



Marginal greenhouse gas emissions displacement of wind power in Great Britain



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ABSTRACT

There is considerable uncertainty over the effect of wind power on the operation of power systems, and the consequent greenhouse gas (GHG) emissions displacement; this is used to project emissions reductions that inform energy policy. Currently, it is approximated as the average emissions of the whole system, despite an acknowledgement that wind will actually displace only the generators operating on the margin. This article presents a methodology to isolate the marginal emissions displacement of wind power from historical empirical data, taking into account the impact on the operating efficiency of coal and CCGT plants. For Great Britain over 2009–2014, it was found that marginal emissions displacement has generally been underestimated with, for example, the emissions displacement factor for wind being 21% higher than that the average emissions factor in 2010. The actual displacement depends upon the relative merit of coal and CCGT, with a greater discrepancy between marginal displacement and average emissions during more normal system operation, suggesting that policies to penalise high-carbon generation can increase the effectiveness of wind at reducing GHG emissions. Furthermore, it was also identified that wind power is almost as technically effective as demand-side reductions at decreasing GHG emissions from power generation.

1. Introduction

Estimates of the greenhouse gas (GHG) emissions reductions from wind power critically inform energy policy and planning applications; however, calculations require estimates of the emissions displacement of wind power, which is currently poorly understood and a matter of some debate. The challenge with estimating this value is that the variable output of wind power is unlikely to displace all forms of generation equally, and may lead to an increase in the emissions intensity of power from conventional plant responding to the fluctuating output of wind farms. The uncertainty over the true emissions displacement of wind power has led to claims that it may increase GHG emissions, or at least be ineffective at reducing them (le Pair, 2011; Lea, 2012). This work presents a realistic picture of the recent historical GHG emissions displacement of wind power in Great Britain (GB), taking into account any negative impact that wind power has on the operation of conventional plant, and compares this to existing estimates.

Current practice in GB is to assume that wind power displaces the annual average emissions of all power generation on the system (Defra, 2013; AEA Technology, 2005; White, 2004): the average emissions factor (AEF). This follows a ruling by the Advertising Standards

Authority (ASA), which acknowledges that it is an approximation due to a lack of better information (Advertising Standards Authority, 2007; CAP, 2013). The ASA consulted National Grid, the GB Transmission System Operator (TSO), who observed that a displacement factor for wind power would lie somewhere between the emissions factors for coal and gas generation, but that calculating this value was highly complicated. Due to this complexity, the calculation tool provided by the Scottish Government to estimate the carbon payback period for wind farm planning applications (The Scottish Government, 2014) uses three different displacement factors: the annual average emissions factor, the emissions intensity of coal-fired generation, and the annual average emissions intensity of the fossil-fuelled generation mix (Nayak et al., 2014). Evidently realistic information on displacement will have intrinsic value.

Wind power will displace the output from generators operating at the margin and the emissions displacement factor of wind power therefore depends upon changes in emissions from these marginal generators. Ideally, this would be found by identifying precisely which power plant respond to changes in wind production, with the marginal generation mix varying with demand across the day and year. In GB several generator types will respond to marginal changes in wind output, with coal and Combined Cycle Gas Turbines (CCGT) the most

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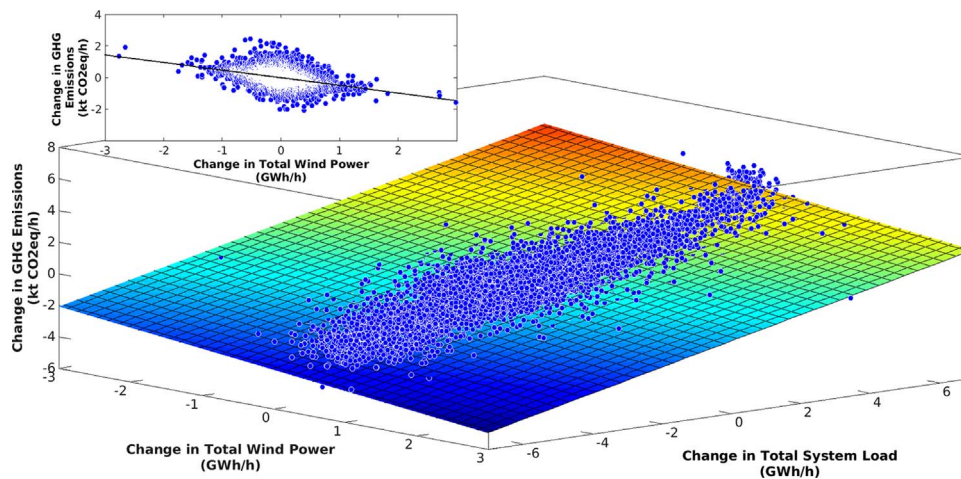


Fig. 1. Relationship between changes in GHG emissions, system generation and wind power output for 2014. Inset shows cases when change in system generation is zero, indicating the MDF.

significant for estimating GHG emissions displacement. In GB, wind variation does not currently affect the output of baseload nuclear generators and, as such, nuclear will influence the average but not the marginal generating mix; therefore the marginal displacement factor (MDF) is unlikely to be similar to the AEF. This conclusion is supported by studies on the emissions associated with marginal changes in demand – marginal emissions factors (MEFs) – which were found to be very different to the AEFs (Bettle et al., 2006; Marnay et al., 2002; Hawkes, 2010; Siler-Evans et al., 2012).

Existing studies on the impact of wind power on the GHG emissions of generation have largely focused on the long-term marginal changes of increased installed capacity, such as those arising from the commissioning or decommissioning of other power stations (Valentino et al., 2012; Delarue et al., 2009; Hart and Jacobson, 2012). These, however, neglect the short-term, operational, marginal impacts of wind power, which account for variations in wind output and forecast accuracy on the dispatch of conventional generators, and corresponding displaced GHG emissions. A few studies have attempted to identify this short-term MDF for other systems (Gil and Joos, 2007; Farhat and Ugursal, 2010; Kaffine et al., 2011; Gutierrez-Martin et al., 2013; Wheatley, 2013; Clancy et al., 2015), but it is system-specific, so the findings do not translate to GB. Furthermore, existing estimates of the MEF of demand (Bettle et al., 2006; Hawkes, 2010; Zheng et al., 2015) cannot be assumed to match the MDF of wind power, as differences such as forecast accuracy mean that conventional generation is dispatched differently in response to wind or demand fluctuations.

A particular challenge in determining the MDF of wind power is that operating fossil-fuelled generation at part-load has an efficiency penalty that increases the fuel consumption and GHG emissions per unit of energy generated; analysis of the MEF of demand fluctuations in the USA found efficiency penalties have a significant impact on emissions reductions (Siler-Evans et al., 2012).

