Wind Power Reassessed: A review of the UK wind resource for electricity generation

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Summary for policymakers

A number of EU Member States are committed to increasing the generation of electricity from renewable resources as part of their bid to cut back on emissions of carbon dioxide. In the UK, this means a focus primarily on wind, both on- and off-shore. Arguments continue to go back and forth on the desirability and effectiveness of this policy, but the governments in both Westminster and Holyrood remain firmly committed at present.

Wind is, by its nature, intermittent and so the extent to which this affects the output of the fleet of wind turbines in a typical year is crucial in determining how much conventional generating capacity is needed by way of backup and thus what the overall system costs are. This study provides a rigorous quantitative assessment of wind variability and intermittency based on nine years of hourly measurements of wind speed on 22 sites across the country. The analysis is based on a model UK wind fleet of 10 GW nominal capacity.

The model reveals that power output has the following pattern over a year:

- **i** Power exceeds 90 % of available power for only 17 hours
- **ii** Power exceeds 80 % of available power for 163 hours
- **iii** Power is below 20 % of available power for 3,448 hours (20 weeks)
- **iv** Power is below 10 % of available power for 1,519 hours (9 weeks)

Although it is claimed that the wind is always blowing somewhere in the UK, the model reveals this 'guaranteed' output is only sufficient to generate something under 2 % of nominal output. The most common power output of this 10 GW model wind fleet is approximately 800 MW. The probability that the wind fleet will produce full output is vanishingly small.

Long gaps in significant wind production occur in all seasons. Each winter of the study shows prolonged spells of low wind generation which will have to be covered by either significant energy storage (equivalent to building at least 15 plants of the size of Dinorwig) or maintaining fossil plant as reserve.

The preceding deficiencies suggest the model wind fleet would require an equal sized fossil fuel generation fleet operating alongside it, especially during winter months.

The study was extended with another 21 sites located in Ireland and across the northern plain of Europe. Performance of the wind fleet in Ireland is slightly better than in the UK, but the northern European fleet (Belgium, Netherlands, Denmark and Germany) is much poorer. Integrating all these with Ireland and European interconnectors will do little to reduce the intermittency levels described above.

The short-term (30–90 minutes) variability of wind generation is also studied and reveals swings in output far higher than would be expected from conventional generation. Swings of 10 % of output are normal. This observation contradicts the claim that a widespread wind fleet installation will smooth variability.

Electricity grid management entails balancing generation against demand even within timescales as short as 10 S. The UK has an island grid, with few interconnectors to other European grids and none of these interconnectors are AC links capable of providing grid stabilization and inertia. It was for this reason that the CEGB designed and built (capital cost over £1 B) the Dinorwig pumped storage power station. But the model wind fleet reveals wind energy production is unlike that of all conventional fossil fuelled or pumped storage plants; it does not follow grid demand on diurnal or even seasonal time patterns. Wind generation will therefore make heavy claims on the UK's response and reserve market. This study has shown that at certain times half of Dinorwig's units would be needed to mitigate the variability of a 10 GW wind fleet. The entire UK pumped storage capability cannot compensate for the wind power fleet's intermittency.

Summary

This study uses wind data extracted from airfield weather-observation reports to calculate the likely performance of wind fleets across Europe, but concentrating mostly on the UK. Airfield weather reports are in the public domain, use a standard reporting format, are taken at a standard observation height, and in many cases use instrumentation provided and operated by national meteorological offices. The study covers a span of 25 degrees of longitude, and ten of latitude and includes 43 'monitoring' sites over a period of nine years; over 6.5 million wind-speed observations are included. The objective has been to explore the scale of onshore wind fleet output variability, and intermittency, the benefits of European interconnectors, the improvement possible with increased storage, and many other matters.

The following conclusions are demonstrated for a UK wind fleet of 10 GW nameplate capacity:

- **i** Power output changes continuously and commonly by as much as 300 MW over each half-hour period; output changes as high as 700 MW within a half-hour period are not uncommon. This variability can be compensated by fossil fuelled or pumped storage generators operating in response mode, but this will increase grid operating costs, and divert this valuable response capability away from more usual grid stabilisation duties.
- **ii** The model wind fleet reveals many instances of high wind-speed power cutouts;

this phenomenon does not appear to be a problem with the present wind fleet and may only occur with larger, higher hub height machines.

iii Claims that there is always somewhere in the UK where the wind is blowing are correct, but only sufficient to generate 2 % or less of full wind fleet output. The power output mode is approximately 800 MW, 8 % of nameplate capacity. The probability that the wind fleet will produce full output is vanishingly small.

iv The capacity credit for the model wind fleet is shown to be 2,300 MW. The sensitivity of this result to various model parameters is explored.

v Power output for the model wind fleet can be characterised by the following statements:

- Power exceeds 90 % of available power for only 17 hours per annum
- Power exceeds 80 % of available power for 163 hours per annum
- Power is below 20 % of available power for 3,448 hours (20 weeks) per annum
- Power is below 10 % of available power for 1,519 hours (9 weeks) per annum

vi Of the 3,448 hours when the power output of the UK wind fleet is below 20 % of maximum, 2,653 hours (77 %) occur in events when that condition continues for 12 hours or more.

vii Of the 1,519 hours when the wind fleet power output is below 10 % of maximum, 1,178 hours (78 %) occur in events when that condition continues for 6 hours or more. Thus production gaps are commonplace in wind fleet operations. Many of these low power events occur during periods of prolonged, cold weather.

viii Slightly more of these low power events seem to occur in autumn, but are otherwise evenly spread amongst the seasons.

ix If this wind fleet were required to offer a guaranteed production output equal to the capacity credit during winter periods (when wind production is highest), this study shows it would require an energy storage facility holding perhaps 150 GWh, which is the equivalent to that held in 15 'Dinorwigs'.

x Given these observations, the model wind fleet would require a conventional generation fleet of equal nameplate capacity to be built and operated alongside it to mitigate the wind fleet deficiencies.

Data for a model Irish wind fleet, based upon airport weather reports, reveals a wind fleet with slightly higher performance than that for the UK. A model of wind operation across the northern European plain and covering Belgium, Holland, Denmark and Germany shows much poorer performance. Both fleets suffer intermittency and variability problems similar to those of the UK.

Unifying all three fleets by installation of European interconnectors does little or nothing to mitigate the intermittency of these wind fleets. For the combined system, which has an available power output of 48.8 GW:

- Power exceeds 90 % of available power for 4 hours per annum,
- Power exceeds 80 % of available power for 65 hours per annum,
- Power is below 20 % of available power for 4,596 hours (27 weeks) per annum,
- Power is below 10 % of available power for 2,164 hours (13 weeks) per annum.

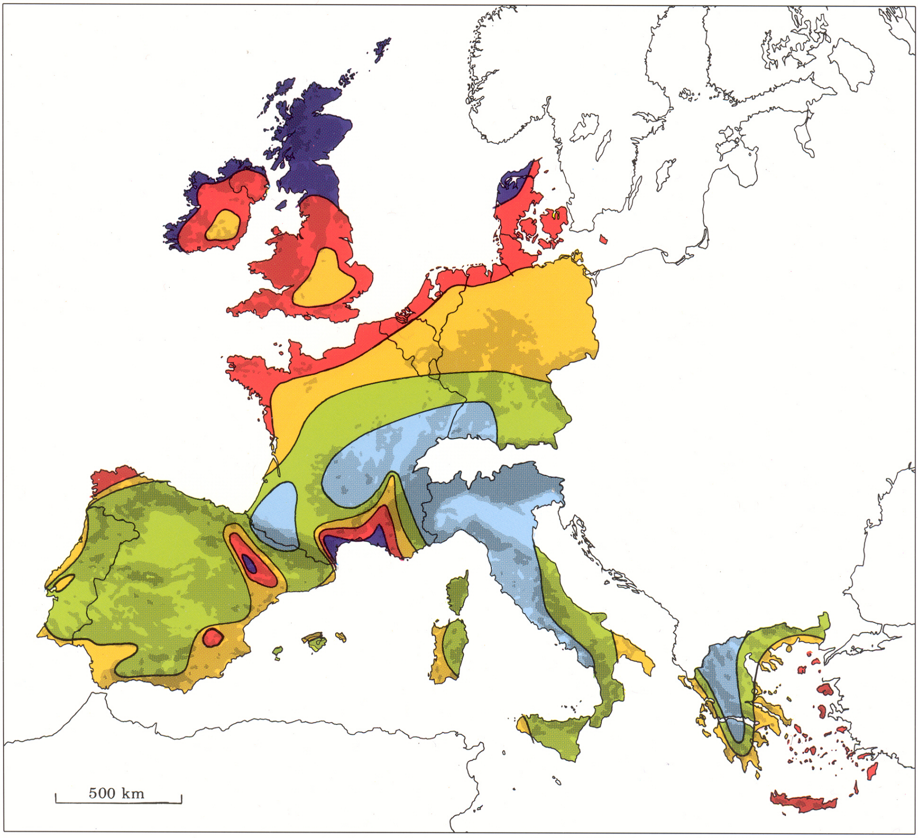
European interconnectors may have other uses for grid management, but they will have little impact upon the mitigation of wind fleet intermittency and variability.

1 Introduction

The UK has the best and most geographically diverse wind resources in Europe, more than enough to meet current renewable energy targets

Sustainable Development Commission

Wind is a free fuel source that can be used for the generation of electricity, and the UK is positioned in one of the windiest regions of Europe (Figure 1).



Wind resources[1] at 50 metres above ground level for five different topographic conditions										
	Sheltered terrain[2]		Open plain[3]		At a sea coast[4]		Open sea[5]		Hills and ridges[6]	
	$m s^{-1}$	Wm^{-2}	$m s^{-1}$	Wm^{-2}	$m s^{-1}$	Wm^{-2}	$m s^{-1}$	Wm^{-2}	$m s^{-1}$	Wm^{-2}
(dark blue)	> 6.0	> 250	> 7.5	> 500	> 8.5	> 700	> 9.0	> 800	> 11.5	> 1800
(red)	5.0-6.0	150-250	6.5-7.5	300-500	7.0-8.5	400-700	8.0-9.0	600-800	10.0-11.5	1200-1800
(yellow)	4.5-5.0	100-150	5.5-6.5	200-300	6.0-7.0	250-400	7.0-8.0	400-600	8.5-10.0	700-1200
(green)	3.5-4.5	50-100	4.5-5.5	100-200	5.0-6.0	150-250	5.5-7.0	200-400	7.0- 8.5	400- 700
(light blue)	< 3.5	< 50	< 4.5	< 100	< 5.0	< 150	< 5.5	< 200	< 7.0	< 400

Figure 1 European Wind-speed map[1], from www.windatlas.dk With kind permission from DTU Wind Energy, formerly Risø National Laboratory

But although the UK has the best wind resource in Europe, that does not necessarily mean that electricity generation using this resource will be either cheap, or free from problems. If we consider the generation characteristics of a range of modern wind turbines (Figure 2) we can see that none of these will average full power generation unless they are positioned on the highest hills and ridges (see rightmost scale of Figure 1 for the blue, red and brown regions of the UK). Since we know that the wind varies constantly, and the typical wind-speeds of Figure 1 fall close to or inside the sharply rising zone of the turbine characteristics of Figure 2, we can expect that electricity energy production from wind to be extremely variable and unpredictable.

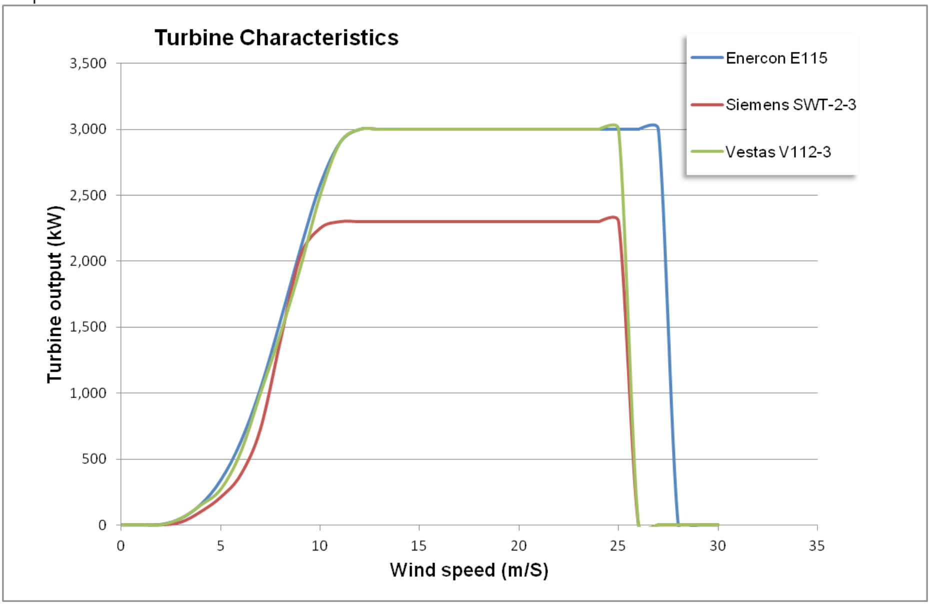


Figure 2 Typical Generation Characteristics for three modern wind turbines with hub heights between 80 and 100 metres[2]

This paper attempts to quantify the reliability, variability, and intermittency using a source of reliable wind data for many locations throughout the UK by modelling large windfarms composed of modern wind turbines at each site. It would be preferable to use production data from existing wind farms but, despite the heavy subsidy paid to these farms, that data is not available to the public. Data taken half-hourly for 22 sites from 2005 to 2013 inclusive is used. We will also go on to study the wind resource for Eire and the northern plane of Europe in order to explore what benefits may follow from tighter inter-connection of these electricity grids.

2 Data source and windfarm modelling

2.1 Data source

Wind-speed and direction data used for any analysis of wind as a fuel source must be gathered from

i sites scattered across the country,
ii where anemometer accuracy and placement meet known standards, and
iii where data has been taken periodically over a reasonable number of years.

There are numerous sites in the UK producing wind data of this quality, many of which are operated by the Meteorological Office. Data was requested from them in 2007; access was permitted but at a prohibitive cost of £1,800 per site, per annum. However, for the aviation industry good quality wind data is freely available from the larger airports and many RAF stations. Until recently the historic data issued from these sites had not been available from any archive with easy access, but recently web sites have appeared where historic data is freely available and can be downloaded. The data records of interest are airport **MET**eorological **A**ctual **R**eports (METARs). These are observed, actual conditions at an airport and include wind-speed and direction, visibility, cloud cover, temperatures, atmospheric pressure, and weather conditions such as rain, snow, etc. In some cases, all this data is acquired and broadcast automatically.

Conditions are reported in a coded form compliant with an international standard. Observations are usually taken at least hourly and within most countries at fixed times. As an example:

04/01/2005 METAR EGLL 040850Z 23019G29KT 9999 BKN026 10/05 Q1023 NOSIG=

(4th January 2005 METAR report for Heathrow (EGLL), time 08:50 Zulu, wind 19 knots from 230 °, gusting 29 knots, visibility 9,999 metres or more, cloud: broken at 2,600 feet, temperature 10 °C, dew point 5 °C, pressure 1,023 mB, no significant change during next two hours).

Wind gusts are only reported when they are significant. METARS are usually produced hourly but many of the locations used in this study report half-hourly. Records for 22 sites over a period of nine years have been downloaded from www.ogimet.com into Excel spreadsheets and the wind data extracted by means of macro analysis. Details of these sites are given in Table 1 and Figure 3.

Name	ICAO code	Latitude	Longitude	No. of Enercon	No. of Siemens	No. of Vestas	Wind Shear Multiplier	Availability P_f	Site maximum power (MW)
Culdrose*	EGDR	N50°05′08	W05°15′17	67	87	67	1.23	0.9	542
Gatwick	EGKK	N51°09′10	W00°11′24	37	48	37	1.39	0.9	299
Cardiff	EGFF	N51°23′51	W03°20′47	67	87	67	1.3	0.9	542
Heathrow	EGLL	N51°28′11	W00°27′08	37	48	37	1.39	0.9	299
Lyneham*	EGDL	N51°30′19	W01°59′36	67	87	67	1.39	0.9	542
Brize*	EGVN	N51°45′00	W01°35′01	67	87	67	1.39	0.9	542
Wattisham*	EGUW	N52°07′32	E00°57′15	37	48	37	1.39	0.9	299
Waddington*	EGXW	N52°07′32	E00°57′15	37	48	37	1.39	0.9	299
Birmingham	EGBB	N52°27′12	W01°44′47	37	48	37	1.39	0.9	299
Shawbury*	EGOS	N52°47′52	W02°40′00	67	87	67	1.39	0.9	542
Valley*	EGOV	N53°14′45	W04°36′45	67	87	67	1.17	0.9	542
Manchester	EGCC	N53°28°15	W02°23′20	67	87	67	1.39	0.9	542
Newcastle	EGNT	N55°02′14	W01°41′24	37	48	37	1.3	0.9	299
Prestwick	EGPK	N55°30′40	W04°35′40	62	81	62	1.23	0.9	502
Glasgow	EGPF	N55°52′20	W04°25′55	62	81	62	1.3	0.9	502
Edinburgh	EGPH	N55°57′09	W03°21′44	62	81	62	1.3	0.9	502
Leuchars*	EGQL	N56°22′23	W02°52′02	62	81	62	1.23	0.9	502
Aberdeen	EGPD	N57°12′15	W02°11′55	62	81	62	1.3	0.9	502
Benbecula	EGPL	N57°28′40	W07°21′55	62	81	62	1.23	0.9	502
Kinloss*	EGQK	N57°38′59	W03°33′33	62	81	62	1.3	0.9	502
Wick	EGPC	N58°25′27	W03°05′45	62	81	62	1.3	0.9	502
Sumburgh	EGPB	N59°52′45	W01°17′30	62	81	62	1.23	0.9	502

Table 1 UK airfields issuing METARS used in this study. ICAO stands for International Civil Aviation Organization. Airports marked with * indicate hourly reporting rather than half-hourly reporting.

