An evaluation of the consumer-funded renewable obligation scheme in the UK for wind power generation

Jing Shao[a], Huanhuan Chen[a,b], Jinke Li[a,*], Guy Liu[c]

[a]*Department of Economics, School of Social Sciences, Swansea University, United Kingdom*

[b]*Zhengzhou Institute of Finance and Economics, China*

[c]*HSBC Business School, Peking University, China*

* Corresponding author. Email: jinke.li@swansea.ac.uk. Address: Department of Economics, School of Social Sciences, Swansea University, Swansea, United Kingdom, SA1 8EN.

Abstract

Wind generation increased dramatically in the UK over the last decade, partially contributed by the consumer-funded Renewable Obligation (RO) scheme introduced in 2002 as part of the government policy to support renewable energy. Despite its success in stimulating electricity generation from renewable sources, the RO scheme was closed in 2017 and succeeded by an alternative scheme, raising questions on the policy change. This paper makes the first attempt to evaluate the RO scheme by comparing the reduced spending on electricity and the costs of the scheme, focusing on wind generation. Using daily average hourly data from April 2009 to March 2021, our results from the Prais-Winsten estimation suggest that a marginal increase of 1GW in hourly wind generation reduced the wholesale electricity price by £1.28/MWh. However, we show that the reduced spending on electricity resulted from the lower price was not enough to offset the costs of the RO scheme attributed to wind farms. Therefore, the RO scheme brought negative gain to consumers through increased wind generation, indicating that its closure was in consumers' best interest.

Highlights:

Wind generation reduced prices in the wholesale electricity market

Reduced spending on electricity was less than cost of the RO scheme

Negative gain to consumers in most financial years from 2009-10 to 2020-21

Keywords: Wind generation; Wholesale electricity price; Renewable Obligation; Merit order effect; Carbon price; Prais-Winsten estimation;

Word Count:6520 (excluding title, author names and affiliations, keywords, abbreviations, table/figure captions, acknowledgements and references)

Abbreviations: Great Britain (GB), RO (Renewable Obligation), ROC (Renewable Obligation certificate), GHG (Greenhouse gas), Market Index Price (MIP), Over-the-counter (OTC), CPS (Carbon Price Support), Emissions Trading System (ETS)

JEL Codes:

Q21 - Renewable Resources and Conservation: Demand and Supply • Prices

Q41 - Energy: Demand and Supply • Prices

Q48 - Energy: Government Policy

Q51 - Environmental Economics: Valuation of Environmental Effects

1. Introduction

The Renewable Obligation (RO) scheme, a tradable green certificate (TGC) system, was introduced in 2002 to stimulate investments in large-scale renewable electricity projects in the UK. The scheme requires electricity suppliers to buy a certain proportion of their total sales from renewable sources.[1] Through a competitive market mechanism, the RO scheme aims to support investments in renewable electricity projects more efficiently from aspects: (i) renewable generators compete with traditional generators in the wholesale electricity market, and (ii) different renewable technologies compete with each other in the certificate market.[2] Under the support of the RO scheme, the UK experienced rapid growth in electricity generated from renewable sources. From 2006 to 2020, electricity generated from three main renewable sources (wind, solar, and biofuels) increased from 14.17TWh to 127.84TWh, representing 3.56% to 40.97% of total electricity generation [20]. In particular, wind generation increased from 4.26TWh in 2006 to 75.37TWh in 2020, representing 1.07% to 24.16% of total electricity generation.

The increase in renewable sources in the generation mix could negatively affect the wholesale electricity price through the merit order effect as renewable technologies tend to have lower operating costs. The wholesale electricity price is determined by the operating costs of the marginal power plant, which is the most expensive one that needs to be online to match total demand at any given time, given the assumption that plants are dispatched by increasing operating costs. Therefore, when the demand for electricity remains the same, an increase in wind generation switches off the most expensive running plants, and then the new marginal plant, with a lower operating cost, sets a lower wholesale electricity price. The empirical evidence of decreasing electricity price with increasing supply of renewable energy through the merit order effect has been found in many countries: Germany (see [21], [22], [23], [24], [25]), Spain (see [26], [27], [28], [29], [30]), Italy (see [31], [32]), Denmark (see [33], [34]); Ireland (see [35], [36]), Australia (see [37], [38]).

As the RO scheme has successfully stimulated investment in renewable projects and electricity generation from renewable sources, the merit order effect may have reduced the electricity price and thus consumer spending on electricity. However, despite its success in

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[1] The TGC system originated from the Renewable Portfolio Standard, which is a state-mandated program in the United States. For recent studies see [1], [2], and [3]. Similar schemes were also implemented in Australia [4, 5], Belgium [6], Sweden [7], Norway [8], Romania [9], Poland [10], South Korean [11], Japan [12], India [13], and China [14]. See [15] for a review on TGC schemes.

[2] Although the early stage of the RO scheme was criticised for the lack of certainty in both price and volume of certificates [16, 17], the headroom mechanism was introduced in April 2010 to ensure excess demand in the certificate market to secure the value of certificates and then stimulate investment in renewable electricity projects [18, 19]. However, [19] suggest that independent suppliers were disadvantaged as vertically integrated firms were more likely to sell/transfer certificates from their subsidiary generators to subsidiary suppliers when there were not enough certificates in the market.

promoting renewable electricity, the RO scheme was closed to new generating capacity in March 2017. One possible explanation is that the reduced spending on electricity as the benefit to consumers was not large enough to offset the costs of the scheme paid by consumers.[3]

