# The Performance of Wind Farms in the United Kingdom and Denmark

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## Contents

## List of Figures and Tables

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## About the Renewable Energy Foundation

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## Author's Note

Note: The views expressed in this paper are strictly personal and do not reflect the position of any organisation with which I am associated. I am grateful to John Constable, Lee Moroney and a referee for their comments on earlier drafts of the paper. The results of this study have been presented at seminars and lectures to various groups in Edinburgh and Glasgow. I have benefited from the questions and comments from participants in those events.

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## Note on the Data

For the convenience of interested researchers both the raw and cleaned data employed in this analysis will published alongside the electronic version of the study on the REF website: www.ref.org.uk.

## Executive Summary


1. Onshore wind turbines represent a relatively mature technology, which ought to have achieved a satisfactory level of reliability in operation as plants age. Unfortunately, detailed analysis of the relationship between age and performance gives a rather different picture for both the United Kingdom and Denmark with a significant decline in the average load factor of onshore wind farms adjusted for wind availability as they get older. An even more dramatic decline is observed for offshore wind farms in Denmark, but this may be a reflection of the immaturity of the technology.
2. The study has used data on the monthly output of wind farms in the UK and Denmark reported under regulatory arrangements and schemes for subsidising renewable energy. Normalised age-performance curves have been estimated using standard statistical techniques which allow for differences between sites and over time in wind resources and other factors.
3. The normalised load factor for UK onshore wind farms declines from a peak of about 24% at age 1 to 15% at age 10 and 11% at age 15. The decline in the normalised load factor for Danish onshore wind farms is slower but still significant with a fall from a peak of 22% to 18% at age 15. On the other hand for offshore wind farms in Denmark the normalised load factor falls from 39% at age 0 to 15% at age 10. The reasons for the observed declines in normalised load factors cannot be fully assessed using the data available but outages due to mechanical breakdowns appear to be a contributory factor.
4. Analysis of site-specific performance reveals that the average normalised load factor of new UK onshore wind farms at age 1 (the peak year of operation) declined significantly from 2000 to 2011. In addition, larger wind farms have systematically worse performance than smaller wind farms. Adjusted for age and wind availability the overall performance of wind farms in the UK has deteriorated markedly since the beginning of the century.
5. These findings have important implications for policy towards wind generation in the UK. First, they suggest that the subsidy regime is extremely generous if investment in new wind farms is profitable despite the decline in performance due to age and over time. Second, meeting the UK Government’s targets for wind generation will require a much higher level of wind capacity – and, thus, capital investment – than current projections imply. Third, the structure of contracts offered to wind generators under the proposed reform of the electricity market should be modified since few wind farms will operate for more than 12–15 years.

# The Performance of Wind Farms in the United Kingdom and Denmark

### *Introduction*

1. Any assessment of the costs of wind power must rely heavily upon assumptions about the average load factor that will be achieved by new wind installations over their lifetime. It is standard practice to calculate average load factors by year and country for onshore and offshore installations as shown in Table 1 (page 40).[1] However, such estimates do not provide a reliable statistical basis for assessing the future performance of wind farms in aggregate. Part of the reason is that the amount of wind in any month or year is influenced by long term meteorological cycles that have periods of many years, notably the North Atlantic Oscillation. In addition, average load factors do not allow for changes in the composition of wind installations by location, age, size and other factors.

2. As the number of wind farms operating in developed countries has grown, engineers have an opportunity to analyse operating experience over extended periods of time. With any (relatively) novel technology the incidence of temporary or permanent breakdowns may be expected to fall over time, so it is difficult to disentangle the effects of age on operating performance from the technological immaturity of turbines installed 10 or 20 years ago. Nonetheless, the technology for onshore wind turbines has been reasonably mature since the early 2000s. This is documented by data produced by the US Department of Energy which shows that the decline in capital costs that is characteristic of immature technologies slowed after 2000 and was reversed after 2004.[2]

3. With at least 10 years of operating data since 2000 it should be possible to examine how the typical operating performance of wind installations in the United Kingdom and Denmark varies with the age of the turbines. The estimated age-performance curves should then be incorporated in estimates of levelised costs, which are often used to compare the costs of wind and other forms of generation.

4. The Appendix provides a detailed description of the data and methods employed for this study. In both the UK and Denmark wind operators have a large incentive to produce electricity whenever there is sufficient wind available since marginal operating costs are small while the operator receives a much higher price. In the UK this price is the sum of the market price plus the value of (a) the Renewable Obligation Certificates (ROCs) awarded for each MWh of electricity produced, and (b) the associated exemption from the Climate Change Levy. In practice, the effective market value of ROCs and associated incentives means that an onshore wind operator earns roughly double the average market price of electricity per MWh. In Denmark, most onshore wind capacity receives a price premium equivalent to about £28 per MWh on top

1 The load factor is calculated as the ratio of the amount of electricity actually produced by a turbine or wind farm over a period of a month or a year divided by the amount of output that would have been produced had it operated at full nameplate capacity for the entire period. This is expressed as a percentage, so that reported load factors lie between 0 and 100.

2 R. Wiser & M. Bolinger (2012) *2011 Wind Technologies Market Report*, Lawrence Berkeley National Laboratory, US Department of Energy. It should be noted that the installed cost of wind plants has fallen since 2010, but these changes reflect the cyclical forces of demand and supply that are well established across the electricity sector and which apply to fossil-fuel as well as renewable generators.

of the market price for about 12.5 years of operation at a typical load factor.[3] Offshore capacity is eligible for a similar price premium but most of it is contracted via tenders that offer a guaranteed feed-in tariff. The tender tariffs have varied from £56 per MWh to twice that figure extending over 16-18 years of operation at a typical load factor.

### *Age-performance curves*

5. A standard indicator of the operating performance of a wind turbine is its normalised load factor defined as the total output over some period divided by the maximum potential output adjusted for wind availability. Normalisation for wind availability is not straightforward. If detailed data on wind speeds at specific locations is available, then the potential output from individual turbines or wind farms can be calculated using standard power curves. Since wind speeds can vary substantially over small distances, such calculations are both difficult to implement and prone to errors when applied to large numbers of wind generators using public sources of data.[4]

6. Many analyses work in the opposite direction. For example, the Danish Wind Index – the longest running series of data on wind availability in Europe – is constructed from the common component of monthly variations in wind output from a large sample of wind turbines.[5] This study adopts a similar approach. Wind availability is treated as an unobserved factor whose contribution to monthly variations in wind output is estimated by a series of fixed period (month/year) effects in a statistical model of monthly output for all wind farms. The reasons for adopting this approach are discussed in Section D of the Appendix. This explains why the method must perform better than the feasible alternative of using a single index of average wind speed for the UK or Denmark.

7. The analysis relies upon standard techniques that are widely used in the biological and medical sciences as well economics and engineering. Full details are given in the Appendix. The idea is to treat the actual load factor (i.e. without adjustment for wind conditions) for a specific wind generator in any time period as being determined by a set of components which reflect specific site conditions and the age-related performance of wind plants in general together with the period fixed effects and an uncorrelated random error. The onshore wind datasets for the UK and Denmark used for the analysis are large with monthly observations on 282 installations in the UK and 823 installations in Denmark with an age range from 0 to 19 years. The offshore wind dataset for Denmark is rather smaller, covering only 30 installations, but it can be used to obtain reasonable estimates of performance up to age 10. The results discussed here are based upon least squares estimation (see page 27) combined with standard errors that are robust to various departures from classical assumptions about the nature of the data generation process.

8. The results of the statistical analysis demonstrate an unambiguous and statistically significant decline in the operating performance of wind farms as they grow older. Figure 1 shows the

3 Conversions to GBP are based on an exchange rate of £1 = DKK 9.18 (as at 19 October 2012).

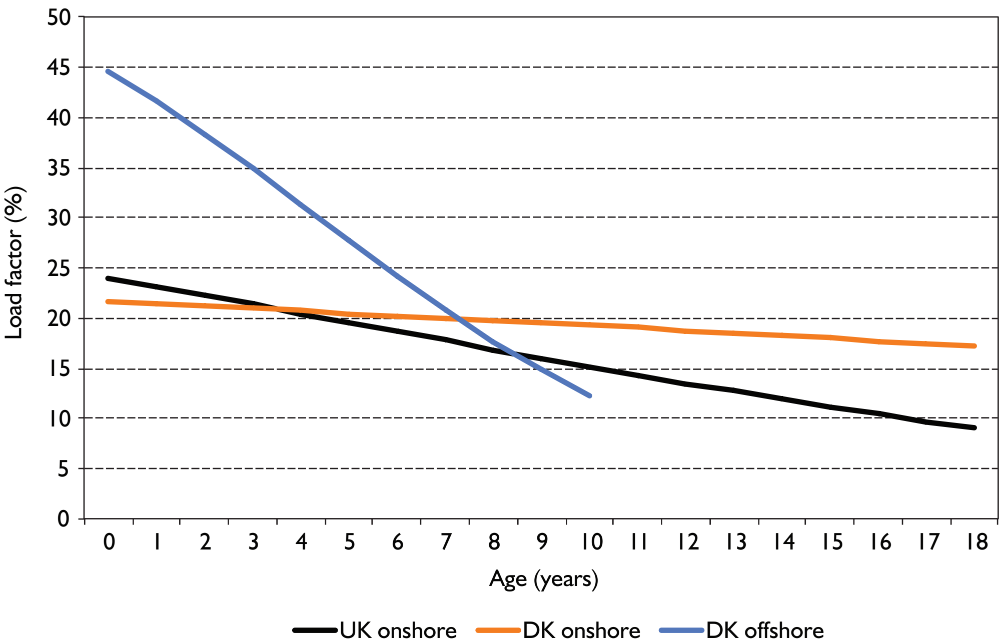
4 All wind generators collect their own information on wind speeds in order to manage their plants but they do not publish such information and will not have access to information collected by other operators.

5 Details of the construction of the Danish Wind Index are given at www.vindstat.dk. A paper by Boccard – N. Boccard (2009) 'Capacity factor of wind power: realized values vs estimates', *Energy Policy*, Vol 37, pp. 2679-88 – includes a discussion of the construction of similar indices of wind availability in Germany, the UK, Netherlands, and Sweden.

simplest variant of the normalised age-performance curve for onshore UK wind installations together with the equivalent curves for onshore and offshore Danish installations. The curves illustrated are calculated from the multiplicative error components model described in the Appendix with log(load factor) as the dependent variable and a quadratic in plant age to represent the variation in plant performance with age.

9. The rate of decline in performance is greatest for offshore installations in Denmark, with a fall from load factors of over 40% at ages 0 and 1 to less than 15% by at ages 9 and 10. Onshore installations in the UK show a more rapid rate of decline – 0.9 percentage points per year over the first 10 years of operation – than is the case for Denmark, though the normalised Danish performance curve lies below the UK curve for the first four years. For the UK the normalised load factor falls to just over 15% at age 10 and to 11% at age 15. With such low load factors it seems likely that many wind farms will be re-powered – i.e. the turbines will be replaced – once they reach the age of 10 or at most 15.

*Figure 1: Performance degradation due to age using equal weights*

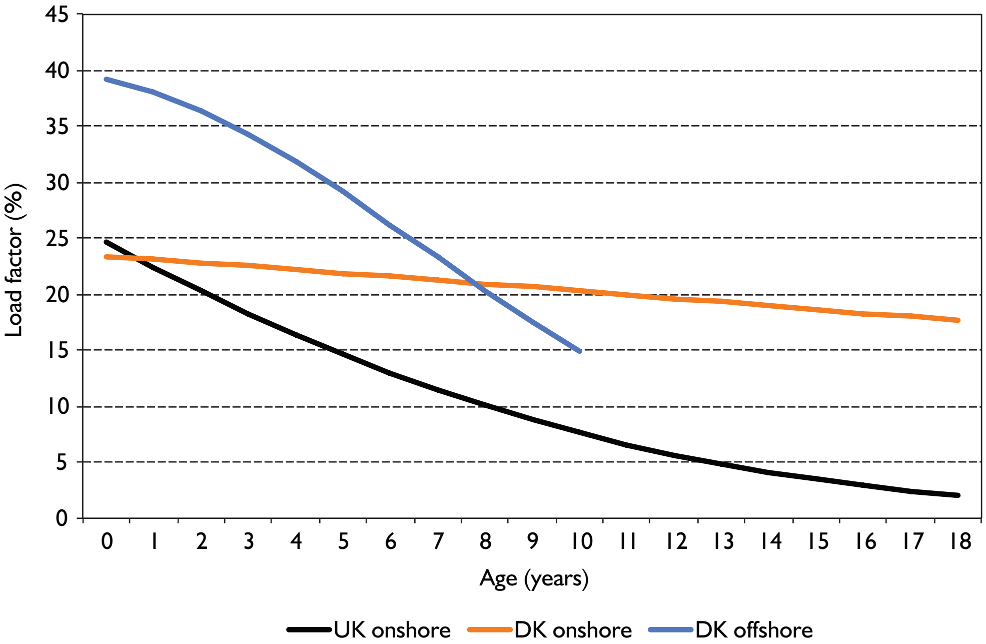



Note: Normalised load factors in %. Source: Author's estimates.

10. There are two plausible explanations for the observed decline in average load factors as wind farms age. The first is that the turbines become less efficient over time as a result of mechanical wear and tear, erosion of the turbine blades and related factors. The second is that the turbines experience more frequent breakdowns and their operators take more time to bring them back into service because they are less concerned about the performance of older plants. Both reasons may be relevant in different circumstances and it is not possible to identify a primary explanation from the data. The frequency of extended shutdowns does seem to increase with age, but this could be a reflection of the timing of planned maintenance operations rather than breakdowns. Whatever the cause, the reduction in performance with age is much greater than would be expected for thermal generating plants.

11. The age-performance curves in Figure 1 are derived from equations estimated by giving equal weight to each wind farm irrespective of its generating capacity. Figure 2 illustrates similar curves but in this case the estimates are constructed by weighting each wind farm by its generating capacity, referred to as capacity-weighted. This gives a better representation of performance degradation per MW of generating capacity. The striking result is that the rate of decline in the performance of UK onshore wind installations is significantly faster when capacity weights are used, which implies that large wind farms in the UK experience a more rapid decline than smaller ones. The differences are smaller in Denmark but the capacity-weighted decline in performance is more rapid than the equal weights decline for Danish onshore installations.

*Figure 2: Performance degradation due to age using capacity weights*




Note: Normalised load factors in %. Source: Author's estimates.