The complexity of estimating the MDF of wind power in GB is compounded by the nature of the British Electricity Transmission Trading Arrangements (BETTA), wherein the operation of the system does not follow the conventional approach of centralised ‘optimal’ dispatch; a more opaque system of generator self-dispatch makes it very difficult to precisely identify which plant are responding to changes in wind output and the corresponding emissions displacement. Furthermore, such operation is challenging to model accurately, increasing the uncertainty of existing studies of short-term MDF that employ dispatch models (Gil and Joos, 2007; Farhat and Ugursal, 2010; Gutierrez-Martin et al., 2013; Clancy et al., 2015).

In addressing these challenges, this work does not attempt to model the network operation, but instead directly analyses historical opera-

tional and market data (2009–2014), while incorporating the effect of efficiency penalties on the emissions of coal and CCGT power stations, in order to provide credible estimates of the marginal emissions displacement of wind power on the GB system, and examine the relationship between increasing wind capacity and operation of conventional plants.

2. Method

2.1. Overview

The approach is based on Hawkes (2010), which calculated the average marginal emissions factor (MEF) of demand from historic GB generation data, identifying a linear relationship between marginal changes in demand and GHG emissions. Here, the analysis extends to isolate the marginal impact of variable wind on emissions, employs more robust power data, and accounts for the part-load efficiency penalties of coal and CCGT plant. The key idea is that any marginal change in system GHG emissions between one time period and the next is a function of the marginal changes in demand, wind output and other system effects (e.g. network constraints, weather, outages, plant warming, reserve requirements, etc.). This is formulated as:

$$\Delta C = a\Delta P_s + b\Delta P_w + c \quad (1)$$

where ΔC is the marginal change in system GHG emissions (t CO₂eq/h), ΔP_s is the marginal change in demand, represented by the change in total system generation (MWh/h), and ΔP_w is the marginal change in wind power output (MWh/h). The three coefficients are: a , the marginal emissions factor (MEF) (kg CO₂eq/kWh); b , the marginal displacement factor (MDF) of wind (kg CO₂eq/kWh); c , a constant representing other system effects (t CO₂eq/h). The change in demand term (ΔP_s) enables the marginal effects of changes in wind generation to be isolated from changes in demand. Multiple linear regression (MLR) identifies the values of the constants that can be visualised as the gradients of a best-fit planar surface, as Fig. 1 shows. The MDF is the gradient of the line where the change in total system generation is zero. Unlike Hawkes (2010), distribution losses (approximately 7%) are not considered as the focus is on emissions displacement of generation; however, the transmission losses are inherently captured within the total system generation. The change in demand is, therefore, represented by the change in total system generation, and includes both domestic demand and exports.

2.2. Analysis

The focus of the analysis is to generate time-series of ‘instanta-

neous' GHG emissions at system level, to be applied alongside wind and demand time-series in (1). The main challenge is in capturing the emissions impact of part-loaded generation, as this lowers unit efficiency, increasing fuel consumption and emissions intensity per unit of production and, in turn, affecting the emissions displacement of wind generation. Capturing this effect requires explicit, detailed time-series of the operating point of individual generating units and their part-load emissions intensity. Explicit modelling of part-loading is limited to coal and CCGT because these are the main plant that operate part-loaded, provide over 70% of production and are the dominant source of emissions. Pumped storage creates a second challenge. The specific calculation steps used are listed here, with additional detail on key aspects given in the following sections:

- Minute-by-minute power output time-series for all coal and CCGT units were created to identify the part-load operating points. With operationally metered data for individual units proprietary and confidential, these were derived from reported market data, as described in Section 2.3. GHG emissions time-series were then created for each coal or CCGT plant from part-load emissions intensity curves detailed in Section 2.4.
- Power time-series for supply types other than coal, CCGT and pumped storage were based on 5-min aggregated operationally metered data and aggregated GHG emissions determined by their respective annual average emissions intensities (described in Section 2.5). As this analysis focusses solely on emissions due to marginal changes in generation, interconnector exports, which are a type of demand, were set to zero. Consumption by pumped-storage hydro was included, as this time-shifts consumption and emissions rather than completely removing them from the system.
- The power and emissions time-series for all supply types were then sampled at half-hourly intervals (by taking the instantaneous values and interpolating where necessary) and aggregated to produce corresponding time-series for system generation. A half-hourly interval was chosen to enable comparison with other market and settlement data; this results in a calculated MDF only 0.7% lower than with 5-min intervals, with a slightly higher uncertainty.
- The emissions intensity for energy stored and subsequently generated by pumped storage hydro is calculated using the approach in Section 2.6. The resulting half-hourly generation emissions time-series was then added to give total system emissions.
- Half-hourly changes in wind output (ΔP_w), total system generation (ΔP_g) and total system emissions (ΔC) were calculated as the difference between successive values, expressed as an equivalent value per hour.
- Quality control discarded outliers arising from the metered data which were considered unrealistic in normal operation: zero aggregate nuclear generation, very short drops to zero for at least two supply types, or sudden large drops and immediate rebound of aggregate values – primarily the French interconnector or nuclear. This removed only 0.26% of data with approximately 105,000 periods remaining.
- The 2009–2014 dataset was disaggregated by year, season, time-of-day, instantaneous wind power output and the contribution of wind power to total generation (penetration). In each case multiple linear regression was used to estimate the coefficients in (1).

An example of the relationship between changes in wind output and GHG emissions is shown in the inset to Fig. 1. There is substantial scatter due to the modest proportion of wind power resulting in relatively small half-hourly fluctuations, which is particularly clear where the change in wind power output is near zero and changes in GHG emissions are caused by other 'system effects'. Details of some of the key parts of the method now follow.

2.3. Power output time-series for coal and CCGT

As detailed metered data is not readily available for individual generating units, power output time-series were derived from public data on the Balancing Mechanism Reporting Service (BMRS). BETTA requires generators to trade bilaterally in several markets on a rolling half-hourly basis up to 'gate closure', 1 h before delivery. From then until the end of the half-hourly delivery (or settlement) period the TSO uses the Balancing Mechanism (BM) to balance the system and resolve constraints (National Grid plc, 2011). All transmission-connected generation and others capable of exporting 100 MW participate as 'BM Units' with unique identifier codes (BM Unit IDs); two-thirds of GB wind is in this category (Hemingway, 2012) with smaller embedded wind appearing to the TSO as negative demand.

At gate closure all BM Units provide minute-by-minute Final Physical Notification (FPN) power levels defining the unit's expected trajectory. The BM uses a system of bids and offers that indicate the willingness of a unit to deviate from its FPN (a bid/offer is the price to reduce/increase generation). When the TSO requires a unit to do this it issues a 'bid-offer acceptance' with a corresponding Bid-Offer Acceptance Level (BOAL) in MW. Although only 5% of energy is traded in the BM, the effects of wind variability is reflected in these bid-offer acceptances. Outside the BM, National Grid procures balancing services such as reserve, to respond quickly to variations in supply and demand. This is typically provided by part-loaded thermal units and their operation is visible in the BMRS data.

