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Banding: A game changer in the Renewables Obligation scheme in the United Kingdom

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A B S T R A C T

The Renewables Obligation scheme was implemented in the UK in April 2002 to support electricity from renewable sources and was designed as technology-neutral to encourage competition. As less developed technologies were disadvantaged, banding was introduced in April 2009 to provide differentiated support to different technologies. A similar feature was used in other countries but its positive impact has not been identified empirically. This is the first quantitative study to examine the impacts of banding based on time series data from March 2003 to December 2018 in the UK, focusing on onshore wind, offshore wind, and solar. This study considers the impacts of banding via its feed-through effect on the markups and then investors' decisions on renewable projects, instead of considering it as an independent policy intervention. The counterfactual analysis shows that, if banding was not introduced, the offshore wind would remain silent for extended periods, then the UK might have difficulty in achieving its target for renewable generation. Besides, the costs of the RO scheme would be less, but additional fuel costs would be added to cover the generation gap.

1. Introduction

In 2018, the share of electricity generated from renewable sources reached 33% (BEIS, 2019), exceeding the 30% target by 2020 (DECC, 2010b). This achievement has been supported by a series of government schemes, and one of the main schemes was the Renewables Obligation (RO) introduced in April 2002 to support large-scale renewable electricity projects.

The quota-based RO scheme imposes an obligation to electricity suppliers that a certain proportion of their sales come from electricity generated using renewable sources by presenting adequate certificates.[1] The scheme allows renewable generators to receive additional revenue from selling awarded certificates to compete with low-cost fossil fuel power stations. The costs of the scheme increased from £228 million in 2002/03 to £5.9 billion in 2018/19, which were ultimately passed to consumers through higher bills.[2]

The RO scheme was initially designed to be technology-neutral, which provided the same level of support to all renewable technologies, aiming to ensure suppliers would meet their obligations by the most economical means. However, concerns were raised on the issue of

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[1] The earliest quota-based scheme was introduced in the United States, which is known as the Renewable Portfolio Standard scheme, started in Iowa in the late 1990s (Berry and Jaccard, 2001b; Upton and Snyder, 2017; Young and Bistline, 2018). In 2021, 30 states and Washington, D.C. in the United States have implemented the Renewable Portfolio Standard scheme (Barbose, 2021).

[2] The financial/reporting year of the RO scheme runs from April to March next year. The RO scheme brought negative gains to consumers as the costs passed to consumers were less than the reduction in the electricity price (Shao et al., 2022). However, from the perspective of the industry, the RO scheme created positive net gains through reducing imports of fossil fuels and carbon emissions (Shao et al., 2023).

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fair competition between renewable technologies at different stages of development (Meyer, 2003; Mitchell et al., 2006; Foxon and Pearson, 2007). Therefore, banding was added in April 2009 to diversify investments in renewable projects, by providing differentiated levels of support for different technologies according to their investment costs and associated risk (DTI, 2007).[3] Although there were still concerns about the impacts of the amendment (Wood and Dow, 2011; Woodman and Mitchell, 2011), later studies confirm the effectiveness of the RO scheme in promoting electricity generation from renewable sources after its reform in 2009 (Bunn and Yusupov, 2015; Shao et al., 2021).

Banding was also used in other countries such as the United States and Australia, and most studies on the effectiveness of banding were based on qualitative analysis, and there were limited studies that examined its impact from the quantitative aspect. In early quantitative studies, dummy variables were used to indicate the existence of support schemes (Menz and Vachon, 2006; Carley, 2009; Shrimali and Kniefel, 2011). In two recent studies, banding was explicitly measured as the maximum number by which a certain renewable resource can achieve (i.e., discrete values between zero and four), but insignificant impacts were found as different factors cancelled out (Carley et al., 2018; Kim and Tang, 2020). Therefore, the question about the impact of banding remains.

This paper is the first to examine the impact of banding on three individual technologies (onshore wind, offshore wind, and solar) based on time series data in the UK. In this study, banding does not directly affect investment decisions but passes through to the markup, which is the crucial factor affecting the investment in renewable projects and thus the added (installed) capacity. The impact will be examined through a counterfactual analysis. We first calculate the markup and then estimate its relationship with the added capacity. Next, we calculate the hypothetical markup based on the assumption that if banding was not introduced, then we calculate the hypothetical added capacity. The comparison between the actual scenario and the hypothetical scenario suggests that offshore wind and solar would remain silent for an extended period because of the negative markup in the scenario if banding was not introduced, and this would have further impacts on other aspects of the electricity sector such as generation and costs of the scheme.

The remainder of this chapter is organised as follows. Section 2 gives a literature review and Section 3 provides the background of the Renewables Obligation scheme and banding. Section 4 explains the data and Section 5 describes the methodology. Section 6 explains estimation results and Section 7 provides the counterfactual analysis. Section 8 concludes the paper.

2. Literature review

2.1. *Renewables obligation and banding*

The RO scheme was initially designed to be technology-neutral to ensure suppliers would meet their obligations by the most economical means. Meyer (2003) is concerned about the fairness of competition between renewable technologies at different stages of development. Mitchell and Connor (2004) echo that the scheme favours established technologies and fails to promote diversity, and Foxon and Pearson (2007) agree that the scheme offers a strong incentive to developed technologies but not enough for the innovation of early-stage technology. Later, banding was added in April 2009 to diversify investments in renewable projects (DTI, 2007). Woodman and Mitchell (2011) indicate that banding makes the RO scheme more complicated, but its benefit remains unseen. Wood and Dow (2011) further suggest that banding may not be enough to significantly increase the deployment level of less mature technologies. Focusing on wave and tidal, Allan et al. (2011) explain that banding largely improves the competitiveness of these less developed technologies but still remains more expensive compared with other technologies. Buckman (2011) argues that banding helps to eliminate excessive subsidies for low-cost renewable technologies and supports less-developed technologies to promote diversity in renewable electricity generation, but it makes the connection between the obligation target and renewable generation less certain. Further, Gürkan and Langestraat (2014) suggest that banding provides adequate incentives to less-developed technologies but may prevent the country from meeting the obligation target. Nonetheless, the effectiveness of the RO scheme in promoting electricity generation from various renewable sources after its reform in 2009 was confirmed by Bunn and Yusupov (2015) and Shao et al. (2021).

Different versions of banding were also seen in other quota-based systems. In the United States, credit multipliers (i.e., banding) were introduced to support solar in fifteen states in 2013, with large variations in different states (Fischlein and Smith, 2013), but concerns were raised that the total renewable energy generation was reduced (Novacheck and Johnson, 2015) and utility companies could achieve the goal through the lowest cost option (Rountree, 2019). In Australia, the multiplier for solar was introduced between 2009 and 13 to provide additional certificates for solar (Choi et al., 2017). Similarly, concerns were raised that the greatly increased number of certificates obtained for solar technology undermines the stability of the RET policy by reducing the certificate prices (Buckman and Diesendorf, 2010) and discourages the development of large-scale renewable projects (Valentine, 2010).

Most studies on the effectiveness of banding were based on qualitative analysis, and there were limited studies that examined its impact from the quantitative aspect. In early quantitative studies, dummy variables were used to indicate the existence of support schemes (Menz and Vachon, 2006; Carley, 2009; Shrimali and Kniefel, 2011). Among recent studies, Fischlein and Smith (2013) consider a dummy variable to indicate the existence of banding and suggest that banding has a negative impact on the policy responses measured as the share of renewable energy sales from 77 utilities in 25 states in 2008. The negative impact was explained as that banding allows utilities to take advantage to produce the types of renewable energy that earn additional certificates, lowering the overall quantity of renewable power necessary to achieve the goal. Banding was also explicitly measured as discrete values between zero and four in the following two studies. Carley et al. (2018) measure banding as the maximum number by which a certain renewable resource can receive and find that banding has insignificant impacts on renewable generation and capacity in a cross-state analysis in the United States from 1992 to 2014. In a subsequent similar study, Kim and Tang (2020) find that banding has insignificant impacts on the diversity of renewable electricity generation based on state-level data from 1997 to 2016. The insignificant impact of banding on renewable generation and capacity was puzzling but was explained by Carley et al. (2018) that different factors cancelled out, such as high costs, falling prices, and geographical locations. Still, the question about the impact of banding remains unanswered.

