

Life cycle costs and carbon emissions of wind power

Executive Summary

R Camilla Thomson, Gareth P Harrison, University of Edinburgh, 2015

For the full reports see:

R Camilla Thomson, Gareth P Harrison, 2015, Life Cycle Costs and Carbon Emissions of Onshore Wind Power. A ClimateXChange report, Scotland,
http://www.climateexchange.org.uk/files/5314/3325/2390/Main_Report_-_Life_Cycle_Costs_and_Carbon_Emissions_of_Onshore_Wind_Power.pdf

And

R Camilla Thomson, Gareth P Harrison, 2015, Life Cycle Costs and Carbon Emissions of Offshore Wind Power. A ClimateXChange report, Scotland,
http://www.climateexchange.org.uk/files/4014/3325/2377/Main_Report_-_Life_Cycle_Costs_and_Carbon_Emissions_of_Offshore_Wind_Power.pdf

Key Points

- Capital cost is a major determinant of levelised costs but production levels and, particularly, financing assumptions are important determinants of headline costs; UK-studies showed above average levelised costs largely as a result of above average discount rates;
- The cost of offshore wind is more uncertain and higher than onshore wind and other established technologies, but there is significant scope to reduce costs to comparable levels;
- The introduction of wind power does result in impacts on the electricity system in terms of costs for balancing, transmission and backup, but these are modest at around 10% of the cost of wind energy;
- The life cycle carbon emissions from both on- and offshore wind are very low at 15 and 12 gCO₂eq/kWh, respectively;
- Wind power variability affects system operation and reduces the efficiency of coal and gas generation, but the impact is modest, and emissions savings due to wind power will remain significant.

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1. Introduction

There is a significant diversity of views on the life cycle levelised costs and carbon emissions of energy technologies, including onshore wind. ClimateXChange commissioned this review to help Scottish policy makers and other interested parties better understand these perspectives, the uncertainties associated with them, and the differing underpinning assumptions. This summary, and the main reports on which it is based (Thomson and Harrison, 2015a; Thomson and Harrison, 2015b):

- Identify the varied academic and wider perspectives on the life cycle costs and emissions of onshore wind technologies and associated infrastructure;
- Synthesise the existing evidence and assumptions used to support these perspectives;
- Identify variations in the evidence and assumptions, as well as areas of consensus and any outliers.

Cost

Understanding the economics of wind energy is vitally important to ensure a rational discussion about the role of wind power within the energy mix. The challenge is that ‘cost’ means different things to different people, with often conflicting views apparently supported by ‘evidence’. In part, this is due to confusion about current and future costs of generation, what is included or excluded from estimates, and the characteristics of wind relative to other generation types. Additionally, there is conflation of ‘costs’, ‘prices’ within the power markets and ‘subsidies’.

Carbon emissions

Another key issue of debate is the extent to which onshore wind farms achieve a net carbon emissions reduction over their lifetime. The carbon emissions reduction of wind power cannot simply be estimated as equal to the carbon emissions of conventional coal- or gas-fired generation that it displaces: firstly, wind power generation is not zero carbon, as greenhouse gases are emitted during installation, maintenance and decommissioning; secondly, wind power will not replace all forms of conventional generation equally. The true carbon emissions displacement will therefore depend upon a combination of factors including:

- the types of power generation being replaced;
- any decrease in efficiency of conventional plant operating at part load; and
- the impact of any increase in frequency of start-up and shut-down of conventional plant.

There may also be longer-term impacts associated with the installation of new conventional plant to back up an increase in installed wind capacity. Many of the existing publications examining the carbon emissions of onshore wind concentrate on either one or other of the above issues, with positive reports often focussing on the relatively small life cycle emissions of wind power in comparison to fossil-fuelled generation, and negative reports highlighting the uncertainty of calculating the true emissions displacement.

Wind farm life cycle

This study has analysed various estimations of the costs and greenhouse gas emissions associated with on- and offshore wind throughout its life cycle. The lifecycle stages considered are illustrated in Figure 1.

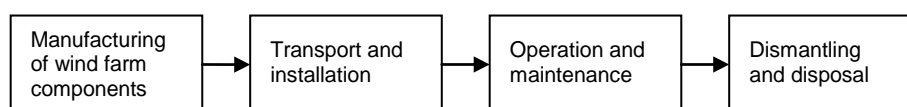


Figure 1 – Life cycle of a wind farm

Key Messages

- There is confusion about current and likely future costs of generation, what might be included or excluded in estimates and the characteristics of wind relative to other generation types.
- There is conflation of 'costs', 'prices' within the power markets and 'subsidies'.
- The carbon emissions reduction of wind power is complex, as life cycle emissions of wind are non-zero and true carbon emissions displacement will depend upon the operation of the whole grid
- Variations in cost and carbon emissions estimates are affected by assumptions made in the calculation itself and also differences in wind turbine designs, manufacturing and installation locations, maintenance and disposal.

2. Life cycle costs

A wide variety of costs are associated with wind farms, and these can be grouped into several life cycle components:

- Capital costs: the fixed costs of construction including manufacturing, installation and transport;
- Operation and maintenance costs: annual fixed costs associated with running the farm;
- Decommissioning: the cost of taking the plant out of commission, dismantling and remediation.

Whilst technologies may be compared on the basis of any of these costs categories, a more holistic view of ‘cost’ can be gained by looking across the life cycle of the technology and considering their overall cost.

Levelised Cost of energy (LCOE)

The levelised cost of energy (LCOE) measures the overall life cycle costs of a technology per unit of electricity produced. It is calculated as the sum of the discounted costs over the generator’s lifetime, spread across the discounted units of energy produced over the lifetime. This requires future costs to be expressed in ‘present value’ terms by discounting.

The calculation of LCOE requires a substantial number of factors to be determined which can be split into those that determine cost and those that determine energy production. Figure 2 shows the main information that is required to estimate the costs and energy production of a typical wind farm.

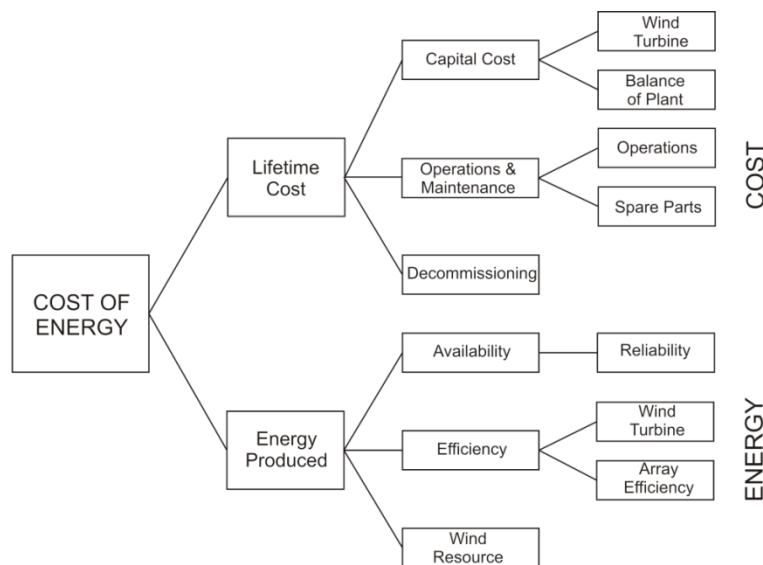


Figure 2 – Cost of energy for a wind farm

Variation in estimates

There is substantial scope for variation in the estimation of LCOE, which is introduced by the use of different assumptions, methods and uncertainty. These are illustrated in Figure 3 and can be divided into four categories:

- variation in input data arising from the scenarios used, timing and locations, and uncertainty in the data itself;
- uncertainties introduced by the financial assumptions, arising from location, such as tax rates and treatment, prevailing financial treatments, whether pre-or post-tax rates are used, and adjustments for risk or inflation;
- the physical and temporal boundaries analysed, and whether specific cost categories are included or not; and
- differences in the methodology used, and its intended scope.