The comparison between the reduction in spending on electricity resulted from lower wholesale electricity prices and the costs of support schemes has been made by several studies. [27] using data from 2005-09 to conclude that the increase in electricity production has generated a net benefit to consumers in Spain. A similar conclusion was drawn by [40] using data from 2007-10 for Spain. In addition, [36] suggest that consumers were better off from the increase in wind generation as the benefits of low electricity prices outweigh the costs of subsidies in Ireland from 2008-12. However, negative gain is also found in the literature. [31] find that, in Italy, the financial saving from the higher solar production was insufficient to compensate for the costs of the supporting schemes from 2009-13. These studies are conducted in countries using the Feed-in Tariff system with transparent information such as tariffs received and the quantity of electricity supplied by accredited generators.[4] In contrast, TGC schemes are less transparent, as the price of certificates and the associated quantity of electricity supplied by accredited generators need to be estimated. [47] suggest that merit order effects were not high enough to compensate consumers for their cost contribution to the TGC scheme in Australia between 2011-13, but [31] find wind generation supported by the TGC system increased consumer surplus in Italy.

By focusing on wind generation, our study is the first attempt to evaluate the RO scheme by comparing the reduction in spending on electricity resulted from lower wholesale electricity prices and the costs of the RO scheme attributed to wind farms. Using data from the Great Britain (GB) wholesale electricity market from April 2009 to March 2021, we find that a marginal increase of 1GW in the daily average hourly wind generation reduced the daily average hourly wholesale electricity price by £1.28/MWh, which is consistent with evidence found in other countries although the magnitude differs. In addition, year-specific marginal effects varied from £0.61/MWh to £1.83/MWh. Using these year-specific marginal effects and annual wind generation from RO accredited wind farms, we calculate annual total reductions in the wholesale price, which are then multiplied by annual electricity consumption

[3] Another possible contributing factor for its closure proposed by [39] is that, in a theoretical model, the recycling mechanism built in the RO scheme for redistribution of penalty to suppliers induces strategic behaviours and leads to lower prices of RO certificates and thus lower subsidies received by renewable generators.

[4] The feed-in tariff system is another type of supporting system, in which electricity generators receive a fixed tariff for each unit of electricity they produce, and network operators are obliged to accept this output to their network. It is used in other European countries, such as Germany [41], Denmark [33], and Spain [42, 43]. The difference between the TGC system and the feed-in tariff system has been discussed in [44], [18], [45], and [46].

to approximate annual reductions in spending on electricity. Our study finds that the reduction in spending on electricity was lower than the costs of the RO scheme attributed to wind generation in most financial years from 2009-10 to 2020-21, suggesting negative gain to consumers. For example, the negative gain to consumers reached £2.49 billion in 2019-20. Our findings favour the government's decision to close the RO scheme for the interest of consumers.

This paper will be constructed in the following way. Section 2 provides background. Section 3 explains data and model specifications, and Section 4 provides empirical results. Section 5 compares the reduced spending and the costs of the scheme to consumers. Finally, Section 6 concludes the paper.

2. Background

2.1 The electricity generation mix in the UK

Table 1 shows that electricity consumption and generation have declined in the UK, mainly due to improved energy efficiency measures [48].[5] Regarding the generation mix, the most striking observation is that electricity generated from coal declined from 148.85TWh in 2006 to 5.50TWh in 2020, while moderate declines were seen in both gas and nuclear. In contrast, electricity generated from renewable sources increased dramatically during the same interval (71.13TWh from wind, 29.38TWh from bioenergy, and 13.16TWh from solar), possibly suggesting the effectiveness of supporting schemes. In addition, net imports of electricity increased from 7.52TWh to 17.91TWh, indicating an increasing degree of integration into the EU electricity market.

Table 1 Electricity consumption, generation by type, and net imports in the UK, in TWh
Source: BEIS [20]

Unit: TWh	2006	2008	2010	2012	2014	2016	2018	2020
Consumption	345.23	341.82	328.84	318.27	302.79	304.03	300.44	280.27
Generation	397.28	388.92	382.07	363.87	338.10	339.16	332.72	312.00
Coal	148.85	124.38	107.59	142.79	100.24	30.67	16.83	5.50
Oil	6.17	6.71	4.81	2.89	1.92	1.89	1.06	0.83
Gas	140.83	176.22	175.65	100.17	100.89	143.36	131.49	111.43
Nuclear	75.45	52.49	62.14	70.41	63.75	71.73	65.06	50.28
Hydro	4.59	5.14	3.59	5.31	5.89	5.37	5.44	6.75
Wind	4.24	7.14	10.29	19.85	31.96	37.16	56.91	75.37
Solar			0.04	1.35	4.05	10.40	12.67	13.16
Bioenergy	9.93	9.57	12.26	14.73	22.62	30.07	34.97	39.31
Other fuels	3.37	3.19	2.54	3.40	3.89	5.57	5.78	7.94
Net imports	7.52	11.02	2.66	11.86	20.52	17.75	19.11	17.91

[5] Figures related to transformation (energy industry use and losses) are not included in Table 1.

2.2 The Renewable Obligation scheme

Under the Renewable Obligation (RO) scheme, the regulator allocates Renewable Obligation Certificates (ROCs) to accredited renewable generators, and then the latter receive revenue when ROCs are sold to suppliers in the market. The revenue from selling ROCs are in addition to the revenue from selling electricity for generators. At the end of each reporting year, suppliers present their ROCs to demonstrate if they have met their obligations, i.e., a certain proportion of their total sales of electricity is from renewable sources. If suppliers fail to present a sufficient number of ROCs, they must pay the penalty (the buy-out price) for each ROC missed. One feature of the RO scheme is the recycling mechanism, which redistributes the total penalty back to suppliers in proportion to the number of ROCs presented. The recycle value is the redistribution payment to suppliers for each ROC they presented. Therefore, by presenting one ROC, suppliers avoid the buy-out price and receive the recycle value, so the suggested ROC price is the sum of these two components [39, 49, 50]. The RO scheme was closed to new generating capacity in March 2017, but accredited renewable generators still receive ROCs for the 20-year period.