Power output time-series for individual coal and CCGT units employed reported FPN levels, modified according to the final published BOAL values and constrained by the Maximum Export Limit (MEL) set by the TSO for system management (National Grid plc, 2011; Elexon, 2012). This process, illustrated in Fig. 2 for an example unit, results in detailed minute-by-minute power output time-series. These are substantially more refined than the half-hourly FPN data used by Hawkes (2010), which neglect actual output changes within the BM and can deviate significantly from the FPN (illustrated for all GB coal-fired generation in Fig. 3). The BOAL data is essential to capture the response of generators to forecast inaccuracy and short-term variation in wind and demand.

Not all BM Units take part in the BM including many wind farms which report FPN values as half-hourly values that only partially resemble actual power output. There may be other constraints that prevent units from meeting contracted output levels, and the imbalances between actual and contracted generation of individual BM Units is not publicly available. As such, the power output time-series based on BMRS data are by necessity approximations. The coal and CCGT unit power output time-series were verified against operationally metered data aggregated by supply type published by National Grid. The series were sampled at half-hourly intervals and aggregated to facilitate direct comparison. All BM Units are operationally metered, so both datasets should correspond. This was found to be the case, with a

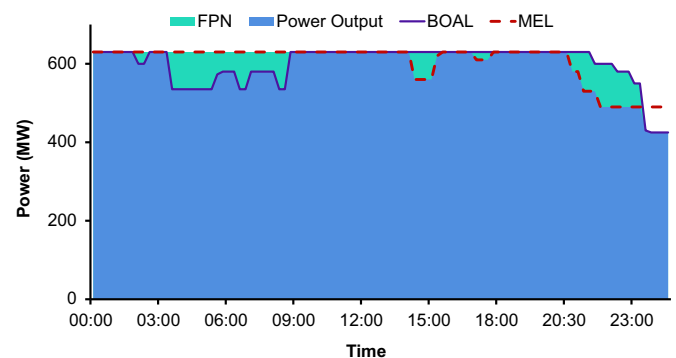


Fig. 2. Development of estimated power output time-series from BMRS messages (Drax 3 Generator, 18th February 2009).

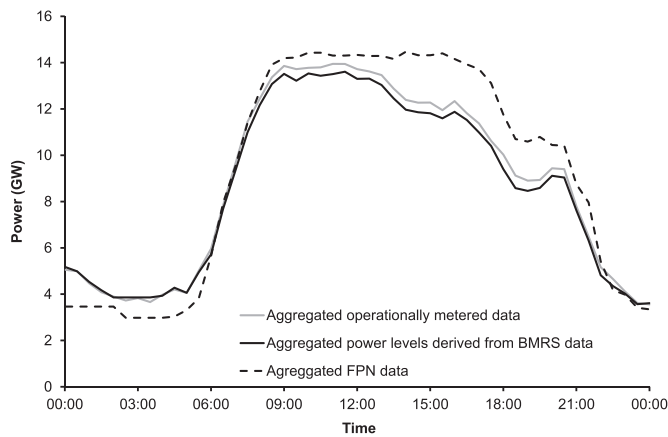


Fig. 3. Comparing operationally metered data, reported FPN and power profile derived from BMRS data for all coal-fired generation on 20th August 2009.

near perfect fit for CCGT and coal being very slightly underestimated with an error of less than 2% as illustrated in Fig. 3; sample scatter plots illustrating the correlation for wind and CCGT plants are included in Supplementary Material S1. This demonstrates that the unit output time-series is fit for purpose.

2.4. Emissions intensity curves for coal and CCGT

Part-load efficiency curves are essential for understanding the GHG emissions intensity of coal and CCGT units. As the operational characteristics of individual coal and CCGT units vary and are commercially sensitive, it was necessary to synthesise 'typical' efficiency characteristics from public information. A typical CCGT efficiency curve was derived from a relative efficiency curve (Kehlhofer et al., 1999), assuming a typical 500 MW unit and maximum 57% efficiency (Kehlhofer et al., 1999). A typical efficiency curve for sub-critical pulverised-coal units was derived from generic part-load data for boiler and turbine efficiencies (Sgourinakis, 2009; Sorour, 2008), assuming a 500 MW unit and maximum efficiency of 42% (Kehlhofer et al., 1999). The curves are shown in Fig. 4 and were validated against empirical data provided by a major generating company. The CCGT curve was a very good match for several common CCGT types but the coal curve had the correct shape but optimistic efficiency. Although it cannot be verified directly, it is believed that the sample coal plant has below-average efficiency as its peak efficiency is comparable with UK average coal efficiency (36% derived from DUKES, 2015) which includes the effects of start-up, shut-down and part-loading. In any

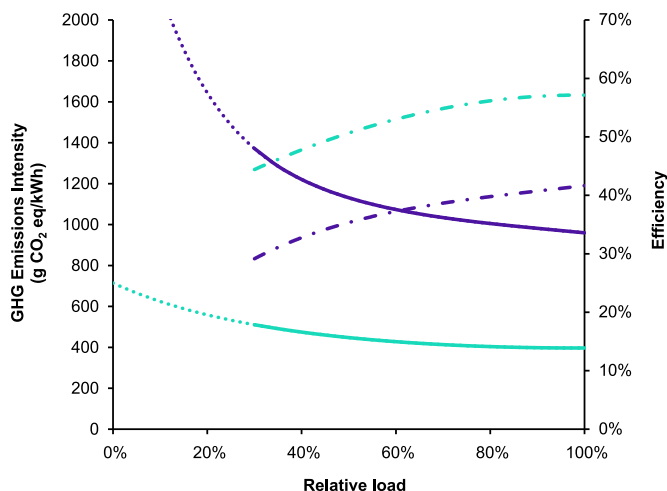


Fig. 4. Assumed efficiency curves for CCGT and coal units with corresponding GHG emissions.

case, applying the lower empirical efficiency data lowers the average MDF by less than 1%, well within the range of uncertainty for the analysis.

