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Early experiences with UK round 1 offshore wind farms

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The UK government plans that offshore wind power should play a major part in meeting the UK's renewable energy and carbon emission targets by 2020. The pioneer UK round 1 offshore wind farm projects, based on sites let in 2001, were supported by the UK Department of Trade and Industry's 'Offshore wind capital grants scheme'. Round 2 offshore sites were let in 2003 and the successful bidders for round 3 offshore sites were announced in January 2010; therefore the published reports from round 1 could provide valuable information on offshore experiences for the operation of later rounds. This paper reviews the performances of those UK round 1 offshore wind farms during their early operation based on published reports from the 'Offshore wind capital grants scheme' available for the period 2004–2007 and early operational issues. UK round 1 offshore wind farms have achieved an average cost of energy of £69 per MWh, in line with expectations, but at 80·3% the average availability fell short of expectations. The availability of UK round 1 offshore wind farms has been shown to decrease with increasing wind speed so it is recommended that improvements of availability at wind speeds 7–14 m/s will be needed to meet more ambitious economic targets.

1. INTRODUCTION

The UK is facing twin challenges of climate change and security of energy supply. To meet these challenges, UK government is developing a strategy of having a diverse mix of low-carbon energy sources, in which renewable sources will play a vital part. A component of that strategy was the development from 2001 of round 1 offshore wind farms, as presented in Figure 1 and Table 1.

In March 2007, the European Union (EU) Council of Ministers agreed that renewable energy should meet at least 20% of EU energy demand by 2020. In December 2008, UK agreed to a legally binding target for 15% of energy production from renewable sources by 2020, increasing from 1·5% in 2006 (DECC, 2009a, p. 4). Offshore wind power is intended to play an important part in meeting these UK renewable energy targets, improving energy security and reducing carbon emission by 2020.

The consultative document published by the Department for Business, Enterprise and Regulatory Reform (BERR) in June 2008 showed that offshore wind power could contribute up to 19% of the UK renewable energy target by 2020 (BERR, 2008, p. 8). In June 2009, the Department of Energy and Climate Change (DECC) announced a new plan for 25 GW of new offshore wind capacity, on top of existing plans for 8 GW (DECC, 2009a, p. 2). In January 2010, The UK's Crown Estate has announced the successful bidders for the round 3 which is anticipated to take the development of at least 25 GW offshore wind capacity.

The UK has a rich offshore wind resource and the deployment of large-scale offshore wind power could have some advantages. Offshore wind speeds are higher, turbulence is less and offshore wind turbines should expect a larger energy capture than equivalent onshore machines. The noise impact of offshore wind farms is less than onshore and their visual impact is perceived to be less. However, there are concerns about offshore wind in the UK owing to the lack of operating experience on large-scale offshore wind farms and the possible risks of energy capture owing to low reliability and availability, in view of the difficulties of accessing offshore turbines for maintenance. In 2001 the 'Offshore wind capital grants scheme' was launched by the Department of Trade and Industry (DTI) to encourage the deployment of large-scale offshore wind farms. Five projects with a total capacity of 390 MW of round 1 offshore wind farms, supported by the scheme, are now fully operational, including the UK's first major offshore wind farms North Hoyle (Carter, 2007), Scroby Sands, Kentish Flats, Barrow and Burbo Bank. Figure 2 presents a view of Scroby Sands offshore wind farm from the beach, demonstrating that these sites are all close inshore. These projects were designed to provide valuable experience for the upcoming larger offshore wind projects in rounds 2 and 3. From 2005, the annual operational reports of round 1 offshore wind farms have been published by DTI, subsequently BERR (DTI and BERR, 2004–2007).

Operational performance is critical to the economics of a wind farm. This is because the operation and maintenance (O&M) costs constitute a sizable share of the annual cost of a wind farm and turbine downtime, owing to repair or maintenance, causes an annual energy production loss. This paper analyses early operational data from the available reports of round 1 offshore wind farms, placing them in context alongside the published performance of onshore wind farms in Europe and their own early operational issues.

The paper is organised as follows: Section 2 explains the terminologies used. Section 3 describes the background of

Figure 1. UK round 1 offshore wind farms (produced by Design & Imaging Unit, Durham University)

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recent onshore wind turbine operational studies, based on public and commercial databases. Section 4 records the operational issues experienced at each of round 1 offshore wind farms. Section 5 presents economic and operational analyses based on the round 1 reports and previous experience; it then goes on to explain the observed performance and proposes suggestions for future improvement in Section 6. Section 7 draws conclusions.

2. TERMINOLOGY

Cost of energy (COE) is commonly used to evaluate the economic performance of different wind farms. This methodology was adopted in a joint report (IEA *et al.*, 2005, p. 173) by the IEA (International Energy Agency), the European OECD (Organisation for Economic Co-operation and Development) and US NEA (Nuclear Energy Agency), referred to

Location	Status	Capacity: MW	Period : reported year	Turbine					Water depth: m	Distance from wind farm centre to shore: km	Operator
				No	Maker	Type	Rating: MW	Swept area: m			
North Hoyle	Operational (July 2004)	60	3	30	Vestas	V80	2	5027	7–11	9·2	RWE npower Renewables
Scroby Sands	Operational (Jan 2005)	60	3	30	Vestas	V80	2	5027	5–10	3·6	E.on UK Renewables
Kentish Flats	Operational (Jan 2006)	90	2	30	Vestas	V90	3	6362	5	9·8	Vattenfall
Barrow	Operational (July 2006)	90	1	30	Vestas	V90	3	6362	15–20	12·8	Centrica/ DONG Energy
Burbo Bank	Operational (Oct 2007)	90		25	Siemens	SWT-3.6-107	3.6	9000	2–8	8	DONG Energy
Rhyl Flats	Partial operational (July 2009)	90		25	Siemens	SWT-3.6-107	3.6	9000	6·5–12·5	10·7	RWE npower Renewables
Lynn/Inner Dowsing	Installed (July 2008)	194		54	Siemens	SWT-3.6-107	3.6	9000	5–10/ 18·6–26	6·9/6·2	Centrica Renewable Energy
Gunfleet Sands I	Under construction	108		30	Siemens	SWT-3.6-107	3.6	9000	0.5–10	7·4	DONG Energy
Robin Rigg	Under construction	180		60	Vestas	V90	3	6362	0–20	11·5	E.on Climate & Renewables UK

* See http://www.bwea.com/offshore/round1.html, accessed on August 2009
† See http://www.4coffshore.com/windfarms, accessed on August 2009

Table 1. Operational round 1 offshore wind farm sites in the UK*†

in this paper as the 'IEA 2005 report'. It compares the cost of different electricity production options. A simplified calculation equation is adopted in the US to calculate the COE (£/MWh) for a wind turbine system (Walford, 2006)

$$\text{COE} = \frac{\text{ICC} \times \text{FCR} + \text{O\&M}\cos\text{t}}{E} \quad (2)$$

where ICC is initial capital cost (£), FCR is annual fixed charge rate (%), E is annual energy production (kWh), O&M cost is annual operation and maintenance cost (£). The result of this approach is the same as that of levelised electricity generation cost used in IEA 2005 report (p. 174), where the parameter FCR is a function of the discount rate r used in the IEA 2005 report, as follows

$$\text{FCR} = \frac{r}{[1-(1+r)^{-n}]} \quad (2)$$

where $r \neq 0$.

The discount rate r is the sum of inflation and real interest rates. If inflation is ignored, the discount rate equals the interest rate. For the special case of a discount rate $r = 0$, unlikely in the real world, FCR will be ICC divided by the economic lifetime of the wind farm in years, currently estimated at 20 years.

Figure 2. Scroby Sands offshore wind farm seen from the beach (see http://en.wikipedia.org/wiki/Scroby_Sands_wind_farm, attribute to Anke Hueper, Germany)

It is essential to clarify the definition of availability. Since 2007, an IEC working group has been working to produce a standard to define availability. Until that standard is published, there is no internationally agreed definition of availability (Harman *et al.*, 2008). However, two availability definitions have been generally adopted in the reports (DTI and BERR, 2004–2007) and are summarised below.