2.2. *Markups and investment*

The negative relationship between competition and investment/innovation was suggested by Schumpeter (1943) because large companies with market power have the advantage of recouping the benefits of investment/innovation. This prediction became the fundamental force in competition models (Dixit and Stiglitz, 1977; Salop, 1977) and is also shared by models of endogenous growth (Romer, 1990; Aghion and Howitt, 1992). However, this negative relationship was confronted by later studies. Nickell (1996) presents evidence that competition is

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[3] Another major amendment was the introduction of headroom in April 2010 to ensure excess demand in the certificate market to protect the values of certificates (Wang et al., 2023). However, the insufficient supply led to unjustified penalties so the total penalty was redistributed back to suppliers via the recycling mechanism (Li et al., 2020).

associated with a higher rate of investment based on an analysis of around 670 UK companies over the period 1972–86. Blundell et al. (1999) find that increased market competition in the industry tends to stimulate innovative activity based on a sample containing 340 manufacturing firms listed on the London International Stock Exchange between 1972 and 82.

Given the different conclusions from the early studies, Aghion et al. (2005) allow for a nonmonotonic relationship based on the data of 311 firms over the period from 1973 to 1994 in the UK. The study confirms that the negative relationship, referred to as the Schumpeterian effect, was found in leader-laggard industries, but it also suggests that a positive relation is found in the neck-and-neck industry, referred to as the escape competition effect. A subsequent study by Hashmi (2013) reinstates the negative relationship between competition and investment based on the data from 116 industries between 1976 and 2001 in the United States. The study suggests that the different findings are because, due to the presence of foreign firms, the analysis of UK domestic firms in Aghion et al. (2005) underestimates the actual technology gap in the industry and then the escape competition effect is overestimated.

According to OECD (2021), competition can be measured by concentration measures such as the Herfindahl-Hirschman Index and/or by profitability measures such as operating margin, return on assets, and markups. Among these measurements, we are focused on markups, which measure the extent to which price exceeds marginal cost as a monotonic indicator of market power. However, firm prices and marginal costs are often not observable in most firm-level data. Hall (1988) proposes an alternative approach based on the observation that, under perfect competition and constant returns to scale, markups will be equal to one. De Loecker and Warzynski (2012) build on this early work to derive estimates of firm-level markups from the cost minimisation problem of the firm. This approach assumes that if firms minimise their costs, then markups can be estimated using information on the costs of an input as a share of the firm's revenue (the input costs revenue share), and the extent to which the firm's output varies based on changes in the quantity of that input used (i.e., the output elasticity). This estimation method has been followed by a series of studies focusing on the issue of competition (Baqaee and Farhi, 2020; Barkai, 2020; De Loecker et al., 2020; Díez et al., 2021). Comprehensive reviews on different firm-level markup estimation approaches and implicit assumptions are provided by Basu (2019) and Syverson (2019).

Regarding the investment in the electricity sector, both costs and revenues were taken into consideration. On the aspect of costs, the concept of levelised cost is defined as the discounted lifetime cost of building and operating a generation asset, expressed as a cost per megawatt hour (BEIS, 2020a). This measurement reflects the total lifecycle cost, including pre-development, capital, operating, fuel, and financing costs (Joskow, 2011). Such method was later used for various technologies, such as wind and solar (Branker et al., 2011; Reichelstein and Sahoo, 2015; Mundada et al., 2016; W. Shen et al., 2020b), geothermal (Clauser and Ewert, 2018), storage (Belderbos et al., 2017), and nuclear (De Roo and Parsons, 2011). A critical assessment of levelised cost is given by Aldersey-Williams and Rubert (2019).

On the aspect of revenue, due to the high costs of renewable technologies, subsidies were often provided to support renewable projects, including price-based Feed-in Tariff (FIT) schemes and quantity-based Tradable Green Certificate (TGC) schemes. Under Feed-in Tariff schemes, electricity generators receive a fixed tariff for each unit of electricity they produce, and these schemes have been introduced in many countries, such as Germany (Grau, 2014; May, 2017; Lancker and Quaas, 2019), Spain (Schallenberg-Rodriguez and Haas, 2012; Costa-Campi and Trujillo-Baute, 2015; Ciarreta et al., 2017), and Canada (Antweiler, 2017). In contrast, under Tradable Green Certificate schemes, generators receive additional revenue from selling certificates on top of the revenue from selling electricity. This type of scheme was also widely implemented, such as the United States (Berry and Jaccard, 2001a; Barbose et al., 2015; Upton and Snyder, 2017; Young and Bistline, 2018), the United Kingdom (Wood and Dow, 2011; Woodman and Mitchell, 2011; Li et al., 2020), and Australia (Valentine, 2010; Simshauser and Tiernan, 2019; Simshauser and Gilmore, 2022).[4]

The costs and revenue are considered in theoretical models to predict the growth of renewable electricity. Chen et al. (2016) illustrate that the Emissions Prediction and Policy Analysis (EPPA) Model is a classical computable general equilibrium model, which includes advanced energy conversion technologies and accounting of both greenhouse gas and conventional pollutant emissions. The EPPA model is a multi-region (18 regions) and multi-sector (14 sectors) recursive dynamic model of the world economy. Morris et al. (2019) argue that levelised cost may be misleading in comparing dispatchable generators and intermittent generators. As a result, the study develops the markup method, which represents the measure of the cost of a technology relative to the price received for electricity generation and provides a consistent comparison of the costs of the different technologies in the EPPA model.

Empirical findings also suggest the importance of costs and revenue. Based on a cross-country firm-level dataset in Europe during 2002–10, Jaraitė and Kažukauskas (2013) show that supporting schemes largely increase the profitability of electricity generating firms, but firms operating in the TGC scheme were more profitable and more effective in promoting investment in renewable projects than those in the FIT scheme. Based on six European countries over the period 1998–2008, Gugler et al. (2013) examine the aggregate investment in the electricity sector and find that an increase in markups, captured by variation in prices, increases the investment. Further, Gugler et al. (2020) examine the disaggregated investment by electricity-generating firms from 13 European countries over the annual period 2006–14 and find positive impacts of Tobin's q, which is positively related to markups as suggested by (Rognlie, 2016; Kerspien and Madsen, 2023).

3. Background

The Renewables Obligation (RO) scheme was implemented in 2002. The RO scheme was first implemented in England, Wales, and Scotland, and then expanded to Northern Ireland in 2005. Under the RO scheme, regulators issue Renewable Obligation certificates to accredited renewable electricity generators and require electricity suppliers to purchase a certain number of certificates to meet their obligations. If suppliers fail to meet their obligations, they need to pay the penalty for the failed obligation. Besides, a recycling mechanism redistributes total penalties to suppliers who presented certificates. The RO scheme closed to new entrants in April 2017, with various grace periods for different technologies.

3.1. *Renewable capacity under the RO*

The total installed capacity of all eligible renewable technologies increased from 1.68 GW in 2002/03 to 35.19 GW in 2018/2019 (Ofgem, 2019b). Fig. 1 shows the accumulative capacity of onshore wind, offshore wind, and solar that received accreditation under the RO scheme. For onshore wind, the accumulative capacity displayed a continuously rising trend, from 0.51 GW in 2002/03 to 12.21 GW in 2018/19. In contrast, offshore wind began to grow from 2009/10, rising to 6.56 GW in 2018/19. Besides, solar began to rise even later from 2012/13, and then increased to 5.94 GW in 2018/19.[5]

Another large category of renewable technology is bioenergy. In the

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[4] The effectiveness of these schemes in promoting renewable generation are documented in several survey studies (Darmani et al., 2016; Schallenberg-Rodriguez, 2017; N. Shen et al., 2020a).

[5] Other renewable technologies were also eligible for the RO scheme but not selected for our analysis due to relatively smaller capacity. In 2018/19, examples include landfill gas (871 MW), sewage gas (210 MW), hydro (721 MW), wave (3 MW) and tidal (14 MW).

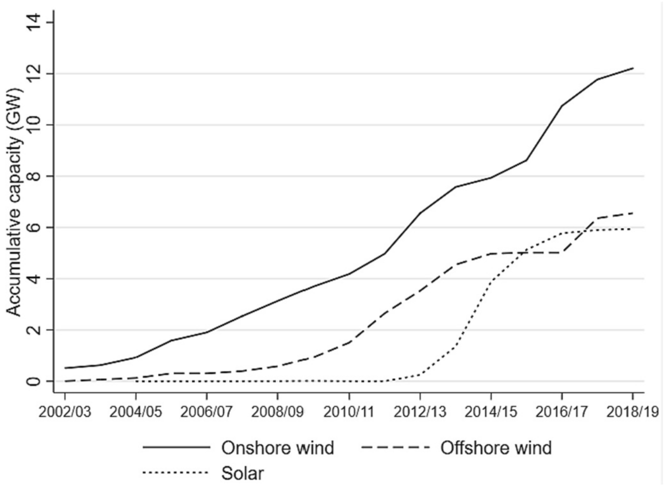

Fig. 1. Renewable capacity accredited under the RO, 2002/03 to 2018/19. Source: Renewables Obligation Annual Reports, Ofgem.