As Table 2 shows, the number of ROCs issued by the regulator increased from 5.58 million in 2002-03 to 114.93 million in 2019-20. While various renewable technologies were eligible for the RO scheme, the number of certificates allocated to wind farms had gradually gained its dominance, reaching 66.24 per cent in 2019-20. The RO scheme provided financial support to renewable electricity projects, but the costs were ultimately passed to consumers via higher electricity bills. According to Ofgem, the costs of the RO scheme were calculated as the product of the number of ROCs presented and the suggested ROC price in each reporting year [50]. As shown in Table 2, the costs of the RO scheme increased from £250.44 million in 2002-03 to £6,310.74 million in 2019-20. Then multiplying the costs with the percentage of ROCs issued to wind, the costs attributed to wind increased from £48.99 million to £4,180.40 million over the same period. Last, wind power capacity accredited under the RO scheme increased from 513 MW to 18,799 MW.

Table 2 The costs of the RO scheme attributed to wind generators

Sources: Ofgem [50, 51]

Obligation period (1 April - 31 March)	(1) ROCs issued (millions)	(2) ROCs issued to wind (%)	(3) ROCs presented (millions)	(4) Suggested ROC value (£)	(5)=(3)*(4) Costs of scheme (£ millions)	(6)=(5)*(2) Costs attributed to wind farms (£ millions)	(7) Wind capacity accredited under RO (MW)
2002-03	5.58	19.56%	5.45	45.94	250	49	513
2003-04	7.55	17.06%	7.61	53.43	407	69	689
2004-05	10.92	18.42%	10.86	45.05	489	90	1,048
2005-06	13.76	22.41%	13.70	42.54	583	131	1,887
2006-07	14.97	32.93%	14.61	49.28	720	237	2,207
2007-08	16.16	35.74%	16.47	52.95	872	312	2,932
2008-09	19.05	40.63%	18.95	54.37	1,030	419	3,715
2009-10	21.36	46.66%	21.34	52.36	1,117	521	4,637
2010-11	24.96	51.00%	24.97	51.34	1,282	654	5,692
2011-12	34.97	58.84%	34.40	42.27	1,454	856	7,627
2012-13	44.40	62.83%	44.77	44.38	1,987	1,248	10,087
2013-14	63.01	67.66%	60.76	42.72	2,596	1,756	12,127
2014-15	71.46	60.41%	71.28	43.65	3,111	1,880	12,914
2015-16	90.56	59.64%	84.38	44.33	3,741	2,231	13,640
2016-17	86.60	58.73%	90.21	49.87	4,499	2,642	15,762
2017-18	101.19	66.06%	103.22	51.34	5,299	3,501	18,134
2018-19	106.45	64.16%	107.64	55.04	5,925	3,801	18,767
2019-20	114.93	66.24%	115.94	54.43	6,311	4,180	18,779

2.3 The GB wholesale electricity market

A Great Britain-wide (England, Wales, and Scotland) wholesale electricity market was established by the British Electricity Trading and Transmission Arrangements (BETTA) in April 2005. The BETTA aims to establish a fully competitive wholesale electricity market, in which electricity can be traded bilaterally over the counter (OTC) or on power exchanges. Liquidity is an important feature to promote competition in the wholesale market. The Churn, which indicates how often a unit of electricity is traded (including OTC and power exchange) before it is delivered to end consumers, remained stable and averaged at 3.46 for 2010-2020, indicating that the UK had one of the most liquid wholesale electricity markets in the Europe [52]. Besides, partially contributed by the increasing demand for short-term adjustment as wind generation is featured with intermittency and unpredictability, the market share of trading through exchanges increased from 4.37% in 2010 to 19.70% in 2020 in the UK [53].

The spot market on exchanges includes both the day-ahead market and the intra-day market. The day-ahead market allows participants to trade wholesale electricity one day before the delivery day through an auction that produces a clearing price that matches bids and offers for each settlement (half-hour). The intra-day market allows participants to trade continuously with delivery on the same day, and the trade is executed when a bid matches an offer. The trading of electricity for each settlement can be continued until one hour before the delivery time, and then National Grid, as the GB Transmission System Operator, takes the responsibility of balancing total electricity generation and demand in real-time via a balancing mechanism. For any imbalanced volumes between actual and contracted volumes, imbalance charges are imposed on individual generators and suppliers through an imbalance settlement process operated by Elexon.

3. Data and model specification

3.1 Data

The data we used ranges from 1st April 2009 to 31st March 2021, consistent with the reporting year used under the RO scheme. The dependent variable, Market Index Price (MIP), represents a weighted average price relating to qualifying contracts from the intra-day trading, which refers to continuous trading of electricity delivered on the same day, on power exchanges. The intra-day market for short-term adjustment (hours ahead) is particularly relevant to wind generation with features of intermittency and unpredictability [54]. This half-hourly data is downloaded from Elexon and reflects the wholesale electricity price in Great Britain [55].[6] Further, MIP is used in the process of calculating imbalance prices, which is imposed on the imbalanced volume (actual volumes compared to contracted volumes) to calculate the imbalance charge for individual generators and suppliers [57].