GHG emissions intensity curves were derived from the efficiency curves using the emissions intensity of input fuel and the unit efficiency at a given level of output. Applying the DECC fuel intensity values of 0.39988 and 0.22674 kg CO₂eq/kWh for coal and gas, respectively (AEA, 2012) results in the following relationships shown in Fig. 4:

$$EI_{\text{coal}} = 6.4P_{\text{rel}}^6 - 29.0P_{\text{rel}}^5 + 54.7P_{\text{rel}}^4 - 56.1P_{\text{rel}}^3 + 33.9P_{\text{rel}}^2 - 12.0P_{\text{rel}} + 3.1 \quad (2)$$

$$EI_{\text{CCGT}} = 0.14P_{\text{rel}}^6 - 0.68P_{\text{rel}}^5 + 1.49P_{\text{rel}}^4 - 1.91P_{\text{rel}}^3 + 1.69P_{\text{rel}}^2 - 1.05P_{\text{rel}} + 0.71 \quad (3)$$

where EI_{coal} and EI_{CCGT} are the respective instantaneous emissions intensities for coal and CCGT (kg CO₂eq/kWh) at a given relative unit power output P_{rel} (instantaneous output/reported maximum unit capacity).

There is a common misconception that increasing emissions intensities of coal and CCGT plant at part-load causes an increase in actual GHG emissions; however, while reduced part-load efficiency makes emissions higher than might otherwise be expected with fixed efficiency, overall GHG emissions remain lower at part-load than at full load (see Supplementary material S2).

Note that the analysis does not capture the GHG emissions of generator start-up and shut-down. Instead it assumes these can be approximated by extrapolating the efficiency curves below 'normal' minimum stable generation levels (shown by dotted line). Start-up and shut-down are complex processes that have different fuel consumption characteristics from part-load operation; however, it is expected that these emissions do not currently contribute significantly to the marginal displacement of wind power. Further work is required to confirm this assumption.

2.5. Other supply types

Since the end of 2008, National Grid has published operationally metered power output data for all BM units, averaged over 5 min ('instantaneous') or 30 min, and aggregated by supply type (Elexon, 2015). There are 13 types of supply types including coal, CCGT, Open Cycle Gas Turbine (OCGT), oil, nuclear, hydro, pumped storage, wind, other (largely biomass), and 4 interconnectors. While this avoids the approximations of individual unit output time-series, its aggregated nature precludes consideration of part-loading of individual units, which is only of relevance for emissions from fossil-fuel. Fossil-fuelled supplies other than coal and CCGT generate only a small amount of electricity, so the impacts of part-loading were not found to be significant within this study; aggregated operationally metered data and average GHG emissions intensities are therefore regarded as credible for estimating emissions.

Emissions intensities for supply types other than coal, CCGT and pumped storage were derived from annual data for GB with different approaches used for fossil/biomass generation, interconnectors and low-carbon generation. Average annual emissions intensities for fossil and biomass generation were derived from historical data using the method applied by Hawkes (2010); an example is shown in Table 1. The information was sourced from the Digest of UK Energy Statistics (DUKES, 2013) and the Defra/DECC GHG conversion factors (Ricardo-AEA, 2013). The values are summarised in Table 2. Estimates for the emissions intensity of the international interconnectors are from Defra/DECC GHG conversion factors (Table 2, Ricardo-AEA (2009, 2010, 2011, 2012, 2013, 2014)) with values from Hawkes (2010), and the Ecoinvent (2010) life cycle database shown for comparison. GHG emissions for nuclear, wind and hydro were taken from the Ecoinvent (2010) database and assumed constant. For nuclear

Table 1
GHG emissions factor calculations for 2012.

Supply type	Emissions intensity of fuel ¹ (kg CO ₂ eq/kWh)	Fuel/energy use in power stations ² (GWh)	Gross electricity supplied ² (GWh)	Average efficiency of gross electricity supplied ³	Average GHG content of gross electricity supplied ⁴ (kg CO ₂ eq/kWh)
OCGT ⁵	0.20435	–	4091	40.0%	0.5109
Oil	0.30704	9076	2735	30.1%	1.0188
Other ⁶	0.03895	61471	13400	21.8%	0.1787

¹ Source: Defra/DECC GHG conversion factors 2012, Annex 1 (AEA, 2012). (For preceding years these were sourced from Defra/DECC GHG conversion factors 2009, Annex 1 (Hill, 2009)).

² Source: Digest of UK Energy Statistics 2013, Table 5.6 (DUKES, 2013).

³ Average efficiency is defined as the GWh of electricity supplied divided by the GWh of fuel consumed.

⁴ Calculated from the emissions intensity of the input fuel divided by the average efficiency.

⁵ CCGT/OCGT breakdown is calculated based on an assumption of 40% efficiency of OCGT - as per Hawkes (2010).

⁶ “Other” generators are currently coal-fired stations converted to run on biomass. Data on the emissions intensity that for “wood pellets” from Defra/DECC GHG conversion factors 2012, Annex 9 (AEA, 2012), with all other data from DUKES based on “thermal renewables” (DUKES, 2013).

these mostly arise during operation, but emissions from wind and hydro mostly arise in manufacture and construction, with near-zero operational emissions. It may be argued that non-operational emissions should not be considered, but the more conservative approach is to include them. In any case, errors in these very low emissions intensities will not have a significant impact on the outcomes, given the dominance of high-carbon energy sources.

2.6. Pumped storage

Pumped storage has the effect of time-shifting GHG emissions, so the emissions intensity of power output will depend on the sequence and timing of energy stored. The carbon intensity of the energy in storage was accounted for using a weighted-average ‘stock accounting’ method. The emissions intensity of energy withdrawn from the grid and put into storage was deemed to be the same as the instantaneous grid average at that time. This is calculated from the aggregate system emissions excluding pumped storage at that time:

$$C = \sum_{i=1}^{12} EI_i P_i \quad (4)$$

where C is aggregate GHG emissions (t CO₂eq/h), EI is emissions intensity of supply type i (kg CO₂eq/kWh) and P is power output of supply type i (MW). The overall weighted emissions intensity of the energy in store is then calculated:

$$EI_{store} = \sum_{s=1}^S EI_s \frac{P_s}{P_{store}} \quad (5)$$

Table 2

Emissions intensities of supply types other than CCGT and coal for 2009–2014 (kg CO₂eq/kWh). Values in **bold** are those used in this study.

Supply Type	2009	2010	2011	2012	2013	2014	Ecoinvent ¹	Hawkes (2010)
OCGT ²	0.4599	0.4599	0.4599	0.5109	0.5109	0.5109	–	0.4600
Oil ²	0.8297	0.8051	0.8210	1.0188	1.0863	1.0863	1.1514	0.9194
Other ²	0.1872	0.1821	0.1797	0.1787	0.1647	0.1647	0.0588	0.6100
French interconnector ³	0.0884	0.1923	0.0883	0.1963	0.0979	0.0756	0.0873	0.0830
Irish interconnector ³	0.6633	0.6195	0.5791	0.5519	0.5712	0.5353	0.7761	0.6990
BritNed interconnector ^{3,4}	–	–	0.5227	0.5227	0.4975	0.4878	0.6859	–
East-west interconnector ^{3,4}	–	–	–	0.5519	0.5712	0.5353	0.7761	–
Nuclear	–	–	–	–	–	–	0.0078	0.0161
Hydro	–	–	–	–	–	–	0.0037	0.0000
Wind	–	–	–	–	–	–	0.0113	0.0000

¹ Source: Ecoinvent database v2.2 with IPCC 2007 LCIA method (Ecoinvent, 2010).