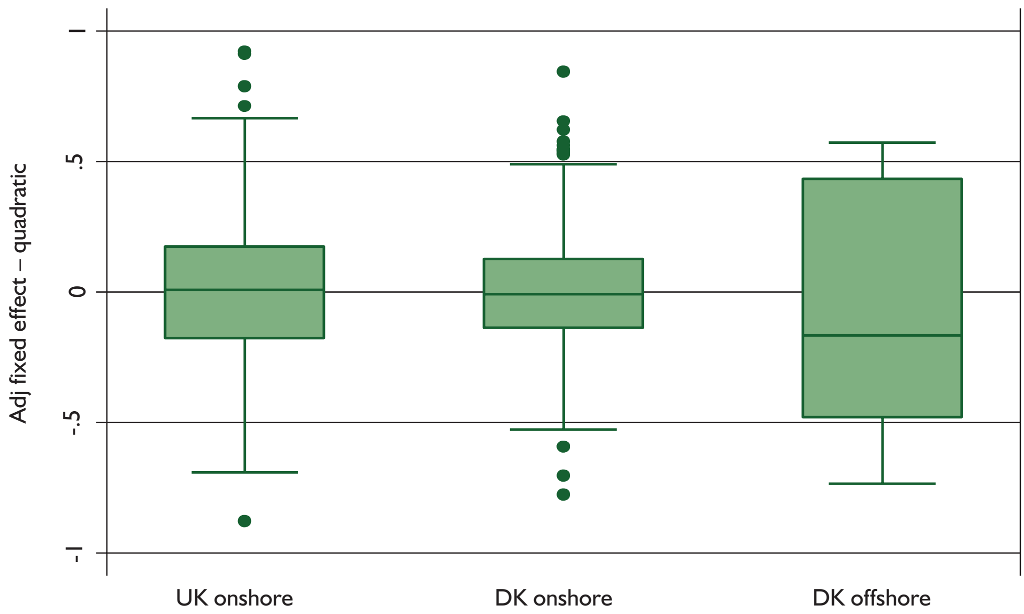
### *Differences between wind farms*

12. The specification of the statistical model means that the unit fixed effects identify the specific performance characteristics of individual wind farms after adjusting for wind availability and age. These characteristics may reflect the site and/or design of the installation as well as the way in which it is operated. A positive value for the unit fixed effect is equivalent to shifting the performance curve up by some percentage applied uniformly at each age, while a negative value shifts it down. It follows that the distribution of unit fixed effects across installations can be used to compare the relative effectiveness of new installations by location, date of commissioning, etc. Care is required when making comparisons between, for example, UK and Danish onshore wind installations because these have been normalised separately, so the unit fixed effects refer to different underlying averages.[6]

6 Some care is required in interpreting the unit fixed effects. By default, the average value of the unit fixed effects for each group is zero but these averages are taken over all observations for each installation in the basic sample. For the purpose of the comparisons in Figure 3 the unit fixed effects have been adjusted so that the average values for each group are zero when using one value for each installation.

13. To give a sense of the numbers, unit fixed effects of (a) 0.2 or (b) -0.2 mean that the base load factor given the age of the plant is multiplied by (a) exp(0.2) = 1.22 or (b) exp(-0.2) = 0.82. Since the base load factor for a plant of age 0 is 23.1%, these fixed effects translate to load factors in the first year of operation of (a) 28.2% and (b) 18.9%. For a wind farm with 50 MW of generating capacity the difference amounts to an additional 40,700 MWh of electricity output per year. Using the standard figures cited by RenewableUK this would be sufficient to supply 12,300 homes for a year. This range (0.40) is slightly greater than the interquartile range of unit fixed effects for UK onshore wind farms (0.35). Again for comparison, operators of thermal power plants would regard any difference of even 10% up or down in efficiency relative to what is expected as a striking and perhaps worrying indication of either good or bad performance.

*Figure 3: Range of unit fixed effects by category*




Source: Author's estimates.

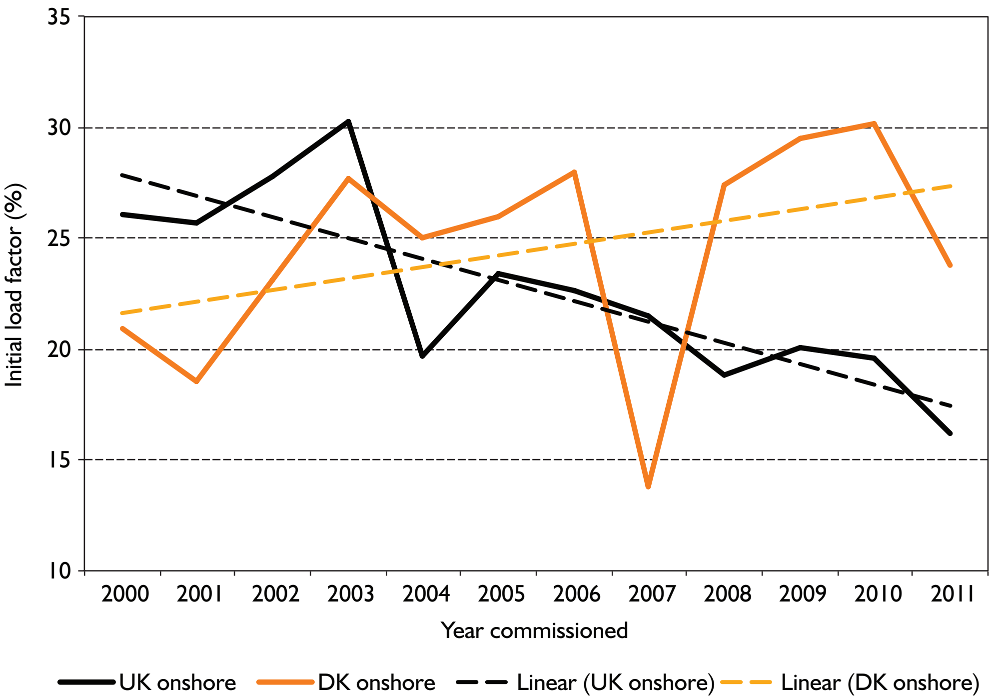
14. A notable feature of the distributions of the unit fixed effects that are summarised in the box plots shown in Figure 3 is the range of variation between the best and worst performers, especially for UK onshore and Danish offshore wind farms. Box plots are constructed so that the top and bottom of the box correspond to the upper and lower quartiles, while the bars at top and bottom correspond to the maximum and minimum values excluding outliers.[7] A plant at the upper quartile of the distribution of UK onshore wind farms will generate an annual output that is about 40% higher than a plant at the lower quartile. The equivalent figure for Danish onshore wind plants is an increase of 30%, while for Danish offshore wind farms the difference between the upper and lower quartiles is equivalent to 2.5 times the output of a lower quartile plant. By any standard such differences are important.

7 The upper quartile is the point in a distribution such that the 25% of values exceed it, while the lower quartile is the point in a distribution such that 75% of values exceed it. The line in the middle of the box marks the median, the point exceeded by 50% of values. Outliers are defined as values that lie outside the range of Tukey adjacent values which are defined as the upper/lower quartiles +/- 1.5 x interquartile range.

15. Outside the range between the upper and lower quartiles, the top and bottom segments of the distributions extend further up and down for UK onshore wind farms than for those in Denmark. The rather different pattern for Danish offshore wind installations is partly a consequence of the relatively small size of the sample, but the evidence points to considerably greater variability in the performance of offshore wind installations than for onshore installations.

16. It is somewhat surprising to observe the magnitude of the differences in the performance in onshore wind farms in the UK. Given the nature of the subsidy regimes and the high capital cost of developing new installations, it might be expected that operators have a strong incentive to identify the best locations and then choose equipment that will deliver the maximum amount of electricity output at a high level of reliability. For UK onshore operators it seems that good or bad performance is somewhat of a lottery. However, if the subsidies provided by ROCs are sufficient to underwrite investment in inefficient plants – as appears to be the case – then those subsidies are extremely generous for plants that operate close to the efficient frontier. As location is likely to be the main factor that determines the performance of a specific plant relative to all other plants, the inference must be that many wind plants have been developed on sites with poor wind characteristics.

*Figure 4: Initial load factors by year of commissioning for onshore wind*




Source: Author's estimates.

17. There is another disturbing characteristic of UK wind farms which is revealed by examination of the unit fixed effects and illustrated in Figure 4. It might be expected that the average performance of recently installed units would be higher than that of older units. This should reflect improvements in turbine design and reliability as well as in the identification of good sites for wind generation. However, that is not the pattern for onshore wind farms in the UK. The figure shows the average values of the initial load factors calculated using equally weighted data by year of commissioning for onshore wind farms in the UK and Denmark together with fitted

trend lines.[8] There has been a clear decline in the initial load factors in the UK which has not occurred in Denmark. This pattern is confirmed by more detailed statistical results shown in the Appendix which take account of location and size of installation.

18. The decline in initial performance is particularly obvious after 2005 when the rate of commissioning new capacity increased sharply from less than 500 MW in the 5 years 2000–04 to more than 500 MW per year from 2005 onwards. In contrast, the peak years for commissioning new onshore wind farms in Denmark were 2000–02 when 920 MW was installed. The rate of new building (or replacement) picked up again in 2008 but it is still much lower than at the turn of century. Not only is the performance of the onshore wind plants in the UK commissioned in recent years significantly worse than that for wind farms commissioned before 2005, but it is possible that this is a direct consequence of an overly rapid expansion of capacity. In essence, the evidence suggests that the industry does not have the capability to identify, develop and operate new onshore wind farms at the rate envisaged by UK government targets while maintaining a satisfactory average level of performance.

### *Implications for future policy and performance*

19. The pattern of performance degradation with age and over time identified in this analysis has implications for the assessment of new investment in wind farms and for the design of the proposed Electricity Market Reform (EMR). There are two related issues that are affected by the results:

    a) What are the implications for the design of policies intended to promote the adoption and expansion of wind generation in the UK? This includes the structure of current subsidies as well as the specification of the contracts that are proposed under the EMR. A related question concerns the expected life of new wind farms.

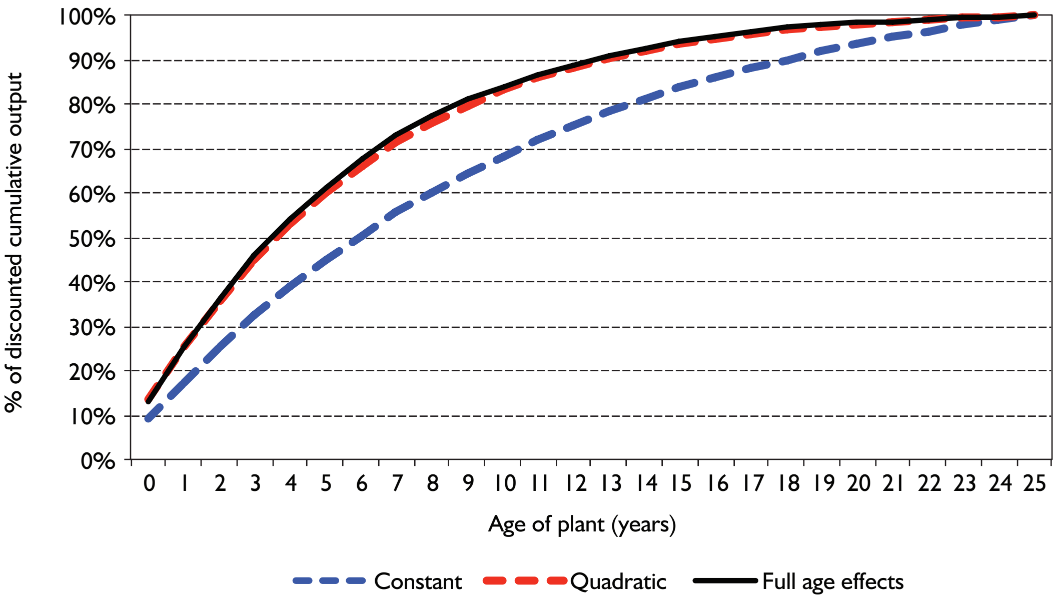
    b) How might the average performance of wind generation develop over the next decade? This is absolutely critical to any assessment of the amount of wind capacity that will be required to meet the UK government's targets for the share of electricity – and, more generally, energy – from renewable sources. The government has assumed that the average load factors for both onshore and offshore wind farms will either remain stable or increase in future. The prospects will be very different if these assumptions are not borne out.

20. The first question can be addressed by considering the discounted sum of cumulative net output from a new wind farm on the assumption that its performance matches the averages identified in the analysis. This takes account of both performance degradation over time plus the annual cost of maintaining the plant which may be expressed as a deduction from gross production so as to calculate the contribution of expected output at age *s* to recovering the original capital cost of building the plant. These figures have to be discounted back to the date of commissioning in order to assess the net present value of the initial investment in the plant. The curves for constant and observed performance using a discount rate of 9% (a typical cost of capital for wind generation) are shown in Figure 5. The black line is based on the full set of age

8 The initial load factors are calculated as the normalised load factor for UK/Danish wind farms at age 0 multiplied by $\exp(u_i)$ where $u_i$ is the unit fixed effect for installation *i*.

effects while the red dashed line is based on the smoothed quadratic performance curve and the blue dashed line shows what the pattern would be if operating performance was not affected by age. The calculation is extended out to age 25 since DECC's standard comparisons assume that wind turbines have a life of 25 years.

*Figure 5: Impact of performance degradation on discounted cumulative output*




Source: Author's estimates.

21. The key points in the figure are that 80% of the discounted cumulative output of a new wind plant is likely to be produced in the first 10 years of its life and 90% in the first 14 years. This is consistent with the structure of Danish subsidies for onshore wind farms which extend over a typical period of 12.5 years. Since sites for wind farms are scarce and involve the payment of significant rents that may be linked to output, it is very unlikely that any new installation of wind turbines will have an expected life of more than 15 years. Instead, as has happened in the past, wind operators will have a strong incentive to decommission plants after no more than 15 years and replace the turbines with newer equipment.

22. As a consequence, any economic assessment of wind generation should not be based on an expected life which is longer than 15 years. In recent work reported in evidence to the House of Commons Select Committee on Energy and Climate Change I assumed that wind plants would have a residual value equal to 20% of their initial cost in real terms at the end of 15 years. The analysis in this paper suggests that this is too favourable an assumption. Given the costs of decommissioning old turbines the residual value is likely to be well below 10% of their initial cost and the decision point may be at 10 rather than 15 years.

23. The corollary of this observation is that it makes little sense to offer long term contracts for 20 years or more that guarantee prices or feed-in tariffs (FiTs) to wind operators. A contract length of 10 to 12 years would be sufficient to remove most of the market risk associated with investment in wind generation. In this respect the subsidy arrangements implemented in Denmark are better designed.