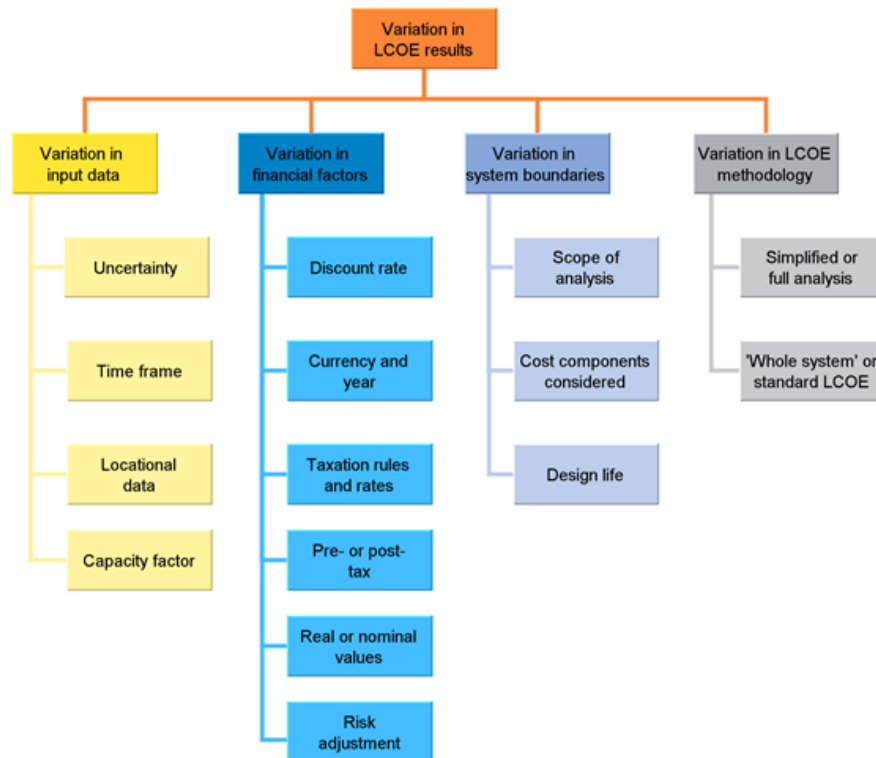


Figure 3 – Causes of variation in LCOE for wind farms

Current Cost Estimates

In recent years there have been a series of studies providing estimates of costs for wind and comparator technologies. As well as a modest amount of peer reviewed academic work, these include UK-specific work for and by DECC and the Committee on Climate Change (CCC), work by international bodies such as the IEA, trade associations, pressure groups and individuals. With the literature reporting variations in costs during the previous decade, only relatively recent studies have been included here. The range of currencies and baseline years required that costs were corrected into a common currency for comparison: 2011 pounds sterling (indicated by '£2011').

While **capital costs** do not provide a complete picture, they are the dominant determinant of LCOE for onshore wind, typically accounting for 80 - 90% of overall life cycle costs. Analysis of key studies showed variation arising from the year of study and location. The central points of these studies indicate a typical capital cost for onshore wind of around £1350/kW, similar to values suggested by UK-specific studies (CCC, 2011; Mott MacDonald; Poyry, 2013) implying that UK costs are about average, internationally. Most studies offer a range of costs although, as there is limited consistency in terms of how uncertainty in capital costs is reported, interpretation requires care.

Capital costs for offshore wind represent a lower proportion of overall costs (60-80%) with site conditions (e.g. water depth, distance from shore, etc.) having a major impact on costs. The central estimates of the studies suggest a typical capital cost of around £3000/kW with UK costs about average, internationally. One complication in comparing offshore wind capital costs is that recent UK studies treat the cost of the offshore grid connection as an operating expense, in line with how they are regulated, while the earlier UK studies, along with those from overseas, include grid connection as a capital cost; therefore, later studies typically estimate capital costs to be £340-500/kW lower. Round 3 sites generally have higher capital costs than Round 2 sites, and grid connection costs are substantially higher due to the increased distance to shore, deeper water and power transfer capacity.

Although **operating costs** are less significant, they remain a key input to levelised cost calculations, accounting for 15 to 24% of overall life time costs onshore and up to 35% offshore as a result of challenging access and grid connection charges. **Decommissioning costs** are largely neglected in studies as the discounted value is generally minimal.

Levelised Costs

The variations in capital and operating costs feed through into the overall levelised cost of energy estimates. Here they are joined by a series of other factors that lead to significant variation in LCOE. Figure 4 and Figure 5 show the range of LCOE estimates. Several things are apparent from the analysis:

- Higher values of capital costs do not automatically translate into higher LCOE; for example Tegen et al. (2013) has one of the higher onshore wind capital cost ranges but one of the lowest LCOE ranges;
- UK-specific studies tend to show higher LCOE values than those for overseas;
- The spread of costs is large with two studies indicating much higher LCOE for both on- and offshore wind.

The levelised cost of wind is very sensitive to assumptions on capacity factor, lifetime, discount rate and financing structure as well as capital costs (Schwabe, 2011). Giberson (2013) illustrates this well by making a series of 'reasonable' adjustments (reducing capacity factor, raising discount rates, altering treatment of depreciation), raising the LCOE estimate of Tegen et al. (2013) from the equivalent of £45 to £68/MWh. For the studies examined here, the central values for LCOE are strongly correlated with capacity factor and discount rate as well as capital cost.

UK studies almost universally apply a simplified LCOE method using pre-tax real discount rates of 10% for onshore wind (or, when risk-adjusted, marginally below this) and up to 13.6% for offshore wind. Other than studies by the IEA (2010) and IRENA (2012), which also use a similar discount rate and method, the international studies tend to have substantially lower real discount rates; this is the main driver for the lower LCOE values internationally. The national variation in discount rates reflects expectations of cost of debt and equity, financing preferences, and perceptions of a range of risks, including those from policy (Oxera, 2011).

Gibson (2011) and Civitas (Lea, 2012) have much higher apparent LCOE for both on- and offshore wind, as a result of adding 'system costs' to baseline levelised costs. Civitas (Lea, 2012) combines the £88/MWh baseline onshore wind LCOE from Mott MacDonald (2010) with £60/MWh of system costs based on Gibson's estimates of balancing, additional backup and transmission costs. Gibson's higher LCOE estimate is made up of a £75/MWh system cost and a baseline LCOE of £112/MWh despite also using Mott Macdonald (2010) cost components. In part both figures are higher as a result of a more conservative 25% capacity factor but importantly, inspection of Gibson's spreadsheets shows a series of factors that serve to inflate the LCOE: a high post-tax equity rate of return, low gearing, inclusion of IDC, and a separate debt repayment charge. The latter item is effectively double counting and it is notable that the financial treatment of on- and offshore wind differs from the other generation types examined. The system costs are examined in more detail in Section 3.