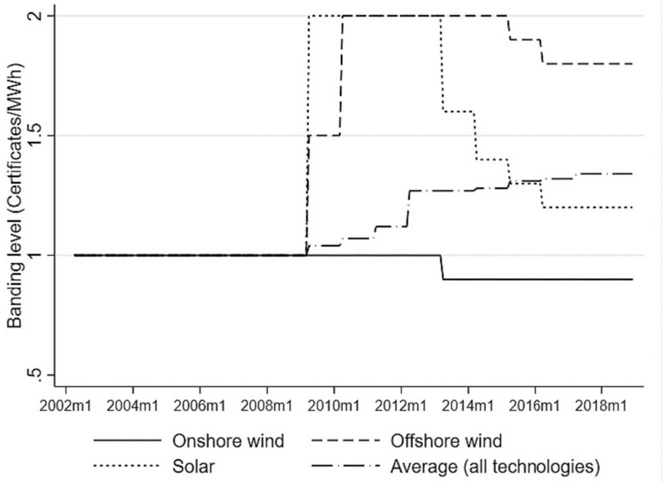

Fig. 2. The banding levels of onshore wind, offshore wind, and solar under the RO, 2002/03 to 2018/19. Source: Ofgem.

RO scheme, it was divided into landfill gas, sewage gas, and fuelled. The fuelled is further divided into dedicated biomass, ACT, and fuelled (co-firing fuelled and biomass). The estimated renewable capacity from fuelled was around 8.66 GW in 2018/19. However, instead of banding, the main policy amendment affecting this category was the co-firing cap, in which suppliers were allowed to meet a certain percentage of their obligation by certificates issued to co-firing generating stations. Therefore, as this study is focused on the impact of banding, fuelled is not included in the analysis due to less relevance.[6]

3.2. Banding

The RO scheme was designed as technology-neutral to encourage competition among different technologies. All technologies received one certificate for each megawatt-hour (MWh) of electricity generated. However, this technology-neutral failed to promote the diversification of renewable technologies as less matured technologies were less favoured due to higher costs. Therefore, in April 2009, banding was introduced to provide differentiated support to technologies at different stages of development.[7]

With banding, a fewer number of certificates would be awarded to each MWh of electricity generated from established technologies, while more were awarded to less-developed technologies. Fig. 2 shows the banding level for three renewable technologies from 2002/03 to 2018/19 (Ofgem, 2013, 2019a). The banding level for onshore wind remained at one certificate/MWh when banding was introduced in 2009/10 but then decreased to 0.9 in 2013/14. For offshore wind, the banding level increased to 1.5 certificates/MWh in 2009/10 and then rose further to 2 in 2010/11. Besides, solar received 2 certificates/MWh in 2009/10, but then decreased continuously from 1.6 in 2013/14 to 1.2 in 2016/17.[8]

For comparison, the weighted average banding level of all technologies increased from 1.04 in 2009/10 to 1.34 in 2018/19, which was calculated as the total number of certificates issued divided by the total generation from accredited generators. Given the price of certificates, the average support per MWh supplied from renewable generators increased from £45.94/MWh in 2002/03 to £73.75/MWh in 2018/19 (Ofgem, 2003, 2019b).

The introduction of banding changes the subsidies received and thus investors' preference, therefore encouraging the development of less matured technologies. Moreover, the banding level also makes the scheme more adjustable as the banding level can be changed to accommodate the speed of development (Buckman, 2011). For example, the periodical review by the government in 2012 amended the banding levels for different technologies effectively from April 2013 (Ofgem, 2019a).

Based on the previous discussion, it may be argued that the introduction of banding stimulates less developed technologies such as offshore wind, which began to rise in 2009/10. However, the impact on onshore wind and solar remained unclear, and in particular, the solar only began to rise from 2012/13. Therefore, this paper will explore the impact of banding on the development of renewable technologies, focusing on onshore wind, offshore wind, and solar.

4. Data

4.1. Added capacity

The series of the added and accumulative capacity of onshore wind, offshore wind, and solar under the RO scheme were collected from the CHP register, which provides the installed capacity of stations accredited under the scheme (Ofgem, 2020).[9] Compared with the accumulative capacity, the added capacity more accurately reflects the impacts of policy intervention and markups on the installation of renewable technologies. When the policy is less favourable, the added capacities may decrease but remain positive. However, the accumulative capacity continues to rise as long as the added capacity is positive. Therefore, the impacts of policy changes may be misleading if the analysis is based on accumulative capacity.

Fig. 3 shows the added and accumulative capacities for three

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[6] The regression analysis on fuelled confirms that banding has an insignificant impact on the added capacity, and results are available upon request.

[7] The banding level introduced in 2009/10 applied to stations accredited after July 2016 (Ofgem, 2010). However, the grandfathering rule was more formally set in 2013/14 to maintain the same level of support as was available at the point of accreditation for the whole duration of its support under the RO (Ofgem, 2019a).

[8] The banding level for solar divides into building-mounted and ground-mounted. As the latter accounts for >90% of capacity, we select its banding level (BEIS, 2020b). The banding level also changed for other eligible technologies in 2009/10. For example, landfill gas (0.25 certificates/MWh), sewage gas (0.5 certificates/MWh), and wave and tidal (2 certificates/MWh) (DECC, 2010a).

[9] The series is the Declared Net Capacity which means “the maximum capacity at which the station could be operated for a sustained period less the amount of electricity that is consumed by the plant” (Ofgem, 2020).

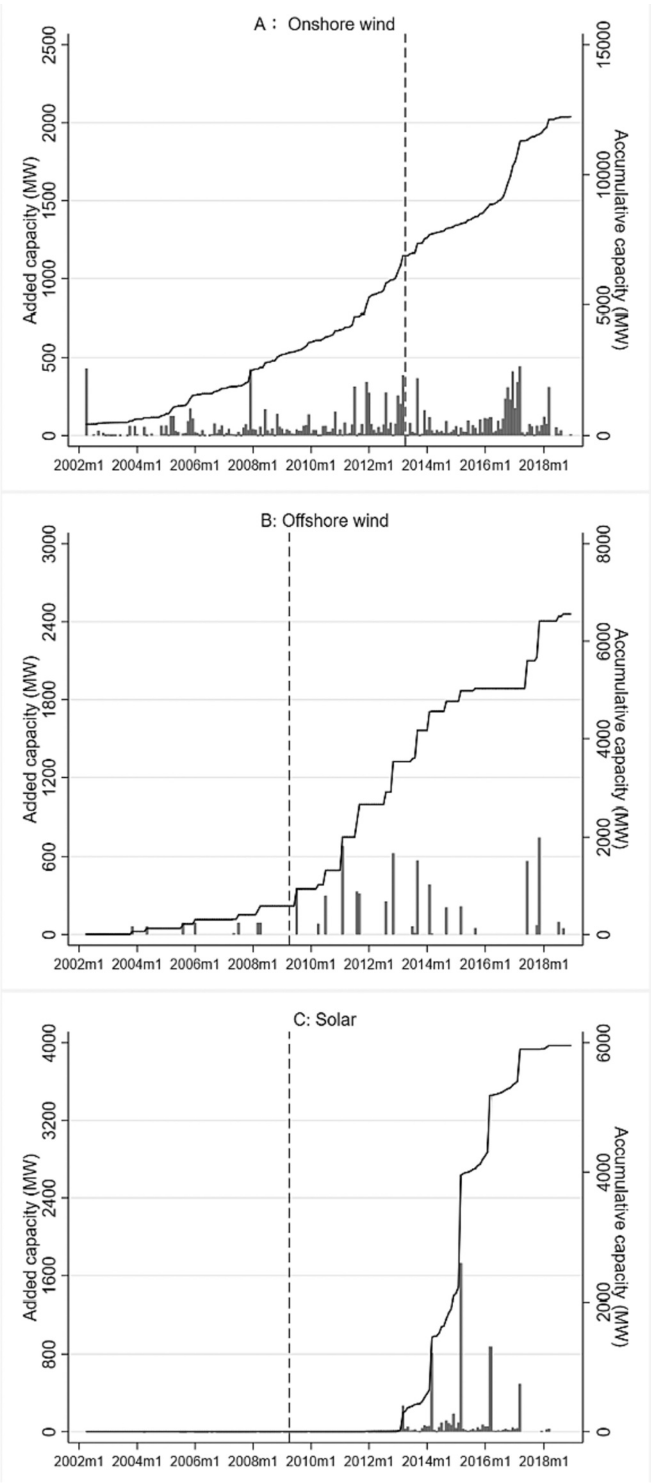

Fig. 3. Added capacity and accumulated capacity for onshore wind, offshore wind, and solar, April 2002 to December 2018. The vertical dashed line indicates the key change in the banding level. Source: Authors' own calculation based on data from Ofgem.