Figure 3 Location of the UK airfields used in this study

Using METAR wind data for a study of wind power generation has two key advantages:

- **i** the standard anemometer placement for such observations is 10 m above ground level, and
- **ii** airports are usually clear of surface obstructions which might elsewhere disturb wind flow.

2.2 Data quality

Data was available for the years 2005–13 inclusive. For those stations reporting half-hourly the expected number of records is 157,776; for hourly 78,888. For some sites these numbers are exceeded because interim METARS have been produced usually when the weather conditions are marginal (poor visibility, high winds). All locations also have gaps in observations, some of which (typically Xmas and Easter) last several days. 77,000 records are missing from the perfect total of 2,761,080, i.e. 2.79 %; half of these gaps occur in just four stations: Cardiff, Newcastle, Prestwick, and Benbecula. There are also 524 records that have missing wind data.

In order to correct these failings data is interpolated where it is missing provided the data gap is less than or equal to two hours duration. For those stations reporting hourly, half-hour data is also interpolated. This will have significance when considering the variability of the wind source. All interstitial readings are deleted. Although METARS are produced at fixed times in each European country, there is no agreed standard for these times. In order to allow comparison of the observed wind data, all observations are shifted to be on the hour and half-hour; for the UK this requires all readings to be shifted forward 10 minutes. At the end of the wind data extraction and correction process each station record has exactly 157,776 synchronised readings.

2.3 Wind Power calculation

Each of the 22 METAR stations are then taken to be sites for wind farms constructed from a mix of wind turbines as shown in Table 1. The design of the model wind fleet was established as follows:

- **i** The wind fleet was to have a nameplate capacity of approximately 10 GW, selected because this is a stated objective for 2020.
- **ii** Of this 10 GW, 5 GW is placed in Scotland, shared equally between the nine Scottish stations. Obviously, there has been little build of windfarms on islands such as Benbecula and Shetland, but they are retained as proxies for the many

wind-farms built upon the upland moorland of the Southern Uplands where wind-speeds will also be high.

iii 3 GW is shared equally amongst the western English/Welsh stations since the majority of the present windfarm build has been located in the west.

iv The remaining 2 GW is placed in the midlands and east of England, again shared equally amongst the stations.

v The target power of each station is shared equally amongst a mix of wind turbines from manufacturers: Enercon, Siemens and Vestas using turbines with the characteristics shown in Figure 2. The turbine numbers at each site are shown in Table 1.

vi All turbines are assumed to have a hub height of 80 metres

vii The maximum output for each site is multiplied by a plant availability constant of 0.9 as it would be unlikely for all of the turbines to be available for production at the same time: some will be undergoing servicing or repair.

viii The maximum output of each site is shown in Table 1. The nameplate capacity of the modelled fleet was 10,033 MW and the available power was 9,030 MW.

Wind-speed v_h at turbine hub height z_h is derived from the wind-speed v_a at anemometer level z_a by the formula[4]

$$v_h / v_a = \frac{\log\left(z_h / z_0\right)}{\log\left(z_a / z_0\right)}$$

z_0 is the roughness length and represents the roughness of the surrounding countryside. Three values are used, as shown in Table 2. Selection of which value to choose for the wind multiplier at each site and thus make the wind shear multiplier entry in Table 1 is described in the next section of this report.

Type of Terrain	**Roughness length z_0 (m)**	**Wind Shear Multiplier** $\frac{\log(z_h/z_0)}{\log(z_a/z_0)}$
Water, snow or sand surfaces	0.001	1.23
Open, flat ground, mown grass, bare soil	0.01	1.3
Farmland with some vegetation	0.05	1.39

Table 2 Wind shear factors (hub height 80 m) used in model wind fleet

The configuration described in Table 1 forms one reference sheet of an Excel workbook alongside sheets for the wind data extractions from all 22 sites; another worksheet describes the turbine characteristics shown in Figure 2. The wind-speeds and wind gust speeds (where applicable) are first modified to the turbine hub heights, and then the turbine powers are calculated by reference to the turbine characteristics, and the availability and numbers of each turbine at each site. If there are blanks of wind data, the power is also left blank. Hub wind-speed and gust speed are checked whether they exceed turbine cut-out speeds; if this is the case, the power output is set to zero, and is only reset once the wind/wind gust speeds drop below 20 m/S for the Enercon turbines, and 18 m/S for the Vestas and Siemens turbines. Finally, the station power outputs at each METAR observation time-stamp are summed to arrive at a total UK wind power production at each half-hour.

3 Wind-speed and direction analysis

Wind-speeds are not constant over time and in this study we need to explore the distribution of the time spent by the wind (and thus power production) within narrow bands of wind-speed. It is also useful to know the distribution of wind direction when selecting the value of wind shear multiplier used for each site.

Wind rose plots for each of the 22 sites were produced using the Wind Rose Pro 3 program supplied by Enviroware[3]. These are shown in Appendix A; that for Edinburgh is given as an example below. To construct these diagrams, the wind measurements are sorted by wind direction, and then counted into speed band sample boxes as defined in the legend of Figure 4. The results are plotted as directional segments, the colour of which indicates the wind-speed, and the length of each colour band (i.e. speed range) denotes the number of counts (and thus duration) in each speed band as a percentage. The scale rings are consistently 1 % steps in all the plots but the presentation cannot show these to the same pictorial scale because the plots have widely varying shapes.

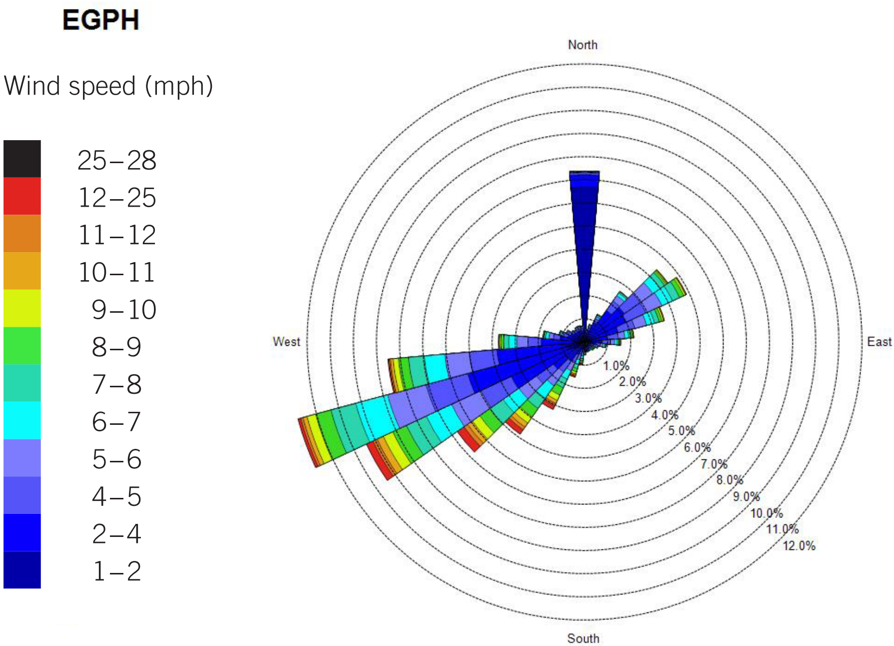


Figure 4 Wind rose for Edinburgh, 2005–13

The wind rose diagrams thus provide comparative wind-speed and direction data between the sites and were used as guidance in determining a set of initial values for the roughness length and thus wind shear multipliers (80 m hub height) shown in Table 1

The average wind-speeds for each site are shown in Table 3. For comparison with the wind atlas map (Figure 1) which plots wind-speeds 50 m above ground level, we need to derive the wind shear multiplier at that height for each site; this is shown in column 4 of Table 3. From that the average 50 m wind-speed appears in column 5 of Table 3. Column six of Table 3 shows the predicted wind-speed from the wind atlas. Columns five and six reveal several large discrepancies between the two predictions of wind-speed at hub heights, particularly for Scotland. There are many sources of error in this study that may have caused these differences:

- **i** selection of inappropriate terrain type.
- **ii** application of the wrong roughness coefficients for each of the terrain types.

It is unlikely that the differences shown for Prestwick (EGPK) and Newcastle (EGNT) can be explained fully by these possible errors, and the wind atlas map for the UK given in Figure 1 may well be somewhat optimistic.

ICAO code	Average wind-speed m/S	Roughness length m	Wind shear Multiplier for 50 m hub height	Calculated hub (50 m) wind-speed m/S	European Wind Atlas Estimated 50 m wind-speed m/S
EGDR	5.39	0.001	1.17	6.33	7.75
EGKK	3.47	0.05	1.30	4.52	5.50
EGFF	4.70	0.01	1.23	5.80	7.00
EGLL	4.07	0.05	1.30	5.31	5.50
EGDL	4.45	0.05	1.30	5.80	4.75
EGVN	3.43	0.05	1.30	4.48	4.75
EGUW	4.61	0.05	1.30	6.01	5.50
EGXW	4.66	0.05	1.30	6.08	5.50
EGBB	4.02	0.05	1.30	5.24	4.75
EGOS	4.14	0.05	1.30	5.40	5.50
EGOV	6.40	0.05	1.30	8.34	7.75
EGCC	4.03	0.05	1.30	5.25	5.50
EGNT	3.65	0.01	1.23	4.51	8.50
EGPK	4.15	0.001	1.17	4.88	7.50
EGPF	4.11	0.01	1.23	5.06	7.50
EGPH	4.29	0.01	1.23	5.28	7.50
EGQL	4.84	0.001	1.17	5.69	8.50
EGPD	4.28	0.01	1.23	5.28	7.50
EGPL	6.52	0.001	1.17	7.66	8.50
EGQK	4.70	0.01	1.23	5.79	7.50
EGPC	5.59	0.01	1.23	6.89	7.50
EGPB	6.35	0.001	1.17	7.46	8.50

Table 3 Comparison of average wind-speeds (at an anemometer height of 10 m) with the Wind Atlas

Wind-speed probability distributions usually take the form of Weibull distributions. Wind Rose Pro 3 also derives the Weibull distribution scale and shape factors that describe the Weibull distributions typical of wind-speed plots and these are shown in Table A1. The wind-speed distributions are shown in Figure 5 superimposed on the turbine characteristic curves of Figure 2.

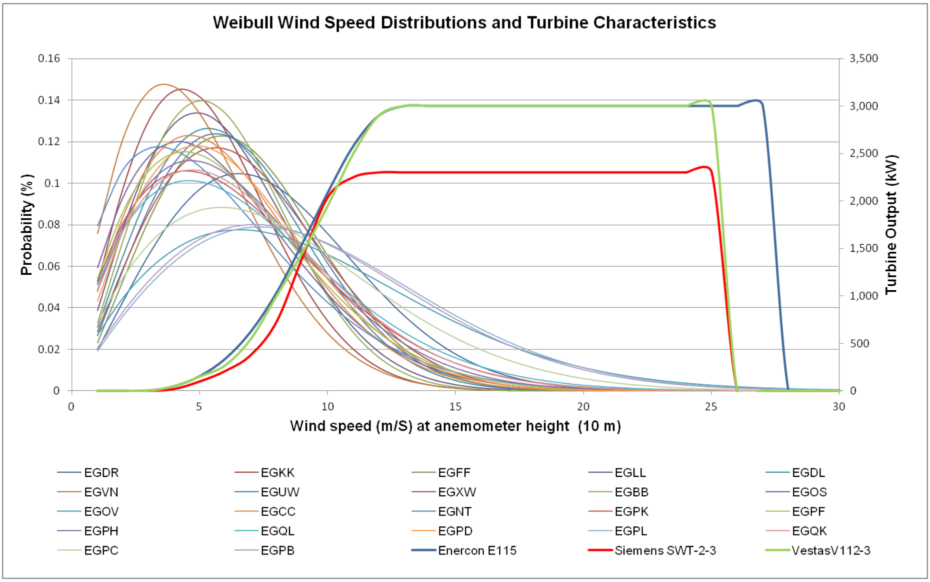


Figure 5 Wind probability functions and the turbine characteristics used in the model

The correlation of wind-speeds between the various sites and at time intervals of 0, 30, 60 and 90 minutes are shown in Figures 6a-d. The correlations were calculated using the Excel CORREL (Pearson-Product) method. The resultant correlation coefficient varies between –1 (negative correlation and 1 (positive correlation). The correlation coefficient may be written as

$$r = \sqrt{\frac{\textit{explained variation}}{\textit{total variation}}}$$

Values above 0.5 show regions were the explained variation is greater than the unexplained variation. In Figure 6 the red values show $r > 0.8$, orange $0.6 < r < 0.8$, pink $0.4 < r < 0.6$, blue $0.2 < r < 0.4$ and white $r < 0.2$.

	EGDR	EGKK	EGFF	EGLL	EGDL	EGVN	EGUW	EGXW	EGBB	EGOS	EGOV	EGCC	EGNT	EGPK	EGPF	EGPH	EGQL	EGPD	EGPL	EGQK	EGPC	EGPB	
EGPB	0.12	0.09	0.13	0.17	0.10	0.08	0.17	0.23	0.19	0.24	0.28	0.23	0.31	0.37	0.35	0.36	0.40	0.41	0.39	0.47	0.55	1.00	EGPB
EGPC	0.16	0.20	0.22	0.25	0.20	0.20	0.25	0.31	0.32	0.31	0.28	0.34	0.42	0.44	0.42	0.39	0.48	0.64	0.41	0.61	1.00	0.55	EGPC
EGQK	0.09	0.21	0.20	0.28	0.18	0.18	0.27	0.33	0.34	0.35	0.30	0.35	0.56	0.53	0.55	0.58	0.65	0.59	0.50	1.00	0.61	0.47	EGQK
EGPL	0.14	0.12	0.17	0.23	0.13	0.10	0.16	0.26	0.25	0.29	0.39	0.32	0.37	0.55	0.49	0.49	0.48	0.38	1.00	0.50	0.41	0.39	EGPL
EGPD	0.20	0.29	0.24	0.32	0.25	0.29	0.32	0.40	0.42	0.40	0.34	0.42	0.51	0.48	0.45	0.44	0.52	1.00	0.38	0.59	0.64	0.41	EGPD
EGQL	0.16	0.25	0.28	0.37	0.24	0.25	0.31	0.46	0.40	0.45	0.42	0.47	0.66	0.65	0.73	0.80	1.00	0.52	0.48	0.65	0.48	0.40	EGQL
EGPH	0.17	0.24	0.27	0.37	0.23	0.24	0.30	0.47	0.41	0.46	0.48	0.50	0.64	0.71	0.80	1.00	0.80	0.44	0.49	0.58	0.39	0.36	EGPH
EGPF	0.21	0.27	0.31	0.39	0.26	0.27	0.30	0.48	0.44	0.48	0.50	0.54	0.59	0.74	1.00	0.80	0.73	0.45	0.49	0.55	0.42	0.35	EGPF
EGPK	0.23	0.28	0.34	0.43	0.28	0.25	0.33	0.49	0.48	0.50	0.56	0.57	0.61	1.00	0.74	0.71	0.65	0.48	0.55	0.53	0.44	0.37	EGPK
EGNT	0.21	0.39	0.38	0.47	0.33	0.38	0.46	0.56	0.54	0.55	0.43	0.57	1.00	0.61	0.59	0.64	0.66	0.51	0.37	0.56	0.42	0.31	EGNT
EGCC	0.44	0.53	0.55	0.63	0.54	0.59	0.54	0.74	0.74	0.72	0.62	1.00	0.57	0.57	0.54	0.50	0.47	0.42	0.32	0.35	0.34	0.23	EGCC
EGOV	0.41	0.31	0.39	0.47	0.34	0.33	0.44	0.57	0.52	0.65	1.00	0.62	0.43	0.56	0.50	0.48	0.42	0.34	0.39	0.30	0.28	0.28	EGOV
EGOS	0.43	0.55	0.55	0.65	0.54	0.59	0.63	0.68	0.72	1.00	0.65	0.72	0.55	0.50	0.48	0.46	0.45	0.40	0.29	0.35	0.31	0.24	EGOS
EGBB	0.45	0.65	0.60	0.71	0.62	0.70	0.63	0.72	1.00	0.72	0.52	0.74	0.54	0.48	0.44	0.41	0.40	0.42	0.25	0.34	0.32	0.19	EGBB
EGXW	0.43	0.58	0.51	0.66	0.52	0.62	0.65	1.00	0.72	0.68	0.57	0.74	0.56	0.49	0.48	0.47	0.46	0.40	0.26	0.33	0.31	0.23	EGXW
EGUW	0.37	0.70	0.50	0.68	0.54	0.63	1.00	0.65	0.63	0.63	0.44	0.54	0.46	0.33	0.30	0.30	0.31	0.32	0.16	0.27	0.25	0.17	EGUW
EGVN	0.51	0.75	0.61	0.66	0.73	1.00	0.63	0.62	0.70	0.59	0.33	0.59	0.38	0.25	0.27	0.24	0.25	0.29	0.10	0.18	0.20	0.08	EGVN
EGDL	0.46	0.63	0.61	0.62	1.00	0.73	0.54	0.52	0.62	0.54	0.34	0.54	0.33	0.28	0.26	0.23	0.24	0.25	0.13	0.18	0.20	0.10	EGDL
EGLL	0.46	0.76	0.61	1.00	0.62	0.66	0.68	0.66	0.71	0.65	0.47	0.63	0.47	0.43	0.39	0.37	0.37	0.32	0.23	0.28	0.25	0.17	EGLL
EGFF	0.50	0.57	1.00	0.61	0.61	0.61	0.50	0.51	0.60	0.55	0.39	0.55	0.38	0.34	0.31	0.27	0.28	0.24	0.17	0.20	0.22	0.13	EGFF
EGKK	0.46	1.00	0.57	0.76	0.63	0.75	0.70	0.58	0.65	0.55	0.31	0.53	0.39	0.28	0.27	0.24	0.25	0.29	0.12	0.21	0.20	0.09	EGKK
EGDR	1.00	0.46	0.50	0.46	0.46	0.51	0.37	0.43	0.45	0.43	0.41	0.44	0.21	0.23	0.21	0.17	0.16	0.20	0.14	0.09	0.16	0.12	EGDR
	EGDR	EGKK	EGFF	EGLL	EGDL	EGVN	EGUW	EGXW	EGBB	EGOS	EGOV	EGCC	EGNT	EGPK	EGPF	EGPH	EGQL	EGPD	EGPL	EGQK	EGPC	EGPB	