The first explanatory variable is the national demand for electricity from Great Britain. We add up the half-hourly data using three components from National Grid. The first component is the measured national demand, which is the sum of metered generations. The second and third components are embedded wind and solar generations estimated by National Grid. Embedded generations are connected to the low voltage regional electricity networks, and their output is equivalent to a decrease in demand from the system operator point of view. The second explanatory variable is the electricity generated from wind power in Great Britain. We add up the half-hourly data of wind generation using (i) wind generation from large wind farms (greater than 100 MW) connected to the Transmission Network, collected from Elexon, and (ii) the estimated embedded wind generation. The third explanatory variable is the electricity generated from solar, using the estimated embedded solar generation.[7] Following [27] and [31], to reduce the excessive and unwanted noise that may arise from using half-

[6] The monthly average MIP was highly aligned with the monthly average electricity price for over-the-counter day-ahead contracts provided by Ofgem, with a correlation of 0.96 over the sample from June 2010 to March 2021. Similarly, [56] find high correlations, 0.89 for peak and 0.93 for off-peak, between prices on exchanges and OTC using daily data from 2002-2005 in the UK.

[7] Elexon and National Grid also provide half-hourly data of imports and exports of electricity. According to previous studies [36, 58, 59], the capacity of interconnectors (or transmission rights) were acquired in advance and the direction of flows were mainly determined by the price differential in day-ahead markets between two ends of the interconnector. Therefore, both imports and exports are not included as our analysis is focused on the intra-day market.

hourly data, we convert all half-hourly data to a daily basis averaged hourly data. Figure 1 plots these four variables.

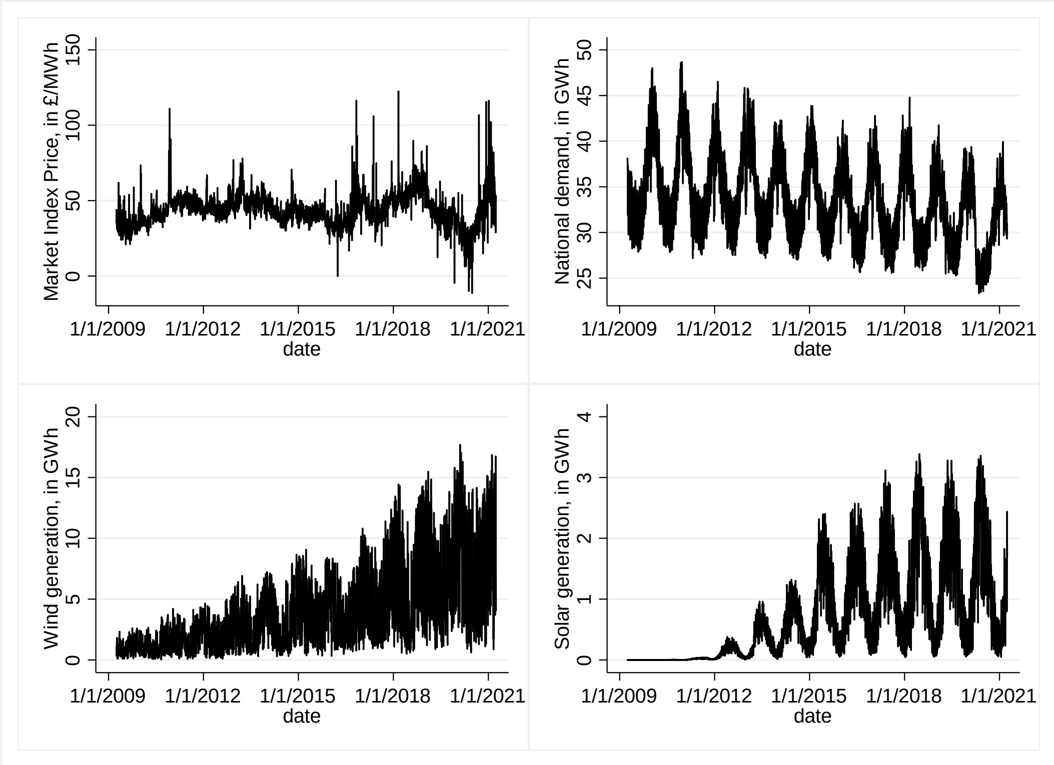

Figure 1 Market Index Price, national demand, wind generation, and solar generation from Jan 2009 to April 2021, daily average hourly data

Sources: authors' own calculation based on data from Elexon and National Grid

Moreover, costs of fossil fuels and greenhouse gas (GHG) emissions are also included to estimate their impacts on the wholesale electricity price and are downloaded from Datastream. As the UK was dependent on imports of fossil fuels, we consider prices from international markets. The daily natural gas price, measured as pence per therm, is taken from the National Balancing Point in the UK.[8] The daily coal price is represented by the API2 index, measured as US dollar per tonne, which is the reference price benchmark for coal imported into Europe. The daily carbon price, measured as euro per tonne, is the price of allowance for GHG emissions traded under the EU Emissions Trading System (ETS). In addition, as the UK government recognised that the EU carbon price was too low to drive low carbon investment, additional costs, known as the Carbon Price Support (CPS), was introduced in April 2013 on top of the EU carbon price, so UK generators using fossil fuels face higher costs (i.e., EU carbon price plus CPS) on GHG emissions than their European counterparts. Regarding different currency units, US dollar and euro are converted to British pound using daily exchange rates. Also, these series have no data on the weekend, so we set

[8] The British NBP had been the most liquid gas trading point in Europe before surpassed by the Dutch TTF in 2016.

their weekend values equal to the previous Friday's level. Figure 2 plots these relevant variables.