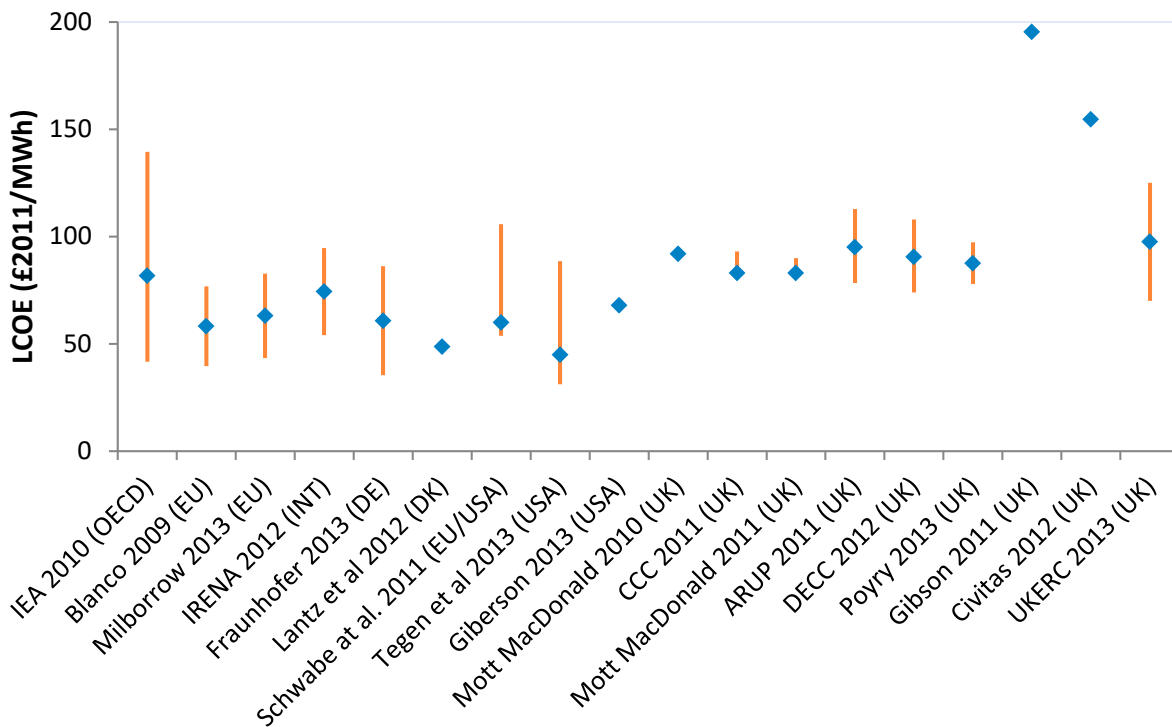


Figure 4 – LCOE of onshore wind (£2011). The bar shows the reported range of costs within each study and the marker shows the reported median value (or mean of the range where none given).

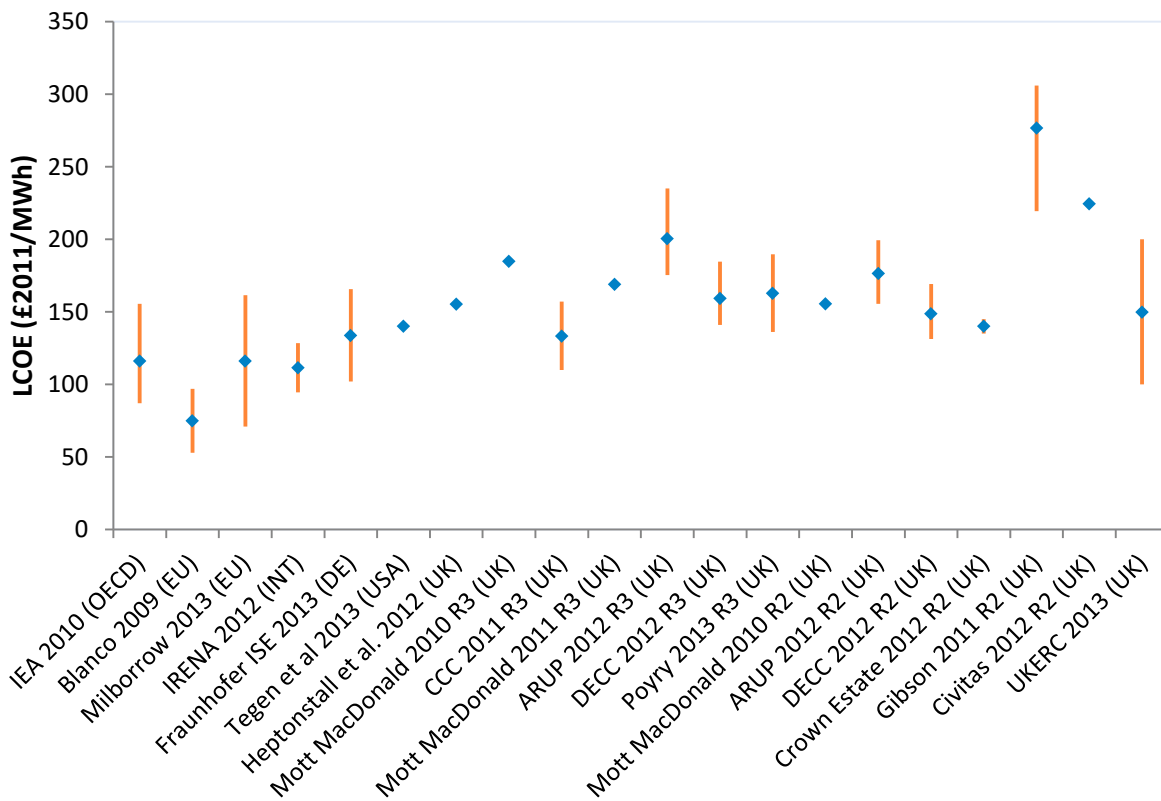


Figure 5 – LCOE of offshore wind (£2011). The bar shows the reported range of costs within each study and the marker shows the reported median value (or mean of the range where none given).

Comparison with other generating technologies

Many studies offer comparisons between wind and other technologies. In the main, the UK-specific analyses are representative, and the UKERC analysis (Gross et al., 2013) of the current spread of levelised costs is summarised in Figure 6. It is apparent that there are substantial uncertainties around all technologies. Capital cost, capacity factor and discount rate are important for nuclear, while fossil fuel and carbon costs are important factors for CCGT. It should be noted that LCOE estimates generally assume that thermal power plants are baseload, with capacity factors of 85-90%; in practice not all thermal generators operate as baseload and capacity factors for gas and coal generation would be expected to decline as more wind enters the system, raising their own LCOE.