24. At the same time, the offer of subsidies and/or guaranteed prices may have serious adverse consequences for the efficiency of wind generation. Returning to the unit fixed effects measuring the performance of wind plants commissioned after 2005, only 28 out of 159 units have an operating performance that exceeds the average for the period. Those 28 units account for 360 MW of capacity whereas the remaining 131 units account for 2,810 MW of capacity. Not only are recent plants less efficient than the average for the whole period, but the plants which are below-average in efficiency are typically larger than the more efficient ones and account for a disproportionate share of the recent additions to generating capacity.

25. In mid-2012 there was approximately 4,500 MW of onshore wind capacity operating in the UK. By 2020 it is expected that there will be at least 10,000 MW (based on proposed wind farms with planning consent) and perhaps as much 15,000 MW of wind capacity in operation. The government is relying upon a substantial contribution from onshore wind farms towards meeting its targets for renewable energy in 2020. To provide context, the government's targets for renewable energy in 2020 specify a total of 234 TWh of energy from all renewable sources of which 90–140 TWh is expected to come from wind and biomass electricity generation.[9] The projections for biomass electricity are extremely vague and have to be reconciled with an assumed increase of 3–4 times in the amount of biomass used separately for heat. So, in concrete terms, it is reasonable to assume that wind generation will account for at least 90 TWh with 24–32 TWh from onshore generation and the remainder from offshore.

26. The average load factor for onshore wind over the 10 year period from April 2002 to March 2012 was 25.6%, which is influenced by the large amounts of new capacity added from 2005 onwards. If this load factor were achieved in 2020, the total amount of onshore wind capacity required to meet the onshore generation target would be 10.7 to 14.3 GW. The average load factor for offshore wind installations (on an unchanged configuration basis) for the five year period 2007–11 was 32.0%.[10] If this load factor were achieved in 2020, the total amount of offshore wind capacity required to meet the remainder of the 90 TWh target would be 20.6 to 23.5 GW, though these estimates would fall to 18.0 to 20.5 GW if the average load factor matched the historic average value of 36.7% for Danish offshore wind installations.

27. The question that has to be addressed is whether these load factors are consistent with (a) the investment programmes that would be required to achieve the total amounts of generation capacity implied by the government's targets, and (b) the age profiles of the performance of wind farms discussed in this paper. The short answer is that this is simply not possible if the initial load factor for new wind farms continues to decline at the rate observed the past decade. So, even as a starting point, it is necessary to assume that this underlying deterioration in wind farm performance ceases. This would be a major change in itself and it is not obvious what factors might lead to such a result.

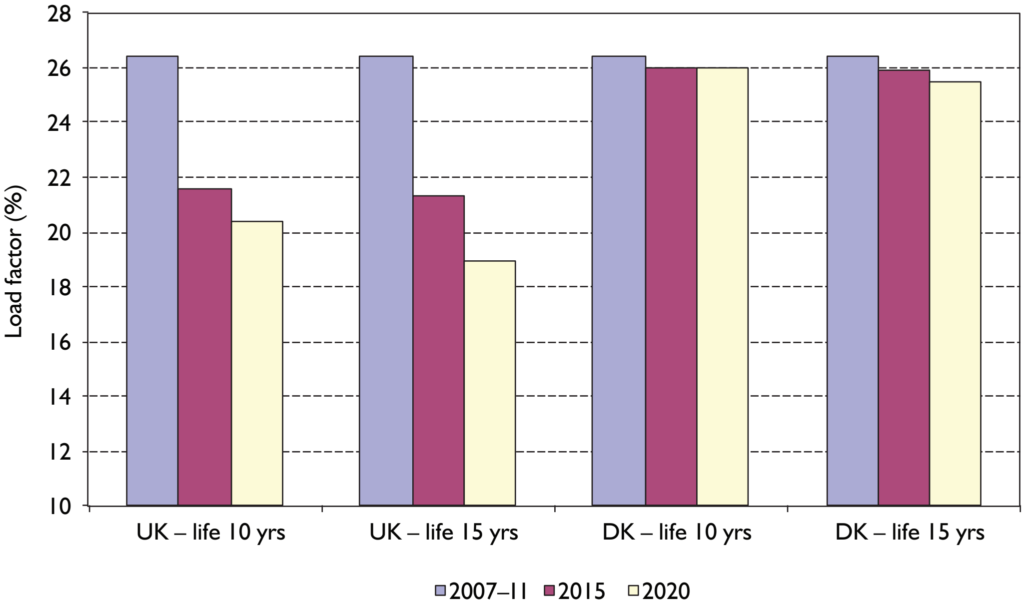
28. The results illustrated below are based on a vintage model of performance that takes account of the actual expansion of capacity up to the end of 2011 plus whatever investment in new or replacement turbines is required to achieve the target levels of wind capacity in 2020. To highlight the full range of potential outcomes these targets are either 10 GW or 15 GW of onshore

9 Department of Energy and Climate Change – *UK Renewable Energy Road Map*, July 2011, Figure 2.

10 The equivalent average load factor for onshore wind farms was 26.4%.

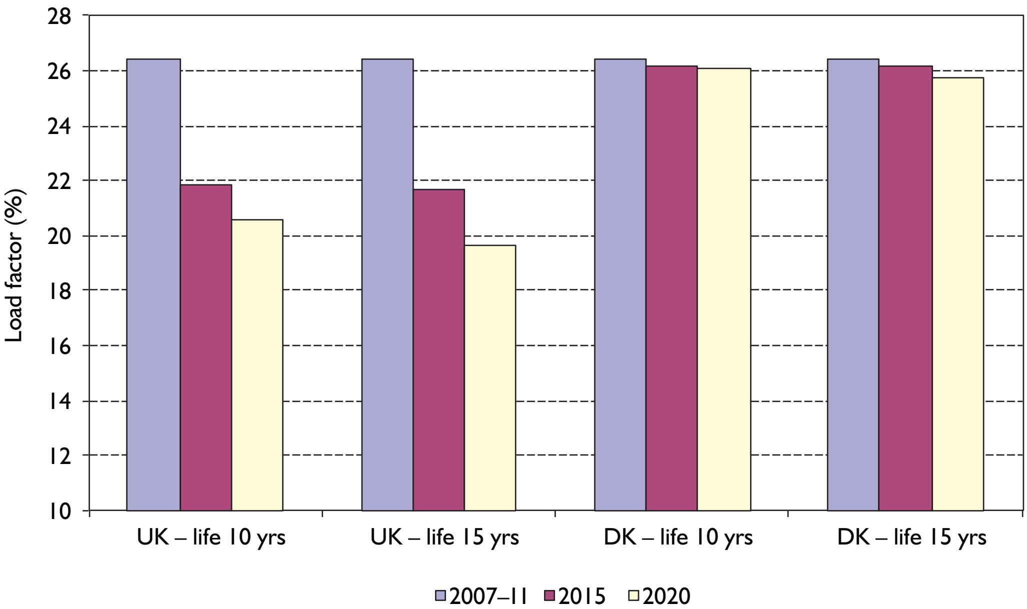
wind and either 18 or 24 GW of offshore wind. The levels of investment required to meet these targets depend upon the expected life of wind turbines. For onshore turbines, an expected life of 10 years is consistent with re-powering decisions over the last decade, while an expected life of 15 years seems to be the maximum consistent with the age-performance profile. For offshore turbines, the analysis uses expected lives of 15 and 20 years.

*Figure 6A: Projected load factors for UK onshore wind (total capacity of 10 GW in 2020)*




Source: Author's estimates.

*Figure 6B: Projected load factors for UK onshore wind (total capacity of 15 GW in 2020)*




Source: Author's estimates.

29. Figure 6A shows projected values of the average normalised load factors for UK onshore wind farms in 2015 and 2020 using a target capacity in 2020 equal to 10 GW plus the age-performance profiles for the UK and Denmark (DK). Since vintage effects are important in this

calculation, the profile of new or replacement investment affects the results. In this case the level of gross investment is assumed to be constant from 2013 onwards at either 930 or 1,220 MW per year – the range is defined by the assumed life of turbines. Achieving a target of 15 GW in 2020 (Figure 6B) would require a level of investment from 2013 onwards of either 1,540 or 1,930 MW per year. Such figures are 3–4 times the average level of investment over the period 2005–11, so the lower target may provide a better indication of what will happen.

30. All of the estimates are calibrated to match the observed average load factor in 2007–11, so that they should be interpreted as relative rather than absolute values. Using the age-performance profile for UK onshore wind installations the average normalised load factor is likely to fall by about 19% from 2007–11 to 2015 and by 23–28% to 2020. If the age-performance curves for Danish onshore installations were to apply, the reduction in the average normalised load factor would be considerably less but there would still be a fall of up to 5% by 2020.

31. In the medium term, the fall is greater if turbines operate for 15 years because the average age of all turbines will be higher and thus the degradation in performance due to age will have a larger effect. By 2020 this effect reduces the average normalised load factor from 20.3% for a 10 year life to 19.5% for a 15 year life. There is a complex economic and commercial trade-off here. To meet a target of 10 GW in 2020 it is necessary to increase the level of investment in onshore capacity by 30% from 2013. Almost all of this will take the form of re-powering existing wind farms.[11] The costs are fairly high because this will usually involve new development consents, decommissioning the original turbines and replacing them with a smaller number of larger and more powerful turbines.

32. Estimates of re-powering costs are generally treated as being commercially sensitive but broad project costs cited in specialist magazines suggest that the unit costs are likely to be at least £1,000 per kW or more than £300 million per year in aggregate. On the other hand, the increase in the amount of energy generated would be about 1.2 TWh for a 10 year turbine life rather than a 15 year turbine life, though this does not allow for the loss of production during re-powering. Under the best circumstances the payback period may be quite short, but the best option from a broader economic and social perspective is not obvious.

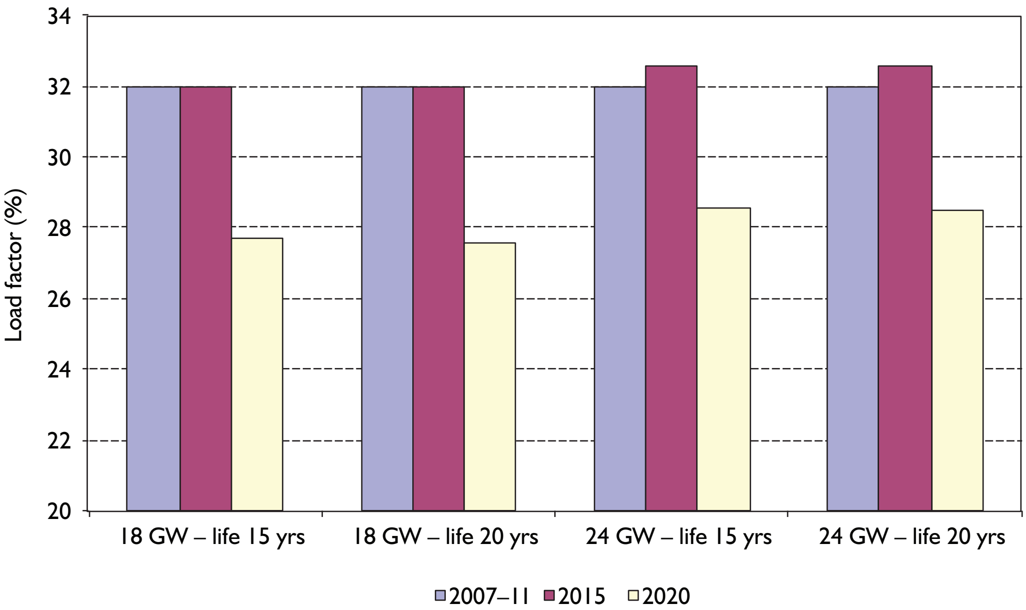
33. Even under the best scenario 10 GW of onshore wind capacity will only generate 17.8 TWh of electricity in 2020, well below the lower end of the target range for onshore wind generation specified in DECC's road map. In fact, allowing for interactions between the age-performance profile and investment the amount of onshore wind capacity required in 2020 to generate 24 TWh would be a minimum of 13.4 GW. At the top end of DECC's target range, the capacity required in 2020 to generate 32 TWh would be a minimum of 17.8 GW. Since these estimates are based on a 10 year turbine life, the level of investment required from 2013 onwards would be 1,650 MW per year for the bottom of the range and 2,350 MW for the top end of the range. In the last 8 years total investment in onshore wind has only ever exceeded 600 MW in one

11 Re-powering is usually defined as the full replacement of existing turbines, whereas retrofitting covers the replacement of various mechanical or electrical components. In the data analysis, re-powering involves the creation of a new unit, whereas retrofitting affects the performance of a continuing unit. Hence, the potential benefits of retrofitting are taken into account in constructing the age-performance curves.

year (883 MW in 2008), so it seems rather unlikely that even the lower end of DECC's range for onshore wind generation will actually be realised.

34. Of course, this assessment would be different if UK onshore wind operators were able to match the Danish age-performance curve. There are many factors which differentiate the UK and Danish wind industries. The average scale of wind farms in the UK is larger, they are more remote and there appears to be significantly greater variation between operating and potential new sites in achieved performance. It would, therefore, require a very optimistic observer to conclude that the difference in age-performance curves between the two countries will disappear in the short or medium term.

*Figure 7: Projected load factors for UK offshore wind in 2020*




Note: Based on Danish age-performance curves. Source: Author's estimates.

35. Figure 7 shows the results from carrying out a similar exercise for offshore wind farms in the UK. The only evidence on the age-performance curves for offshore installations is based upon the Danish experience, so these have been used to construct the projections. Further, the profile of investment assumes a progressive increase in additions to capacity from 2013 to 2016 and then a stable level of investment from 2017 to 2020. The DECC road map involves a very large commitment to offshore wind investment – in the range 2.5-3.5 GW of new capacity annually from 2016 onwards. As a consequence, the average age of offshore capacity in 2020 will be quite low and the full effects of the age-performance curves will only be felt during the decade following 2020. Even so, the average normalised load factor in 2020 will be about 15% lower than for 2007–11, while by 2025 it will be about 30% below the base level.

36. On these projections 23.2 GW of offshore capacity is the minimum necessary to generate 58 TWh of electricity from offshore wind in 2020. This requirement will increase to 29.8 GW by 2025 simply to offset the effect of the ageing of offshore generation capacity on total output.

37. Combining the estimates for onshore and offshore wind generation the total amount of wind capacity required in 2020 to produce 90 TWh of electricity from wind will be in the range 39

to 41 GW once allowance is made for the observed age-performance curves for both onshore and offshore installations. These estimates are roughly a third higher than official predictions of 28–31 GW of wind capacity in 2020.