² Calculated with the method presented in Table 1. 2013 values were used for 2014 as the Digest of UK Energy Statistics had yet to be published at the time of analysis.

³ Source: Defra/DECC GHG conversion factors (Ricardo-AEA, 2009, 2010, 2011, 2012, 2013, 2014). Interconnector imports include transmission and distribution losses, and all relevant well-to-tank conversion factors.

⁴ The BritNed interconnector went live in 2011, and the East-west interconnector in 2012.

where EI_{store} is overall GHG emissions intensity (kg CO₂eq/kWh), EI_s is instantaneous emissions intensity during storage event s (kg CO₂eq/kWh), P_s is energy stored in a single event (MWh) and P_{store} is total energy in storage (MWh).

When power is generated from pumped storage, it has the weighted average stored emissions intensity, adjusted by the round-trip efficiency of the storage system, taken to be 74.5%.

3. Results and discussion

3.1. Overview

Table 3 and Fig. 5 show the marginal emissions factors for each year along with 95% confidence bounds and quality of fit (R^2). The ‘offset’ is the changes in GHG emissions that are not caused by changes in system load or wind output – factor ‘ c ’ from (1).

DECC’s annual AEF (Ricardo-AEA, 2016), currently used to estimate emissions displacement for wind, as well as the emissions intensity of fossil-fuelled generation (FEI) used by The Scottish Government (2014) (emissions from fossil generation per unit of energy generated from fossil fuels) are also included in Fig. 5. It can be seen that neither the AEF reported by DECC nor the FEI are a good approximation for the emissions displacement of wind power, with the AEF generally being an underestimate (detailed in Table 4) and the FEI an overestimate.

The convergence of average and marginal values apparent in Fig. 5 is an artefact of market conditions, as discussed in Section 3.2; the marginal emissions displacement of wind power is strongly related to

Table 3
Annual emissions factors in kg CO₂eq/kWh.

Year	MDF (wind)	MEF (supply)	AEF	FEI	Offset	Fit (R ²)
2009	0.597 ± 0.065	0.660 ± 0.002	0.490	0.630	0.013 ± 0.005	0.961
2010	0.611 ± 0.049	0.635 ± 0.002	0.504	0.627	0.010 ± 0.004	0.967
2011	0.553 ± 0.032	0.608 ± 0.002	0.494	0.662	0.006 ± 0.004	0.964
2012	0.547 ± 0.025	0.548 ± 0.002	0.548	0.775	-0.005 ± 0.004	0.957
2013	0.487 ± 0.017	0.493 ± 0.002	0.517	0.779	-0.004 ± 0.004	0.953
2014	0.483 ± 0.014	0.504 ± 0.002	0.472	0.731	-0.002 ± 0.004	0.961

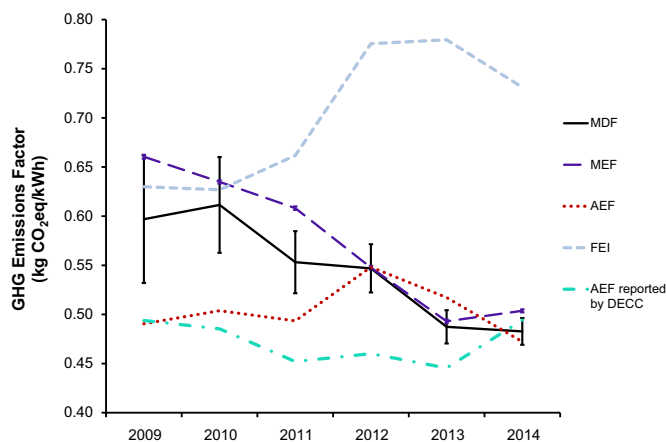


Fig. 5. Annual emissions factors.

Table 4
Difference between average emissions factor reported by DECC and calculated emissions displacement.

Year	MDF (wind) (kg CO ₂ eq/kWh)	Reported AEF (kg CO ₂ eq/kWh)	Difference
2009	0.597	0.494	-17%
2010	0.611	0.485	-21%
2011	0.553	0.452	-18%
2012	0.547	0.460	-16%
2013	0.487	0.445	-9%
2014	0.483	0.494	2%

the operational patterns of coal and CCGT, which are driven by fuel prices and policy factors. In recent years, as coal has increasingly been operated in preference to CCGT, the average emissions from transmission-connected generation have risen (increasing total emissions) and the marginal emissions displacement of wind power has fallen (decreasing the emissions savings of wind power). Operation of the system during 2012–2014, however, was unusual, so it is likely that the future operation will resemble 2009–2011, with MDF significantly higher than the AEF.

Despite the decrease in MDF from 2009 to 2014, rising wind capacity ensured that there has been an increase in total displaced emissions totalling 35.8 Mt CO₂eq over 6 years. This is 11% more than that calculated from published average emissions factors and lies outside the uncertainty ranges (Table 5). If the system had been operated the same way as in 2010 (more usual operation, as discussed in Section 3.2), the use of AEF to calculate displaced emissions would have resulted in an underestimate of 21%. This finding is of particular significance for onshore wind farms built on peatlands, which are relatively common in the UK. As discussed in Thomson and Harrison (2014), Smith et al. (2014), Mitchell et al. (2010) and Nayak et al. (2008), the GHG emissions associated with construction on peat increase the ‘carbon footprint’ of the wind farm, so in order to achieve a carbon payback they must be displacing the most carbon-intensive forms of generation. Furthermore, it demonstrates that marginal

Table 5
GHG emissions displacement in Mt CO₂eq.

Year	Emissions Displacement from reported AEF	Emissions Displacement from calculated MDF	Cumulative Underestimate
2009	1.64	1.99 ± 0.22	0.34 ± 0.22
2010	1.79	2.25 ± 0.18	0.81 ± 0.40
2011	4.40	5.38 ± 0.31	1.79 ± 0.70
2012	5.80	6.90 ± 0.31	2.89 ± 1.01
2013	8.29	9.08 ± 0.32	3.67 ± 1.33
2014	10.45	10.21 ± 0.29	3.42 ± 1.62
TOTAL	32.37	35.80 ± 1.62	3.42 ± 1.62

abatement costs have been overestimated by up to 21% and the potential emissions abatement of wind power has been underestimated. The former would correspond to a marginal abatement cost of 43–73 instead of 55–92\$/t CO₂, based on figures published by the Committee on Climate Change (Committee on Climate Change, 2008). For comparison, the total price paid for carbon emissions by fossil-fuelled generators is estimated to be around 7–15\$/t CO₂ (based on the values used to create Fig. 6).