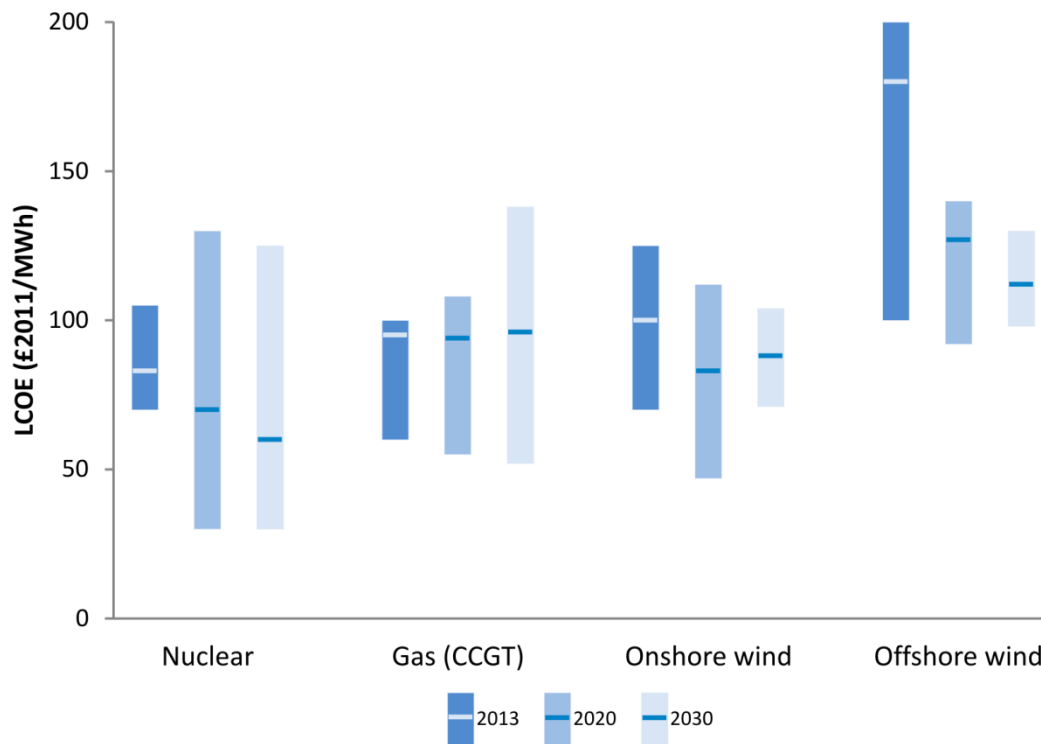


Figure 6 – Current and projected LCOE of a range of generating technologies: on and offshore wind, combined cycle gas turbines and nuclear generation (in £2011) based on sample of UK studies by UKERC (2013)

Although it is evident that offshore wind is substantially more expensive at present, the overlapping of the ranges for nuclear, onshore wind and combined cycle gas turbines means there is no clear outcome in terms of which technology is currently 'cheapest' on the basis of levelised costs. In terms of the evolution of levelised costs over the coming decades, a wide range of studies offer estimates of how capital, operation and fuel costs as well as operational performance will change. The methods, scenarios and assumptions vary, impacting on the projected LCOE. Although specific studies are not explicitly identified, UKERC (Gross et al., 2013) offer an assessment of the range of future costs, as shown in Figure 6. There appears to be scope for reductions in costs of onshore wind arising from advances in turbine technology, manufacturing and turbine performance. Offshore wind has very substantial opportunities for gains from economies of scale, performance improvements, improved deployment and servicing approaches and reduced numbers of offshore cables as a result of a shift to high voltage DC systems. Furthermore, the expectation is that, as deployment increases and practices mature, the risk associated with offshore wind will decrease, driving the discount rate and LCOE downwards. The main reports provide some additional information on the projections for on- and offshore wind from key studies.

Key Messages

- Capital costs for onshore wind are approximately £1350/kW and £3000/kW for offshore wind.
- Two studies (Gibson, 2011; Lea, 2012) show life cycle costs that are notably above others arising from inclusion of very high estimates of system costs. Further Gibson (2011) uses high discount rates, low capacity factors and otherwise unusual financial treatments.
- Lantz et al (2012), Tegen et al (2013) and Blanco (2009) suggest exceptionally low cost of energy estimates; these are attributed to relatively low discount rates and either capacity factors that are very high for the UK or very low estimates of capital cost.
- Discount rate assumptions are critical to the eventual levelised cost of wind; post tax real discount rates of 10% are typical for the UK and higher than international comparators.
- Currently onshore wind is broadly comparable with nuclear and gas generation with moderate scope to reduce costs by 2020.
- Offshore wind is by some margin more expensive than alternatives but there appears to be substantial scope to reduce costs significantly by 2020.

3. System Costs

The impact of wind on other generators and the system as a whole is generally excluded from levelised cost calculations, although some studies do include them. Some studies that include 'system costs' use it as evidence that wind energy costs are "significantly understated [because] they failed to take its unusual indirect and infrastructure costs into account" (Taylor and Tanton, 2012). In essence the 'system' costs that are referred to are:

- The costs of balancing the power system arising from wind;
- The costs of providing 'backup' or ensuring there is sufficient generation capacity to meet demand;
- The cost of additional transmission required to connect wind plants and the associated losses.

There have been several reviews of aspects of these costs, notably the UKERC Costs and Impacts of Intermittency (Gross et al., 2006). The IEA (2010) make the point that "there is no disagreement between experts that such system costs for non-dispatchable renewables exist [but there is] little agreement (and, in fact, very little information) about their precise amount". Studies show that generation mix, network capacity and interconnection, as well as the availability of mechanisms for managing variability, are important in determining costs; this makes comparison challenging.

Balancing

The variable nature of wind power, in contrast to conventional, dispatchable technologies, requires flexible 'reserves' to be on hand for when the resource is not available (IEA, 2010). Reserves are used to handle unpredicted variations in demand or generation on a range of timescales from seconds to around four hours. Reserves are provided by power stations running at part load, standby generators that can be started quickly (e.g. open cycle gas turbines) as well as (some) contracted demand response. Costs are incurred by operating power plants less efficiently and ensuring standby generation is available. The amount of reserve is specified by National Grid on the basis of the largest generator that can be lost and the level of error in forecasting demand and wind four hours ahead of delivery. Increases in wind capacity will therefore increase the amount of reserve that needs to be held but the amount depends on overall expected errors, not simply wind capacity.

An IEA (2010) international comparison shows balancing costs increase with wind penetration, although the rate of increase levels off, with costs up to around £4/MWh for 20% wind penetration. Specific studies for the UK suggest increases in the volume of reserve held; National Grid (2010) estimate extra balancing costs for a 40% wind penetration in 2020 as around £500–1000 million per year or £3.5–7.0/MWh. For comparison, the cost of balancing the system in 2012/13 was £803 million (representing around 1% of customer's bills) of which £170 million was due to managing grid constraints and £7 million specifically for constraining wind farms. Recent concerns have also arisen that 'cycling' of thermal power plant is raising fuel and maintenance costs and offsetting fuel savings due to wind power generation (Taylor and Tanton, 2012); however, a recent analysis by the National Renewable Energy Laboratory (NREL) (2013b) found that, for the western USA, the increase in fuel and maintenance costs from cycling were less than £0.40/MWh compared to around £20/MWh of savings from avoiding fossil fuel use.

Overall, the literature suggests that balancing costs are likely to be lower in larger markets, with a geographical spread of plants, and when wind is part of a complementary portfolio of other generation technologies (IEA, 2010). This is important in considering wind integration in Scotland as, while Scotland's wind penetration will be locally very high, it is the penetration at GB level and the extent of transmission and external interconnections that will strongly govern balancing costs. While there are undoubtedly additional balancing costs arising from integrating variable wind, the IEA (2010) and other studies suggest they are not prohibitive. Additionally, the Committee on

Climate Change (CCC, 2011) suggest that, with the right investment in flexibility in the form of storage, demand side management and interconnection, costs can be managed at even relatively high renewable penetration.