Figure 6a Wind correlations at same times

	EGDR	EGKK	EGFF	EGLL	EGDL	EGVN	EGUW	EGXW	EGBB	EGOS	EGOV	EGCC	EGNT	EGPK	EGPF	EGPH	EGQL	EGPD	EGPL	EGQK	EGPC	EGPB	
EGPB	0.12	0.09	0.13	0.17	0.10	0.08	0.17	0.23	0.19	0.24	0.28	0.22	0.30	0.36	0.35	0.36	0.39	0.41	0.38	0.47	0.54	0.95	EGPB
EGPC	0.16	0.21	0.22	0.25	0.20	0.20	0.25	0.31	0.32	0.31	0.27	0.34	0.42	0.43	0.41	0.39	0.47	0.65	0.40	0.60	0.94	0.55	EGPC
EGQK	0.09	0.21	0.20	0.28	0.17	0.18	0.27	0.32	0.34	0.35	0.29	0.34	0.56	0.53	0.55	0.58	0.65	0.59	0.48	0.96	0.60	0.47	EGQK
EGPL	0.14	0.13	0.17	0.23	0.14	0.10	0.16	0.26	0.25	0.30	0.39	0.32	0.37	0.55	0.49	0.49	0.49	0.39	0.95	0.51	0.42	0.39	EGPL
EGPD	0.20	0.29	0.24	0.32	0.25	0.28	0.32	0.40	0.42	0.40	0.34	0.41	0.50	0.47	0.45	0.44	0.51	0.91	0.37	0.59	0.64	0.41	EGPD
EGQL	0.16	0.25	0.28	0.37	0.23	0.24	0.31	0.45	0.39	0.45	0.41	0.46	0.66	0.64	0.72	0.79	0.97	0.52	0.47	0.66	0.48	0.40	EGQL
EGPH	0.17	0.24	0.27	0.38	0.23	0.24	0.30	0.47	0.41	0.46	0.48	0.50	0.64	0.70	0.79	0.93	0.80	0.44	0.48	0.59	0.39	0.36	EGPH
EGPF	0.21	0.26	0.31	0.39	0.26	0.27	0.30	0.48	0.44	0.48	0.49	0.53	0.60	0.73	0.92	0.80	0.73	0.46	0.48	0.56	0.42	0.35	EGPF
EGPK	0.23	0.28	0.34	0.43	0.27	0.25	0.33	0.49	0.48	0.50	0.56	0.57	0.62	0.93	0.74	0.71	0.65	0.48	0.54	0.54	0.44	0.37	EGPK
EGNT	0.20	0.39	0.38	0.47	0.33	0.37	0.46	0.56	0.53	0.54	0.42	0.57	0.94	0.61	0.59	0.63	0.65	0.50	0.36	0.56	0.42	0.30	EGNT
EGCC	0.44	0.53	0.55	0.63	0.54	0.59	0.55	0.75	0.74	0.71	0.61	0.92	0.57	0.57	0.53	0.50	0.47	0.42	0.31	0.35	0.34	0.23	EGCC
EGOV	0.41	0.32	0.39	0.48	0.34	0.34	0.44	0.58	0.53	0.65	0.98	0.63	0.44	0.56	0.50	0.48	0.42	0.35	0.39	0.30	0.28	0.29	EGOV
EGOS	0.42	0.55	0.54	0.65	0.54	0.59	0.64	0.68	0.73	0.96	0.63	0.72	0.55	0.50	0.48	0.46	0.45	0.40	0.29	0.35	0.31	0.24	EGOS
EGBB	0.44	0.66	0.59	0.71	0.61	0.70	0.64	0.72	0.92	0.72	0.51	0.73	0.54	0.47	0.44	0.41	0.39	0.42	0.25	0.34	0.32	0.19	EGBB
EGXW	0.42	0.58	0.51	0.67	0.52	0.62	0.66	0.97	0.72	0.68	0.56	0.74	0.56	0.49	0.48	0.47	0.46	0.40	0.26	0.33	0.31	0.23	EGXW
EGUW	0.36	0.70	0.50	0.67	0.54	0.62	0.97	0.64	0.62	0.63	0.43	0.54	0.45	0.32	0.30	0.29	0.31	0.32	0.16	0.27	0.24	0.17	EGUW
EGVN	0.50	0.76	0.61	0.67	0.72	0.97	0.64	0.62	0.70	0.58	0.32	0.58	0.37	0.25	0.27	0.24	0.25	0.28	0.10	0.18	0.20	0.08	EGVN
EGDL	0.45	0.63	0.60	0.63	0.98	0.73	0.55	0.52	0.61	0.53	0.33	0.53	0.33	0.27	0.26	0.23	0.23	0.25	0.13	0.18	0.20	0.10	EGDL
EGLL	0.46	0.75	0.60	0.93	0.61	0.65	0.68	0.66	0.70	0.64	0.47	0.62	0.47	0.42	0.39	0.37	0.37	0.31	0.22	0.28	0.24	0.17	EGLL
EGFF	0.50	0.58	0.92	0.62	0.61	0.62	0.51	0.50	0.60	0.55	0.38	0.55	0.38	0.34	0.31	0.27	0.28	0.24	0.17	0.20	0.22	0.13	EGFF
EGKK	0.45	0.92	0.57	0.75	0.62	0.74	0.71	0.57	0.65	0.54	0.31	0.52	0.38	0.27	0.26	0.24	0.25	0.28	0.12	0.21	0.20	0.09	EGKK
EGDR	0.97	0.47	0.51	0.47	0.47	0.51	0.38	0.44	0.46	0.43	0.40	0.44	0.21	0.23	0.21	0.17	0.16	0.20	0.14	0.10	0.16	0.12	EGDR
	EGDR	EGKK	EGFF	EGLL	EGDL	EGVN	EGUW	EGXW	EGBB	EGOS	EGOV	EGCC	EGNT	EGPK	EGPF	EGPH	EGQL	EGPD	EGPL	EGQK	EGPC	EGPB	

Figure 6b Wind correlations at 30 minute separation

	EGDR	EGKK	EGFF	EGLL	EGDL	EGVN	EGUW	EGXW	EGBB	EGOS	EGOV	EGCC	EGNT	EGPK	EGPF	EGPH	EGQL	EGPD	EGPL	EGQK	EGPC	EGPB	
EGPB	0.11	0.09	0.13	0.17	0.10	0.08	0.17	0.23	0.19	0.23	0.28	0.22	0.30	0.36	0.35	0.36	0.39	0.40	0.37	0.46	0.53	0.93	EGPB
EGPC	0.16	0.21	0.22	0.25	0.20	0.20	0.25	0.31	0.32	0.31	0.27	0.33	0.42	0.43	0.41	0.39	0.47	0.64	0.39	0.60	0.90	0.56	EGPC
EGQK	0.09	0.21	0.19	0.28	0.17	0.17	0.26	0.31	0.34	0.34	0.29	0.34	0.55	0.52	0.54	0.57	0.64	0.59	0.47	0.90	0.60	0.47	EGQK
EGPL	0.14	0.13	0.18	0.24	0.14	0.10	0.17	0.27	0.26	0.30	0.39	0.32	0.38	0.56	0.50	0.49	0.49	0.39	0.92	0.52	0.43	0.40	EGPL
EGPD	0.19	0.29	0.24	0.32	0.25	0.28	0.32	0.39	0.42	0.39	0.33	0.41	0.50	0.46	0.44	0.43	0.51	0.87	0.35	0.58	0.63	0.41	EGPD
EGQL	0.16	0.25	0.27	0.37	0.23	0.24	0.31	0.45	0.39	0.44	0.41	0.46	0.65	0.63	0.71	0.78	0.92	0.51	0.46	0.65	0.47	0.40	EGQL
EGPH	0.16	0.24	0.27	0.38	0.23	0.24	0.30	0.47	0.40	0.46	0.47	0.49	0.64	0.69	0.78	0.89	0.80	0.44	0.47	0.59	0.39	0.36	EGPH
EGPF	0.20	0.26	0.31	0.39	0.26	0.27	0.30	0.47	0.44	0.48	0.48	0.53	0.60	0.72	0.88	0.79	0.74	0.46	0.47	0.56	0.41	0.35	EGPF
EGPK	0.23	0.27	0.34	0.43	0.27	0.25	0.33	0.49	0.48	0.50	0.55	0.57	0.62	0.90	0.73	0.71	0.65	0.48	0.53	0.54	0.44	0.37	EGPK
EGNT	0.20	0.38	0.37	0.47	0.33	0.37	0.45	0.55	0.53	0.53	0.41	0.56	0.90	0.60	0.58	0.62	0.65	0.50	0.35	0.56	0.41	0.30	EGNT
EGCC	0.43	0.54	0.55	0.63	0.54	0.59	0.55	0.74	0.74	0.71	0.60	0.88	0.57	0.56	0.53	0.49	0.46	0.42	0.31	0.35	0.34	0.23	EGCC
EGOV	0.41	0.33	0.40	0.49	0.35	0.34	0.45	0.59	0.53	0.66	0.96	0.64	0.44	0.56	0.50	0.48	0.42	0.35	0.39	0.31	0.28	0.29	EGOV
EGOS	0.41	0.55	0.54	0.65	0.53	0.59	0.64	0.68	0.72	0.91	0.62	0.71	0.55	0.50	0.48	0.46	0.45	0.40	0.28	0.35	0.31	0.23	EGOS
EGBB	0.43	0.65	0.58	0.71	0.61	0.70	0.64	0.71	0.88	0.71	0.50	0.72	0.53	0.47	0.43	0.40	0.39	0.41	0.24	0.34	0.31	0.19	EGBB
EGXW	0.42	0.59	0.50	0.67	0.52	0.61	0.66	0.93	0.71	0.67	0.55	0.73	0.56	0.48	0.48	0.47	0.46	0.40	0.25	0.33	0.31	0.23	EGXW
EGUW	0.35	0.68	0.49	0.66	0.53	0.61	0.93	0.62	0.61	0.61	0.42	0.52	0.45	0.32	0.30	0.29	0.31	0.31	0.15	0.26	0.24	0.16	EGUW
EGVN	0.48	0.75	0.60	0.67	0.71	0.92	0.64	0.61	0.69	0.57	0.31	0.57	0.37	0.25	0.27	0.24	0.24	0.28	0.09	0.18	0.20	0.08	EGVN
EGDL	0.44	0.63	0.59	0.63	0.93	0.72	0.55	0.52	0.61	0.52	0.32	0.53	0.33	0.27	0.26	0.22	0.23	0.25	0.12	0.17	0.20	0.10	EGDL
EGLL	0.45	0.74	0.60	0.90	0.60	0.64	0.68	0.65	0.69	0.63	0.46	0.61	0.46	0.42	0.38	0.36	0.36	0.31	0.21	0.28	0.24	0.16	EGLL
EGFF	0.49	0.58	0.87	0.62	0.61	0.61	0.51	0.50	0.60	0.54	0.37	0.55	0.38	0.34	0.31	0.26	0.27	0.24	0.17	0.20	0.22	0.13	EGFF
EGKK	0.44	0.89	0.56	0.74	0.61	0.73	0.70	0.56	0.63	0.53	0.30	0.51	0.38	0.27	0.26	0.23	0.25	0.28	0.11	0.21	0.20	0.08	EGKK
EGDR	0.92	0.48	0.51	0.48	0.47	0.52	0.38	0.44	0.46	0.44	0.40	0.45	0.21	0.23	0.21	0.17	0.16	0.20	0.14	0.10	0.16	0.12	EGDR
	EGDR	EGKK	EGFF	EGLL	EGDL	EGVN	EGUW	EGXW	EGBB	EGOS	EGOV	EGCC	EGNT	EGPK	EGPF	EGPH	EGQL	EGPD	EGPL	EGQK	EGPC	EGPB	

Figure 6c Wind correlations at 60 minute separation

	EGDR	EGKK	EGFF	EGLL	EGDL	EGVN	EGUW	EGXW	EGBB	EGOS	EGOV	EGCC	EGNT	EGPK	EGPF	EGPH	EGQL	EGPD	EGPL	EGQK	EGPC	EGPB	
EGPB	0.11	0.09	0.12	0.17	0.10	0.08	0.16	0.23	0.18	0.23	0.28	0.22	0.30	0.36	0.34	0.35	0.39	0.40	0.37	0.46	0.52	0.90	EGPB
EGPC	0.15	0.20	0.21	0.25	0.20	0.20	0.24	0.30	0.31	0.31	0.26	0.33	0.42	0.42	0.41	0.38	0.46	0.64	0.38	0.59	0.87	0.56	EGPC
EGQK	0.08	0.20	0.19	0.27	0.16	0.17	0.26	0.31	0.33	0.33	0.28	0.33	0.55	0.51	0.53	0.55	0.63	0.58	0.46	0.86	0.59	0.47	EGQK
EGPL	0.14	0.13	0.18	0.24	0.14	0.10	0.17	0.27	0.26	0.30	0.39	0.33	0.38	0.56	0.50	0.50	0.50	0.40	0.90	0.53	0.44	0.41	EGPL
EGPD	0.19	0.28	0.23	0.31	0.24	0.28	0.32	0.39	0.41	0.39	0.32	0.40	0.49	0.45	0.43	0.42	0.50	0.84	0.34	0.57	0.61	0.41	EGPD
EGQL	0.15	0.24	0.27	0.37	0.23	0.24	0.31	0.44	0.38	0.43	0.40	0.45	0.65	0.62	0.70	0.76	0.89	0.51	0.45	0.65	0.47	0.40	EGQL
EGPH	0.16	0.23	0.26	0.38	0.23	0.23	0.29	0.46	0.40	0.45	0.46	0.49	0.64	0.68	0.77	0.86	0.79	0.43	0.46	0.59	0.38	0.36	EGPH
EGPF	0.20	0.26	0.31	0.39	0.26	0.26	0.30	0.47	0.43	0.47	0.48	0.52	0.59	0.71	0.84	0.78	0.73	0.45	0.46	0.56	0.41	0.35	EGPF
EGPK	0.22	0.27	0.34	0.43	0.27	0.25	0.33	0.48	0.47	0.50	0.54	0.56	0.62	0.87	0.72	0.71	0.65	0.48	0.53	0.54	0.43	0.37	EGPK
EGNT	0.19	0.38	0.36	0.46	0.32	0.36	0.45	0.54	0.52	0.52	0.41	0.55	0.87	0.59	0.57	0.61	0.64	0.49	0.34	0.55	0.41	0.30	EGNT
EGCC	0.42	0.53	0.55	0.63	0.53	0.58	0.55	0.74	0.73	0.69	0.58	0.85	0.57	0.56	0.52	0.49	0.46	0.41	0.30	0.35	0.33	0.22	EGCC
EGOV	0.41	0.33	0.40	0.49	0.35	0.35	0.45	0.59	0.54	0.66	0.93	0.64	0.44	0.56	0.50	0.48	0.42	0.35	0.38	0.31	0.28	0.29	EGOV
EGOS	0.40	0.54	0.53	0.65	0.53	0.58	0.64	0.67	0.71	0.86	0.61	0.69	0.54	0.49	0.47	0.45	0.44	0.39	0.27	0.35	0.31	0.23	EGOS
EGBB	0.42	0.65	0.57	0.70	0.60	0.68	0.64	0.70	0.84	0.69	0.48	0.70	0.53	0.46	0.43	0.40	0.38	0.41	0.23	0.34	0.31	0.18	EGBB
EGXW	0.41	0.58	0.50	0.66	0.51	0.60	0.66	0.89	0.70	0.66	0.54	0.71	0.56	0.48	0.47	0.46	0.46	0.39	0.25	0.33	0.31	0.23	EGXW
EGUW	0.34	0.67	0.48	0.65	0.51	0.59	0.90	0.60	0.59	0.60	0.41	0.51	0.44	0.31	0.29	0.28	0.30	0.30	0.14	0.26	0.23	0.16	EGUW
EGVN	0.47	0.75	0.59	0.66	0.70	0.88	0.64	0.60	0.67	0.56	0.30	0.56	0.37	0.25	0.26	0.23	0.24	0.27	0.09	0.18	0.19	0.08	EGVN
EGDL	0.43	0.63	0.58	0.62	0.90	0.71	0.55	0.51	0.60	0.51	0.31	0.52	0.33	0.27	0.25	0.22	0.23	0.25	0.12	0.17	0.19	0.10	EGDL
EGLL	0.44	0.72	0.59	0.87	0.59	0.62	0.68	0.63	0.67	0.62	0.45	0.60	0.46	0.41	0.38	0.35	0.35	0.30	0.21	0.27	0.24	0.16	EGLL
EGFF	0.48	0.57	0.83	0.62	0.61	0.61	0.51	0.49	0.59	0.54	0.37	0.54	0.38	0.34	0.30	0.26	0.27	0.24	0.16	0.20	0.21	0.13	EGFF
EGKK	0.43	0.86	0.55	0.73	0.60	0.71	0.69	0.55	0.62	0.52	0.29	0.50	0.37	0.26	0.25	0.23	0.24	0.27	0.10	0.21	0.19	0.08	EGKK
EGDR	0.89	0.49	0.52	0.48	0.48	0.52	0.39	0.44	0.46	0.44	0.39	0.45	0.21	0.23	0.21	0.17	0.16	0.20	0.14	0.10	0.16	0.12	EGDR
	EGDR	EGKK	EGFF	EGLL	EGDL	EGVN	EGUW	EGXW	EGBB	EGOS	EGOV	EGCC	EGNT	EGPK	EGPF	EGPH	EGQL	EGPD	EGPL	EGQK	EGPC	EGPB	

Figure 6d Wind correlations at 90 minute separation.