38. Turning the figures round gives a slightly different picture of the reality of the government's strategy on renewable electricity generation. A total of 30 GW of wind capacity in 2020 (12 GW onshore, 18 GW offshore) will generate about 64 TWh of electricity in a normal year. Since electricity generation from wind and biomass are expected to account for 50% of renewable energy in 2020, the consequence is that biomass is expected to account for 53 TWh. In 2011 landfill gas and sewage sludge digestion accounted for 44% of electricity from bioenergy (DUKES Tables 6.4). There are limited opportunities to expand production from these sources, so a continuation of historic rates of growth would mean that renewable generation from other sources of bioenergy would have to increase from 7.2 TWh in 2011 to 46 TWh in 2020. There are severe constraints on increasing the amounts of electricity generated from animal biomass, biodegradable municipal solid waste and anaerobic digestion, so it would be optimistic to assume that these will contribute more than 6-8 TWh in 2020 (up from 2.6 TWh in 2011).

39. In practice, if the projections for renewable energy are to be believed, they rest upon an assumption that there will be a large increase in the amount of electricity that is generated from plant biomass – either on its own or through co-firing with coal. This increase will involve increasing the amount of electricity generated in these ways from 4.6 TWh in 2011 to 38-40 TWh in 2020. Since the amounts of straw and UK-grown timber available for this purpose are strictly limited, this will come down to the amount of wood chips that can be imported and the cost of doing this.

40. The historic average load factor for biomass plants is just over 60%, so about 7,500 MW of biomass capacity will be required to supply 40 TWh of electricity. The weight of wood chips per MWh of electricity depends upon moisture content, storage, boiler design and other factors but an indicative range is 0.85 to 1.15 tonnes per MWh of wood chips with a moisture content of 30%. According to DECC and Forestry Commission estimates, the UK imported 26.5 million tonnes of steam coal and 2.6 million tonnes of other wood products (including wood chips) in 2011. It seems that the net effect of the government's strategy will be to replace 15 million tonnes of coal imported in 2011 by 32 to 44 million tonnes of imported wood chips. This is a somewhat strange way of increasing energy security.

### *Conclusion*

41. Wind power is a highly capital-intensive technology for generating electricity. Its merits rely entirely upon a substitution of capital for fuel inputs. The same is true for hydro or tidal or wave power. In comparison with hydro power, wind is a low quality resource because of its variability and because it cannot be stored. So, the economic case for wind power must rest on obtaining the most out of the wind that is available.

42. While the decline in the achieved performance of onshore wind turbines in Denmark is much less than that for the UK or offshore, nonetheless the decline in expected output under standardised wind conditions over 10 years is 10% unweighted and 13% capacity weighted. These declines accelerate after age 10 so that the reductions in performance are 17% and 20%

respectively after 15 years. For UK onshore wind farms the reduction in performance due to age is much worse at 27% unweighted and 69% capacity weighted by age 10.

43. Evidence on the performance of Danish offshore installations is both restricted and so poor that there may be concern that the results are affected by a small number of outliers. Still, the sample contains a reasonable number of sites with at least 5 years of operating experience and the decline in performance by age 5 is 38% unweighted and 26% capacity weighted.

44. In addition to these results there is strong evidence that the average normalised load factor for new onshore wind installations in the UK has fallen significantly over the period from 2000 to 2011. This is consistent with a pattern in which the most favourable sites are developed first. Equally, it could mean that wind developers have been unable to keep up with the rate of new investment while maintaining the quality of development and operations. For example, the site design or selection of turbine characteristics may make less effective use of the available wind resources for the sites available than was the case in the past.

45. Whatever the reasons, the deterioration in initial performance means that the expected returns from the expansion in wind capacity, both for investors and in terms of the reduction in $CO_2$ emissions, have been falling without a concomitant decrease in the private and social costs that are borne by customers and the general public. Clearly this is unsatisfactory at best and it suggests that the benefits claimed for current policies cannot be taken at face value.

# Appendix: Data and Methods

## A. Data for the United Kingdom

The raw data used for this study was extracted by the Renewable Energy Foundation from the Renewables and CHP Register database compiled by Ofgem.[12] This information is used in the administration of the market in Renewable Obligation Certificates (ROCs). The Renewables Obligation is the primary mechanism by which large scale generators of renewable electricity receive subsidies, so the operators of wind farms have a very strong incentive to submit complete and up-to-date information to the database. The data extracted covered all onshore wind generators with at least 0.5 MW of generating capacity which are eligible for ROCs for the 10 year period April 2002 to March 2012. The key variables are the monthly output of electricity (used for the purpose of allocating ROCs) and nominal generating capacity. There are 282 reporting units in the final dataset. A reporting unit may correspond to an entire wind farm or to separate phases of development. Complications arise when an existing wind farm is re-powered, i.e. when old wind turbines are replaced by newer and usually more powerful turbines. The database reports this as a change in the generating capacity of the recording unit, but in this analysis repowering is treated as the termination of the old recording unit and the creation of a new recording unit.

A considerable amount of data checking and cleaning was required before the data could be analysed. The first step was to add the age of each reporting unit. This was calculated by reference to the month in which the turbines were commissioned. For wind farms in operation in or before June 2002 the commissioning date was obtained from various online sources – notably the thewindpower.net database of UK wind farms[13] which was cross-checked against the information provided on the websites of wind operators and other sources. For recording units whose first data relates to dates after June 2002, the commissioning date was initially assumed to be the month for which data is first reported. Cross-checks were carried out for all recording units which commenced reporting in the period July 2002 to December 2003. In more than 80% of cases the externally-reported commissioning date is within one month of the first month for which data is reported. The exceptions – Bu Farm and Mablethorpe – appear to be due to delays by small operators in reporting data to Ofgem.

In a number of cases it is clear from the data that plants were not in full operation at the time when data was first reported to the database. There are two indicators of partial or delayed commissioning:

- For an initial series of months the calculated load factor is very low – usually below 5% – and then increases abruptly. In such cases, the data for the early months is dropped and the commissioning date is treated as the month immediately preceding the first month with a 'normal' load factor.[14]

12 https://www.renewablesandchp.ofgem.gov.uk/

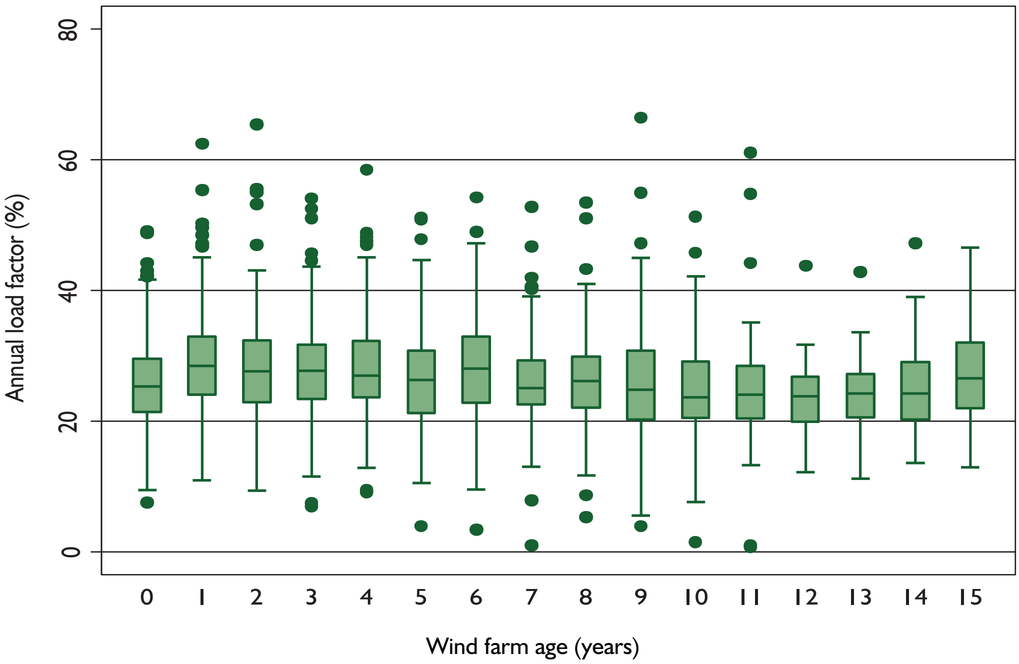
13 See: http://www.thewindpower.net/windfarms_list_en.php .

14 The month in which a plant is reported as having been commissioned is not included in the analysis.

- The reported generating capacity for the recording unit increases after a period of months or even years after the commencement of data reporting. All such cases were checked against external sources. In some cases the increase in generating capacity represented either a repowering or a major extension of the plant, in which case a new recording unit was created. In other cases, primarily when the increase in generating capacity was less than 25% of the original generating capacity, the data appears to reflect delays in commissioning individual turbines, so that the commissioning date was not amended and load factors were calculated by reference to the reported capacity in each period. Finally, in a few cases the changes were patently due to changes in reporting practices such as rounding total generating capacity from 9.95 MW to 10 MW. These records were corrected to record generating capacity consistently over time.[15]

For a small number of recording units the reported generating capacity is reduced after commissioning, either permanently or for a number of months or years. This can lead to anomalies in which the calculated load factor exceeds 100%. In all cases, reductions in generating capacity have been overridden unless there is external evidence that some of the turbines at the reporting unit have been decommissioned. In other circumstances, a reduction in rated capacity is a symptom of performance degradation and has to be treated as such.

*Figure 8: Box plots of load factors by age for UK onshore wind farms*




Source: Author's estimates.

The general principle that was applied in making adjustments to the raw data – other than the correction of obvious reporting discrepancies – was that any changes should have the effect of either (a) reducing the estimated age of the plants concerned, or (b) reducing any estimates of

15 In statistical terms, it does not matter which value for generating capacity is used, because this is captured by the unit fixed effects in the model that were estimated. In practice, the generating capacity reported for the majority of records was used for all records in such cases.

the decline in the plant's load factor as it ages. As an example, consider a plant whose reported capacity was increased from 9.9 MW to 10 MW at age 3. If this was simply a change in reporting practice, this would reduce the estimated load factor from age 3 onwards. By increasing the initial capacity from 9.9 MW to 10 MW – or by reducing the capacity from 10 MW to 9.9 MW from age 3 onwards – this bias is removed. It is not important which adjustment is made because the difference between the alternative assumptions is captured by the unit fixed effect.

The numbers of separate sites and of observations per site mean that it is not possible to provide a simple visual representation of the data. Figure 8 provides a summary by illustrating the distributions of load factors by the age of the wind farm pooled across all years. The ranges of the load factors for each age are wide while the medians show no clear trend by age. Thus, a naïve analysis might conclude that there is nothing to investigate. However, as will be explained below, the distributions mask crucial differences between the performance of wind farms as they age because they do not control for the differences in location and wind availability over time.

## B. Data for Denmark

The data for Danish wind farms used in this study comes from a database compiled by the Danish Energy Agency covering the characteristics and performance of all wind turbines from 2002 up to the end of August 2012.[16] The basic recording unit for the register is the individual wind turbine, but where a number of turbines are connected to a single meter an identical average output per turbine is recorded for all turbines in the group. The presence of what are, in effect, repeated observations increases the noise in the data. In addition, the model that is used for the analysis assumes that site, operator and turbine characteristics are common for all of the units that make up a single wind farm. To address this point, separate wind farms have been identified by grouping all turbines which have identical values for: turbine manufacturer and type, local authority, date of commissioning and date of decommissioning (where applicable).

The register contains information on 7,569 turbines commissioned from 1977 onwards. This includes a large number of small turbines which would not fall within the scope of the ROC scheme in the UK. Hence, for comparability with the UK data all turbines commissioned prior to 1992 were dropped as well as all wind farms with a generating capacity of less than 1 MW. The resulting sample covered 823 onshore wind farms and 30 offshore wind farms with monthly load factors for various periods from January 2002 to August 2012. Given the cut-off for wind farms commissioned prior to 1992 the maximum age for an onshore wind farm was 20 years and the maximum age for an offshore wind farm was 17 years.

The total capacity of the onshore wind farms recorded in the Danish database was 2757 MW. The average size of an onshore wind farm in Denmark is small – only 3.3 MW as compared with 16.1 MW for the UK – because 84% of the sample consists of installations with between 1 and 4 turbines. The largest onshore installation has 39 turbines with a capacity of 23.4 MW while the onshore installation with the greatest capacity has 19 turbines with a capacity of 58.4 MW. Overall, the sample of Danish onshore wind farms is older and smaller than the sample of UK onshore wind farms, reflecting the much longer history of wind generation in Denmark.

16 http://www.ens.dk/EN-US/INFO/FACTSANDFIGURES/ENERGY_STATISTICS_AND_INDICATORS/OVERVIEWOFTHEENERGYSECTOR/REGISTEROFWINDTURBINES/Sider/Forside.aspx

The larger scale of UK wind farms may account for some of the differences in performance curves for the two countries.

The sample of offshore wind farms in Denmark is quite small with 30 installations in total. Still, it is useful to analyse the performance of these installations since there is very little comparable data for the UK. The sample covers 394 turbines with an average of just over 13 turbines per installation and an average capacity of 28.8 MW. The largest installation, which was commissioned in 2003, has 72 turbines with a total capacity of 165.6 MW. Again, offshore installations are smaller and older in Denmark than is the current pattern in the UK. The first two wind farms in the sample were commissioned in the years 1995 and 2000 but the sample increases significantly from 2002 onwards. To avoid reliance upon a sample of 1 or 2 wind farms to determine specific coefficients for ages > 10 years, all observations with an age greater than 10 were omitted from the analysis.[17]

A somewhat different problem with the offshore wind farm data arose because the coefficients estimated using capacity weights (see below) were heavily influenced by the largest wind farm. This has had an extremely erratic profile of performance over time with a very low average load factor. The treatment of this wind farm is discussed in more detail in Section F below.

## C. *Specification and estimation methods*

As Figure 8 illustrates, it is necessary to go beyond simple summary statistics in order to assess whether there is any systematic relationship between age and the average performance of wind farms. The performance of wind farms varies over both time and space: some months and years have more or less wind than the long term average, while specific characteristics of wind farms – including location, type of turbine and operating regime – will influence the performance of each plant under identical wind conditions.

The combination of (a) site-specific characteristics which are constant over time, and (b) period-specific characteristics which are constant across wind farms can be represented by what statisticians call an error components model with fixed effects for each wind farm and each time period. The dependent variable in the model consists of a sequence of load factors – denoted by $lf_{it}$ for unit $i$ in month $t$ – for each wind farm (the panel unit) over time. The load factors are calculated by dividing the total output in MWh by (24 x number of days in month x reported generating capacity in MW) and are multiplied by 100 to convert to percentages.