Backup

Ensuring there is sufficient generating capacity to provide secure electricity supply is a key issue and concern is expressed about ensuring 'backup' is provided to cover days when there is little or no wind. However, in analysing this issue some studies (Gibson, 2011; Lea, 2012; PB Power, 2004; Taylor and Tanton, 2012) make an explicit assumption that additional dedicated generating capacity must be built to 'firm up' wind, and that this entails high additional costs of £11 to £28/MWh to cover capital and operating expenses.

This is not a realistic assumption as, in practice, all fossil fuel and nuclear power stations provide backup to all others (Milborrow, 2009). As each has a statistical probability of experiencing an outage, more capacity is built than is required at peak demand levels to cover this eventuality. Wind is essentially no different although its availability is governed by the weather rather than the mechanical reliability alone. As wind is added to the system it, in itself, adds to system reliability, and this is referred to as its 'capacity credit'. Importantly, as wind is added, it is not automatically the case that other power plants are retired.

Analysis for the CCC show that use of flexibility introduced by storage, demand side response and interconnection, mean requirement for peaking plant, such as open cycle gas turbines for meeting shortfalls, is low (Poyry, 2011), with costs around £0.2/MWh at 40% wind penetration. The key point is that provision of full backup of renewable capacity is not necessary for secure supplies, where flexibility is encouraged.

Transmission

The cost of investment in transmission lines, cables and associated infrastructure is also a key theme, with Gibson (2011) and Civitas (Lea, 2012) attributing very high transmission costs to wind. In determining a £31/MWh cost of transmission, Gibson (2011) extrapolates the costs from the contentious Beaulieu-Denny line. For simple situations, such as a wind farm on the end of line, analysis based on recent lifetime transmission costs (Parsons Brinckerhoff, 2012; Thomson and Harrison, 2015a; Thomson and Harrison, 2015b) suggest that costs are actually much lower. A difficulty in estimating cost of transmission on this basis is that transmission lines generally add to, or upgrade, an existing interconnected system. The power flows are therefore more complex, lines are not loaded to maximum to ensure stability and security, and there are often a series of related upgrades. Additionally, having insufficient transmission capacity necessitates the constraining of generation, which itself adds to balancing costs. In considering the cost of transmission expansion, it is important to note that other generation sources will also require transmission expenditure, not just wind. Mills et al. (2009) emphasise that transmission expansion typically serves multiple purposes, and that assigning the full costs of expansion to new (wind) generation capacity effectively ignores other benefits. The CCC (Barrs, 2011) suggest that transmission costs are likely to rise with renewables penetration: wind generation in the north will tend to increase need for capacity but where it is closer to the south it may save costs accommodating non-renewable plant elsewhere. Transmission costs are estimated at £5 to £10/MWh (Barrs, 2011).

Total 'System' Costs

Analyses presented in the main reports (Thomson and Harrison, 2015a; Thomson and Harrison, 2015b) show that the estimates of Gibson (2011), Civitas (Lea, 2012) and others for the system costs of wind are very much overstated; however, it remains the case that system costs are real. The IEA (2010) suggest that "part of the cost of such system's reserves should in principle, be added to the LCOE of intermittent renewables when compared to other baseload generation sources". Substantial system costs exist, even in zero wind systems, precisely because the nature of electricity supply requires backup, balancing and transmission to allow individual, isolated, generators to contribute. The range of credible estimates from the literature for each component allows an

estimate of total systems costs to be made for penetrations of up to 40% wind (Table 1). These represent around 10% of the cost of onshore wind.

Cost component	Range (£/MWh)
Balancing costs	2 – 7
Backup costs	0.2 – 0.5
Transmission costs	5 – 10
Total 'system' costs	7 – 18

Table 1 – Range of 'system' costs associated with wind power (Thomson and Harrison, 2015a; Thomson and Harrison, 2015b)

Key Messages

- System costs such as balancing, provision of backup and transmission arise in accommodating wind energy but are relatively small compared to the overall cost of electricity supply or the levelised cost of wind; values of £7 to 18/MWh are credible.
- Studies that included system costs in their levelised cost estimates (PBPower, 2004; Gibson, 2011; Lea, 2012; Taylor and Tanton, 2012) tended to systematically overstate them.
- There is particular overstatement of the cost of 'backup' where it is assumed that dedicated conventional generation must be constructed for periods when the 'wind is not blowing'; the reality is that with other generation on the system operating flexibly the requirement for backup is modest.
- There is substantial scope for energy storage, demand side response to provide flexibility.

4. Life cycle carbon emissions

While wind power is low-carbon, it is not zero-carbon – carbon is emitted throughout the wind farm life cycle due to manufacture, construction, maintenance and decommissioning processes. The life cycle carbon emissions of wind power generation have been very widely studied, mostly by proponents of wind power who wish to demonstrate its low-carbon credentials; however, it is worth bearing in mind that life cycle carbon emissions estimates are not a complete picture, and that there are also system effects of wind intermittency that may actually increase the carbon emissions of other parts of the network. This is examined in more detail in Section 0.

Calculation Methodology

The life cycle carbon emissions of wind farms are conventionally calculated using partial process-based Life Cycle Assessment (LCA), defined by a number of national and international standards (BSI, 2011; ISO, 2006a; ISO, 2006b; ISO, 2013). This involves systematically analysing the greenhouse gas emissions of each process in each stage of the life cycle of the wind farm (Figure 1). There is considerable scope for variations to be introduced to the results by variations in assumptions, methodological choices and data uncertainty. Figure 7 illustrates the key areas where such variations might be introduced to estimates of the life cycle carbon emissions of onshore wind power. These can be divided into four categories, which are described in greater detail in the main reports:

- variations in the input data stemming from variations in the wind farm scenarios, year, location, and equipment, as well as uncertainty in this input data;
- uncertainties in the emissions factors extracted from life cycle datasets, variations in processes in different countries, and differences in the scope of GHG emissions included;
- differences in physical and temporal system boundaries; and
- variations introduced by differences in LCA methodology.