The following patterns can be seen:

- **i** There is strong correlation between Prestwick (EGPK), Edinburgh (EGPH) and Leuchars (EQPL),
- **ii** Correlation coefficients greater than 0.6 occur in a cluster comprising most of the English stations even at time intervals as long as 90 minutes,
- **iii** Similarly the Scotland stations show correlation greater than 0.6 at time intervals as long as 90 minutes; only Benbecula (EGPL) does not fit this pattern quite as strongly.
- **iv** Correlation between the clusters noted in (ii) and (iii) is also quite strong.

Plots of correlation of wind-speeds as a function of both station separation distance (nm) and at the above time intervals are given in Figure 7. These are drawn as four, fourth-order polynomial trend lines; for clarity only the correlation scatter data for dT=0 is shown. All of the trend lines plotted in Figure 7 have residual-squared values greater than 0.88. Figure 7 supports the qualitative observations given above and also demonstrates the high degree of wind-speed correlation across the observation stations of the UK. This point will be returned to in the capacity credit discussion of Section 9.

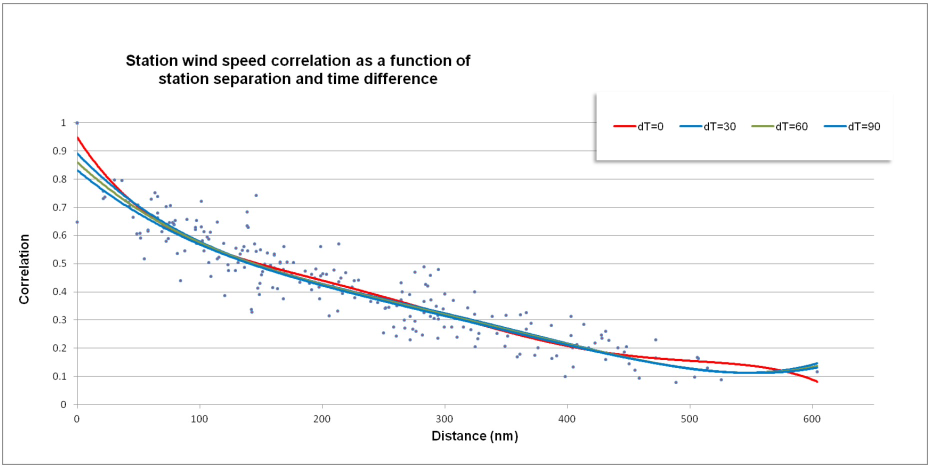


Figure 7 Wind-speed correlation trends as a function of station separation distance and time difference

4 Model capacity factors

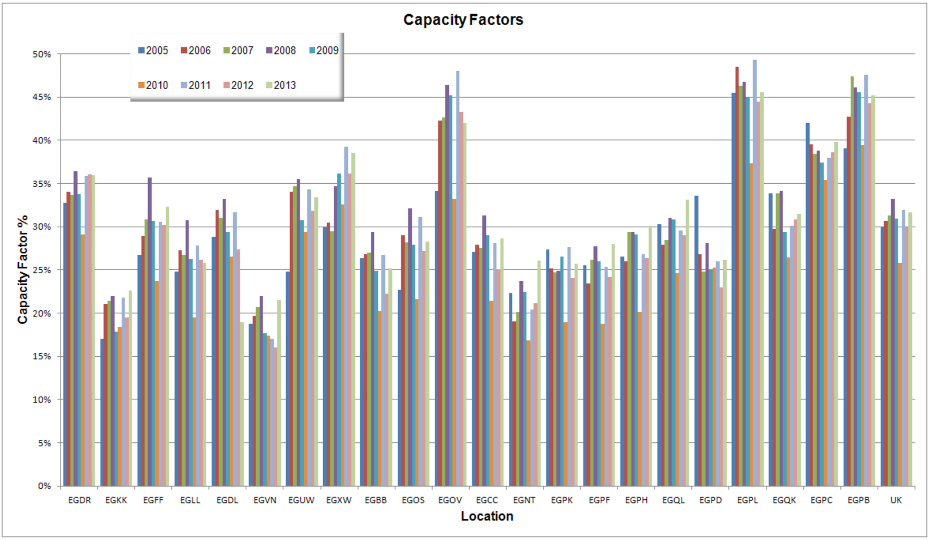


Figure 8 Capacity factors for the modelled UK wind fleet

The capacity factor for a wind fleet is usually taken to be the ratio between actual energy production and the energy produced if production at nameplate output were continuous. Here capacity factor is based on the wind fleet model available power, i.e. after application of the availability factor P_f. The calculated values for the model are shown in Figure 8.

These results were used to check the selected wind shear multipliers for each station by comparison with data from existing wind farms close to the stations used in the model. However, windfarm production data is scarce since there are few wind farms in the south east and midlands of England and the Outer Hebrides, and the Renewable Energy Foundation database[5] does not seem to have been maintained much beyond 2009. Valley (EGOV) had an initial wind shear value of 1.23 (the station is about 500 metres from the open sea) but this value resulted in a capacity factor of 44.2 %, far higher than any of the existing Anglesey windfarms; the value was therefore reduced to 1.17. No other changes were made. It may be that the capacity factors derived from the model are perhaps higher than those achieved by the installed wind fleet examples, but it should be remembered that the model has the advantage of large, modern, wind turbines, and perhaps high availability (0.9) for the entire fleet.

The capacity factor results are rather poor for stations in the south and midlands of England. Most of the better results are seen for stations close to the coast, the west of England and Wales, and Scotland. All of the better locations are rather remote from the UK's load centres.

5 Sensitivity of power calculations to wind shear multiplier value

The calculated wind farm power outputs for a given wind-speed will be sensitive to the values selected for availability and wind shear multiplier. The sensitivity to plant availability will obviously be linear and involve trivial scaling of the model results. The sensitivity to wind shear multiplier will not be linear since this multiplier can shift the wind-speed distribution at anemometer level into a non-linear intersection portion of the turbine characteristics, see Figure 5. This dependency has therefore been modelled for 5 % step changes of wind shear multiplier and the results shown in terms of the impact upon calculated capacity factor—see Figure 9. (As an example, the wind shear multiplier used for EGDR Culdrose in the main study was 1.23; varying this factor between 70 and 110 % in Figure 9 will have shifted the wind shear multiplier between 0.86 and 1.35). The turbine averaged wind shear multiplier for the whole of the UK is 1.31. Figure 9 shows the capacity factor change as this multiplier moves between 0.92 and 1.44.

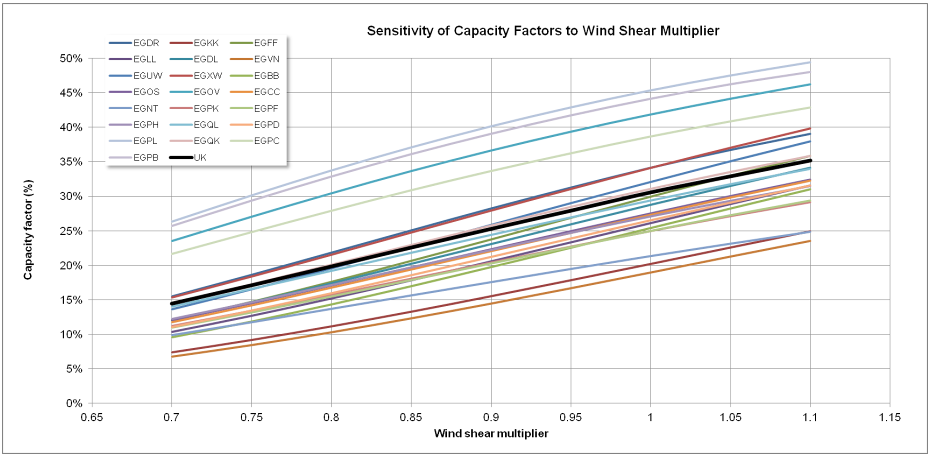


Figure 9 Sensitivity of capacity factors to wind shear multiplier.

The wind fleet capacity factor for the whole of the UK has close to a linear dependency on wind shear multiplier and increases by 5 % for every 10 % step increase in wind shear multiplier.

6 Time dependency of wind generation

Several authors, including National Wind Power, have also found that peak demand periods actually tend to coincide with above-average wind plant output.[5]

The model output was analysed by year, season, month and half-hour period.

There is a marked variation in annual production—Figure 10; 2010 was a poor year, being only 84 % of average. (In Ireland capacity factor fell to 75 % of average in the same year. Across northern Europe capacity factors also fell to their lowest values in 2010, but not to such a marked extent). This fall is equivalent to losing the output from one 600 MW rated fossil-fuelled plant.

Both the seasonal (Figure 11) and monthly (Figure 12) output averages show the highest production occurs in the coldest months.

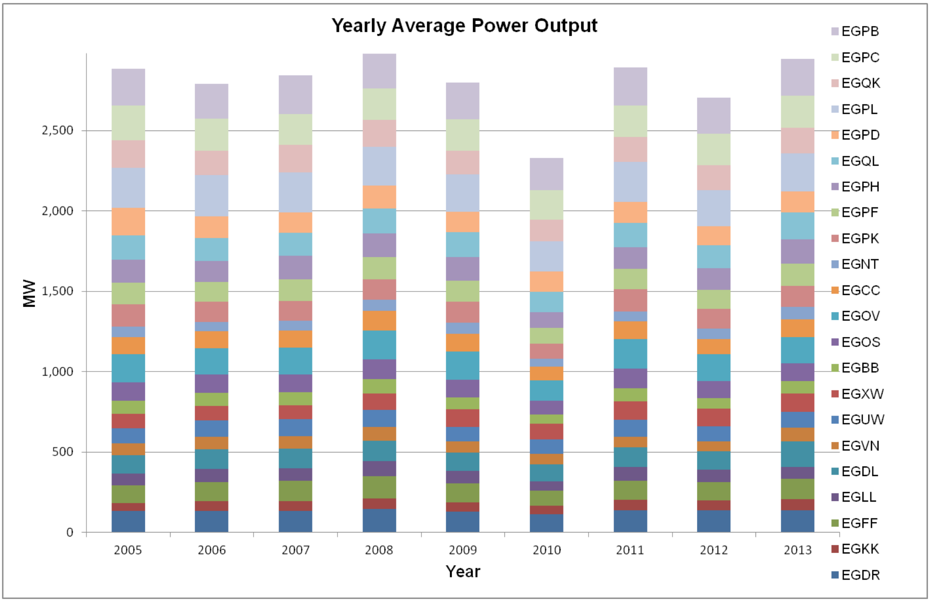


Figure 10 Yearly wind fleet average outputs

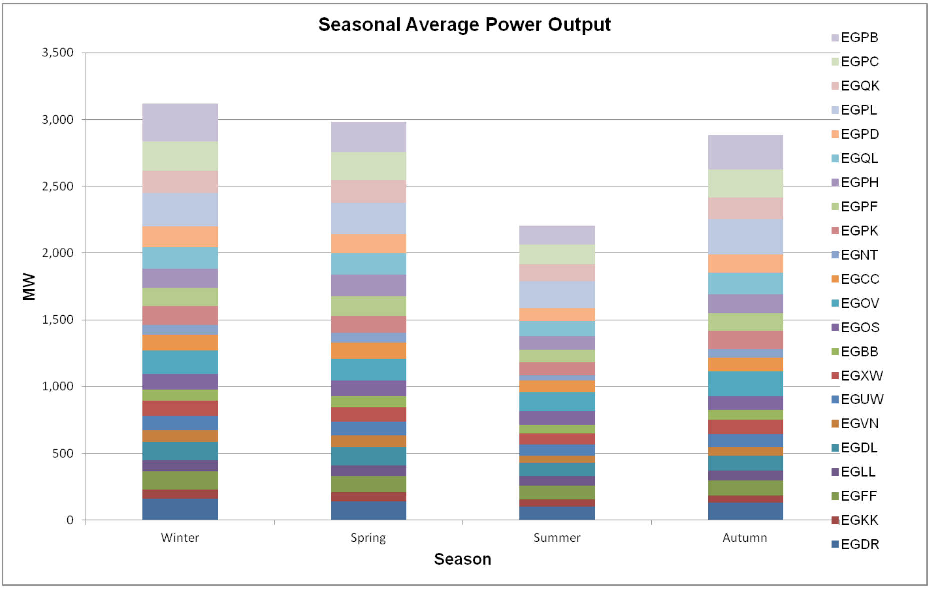


Figure 11 Seasonal wind fleet average output

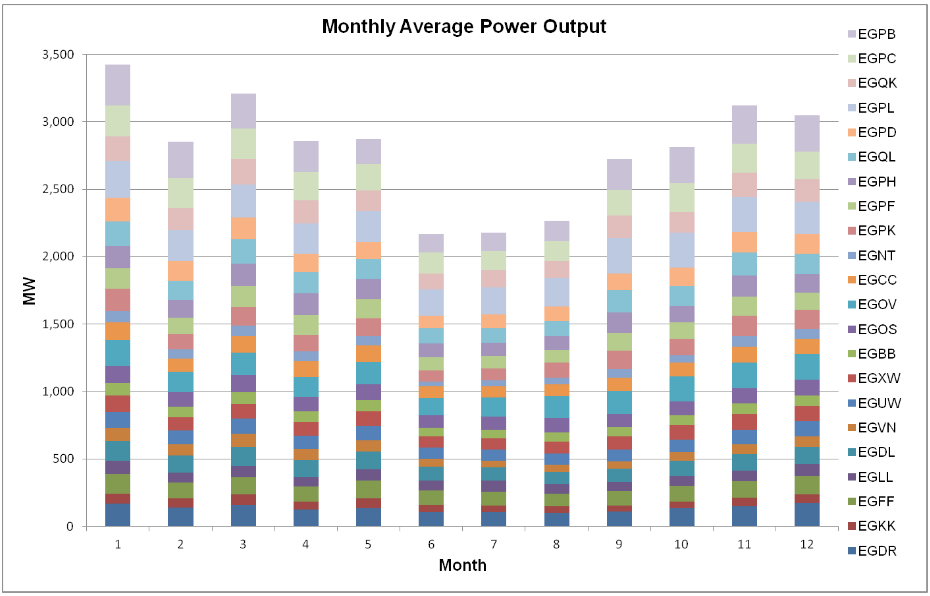


Figure 12 Monthly wind fleet output

Figure 13 shows the average half-hourly output which peaks just after midday. A typical demand curve for winter is shown. However, most of the diurnal variation shown does *not* occur in the winter months; the summer months show the strongest diurnal variation (plots demonstrating this are not shown). This summer peak will coincide with peak solar power output.

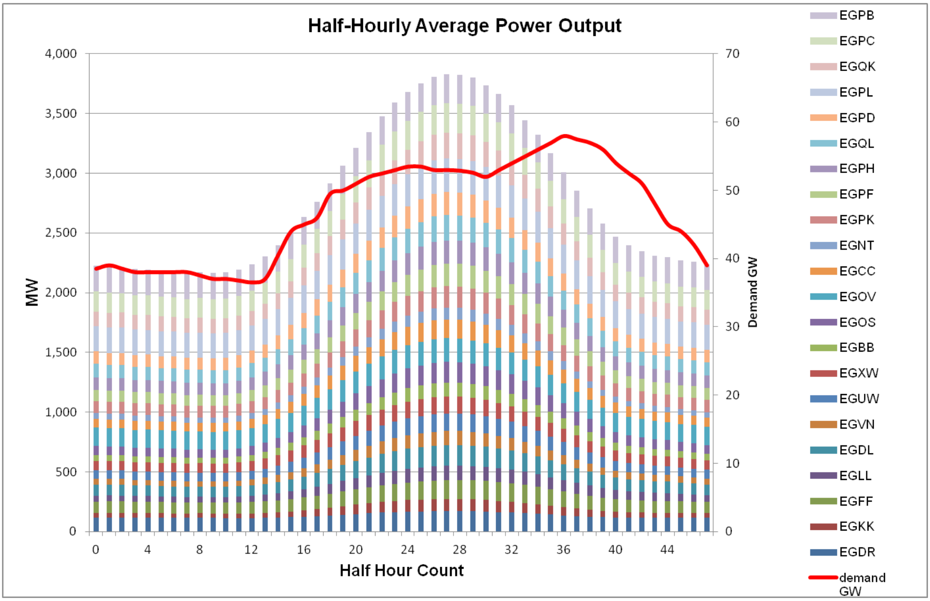


Figure 13 Half-hourly wind fleet output

7 Wind power variability

Two possible sources of wind power variability are:

i the time variability of the wind-speed, and

ii turbines cutting out because the wind-speeds exceed the preset limits.

Table 4 shows the total and annual average number of instances where the wind or wind gust speed surpassed the highest cut out speed of the three wind turbine types in the study—28 m/S for the Enercon V115s. Since the Siemens and Vestas turbines cut out at 25 m/S these will not have been counted unless the wind-speed exceeds 28 m/S.

Station	Total number	Annual number of cut outs
EGDR	455	51
EGKK	39	4
EGFF	56	6
EGLL	36	4
EGDL	60	7
EGVN	31	3
EGUW	54	6
EGXW	81	9
EGBB	48	5
EGOS	66	7
EGOV	103	11
EGCC	95	11
EGNT	190	21
EGPK	88	10
EGPF	116	13
EGPH	139	15
EGQL	67	7
EGPD	77	9
EGPL	329	37
EGQK	167	19
EGPC	348	39
EGPB	304	34

Table 4 Number of high wind-speed cut outs at each station

Since there is a discernible correlation of wind-speeds between groups of the stations (Section 3), it is possible that these cut-out incidents may occur at similar times across the wind fleet.

The variation of the station and country power outputs across timespans of 30 minutes ($\Delta P30$), 60 minutes ($\Delta P60$) and ninety minutes ($\Delta P90$) have been calculated and plotted, Figures 14a–c. Each of the plots shows the average MW variation as a function of the station percentage output. Since nine of the stations have interpolated half-hour data (Section 2.2) these have been dropped from the $\Delta P30$ and $\Delta P90$ studies, and so for these plots the maximum total output has been reduced from 9,030 MW to 5,489 MW. Standard deviation error bars are shown for the UK variation plots.