The additive version of the error components model may be written as:

$$lf_{it} = f(A_{it}) + u_i + v_t + e_{it} \tag{1}$$

in which $A_{it}$ denotes the age of plant $i$ in period $t$ and $f()$ is some function that is either a representation of or an approximation to the normalised age-performance relationship. The multiplicative version is similar except that $lf_{it}$ is replaced by $\ln(lf_{it})$, where ln() denotes the natural logarithm. The $u_i$ terms are wind farm or unit fixed effects which capture factors such as location, type of turbine, operating regimes, etc. The $v_t$ terms are period fixed effects which capture the influence of wind conditions over the UK or Denmark as a whole as well as seasonal maintenance and demand. Without loss of generality it may be assumed that the fixed effects are

17 For the avoidance of doubt, this means that no attempt was made to estimate the effect of age on the performance of offshore wind farms beyond age 10, while the data for the oldest wind farms was included in the analysis up to and including age 10.

normalised so that $\sum_i u_i = \sum_t \upsilon_t = 0$, i.e. all of the error components have a zero mean, while the mean of the random error is zero by definition. The $\epsilon_{it}$ terms are random errors which capture random variations in wind conditions that are not specific to the site, turbine breakdowns, and other factors that are uncorrelated with either the site or the time period. It is assumed that the mean of the random error is zero, while additional assumptions depend upon the method of estimation that is adopted.

The model specified in equation (1) can be estimated in a variety of ways.[18] A crucial issue is whether the $u_i$ are or may be significantly correlated with the age terms or any other independent regressors. If it is assumed that there is no such correlation, the model is usually referred to as a random effects model. In that case, the equation can be estimated by a variant of least squares (LS), generalised least squares (GLS), generalised methods of moments (GMM) or maximum likelihood (ML) – all of which should be yield parameter estimates that will converge in probability to the true parameter values as the sample size increases. An alternative, but less restrictive, specification is known as the fixed effects model in which no assumption is made about the correlation between the unit fixed effects and other regressors. The limitation of the fixed effects model is that it cannot be used to estimate parameters for regressors that vary across panel units but are constant over time for a panel unit (time-invariant regressors) – e.g. the year in which a wind farm was commissioned, its location or its rated generating capacity. The influence of such variables is captured by the unit fixed effects.

In order to avoid the risk of obtaining biased estimates of the age effects, the results reported in this note are based upon estimates using the fixed effects model. The influence of time-invariant regressors is examined in a second stage by regressing the estimates of the unit fixed effects on these variables. The simplest method of estimating the fixed effects model is known as the 'within' estimator in which the mean value for each unit is subtracted from all observations for that unit. For example, if $f(A)$ is a general polynomial of order M in A, equation (1) becomes:

$$lf_{it} - \overline{lf_i} = \sum_{m=1}^{M} \beta_m \left[ A_{it}^m - \frac{1}{T_i} \sum_{i=1}^{t_i} A_{it}^m \right] \upsilon_t + \epsilon_{it} \tag{2}$$

so that the model can be estimated by least square with the inclusion of dummy variables for each period *t*. The variance-covariance matrix of the coefficients have been estimated by using (a) a robust sandwich estimator adjusted for clustering by panel unit, and (b) a bootstrap estimator with 400 repetitions. The estimates of the standard errors will be consistent even if the random error component is serially correlated within panel units and/or has different variances across panel units.19 Since the number of panel units and the average number of time periods per panel units are both large (other than for Danish offshore wind farms), the least square estimates of the parameters will be unbiased under these assumptions.

The bootstrap method is expensive to carry out but it provides a useful cross-check on the standard errors generated by other methods. Unfortunately, the bootstrap method of

18 See Chapter 21 of A.C. Cameron & P.K. Trivedi – *Microeconometrics: Methods and Applications* (Cambridge: Cambridge University Press, 2005) for a standard textbook treatment of estimation methods for panel data models.

19 The estimation was carried out using the xtreg procedure in Stata Version 12. The methods of constructing the sandwich and bootstrap estimates of the variance-covariance matrix are described in Chapters 8 & 13 of A.C. Cameron & P.K. Trivedi – *Microeconometrics using Stata* (Revised Edition, College Station, Texas: Stata Press, 2010)

resampling panel units with replacement can lead to degeneracy in the estimation for some of the bootstrap samples. When the proportion of degenerate samples is significant, the statistical properties of the bootstrap standard errors are not clear. This was a particular problem for the sample of Danish offshore installations and the robust standard errors are reported in this case. In practice, the robust and bootstrap standard errors are very similar, so that the method of estimating the standard errors does not alter any general conclusions about changes in the performance of wind farms as they age.

If standard methods of estimation are applied to the data for the UK and Denmark, the results will generate performance curves that reflect the performance of the typical wind farm. Since the distribution of wind farms by capacity is heavily skewed, the typical wind farm has a much smaller capacity than the average of all wind farms. If there is any kind of relationship between scale and performance, the performance curves may not provide a good guide to the aggregate performance of all wind farms. Hence, as an alternative the models have also been estimated using weights for each wind farm that are proportional to the capacity of the wind farm normalised so that the sum of the weights is equal to the to number of observations. These are referred to as capacity-weighted estimates and the performance curves derived from the estimates reflect the performance of the typical MW of wind capacity.

## D. *Period fixed effects vs normalisation by wind speeds*

In its quarterly publication *Energy Trends* the UK Department of Energy and Climate Change publishes a monthly index of average wind speeds based upon data collected at 14 sites spread over the UK. The descriptive material that accompanies the table (including an article published in the September 2008 issue of *Energy Trends*) does not provide details of how the data for the separate sites is combined but it seems reasonable to infer that the index is simply an average of the wind speeds for each site.

An obvious question is whether this wind index offers a satisfactory or, perhaps, better way of normalising for wind availability than the inclusion of period fixed effects $v_t$ as specified in equation (1) above. Though it may be surprising to some, there are strong mathematical reasons for preferring the period fixed effects. The reason is based on the fact that the relationship between wind speed and electricity output for a wind turbines is highly non-linear. The direct relationship between wind speed and energy follows a cube power law. In addition, wind turbines have cut-in speeds and are designed so that they will not produce more than their rated capacity even if wind speed increases above the level at which capacity output is achieved. Finally, for safety reasons turbines have a cut-out wind speed so that output is zero above that level, though this does not have much effect on the analysis that follows.

Hence, the amount of electricity $E_{jmt}$ generated per MW of capacity in monitoring location $j$ in period $t$ of month $m$ with a steady wind speed of $W_{jmt}$ may be written as:

$$E_{jmt} = \varphi(W_{jmt}) \tag{3}$$

where $\varphi()$ is a non-linear (roughly S-shaped) function. Wind speeds vary almost continuously but it is fairly standard to use an averaging period of 5 minutes so that $t$ refers to time measured in 5 minute intervals. The total output for month $m$ will be:

$$E_{jm} = \sum_{i=1}^{T} \varphi(W_{jmt}) \neq T\varphi(\overline{W}_{jm}) \tag{4}$$

where $\overline{W}_{jm}$ is the average wind speed at location $j$ for month $m$. The inequality states that we cannot rely on being able to calculate total electricity output during the month as a function φ() of average wind speed. Clearly the inequality remains if $\overline{W}_{jm}$ is replaced by the wind index $W^{\%}_{m} = \frac{1}{J}\sum_{j=1}^{J}\overline{W}_{jm}$.

Now, consider the unobserved profile of wind speeds $W_{imt}$ over periods $t = 1\ldots$T at unit $i$ for month $m$. The monthly equivalent wind speed $W^{'}_{im}$ is defined by:

$$T\varphi(W^{'}_{im}) = \sum_{i=1}^{T}\varphi(W_{imt}) \tag{5}$$

This is the wind speed which, if maintained steadily at unit i throughout month m, would have generated the same level of output as generated by the actual profile of wind speeds. Averaging the equivalent wind speeds over all units gives $\hat{W}_m = \frac{1}{I}\sum_{i=1}^{I}W^{'}_{im}$ and $W^{'}_{im} = \hat{W}_m + \omega_{im}$ in which the $\omega_{im}$ are deviations from average equivalent wind speed for unit i and month m. By construction the monthly averages of these deviations are all zero. Using a standard first order expansion, the electricity output per MW for unit $i$ in month m may be expressed as:

$$E_{im} = T\varphi(\hat{W}_m + \omega_{im}) = T\varphi(\hat{W}_m) + T\omega_{im}\varphi^{'}(\hat{W}_m) \tag{6}$$

where $\varphi^{'}()$ is the first derivative of the output function with respect to wind speed at the average equivalent wind speed.

The point of this derivation is that the first term in equation (6) is a period fixed effect which is common to all units in month $m$, while the second term is a random error that is specific to the unit and month. It follows that the specification in equation (1) may be interpreted as a generalisation of (6). A corollary is that a statistical model in which the period fixed effects are replaced by a function of the wind index – denoted by $\phi(W^{\%}_{m})$ – will only perform as well as (1) if $\phi(W^{\%}_{m}) = \varphi(\hat{W}_m)$ for all $m$, which requires that the wind index is a perfect measure of equivalent wind speed for all wind farms in the UK. In practice, this is impossible with a fixed index because the population of wind farms changes over time.

The relevance of this exercise is that it establishes as a matter of principle, not just empirical observation, that the specification in terms of period fixed effects is a more efficient way of normalising performance for variations in wind availability over time than using any wind index of the kind constructed from (weighted) averages of wind speeds at a fixed set of locations. If the output function was linear in $W$, then it might be possible to construct a wind index that would provide a close approximation to the average equivalent wind speed, but that is certainly not the case with the data analysed for this study. However, in the general case it is simple to show that estimating a model with some function of the wind index may yield biased estimates of the coefficients if the period fixed effects are not included as well.[20]

20 Wind operators tend to treat detailed data on output and local wind conditions as being commercially confidential. It would be instructive to extend the analysis in this study by using examining daily output as a function of age, local wind speeds and other variables if such data were available.

## E. Estimation results for the UK

Alternative specifications for the period effects $\upsilon_t$ have been examined. The most general specification is to estimate 120 separate coefficients, one for each month in the 10 year period. A more restrictive specification is to assume that if period $t$ corresponds to year s and month $m$, then $\upsilon_t = \phi_s + \theta_m$ so that the period effect is a composite of a year effect and a month effect. Since weather patterns are clearly seasonal, the assumption of a monthly fixed effect seems reasonable. The addition of an annual fixed effect is less obvious but there are clear differences over a run of years in average wind speeds and the inclusion of an annual fixed effect eliminates potential correlations between age and year. The results are very similar for the two specifications, so the tables report the more general variant with a full set of period effects.

For each of the main models which have been estimated a comparison has been carried out between three alternative specifications of wind availability: (a) a full set of period fixed effects, (b) the log of average wind speed, and (c) the combination of period fixed effects and the log of average wind speed. The results are quite consistent and correspond to the implications of the analysis in the previous section. They are:

- The between-units values of R-square, which is the key measure of goodness of fit for the model, are substantially higher for the specification with period fixed effects than for the one with the wind variable.
- The between-units values of R-square and estimates of the coefficients on age and other independent regressors are identical for the specifications with full period effects with or without the wind variable. In effect, the only consequence of adding the wind variable is to redistribute the explanatory power of the equation between the period fixed effects and the wind variable.

It follows that the wind variable is redundant when the period fixed effects are included in the model, but it performs much less well than the period fixed effects when a comparison is made between the alternative specifications with each variable or set of variables included on their own. Since this outcome conforms with what would have been expected, the results are not reported in detail and the wind variable is not examined in the discussion of the estimation results.

Detailed results are reported for two versions of the age-performance relationship $f(A)$. The first is a quadratic approximation $-f(A) = \beta_0 + \beta_1 A + \beta_2 A^2 -$ while the second includes a full set of age effects $- f(A) = \sum_s \beta_s D_s$ where $D_s = 1$ if $A$=s and $D_s = 0$ otherwise. The quadratic specification was chosen as a smooth approximation to the 'true' age-performance relationship because statistical tests showed that higher order polynomials added little to the explanatory power of the estimated equations while the coefficient on the quadratic term was significantly different from zero with $p < 0.01$ in almost all of the models examined. The constant in the quadratic approximation gives the normalised load factor for age = 0.

The reason for estimating the specification with a full set of age effects is that this does not force year-to-year changes in performance to follow some smooth pattern. For example, there are strong *a priori* reasons to expect that the average load factor in the first year of operation (age = 0) will be compromised by the time required to establish a satisfactory operating regime and to sort out any initial mechanical problems. Hence, it should be expected that the second year of operation will be the year in which the design performance of a wind farm is achieved. As a consequence age = 1 is used as the baseline category in presenting the results estimated with a full set of age effects as this means that the coefficients capture either out-performance (positive values) or the shortfall in performance (negative values) relative to expected design performance.

The additive model can yield extreme or infeasible projections such as negative load factors if it is extrapolated too far, whereas the projections from the multiplicative model must be greater than zero. Hence, unless stated otherwise the results of estimating the multiplicative (log-linear) model provide the basis for the analysis in the remainder of the paper. There is no straightforward way of testing statistically whether a linear or log-linear specification fits the data better as they do not provide nested hypotheses and the different transformations mean that the variances of the errors cannot be compared so that their $R^2$ and other summary statistics do not measure the same thing.

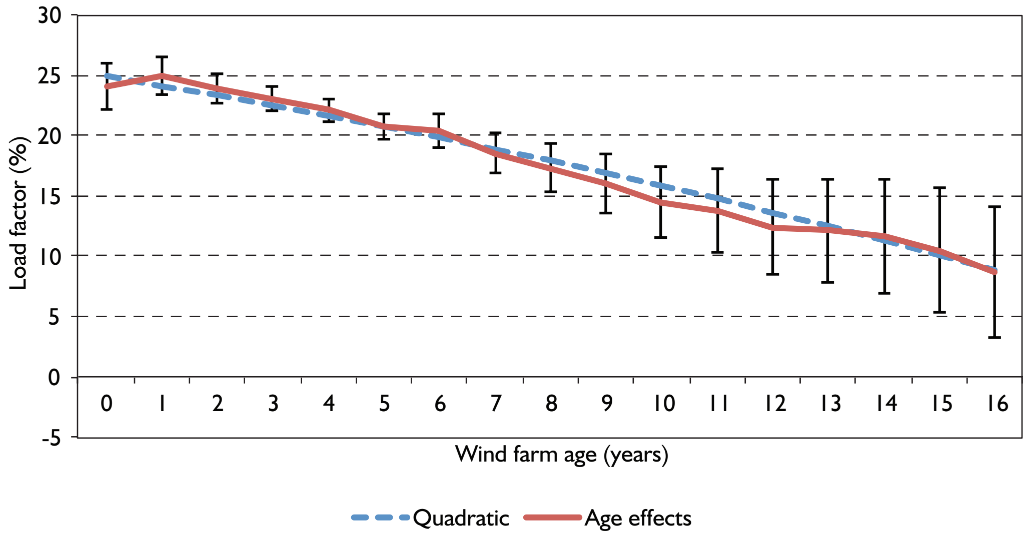
The results of estimating the alternative specifications with a full set of period effects are shown in Table 2 (page 41). The period effects have been normalised by adopting August 2007 as the default period, i.e. with $\upsilon_t = 0$. This normalisation was selected in order to ensure that $\sum_i \upsilon_i \approx 0$. As a consequence the constant terms in the equations are equal to the means of the load factors after normalising for unit characteristics and age. These means are 24.0% for the multiplicative specification with quadratic age effects and 24.3% for the full set of age effects.