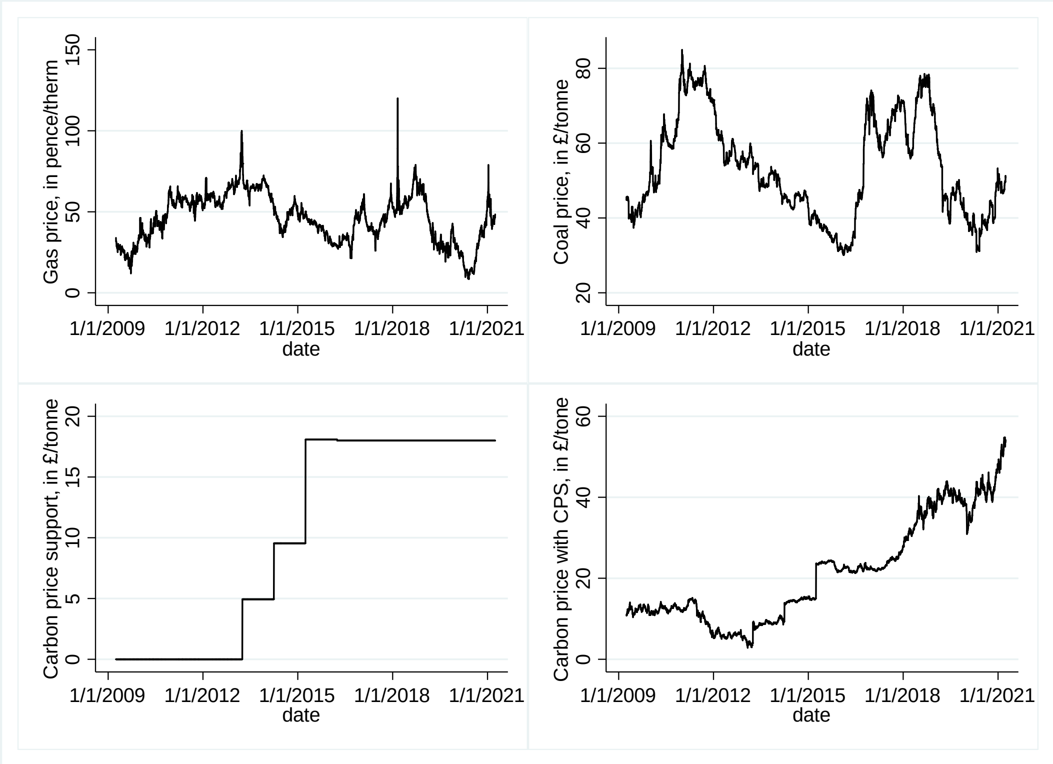

Figure 2 Daily gas price, coal price, carbon price support, and carbon price with carbon price support, from Jan 2009 to April 2021

Sources: Datastream; National Grid; BEIS

Table 3 shows the descriptive statistics of these variables related to the wholesale electricity market. The number of observations is 4,383 as we consider daily data from 1st April 2009 to 31st March 2021.[9] We test for unit root using the Augmented Dickey-Fuller test. For most variables, we reject the null hypothesis that there is a unit root at the 5% significance level. However, the coal price and carbon price fail to reject unit root, so we include time dummies in the regression and then conduct stationarity tests for the residuals.

[9] Among 4383 observations, eleven outliers are revised in the data. Four daily average hourly price and ten daily average hourly price in peak times with values above £150/MWh were converted to the values in the previous date. On 1st March 2018, the gas price jumped to 230 pence per therm so it was also converted to the values in the previous date.

Table 3 Descriptive statistics of variables related to the wholesale electricity market

Source: Elexon, National Grid, Datastream

	All-day				Peak	Off-peak
Variables	Observations	Mean	Min	Max	Mean	Mean
Market index price (£/MWh)	4,383	43.59	-11.35	158.05	47.59	35.09
National demand (GWh)	4,383	34.30	23.36	48.67	38.44	26.28
Wind generation (GWh)	4,383	4.00	0.04	17.69	4.11	3.81
Solar generation (GWh)	4,383	0.71	0.00	3.39	1.35	0.01
Gas price (pence/therm)	4,383	45.81	8.50	120.00	-	-
Coal price (£/tonne)	4,383	53.34	30.11	84.96	-	-
Carbon price with support (£/tonne)	4,383	21.23	2.83	54.79	-	-

3.2 Model specification

In our specifications, the dependent variable is the daily average hourly value of the Market Price Index (*price*). The first independent variable is the daily average hourly national demand (*nd*). Following [22] and [23], daily electricity consumption is price-insensitive and inelastic, making it an exogenous variable. The second and third independent variables are the daily average hourly wind generation (*windgen*) and solar generation (*solargen*). Because of their low operating costs, wind farms and solar farms are more likely to be price takers, so their generations are less likely to be affected by the wholesale electricity price. Therefore, we assume that wind and solar generations are exogenous and mainly influenced by weather conditions.

We also add costs of fossil fuels and GHG emissions into the model. First, gas price (*gasp*) is included as natural gas accounted for around 30-40% of electricity generated over the sample period. Second, despite that coal only accounted for 1.76% of electricity generated in 2020, coal price is included for the importance of coal in the early years of our sample period. Third, carbon price with CPS (*carbonps*) charged on GHG emissions from electricity generation increased the costs of fossil-fuelled plants and should also affect the electricity price. Gas price, coal price, and carbon price from international markets are assumed to be exogenous to the GB wholesale electricity price. To control for seasonal effects, we include a vector of time dummies (*D*), including ten annual dummies indicating the reporting years, eleven dummies indicating the month, and six dummies indicating the days of the week. Our specification is given as

$$\begin{aligned} price_t &= \beta_0 + \beta_1 \cdot nd_t + \beta_2 \cdot windgen_t + \beta_3 \cdot solargen_t \\ &+ \beta_4 \cdot gasp_t + \beta_5 \cdot coalp_t + \beta_6 \cdot carbonps_t + \gamma D_t + \varepsilon_t \end{aligned} \tag{1}$$

where t represents daily intervals.