(*a*) Technical availability, also known as system availability (Harman *et al.*, 2008), is the percentage of time that an individual wind turbine/wind farm is available to generate electricity expressed as a percentage of the theoretical maximum.
(*b*) Commercial availability, also known as turbine availability (Harman *et al.*, 2008), is the focus of commercial contracts between wind farm owners and wind turbine manufacturers

to assess the operational performance of a wind farm project. Some commercial contracts may exclude downtime for agreed items, such as requested stops, scheduled repair time, grid faults and severe weather, when wind turbines cannot operate normally.

For the rest of the paper, the term 'availability' refers to the technical or system availability, as defined above. It lends itself to comparison from project to project (Harman *et al.,* 2008). From above definitions, it follows that technical or system availability will be always lower than the turbine or commercial availability because there is more alleviation of downtime for the latter.

Capacity factor and specific energy yield are two commonly used terms describing the productivity of a wind turbine or wind farm. Capacity factor is defined as the percentage of the actual annual energy production E (kWh) over the rated annual energy production from a wind turbine or wind farm (Hau, 2006, p. 530)

$$\text{Capacity factor} = \frac{E}{\text{rated power} \times 8760} \times 100\% \tag{3}$$

Specific energy yield (kWh/m/year) is defined as the annual energy production of a wind turbine normalised to the swept rotor area (m^2) of the turbine

$$\text{Specific energy yield} = \frac{E}{\text{swept rotor area}} \tag{4}$$

The ratio of rated power over swept rotor area is a fixed value for a type of wind turbine

$$\text{Ratio}_{\text{rs}} = \frac{\text{rated power}}{\text{swept rotor area}} \tag{5}$$

or

$$\text{Ratio}_{\text{rs}} = \frac{\text{specific energy yield}}{\text{capacity factor} \times 8760} \tag{6}$$

For a specific type of wind turbine, the specific energy yield is proportional to the capacity factor

$$\text{Specific energy yield} = \text{ratio}_{\text{rs}} \times \text{capacity factor} \times 8760 \tag{7}$$

Therefore, the operational performance factor of a wind turbine or wind farm can be defined as the percentage of the achieved capacity factor (or specific energy yield) over the expected capacity factor (or expected specific energy yield)

$$\text{Performance factor} = \frac{\text{achieved capacity factor}}{\text{expected capacity factor}} \tag{8}$$

or

$$\text{Performance factor} = \frac{\text{achieved specific energy yield}}{\text{expected specific energy yield}} \tag{9}$$

3. BACKGROUND

Quantitative reliability studies of onshore wind turbine operation have been carried out recently (Harman *et al.,* 2008; Spinato *et al.,* 2009; Tavner *et al.,* 2006). The objectives of these studies were to extract information from existing commercial or public databases to understand wind turbine reliability from a statistical point of view and provide a benchmark for future analysis.

Harman *et al.* (2008) shed light on the availability by considering a commercial database representing turbines of 14 000 MW operating in onshore wind farms, approximately 15% of the total worldwide installed capacity. The work focused on the annual availability risks of wind farms. The results showed that the mean average annual availability of onshore wind farms over their economic lifetime, that is 20 years, was approximately 97%. The probability of a wind farm annual availability being less than 80% is low at 1%. The availability rises from 93% in the first quarter of first year operation to over 96% after the end of the second year. The availability, studied from the 10 min average SCADA data, remains relatively constant for wind speeds between 7 and 14 m/s and it is in this range that the majority of energy is delivered. However, the availability reduces at wind speeds above 14 m/s and at low wind speeds below 7 m/s. At high winds above 14 m/s, high load faults may be more common causing a reduction in availability; while at low winds below 7 m/s, downtime may be associated with non-urgent maintenance activities which have been scheduled for periods of low wind.

Commercial databases are not open to public scrutiny for confidentiality reasons. Tavner *et al.* (2006) published a comprehensive study of wind turbine reliability based on publicly available Windstats data investigated over 10 years of modern wind turbine operation, paying particular attention to 904 Danish and 4285 German turbines, representing about 15 000 MW and 46 500 turbine-years in total. The investigation focused on reliability because that depends intrinsically upon the turbine itself and should therefore be predictable. The study analysed in detail how turbine design, configuration, time and weather affected reliability. This research was later extended (Spinato *et al.,* 2009) to a study of the reliability of wind turbine subassemblies, which paid particular attention to 1740 turbines in Germany representing about 1500 MW and 21 200 turbine-years.

Operational data in the public domain from relatively new offshore projects are rare compared to data collected from onshore projects developed from the 1980s to date. The operational reports published under the 'Offshore wind capital grants scheme' (DTI and BERR, 2004–2007) have provided an opportunity to learn about offshore wind turbine experience through quantitative study and comparison with the accumulated onshore data. Table 2 shows the population information, including the relative size and significance of the data in this paper in relation to the studies already completed.

4. SITES AND OPERATIONAL ISSUES

Four offshore wind farms have reported under the Government's 'Offshore wind capital grants scheme'

(*a*) Barrow (July 2006–June 2007)
(*b*) North Hoyle (July 2004–June 2007)

	Turbine	MW	Turbine years	Onshore/offshore
Harman *et al.* (2008)	Not available	~14 000	Not available	Onshore
Tavner *et al.* (2006)	~5000	~15 000	~46 500	Onshore
Spinato *et al.* (2009)	~1740	~1 500	~21 200	Onshore
This paper	120	300	270	Offshore

Table 2. The population information of wind turbine reliability studies

(*c*) Scroby Sands (January 2005–December 2007)
(*d*) Kentish Flats (January 2006–December 2007).

These reports represent data from turbines of 300 MW and 270 turbine-years. 0 shows the monthly data from these wind farms, including availability, capacity factor and wind speed to provide an overall impression of performance. 0 shows that the mean wind speed conditions at the four sites are similar and that the capacity factors and availabilities of the wind farms, particularly during the winters of 2004/5 and 2006/7, were also similar during relatively windy conditions (Figure 3).

The following sections record the operational issues experienced at each of these four sites concerning unplanned work affecting availability. The reader can consider that most of these issues represent teething problems during early operation and have a bearing on the results in Section 5.