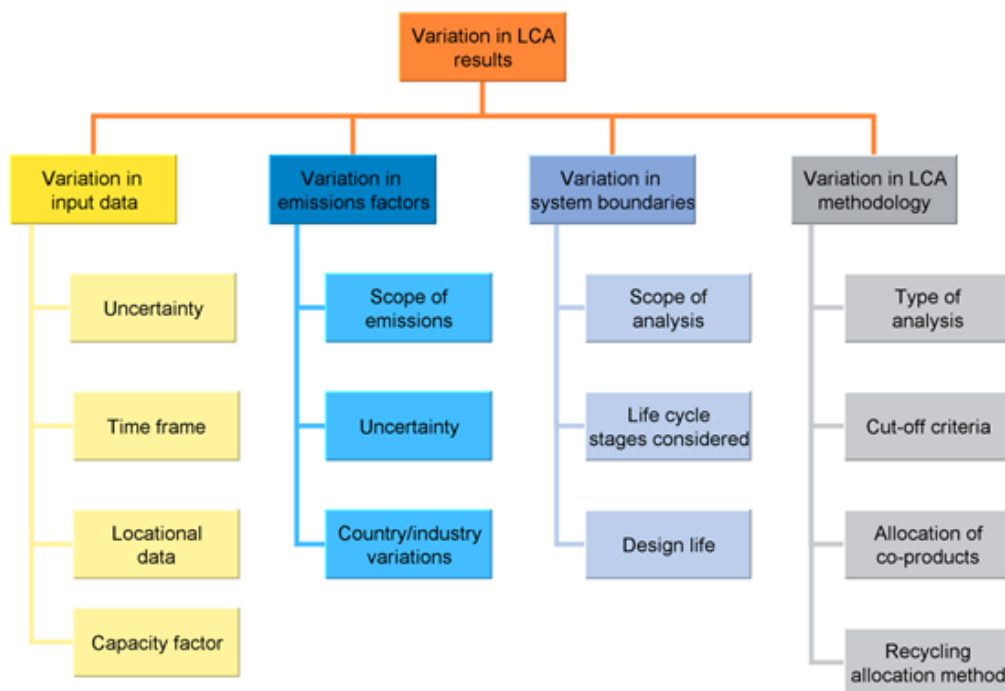


Figure 7 – Causes of variation in LCA of wind farms

In a recent comprehensive review and harmonisation of carbon footprinting studies for wind power generation, the National Renewable Energy Laboratory (NREL) in the USA identified that the most significant variations in carbon emissions estimates were introduced by variations in capacity factor, but that there was generally a tight distribution of results, suggesting that “new process-based LCAs of similar wind turbine technologies are unlikely

to differ greatly” (Dolan and Heath, 2012). In another review of the source of variation in carbon emissions estimates, Thomson (2014) identified that system lifetime and the methodology used for allocating recycling credits were also significant. It is important to note, however, that capacity factor and system lifetime are a function of the specific design and location of each wind farm, and are therefore likely to vary between farms. In arriving at their harmonised values (Dolan and Heath, 2012) found the mean assumed capacity factor of existing studies to be 30% onshore and 40% offshore, which are slightly higher than the respective values for the UK (27% and 39%). Good quality studies should include a sensitivity and uncertainty analysis to test the robustness of the results, and their sensitivity to variations in methodology and key assumptions; and estimates of life cycle emissions should be presented with uncertainty ranges.

Lifecycle impacts

The quality of published lifecycle carbon emissions estimates for on- and offshore wind vary widely, with only 41% of those identified by researchers at NREL meeting their basic quality screening criteria (Dolan and Heath, 2012); therefore, only a selection of most robust and reliable estimates are considered here, illustrated in Figure 8 and Figure 9. Most of these studies apply process-based LCA, which is thought to suffer from truncation errors, but a small selection have been identified that are based on hybrid methods, which avoid these but may introduce double-counting errors – significantly there is no clear difference between the results from these two methods.

The recent harmonisation published by NREL (Dolan and Heath, 2012) provides the most comprehensive review of published estimates of carbon emissions of wind power to date, finding mean estimates of 15 and 12 gCO₂eq/kWh for on- and offshore wind, respectively, following harmonisation of key assumptions. The actual carbon emissions of onshore wind power generation in the UK might be higher than this, as the capacity factor is slightly lower than the NREL estimate, and also some wind farms in the UK are constructed on peatlands, which was not considered in the NREL study. Peat plays a significant role in the carbon cycle, and disturbance of the peat can lead to an increase in carbon emissions from the soil (Nayak et al., 2008) – some estimates of these emissions have been included in studies shown in Figure 8, showing a significant increase (Thomson and Harrison, 2015a; Thomson and Harrison, 2015b).

The **manufacture and installation** stages together account for over 90% of the total life cycle carbon emissions of an onshore wind farm not constructed on peatlands (Ardente et al., 2008; Guezuraga et al., 2012; Tremeac and Meunier, 2009), and 70% of an offshore farm (Ecoinvent, 2010; Wagner et al., 2011), with the vast majority of these emissions arising during the extraction of materials and manufacture of components. Transport and installation typically contributes only about 6% of these emissions for an onshore wind farm if the carbon impacts of land-use change, such as construction on peatlands, are not included (which is common practice in existing studies). Offshore, the proportion will be higher as a result extensive use of vessels, although no study explicitly estimates the division between manufacture and installation impacts (Thomson and Harrison, 2015a).

Of the remaining emissions, **operation and maintenance** activities contribute around 6% to the total life cycle impacts of an onshore wind farm and around 20% offshore (the latter being significantly higher due to the installation site being more challenging to access), while **decommissioning** accounts for a further 6%.

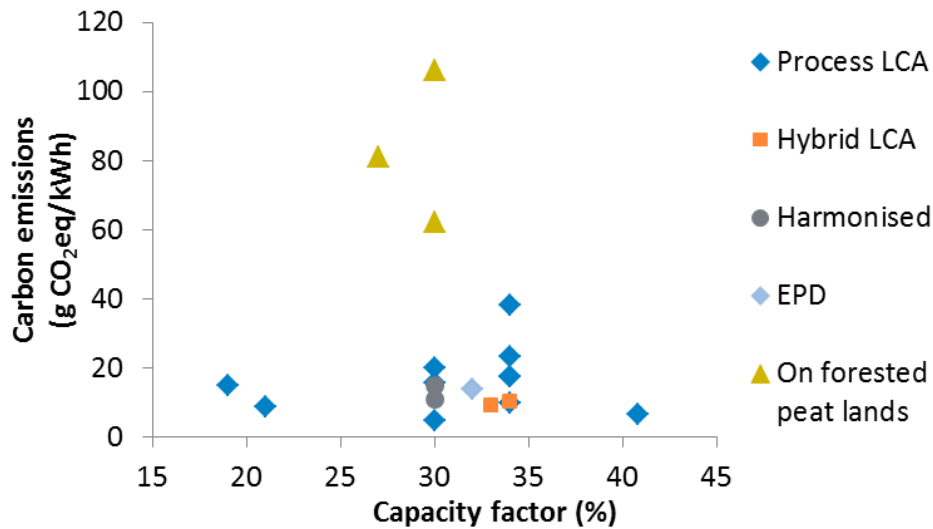


Figure 8 – Selection of carbon emissions estimates for onshore wind

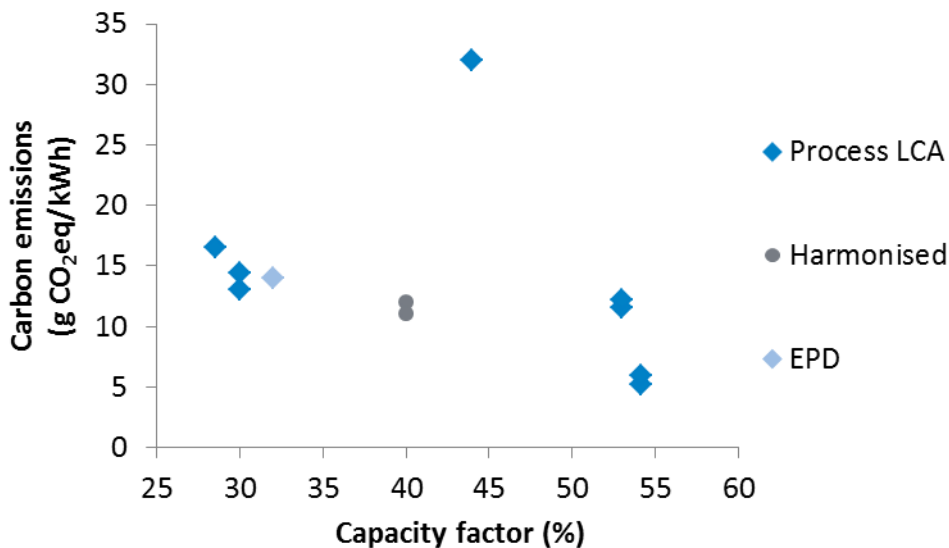


Figure 9 – Selection of carbon emissions estimates for offshore wind

Comparisons with other generating technologies

Despite variations in estimated carbon footprint of wind power generation, it is significant to note they are all significantly lower than for fossil fuelled generation. Figure 10 compares the values presented here with those gathered by NREL for other types of generation, with the ranges showing the maximum range of published estimates (NREL, 2013a; Warner and Heath, 2012; Whitaker et al., 2012). There is no overlap between wind generation and any type of fossil fuelled generation. Furthermore, there is greater consensus on the carbon emissions of wind than there is for other forms of low carbon generation, such as hydro and nuclear power.