Further, Eq. (1) will be estimated using the daily average hourly value of the Market Price Index for peak times and off-peak times as dependent variables, respectively. The peak times is defined as a 12-hour period from 7:00 to 19:00, and the off-peak times is defined as an 8-hour period from 23:00 to 7:00 [55]. The daily average hourly prices for peak and off-peak times are calculated as the average hourly value for the corresponding settlement periods from each date using the half-hourly data. Similarly, national demand, wind generation, and solar generation are also converted to peak and off-peak times, but solar generation is removed from the estimation for off-peak times due to zero or close to zero values. Besides, as the accumulated level of renewable electricity generation increased over time, previous studies (see [31], [36], and [25]) suggest that the impact of wind generation on the electricity price may differ. Therefore, Eq. (1) will also be estimated for year-specific impact from wind generation to calculate the year-specific reduction in spending on electricity.

For our specifications, we apply the Breusch-pagan test for heteroscedasticity and the Durbin Watson test for serial correlation. Both heteroscedasticity and serial correlation are found in the residual when the OLS estimator is used. Therefore, following [60] and [31], we assume that the residual follows a first-order autoregressive process AR(1), $\varepsilon_t = \rho\varepsilon_{t-1} + \omega_t$ with $|\rho| < 1$ and ω being the white noise. Then we estimate our model using the Prais-Winsten estimator, which uses the generalised least-square method to estimate the parameters.

4. Estimation results

4.1 Estimation results from the full sample

Results from estimation are provided in Table 4. When the Prais-Winsten estimator is used, the null hypothesis of serial correlation in the residuals is rejected, as the Durbin-Watson statistics is greater than 2. Also, the results are robust to heteroscedasticity as we specify the White estimator for the variance-covariance matrix of the estimates. In addition, the coefficient $\rho < 1$ suggests that the AR(1) assumption is valid. The Phillips-Perron test and the ADF test run on the residuals confirms that they are stationary in all models.

We first describe the results from the benchmark model using data from 1st April 2009 to 31st March 2021. After controlling independent variables, our model explains 59.6% of the variation in the daily average hourly wholesale electricity price. The coefficients presented in Table 4 are the partial effects of individual independent variables on the wholesale price, holding other variables fixed. The coefficient of national demand is positive and significant, showing a marginal increase of 1 GWh in the daily average hourly national demand increases the daily average hourly electricity price by £0.90/MWh. Meanwhile, the coefficient of wind generation is negative and significant, showing that a marginal increase of

1 GWh in the daily average hourly wind generation reduces the wholesale electricity price by £1.28/MWh, consistent with the merit order effect found in the literature. Similarly, solar generation has a negative coefficient of £2.98/MWh, and this larger impact can be explained as solar generation tends to be coincident with peak hours when more expensive marginal plants are running. The coefficients of gas price and carbon price with CPS are positive and significant. Specifically, for the gas price, a marginal increase of one penny per therm increases the wholesale electricity price by £0.58/MWh, and for the carbon price with CPS, a marginal increase of one pound per tonne increases the wholesale electricity price by £0.47/MWh. The coefficient of coal price is positive but not significant at any conventional significance level.

Table 4 Results from the Prais-Winsten estimation of daily average hourly wholesale electricity price

Dependent variable: wholesale electricity price (£/MWh, daily average hourly value)			
	(1)	(3)	(2)
Variables	All-day	Peak	Off-peak
National demand	0.898***	1.014***	0.657***
Wind generation	-1.278***	-1.414***	-1.358***
Solar generation	-2.981***	-2.574***	-
Gas price	0.581***	0.574***	0.463***
Coal price	0.0498	0.109***	0.0552**
Carbon price with CPS	0.467***	0.415***	0.581***
Constant	-24.71***	-30.12***	-15.78***
Observations	4,383	4,383	4,383
R-squared	0.617	0.557	0.640
Year FE	Yes	Yes	Yes
Robust	Yes	Yes	Yes

Statistical significance at the 1% level (***), 5% level (**), 10% level (*)

Next, we estimate the model for peak times (7:00 to 19:00) and off-peak times (23:00 to 7:00) separately for two reasons: (i) the demand for electricity varies largely, and (ii) the slope of the supply curve of electricity is increasing [61, 62] and the merit order is different due to no solar generation in off-peak times. The first observation is that the impact on the wholesale price from an increase in wind generation is larger in peak times than that in off-peak times. Table 4 shows that a marginal increase of 1 GWh in the average hourly wind generation reduces the wholesale electricity price in peak and off-peak times by £1.41/MWh and £1.36/MWh, respectively. The larger impact of wind generation in peak times were also found in previous studies [31, 36]. In peak times, expensive peaking power plants are switched on to meet the demand, so an increase in wind generation switches off these plants, leading to a larger drop in the price. In the off-peak times, the demand is met by plants with lower marginal costs, and the supply curve is relatively flatter, so an increase in wind generation has a smaller impact on the price. These two scenarios are illustrated in Figure 3.