technologies. First, the added capacity of onshore wind increases consistently. One fast-growing period was seen before 2013 as the wind farms that received accreditation after April would receive 0.9 certificates/MWh due to the decrease in the banding level. Another fast-growing period was before the closing date for new applications for onshore wind, which was in *May 2016* with grace periods to *January* 2019. Second, the added capacity of offshore wind increased obviously after the change in the banding level in April 2009, and, similar to onshore wind, there was a surge in the added capacity before the scheme closed in *March 2017* with grace periods to *March 2018*. The added capacity of offshore wind was sparser, possibly due to the availability of sites. Third, although the banding level for solar increased in April 2009, the installed capacity of solar only began to increase from March 2013. The added installed capacity continued to increase and then displayed a downward trend because the RO scheme was closed to solar PV in *March 2015* with grace periods to *March 2017*.[10],[11]

4.2. *Electricity price*

The series of half-hourly wholesale electricity price is downloaded from Elexon and converted to the monthly average. As Fig. 4 shows, the electricity price was quite volatile between March 2003 and March 2010, with two spikes observed in March 2006 (at £63.20/MWh) and September 2008 (at £96.19/MWh). After March 2010, the electricity price was less volatile but still fluctuated between £31.96/MWh to £63.34/MWh.

4.3. *Levelised cost*

The levelised cost measures the average net present costs of electricity generation during the life cycle of a station and is calculated as the total costs over the station's lifetime divided by the total electricity generated over the station's lifetime. The annual weighted global average levelised costs are collected from the International Renewable Energy Agency (IRENA, 2020) and converted to monthly data by Denton's method.

As Fig. 5 shows, the levelised cost of onshore wind were on a decreasing trend, from £81.11 in April 2002 to £43.44/MWh in December 2018. Compared with onshore wind, the levelised cost of offshore wind was quite similar at the early stage but began to increase in 2007 as projects were located in deeper waters further from shore (IRENA, 2020), reaching £99.52/MWh in December 2018. Besides, the

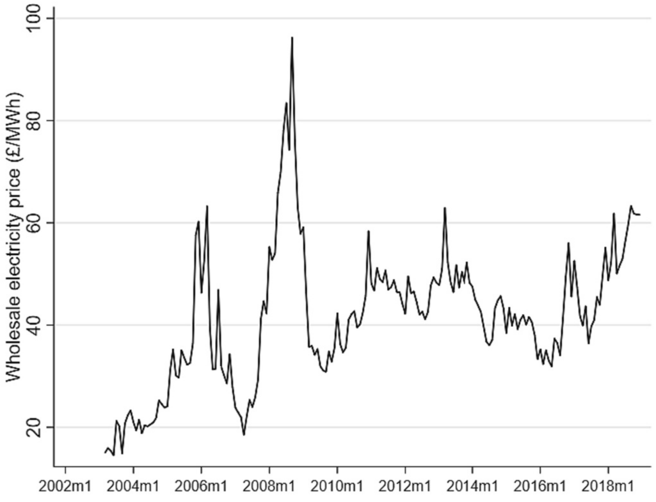

Fig. 4. The GB wholesale electricity price, March 2003 to December 2018. Source: Elexon.

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[10] This grace period was for small-sized solar PV <5 MW. For solar PV >5 MW, the grace period was to March 2016.

[11] For Northern Ireland, the close dates were later: March 2016 for onshore wind (with grace periods to December 2018). The official close date, March 2017, applies to solar PV and offshore wind.

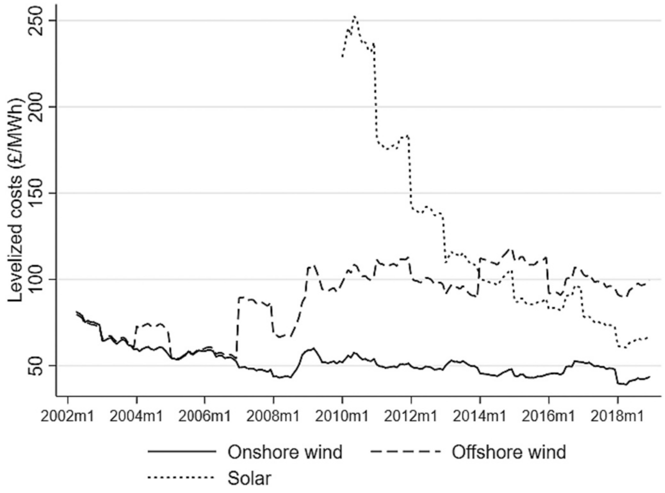

Fig. 5. The levelised costs of onshore, offshore wind and solar (onshore and offshore wind, April 2002 to December 2018; solar, January 2010 to December 2018). Source: Renewable Power Generation Costs Report, IRENA.

levelised cost of solar decreased sharply during the same interval, from £228.96/MWh in January 2010 to £67.14/MWh in December 2018, largely resulted from the dramatic decline in the price of crystalline silicon modules (IRENA, 2020).

4.4. *Subsidies from the RO scheme and the banding level*

In addition to the wholesale electricity prices, support schemes, such as the RO scheme, provide additional revenue to suppliers to cover the costs. Under the RO scheme, depending on the banding level, renewable generators receive a specific number of certificates for each MWh of electricity generation and then the support level per MWh can be calculated after multiplying with the certificate price, which fluctuated between £42.27 and £55.04 between 2002 and 2018.[12] For example, as the banding level for offshore wind was 2 certificates per MWh and the certificate price was £42.27 in 2011/12, each MWh of electricity generated by an accredited offshore wind station in this financial year received £82.54.

4.5. *Markup*

In this analysis, the markup is defined as the difference between revenues (from both the wholesale market and the support level) and costs, and we consider it as the crucial factor in determining investment decisions by investors and thus the added capacity of renewable technologies.

4.5.1. *Markup without banding (before April 2009)*

Before banding was introduced, the design of ‘technology neutral’ in the RO scheme indicates that renewable generators with different technologies receive one certificate and thus the same level of subsidy for each MWh of electricity generated. Therefore, before April 2009, the markup per MWh for renewable technology *i* with technology neutrality (no banding), $mk_{i,t}^{nb}$, can be written as:

$$mk_{i,t}^{nb} = wp_t - lc_{i,t} + rp_t \tag{1}$$

where wp_t denotes the wholesale electricity price, $lc_{i,t}$ denotes the levelised cost for technology *i*, and rp_t denotes the price of certificates.

4.5.2. *Markup with banding (since April 2009)*

Banding changed the support level of different renewable technologies, and thus changed the markup of different renewable technologies to encourage less developed technologies. The banding level means the number of certificates renewable generators can receive when they generate one MWh of electricity. After taking the banding level, the markup per MWh for technology *i*, $mk_{i,t}^{b}$, becomes

$$mk_{i,t}^{b} = wp_t - lc_{i,t} + b_{i,t} \bullet rp_t \tag{2}$$

where $b_{i,t}$ is the banding level for technology *i*, measured as the number of certificates per MWh.

4.5.3. *Markups of the three renewable technologies in 2003–18*

As shown in Fig. 6, the markups of onshore wind and offshore wind were quite volatile mainly due to the volatility in the wholesale electricity prices before 2009 and settled down afterwards. Although the rising steel prices pushed up the levelised cost for offshore wind since 2009, the increase in the banding level from 1 certificate/MWh to 2 certificates/MWh helped offset its cost disadvantage. From 2016, the markups were quite close between onshore wind and offshore wind, and then reached £67.69/MWh for onshore wind and £61.14/MWh for offshore wind in December 2018, respectively. Meanwhile, due to the limited availability of data on the levelised cost, the markup of solar was shown from 2010 to 2018, which turned positive from December 2012 but rose sharply since then to £60.50/MWh in December 2018.

4.6. *Markup and added capacity*

This subsection depicts markups and added capacities to provide a preliminary graphical analysis, as shown in Fig. 7. First, for onshore wind, after the banding level was reduced to 0.9 in 2013, th e markup moved to a slightly lower level, and the added capacity seems to be subdued. The added capacity later picked up, possibly due to the rising markup and the closure of the RO scheme. Second, for offshore wind, the markup was more volatile due to the levelised cost, although the banding level was doubled. Its added capacity seems to be positively correlated with the markup.