With a very large number of degrees of freedom any coefficient with a t-ratio whose absolute value is greater than 2.58 is significantly different from zero at the 1% level or better. Both of the coefficients in the quadratic specification and all of the age effects for age > 1 meet this criterion, so that there can be no doubt that there is a statistically significant deterioration in plant performance as wind farms get older. Both variants of the relationship between load factor and age perform relatively well in capturing within-unit variance in load factors, but the variance between units (measured by the standard deviation of $u_i$) due to site and other characteristics is as large as the variance of the pure error term (measured by the standard deviation of $\epsilon_{it}$).

Figures 9A and 9B illustrates the results of using the estimated coefficients for the additive and multiplicative models to generate the age-performance curves standardised for wind conditions and site characteristics. The error bars illustrate the 95% confidence intervals for the models with a full set of age effects. The quadratic representation of the age-performance curves yields a close approximation to the more detailed specification with individual age effects. Comparing the additive and multiplicative (log-linear) versions of the age-performance curves, the latter has narrower confidence intervals for ages of 10 years or greater which is a further reason for preferring this specification.

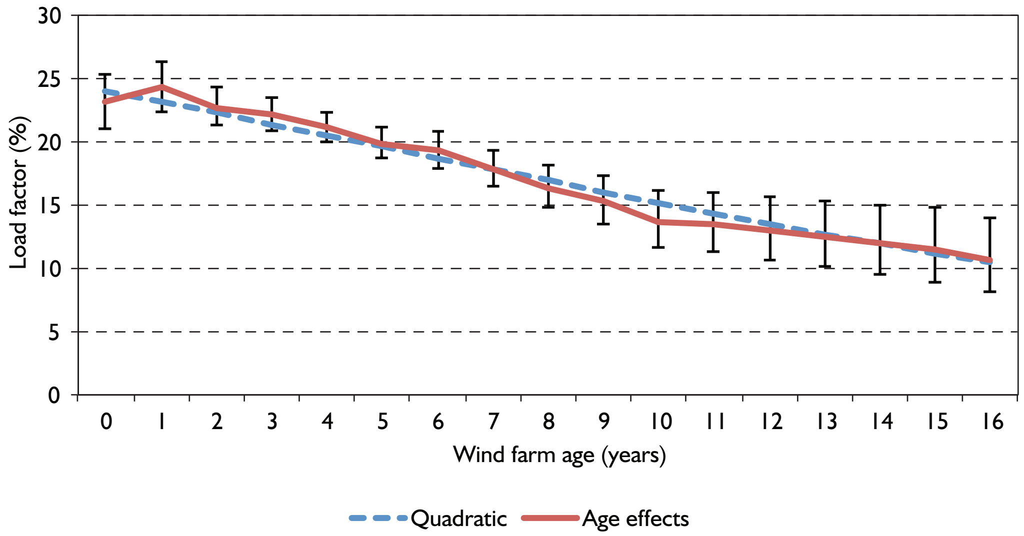
The normalised age-performance curves in Figures 9A and 9B were estimated by giving an equal weight in the estimation to each wind farm irrespective of the amount of installed capacity. These results are representative of the typical wind farm. However, to obtain results that are representative of the average MW of wind generating capacity it is necessary to estimate the model using a weight for each wind farm that is proportional to the installed generating capacity of the plant – referred to here as capacity weights. Figure 10 compares the normalised age-performance curves (including the 95% confidence intervals) for the multiplicative specification with full age effects estimated using equal and capacity weights.

*Figure 9A: Additive age-performance curves for UK onshore wind farms*



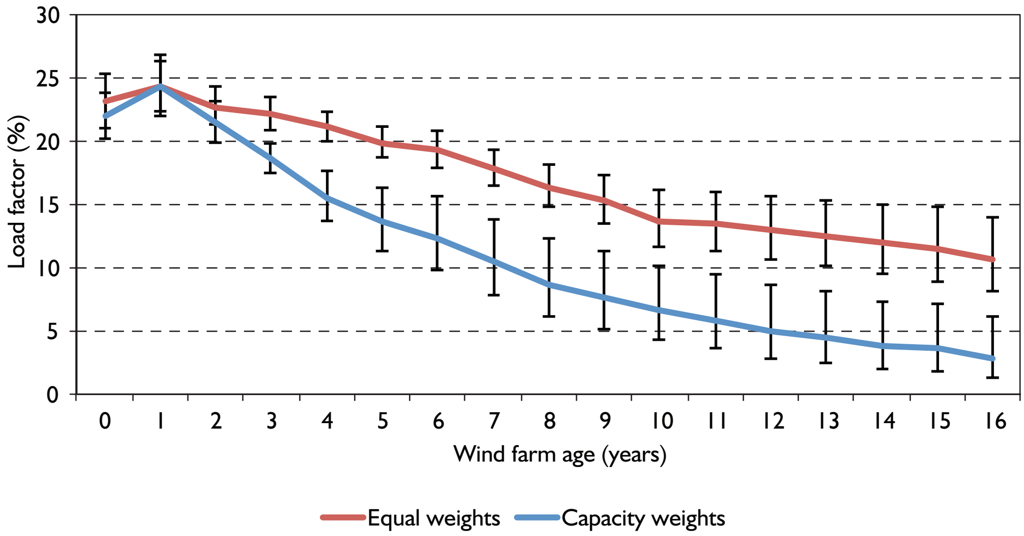

Source: Author's estimates.

*Figure 9B: Multiplicative age-performance curves for UK onshore wind farms*




Source: Author's estimates.

*Figure 10: UK onshore age-performance curves using equal and capacity weights*

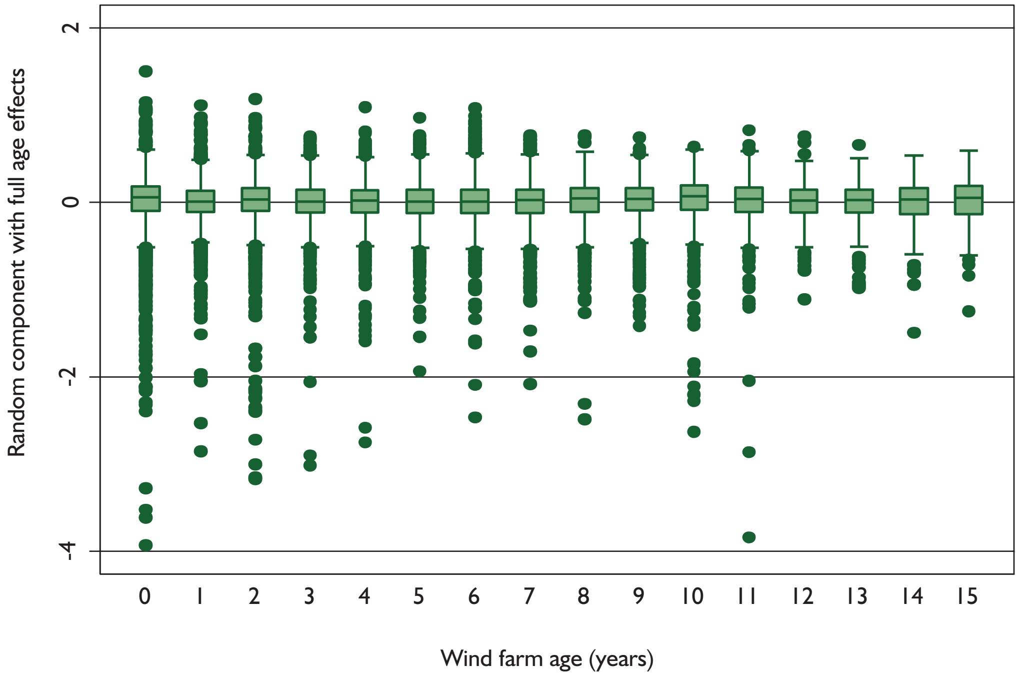



Source: Author's estimates.

The decline in performance with age is considerably greater when capacity weights are used. This implies that the performance of large wind farms declines more rapidly than that of smaller ones. From age 3 onwards the confidence intervals for the two age-performance curves do not overlap, so that it is unlikely that the difference between the two curves arises merely by chance. The normalised load factor per MW of capacity falls to about 7% at age 10 and 3.5% at age 15. With such low levels of performance it seems very unlikely that large wind farms will continue in operation beyond 10 years of age, with a strong likelihood of re-powering at that point. The consequence is that large scale reliance upon wind power seems likely to involve a regular – and costly – commitment to upgrading major components of the wind turbines.

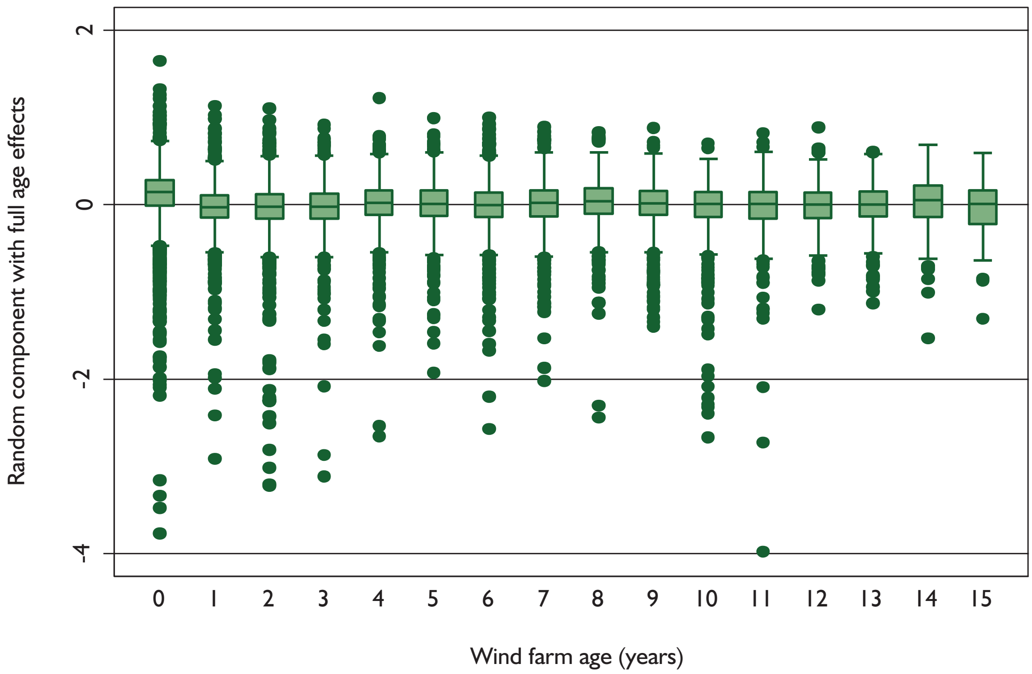
As a cross-check on the estimated models, Figures 11A and 11B show box plots of the distributions of residuals plotted against plant age for the specifications with full age effects using equal and capacity weights respectively. The inter-quartile and Tukey adjacent values show little variation across plant age. The numbers of observations are much greater for plant ages at the bottom of the range (N > 2000 for ages = 0, 1 or 2 but N < 400 for ages > 13). The larger numbers of outliers for the lowest age groups reflect differences in sample size. The standard deviations of the residuals by age group in Figure 11A fall in a range from 0.22 to 0.42 with the highest values for ages 0, 2, 10, 11, and 15. While the residuals are heteroskedastic, there is no systematic relationship between plant age and the residuals. The use of robust or bootstrap standard errors means that there should be no reason to be concerned about statistical inference based on the results in Table 2 (page 41).

*Figure 11A: Residuals by age for performance curves using equal weights*




Source: Author's estimates.

*Figure 11B: Residuals by age for performance curves using capacity weights*

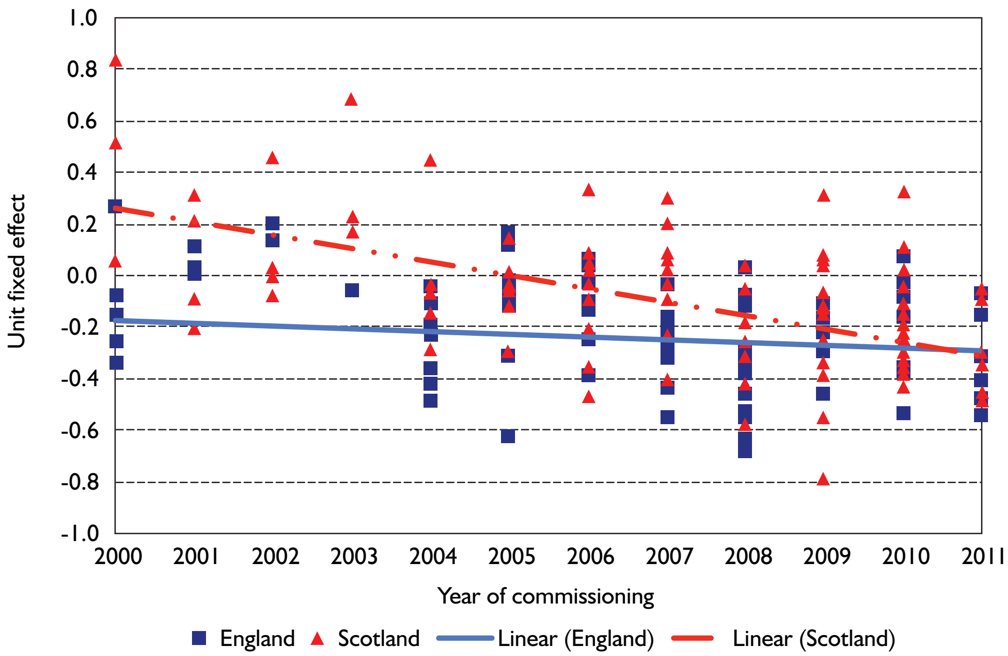



Source: Author's estimates.

The unit fixed effects $u_i$ for each unit $i$ can be used as an indicator of the relative effectiveness of different wind plants. Since wind turbines use no fuel, the crucial determinant of their effectiveness is the number of hours per month or year that they operate, assuming that their output is not constrained by demand or transmission considerations. Periods of constrained production were minimal over the period covered by the data, so this is not a significant consideration. Hence, a unit with a value of $u_i$ at the top end of the distribution will operate for more hours in any year than the average, after adjusting for wind conditions, while a unit with a value of $u_i$ at the bottom end of the distribution will operate for fewer hours per years. The factors which influence average efficiency for particular units will include site location, the type of wind turbines installed, and operating practices. Site location is likely to be the most important factor since this will determine how far the turbines can take advantage of exogenous wind conditions.