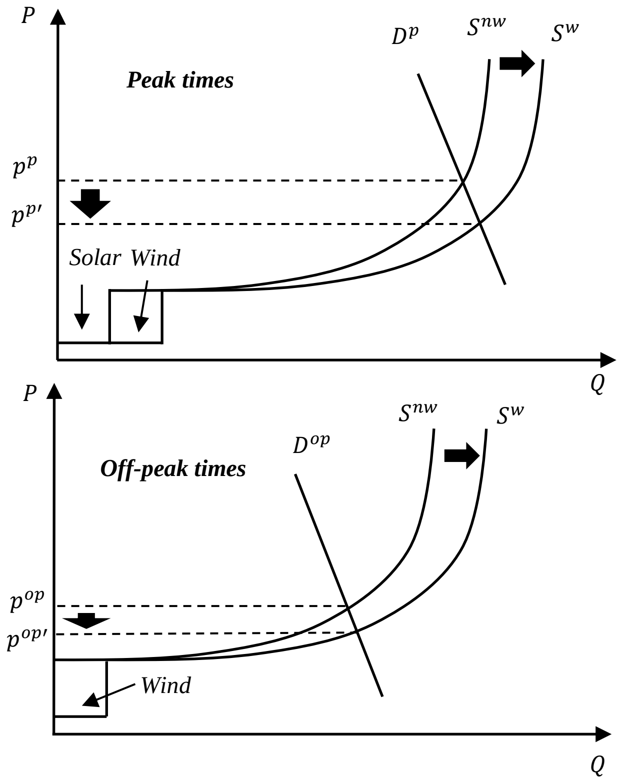

Figure 3: The impact on the wholesale price of an increase in wind generation. D^p and D^{op} are the demand curves in peak times and off-peak times, respectively, S^{nw} and S^w are the supply curves before and after the increase in wind generation, respectively.

The second observation is that the impact on the wholesale prices from an increase in national demand was larger in peak times than that in off-peak times. Table 4 shows that a marginal increase of 1 GWh in the average hourly national demand increases the wholesale electricity price in peak and off-peak times by £1.01/MWh and £0.66/MWh, respectively. In peak times, additional demand calls for more expensive generators to balance the system. In contrast, in off-peak times, additional demand can be met by less expensive generators, so an increase in demand has a smaller impact on the price.

4.2 Estimation results from individual years

Since wind generation has increased persistently over time, we estimate our specification for individual reporting years. Table 5 shows that the year-specific marginal impacts of wind generation varied from £0.61/MWh to £1.83/MWh, but all are negative and significant at the 5% significance level. We suggest that the impacts of wind generations on the wholesale price are dependent on the position of the intersection of the demand curve and the supply curve (i.e., the merit order). Specifically, the merit order is decided by several factors such as renewable generations and prices of fossil fuels and carbon emissions. As these factors varied year by year, the merit order and thus the marginal impacts of wind generation also varied across years in our sample. These year-specific marginal impacts will be used to calculate the year-specific total decrease in wholesale electricity prices and the reductions in spending on electricity in Section 5.1.

Table 5 Results from the Prais-Winsten estimation for individual reporting years

Dependent variable: wholesale electricity price (£/MWh, daily average hourly value)												
Variables	09-10	10-11	11-12	12-13	13-14	14-15	15-16	16-17	17-18	18-19	19-20	20-21
National demand	1.65***	1.50***	0.58***	0.62***	0.99***	0.61***	0.50***	1.98***	1.39**	1.09***	0.96***	2.23***
Wind generation	-1.39**	-1.57***	-1.83***	-1.71***	-1.57***	-1.22***	-1.19***	-1.65***	-0.61***	-1.05***	-0.98***	-1.77***
Solar generation		65.04	0.07	-6.49*	-0.54	-2.59***	-2.81***	-1.66	-3.32**	-2.31***	-2.13***	-1.54**
Gas price	0.07	0.34***	0.32***	0.49***	0.23***	0.50***	0.28**	0.29	0.80***	0.55***	0.39***	0.89***
Coal price	0.16	0.34	0.06	-0.03	0.23	-0.55**	0.59	0.47	-0.21	0.24	0.26	-0.11
Carbon price with CPS	-0.37	1.03	0.05	-0.01	1.33**	2.77*	1.76	-1.24	-0.16	0.20	-0.17	0.13
Observations	365	365	366	365	365	365	366	365	365	365	366	365
R-squared	0.36	0.62	0.55	0.67	0.61	0.60	0.60	0.46	0.60	0.74	0.61	0.73
Robust	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes

Statistical significance at the 1% level (***), 5% level (**), 10% level (*).

5. Discussion

5.1 The comparison between the reduced spending and the costs of the RO scheme

The increase in wind generation reduced the wholesale electricity price and then lowered the spending on electricity, but the subsidies provided to support investment in renewable generation through the RO scheme were ultimately passed to consumers. Therefore, a comparison of the reduced spending and the costs of the RO scheme helps us understand if the scheme has generated gain to consumers from increased wind generation.

For our analysis, two adjustments are made. First, as the RO scheme was implemented in the UK, we consider relevant series at the UK level but using the estimated coefficients from the GB wholesale market. Second, as we aim to evaluate the RO scheme, generation from RO accredited wind farms should be disentangled from wind generation supported by other schemes (Feed-in Tariff and Contracts for Difference).[10] Therefore, we

[10] The FIT was introduced in 2010 to support small-scale renewable generation, mainly solar photovoltaics. As the successor of the RO scheme, the Contracts for Difference, though a competitive bidding process, aims to provide long-term price stability to low carbon generation

calculate the percentage of wind capacity accredited by the RO scheme to total UK wind capacity.[11,12] Then we multiply this percentage with the total wind generation to approximate the electricity generated from wind farms under the RO scheme, as shown in Table 6 Column 1. Dividing by 365 days and 24 hours, the hourly wind generation from RO wind farms is derived, shown in Column 2. Then the hourly wind generation is multiplied with marginal impacts, gives the total reductions in prices, which varied from -£1.50/MWh to -£7.05/MWh. As the intra-day trading price reflects the wholesale electricity price and can be considered as a benchmark for other products via OTC or exchanges [53, 55], we apply the reductions in prices to total electricity consumption to approximate the reductions in spending on electricity.

