	0.450	0.361
	(0.012)	(0.020)	(0.007)	(0.026)	(0.005)	(0.021)
N treated	8,660	8,660	8,807	8,807	8,962	8,962
N control	8,660	8,660	8,2,021	2,021	5,059	5,059

Notes: The dependent variable is the generation capacity factor in hour t (generation in MWh divided by total installed capacity in MW) for unit i. NR = no replacement or without replacement, WR = with replacement. NN: 1:1 nearest neighbor matching. $Treated_H$ are observations with (day-ahead (DA) price $>$ strike price) $>$ imbalance price. Standard errors in parentheses, clustered on matched group and unit level for NN without replacement and on unit level for NN with replacement. *$p < 0.1$, **$p < 0.05$, $^{***}p < 0.01$.

Table K.2: Matching estimates under different methods when the imbalance price is negative.

	Radius 1:1 NR		Radius 1:1 WR		NN 1:3 WR	
	(1)	(2)	(3)	(4)	(5)	(6)
$L_{treated}$	0.323***		0.211***		0.234***	
	(0.062)		(0.024)		(0.018)	
$L_{treated}$ intensity		0.001777***		0.001125***		0.001142***
		(0.000)		(0.000)		(0.000)
Constant	0.462	0.469	0.488	0.561	0.465	0.560
	(0.064)	(0.057)	(0.024)	(0.050)	(0.018)	(0.049)
N treated	559	559	24,265	24,265	24,864	24,864
N control	559	559	185	185	338	338

Notes: The dependent variable is the generation capacity factor in hour t (generation (MWh) divided by total installed capacity (MW)) for unit i. NR = no replacement or without replacement, WR = with replacement. NN: 1:1 nearest neighbor matching. $Treated_L$ are observations with (day-ahead (DA) price $<$ strike price) $<$ imbalance price. Standard errors in parentheses, clustered on matched group and unit level for NN without replacement and on unit level for NN with replacement. *$p < 0.1$, **$p < 0.05$, $^{***}p < 0.01$.