Third, for solar, the added capacity remained close to zero when the markup remained negative before December 2012, even the banding level changed to 2 in April 2009. The added capacity began to increase when the markup turned positive, due to the continuous fall in the

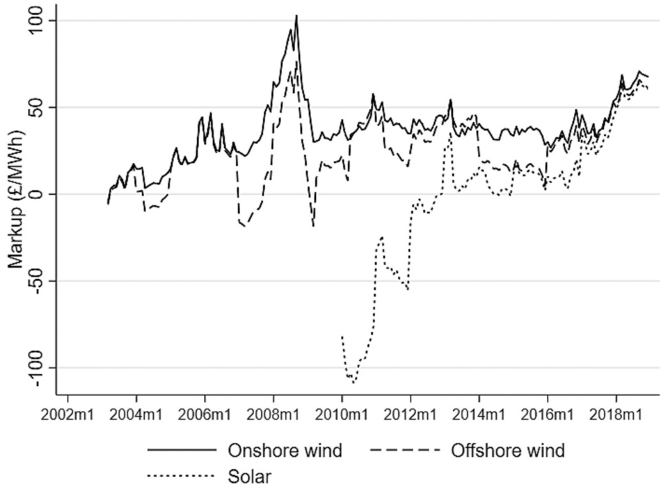

Fig. 6. The markups of onshore, offshore wind and solar (onshore and offshore wind, March 2003 to December 2018; solar, January 2010 to December 2018). Source: Authors' own calculation based on data from Elexon, IRENA, and Ofgem.

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[12] The annual certificate price was collected from the Renewable Obligation Annual Report, and it was approximated by the sum of the penalty and the recycling value (Ofgem, 2019b; Li et al., 2020).

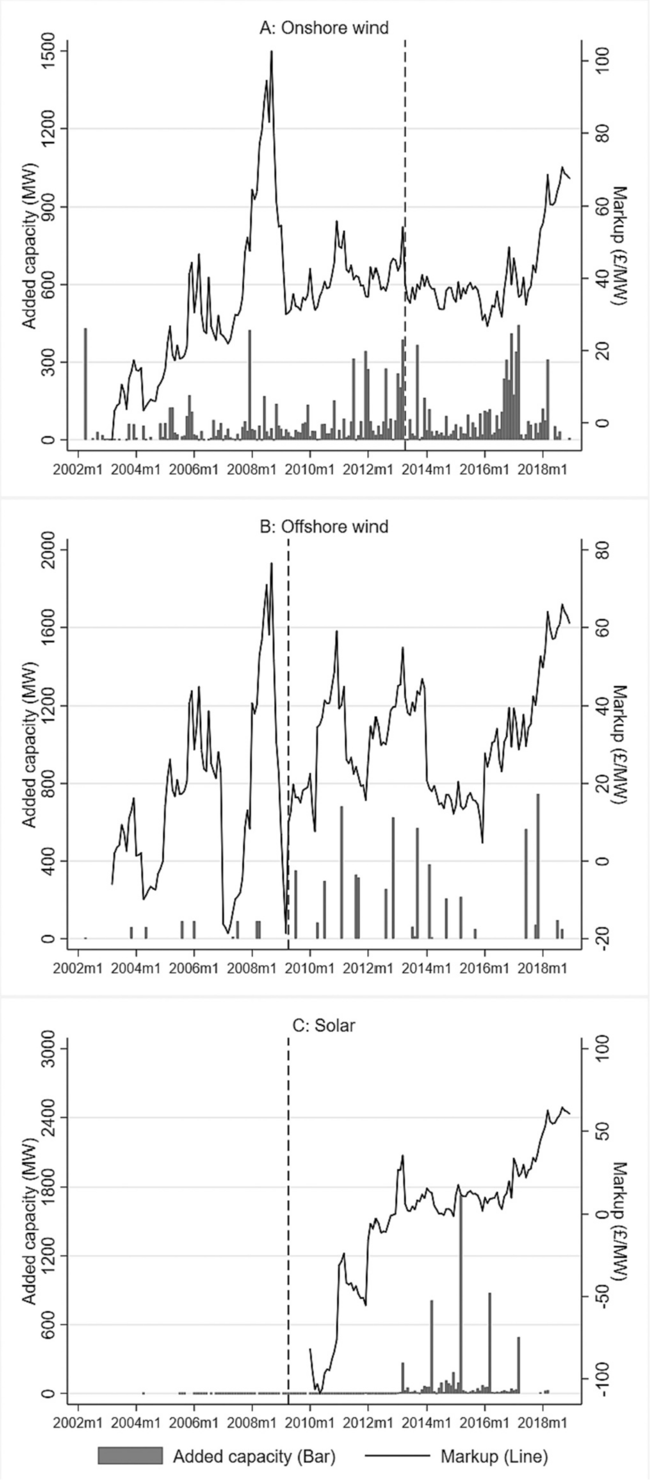

Fig. 7. The added capacity of onshore, offshore wind and solar (April 2002 to December 2018) and markups of onshore, offshore wind (March 2003 to December 2018) and solar (January 2010 to December 2018). Source: Authors' own calculation based on data from Elexon, IRENA, and Ofgem.

levelised cost. After the RO scheme closed to solar in March 2015, the added capacity decreased in the grace periods. The example of solar clearly indicates that the banding level does not directly affect the added capacity as an independent policy change, but through changing the markup and then the decisions of investors.

4.7. Statistics of variables

Table 1 shows the statistics of variables with different periods for these technologies due to the availability of data and various closure dates. We first consider sample periods to the closure dates. The sample period covers from March 2003 to March 2016 (closure date) for onshore wind and to March 2017 (closure date) for offshore wind. For solar, due to the limited availability of data on the levelised cost, the sample period is from January 2010 to March 2015.[13]

Second, as added capacity still increased after the closure data during the grace periods, we also consider the sample periods to the end of grace periods for robust analysis.[14] Therefore, the sample periods ended in December 2018 for onshore wind, September 2018 for offshore wind, and March 2017 for solar.

5. Model specification and methodology

Banding provides differentiated support to different renewable technologies and the focus of this analysis is to understand its impacts on the added capacity. The existing papers employ a dummy variable or discrete values for banding in cross-states analysis. This paper provides a deeper quantitative analysis based on time series. Further, this paper conducts a counterfactual analysis to facilitate a comparison between the actual scenario and the hypothetical scenario in which banding was not introduced.[15]

The analysis includes two parts. In the first part, the impact of markups on the added installed capacity for three technologies under the RO scheme is examined. The specification is

$$adc_{i,t} = \beta_{i,0} + \beta_{i,1} mk_{i,t} + \varepsilon_t \tag{3}$$

for technology i, including onshore wind, offshore wind, and solar. The $adc_{i,t}$ is the added capacity, the $mk_{i,t}$ is the markup, t indexes the observation month, and ε_t is the error term.[16] The model is estimated using OLS methods with the Newey-West estimator to correct the problems of autocorrelation and heteroscedasticity (Newey and West, 1986).

In the second part, the counterfactual analysis is conducted. The banding level is removed, and all technologies are assumed to receive one certificate for each MWh of generation. Then the hypothetical markup, $mk_{i,t}^{nb}$, is generated, which is used to calculate the hypothetical added capacity, $adc_{i,t}^{nb}$, based on the estimated relationship from the first part,

$$adc_{i,t}^{nb} = \widehat{\beta}_{i,0} + \widehat{\beta}_{i,1} mk_{i,t}^{nb} \tag{4}$$

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[13] For solar, the closure date was March 2015 for capacity >5 MW, and March 2016 for capacity equal or <5 MW, both with one year of grace period. Our analysis will not be affected if we select March 2016 as the closure date and March 2017 as the end of the grace period. Results are available upon request.

[14] Grace periods enable generating capacity to be accredited after the closure date if the eligibility requirements are met.

[15] A method assessing the effect of intervention at a point of time is known as the interrupted time series analysis (Kyritsis et al., 2017) or quasi-experimental time series analysis (Bernal et al., 2017; Michanowicz et al., 2021). However, this study does not consider the introduction of banding as an independent intervention that has a direct effect on the installed capacity. Instead, we consider that the impact of banding level feeds through to investors via its impact on the markup, which is the crucial factor in determining investment in renewable technology.

[16] Similar with early studies such as (Gugler et al., 2013) and (Morris et al., 2019), interest rates are not considered in our analysis for two reasons. First, interest rates do not capture decision-making between different investment opportunities. Second, interest rates remained flat at around 0.5% for an extended period (between March 2009 and March 2022), making it less relevant to investment decisions during this period.

Table 1

The statistics of variables. Added capacity is measured by MW and markup is measured by £/MWh.