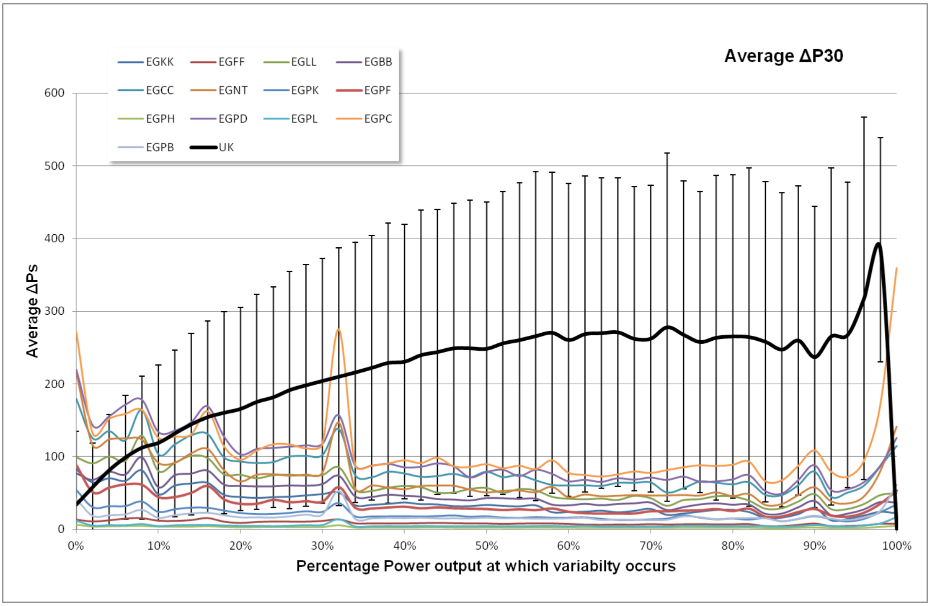


Figure 14a Power variation across a time interval of 30 minutes. Standard deviation spread shown for the UK curve in all such plots.

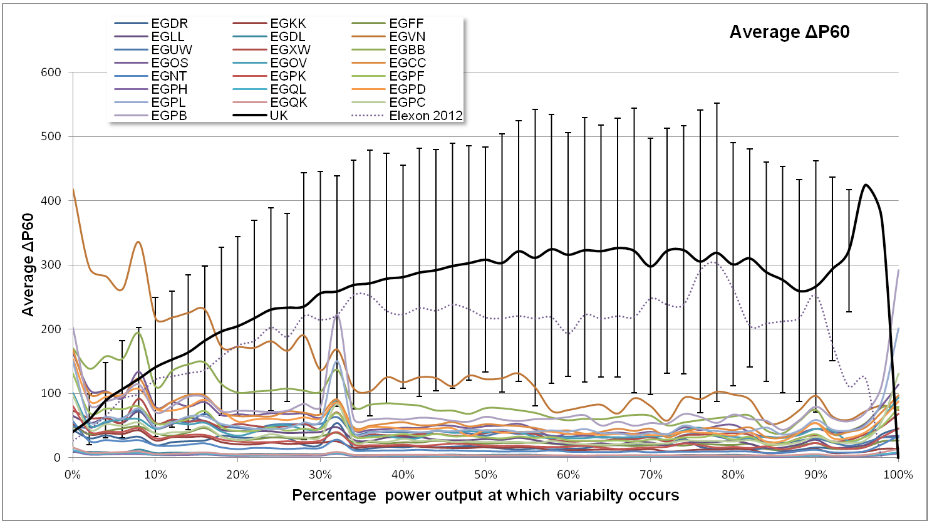


Figure 14b Power variation across a time interval of 60 minutes. (This shows dP60 analysis of data gathered from the balancing mechanism Elexon portal[11] and demonstrates good agreement with the model results; the UK wind fleet size was then slightly smaller than the modelled 10 GW fleet. This Exelon comparison continues in Figures 21 and 22).

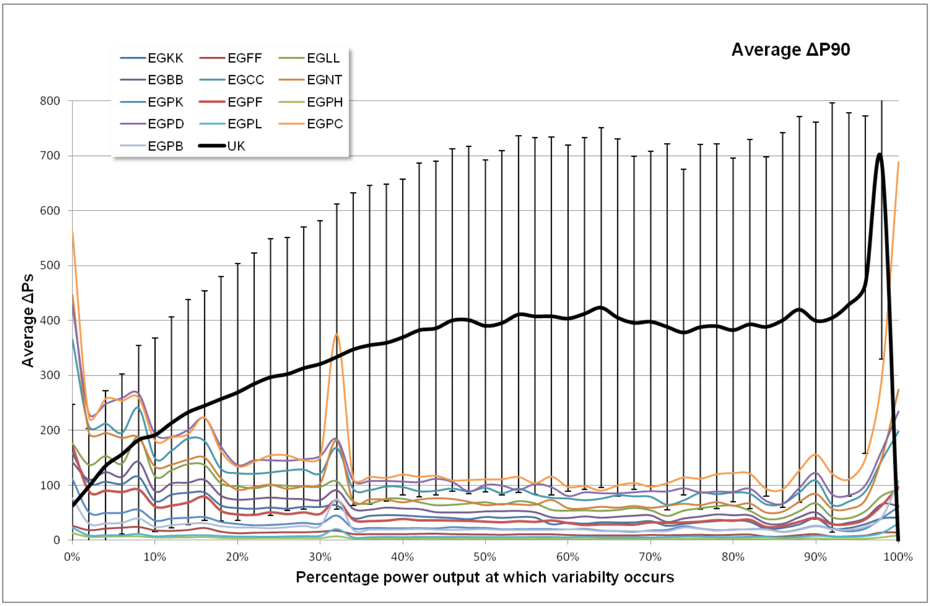


Figure 14c Power variation across a time interval of 90 minutes

These graphs show large variations in the wind fleet output which will inevitably perturb grid frequency. The high variability seen close to full power is due to the high speed turbine cut-outs, see Table 4.

Variability of grid frequency is usually mitigated by operating units such as those of Dinorwig pumped storage station at part load. However, these units are also required for reserve and response duties, so this variability of wind output could increase the costs of maintaining grid frequency close to a steady value.

The cause of this variability is easy to determine if we consider the Weibull wind probability functions for the various stations superimposed on the turbine characteristic curves of Figure 2—see Figure 5. Most of these probability functions peak at wind-speeds below or close to the speed at which the three model turbines start to generate power. In the steeply rising portion of the turbine power output curves the wind distribution curves reveal the main cause of variability of turbine power output.

8 Wind Generation probability distribution and production duration curves

Figures 15 and 16 show the probability distribution (pdf) and production duration curves for the modelled wind fleet.

Both figures show plots typical of fossil fuel plant and demonstrate how different the wind fleets perform. All of the stations have considerable periods where their outputs are close to zero. There have been claims that there is always somewhere in the UK where the wind is blowing. Figure 15 shows that this is the case, but is only sufficient to generate 2 % or less of full wind fleet output. The output mode is approximately 800 MW, 8 % of nameplate capacity. The probability that the wind fleet will produce full output is vanishingly small.

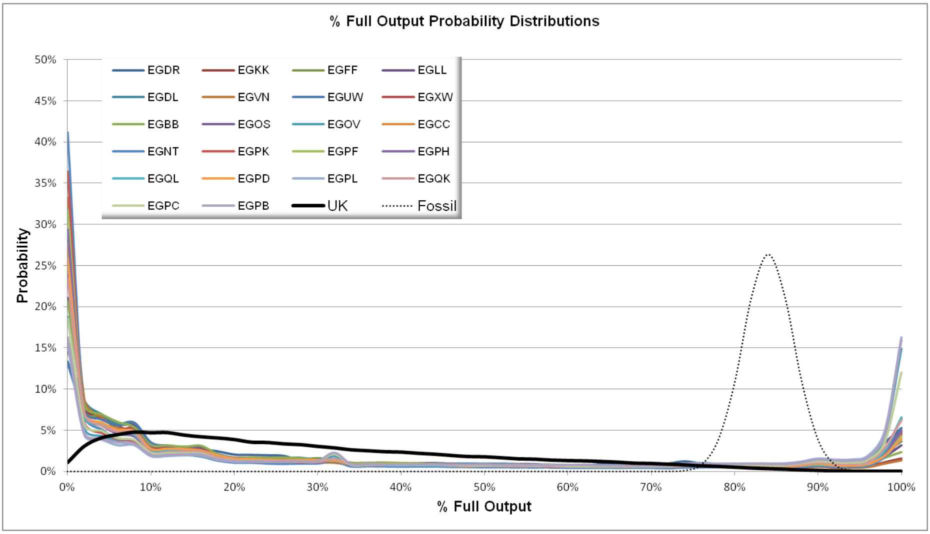


Figure 15 Wind generation power distribution function

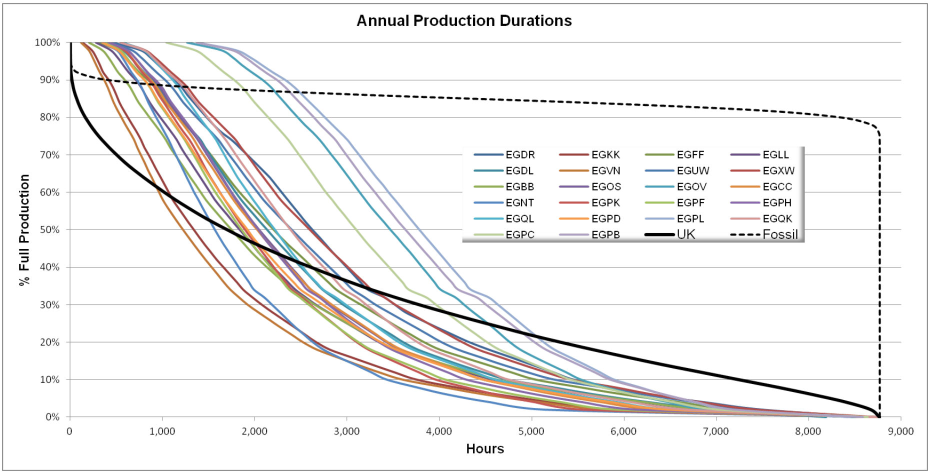


Figure 16 Wind production duration curve

Figure 16 supports the following statements for the entire wind fleet:

- **i** Power exceeds 90 % of available power for 17 hours per annum
- **ii** Power exceeds 80 % of available power for 163 hours per annum
- **iii** Power is below 20 % of available power for 3,448 hours (20 weeks) per annum
- **iv** Power is below 10 % of available power for 1,519 hours (9 weeks) per annum

The impact of the last two statements will be seen when intermittency is discussed in Section 10.

9 Capacity Credit

The capacity credit of a power source is the amount of power output that may be statistically relied upon for grid management purposes, expressed as a percentage of nameplate power capability. Reliability for the UK grid supply system was historically taken as a risk of no more than four winters of grid supply failures every 100 years, implying a risk of failure of 4 %.

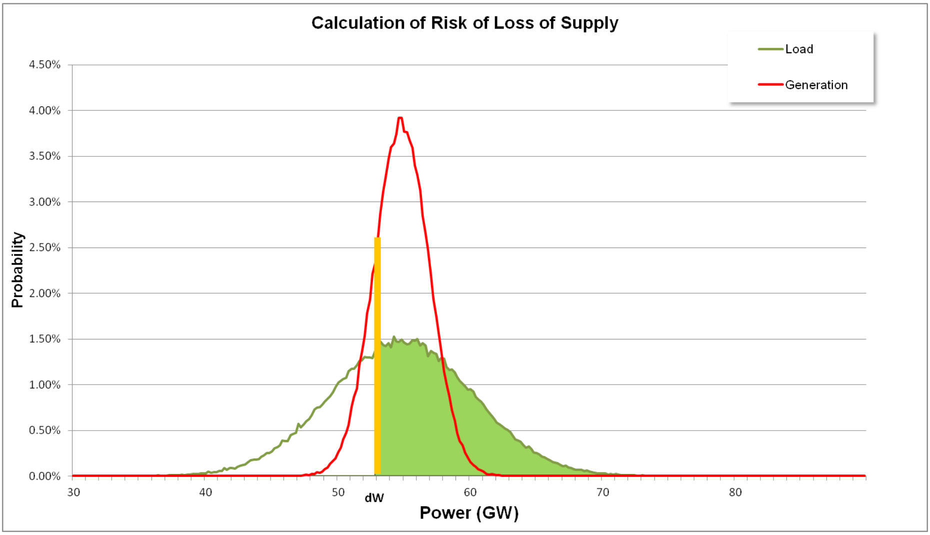


Figure 17 The risk calculation method

Figure 17 illustrates the method of calculating the risk of loss of supply for a given demand load forecast and generation capacity. The probability of not being able to meet the demand for each segment of the generation pdf is the product of generation probability (the orange shaded area) and the probability that the demand load will exceed the generation level (the green shaded area). Summing across all segments of the generation pdf then gives a total risk of loss of supply for the modelled generation capacity.

To determine the capacity credit for the wind fleet proportion of a mixed wind and fossil fuelled fleet it is necessary to

- **i** Define the demand load size and distribution. Here the mean load is taken to be 55 GW, following a normal distribution with a standard deviation of 9.77 % (comprising 9 % forecast uncertainty and 3.8 % weather uncertainty).

ii Take the fossil fuel generation to have a normal distribution with a standard deviation of 3.75 %.

iii Using the techniques described above and illustrated in Figure 17, vary the fossil fuel size to determine that needed to supply the test demand with a risk of supply of 4 %.

iv Repeat this exercise, but now with a combination of the modelled wind fleet and varying fossil fuel fleet sizes. The pdf for the combined wind and fossil fleet was generated by adding at each time-stamp of the model the outputs of wind fleet and the fossil fleet. The wind fleet output was determined as described in Section 2.3; the fossil fuel fleet was calculated using random figures from Excel NORMINV function scaled to the trial fossil fleet size and the standard deviation fixed at 3.75 %. This process of varying the wind/fossil fleet size is illustrated in Figure 18.

v The reduction in fossil fuel capacity requirement seen between steps iii and iv gives the wind capacity credit in GW.

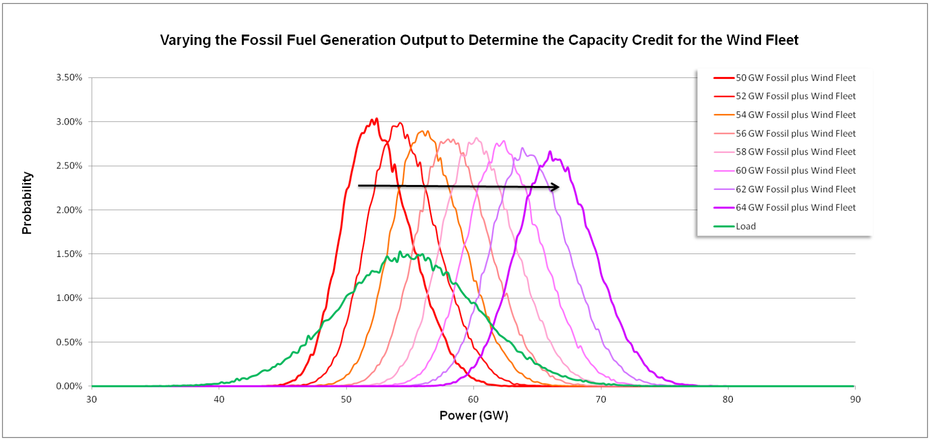


Figure 18 Varying the size of the fossil fleet, mixed with wind

The results are shown in Figure 19 and reveal that the output from the 10 GW of wind plant has displaced the need for approximately 2,300 MW of fossil plant. In section 6 we saw that wind energy production varies seasonally and diurnally, and indicated that more wind energy production may be available to meet the wind peak demand. Using the production data for the winter months only increases the capacity credit by 135 MW; further restricting the data to those periods during the peak demand hours increases the capacity credit by 158 MW. (N.B. The two increases mentioned here are *not* additive).

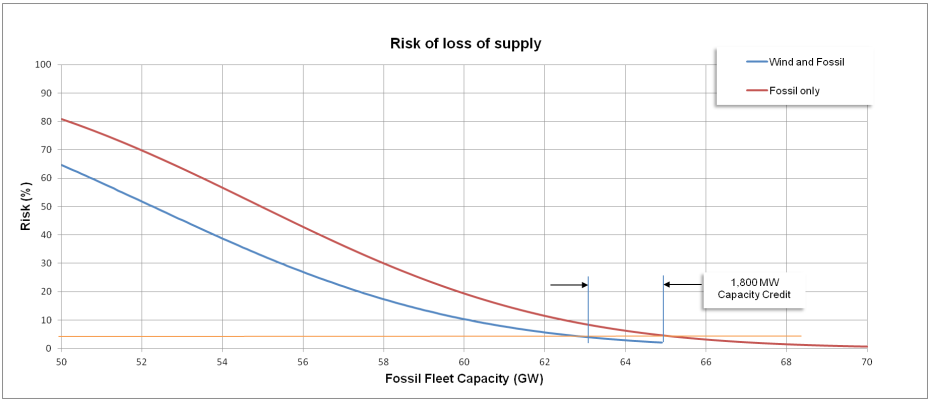


Figure 19 Credit capacity study for the 10 GW wind fleet.

By scaling the wind fleet over a range of available power outputs, calculating the credit capacity at each step, we obtain Figure 20. At low wind fleet sizes the capacity credit is the same as the capacity factor (Figure 8) but declines as more wind power is built. At 40 GW available power the fossil plant displaced is 5,800 MW when the wind shear multiplier figures of Table 1 are used. Figure 20 includes results at varying wind shear multipliers as discussed in Section 5 to portray the sensitivity of the capacity credit values to this variable.