The calculated AEF is included in Fig. 5 for information – it differs from DECC’s value due to: (1) different emissions intensity values; (2) DECC’s inclusion of non-reporting embedded generation excluded here; and (3) data here being limited to GB while DECC includes the entire UK. The exclusion of embedded generation should not fundamentally affect the resulting MDF, as it does not take part in the balancing mechanism and is not dispatched to respond to fluctuating wind output.

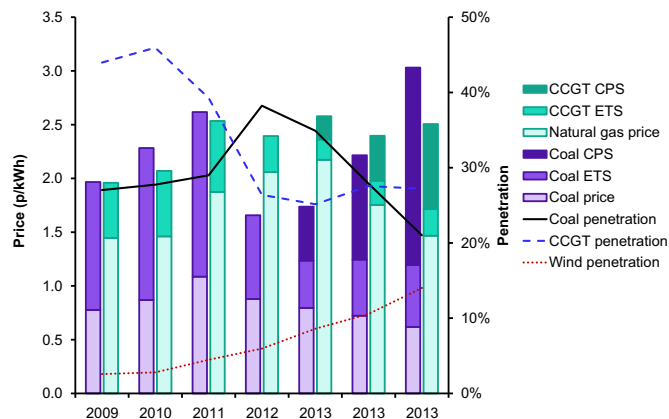


Fig. 6. Annual fuel prices and carbon costs from the EU Emissions Trading System (ETS) and UK Carbon Price Support (CPS). The corresponding penetrations of coal, CCGT and wind are also shown. Average prices of fuels from DECC (2015). Carbon prices based on a carbon intensity of 1.016 and 0.437 kg CO₂eq/kWh for coal and CCGT respectively, calculated from Ricardo-AEA (2014) according to the method in Table 1. EU ETS price is estimated as average annual carbon emissions futures price from Investing.com (2016a), converted to British currency according to the average exchange rate from Investing.com (2016b). The CPS is as published in HM Treasury (2011, 2012, 2013). Penetration is calculated from values in DUKES (2016).

It is of significance that the results of this analysis contrast strongly with those of Wheatley (2013) in that the MDF is generally higher than the AEF. This is due to the GB system having a significant proportion of baseload nuclear, while the Irish system studied by Wheatley uses coal as a baseload generator significantly raising the AEF. This contrast was also identified in a study of regional fluctuations in MEF across the USA (Siler-Evans et al., 2012).

The analysis disproves claims by some (le Pair, 2011; Lea, 2012) that DECC's emissions factors are too high, because 'only' CCGT, OCGT and hydro power can be ramped sufficiently fast to 'follow the variations in wind power output'. As the emissions factors for these generation types are substantially less than 0.5 kg CO₂eq/kWh and the MDF of wind power is typically higher, wind must be displacing higher-carbon generation. With the metered data (Elexon, 2015) showing that OCGT plant is only typically used for an hour every few days and the proportion of oil generation is very small, wind power must be displacing some coal. This conclusion is supported by the findings of Kaffine et al. (2011) and a statement by National Grid (Advertising Standards Authority, 2007).

Some commentators, notably Udo (2011), have also asserted that that increasing wind penetration will decrease its emissions savings potential. This is investigated in Section 3.4 and it is found that, overall, there is no evidence that increasing wind output tends to reduce its marginal displacement benefit.

Fig. 5 also shows that the MEF of total system generation follows a similar path to MDF of wind power, but is slightly higher. This suggests that the system is responding differently to supply and demand and that wind is nearly, but not quite, as technically effective at reducing emissions as demand reduction, supporting policies that incentivise wind power (although, it is acknowledged that the cost implications are very different, as demand reduction should result in a cost saving). The MEF often falls within the uncertainty range of the MDF, however, and the two follow the same general trend, suggesting that MEF may be a fair first approximation for MDF.

The results can be compared to those of Hawkes (2010) where the two studies overlap for 2009, with the MEF calculated to be 0.660 kg CO₂eq/kWh compared to 0.7 kg CO₂eq/kWh from Hawkes (2010). Hawkes' higher values could be accounted for by the inclusion of around 7% distribution network losses and, as Hawkes did not consider efficiency penalties, the similarity suggests that the relationship between total supply or demand and GHG emissions is robust despite different raw datasets and carbon intensity estimates.

While there is uncertainty in the estimates of MDF shown in Fig. 5, this has decreased as greater wind capacity and larger changes in wind generation allow clearer observation of the relationship between wind and emissions. It is also likely that the accuracy of wind power forecasts have improved and the fluctuations in wind power output are now more distributed across the system, allowing for greater consistency in the response from conventional generation, and clearer relationships between changes in wind output and GHG emissions.

3.2. Displaced generation mix

The key question is: how much coal is wind displacing and what has driven the changes in marginal and average emissions? The answer to this lies in three distinct time 'periods' evident in the pattern of AEF, MEF, MDF and FEI values, and supported by the investigation into diurnal and seasonal trends detailed in Section 3.3: 2009–2010, 2011–2012 and 2013–2014 (with additional data in Supplementary Material S3). These are related to the underlying generation mix and relative penetration of generation technologies:

- In 2009–2010 the penetration of coal was relatively low and CCGT relatively high, suggesting that CCGT was being operated in preference (i.e. higher merit) to coal. As the carbon intensity of coal is more than double that of CCGT (~1.0 vs. 0.4 kg CO₂eq/kWh) this

results in lower AEF and, with coal as the dominant marginal fuel, the MDF and MEF are high.

- Between 2011 and 2012 the penetration of coal generation rose sharply (Fig. 6), with a corresponding fall in CCGT. This suggests that coal was now being operated in preference to CCGT, with the latter providing a greater proportion of the marginal mix. As a result, the AEF rose while the MDF and MEF fell.
- From 2012–2014 the penetration of CCGT remained relatively stable, while the penetration of coal fell, with low-carbon imports and renewables meeting the balance. The MDF, MEF and AEF all decreased. It is likely that in this period coal continued to be operated in preference to CCGT, but as the volume of coal decreased, all emissions factors reduced.

An important feature of these results is that the marginal mix is never just coal or just CCGT. This reflects the more complex operation that goes beyond the simplified market 'merit order'. Even when CCGT is more expensive than coal, there is always some proportion of CCGT in the mix to provide reserve and follow variations in demand and wind.