Variables		Obs	Sample period to the closure date	Mean	Obs	Sample period to the end of the grace period	Mean
Onshore wind	Added capacity	157	03/2003–03/2016	53.23	190	–01/2019	61.77
	Markup			34.63			36.98
Offshore wind	Added capacity	169	03/2003–03/2017	29.74	187	–09/2018	35.05
	Markup			22.44			24.99
Solar	Added capacity	63	01/2010–03/2015	62.64	87	–03/2017	57.27
	Markup			–23.40			–13.46

After having the hypothetical added capacity, the hypothetical accumulative capacity, $acc^{np}_{i,t}$, can be calculated as

$$acc^{np}_{i,t} = \sum\nolimits_{i=1}^{n} adc^{np}_{i,t} \tag{5}$$

The hypothetical added and accumulative capacity should shed light on the possible mix of different technologies if banding was not introduced in April 2009, thus helping understand the impacts on generation and costs of the scheme.

6. Empirical results

Table 2 reports the results from the OLS estimation.[17] The coefficient of markup measures the marginal impact of markup on the added capacity, and the constant captures the structural component of the added capacity that does not depend on the markup.

We first discuss the results for the sample periods that ended at the closure dates. For onshore wind, the coefficient on the markup is 0.876, suggesting that a £1/MWh increase in the markup increases the added capacity by 0.876 MW. For offshore wind, the coefficient on the markup is 0.664, suggesting that a £1/MWh increase in the markup increases the added capacity by 0.664 MW. For solar, the coefficient on the markup is 1.052, suggesting that a £1/MWh increase in the markup increases the added capacity by 1.052 MW. All these coefficients are statistically significant at the 5% or the 10% level.[18] Next, we estimate the relationship using the samples extended to the end of grace periods as added installed capacity still increased after the closure date. This robust analysis shows that coefficients are similar and also statistically significant at the 5% or the 10% level.

7. Counterfactual analysis

The previous section estimated the relationship between the added capacity and the markups of onshore wind, offshore wind, and solar, respectively. In this section, to examine the impact of banding, we remove banding by setting the banding level to one for all technologies in Eq. (2). Therefore, we produce the hypothetical markup and then calculate the hypothetical added capacity and accumulative capacity.

7.1. Hypothetical capacity of onshore wind

For onshore wind, the banding level decreased from one to 0.9 in April 2013, and Fig. 8 plots the actual markup and the hypothetical markup. As the banding level decreased slightly, the actual markup was marginally lower than the hypothetical markup.

Next, the estimated relationship between the added capacity and actual markup of onshore wind from Table 2 is

$$\widehat{adc}_{on,t} = 0.876^{*} mk_{on,t} + 22.885 \tag{6}$$

where $mk_{on,t}$ is the actual markup of onshore wind.

Based on this relationship, we substitute the actual markup with the hypothetical markup to produce the hypothetical added capacity for the period from April 2013 as

$$adc^{nb}_{on,t} = 0.876^{*} mk^{nb}_{on,t} + 22.885 \; t \geq 2013m4 \tag{7}$$

where $mk^{nb}_{on,t}$ is the hypothetical markup and $adc^{nb}_{on,t}$ is the hypothetical added capacity in the scenario without banding.

Then we calculate the hypothetical accumulative capacity according to Eq. (5). Fig. 9 shows that the accumulative capacity of onshore wind has similar trends in both scenarios after April 2013. In another word, after the introduction of banding, the markup of onshore wind is still attractive to investors and promotes onshore projects. Nonetheless, we expect that the hypothetical accumulative capacity should be slightly higher than the actual value as the hypothetical banding level was higher. But the higher actual accumulative capacity can be explained by the surge in the application before the closure date for onshore wind in March 2017.

7.2. Hypothetical capacity of offshore wind

For offshore wind, the banding level increased from one to 1.5 in April 2009 and then rose further to 2 in April 2010, but slightly reduced to 1.9 in April 2015 and 1.8 in April 2016. The large increase in the banding level indicated that the actual markup was much higher than the hypothetical markup, as shown in Fig. 10. In particular, without the increase in the banding level, the markup of offshore wind would remain negative for an extended period.

The estimated relationship between the added capacity for offshore wind from Table 2 is

$$\widehat{adc}_{off,t} = 0.6648^{*} mk_{off,t} + 14.835 \tag{8}$$

where $mk_{off,t}$ is the actual markup of offshore wind.

Based on this relationship, we substitute the actual markup with the hypothetical markup to produce the hypothetical added capacity from April 2009,

$$adc^{nb}_{off,t} = 0.664^{*} mk^{nb}_{off,t} + 14.835 \; t \geq 2009m4 \tag{9}$$

where $mk^{nb}_{off,t}$ is the hypothetical markup without banding and $adc^{nb}_{off,t}$ is the hypothetical added capacity.

However, as Fig. 10 shows, the hypothetical markup remained negative for an extended period, leading to negative hypothetical added capacity between February 2014 and December 2015. We assume that the negative hypothetical added capacity indicates that no investment was attracted rather than that existing capacity was demolished, so we converted these negative values into zero,

$$adc^{nb}_{off,t} = 0 \; if \; adc^{nb}_{off,t} < 0 \tag{10}$$

Then we calculate the hypothetical accumulative capacity according to Eq. (5). Fig. 11 shows that there was a large gap between the actual and hypothetical accumulative capacity of offshore wind. This is because the hypothetical added capacity increased slowly if the banding

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[17] The results from the Dickey-Fuller test confirm that the series in the analysis are stationary.

[18] To reduce the impact of outliers on the regression results, we replace the unusually high added capacity in March 2015 (1728.482 MW) with the second highest added capacity (812.266 MW) in March 2014.

Table 2
Results from the OLS estimation for onshore, offshore wind and solar.

	Samples end at the closure date			Samples end at the grace period date		
	(1)	(2)	(3)	(4)	(5)	(6)
	Onshore wind	Offshore wind	Solar	Onshore wind	Offshore wind	Solar
Dependent variables: added installed capacity						
Markup	0.876**	0.664*	1.052**	0.773**	0.705*	1.03***
	(0.335)	(0.383)	(0.402)	(0.331)	(0.361)	(0.312)
Constant	22.885**	14.835**	72.709***	33.188***	17.424**	71.135***
	(10.176)	(6.428)	(26.758)	(11.527)	(6.878)	(20.436)
Observations	157	169	63	190	187	87

Standard Error in parentheses, *** $p < 0.01$, ** $p < 0.05$, * $p < 0.1$.

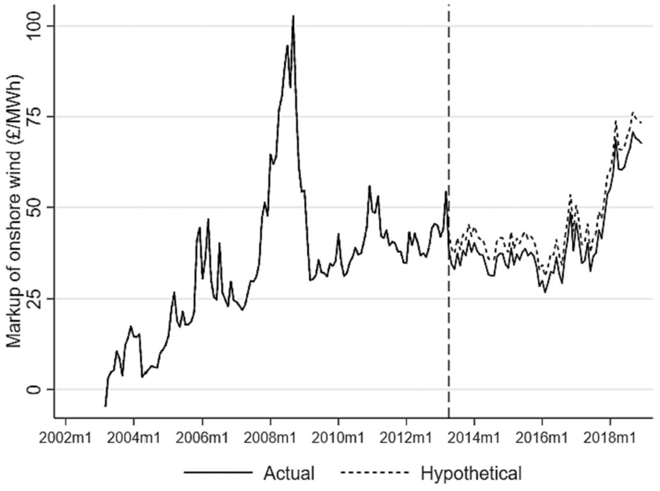

Fig. 8. The actual (solid line) and hypothetical markup (dashed line) of onshore wind, March 2003 to December 2018. Source: Authors' own calculation based on data from Elexon, IRENA, and Ofgem.

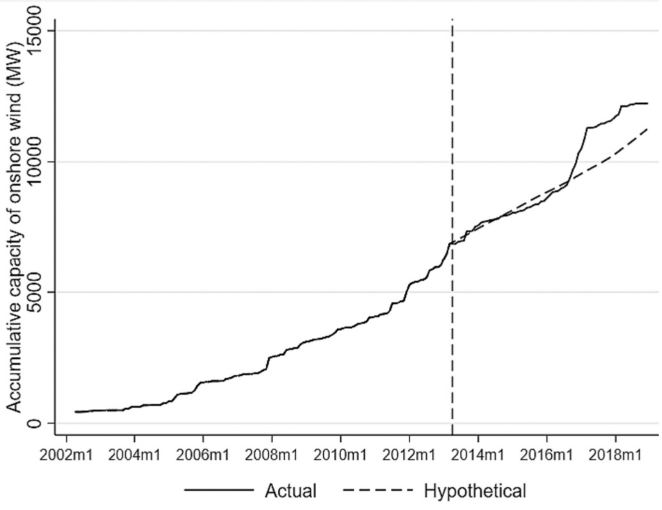

Fig. 9. The actual (solid line) and hypothetical accumulative capacity (dashed line) of onshore wind, April 2002 to December 2018. Source: Authors' own calculation based on data from Elexon, IRENA, Ofgem, and estimated results.

level stayed at one, and even remained silent during the period between February 2014 and December 2015. The large difference between these two scenarios indicates the important impact of banding on the capacity of offshore wind.