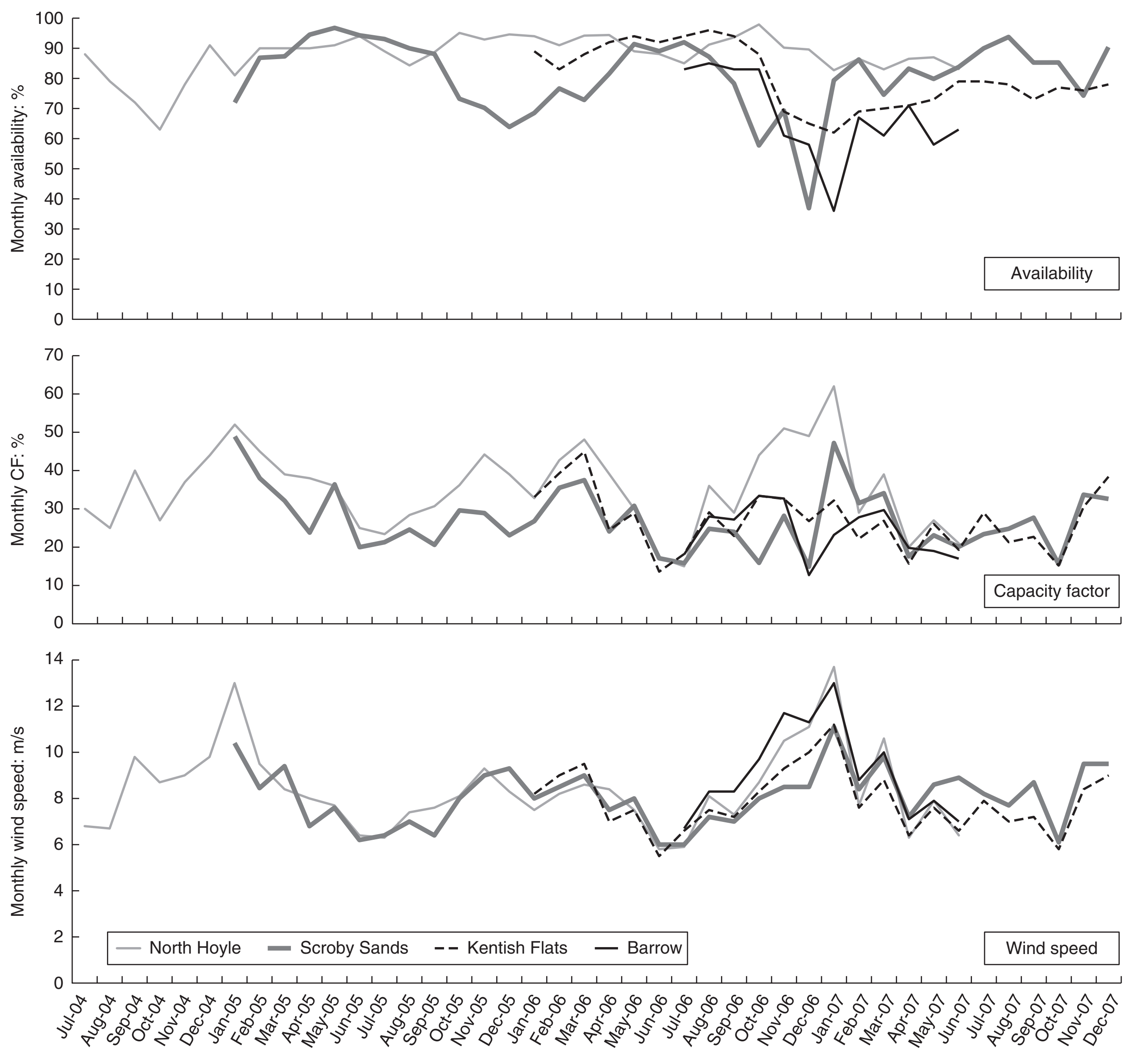

Figure 3. Monthly data of UK offshore wind farm (July 2004–December 2007)

4.1. Scroby Sands

In 2005 there was substantial unplanned work attributed to minor commissioning issues, corrected by remote turbine resets, local turbine resets or minor maintenance work, mostly resolved within a day. A smaller number of unplanned works involved larger-scale plant problems with more serious implications, the primary cause being gearbox bearings.

In 2005 27 generator side intermediate speed shaft bearings and 12 high-speed shaft bearings were replaced. A number of reasons for the gearbox bearing damage were identified related to the bearing designs.

In 2005 four generators were replaced with generators of alternative design.

In 2006 unplanned work involved three outboard intermediate speed shaft gearbox bearings, nine high-speed shaft gearbox bearings and eight generator failures. Generating capacity was also significantly reduced for two months when one of the three transition joints in the cable to the beach failed.

In 2007 problems experienced with the generators were resolved by replacing all original generators with a generator of proven design. The gearbox bearing issue was managed in the short term by proactive replacement of the outboard intermediate speed bearings, in addition 12 high-speed shaft bearings were identified as worn during routine internal inspections and proactively replaced before failure. Three gearboxes were also identified as requiring replacement. Capacity was also affected by a transition joint failure in another cable to the beach, commissioning tests also identified a fault in the sub-sea portion of the cable, for which replacement was planned for spring 2008.

4.2. North Hoyle

In 2004–5 unplanned work involved a high voltage cable fault, generator faults associated with cable connections and SCADA electrical faults.

In 2006 the following issues arose

(*a*) two generator bearing faults
(*b*) six gearbox faults
(*c*) an unplanned grid outage
(*d*) preparation and return of turbines to service further extended down time
(*e*) downtime owing to routine maintenance and difficulties in the means of access to the turbines.

In 2007 the following issues arose

(*a*) four gearbox bearing faults and chipped teeth resulting in gearbox replacements delayed by the lack of a suitable maintenance vessel
(*b*) two generator rotor cable faults
(*c*) two circuit breaker failures
(*d*) one cracked hub strut
(*e*) one turbine outage for yaw motor failures
(*f*) an unplanned grid outage
(*g*) again downtime owing to difficulties in the means of access.

4.3. Kentish Flats

In 2006 there was substantial initial unplanned work attributed to minor commissioning issues corrected by remote turbine resets, local turbine resets or minor maintenance work. Other unplanned work involved larger-scale plant problems included

(*a*) main gearbox
(*b*) generator bearings
(*c*) generator rotor cable connections from the slipring unit
(*d*) pitch system.

The generator bearing and rotor cable problems were prolonged as the generator sub-supplier undertook the repairs to avoid jeopardising the warranty.

The first main gearbox damage was detected in late 2006 and an intensive endoscope campaign revealed that 12 gearboxes required exchange. In 2007 all 30 gearboxes were exchanged owing to incipient bearing failures in the planetary gear. The exchange programme was scattered over the year, and due to waiting time and the lack of a crane ship, the outages were longer than the repair time. About half of the generators were refurbished owing to

(*a*) damage on internal generator rotor cable connections
(*b*) shaft tolerances
(*c*) grounding of bearings to avoid current passage.

Other unplanned tasks included

(*a*) pitch system repair
(*b*) blade repair on one turbine due to crane impact during gearbox exchange.

4.4 Barrow

In 2006–2007 unplanned work on the turbines was substantial although some issues were minor, solved by a local reset or minor work to the turbine. Other larger issues were

(*a*) generator bearings failed and replaced with a new type
(*b*) generator rotor cables replaced with a new type
(*c*) pitch systems modified.

Owing to gearbox problems seen on other turbines of the same type an inspection process commenced in 2007 showing a few gearboxes beginning to show similar problems. It was decided proactively to replace gearboxes before failure and this started in July 2007 completing in October 2007.

5. RESULTS

5.1. Capacity factor and availability

Table 3 shows the average operational performance of the four offshore wind farms for 2004–7. The figures are calculated using the data published in the reports and the annual averages are weighted taking account of the number of reporting year for each wind farm.

The comparison that can be made between the four offshore wind farms and for the period reported is as follows

(*a*) Barrow has a low availability of 67·4%, low capacity factor of 24·1% with higher average wind speed, much of which may be attributable to the generator, gearbox and pitch system issues recoded above bearing in mind that only one year's performance has been reported.
(*b*) Scroby Sands and Kentish Flats are similar with availabilities of ~80%, capacity factors of ~27% and annual average wind speeds of ~8 m/s.

	Turbine type	Annual average wind speed: m/s	Specific energy yield: kWh/m/year	Capacity factor: %	Performance factor: %	Availability: %
Barrow	V90	9·15	996	24·1	68·9	67·4
North Hoyle	V80	8·36	1220	35·0	100·0	87·7
Scroby Sands	V80	8·08	943	27·1	77·4	81·0
Kentish Flats	V90	7.88	1146	27·7	79·1	80·4
Annual average				29·5		80·2

Table 3. The operational performance of four UK round 1 offshore wind farms

(c) North Hoyle has the highest availability of 87·7% and capacity factor of 35% despite the operational experiences recorded above.

The annual average availability for UK round 1 offshore wind farm for the reported period is low at only 80·2%, lower than the availability reported by Harman *et al.* (2008) achieved by onshore wind farms at 97% and lower than a typical EU established offshore wind farm, Middelgrunden, calculated at 93·3% based on data provided by Larsen *et al.* (2005). However, these data from UK round 1 wind farms were collected during periods of early operation.

The annual average capacity factor for reporting UK round 1 offshore wind farms is 29·5%, higher than the average value of 27·3% reported in 2007 for UK onshore wind farms (DECC, 2009b) but lower than the expected 35·0% estimated from EU offshore wind farms. The latter being based on Horns Rev, Denmark 33%, Nysted, Denmark 40% (IEA, 2005), Samsø, Denmark 38% (see http://www.samsohavvind.dk/windfarm/), Egmond aan Zee, Netherlands 35% (Noordzee Wind, 2008) and Middelgrunden, Denmark 27% (Svenson and Larsen, 2008) as summarised in 0 (Figure 4).