These features can be substantially explained by the prices of coal, gas and carbon (Fig. 6) and changes in power station capacity. In 2009–2011 the additional cost of carbon emission allowances in the European Union Emissions Trading System (ETS) meant that coal and gas prices were similar but rising, favouring CCGT. Between 2011 and 2012 the price of ETS emission allowances fell dramatically, corresponding with a drop in coal prices while gas prices continued to rise, and the UK government announcement of a carbon price floor and corresponding Carbon Price Support (CPS) rates to be introduced in 2013, which precipitated a dramatic switch towards coal generation. Since 2012 the proportion of coal generation has fallen as CPS rates have risen and older coal stations that opted out of the Large Combustion Plant Directive (LCPD) (National Grid, 2007) are decommissioned. It is likely that the surge in coal generation in 2012 was also magnified by an interaction between the LCPD and carbon price floor, as generators that were due to be decommissioned rushed to use their allocated hours before the CPS rates rose. The fall in the gas price from 2013 to 2014 was only reflected by a slight increase in CCGT penetration; much of the balance came from an increase in wind penetration from major producers from 2% to 9% over 2009–2014 (DUKES, 2015).

In terms of GHG emissions reduction it is preferable for lower-carbon CCGT to be operated in preference to high-carbon coal-fired generation: in this instance average emissions will be lower, and wind power will also have a greater impact on emissions when it is available. The findings of this study suggest that policies like the carbon price floor price, which serve to make coal relatively more expensive, will serve this purpose.

3.3. Diurnal and seasonal trends

In order to investigate the results further, diurnal and seasonal fluctuations in emissions factors were investigated by disaggregation into 2-h and bi-monthly periods, respectively (Fig. 7 and Supplementary Material S4). In both cases it can be seen that fluctuations are driven by generation mix (Fig. 8 and Supplementary Material S4), supporting the findings of Section 3.2. In 2009–2010 all emissions factors tended to rise during the day and fall at night, as coal provides a higher proportion of both average and marginal mixes during the day. In later years, however, the MDF and MEF are higher at night than during the day, following the trend of the FEI, as coal only contributes to the marginal mix at night, when there is little CCGT operating, but during the day marginal changes in demand and wind output mostly displace CCGT.

As wind patterns cannot be controlled, the implications of these findings are of particular relevance for demand-side management:

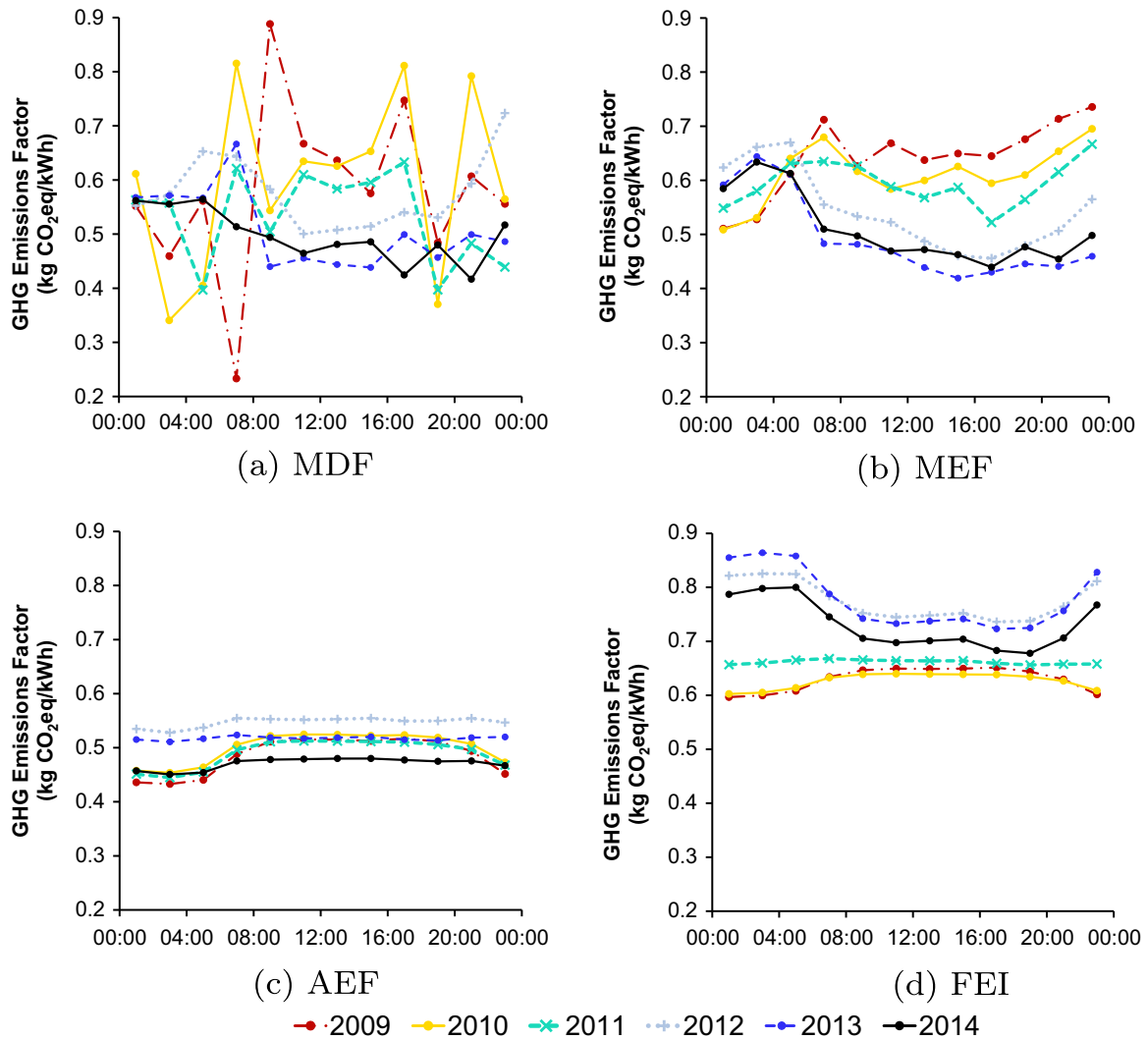


Fig. 7. Diurnal fluctuations in emissions factors, (a) MDF (b) MEF (c) AEF (d) FEI.