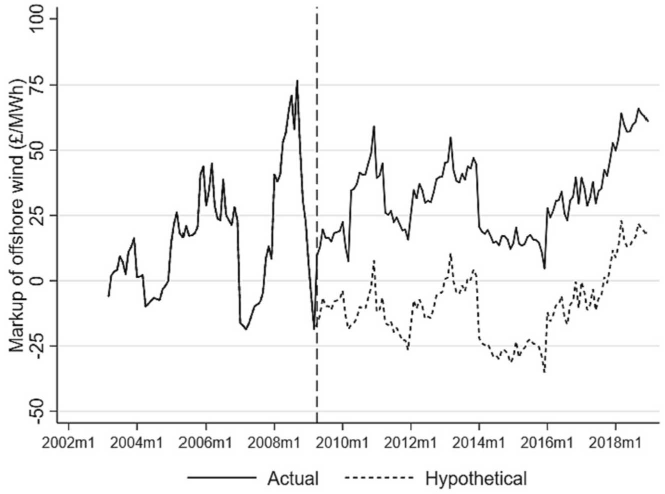

Fig. 10. The actual (solid line) and hypothetical markup (dashed line) of offshore wind in the UK, March 2003 to December 2018. Source: Authors' own calculation based on data from Elexon, IRENA, and Ofgem.

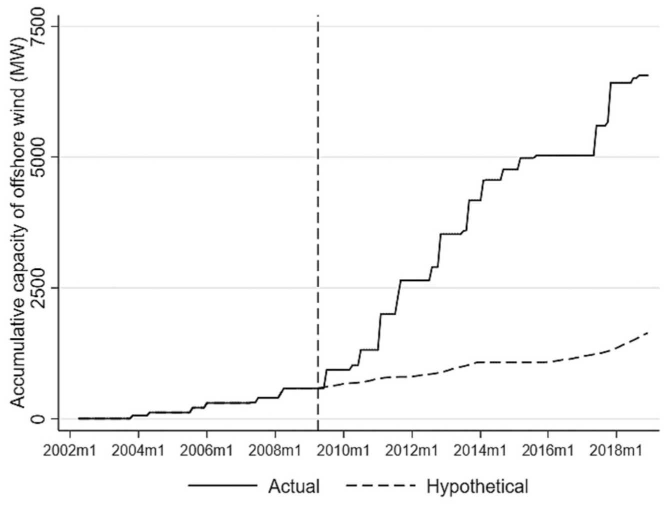

Fig. 11. The actual (solid line) and hypothetical accumulative capacity (dashed line) of offshore wind, April 2002 to December 2018.
Source: Authors' own calculation based on data from Elexon, IRENA, Ofgem, and estimated results.

7.3. Hypothetical capacity of solar

For solar, the banding level increased to 2 in April 2009, and then decreased to 1.6 in April 2013, 1.4 in April 2014, 1.3 in April 2015 and

1.2 in April 2016. As shown in Fig. 12, with the increased banding level, the markup turned positive in December 2012. If the banding level stayed at one, the hypothetical markup would remain negative for longer and turn positive in September 2016.

For solar, the estimated relationship between the added capacity and the markup from Table 2 is,

$$\widehat{adc}_{sol,t} = 1.052*mk_{sol,t} + 72.709 \tag{11}$$

where $mk_{sol,t}$ is the actual markup of solar.

Based on this relationship, we substitute the actual markup with the hypothetical markup to produce the hypothetical added capacity from January 2010,[19]

$$adc^{nb}_{sol,t} = 1.052*mk^{nb}_{sol,t} + 72.709 \; t \geq 2010m1 \tag{12}$$

where $mk^{nb}_{off,t}$ is the hypothetical markup without banding and $adc^{nb}_{off,t}$ is the hypothetical added capacity.

However, as Fig. 11 shows, the hypothetical markup remained negative for an extended period, leading to negative hypothetical added capacity until December 2011. Again, we assume that the negative hypothetical added capacity indicates that no investment was attracted, so we converted these negative values into zero,

$$adc^{nb}_{sol,t} = 0 \; if \; adc^{nb}_{sol,t} < 0 \tag{13}$$

Then we calculate the hypothetical accumulative capacity according to Eq. (5). Fig. 13 shows that both the actual and hypothetical accumulative capacity began to increase in early 2012. As the RO scheme was closed to solar, the actual accumulative capacity became flat at the end of the grace period in March 2017. The hypothetical accumulative capacity was moderately behind but has caught up in the last two years, reaching a similar level in March 2019. Without the increase in banding, solar would still increase but at a lower speed, but ultimately caught up.

7.4. Discussions

This section compares the accumulative capacity from both scenarios for onshore wind, offshore wind, and solar, and then discusses the impacts on the other aspects of the electricity sector, such as generation and costs of the RO scheme. To compare with the actual achievement, the values in this section are based on the calendar year 2018.[20]

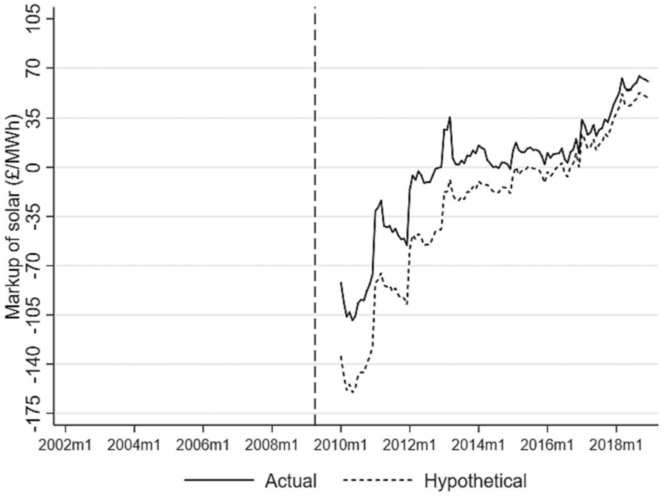

Fig. 12. The actual (solid line) and hypothetical markup (dashed line) of solar, January 2010 to December 2018. Source: Authors' own calculation based on data from Elexon, IRENA, and Ofgem.

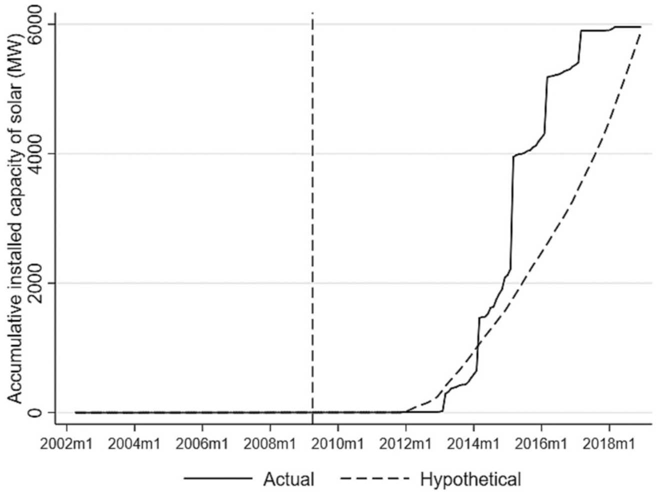

Fig. 13. The actual (solid line) and hypothetical accumulative capacity (dashed line) of solar, April 2002 to December 2018. Source: Authors' own calculation based on data from Elexon, IRENA, Ofgem, and estimated results.

7.4.1. Capacity

We first compare the capacity of renewable generators between these two scenarios. Table 3 shows the capacity of onshore wind, offshore wind, and solar under these two scenarios. The actual values of installed capacity by the end of 2018 were collected from the CHP register (Ofgem, 2020) and the hypothetical values were constructed in previous

Table 3
The capacity and generation from onshore wind, offshore wind, and solar under the RO scheme in the actual and the hypothetical scenario, 2018.

Installed capacity under the RO scheme (GW)	Actual	Hypothetical	Hypothetical to Actual ratio, in %
Onshore wind	12.23	11.25	92.01%
Offshore wind	6.56	1.64	25.02%
Solar	5.96	5.87	98.45%
Total capacity under the RO (onshore wind, offshore wind, solar) (GW)	24.74	18.76	75.81%
Generation under the RO scheme (TWh)	Actual	Hypothetical	Difference
Onshore wind	27.88	25.65	
Offshore wind	21.11	5.28	
Solar	7.07	6.96	
Total generation under the RO (onshore wind, offshore wind, solar) (TWh)	56.05	37.89	18.16
All renewable energy generation (TWh)	110.00	91.84	
Total generation (TWh)	332.72	332.72	
Percentage of generation from renewables	33.06%	27.60%	

Source: Authors' own calculation based on data from Ofgem, BEIS, and estimated results.