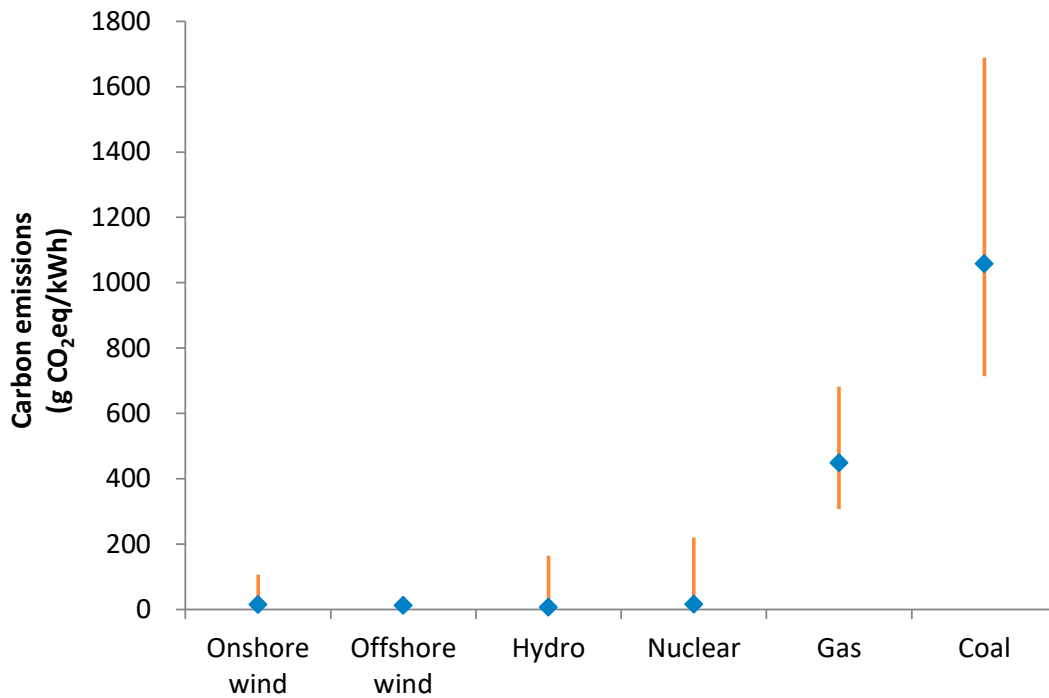


Figure 10 – Comparison of carbon emissions of wind with other types of generation

Key Messages

- This review considers only a selection of the most reliable and robust published studies.
- Significant variations to carbon emissions estimates are introduced by uncertainties in raw data, assumed capacity factor and design life, and the way that recycling is dealt with, as well as the inclusion of land-use-change impacts, such as deforestation and peat disturbance.
- There is disagreement over whether process-based analyses or hybrid methods (which use input-output data) are the most reliable; however, this review has found that the results of both types of study are comparable.
- The lowest estimates are attributable to a high assumed capacity factor, consideration of carbon dioxide only and low assumed impacts for electricity consumption.
- The highest estimates consider more conservative assumptions and, in the case of onshore wind, include the impacts of land-use change on forested peatlands.
- Credible estimates of the carbon emissions for onshore wind range from 3 to 45 g CO₂eq/kWh, but when farms are constructed on forested peatlands these increase to 62 to 106g CO₂ eq/kWh.
- Credible estimates of the carbon emissions for offshore wind range from 7 to 23g CO₂eq/kWh.

5. Carbon emissions displacement and payback of wind power

Estimates of the life cycle carbon emissions of wind farms are not, in themselves, particularly useful, and are only really of interest for comparison with other forms of low-carbon generation. Further interpretation is required to calculate other values that may be more meaningful, such as the lifetime emissions reduction of a wind farm (the net reduction of greenhouse gas emissions taking into account both the life cycle carbon emissions and the lifetime emissions displacement) or the carbon payback period (the time for the emissions displacement to offset the life cycle carbon emissions). Estimates of carbon emissions displaced by wind power vary widely, as they are a measure of the displaced emissions resulting from wind power replacing other forms of generation. Current practice in both scholarly research and policy implementation is to estimate this based on the average emissions of the whole network using annual figures published by DECC/Defra, currently 460 gCO₂/kWh (Ricardo-AEA, 2012); however, analysis of current research indicates that, while the carbon displacement of wind power generation can be approximated using such figures, this is likely to underestimate the positive impacts of wind power on carbon emissions.

Marginal emissions displacement

Accurate accounting of the emissions displaced by wind generation should reflect the fact that wind power only replaces certain types of generation (nuclear, for example, does not respond to fluctuations in wind). Generators operating on the margin, including conventional gas and coal power stations, operate at part load to provide reserve and respond to fluctuations in wind power and demand – the emissions displacement of wind power will be related to this marginal generating mix. There are also efficiency penalties associated with operating these power stations at reduced outputs, which causes the carbon emissions intensity of these generators to increase as a result of the presence of wind generation on the network. This effect has led to some reports that wind power generation actually results in an increase in carbon emissions (Lea, 2012; Udo, 2011), but these are based on flawed analysis (see the deconstruction of one such analysis (le Pair, 2011) in the Appendices to the main reports): while the carbon emissions per unit of energy output (emissions intensity) of thermal generators does increase at part load, overall the total emissions still fall as their output decreases, so that the effect of the efficiency penalties is to decrease the magnitude of the emissions savings from wind, but not completely negate them. This has been demonstrated by a number of studies of the marginal emissions of networks around the world (Kaffine et al., 2011; Siler-Evans et al., 2012; Thomson, 2015; Voorspools and D'Haeseleer, 2000).

Studies internationally confirm that the marginal emissions are significantly different from the system average emissions of the corresponding networks (Bettle et al., 2006; Farhat and Ugursal, 2010; Gil and Joos, 2007; Hawkes, 2010; Marnay et al., 2002; Siler-Evans et al., 2012; Thomson, 2015), with the actual values depending upon the types of generation available on the network and the relative prices of different fuels. The most relevant study specifically examined the recent marginal emissions displacement of wind power in Great Britain, taking efficiency penalties into account (Thomson, 2015), and found that, although efficiency penalties did reduce marginal emissions estimates, they remained higher than the corresponding system average emissions; for example, in 2012 the marginal displacement of wind power was 550g CO₂ eq/kWh, some 20% higher than reported UK-average emissions for that year.

Payback periods and lifetime emissions savings

The carbon payback period is the time for the carbon emissions displaced by wind power to equal the life cycle carbon footprint of the wind farm. In order to achieve a net reduction in GHG emissions, this should be significantly shorter than the intended lifetime of the wind farm. At current marginal displacement rates carbon payback is typically around 6 months to a year, although this can be several years for onshore farms built on peatlands where no effort has been made to mitigate the effects of wind farm construction.