The ratio of rated power over swept rotor area $Ratio_{rs}$ is 398 W/m for a V80 turbine and 472 W/m for a V90 turbine. From Equation 7, the expected specific energy yields for these two types of turbine are quite different, even though the capacity factors expected from them, based on European experience, should be the same at 35%. The expected specific energy yield for a V80 is calculated to be 1220 kWh/m/year and for a V90 turbine 1446 kWh/m/year. For the wind farms with the same type of turbine, the specific energy yield varies with the availability as shown in Table 3. For example, the specific energy yield of North Hoyle is greater than that of Scroby Sands owing to higher capacity factor and availability.

To compare wind farms with different types of turbine, the performance factor defined in Equations 8 and 9 is suggested. Although the absolute value of the specific energy yield of Scroby Sands (943 kWh/m/year) is much lower than that of Kentish Flats (1146 kWh/m/year), the performance factor of Scroby Sands is at 77·4% which is very close to that of Kentish Flats at 79·1%. The performance factors for North Hoyle and Barrow are 100% and 68·9% respectively.

5.2. Cost of energy

Table 4 shows the COE, capital cost, O&M cost, percentage of O&M cost over COE of the four UK round 1 reporting offshore wind farms. The figures are calculated using the data published in the reports at a discount rate 10%. In the absence of other information the discount rate adopted throughout the paper will be 10%, close to the FCR of 11·85% used by US NREL in some studies (see http://www.nrel.gov/wind/coe.html). The COE average and O&M cost average are weighted taking account of the number of reporting year for each wind farm.

The discount rate has a big impact on the COE estimation. Analysis of the sensitivity of offshore wind COE to the discount

	COE: £/MWh	Capital cost: £/kW	O&M cost: £/kWh	O&M cost/COE: %
Barrow	86	1367	10	12
North Hoyle	67	1350	15	22
Scroby Sands	67	1113	11	16
Kentish Flats	67	1167	11	16
Average	69	1249	12	18

Table 4. The economics of four UK round 1 offshore wind farms (calculated at a discount rate 10%)

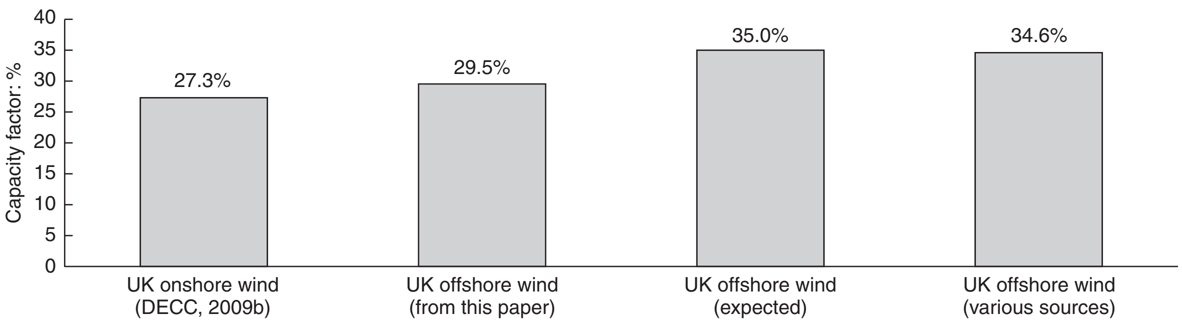

Figure 4. The capacity factors of UK and EU offshore wind farms

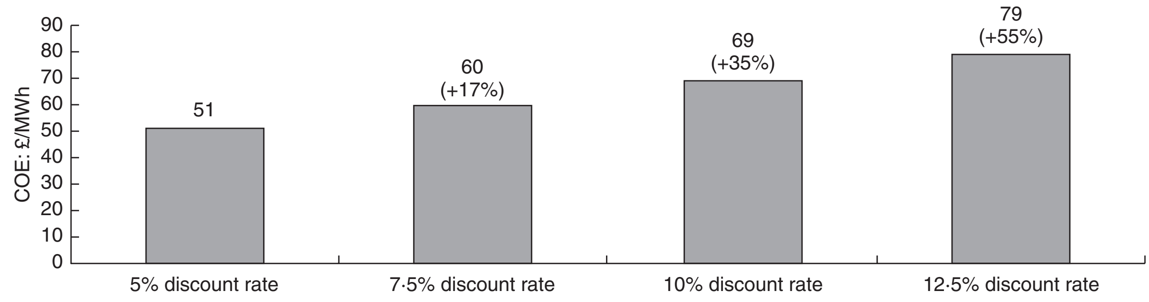

Figure 5. The sensitivity analysis of the COE of UK round 1 offshore wind farms

rate risk is shown in Figure 5. When the discount rate increases by 1%, the COE increases by ~£3·60 per MWh, or ~7%.

To provide a benchmark comparison of wind turbine COE performance we estimate the COE for coal- and gas-fired plants with carbon capture storage systems (CCS) by adopting the median values reported by DTI in 2006 (DTI, 2006), where approximately the COE for coal with CCS was £45 per MWh and for gas with CCS was £56 per MWh, in which the assumption of discount rate at 10%, median prices for coal of £25/t, for gas of 37p/therm and for carbon dioxide €36/t were made.

Note that DECC and BERR regularly update their fuel and carbon dioxide price assumptions. In May 2009, the latest communication, the assumed price in 2015 for coal was £48/t, with a GB pound £: US dollar $ exchange rate of 1 : 1.65 in 2009, and for gas 63p/therm, predicted for moderate global energy demand (DECC, 2009c). These price assumptions are almost the double those cited by DTI in 2006.

Therefore, the COE estimations adopted here for fossil-fired plant are likely increase dramatically in the future. The latest price assumption for carbon dioxide made by BERR on April 2009 was €34/t, close to the figure cited by DTI in 2006.

Krohn *et al.* (2009) has suggested a risk-based model for comparing power generating cost of different technologies by taking into account the fuel and carbon price risk. Fuel and carbon prices are highly unpredictable and have added extra risk cost to the basic estimation of the COE for coal and gas. Whereas for wind power the fuel is free and is classified in cost estimation as a low-risk fuel. Based on the estimation made for the EU, the historic fuel price has been assumed, a 'no-cost 40 year fuel purchase' contract and a proportional fuel risk cost added to the basic COE estimation of coal-fired or gas-fired plant for UK.

For the COE of coal with CCS, the historic fuel risk and 'no-cost 40 year fuel purchase' will each increase the basic estimation by 108% and 65% respectively. For the COE of gas with CCS, the historic fuel risk and no-cost contract will each increase the basic estimation by 85% and 65%, respectively.

A comparison between the COE of the two fossil fuel options above, the current COE for onshore wind farms given by E.ON at mean £47 per MWh in the report to House of Commons (2006) and the average COE results from the four reporting UK offshore wind farms are shown in Figure 6 together with their sensitivity to the fuel risk. The figure shows the strategic economic advantage for onshore and offshore wind energy, in that the COE remains unchanged because the technology carries no fuel price risk.

A comparison is made in Figure 7 between the COE of the reporting UK offshore wind farms and EU wind farms based on the discount rate at 10%. The average COE for several Danish offshore wind farms (Krohn *et al.*, 2009, p. 67); that is, Middelgrunden, Horns Rev I, Samsø and Nysted is calculated at £104 per MWh with discount rate 10% using a GB pound £: Euro € exchange rate of 1 : 1·5 for year 2006. The COE of EU onshore is £80 per MWh for a coastal site at discount rate 10% (Krohn *et al.*, 2009, p. 60). As shown in Figure 7, the COE of UK or EU offshore wind farm is generally higher than that of onshore wind farm by £22–24 per MWh.