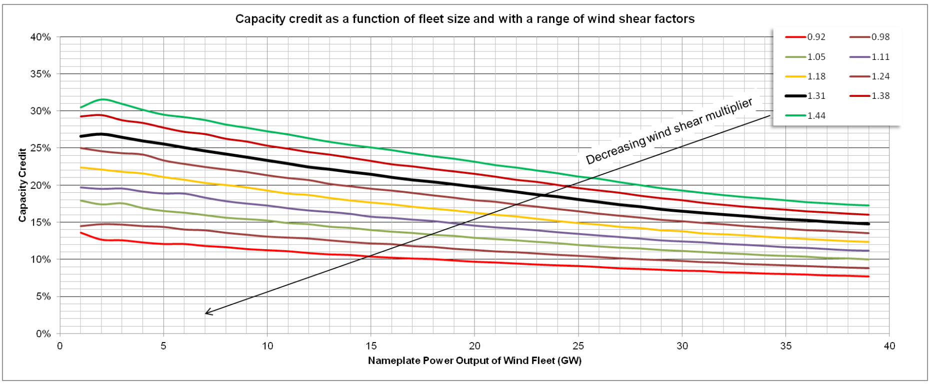


Figure 20 Capacity credit for wind fleets of varying size. The capacity credit is here expressed as a percentage of nameplate fleet power output.

10 Intermittency

Intermittency of wind generation is the term used to refer to periods of long duration when the output of the UK wind fleet falls below certain limits. Although Section 8 has pointed to total durations of low power output from the wind fleet, this feature could be mitigated by demand shedding if low output was confined to short periods of time. However, this is not the case.

The model wind power production was analysed for periods when the output fell below 20 % of the available fleet capacity (~9 GW) for periods longer than 12 hours, and below 10 % for periods longer than 6 hours. These are show in Tables 5 and 6.

Of the 3,448 hours when the power output of the UK wind fleet is below 20 % of maximum, 2,653 hours (77 %) occur in events when that condition is maintained for 12 hours or more.

Of the 1,519 hours when the wind fleet power output is below 10 % of maximum, 1,178 hours (78 %) occur in events when that condition is maintained for 6 hours or more.

Slightly more of these events seem to occur in autumn, but are otherwise evenly spread amongst the seasons.

There were no incidents in the nine year study where the power output exceeded 90 % of full power for a period longer than 6 hours. Reducing the time period to 3 hours reveals 5 incidents when power output exceeded 90 % during the study years, totalling 20 hours duration. There were just 2 incidents when the power output remained above 80 % of full power for a period longer than 12 hours.

Figure 21 shows the longest duration incident where the UK fleet power output fell below 5 % of full power. This occurred on the 6th December 2012 and lasted nearly 24 hours. Data from the actual UK wind fleet extracted from the Exelon portal portal is shown alongside the model data.

Airport	Annual count of periods longer than 12 hours when power fell below 20 % of maximum output				Annual duration (hrs) of these incidents			
	Winter	Spring	Summer	Autumn	Winter	Spring	Summer	Autumn
EGDR	20	28	35	26	591	683	888	753
EGKK	32	43	52	40	1078	1119	1261	1295
EGFF	24	29	34	26	676	705	806	770
EGLL	26	38	36	33	929	970	899	1057
EGDL	23	32	35	25	738	791	857	784
EGVN	31	40	49	40	1174	1166	1470	1364
EGUW	23	33	42	33	687	754	866	871
EGXW	23	31	36	25	744	733	868	690
EGBB	26	33	37	31	915	847	917	941
EGOS	24	35	39	31	851	850	891	935
EGOV	20	26	28	22	671	691	746	644
EGCC	26	35	44	30	940	847	1001	885
EGNT	26	36	42	30	1059	1100	1417	1135
EGPK	22	37	42	27	1042	978	1216	972
EGPF	25	35	48	32	1042	825	1106	984
EGPH	24	34	42	31	994	819	1099	933
EGQL	25	38	46	30	938	846	1122	893
EGPD	25	38	49	31	760	857	1157	855
EGPL	17	21	24	17	470	458	577	447
EGQK	22	36	43	28	824	784	1062	809
EGPC	19	22	37	21	498	494	868	516
EGPB	14	19	29	16	335	540	928	412
UK	23	18	28	37	617	594	562	880

Table 5 Periods of longer than 12 hours when power outputs have fallen below 20 % of the station maximum output

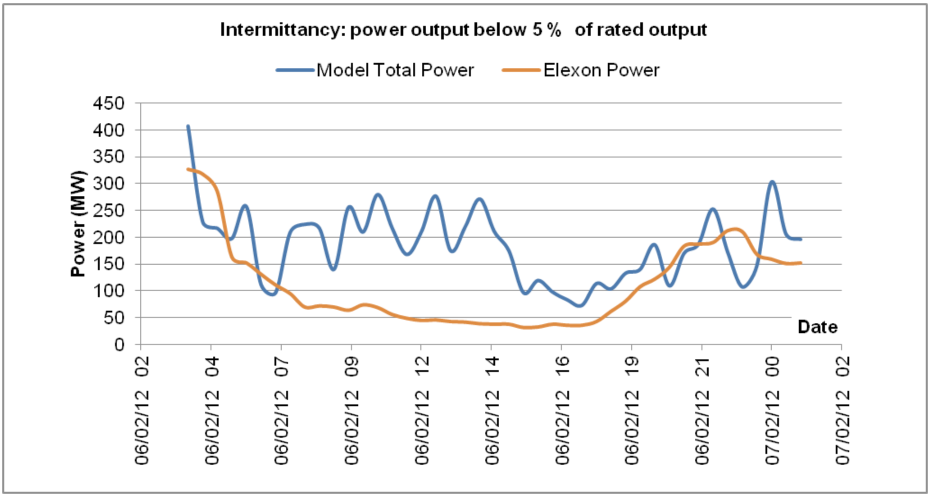


Figure 21 An example of output intermittency

Airport	Annual count of periods longer than 6 hours when power fell below 10 % of maximum output				Annual duration (hrs) of these incidents			
	Winter	Spring	Summer	Autumn	Winter	Spring	Summer	Autumn
EGDR	31	37	46	37	500	544	687	603
EGKK	44	59	70	56	911	947	1027	1094
EGFF	32	42	49	38	548	590	669	609
EGLL	35	51	50	44	722	767	695	802
EGDL	32	41	49	36	553	617	686	603
EGVN	44	55	68	55	980	962	1225	1162
EGUW	29	39	49	39	513	533	636	636
EGXW	32	41	48	34	555	581	686	518
EGBB	35	44	51	42	709	666	737	709
EGOS	36	48	55	45	714	723	774	777
EGOV	30	37	39	32	604	599	624	572
EGCC	38	47	56	42	795	731	831	747
EGNT	38	53	65	44	980	1031	1277	1073
EGPK	33	48	61	41	981	872	1049	884
EGPF	37	48	63	44	955	755	979	876
EGPH	36	47	59	44	891	730	945	830
EGQL	38	50	62	42	795	722	933	757
EGPD	36	51	64	42	681	735	973	714
EGPL	26	28	33	24	429	399	466	393
EGQK	31	45	60	40	722	677	914	708
EGPC	27	34	49	31	438	460	764	462
EGPB	22	29	41	22	319	453	737	352
UK	17	12	21	35	261	216	250	451

Table 6 Periods of longer than 6 hours when power outputs have fallen below 10 % of the station maximum output

The impact of this power output intermittency can be portrayed by calculating an accumulating deficit of 'lost' energy production for those periods when wind output falls below various target values. As a first step, we make our target production output equal to the capacity credit value of 2,300 MW calculated in Section 9 and for each period when the wind fleet output falls below this we calculate the lost energy production in that half-hour period and add that to a running energy deficit accumulator. We reset this accumulator to zero only when the wind output surpasses 2,530 MW (10 % above 2,300 MW). We can liken this process to the wind fleet being required to deliver a guaranteed minimum power output, and accomplishing this by calling upon a pumped storage system of limitless energy storage. In Figure 22 we show the running deficit accumulator during winter of 2012–13 together with the calculated model output and the UK wind power recorded by the Exelon portal[11].

The reader should first note the number of periods during this winter period when the wind fleet does not meet the target production. Similar results are observed in all of the study winter periods.

This is the MET Office narrative for the 10th to 13th December 2012:

> *10th to 13th:*
>
> **Pressure built**, *and there were then a few days of quiet anticyclonic weather, allowing the first really* **severe frosts** *of the season. 10th was bright and sunny for most, with the exception of light wintry showers in the east. Overnight fog was often slow to clear during the day and caused some travel problems. A few wintry showers continued to affect eastern coastal areas. By 13th cloud and milder conditions reached the far south-west.*

(author's bold)

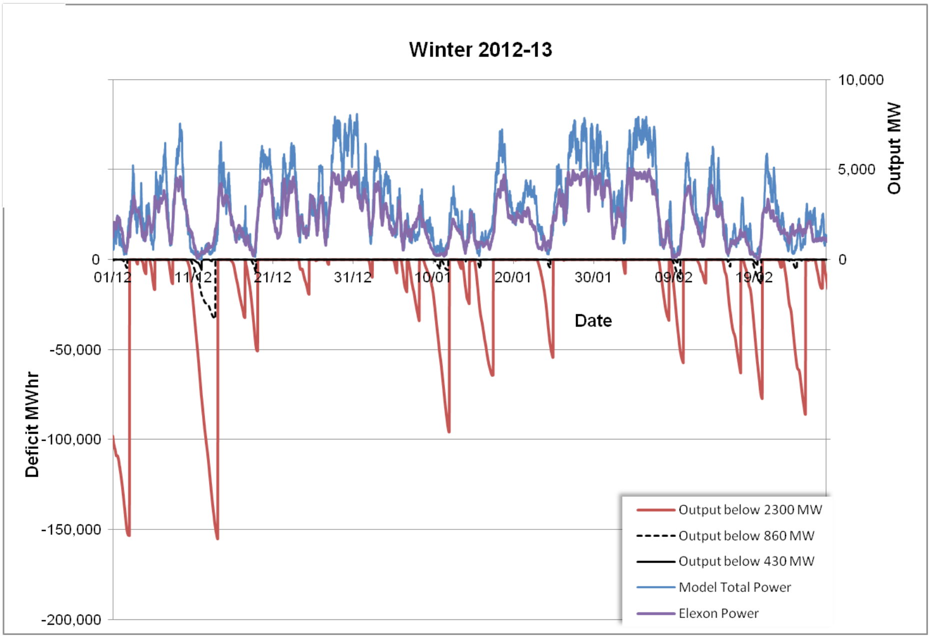


Figure 22 Energy deficit calculated against a wind fleet output targets of 2,300 MW (red plot) and 943 MW (dashed black plot).

Secondly, Figure 22 shows production deficits as high as 150 GWh. The storage capacity of one of the UK's largest pumped storage station (Dinorwig) is only 10 GWhr. Figure 15 (the wind pdf) reveals a weak mode at 9.5 % of maximum available power (860 MW) and this was tested (reset limit set to 946 MW) as a possible production target, see Figure 22, dashed black series. This result is an improvement but is still too high. Halving the target again, to 430 MW reduces the deficit to small amounts. In January 2005 the model shows the deficit running as high as 260 GWh with the deficit limit set to 2,300 MW, but reducing this to 430 MW again clears the deficit.

The UK fossil fleet relies on four primary sources of energy: oil, gas, coal and nuclear. The fossil fuel routes are either our own production or imports from several different countries using different transport systems and UK entry points. Apart from imports of uranium we also have a considerable stockpile. The generating plants are varied in design and supply manufacturer. This generation diversity is important because the UK is an island grid and would thus be at risk if the generation system had common mode methods of failure. However, the wind fuel route is completely outside our control and does show correlation across the UK (Figure 7). This gives the wind fleet a common mode failure mechanism which has been shown in this section to occur several times a year. Figure 13 indicates that there may even be some correlation between wind and solar generation performance, since wind production is consistently higher during daylight periods.

11 Interconnection to Ireland and Europe

Europe has the world's richest wind resources and advances in technology have made the process of converting wind to electricity more effective and commercially competitive. Airtricity's vision is to harness this natural energy resource by creating a European Offshore Supergrid located in the seas of Northern, Western and Southern Europe.

By connecting and integrating geographically disperse wind farms across Europe, each experiencing a different phase of the region's weather system, electricity is produced wherever the wind is blowing and transported to regions of demand, ensuring a reliable and predictable source of energy.

Airtricity

Can interconnection to Ireland and Europe solve the problem of wind intermittency? This was investigated by extending the modelling system employed for the UK to northern Europe and Ireland. The northern Europe study included wind farms in Belgium, Holland, Denmark and the northern plane of Germany. Details of the stations studied are given in appendix B. The wind farms were scaled to reflect the present size of the onshore wind installation in each country. A similar study was applied to four stations in the island grid of Ireland, details in appendix C. The full study therefore covers a span of 25 degrees of longitude, and ten of latitude and includes 43 'monitoring' sites over a period of nine years.

The available power from the north European system is 35.4 GW, and the production duration curves reveal the same symptoms of intermittency seen for the UK:

- **i** Power exceeds 90 % of available power for 23 hours per annum,
- **ii** Power exceeds 80 % of available power for 143 hours per annum,
- **iii** Power is below 20 % of available power for 5,214 hours (31 weeks) per annum,
- **iv** Power is below 10 % of available power for 3,353 hours (20 weeks) per annum.

As before, the incidents of low power output were of long duration, see Table 7.

Little wonder, then, that for the German system the IFO Institute has commented:

[for] the year 2011 … the installed capacity of [wind and solar] … was 54 gigawatts. For some hours up to 27 gigawatts were generated, but at other times it was as low as 0.5 gigawatts. The average generation was 7.3 gigawatts. The secured capacity that was available in 99.5 percent of all hours was only 0.9 gigawatts.[7]

Duration below percentage power	Annual count of periods				Annual duration (hours) of these incidents			
	Winter	Spring	Summer	Autumn	Winter	Spring	Summer	Autumn
>12 hours, < 20 %	33	18	38	45	1173	863	1060	1385
>6 hours, < 10 %	36	21	42	59	760	548	650	931
>6 hours, < 5 %	24	13	23	38	360	239	280	460

Table 7 North European intermittency analysis for periods when the total output fell below 7.08, 3.54 and 1.77 GW out of an available capacity of 35.4 GW.

The total available capacity of the modelled Irish system was 2,232 MW. The production duration curves for Ireland reveal:

- **i** Power exceeds 90 % of available power for 374 hours per annum,
- **ii** Power exceeds 80 % of available power for 795 hours per annum,
- **iii** Power is below 20 % of available power for 3,812 hours (23 weeks) per annum,
- **iv** Power is below 10 % of available power for 2,433 hours (14 weeks) per annum.

The tabulation of long duration low power output incidents for Ireland is given in Table 8.

Duration below percentage power	Annual count of periods				Annual duration (hours) of these incidents			
	Winter	Spring	Summer	Autumn	Winter	Spring	Summer	Autumn
>12 hours, < 20 %	22	19	26	30	605	581	612	753
>6 hours, < 10 %	25	21	29	34	413	364	410	495
>6 hours, < 5 %	14	11	16	21	179	159	187	233

Table 8 Irish wind system intermittency for periods when the wind output fell below 446, 223, and 112 MW.

Because all three areas studied have half-hourly observations at times within 10 minutes of each other, synchronised during the data handling process (Section 2.2) it is possible to combine the three and determine whether there is any indication of pan European intermittency, or if the large geographical spread of the stations eliminates this problem. The power distribution functions of the three systems can be combined into one for the whole of Europe, and then we can assess the capacity credit for this system. Figures 23–25 show plots for the combined system.

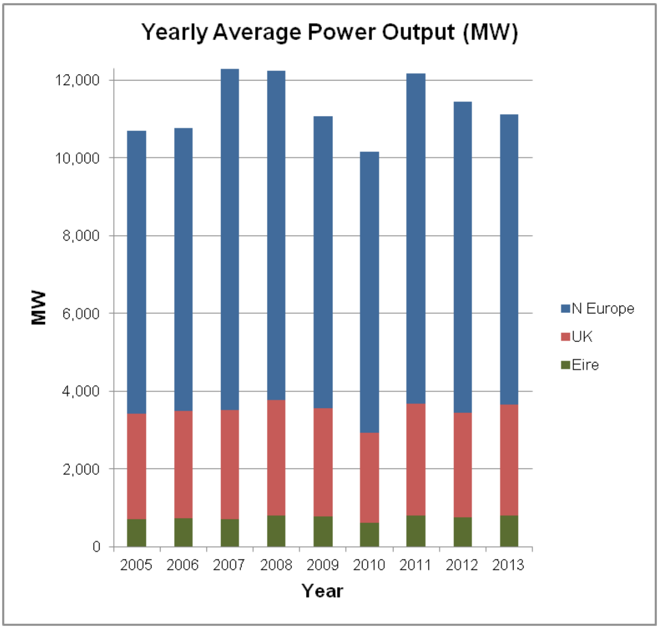


Figure 23 Total European wind production in each year.