Figure 12 plots the unit fixed effects – i.e. the efficiencies – of wind plants in England and Scotland commissioned in or after 2000 together with trend lines over time.[21] A small number of extreme outliers, all with very low load factors, have been excluded. There is a very clear downward trend over time in the unit fixed effects for Scotland – marked with red triangles and a red dashed trend line. The variance of performance of wind plants in Scotland commissioned in any one year is also large. The performance of wind plants in England has also fallen over time but more gradually.

*Figure 12: Unit fixed effects by year of commissioning for England and Scotland*




Note: The unit fixed effects are based on the log-linear specification with full age effects.
Source: Author's estimates.

A more comprehensive analysis can be constructed by treating the 282 values of the unit fixed effects as data observations and estimating a regression equation in which the performance of a plant is affected by the year in which it was commissioned and its generating capacity. Table 3 (page 43) shows the results of estimating regression equations to identify how the unit fixed effects vary with the date of commissioning and capacity of wind farms. The results indicate an annual reduction of 3.8% in the normalised load factor by date of commissioning for the equally weighted fixed effects and of 11.3% for the capacity-weighted fixed effects. These trends

21 A fall in the unit fixed effect from 0.2 to 0.1 translates to multiplying the normalised load factor by exp(0.1)/exp(0.2) = 0.905.

have been reinforced by diseconomies of scale so that recently commissioned and larger wind farms have much lower normalised load factors than older and smaller wind farms. In addition, wind farms in Northern Ireland and Scotland perform better than those in England and Wales.

The average load factor for a plant with a generating capacity of 50 MW is estimated to be about 8% lower than that for a plant with a generating capacity of 10 MW commissioned in the same year. The combination of less favourable sites and larger units as the number of wind farms has grown has had a major impact on average load factors.

One hypothesis which merits investigation is that any performance degradation is determined by usage rather than the passage of time. This would imply that wind plants with relatively low load factors experience less rapid degradation in performance than those with relatively high load factors. This may be tested by including cumulative actual output normalised by generating capacity as an explanatory variable along with age effects. Since output is not recorded for periods prior to April 2002 for wind plants that were commissioned before that date, the analysis is restricted to the subset of plants commissioned after April 2002. The analysis (available on request from the author) indicates that cumulative output does not have any statistically significant influence on performance degradation, which depends upon age alone.

The most plausible explanation is that performance degradation is linked to the cumulative number of starts and stops for the wind turbines. This is certainly the case for thermal generating plants for which maintenance requirements and performance are strongly influenced by the thermal stresses of start and stop cycles. As a consequence, thermal plants operate most efficiently on base load when the number of starts and stops is minimised. The inescapable variability of wind speeds means that the stresses on mechanical and other components due to start and stop cycles cannot be minimised by similar strategies.

## F. *Estimation results for Denmark*

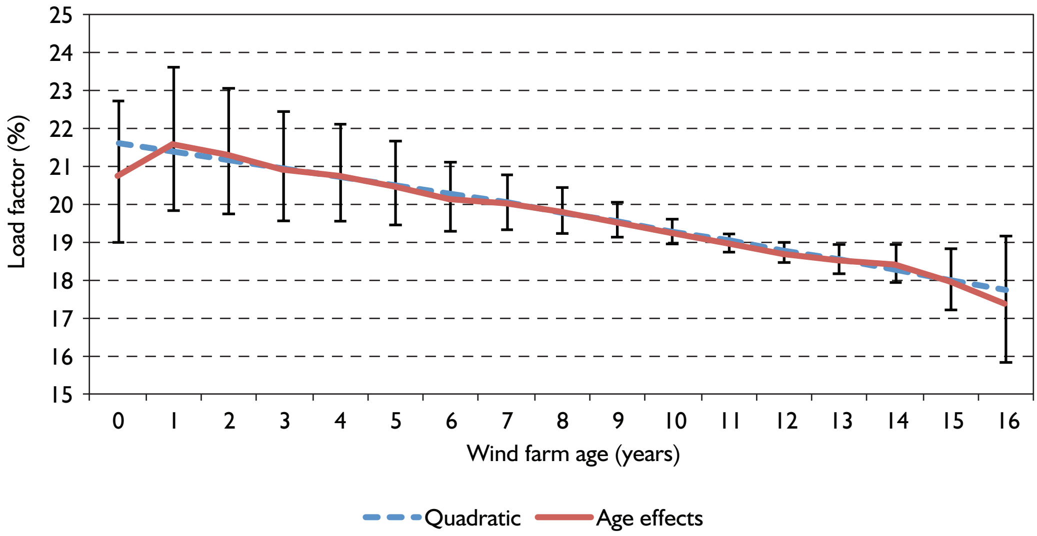
The results of estimating the model for Danish onshore and offshore wind farms are shown in Tables 4 (page 44) and 5 (page 46). Because the sample of offshore wind farms is fairly small the process of bootstrapping the standard errors generates a relatively high proportion of degenerate results, especially for the specification with a full set of age effects, so cluster-robust standard errors are reported for all of the models estimated for offshore wind farms. For both onshore and offshore wind farms the specification with full age effects yields no statistical improvement on the quadratic specification.

In Section B it was noted that the largest offshore wind farm appears to be an outlier and has a very large influence on offshore age-performance curve estimated using capacity weights.[22] To highlight the impact of including this observation, the normalised load factor at age = 0 is 76.8% but it falls to 0.6% at age = 10 if this observation is included. In contrast, the equivalent estimates are 32.8% at age = 0 falling to 9.9% at age = 10 when the observation is excluded. The time profile of normalised load factors when this observation is retained in the sample is so extreme and implausible on technical grounds that the wind farm was excluded from the sample used to estimate the capacity-weighted model for offshore wind farms. An alternative

22 This wind farm suffered from some kind of major equipment failure in 2007 with the consequence that the total output from 72 turbines was almost zero for more than 4 months.

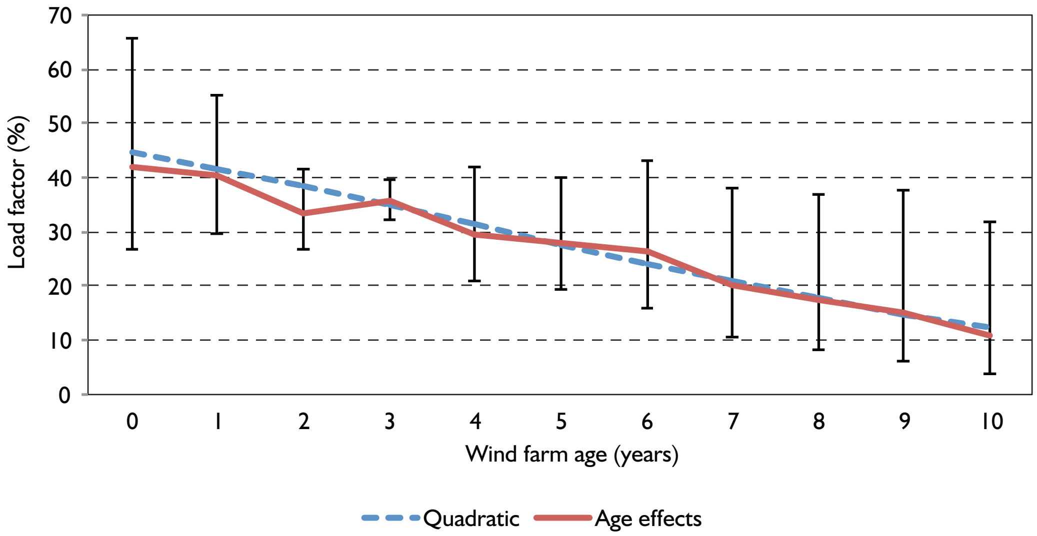
that was considered and which yields very similar results is to drop only the observations for the year 2007, the year in which there was some kind of major failure for this wind farm. None of the conclusions drawn from the analysis of the capacity-weighted age-performance relationship are affected by which of these alternative adjustments is adopted.

*Figure 13A: Age-performance curves for Danish onshore wind farms*




Source: Author's estimates.

*Figure 13B: Age-performance curves for Danish offshore wind farms*

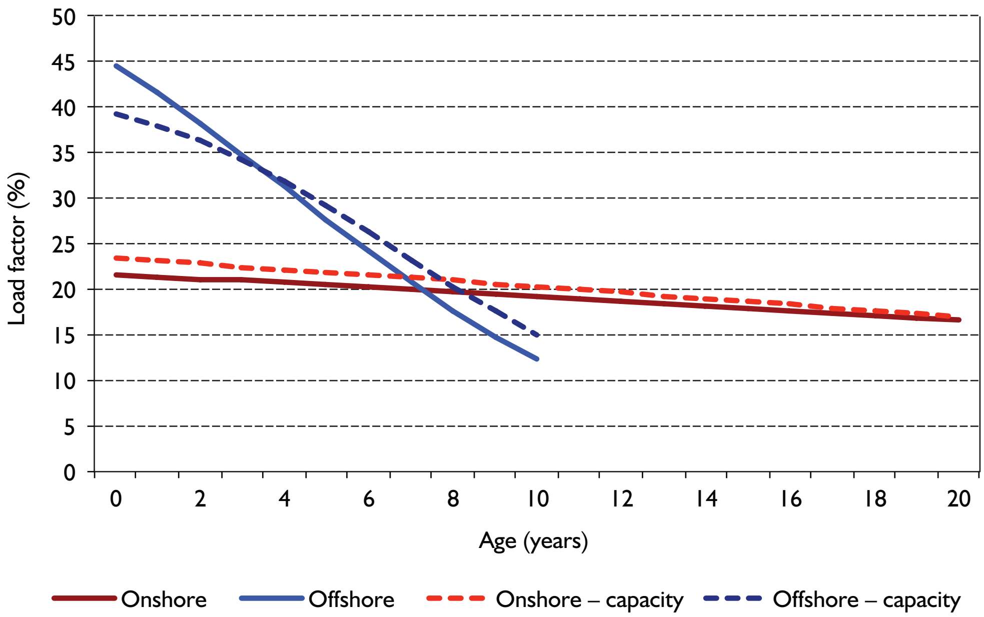



Source: Author's estimates.

The within R-square values are about 0.76 for all of the onshore equations and 0.74 for the capacity-weighted offshore equations. This indicates that the equations provide a better fit for variations in performance over time than would normally be expected for a large sample of separate panel units. The unit fixed effects account for about 50% of the residual variation for onshore wind farms and more than 75% of the residual variation for offshore installations. The correlations between the unit fixed effects and other regressors are very small for onshore wind farms, which would permit the use of a random effects model in this case, but the correlations reject the random effects assumption for offshore installations. In practice, using the random effects model for onshore wind farms generates results that are broadly similar to those reported based on the fixed effects model.

The normalised age-performance curves for Danish wind farms using equal weights are shown in Figures 13A and 13B while the comparison between the age-performance curves estimated using equal and capacity weights is shown in Figure 14. The confidence intervals for the age-performance curves for offshore wind farms are large because of the limited sample of sites but the hypothesis that the load factor remains constant as plants age – i.e. that the coefficients on age in columns (5) to (8) of Table 4 (page 44) are all zero – is rejected for each specification ($p \leq 0.02$). The comparison of the age-performance curves derived using equal and capacity weights in Figure 13 is based upon the quadratic specifications as these provide simpler approximations which are not statistically different from the estimates based on the models with the full set of age effects.

*Figure 14: Danish age-performance curves using equal and capacity weights*




Source: Author's estimates.

The decline in the performance of onshore wind farms in Denmark is less marked than for the UK but there is a significant decline at an average of 1% of the previous year's load factor for each year. The decline is much more rapid for offshore wind farms with highly significant negative coefficient on the quadratic term. In both cases the rates of decline are larger when wind farms are weighted by capacity in the analysis. The estimates using a full set of age effects show that the normalised load factor in the first year of operation (age = 0) is lower than in the baseline year with age = 1. From age = 3 to age = 16 the coefficients are increasingly negative. The results for ages > 16 are erratic but it is likely that this reflects sample selection bias, i.e. older wind farms with poor performance are more likely to be decommissioned early and thus not appear in the sample.

The age-related decline in the performance of offshore wind farms is very rapid. The normalised performance of an offshore wind farm falls from a load factor of 45% at age = 0 to

12% at age = 10. The decline in the capacity-weighted load factors has a slightly different profile with a stronger quadratic term that reflects a slower initial rate of decline in performance which accelerates after age = 8. Overall, the average load factors for ages up to and including age = 10 are very similar – about 28% – for the estimates derived using equal and capacity weights. This average is well below the load factor immediately after commissioning. Since typical load factors after age = 10 are likely to be well below this average, the steady state load factor for a large sample of offshore wind farms will be well below the figure of 35% that is often used as the basis for policy assessments in the UK. This will have important consequences for the cost of offshore wind generation and its potential contribution to meeting the demand for electricity.

Analysis of the unit fixed effects for the performance equations reveals another systematic pattern that must raise concerns about the future of the offshore wind industry. Table 5 (page 46) gives the median values of capacity and the unit fixed effects for onshore and offshore wind farms by year of commissioning. The unit fixed effects used in constructing the table are based upon the quadratic performance equations, but similar results are obtained if the unit fixed effects for the performance equations with a full set of age effects had been used instead.

In the case of onshore wind farms both the size of new installations and the associated unit fixed effects have tended to increase with time. Hence, the typical onshore wind farm commissioned in 2010 was larger and had a better performance than the typical installation commissioned in 2000, though onshore wind farms remain very small by UK standards. The year 2007 appears to be an anomaly with respect to this general trend but it should be noted that the median capacity of new plants commissioned in 2007 was only 1.5 MW, well below the medians for other years in the period 2005-10 The trend in the typical load factor trend over time is confirmed by estimating regressions for the unit fixed effects with capacity and year of commissioning as regressors. In Denmark larger wind farms tend to have higher load factors than small wind farms. Even after allowing for that trend, the normalised load factor for new wind farms has been increasing at about 1% per year over time. This is consistent with the normal pattern of technical progress and learning which one would expect to observe for a (relatively) mature industry.

The pattern is very different for offshore wind farms. In this case the results of the regressions show no significant relationship between capacity and the unit fixed effects combined with a very substantial deterioration (at rates of 8–10% per year) in the unit fixed effects. Even allowing for the small sample of offshore wind farms the trends are so strong that the probabilities of obtaining the results by chance are well below 0.1%. Thus, the median values of the unit fixed effects for offshore wind farms shown in Table 5 (page 46) illustrate a sharp and systematic decline in the performance of new offshore wind farms in Denmark. If this were to continue and/or to be reproduced in other countries where offshore wind is being developed, then there can be no prospect that offshore wind farms will ever be financially viable at reasonable prices for electricity.