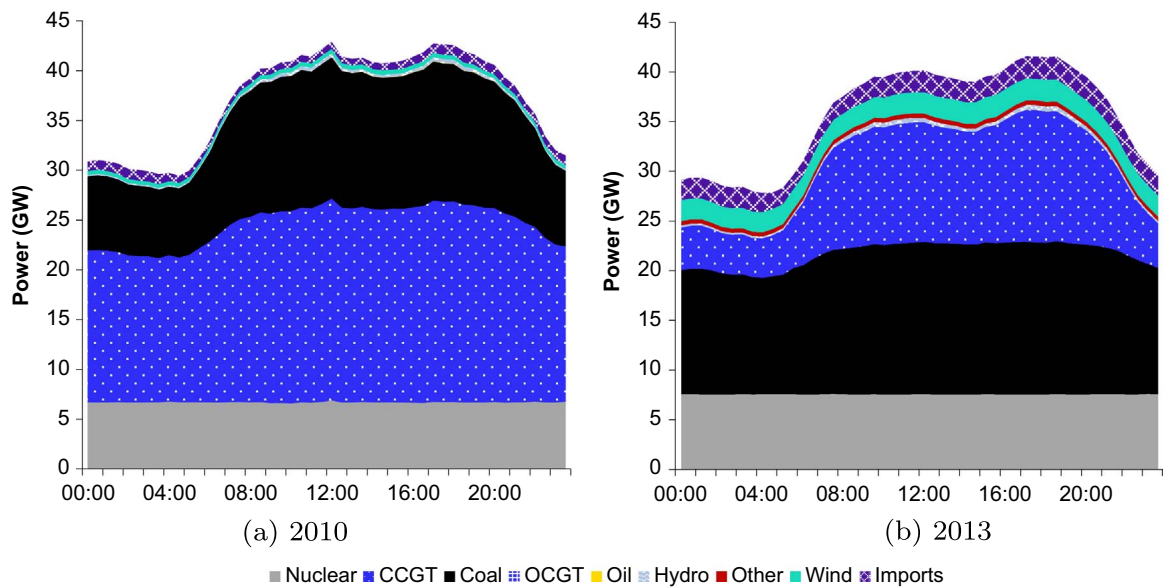


Fig. 8. Diurnal fluctuations in types of generation (Elexon, 2015), (a) 2010 (b) 2013.

demand-shifting away from the peak daytime hours to towards the night decreased overall GHG emissions in 2009–2010; in 2012–2014 it would have increased them.

3.4. Impact of wind penetration

It is possible that the decline in MDF from 2009 to 2014 has also been driven by increasing wind penetration, as suggested by Udo (2011). Udo found that emissions saving from wind in Ireland falls at higher instantaneous wind ‘penetration’ levels (penetration is ratio of wind output to system output). Although the highest wind output tends to occur in winter, the highest penetration levels occur when demand is low, typically in summer. As such, penetration levels cannot be used to directly infer whether observed trends are as a result of changes in wind output or decrease in system output.

To investigate any relationship between wind generation and emissions displacement, power and CO₂ data was disaggregated by instantaneous wind power and total system output. The results are discussed in detail in Supplementary Material S5. Firstly, it was confirmed that greater wind output occurs at times of greater demand, on average, so a high ‘penetration’ level does not necessarily imply a higher wind output. More importantly, clear differences in system behaviour between 2009–2011 and 2012–2014 were observed:

- In 2009–2011 (CCGT operated in preference to coal) the increase in coal generation with system output raises average and marginal emissions factors, except at very high system outputs where the available marginal mix includes other types of lower-carbon generation, such as hydro. The relationships with wind power output are not as clear, but the MDF is high when wind output is low, and falls as wind output increases, suggesting that a greater proportion of CCGT is being displaced.
- In 2012–2014 (coal operated in preference to CCGT) CCGT forms a greater proportion of the marginal generating mix as system output increases, which lowers the FEI, MDF and MEF. Increasing wind output has a more varied affect, with the MDF being fairly constant with wind output and the MEF rising when the wind output exceeds approximately 1.5 GW; it is likely that CCGT is the principal source of marginal generation, but at high levels of wind most of the available marginal CCGT has been displaced so the remaining marginal generating mix contains more coal. It is also of interest that higher wind output decreases the AEF overall, despite these bins also tending to have a higher system output that should increase the FEI and AEF.

Overall, this analysis shows that increasing wind output does not reduce its marginal displacement benefit; rather any changes in MDF over time are largely driven by underlying changes in system operation and coal and gas prices.

4. Conclusions and policy implications

This article has presented a methodology for determining the greenhouse gas (GHG) emissions displacement of wind power. Based on operational system data, it avoids the limitations of similar analyses based on system models and does not impose any assumptions about dispatch. It also takes into account the efficiency penalties of operating conventional thermal generation at part load. This can be applied to any system over any time-frame to find more accurate estimates to be used in carbon payback and net emissions reduction calculations, which are required by renewable energy developers, planners and policy makers.

This methodology was applied to the electricity system in Great Britain, analysing historical metered and market data from 2009 to 2014. For most years the marginal emissions displacement was significantly higher (21% in 2010) than the system-average emissions

published by the Department for Energy and Climate Change, most commonly applied in carbon payback and emissions reduction calculations (Ricardo-AEA, 2016). This suggests that emissions displacement has historically been underestimated and published carbon payback periods are generally pessimistic, which is of particular significance for carbon abatement cost estimates and for the viability of wind farms built on peatlands. The discrepancy between marginal and average emissions also confirms that wind power does not displace all forms of generation equally. Furthermore, the high values found for the emissions displacement demonstrate that the offset generation mix contains a significant proportion of coal (disproving claims in le Pair (2011) and Lea (2012)); however, it is not as high as the estimated emissions intensity of fossil generation, an alternative emissions displacement estimate suggested by the Scottish Government (Nayak et al., 2014). The efficiency penalty of operating conventional generation at part load was not found to be great enough to negate the emissions reductions.

Both the marginal emissions displacement of wind and the marginal emissions factor of changes in demand were found to be strongly influenced by the relative merit of coal and CCGT plants, with higher marginal values coinciding with lower average emissions. When CCGT is being operated in preference to coal (the situation from 2009 to 2011), the average emissions of the system are low and wind will also be displacing the most carbon-intensive generation, reducing these emissions even further. In contrast, when coal is being operated in preference to CCGT (as in 2012–2014) average emissions tend to be higher, and wind is less effective at emissions reduction because it is displacing less carbon-intensive generation. This relationship appeared to have been driven by fuel price and government policy changes, with 2009–2011 operation considered the more usual case. This reinforces the need for policies to penalise high-carbon generation and enhance the effectiveness of wind at reducing emissions. It also has implications for other variable renewables.

Disaggregation of the data to investigate relationships with other system factors found that there was no adverse impact of increasing wind capacity on emissions displacement over the studied time frame, contrary to the findings of Udo (2011).

Finally, this work also found that the marginal emissions displacement of wind is very similar to the marginal emissions of changes in demand, demonstrating that wind power is almost as technically effective as demand-reduction interventions at reducing emissions from generation. This supports policies that encourage increasing wind capacity as a means of reducing GHG emissions.

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Data used within this publication can be accessed at: <http://dx.doi.org/10.7488/ds/1585>.

Appendix A. Supplementary data

Supplementary data associated with this article can be found in the online version at <http://dx.doi.org/10.1016/j.enpol.2016.11.012>.

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