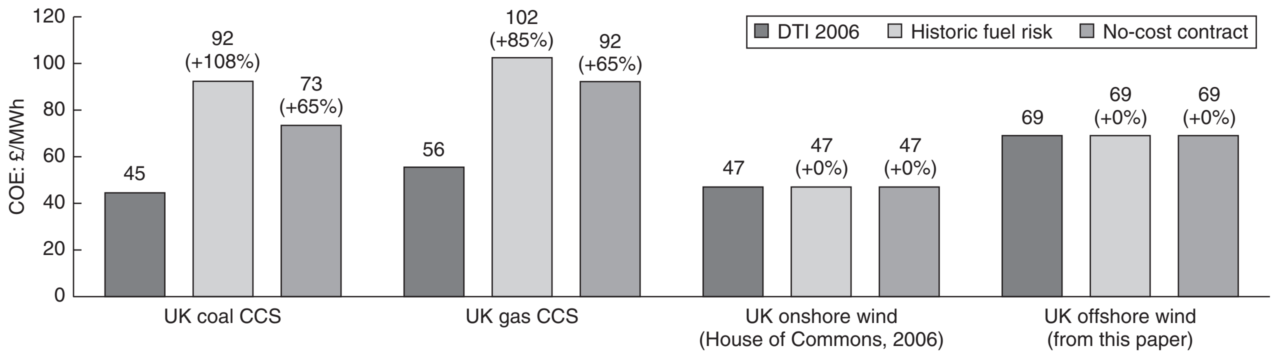

Figure 6. COE for four electricity generation technologies

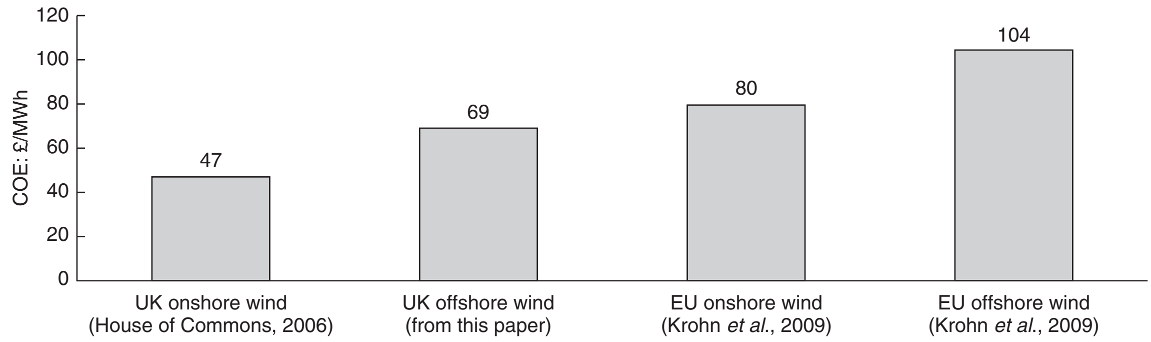

Figure 7. The COE of UK and EU wind generated power

5.3. O&M costs

Table 4 showed the average O&M cost as a percentage of COE for an offshore wind farm in UK. The average O&M cost of UK round 1 offshore wind farms is calculated from this paper to be £12 per MWh. For the UK offshore wind farms, annual operation and maintenance cost includes land rental, electricity charges, site maintenance and service fees, insurance, management fees and miscellaneous charges (Greig, 2004). A comparison of the percentage of O&M and fuel costs in the COE is given in Figure 8.

The cost percentages related to UK coal and gas, onshore wind technologies are estimated based on the data published by PB Power in 2006. Offshore wind power is a capital-intensive technology but the fuel is free. The variable costs of wind farm are much lower than that of the conventional fossil fuel-fired technologies in which as much as 37–73% of the COE are related to the fuel and O&M costs. The percentage O&M cost of UK offshore wind farms, at 18%, is higher than that of UK onshore wind, at 12%, but is not as high as the premium for offshore wind O&M costs which is suggested by some early models, accounting the percentage O&M cost as 25–30% or the two to three times of onshore O&M costs (Marsh, 2007). A reason for this disparity may be that some EU authors have included the revenue losses owing to maintenance downtime. However, this would double-count revenue losses which, when the calculation is per MWh, should have already been factored into the annual energy production E. It should be noted that the optimisation of offshore O&M strategies aims at minimising both the O&M and revenue loss costs. Occasionally, some authors might have quoted the COE values rather than O&M costs. The COE of offshore EU offshore wind farm is 2·2 times of that of the UK onshore costs, as shown in 0.

The components of O&M costs in Europe, which are similar to those in UK, also do not include the revenue losses (Krohn *et al.*, 2009). The O&M cost of Middelgrunden offshore wind farm, established in 2000, was reported as approximately €16 per MWh (Svenson *et al.*, 2008). The O&M cost percentage of Middelgrunden at 24% is higher than for the reporting UK offshore wind farms at 18%, but this contained an unexpected transformer-related cost. If the transformer-related cost was excluded, the O&M percentage of COE for Middelgrunden would be 18%, the same as the UK offshore.

5.4. Interaction between capital and O&M costs, capacity factor, availability

Table 4 shows the capital costs at North Hoyle and Barrow were higher, owing to increased construction costs associated with further distance offshore and deeper water. The capital cost of Barrow was the highest while the O&M cost was the lowest. The capital and O&M costs of North Hoyle were both high. The capital and O&M costs of Scroby Sand and Kentish Flats were both lower than North Hoyle.

The data from Tables 2 and 3 show when the O&M cost was higher the availability and capacity factor were higher. When the capital cost was high, the wind farm itself must work harder to achieve a low COE for an acceptable payback time. The only way that a wind farm can improve its capacity factor is through the higher availability since there is little control over wind speeds. The outcomes of this effort are shown in North Hoyle

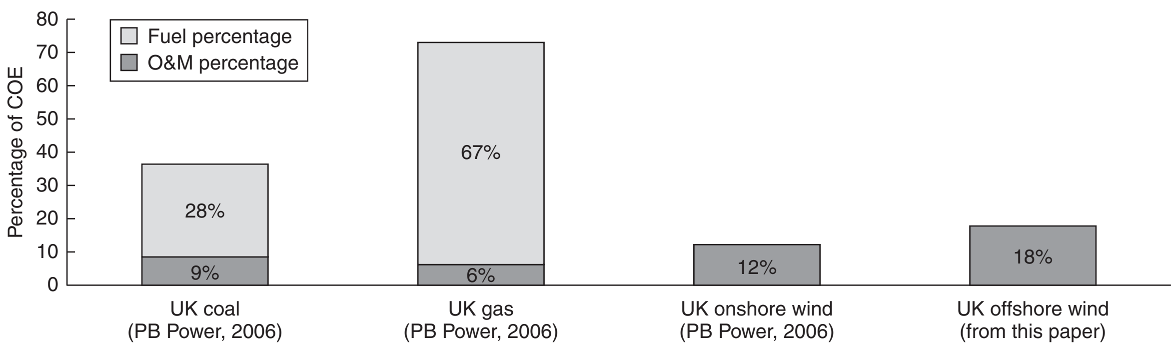

Figure 8. The O&M and fuel cost percentage in COE for four electricity generation technologies

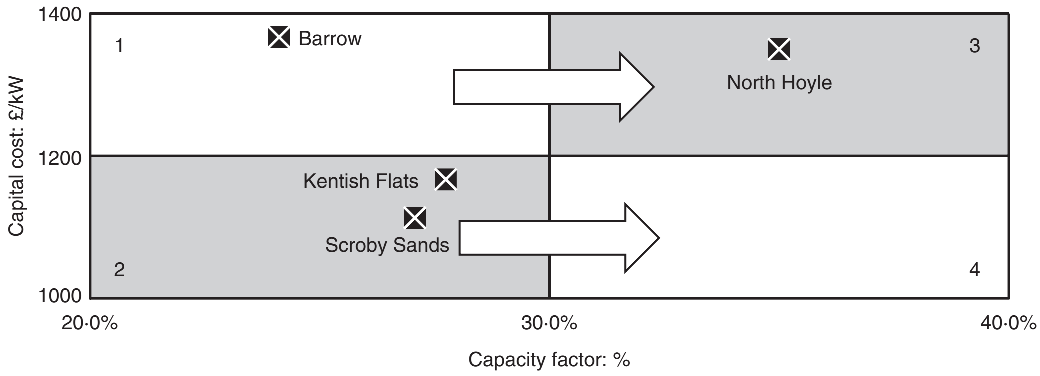

Figure 9. Improving the capacity factor can help the offshore wind farms to reduce COE

where the availability and capacity factor have been improved to 87·7% and 35·0%, respectively. Therefore, despite a relative high capital cost at North Hoyle, the COE has been kept down to approximately £67/MWh, the same level as Scroby Sands and Kentish Flats.