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[19] The levelised cost of solar (thus the markup of solar) is only available from January 2010.

[20] If the series is in financial years, we convert it to calendar years by taking a weighted average, with a quarter in the formal financial year and three quarters in the latter financial year. For example, the value for 2018 is produced as one-fourth of 2017–18 (i.e., January 2018 to March 2018) and three-fourth of 2018–2019 (i.e., April 2018 to December 2018).

sections. While offshore wind and solar show similar values between the two scenarios, offshore wind has much lower capacity in the hypothetical scenario because it was not attractive to investors if banding was not introduced. In 2018, the hypothetical accumulative capacity of these three technologies was 18.76 GW, lower than the actual capacity of 24.74 GW. Here we also calculate the ratio of hypothetical capacity to actual capacity, which will be used to approximate the generation in the hypothetical scenario in the analysis below.

7.4.2. Generation

The data about generation from these three technologies under the RO scheme is collected from RO annual reports and then converted to the calendar year 2018. Next, we approximate the hypothetical generation by multiplying the actual generation with the ratio we calculated from the capacity. The second part of Table 3 shows that, if banding was not introduced in the hypothetical scenario, the generation would be 18.16 TWh less than the actual value.

This gap of 18.16 TWh would help understand if the UK was on track to meet its target of 30% of electricity from renewables by 2020. In the actual scenario, the generation from all renewable sources was 110.00 TWh, and the total generation was 332.72 TWh (BEIS, 2019), so the share of electricity generated from renewable sources was *33.06%* in 2018, exceeding the target of *30%* for 2020.

In contrast, in the hypothetical scenario, the renewable generation would be 91.84 TWh, after deducting the gap of 18.16 TWh. Therefore, the share of electricity from renewables would be *27.60%* in 2018, assuming the total generation remained the same to meet the demand. Therefore, the UK would not meet the 30% target in 2018, and there was no guarantee that the target would definitely be met in 2020.

7.4.3. Costs of the RO scheme and fuel costs

Renewable generation was lower in the hypothetical scenario, but the costs of the scheme should also be lower. In the actual scenario, the costs of the RO scheme reached £5.67 billion in 2018, given the total renewable electricity under the RO was 78.13 TWh and the certificate price was £54.12.

In contrast, in the hypothetical scenario, the renewable electricity under the RO would be 18.16 TWh less, so the total renewable generation under the RO would be 59.97 TWh. As the banding level was at one for all technologies and assumes the certificate price remained the same, the costs of the RO scheme would be £3.25 billion, which is £2.42 billion less than the actual scenario, as shown in Table 4.

However, while the costs of the RO scheme are lower in the hypothetical scenario, the costs of fuels should also be taken into account if the gap of 18.16 TWh is replaced by coal or gas. As shown in Table 5, in the case of coal, as 0.508 kg of coal is required to generate one kWh of electricity (EIA, 2021), a total of 9.34 million tonnes of coal would be needed. Given the price of coal was £69.02 per tonne in 2018, the costs of coal would be £0.64 billion, which will be passed to consumers. In the case of gas, 7.40 cubic feet is required to generate one kWh of electricity (EIA, 2021), so a total of 134.4 billion cubic feet (1.344 billion therms) of natural gas would be required. As the gas price was 60.15 pence per therm in 2018, the costs of gas would be £0.81 billion, and these costs would be passed to consumers.

Table 4
The costs of the RO scheme in the actual and hypothetical scenarios, 2018.

	Actual	Hypothetical
Reduction in RE generation without banding under the RO (TWh)		18.16
All RE generation under the RO (TWh)	78.13	59.97
Average banding level (certificates/MWh)	1.34	1
Total number of certificates (million)	104.69	59.97
Certificate price (£/certificate)	54.12	54.12
Subsidy under the RO (£billion)	5.67	3.25

Source: Authors' own calculation based on data from Ofgem and estimated results.

Table 5
The costs of fossil fuels required to cover the generation gap, 2018.

	Case 1: Coal	Case 2: Gas
Fuel consumption per kWh	0.508 kg	7.40 cubic feet
Fuel consumption to cover the gap	9.34 mn tonnes	1.344 bn therm
Fuel prices in 2018	£69.02 per tonne	60.15 pence per therm
Additional fuel costs	£0.64 billion	£0.81 billion

Source: Authors' own calculation based on data from EIA, DataStream, and estimated results.

8. Conclusion

In the Renewables Obligation scheme implemented from April 2002 in the UK, the feature of technology-neutral in its early stage implied that all renewable technologies received one certificate for each megawatt hour of electricity generated. This feature aimed to encourage competition and helped achieve renewable targets by the most economical means, but less-developed renewable technologies were severely disadvantaged. Therefore, banding was introduced in April 2009 to improve the diversity of renewable technologies by providing differentiated support according to their investment costs and associated risks.

The impacts of banding were discussed qualitatively by existing studies, and only a limited number of studies have examined its impacts from quantitative aspects. In these quantitative studies based on cross-state analysis in the United States, banding was measured as a dummy variable or discrete values between zero and four, and had an insignificant impact on the development of renewable generation, and this was explained as different factors cancelled each other out. Therefore, the positive impact of banding was not found, and this remained unsatisfactory as it was considered as an important design by qualitative studies.

This study was the first quantitative study to examine the impacts of banding in the UK. Unlike the cross-state studies, our analysis was based on time-series data from March 2002 to December 2018, and the analysis of three technologies (onshore wind, offshore wind, and solar) should provide a deeper understanding of the dynamic impacts of banding on the added capacity.

First, the introduction of banding was not considered as an independent policy intervention. Instead, this study considered its impact via its feed-through effect on the markups and then investors' decisions on renewable projects (and thus added capacity). In other words, the increase in the added capacity was the direct result of markups, which were affected by the banding level (and thus the support level). We calculated the markups using the electricity price, levelised cost, and support level for these three technologies, and our estimation found that the markups had significantly positive impacts on the added capacity of all three technologies.

Second, to understand the impact of banding, we removed this feature by assuming that all technologies still received one certificate per megawatt hour after April 2009, and in this way, we constructed the hypothetical markups. Based on the estimated relationship between added capacity and actual markups, we substituted the actual markups with hypothetical markups to derive hypothetical added capacity and thus accumulative capacity. We found that (i) onshore wind displayed a similar growth pattern in both scenarios, and (ii) hypothetical offshore wind grew slowly and led to a large gap between the two scenarios, and (iii) hypothetical solar initially fell behind but ultimately caught up.

The comparison between the actual and hypothetical scenarios in 2018 sheds light on the impact of banding. First, the accumulative capacity of offshore wind would be much less in the hypothetical scenario, accounting for 25.02% of actual capacity. Second, the UK achieved 33.06% of electricity from renewables in 2018, exceeding the 30%

target for 2020, but the hypothetical scenario suggests that, if banding was not introduced, the percentage would be 27.60% in 2018 as the electricity from renewable sources would be 18.16 TWh lower. Third, the reduced renewable generation implied that the costs of the RO scheme were lower, £2.42 billion less than the actual scenario. However, depending on whether coal or gas was used to cover the gap, additional fuel costs of £0.64 billion or £0.81 billion would be added to consumers' utility bills.

On the one hand, our analysis suggested that banding was crucial to help the UK achieve its targets on electricity generation from renewable sources. Without banding, the UK might have difficulty in meeting the target of 2020. On the other hand, banding increased the costs of the RO scheme, but it should be acknowledged that these costs were partially offset by the reduced fuel costs. Nonetheless, our analysis should provide a wider picture of the impacts of banding if other small-weighted technologies could be included, such as landfill gas, sewage gas, and wave and tidal. Other than the three technologies we discussed, another large category eligible for the RO scheme was co-firing fuelled and biomass, with an estimated capacity of around 8.66 GW in 2018/19. However, this category was mainly affected by the co-firing cap, rather than banding, so further study may be required to examine the impacts of caps on specific technologies, which is another approach to promoting the diversity of renewable technologies.

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CRediT authorship contribution statement

Yunfei Wang: Conceptualization, Data curation, Formal analysis, Investigation, Writing – original draft. **Jinke Li:** Conceptualization, Investigation, Methodology, Writing – review & editing. **Nigel O'Leary:** Supervision. **Jing Shao:** Methodology, Validation, Writing – review & editing.

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Appendix A. Supplementary data

Supplementary data to this article can be found online at https://doi.org/10.1016/j.eneco.2024.107331.

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