Compared the reductions in spending with the costs of the RO scheme attributed to wind generation (Table 2 Column 6), Column 7 shows that the gain to consumers was negative in most years over our sample, and reached £2 billion per annum between 2017-2020. Therefore, for wind generation, the benefits of reduced spending brought to consumers by the RO scheme were not enough to offset the costs they contributed.

Table 6 The reduced spending on electricity and the gain to consumers

Source: authors' own calculation based on data from Ofgem, BEIS, and estimation results from Table 5

Year	(1) Wind generation from RO wind farms (GWh)	(2)=(1)/(365*24) Annual average hourly wind generation, from RO wind farm (GWh)	(3) Estimated marginal impact of 1 GW wind on the price (£/MWh)	(4)=(2)*(3) Total impact on price (£/MWh)	(5) Electricity consumption (GWh)	(6)=(4)*(5) Total reduction in spending (£ million)	(7) Gain to consumers (£ millions)
09-10	9,420	1.08	-1.39	-1.50	323,520	484	-37
10-11	11,480	1.31	-1.57	-2.05	326,096	669	15
11-12	16,934	1.93	-1.83	-3.54	317,972	1,124	269
12-13	21,985	2.51	-1.71	-4.29	317,771	1,362	114
13-14	29,288	3.34	-1.57	-5.26	312,900	1,646	-110
14-15	32,847	3.75	-1.22	-4.59	302,959	1,390	-489
15-16	36,497	4.17	-1.19	-4.96	303,618	1,505	-726
16-17	37,367	4.27	-1.65	-7.05	302,937	2,136	-506
17-18	46,354	5.29	-0.61	-3.25	299,848	974	-2,527
18-19	49,232	5.62	-1.05	-5.91	299,330	1,770	-2,031
19-20	51,669	5.90	-0.98	-5.80	292,058	1,693	-2,487

5.2 Adjustment for inflation

Our analysis has been based on nominal values consistent with government reports and market prices. However, as our analysis covers eleven years periods and the impact of

[11] Data from calendar years is converted to reporting years using weighted average, with coefficients of 9/12 and 3/12 respectively.

[12] The percentage remained at or closed to 100% before 2014, and then began to decline, reaching 84% in 2018-19 and 77% in 2019-20.

inflation should be adjusted. Therefore, we collect Consumer Price Index from the Office of National Statistics and rebase it to 2009-10. Table 7 shows the inflation-adjusted gain to consumers. Due to the rising price level, the series had smaller absolute values in real terms compared with nominal terms, but our conclusions of negative gain to consumers should remain valid.

Table 7 Inflation-adjusted gain to consumers

Sources: authors' own calculation based on data from ONS and results from Table 6

	(1)	(2)
Year	CPI index (09-10=100)	Inflation-adjusted gain to consumers (£ millions)
09-10	100.0	-37
10-11	103.5	15
11-12	108.0	249
12-13	110.8	103
13-14	113.4	-97
14-15	114.6	-427
15-16	114.7	-633
16-17	116.0	-436
17-18	119.2	-2,119
18-19	121.9	-1,666
19-20	124.1	-2,005

6. Conclusion

The electricity generation mix in the UK has changed dramatically due to the growth of renewable generations, partially contributed by the RO scheme implemented in 2002 to support renewable electricity. On the one hand, through the merit order effect, the increase in renewable electricity has reduced wholesale electricity prices and thus consumer spending on electricity. On the other hand, the increase in renewable electricity has been stimulated by the subsidy from consumers to generators via the RO scheme. Despite its success in stimulating renewable electricity, the RO scheme was closed in April 2017. Our study compared the reduced spending on electricity and the costs of the RO scheme, focusing on wind generation.

Using the daily average hourly data from April 2009 to March 2021, our results from the Prais-Winsten estimation showed that a marginal increase of 1GW of wind generation reduced the electricity price by £1.28/MWh in the GB wholesale electricity market. A higher value of £1.41/MWh was found in peak times as the increased wind generation switched off expensive peaking power plants, while a lower value of £1.36/MWh was found in off-peak times when the demand was met by baseload power plants. The year-specific marginal effects of wind generation on the wholesale electricity price varied from £0.61/MWh to £1.83/MWh. Based on these year-specific impacts, we compared the reduction in spending on electricity with the costs of the RO scheme attributed to wind, and we found that the benefits were lower than the costs in most years over our sample period, bringing negative gain to consumers. Our results support the government's decision on the closure of the RO scheme in the interest of consumers.

Evaluating government renewable energy policy in terms of its costs and benefits is challenging, and our research presents the first attempt to compare the reduced spending on electricity and the costs contribution to understand the impact of the RO scheme on consumers. Further research should help build a more comprehensive understanding of the RO scheme. First, we have focused on wind under the RO scheme as it was the main support mechanism for wind generation featured with intermittence and unpredictability. Among other renewable technologies, bioenergy tended to be used for baseload and solar was mainly supported by the Feed-in Tariff. A full evaluation of the whole RO scheme requires further research on other technologies. Second, the suggested ROC prices, which were the sum of the buy-out price and the recycle value, were collected from Ofgem. If more information could be obtained from bilateral trades in the ROC market, the costs of the scheme and the costs attributed to wind could be more precisely measured. Third, we only consider the direct benefits and costs of the RO scheme, but the transition to renewable energy might have more profound impacts on the economy. One was the impact on the environmental quality through reduced carbon emissions and the resulted decreases in health care expenditure.[13] Other impacts include increased exports of skills and technology to the international market, improved energy security through reduced energy dependence on imports, and reduced impact of volatile international fossil fuel prices on domestic economic activities. These wider considerations shall be included to evaluate the government policy for the development of renewable energy.

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[13] The impacts of renewable generations on carbon emissions see [63, 64], and the impacts of environmental quality on healthcare expenditure see [65].

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