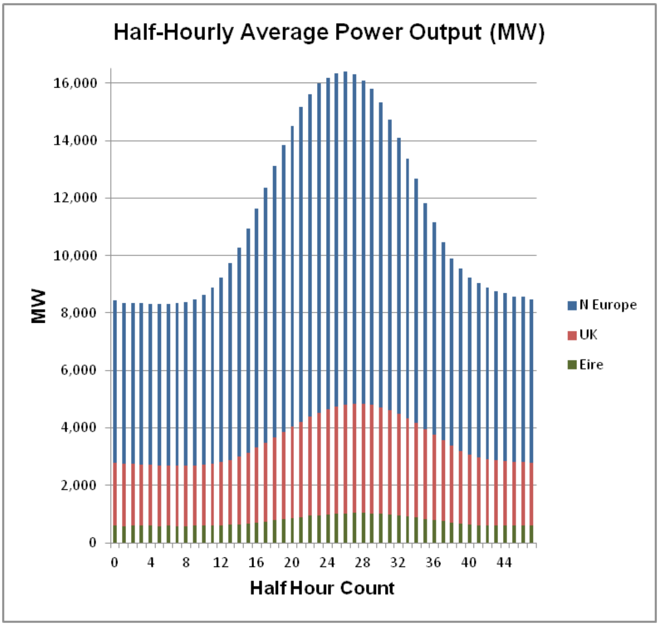


Figure 24 European wind diurnal production

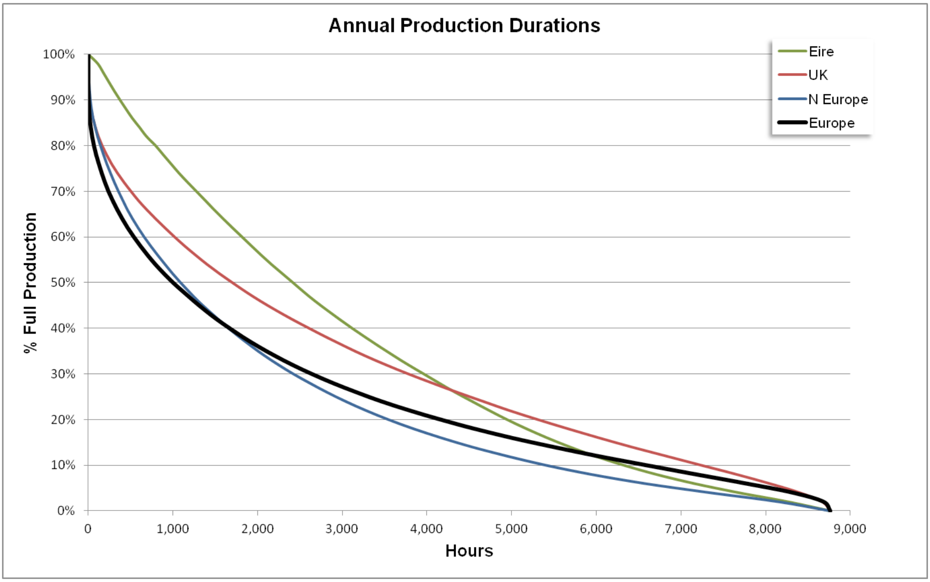


Figure 25 European wind production duration curves

For the combined system, which has an available power output of 48.8 GW, Figure 25 shows:

- **i** Power exceeds 90 % of available power for 4 hours per annum,
- **ii** Power exceeds 80 % of available power for 65 hours per annum,
- **iii** Power is below 20 % of available power for 4,596 hours (27 weeks) per annum,
- **iv** Power is below 10 % of available power for 2,164 hours (13 weeks) per annum.

Comparing these results with those for the UK the 80 % and 90 % power bands for the combined system have lower occupancy, and the 10 % and 20 % power bands have higher occupancy.

Determining what proportion of the low power output occur within prolonged periods of low power output across all of Europe we have Table 9:

Incident parameters duration/power	Annual count of periods				Annual duration (hours) of these incidents			
	Winter	Spring	Summer	Autumn	Winter	Spring	Summer	Autumn
>12 hours, < 20 %	34	18	40	49	605	581	612	753
>6 hours, < 10 %	28	18	32	52	480	359	405	695
>6 hours, < 5 %	9	6	10	22	119	79	100	224

Table 9 Analysis of intermittency incidents from wind turbines for European wind fleet.

Interconnection has reduced the number and duration of prolonged wind power breaks, but it has not eliminated them. Here (Figure 26) is an example of a period when the power was below 5 % of available power for as long as 44 hours spanning part of an autumn peak demand period:

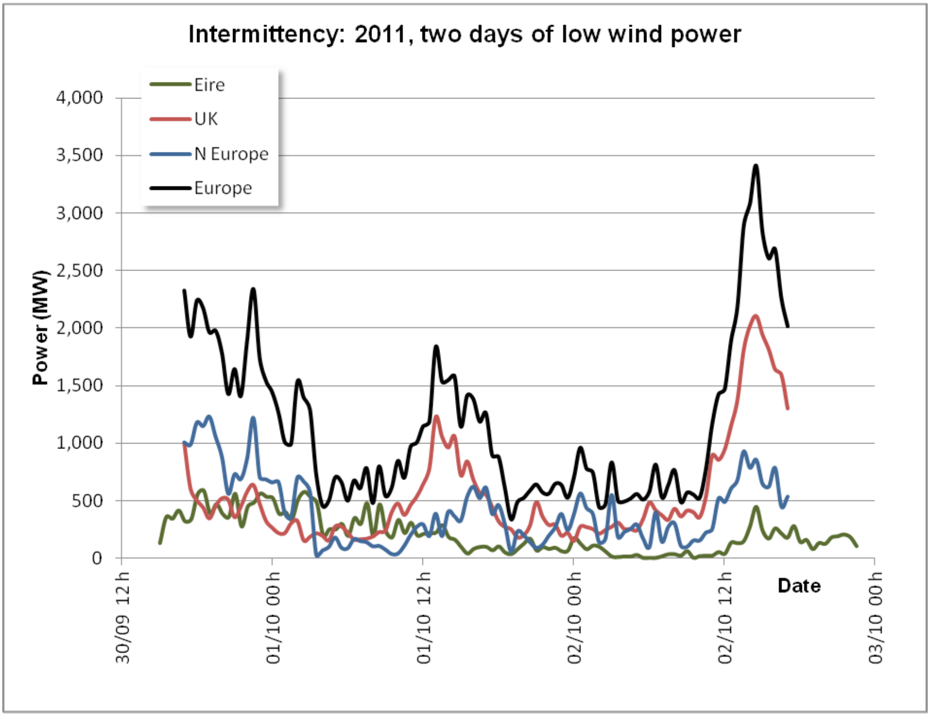


Figure 26 European grid intermittency: example.

The combined power distribution function for the whole system is shown in Figure 27.

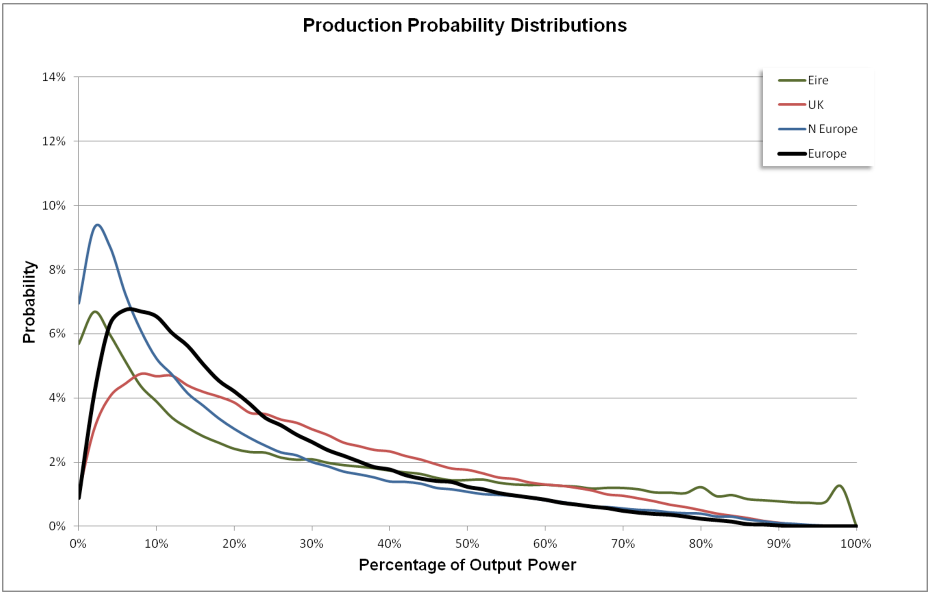


Figure 27 European wind pdf

The capacity credit calculation method described in Section 9 can now be applied using the European wind pdf as if it were available for the UK system. It is capable of displacing 3,740 MW of fossil plant, compared to 2,300 MW for the UK wind system. On that basis, the net benefit of the interconnectors to the UK would be approximately 1,400 MW, assuming that the other European grids have no need of their wind fleet outputs, and there is sufficient interconnection capacity when required.

If the energy deficit macro is run based on European wind production with the deficit criteria set to 3,740 MW this reveals energy deficits reaching 20,000 GWh see Figure 28. Reducing the deficit limit to 2,000 MWh comes close to reducing the deficit to zero.

Figures 26 and 28 reveal large variability of output from the pan European wind fleet.

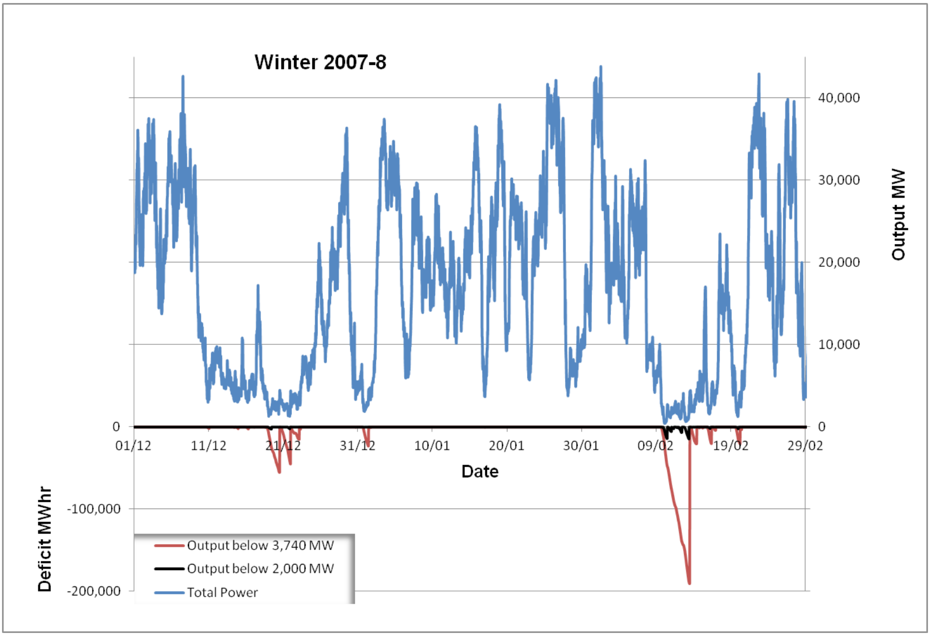


Figure 28 Energy deficit plot for the European wind fleet, low power limit set to 3,740 MW

12 Conclusions

The study is based upon wind observations at sites where accuracy is critical to aviation safety and the anemometers are installed to an international standard. The turbine characteristics for the model stations are taken from manufacturers' data sheets where commercial sales and risk encourage accuracy. The main sources of systematic error in this paper are the selection of the wind shear multiplier described in Section 2.3 and the assumed wind plant availability. The derived capacity factors suggest that such errors will be small, as does comparisons with data from the Elexon portal (Figures 14b, 21 and 22).

Wind-speeds have a considerable correlation across the whole of the UK, and over time periods as long as 90 minutes—Section 3. This is probably because the UK is subject to a succession of depressions that waft (and occasionally rush) in from the Atlantic, interspersed with regions of high pressure (and low wind) which can stretch across the whole of Europe.

The average wind-speeds over the nine-year study observation period suggest that some wind-speeds given in the European Wind Atlas may be optimistic, especially for the east coast of the UK, and most of Scotland, see Section 3.

In Sections 6 and 7 it can be seen that in spite of the geographical spread of the modelled wind fleet, the output for the whole system shows high levels of variability. During periods of low demand, when the grid is lightly loaded, this will cause grid frequency variations which will require regulation from part-loaded, fossil-fuelled/pumped-storage plant with strong governor action. Figure 5 shows that the wind-speed probability distributions at all of the sites have peaks coincident with low wind turbine outputs; most of the power production will occur in the rising portion of the turbine power characteristic, and that very little maximum power production will be seen.

In Section 7 we have also revealed the large number of high wind-speed cut-outs the model fleet experienced. Given the correlation of wind-speeds reported in Section 3 it is inevitable that some of these power cut-outs may be coincident which raises further stability control problems for the grid. This has been reported as merely an occasional feature of the present wind fleet operations, perhaps because it employs very few wind turbines with hub heights similar to those of the model.

Claims that there is always somewhere in the UK where the wind is blowing are correct, but only sufficient to generate 2 % or less of full wind fleet output. The power output mode is approximately 800 MW, 8 % of nameplate capacity. The probability that the wind fleet will produce full output is vanishingly small.

The capacity credit for the model wind fleet was determined to be 2,300 MW. The variation of this value with wind fleet size and average wind shear multiplier has also been shown (Section 9).

The UK wind resource is very intermittent. The power duration curve reveals many hours in each year when the power output falls below 20 % of available power (3,448 Hours) and 10 % of available power (1,519 hours). Moreover, over three quarters of these low power output occurrences have durations longer than six hours or more.

If a notional target power equal to the capacity credit for the 10 GW modelled fleet is tested during winter periods, this can only be maintained at a constant supply level by building considerable amounts of pumped storage (perhaps 15 'Dinorwigs'), or providing sufficient fossil-fuelled plant to protect against loss of supply during these wind lulls. Only reducing this target power output to 430 MW eliminates the requirement for backup storage.

The model wind fleet would require a conventional generation fleet to be built and operated alongside it to provide energy delivery to compensate for the deficiencies described in the preceding four paragraphs.

There is a strong diurnal effect in wind energy production which shows some correlation with the time of the afternoon peak demand, but this is not sufficient to show any significant effect upon the calculation of capacity credit described in Section 9. Wind power is therefore an unreliable aid to meeting this peak demand. The coincidence of this wind production surge with solar production will cause further difficulties in grid system management.

The Irish wind resource is similar to that of the UK's and since that is also an island grid, will also face grid system management problems similar to the UK. The modelled wind fleet for the northern European plane shows much poorer levels of production. Most of the German stations have capacity factors close to 20 %.

Even if these three systems are interconnected, the problem of wind intermittency remains.

Given the above conclusions the only benefit the UK wind fleet brings to the UK is that of reduced dependency on fossil-fuel imports. However, mitigation of wind variability and intermittency will reduce this saving[8].

It is difficult to see how these problems of variability and intermittency can be resolved by improved wind turbine engineering. It is often claimed that this is a new technology, but that is incorrect. Most of the blade aerofoil design and control will depend on nearly a century of aviation research, and the electrical generator will follow common electrical engineering practise.

The study has assumed a constant availability for the wind plant of 90 %. However, recent studies (Hughes[9], Staffel and Green[10]) show wind output declining quite markedly over time, but the rates of decline are disputed. The use of wind data as used in this study could perhaps resolve this disagreement.

Acknowledgements

I am grateful to Professor David Last and Professor Iain MacLeod for their patient encouragement, guidance and suggestions through several drafts of this paper.

Dr Chris Dent put me on the right track with the Capacity Credit section and with comments elsewhere.

Throughout this study I have been helped enormously by Colin Gibson who not only brought his insight and experience with National Grid to this paper, but also had to read, and then reread this paper through several drafts.

About the author

Dr Capell Aris worked in the Electricity Supply Industry first as reactor physics specialist at Wylfa nuclear power station, and then at Dinorwig and Ffestiniog pumped storage stations in the control and instrumentation section and later with additional responsibility for information technology systems. He holds a private pilot's licence and is a Fellow of the Institute of Engineering and Technology.

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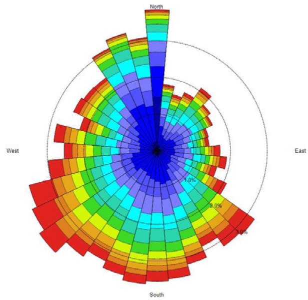
Appendix A

Wind Roses for the 22 stations for the period 2005–13

Wind speed (mph)

25–28
12–25
11–12
10–11
9–10
8–9
7–8
6–7
5–6
4–5
2–4
1–2

EGPB



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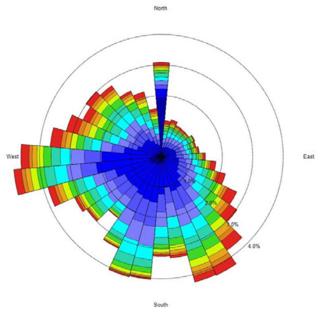

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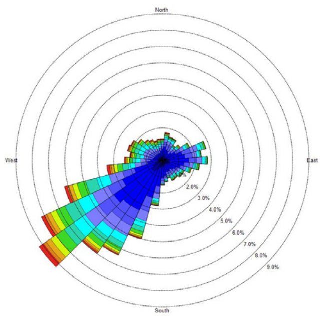

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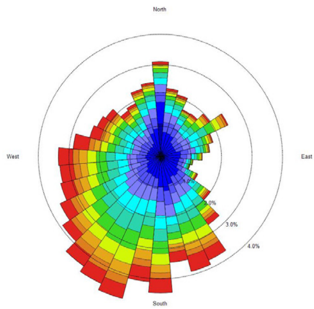

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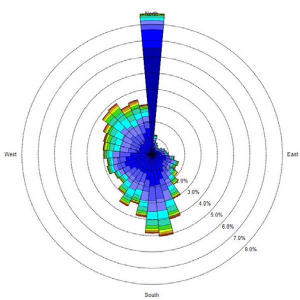

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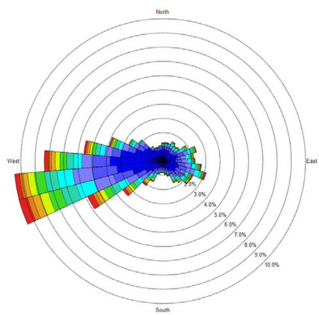

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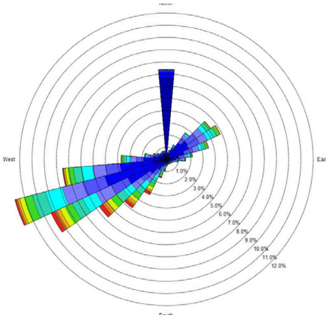
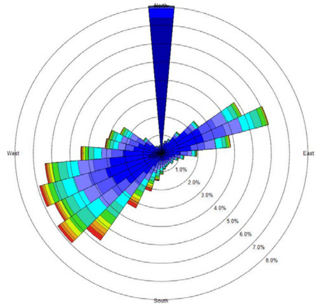