Figure 9 shows the relative position of capital cost and capacity factor for the different UK round 1 offshore wind farms. Barrow locates in region 1 which represents its high capital cost and low capacity factor and is attributable to the operational issues identified above. This is reflected in its high COE at approximately £86/MWh. Kentish Flats and Scroby Sands locate in region 2 which represents their lower capital cost and capacity factor. They both have great potential to reduce their COE by improving their capacity factor. North Hoyle locates in region 3 which represents high capital cost and capacity factor.

All three wind farms have COE at approximately £67/MWh. Region 4 would be the best option for economic performance, representing a low capital cost and a high capacity factor. Kentish Flats and Scroby Sands have the opportunity to enter region 4, while Barrow could enter region 3.

Figure 10 shows the monthly capacity factor against availability for four wind farms. Note that the bottom-left light-grey region shows a 'bad region' where monthly capacity factors are lower than 35% and availability is less than 70% regardless of wind speed. For availability more than 70%, the capacity factors achieved ranges from 10% up to 65%. This is attributed to wind speed influencing the capacity factor. The upper-right region shows a 'good region' of monthly performance in which availability is greater than 80% and capacity factors are greater than 20%.

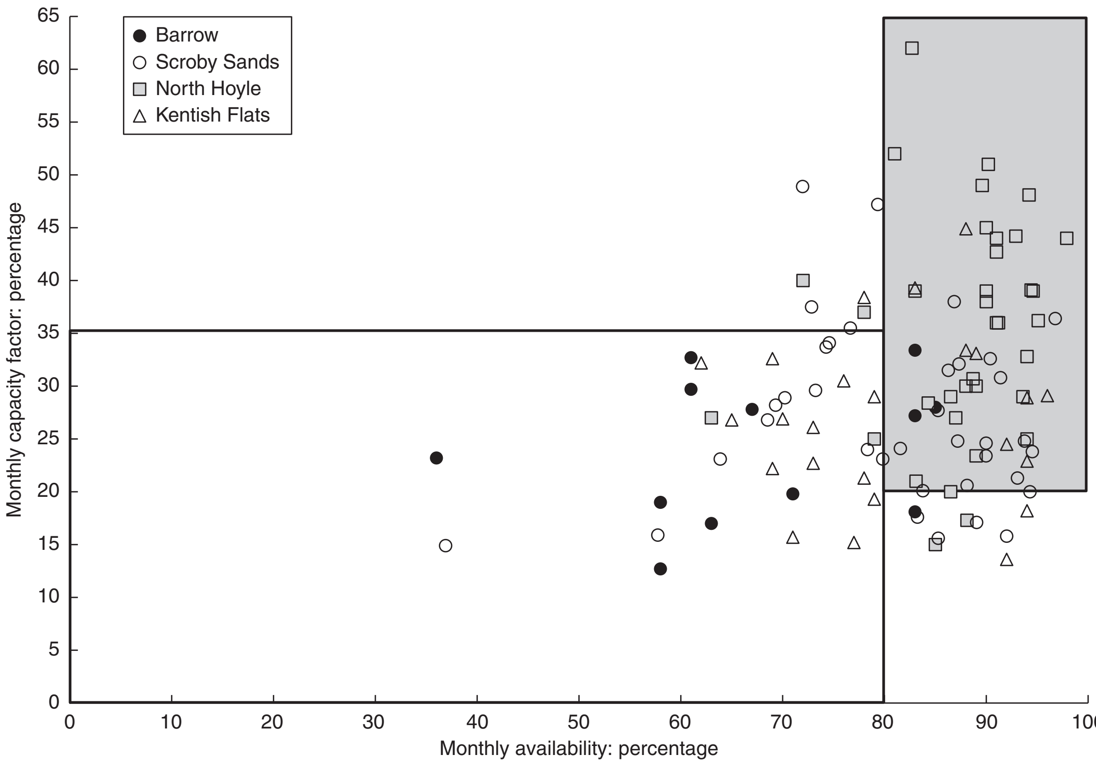

Figure 10. Monthly capacity factor against availability for the offshore wind farms, each point representing 1 month's operational data

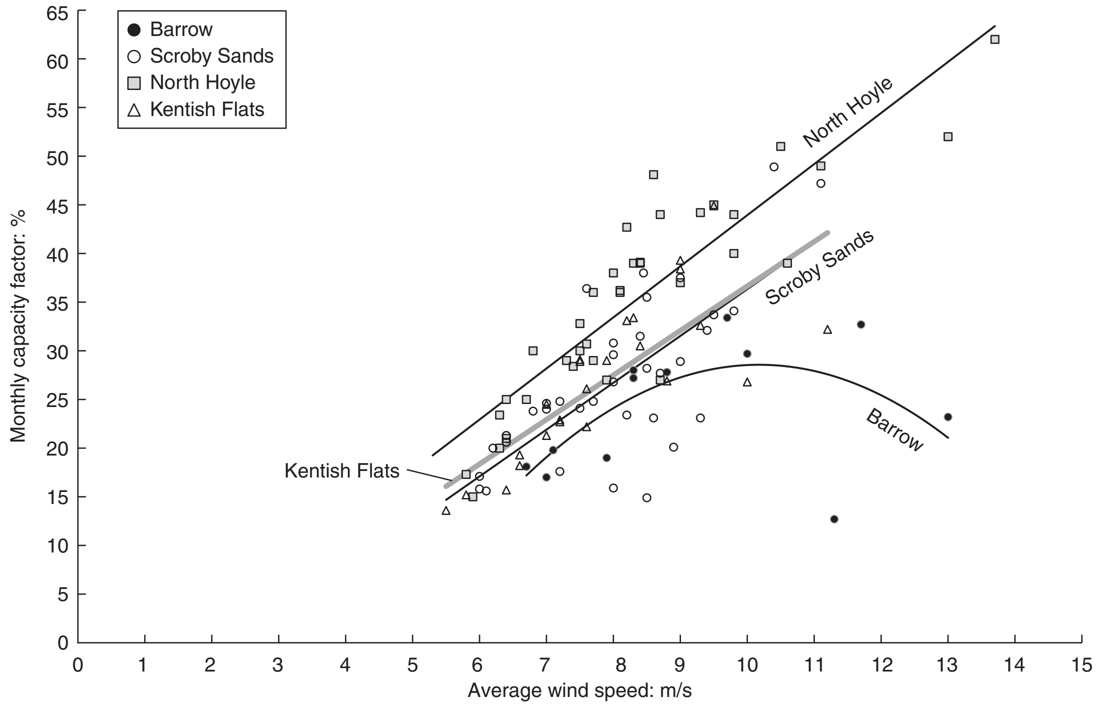

Figure 11. Monthly capacity factor against wind speed for the offshore wind farms Q13

5.5. Influence of wind speed on performance

It has been shown in Section 4.4 that capacity factor and capital cost are the driving factors for the economic performance of UK offshore wind farms. Despite a mean annual wind speed over 9·15 m/s at Barrow, the wind farm's economic performance has not been as strong as might be expected. Possibly this has been the result of the pitch systems issues raised above and the data here records only the first year of operation.

Figure 11 shows that higher average wind speed usually brings a higher monthly capacity factor, except at Barrow which follows a non-linear trend. Wind speed does not affect the performance at Barrow positively, instead the capacity factor goes down as wind speed rises. For the same wind speed, the capacity factor of North Hoyle can usually reach a higher value than at other wind farms.

Figure 12 to Figure 15 show the availability against wind speed on a monthly basis for the four wind farms, in which the larger circles represent higher capacity factors and vice versa. It can be seen that high capacity factors are all gathered around wind speeds 7–14 m/s, in line with the result of capacity factor shown in Figure 11. The monthly wind speed range 7–14 m/s deliver the majority of energy for UK round 1 offshore wind farms. For example, the highest monthly capacity factor achieved at North Hoyle in January 2007 was 62%, with a mean wind speed of 13·7 m/s and an availability of 82·7%.