Both the average and marginal emissions of electricity generation are likely to reduce over time, as the most polluting power stations are replaced with lower carbon alternatives (Hawkes, 2010; Voorspools and D'Haeseleer, 2000). As such, the emissions displaced by a given wind farm will tend to decline over time, so that farms built further into the future will take longer to pay back. Pay back will be achieved as long as lifetime average emissions reduction factor exceeds the carbon footprint (Smith et al., 2015). Based on the most recent DECC forecasts (DECC, 2013) for future grid emissions, Figure 11 shows the lifetime average payback threshold for wind farms with a design life of 20 years, constructed between 2010 and 2050. It can be seen that the vast majority of carbon footprint estimates for onshore farms fall below this line and will achieve carbon payback; however, the highest three, which correspond to onshore wind farms constructed on forested peat lands, will not achieve carbon payback if they are constructed after the mid-2020s. This is significant for wind farms currently being planned and highlights the importance of ensuring that undegraded peatlands are disturbed as little as possible. For offshore wind farms, all the current carbon footprint estimates fall below the payback threshold up until 2050.

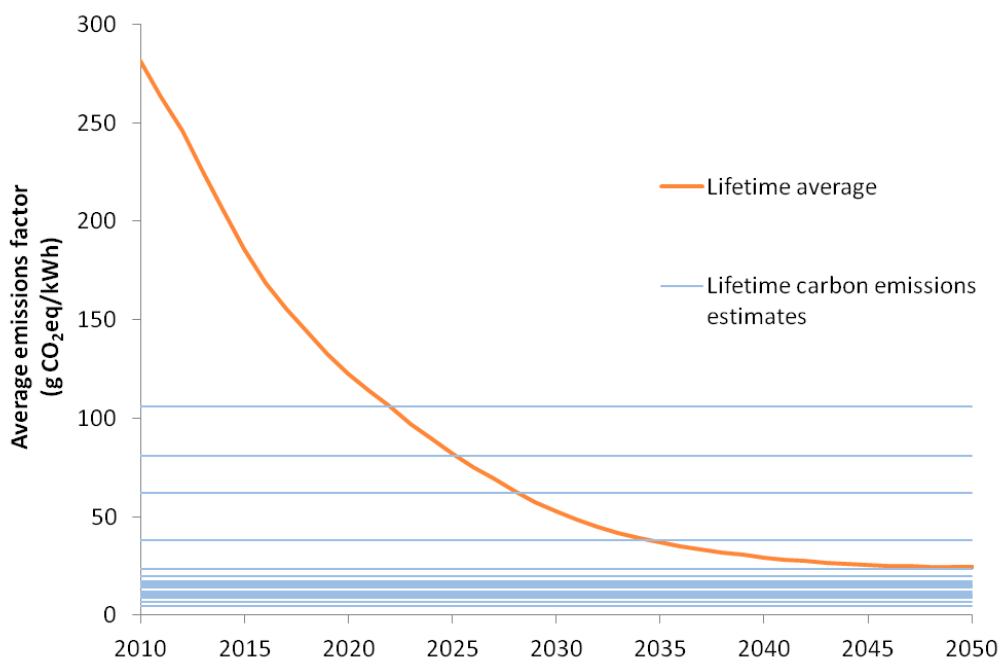


Figure 11 – Carbon payback thresholds for wind farms constructed in the future, with estimates of emissions factor for onshore wind

Key Messages

- To achieve net reduction in carbon emissions, the carbon payback period of a wind farm should be significantly shorter than the intended lifetime (typically 20 years).
- Estimates of carbon emissions displacement are currently based on the average emissions of the whole network – 460g CO₂eq/kWh for 2012 (Ricardo-AEA, 2012) – but use of this value is disputed.
- An influential report by Civitas (Lea, 2012) suggesting that wind power is not effective at reducing CO₂ emissions is based on flawed analysis by le Pair (2011).
- The most reliable recent estimate for the emissions displacement of wind power in Great Britain is 550g CO₂eq/kWh for 2012 (Thomson, 2014), some 20% higher than ‘official’ estimates.
- Estimates for the carbon payback of onshore wind range from 6 months to 2 years but construction on forested peatlands suggests this can approach 6 years (2012 values).
- Harmonised estimates for the carbon payback of offshore wind range from 5 months to 1 year.
- When expected decrease in grid-average emissions is taken into account, most current lifecycle emissions estimates indicate payback will be achieved within the farm lifetime up to 2050.
- Wind farms constructed on forested peatlands after 2022 may not achieve payback. Efforts must be made to minimise the carbon impacts of construction in such locations.

6. Conclusions

While levelised cost and life cycle carbon analysis is well established with clear methodologies, there is scope within these to create quite large variations in headline figures.

For levelised cost of energy estimates the most important factors are capital cost of turbines, capacity factor of wind and financing assumptions – specifically the discount rate. There are a substantial number of different ways of expressing these key factors, which makes comparison challenging. There is a spread in current estimates of levelised cost with UK studies showing higher average costs than internationally, which can largely be attributed to the use of above average discount rates.

Several cost estimates are much higher than others, which has been identified to be due to the inclusion of ‘system costs’. It is customary for levelised cost of energy calculations not to include ‘system effects’. The review found that system costs arising from accommodating wind (balancing, provision of backup and transmission) do exist, but at relatively modest levels that are not prohibitive when compared to overall costs of delivering electricity supplies or the levelised cost of wind power itself. Studies that do include system costs in the levelised cost analysis tend to systematically overestimate them, and suffer from a number of methodological flaws. There is no issue methodologically in including system costs, but credible approaches must be used, and other factors that are also not generally included in LCOE, such as external costs, should also be considered.

At present the range of levelised costs for onshore wind is broadly comparable to nuclear and combined cycle gas turbines and substantially cheaper than offshore wind. Although there is some uncertainty, there are prospects for cost reduction in onshore wind and very substantial opportunities offshore.

For life cycle carbon emissions the most critical aspects are the wind farm capacity factor, the system lifetime, the approach to recycling credits and uncertainty in emissions factors. Additionally, the emissions associated with construction on peatlands are important for onshore farms, while vessel use for installation and maintenance is significant offshore. While there is modest uncertainty associated with estimates of lifecycle emissions, values for both on- and offshore wind are substantially lower than unabated gas and coal generation, and there are fewer inherent uncertainties than nuclear. Estimates of the lifecycle carbon emissions of offshore wind are generally lower than for onshore, due to better wind profiles and economies of scale.

Lifecycle carbon emissions also exclude ‘system effects’, as these are instead considered when examining carbon payback time or lifetime emissions savings; however the literature shows that, although efficiency penalties from operating thermal generation at part-load reduce the carbon savings from wind, the effect is modest. Furthermore, the rates currently used in wind farm analysis appear to systematically underestimate the emissions savings. Wind generation is, therefore, effective at displacing fossil fuelled generation and reducing emissions, with carbon payback periods typically less than a year (although onshore construction on undegraded peatlands can extend this to several years). Long term, the expectation is that wind will remain effective at reducing emissions, even within an electricity system undergoing major decarbonisation. Furthermore, while wind farms on constructed on peatlands could soon reach the point that they would not be effective in reducing emissions, existing measures are available to minimise the impact on the peatlands (Nayak et al., 2008) so that this point can be pushed some distance in the future.

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