*Table 1: Average load factors by year and country (%)*

| | **Onshore** | | | | | **Offshore** |
|---|---|---|---|---|---|---|
| | **England** | **Northern Ireland** | **Scotland** | **Wales** | **Denmark** | **Denmark** |
| 2002 | 22.2 | | 26.4 | 21.5 | 21.8 | 26.1 |
| 2003 | 24.1 | | 28.6 | 24.9 | 20.1 | 30.1 |
| 2004 | 25.0 | | 27.7 | 25.8 | 22.8 | 33.3 |
| 2005 | 25.0 | 30.8 | 27.1 | 24.8 | 22.1 | 39.4 |
| 2006 | 23.9 | 29.4 | 24.5 | 26.5 | 20.2 | 37.1 |
| 2007 | 24.2 | 26.3 | 26.9 | 25.8 | 24.7 | 37.1 |
| 2008 | 24.4 | 29.4 | 23.9 | 29.9 | 23.1 | 41.2 |
| 2009 | 24.1 | 30.0 | 27.2 | 25.5 | 21.3 | 38.0 |
| 2010 | 20.8 | 23.5 | 21.6 | 18.9 | 21.0 | 39.8 |
| 2011 | 26.6 | 30.7 | 27.9 | 27.0 | 25.3 | 44.9 |

Source: Author's estimates. See text for source of data.
Note: The average load factors are the sums of total electricity output by country and year divided by the average total nameplate capacity in the country multiplied by number of hours in the year. For new installations, the first full month after the date of commissioning is excluded. Total nameplate capacity is calculated monthly and averaged to give a monthly average of total nameplate capacity.

*Table 2: Estimation results for UK onshore wind farms*

| | **Unweighted** | | | | **Weighted by capacity** | | | |
|---|---|---|---|---|---|---|---|---|
| | **Linear** | | **Log-Linear** | | **Linear** | | **Log-Linear** | |
| | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) |
| Age | -0.74*** | | -0.036*** | | -1.31*** | | -0.092*** | |
| | (0.21) | | (0.010) | | (0.31) | | (0.020) | |
| Age ^ 2 | -0.017*** | | -0.0010*** | | -0.043*** | | -0.0026*** | |
| | (0.005) | | (0.0003) | | (0.011) | | (0.0007) | |
| Age effects | | | | | | | | |
| 0 | | -0.89** | | -0.050*** | | -1.85* | | -0.103 |
| | | (0.34) | | (0.015) | | (0.90) | | (0.055) |
| 2 | | -1.04** | | -0.066*** | | -1.87*** | | -0.127*** |
| | | (0.32) | | (0.018) | | (0.36) | | (0.025) |
| 3 | | -1.89*** | | -0.093*** | | -4.01*** | | -0.269*** |
| | | (0.51) | | (0.024) | | (0.74) | | (0.062) |
| 4 | | -2.86*** | | -0.140*** | | -6.52*** | | -0.446*** |
| | | (0.75) | | (0.036) | | (1.21) | | (0.102) |
| 5 | | -4.23*** | | -0.200*** | | -9.00*** | | -0.582*** |
| | | (0.96) | | (0.047) | | (1.68) | | (0.135) |
| 6 | | -4.52*** | | -0.231*** | | -9.98*** | | -0.676*** |
| | | (1.19) | | (0.057) | | (2.03) | | (0.158) |
| 7 | | -6.45*** | | -0.308*** | | -13.02*** | | -0.850*** |
| | | (1.41) | | (0.069) | | (2.39) | | (0.186) |
| 8 | | -7.61*** | | -0.394*** | | -15.50*** | | -1.033*** |
| | | (1.60) | | (0.082) | | (2.72) | | (0.218) |
| 9 | | -8.89*** | | -0.465*** | | -17.58*** | | -1.161*** |
| | | (1.88) | | (0.097) | | (3.11) | | (0.244) |
| 10 | | -10.45*** | | -0.574*** | | -19.75*** | | -1.310*** |
| | | (2.12) | | (0.117) | | (3.39) | | (0.265) |
| 11 | | -11.14*** | | -0.591*** | | -21.67*** | | -1.422*** |
| | | (2.40) | | (0.120) | | (3.69) | | (0.289) |
| 12 | | -12.54*** | | -0.632*** | | -24.55*** | | -1.598*** |
| | | (2.66) | | (0.131) | | (4.16) | | (0.330) |
| 13 | | -12.84*** | | -0.666*** | | -25.42*** | | -1.701*** |
| | | (2.83) | | (0.140) | | (4.57) | | (0.356) |
| 14 | | -13.37*** | | -0.708*** | | -27.87*** | | -1.855*** |
| | | (3.04) | | (0.148) | | (4.78) | | (0.373) |
| 15 | | -14.45*** | | -0.752*** | | -28.78*** | | -1.910*** |
| | | (3.26) | | (0.159) | | (5.14) | | (0.395) |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 16 | | -16.27*** | | -0.825*** | | -32.87*** | | -2.155*** |
| | | (3.42) | | (0.171) | | (5.63) | | (0.447) |
| 17 | | -16.95*** | | -0.911*** | | -35.37*** | | -2.372*** |
| | | (3.71) | | (0.191) | | (5.98) | | (0.473) |
| 18 | | -18.99*** | | -0.982*** | | -38.00*** | | -2.482*** |
| | | (3.96) | | (0.195) | | (6.30) | | (0.493) |
| 19 | | -22.40*** | | -1.156*** | | -46.05*** | | -3.011*** |
| | | (4.63) | | (0.276) | | (7.40) | | (0.582) |
| Constant | 24.90*** | 24.93*** | 3.180*** | 3.190*** | 23.94*** | 23.88*** | 3.206*** | 3.192*** |
| | (0.99) | (0.88) | (0.045) | (0.038) | (0.74) | (0.696) | (0.052) | (0.052) |
| | | | | | | | | |
| Observations | 18224 | 18224 | 18224 | 18224 | 18224 | 18224 | 18224 | 18224 |
| No of units | 282 | 282 | 282 | 282 | 282 | 282 | 282 | 282 |
| R-square Within | 0.653 | 0.657 | 0.549 | 0.555 | 0.687 | 0.700 | 0.585 | 0.607 |

Source: Author's estimates. See text for source of data.
Notes: (a) Standard errors in parentheses. Probabilities are measured in stars:
* $p < 0.05$, ** $p < 0.01$, *** $p < 0.001$.
(b) Bootstrap standard errors for models (1)–(4); cluster- robust standard errors for models (5)-(8).
(c) The equations are estimated with a full set of period effects in addition to the variables reported. The default (missing categories) are age = 1 and period = August 2007. The constant term corresponds to the estimate of the load factor or ln(load factor) for a unit of age=1 in August 2007.

*Table 3: Equations for trends in unit fixed effects*

| | **Quadratic** | **Age effects** | **Quadratic – capacity** | **Age effects – capacity** |
|---|---|---|---|---|
| | (1) | (2) | (3) | (4) |
| Year of commissioning – 2000 | -0.038*** | -0.039*** | -0.117*** | -0.121*** |
| | (0.003) | (0.003) | (0.003) | (0.003) |
| Capacity (MW) | -0.0021*** | -0.0021*** | -0.0020*** | -0.0020*** |
| | (0.0005) | (0.0005) | (0.0005) | (0.0005) |
| Northern Ireland | 0.198*** | 0.192*** | 0.207*** | 0.199*** |
| | (0.040) | (0.041) | (0.041) | (0.042) |
| Scotland | 0.207*** | 0.206*** | 0.202*** | 0.202*** |
| | (0.036) | (0.035) | (0.036) | (0.040) |
| Wales | 0.081 | 0.0824* | 0.0844* | 0.0882* |
| | (0.042) | (0.042) | (0.040) | (0.042) |
| Constant | 0.022 | 0.0273 | 0.475*** | 0.504*** |
| | (0.029) | (0.032) | (0.030) | (0.032) |
| | | | | |
| Observations | 282 | 282 | 282 | 282 |
| R-square | 0.413 | 0.423 | 0.848 | 0.857 |

Source: Author's estimates.
Notes: (a) Standard errors in parentheses. Probabilities are measured in stars:
* $p < 0.05$, ** $p < 0.01$, *** $p < 0.001$.
(b) England is the baseline country in the model.
(c) Bootstrap standard errors.

*Table 4: Estimation results for Danish wind farms*

| **Regressors** | **Dependent variable: ln(load factor)** | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | **Onshore wind farms** | | | | **Offshore wind farms** | | | |
| | **Unweighted** | | **Weighted by capacity** | | **Unweighted** | | **Weighted by capacity** | |
| | **(1)** | **(2)** | **(3)** | **(4)** | **(5)** | **(6)** | **(7)** | **(8)** |
| Age | -0.010* | | -0.013** | | -0.062 | | -0.022 | |
| | (0.004) | | (0.005) | | (0.077) | | (0.020) | |
| Age ^ 2 | -0.0002 | | -0.0002 | | -0.0067** | | -0.0075** | |
| | (0.0001) | | (0.0002) | | (0.0019) | | (0.0022) | |
| Age in years | | | | | | | | |
| 0 | | -0.041*** | | -0.036** | | 0.036 | | 0.0155 |
| | | (0.011) | | (0.012) | | (0.090) | | (0.025) |
| 2 | | -0.014 | | -0.020* | | -0.197* | | -0.0600 |
| | | (0.009) | | (0.010) | | (0.091) | | (0.032) |
| 3 | | -0.031** | | -0.043*** | | -0.127 | | 0.0784 |
| | | (0.012) | | (0.013) | | (0.200) | | (0.061) |
| 4 | | -0.040** | | -0.053** | | -0.312 | | -0.224 |
| | | (0.015) | | (0.016) | | (0.307) | | (0.112) |
| 5 | | -0.052** | | -0.068** | | -0.374 | | -0.359** |
| | | (0.019) | | (0.021) | | (0.308) | | (0.118) |
| 6 | | -0.069** | | -0.088*** | | -0.432 | | -0.432* |
| | | (0.022) | | (0.026) | | (0.380) | | (0.182) |
| 7 | | -0.076** | | -0.097** | | -0.700 | | -0.681** |
| | | (0.027) | | (0.031) | | (0.451) | | (0.192) |
| 8 | | -0.087** | | -0.115** | | -0.838 | | -0.734** |
| | | (0.031) | | (0.035) | | (0.511) | | (0.208) |
| 9 | | -0.100** | | -0.131** | | -0.983 | | -0.828** |
| | | (0.035) | | (0.041) | | (0.590) | | (0.254) |
| 10 | | -0.115** | | -0.151** | | -1.313 | | -1.183*** |
| | | (0.040) | | (0.046) | | (0.676) | | (0.270) |
| 11 | | -0.131** | | -0.170*** | | | | |
| | | (0.044) | | (0.051) | | | | |
| 12 | | -0.144** | | -0.184** | | | | |
| | | (0.048) | | (0.057) | | | | |
| 13 | | -0.154** | | -0.201** | | | | |
| | | (0.053) | | (0.062) | | | | |
| 14 | | -0.160** | | -0.210** | | | | |
| | | (0.057) | | (0.066) | | | | |

| Regressors | Dependent variable: ln(load factor) | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | Onshore wind farms | | | | Offshore wind farms | | | |
| | Unweighted | | Weighted by capacity | | Unweighted | | Weighted by capacity | |
| | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) |
| 15 | | -0.184** | | -0.228** | | | | |
| | | (0.064) | | (0.073) | | | | |
| 16 | | -0.217** | | -0.231* | | | | |
| | | (0.083) | | (0.090) | | | | |
| 17 | | -0.157* | | -0.179 | | | | |
| | | (0.073) | | (0.097) | | | | |
| 18 | | -0.188* | | -0.256** | | | | |
| | | (0.083) | | (0.095) | | | | |
| 19 | | -0.083 | | -0.143 | | | | |
| | | (0.082) | | (0.095) | | | | |
| 20 | | -0.161 | | -0.246* | | | | |
| | | (0.084) | | (0.101) | | | | |
| Constant | 3.073*** | 3.074*** | 3.154*** | 3.160*** | 3.798*** | 3.701*** | 3.668*** | 3.475*** |
| | (0.048) | (0.045) | (0.053) | (0.050) | (0.179) | (0.158) | -0.032 | -0.056 |
| | | | | | | | | |
| Observations | 93929 | 93929 | 93929 | 93929 | 2201 | 2201 | 2091 | 2091 |
| No of units | 823 | 823 | 823 | 823 | 30 | 30 | 29 | 29 |
| R-square Within | 0.766 | 0.766 | 0.762 | 0.762 | 0.345 | 0.350 | 0.738 | 0.751 |

Source: Author's estimates. See text for source of data.
Notes: (a) Standard errors in parentheses. Probabilities are measured in stars:
* p < 0.05, ** p < 0.01, *** p < 0.001.
(b) Bootstrap standard errors for models (1)-(2); cluster- robust standard errors for models (3)–(8).

*Table 5: Performance by year of commissioning for Danish wind farms*

| **Year** | **Onshore** | | | **Offshore** | | |
|---|---|---|---|---|---|---|
| | **Capacity (MW)** | **Unit fixed effects** | | **Capacity (MW)** | **Unit fixed effects** | |
| | | **Unweighted** | **Capacity weighted** | | **Unweighted** | **Capacity weighted** |
| | | | | | | |
| 2000 | 2.3 | -0.055 | -0.076 | 40.0 | 0.001 | -0.035 |
| 2001 | 2.6 | -0.151 | -0.177 | | | |
| 2002 | 2.7 | 0.036 | 0.008 | 22.0 | 0.196 | 0.215 |
| 2003 | 2.3 | 0.185 | 0.153 | 4.0 | -0.059 | 0.082 |
| 2004 | 3.0 | 0.047 | 0.012 | | | |
| 2005 | 3.6 | 0.278 | 0.241 | | | |
| 2006 | 5.6 | 0.256 | 0.216 | | | |
| 2007 | 1.5 | -0.451 | -0.494 | | | |
| 2008 | 4.0 | 0.263 | 0.216 | | | |
| 2009 | 4.6 | 0.326 | 0.274 | 23.2 | -0.546 | -0.305 |
| 2010 | 7.2 | 0.406 | 0.351 | 39.1 | -0.727 | -0.466 |
| 2011 | 6.5 | 0.050 | -0.008 | 3.6 | -0.979 | -0.673 |

Note: Median values of capacity and unit fixed effects. Source: Author's estimates. See text for source of data.