The availabilities of UK round 1 offshore wind farms tend to decrease with increasing wind speed. These are illustrated by Figures 12–15, although some of the early problems reported above may be a cause, however, this trend confirms that reported in much larger survey (Harman *et al.*, 2008). The trend

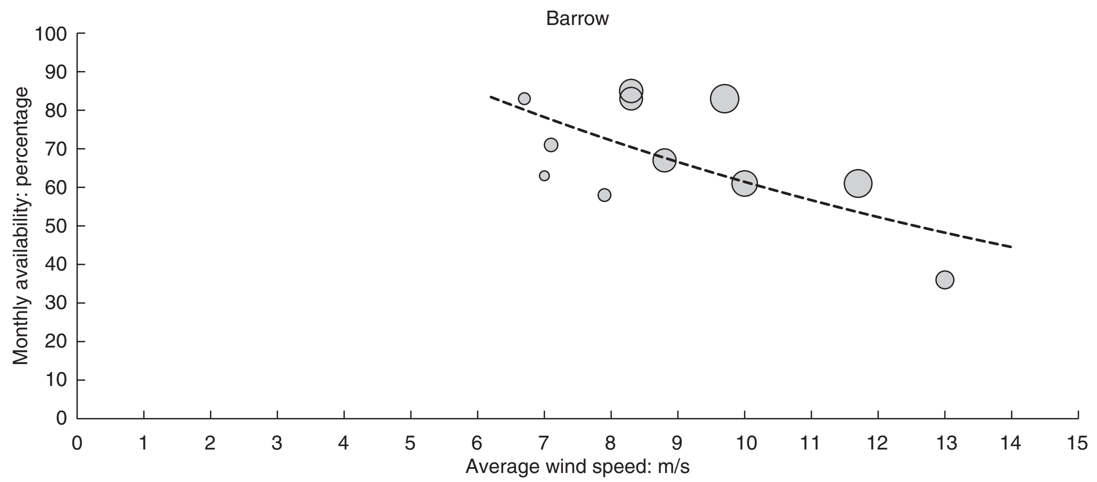

Figure 12. Monthly availability against wind speed for Barrow offshore wind farm

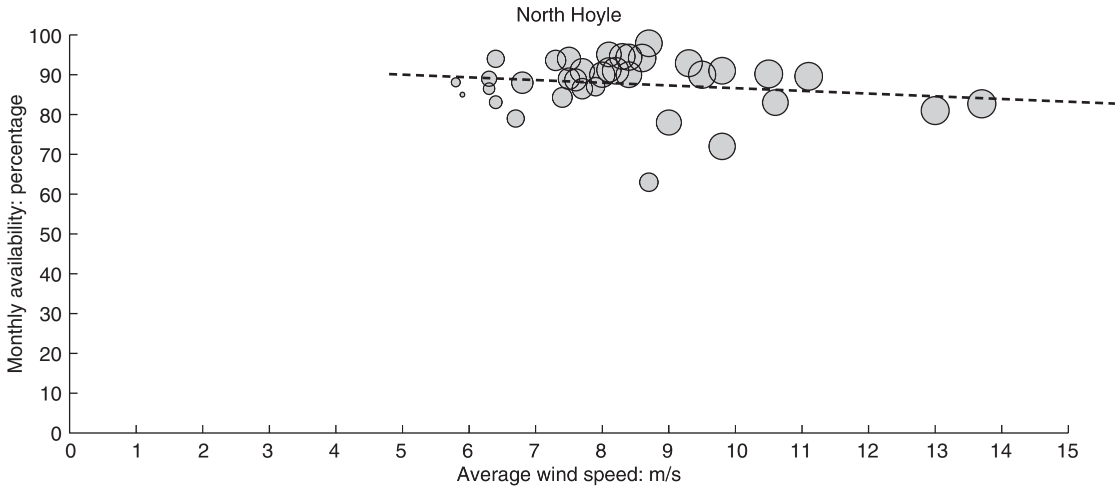

Figure 13. Monthly availability against wind speed for North Hoyle offshore wind farm

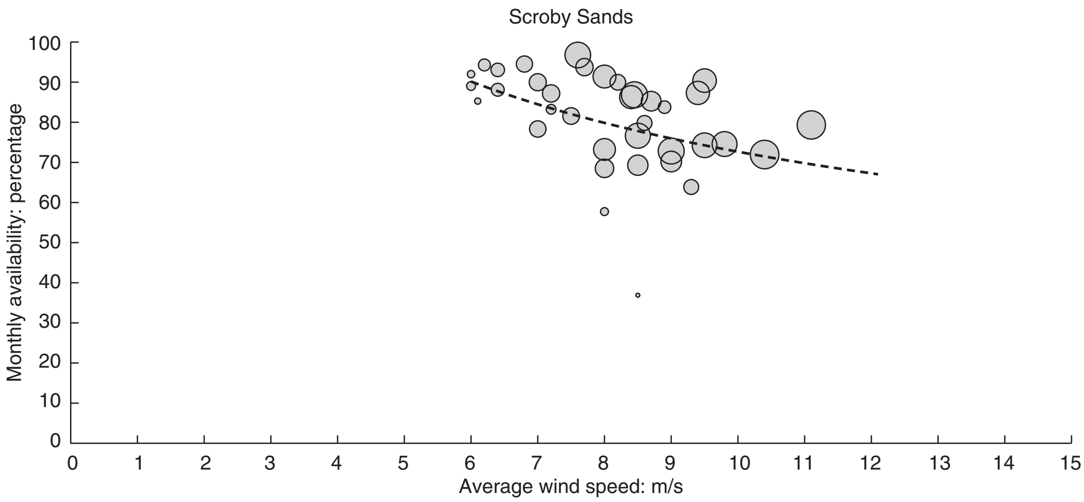

Figure 14. Monthly availability against wind speed for Scroby Sands offshore wind farm

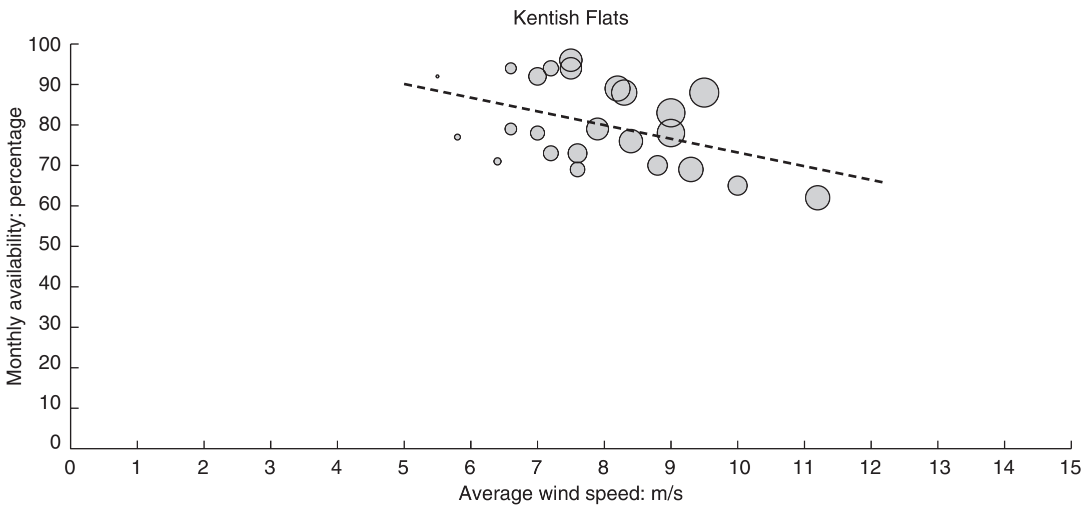

Figure 15. Monthly availability against wind speed for Kentish Flats offshore wind farm

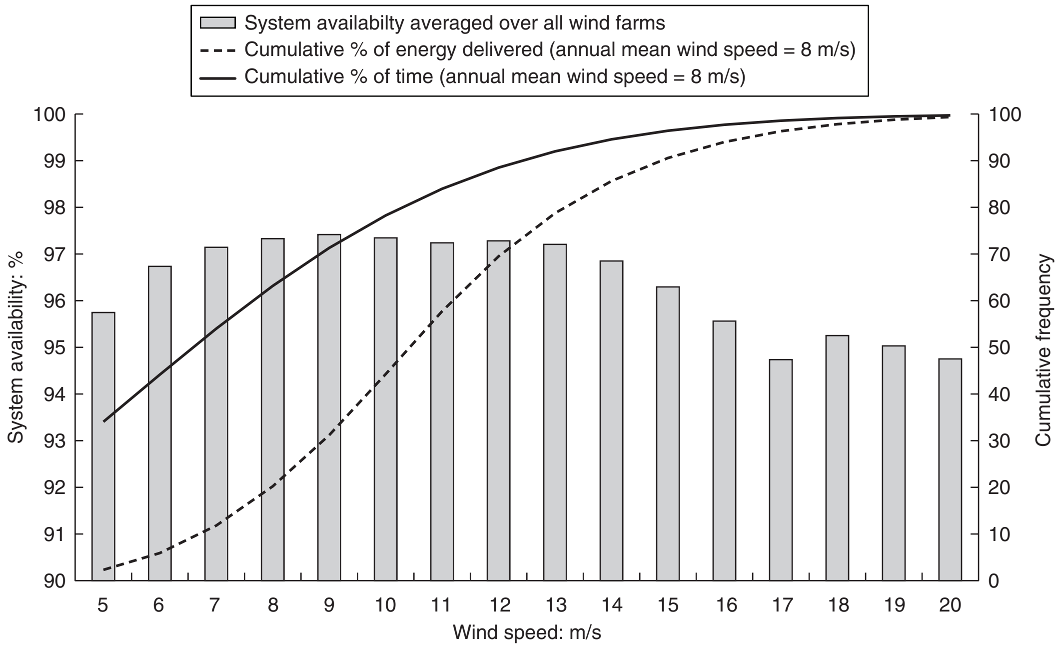

Figure 16. Worldwide onshore availability against wind speed (Harman *et al.* 2008, courtesy of the original authors for assistance to reproduce the figure)

line of Barrow is the steepest, while North Hoyle is the flattest. The trend lines of Scroby Sands and Kentish Flats are similar but steeper than North Hoyle. The gradient of the availability trend line is apparently correlated with the capacity factor trend line shown in Figure 11. In other words, the smaller the gradient of the availability trend line against wind speeds, the better the operational performance of offshore wind farms. The decreasing trends as shown above are much more severe than those can be estimated from worldwide onshore wind farms, as shown in Figure 16 (Harman *et al.*, 2008). The 10-min average SCADA data show the onshore availabilities vary only from 94·5% to 97·5%, although they also tend to decrease at high wind speeds.

6. DISCUSSION

Two government reports (House of Commons, 2006; DTI, 2006) estimated that the COE for UK offshore wind generation would be £55–90/MWh (at discount rate 10%) and £55–84/MWh respectively. Based on published reports from the 'Offshore wind capital grants scheme' during the period 2004–7, the economic performance of round 1 offshore wind farms with a COE of £69/MWh at discount rate 10% lies within those expectations, despite the early operational difficulties reported above.

The annual average capacity factor of round 1 offshore wind farms to date has been 29·5% and the annual average availability 80·2%. Onshore experience confirms that availability can improve after teething problems have been resolved in the first few years' operation (Harman *et al.*, 2008). Can offshore availability also be improved with time? The answer must be yes but the data period for 'Offshore wind capital grants scheme' reports was limited to 3 years in the early part of operation, so future data will need to be studied to find a definitive answer.

Although annual average availabilities were low the wind farms still achieved an average capacity factor of 29·5%, greater than onshore UK wind farms with an average availability of 97%, because onshore wind speeds are lower than offshore. From this point of view, UK offshore wind farms, with higher wind speeds, have the potential to improve their capacity factors as can be seen from Figure 11. On the other hand, rich wind resources pose new challenges for the operation of offshore wind farms. The average availability achieved by these UK offshore wind farms is only at the level of Danish onshore wind turbines in early 1980s. This might be because for the wind farms reported the wind turbines being used were originally designed for onshore rather than offshore use therefore may not have been sufficiently modified to meet the challenging offshore environment.

The results show that despite a good COE the reported UK round 1 offshore wind farms lost substantial annual energy production due to low availability, this is clear in Figure 3. The early economic performance of the reported UK round 1 offshore wind farms depends strongly on the availability. In one case, Barrow, an offshore wind farm with good wind resource did not achieve strong economic performance during the reporting period because of low availability, although there were extenuating operational difficulties which will have caused this.

If project capital costs increase, a strategy that may have to be adopted by some wind farm operators to improve offshore economics, as appears to have been done at North Hoyle, is to encourage more proactive O&M, raising O&M costs but increasing energy yield. This will mitigate high capital costs by improving annual energy production.

The results also show that the availability of reported UK offshore wind farms tend to decrease at monthly wind speeds 7–14 m/s while the majority of energy is delivered in this speed range. For onshore wind farms, the causes of this availability reduction could be severe climate issues causing systematic turbine faults due to excessive loads, which wind sector managers will try to minimise by operational management. For the UK offshore wind farms, the early operational issues are likely the causes of the availability reduction. Therefore, it is important to solve these operational problems and improve availability at wind speeds 7–14 m/s to raise the overall economic performance.

Given poorer accessibility for maintenance offshore, it is essential to improve the intrinsic reliability of offshore wind turbines, needing close collaboration between turbine manufacturers, wind farm operators and research institutes. To this end, future research for wind energy in UK could be

(*a*) to develop a generic methodology for reliability data collection and analysis
(*b*) to establish a reliability benchmark of wind turbine subassemblies
(*c*) to understand the failure modes and failure mechanisms of different wind turbine subassemblies
(*d*) to develop a guideline for wind turbine manufacturers to conduct the reliability centred maintenance (RCM)
(*e*) to develop an advanced health monitoring system for wind turbines
(*f*) to develop cost-effective condition monitoring methods for wind turbine.

7. CONCLUSIONS

(*a*) At an approximate cost of energy (COE) of £69 per MWh during the period 2004–7 the reporting UK round 1 offshore wind farms have an economic performance within the expectations of the government reports prior to these investments, despite the early operational problems at these wind farms.
(*b*) The annual average capacity factor for reporting UK round 1 offshore wind farms during their early period of operation is 29·5%, greater than the current 27·3% average for onshore UK wind farms but less than that achieved by other European established offshore wind farms.
(*c*) The greatest cause of loss of energy for reporting UK round 1 offshore wind farms is low technical or system availability. The annual average technical availability for reporting UK round 1 offshore wind farms is 80·2%, much less than the average availability of 97% achieved by onshore wind farms in UK or the availability at 93·3% achieved by an established EU offshore wind farm, Middelgrunden. It is likely that these low availabilities are a direct result of the early operational issues at these wind farms.
(*d*) The annual average O&M cost as a percentage of COE for reporting UK round 1 offshore wind farms is 18% and the O&M cost is approximately £12 per MWh. This percentage compares well with the value of 12% O&M costs for onshore wind in the UK and this is much less than the premium for O&M costs for offshore wind predicted in the industry.
(*e*) A strategy that could be adopted by wind farm operators to improve offshore economics would be to encourage more proactive O&M, raising O&M costs but increasing energy yield. This will mitigate high capital costs by improving annual energy production.
(*f*) The availability of reporting UK round 1 offshore wind farms tends to decrease with increasing wind speed, though North Hoyle is an exception to this.
(*g*) Improvements in the performance of these and other offshore wind farms should focus on improving the availability at wind speeds 7–14 m/s.
(*h*) UK offshore wind farms have great potential to extract more energy from the wind and achieve lower COEs, but their reliability and availability must be substantially improved. This could be achieved through intensive R&D activities by manufacturers and operators and a plan for such activities has been set out in the paper.

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