EGPF



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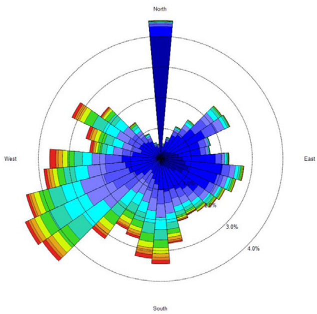

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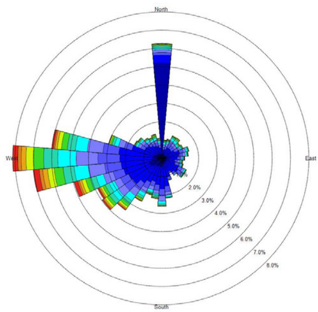
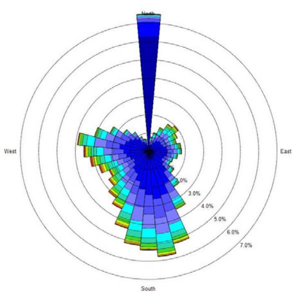


EGCC



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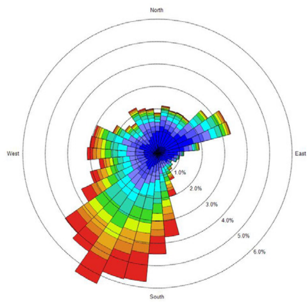

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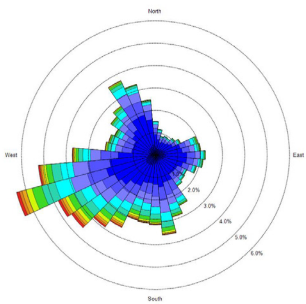
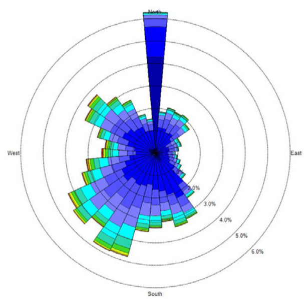


EGBB



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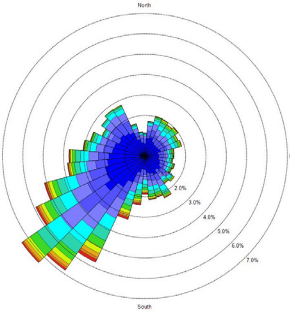

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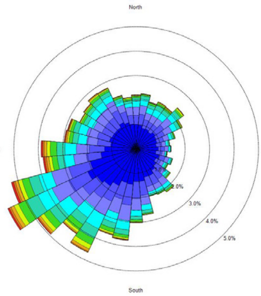

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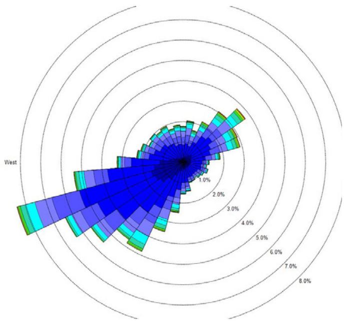

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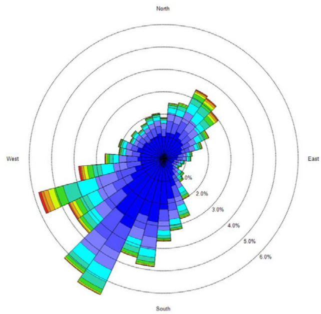

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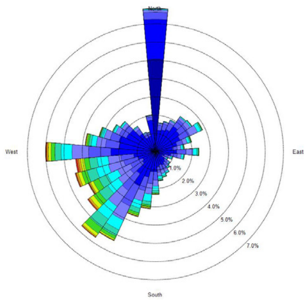

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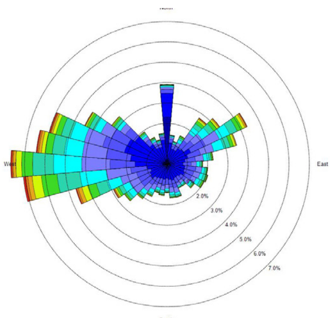

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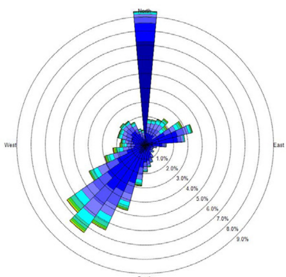

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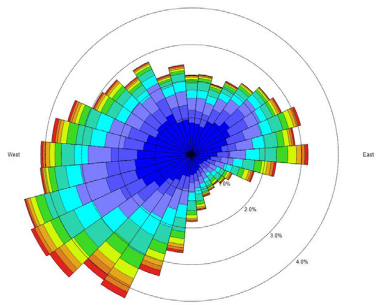

Location	ICAO	Weibull Constants	
		Shape	Scale
Culdrose	EGDR	2.171031	8.662663
Gatwick	EGKK	2.043133	5.984332
Cardiff	EGFF	2.25212	7.584025
Heathrow	EGLL	2.101957	6.626302
Lyneham	EGDL	2.154609	7.131918
Brize	EGVN	1.842572	5.515794
Wattisham	EGUW	2.200623	7.39692
Wadington	EGXW	2.114967	7.605627
Birmingham	EGBB	2.226706	6.610413
Shawbury	EGOS	1.774141	6.653557
Valley	EGOV	1.791079	10.32089
Manchester	EGCC	1.913795	6.776587
Newcastle	EGNT	1.574323	6.435566
Prestwick	EGPK	1.721811	7.417242
Glasgow	EGPF	1.785287	6.962832
Edinburgh	EGPH	1.806912	7.260308
Leuchars	EGQL	1.698499	7.717237
Aberdeen	EGPD	1.92495	7.089075
Benbecula	EGPL	1.942495	10.67381
Kinloss	EGQK	1.772917	7.505987
Wick	EGPC	1.805617	9.129729
Sumburgh	EGPB	1.928471	10.44029

Table A1 Weibull constants for the fleet stations

Weibull Equation:

$$f(x) = \frac{k}{\lambda}\left(\frac{x}{\lambda}\right)^{k-1} \exp\left(\left(-{}^{x}\!/_{\lambda}\right)^{k}\right)$$

where k is the shape parameter and λ is the scale parameter.

Appendix B

Northern Europe Analysis

Total, modelled, available capacity for the north European area was 35.4 GW. Station details are given in Table B1.

Name	ICAO	Latitude	Longitude	No. of Enercon	No. of Siemens	No. of Vestas	Wind shear Multiplier	Availability P_f	Site maximum power (MW)
Ostend	EBOS	N51°11′59	E02°51′49	40	52	40	1.23	0.9	324
Lille	LFQQ	N50°33′48	E03°05′13	40	52	40	1.3	0.9	324
Brussels	EBBR	N50°54′05	E04°29′04	40	52	40	1.3	0.9	324
Amsterdam	EHAM	N52°18′29	E04°45′51	111	145	111	1.3	0.9	900
Eelde	EHGG	N53°07′30	E06°35′00	111	145	111	1.3	0.9	900
Dusseldorf	EDDL	N51°17′22	E06°46′00	404	527	404	1.3	0.9	3272
Esbjerg	EKEB	N55°31′33	E08°33′12	144	188	144	1.23	0.9	1167
Bremen	EDDW	N53°02′15	E08°47′12	404	527	404	1.3	0.9	3272
Billund	EKBI	N55°44′25	E09°09′07	144	188	144	1.3	0.9	1167
Hannover	EDDV	N52°27′39	E09°41′06	404	527	404	1.3	0.9	3272
Hamburg	EDDH	N53°37′49	E09°59′28	404	527	404	1.3	0.9	3272
Roskilde	EKRK	N55°35′08	E12°07′53	144	188	144	1.23	0.9	1167
Dresden	EDDC	N51°25′20	E12°14′11	404	527	404	1.3	0.9	3272
Rostok	ETNL	N53°55′06	E12°16′42	358	468	358	1.3	0.9	2902
Berlin	EDDB	N52°22′43	E13°31′14	404	527	404	1.3	0.9	3272
Leipzig	EDDP	N51°08′04	E13°46′05	404	527	404	1.3	0.9	3272
Stettin	EPSC	N53°35′05	E14°54′08	404	527	404	1.3	0.9	3272

Table B1 Northern European airfields issuing METARS used in this study

Capacity factors for these stations were lower than the UK's, see Figure B1.

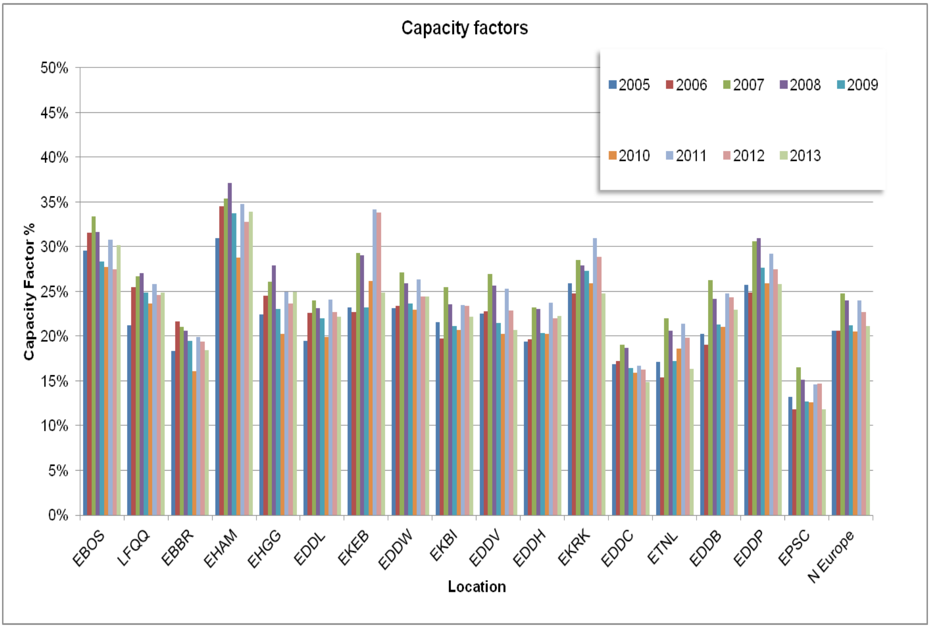

Figure B1 Northern Europe capacity factors

The yearly production (Figure B2) reveals 2010 to be the lowest year but here the fall is not so marked as for the UK. The diurnal variation of wind production (Figure B3) shows the same peak about local noon. Figure B4 shows the production duration.

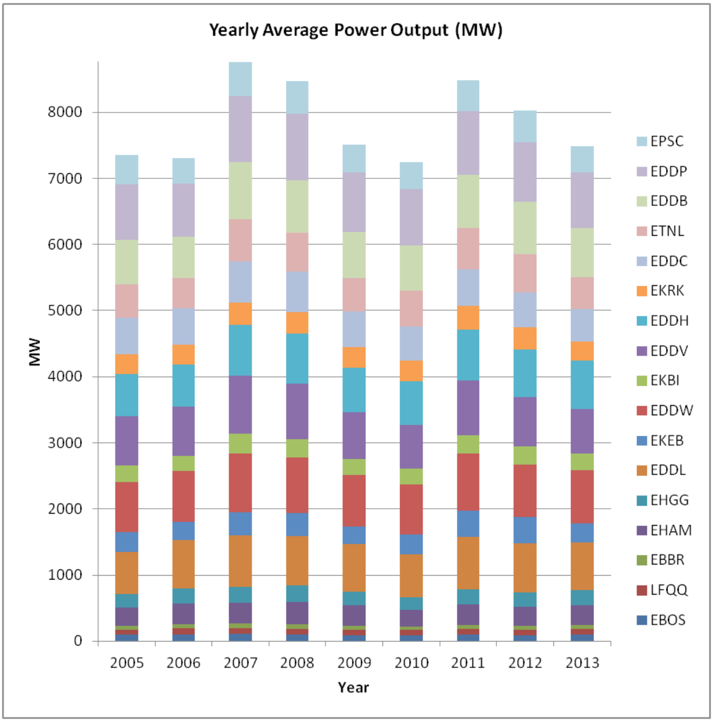

Figure B2 Northern Europe yearly wind production.

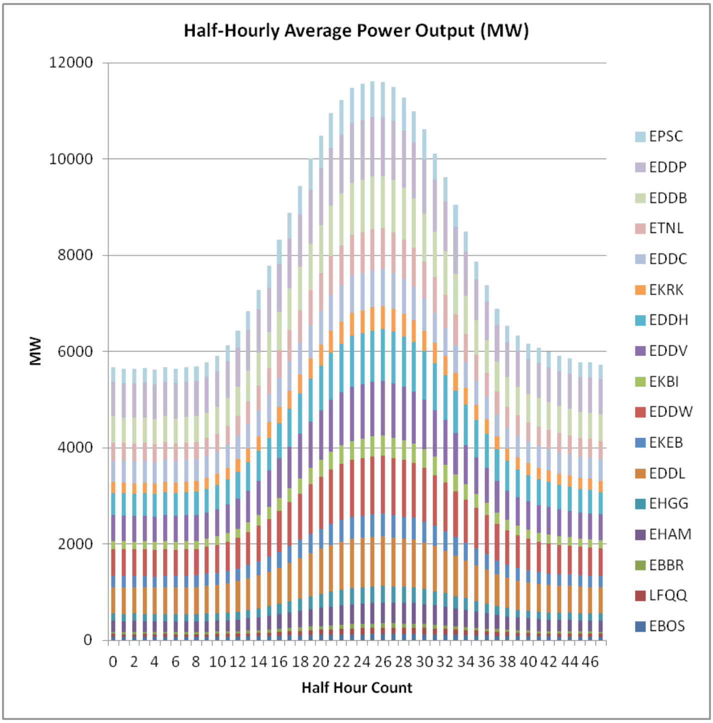

Figure B3 Northern Europe diurnal wind production.

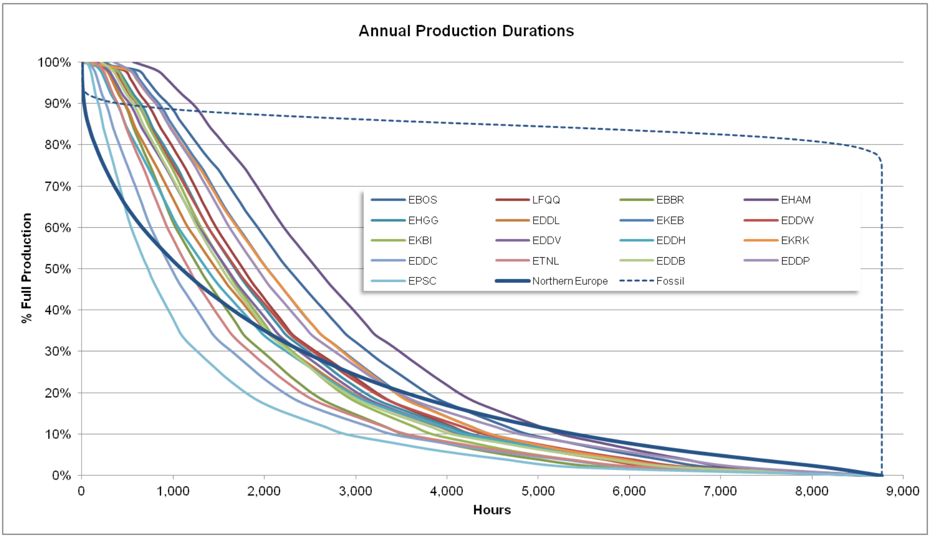

Figure B4 Production duration curves for northern Europe.

Appendix C

Irish System Analysis

Total, modelled, available capacity for the Irish system was 2,223 MW. Station details are given in Table C1.

Name	ICAO	Latitude	Longitude	No. of Enercon	No. of Siemens	No. of Vestas	Wind shear Multiplier	Availability P_f	Site maximum power (MW)
Cork	EICK	N51°50′27	W08°29′20	77	101	77	1.3	0.9	625
Shannon	EINN	N52°42′04	W08°55′15	77	101	77	1.23	0.9	625
Dublin	EIDW	N53°25′52	W06°15′12	77	101	77	1.3	0.9	625
Belfast	EGAA	N54°39′15	W06°13′30	44	58	44	1.3	0.9	358

Table C1 Irish airfields issuing METARS used in this study.

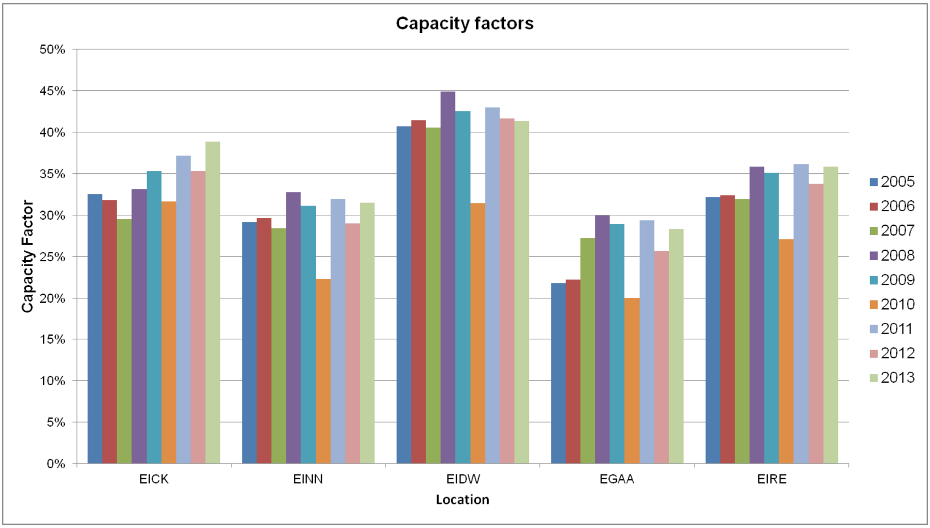

Figure C1 Irish capacity factors

Production in 2010 was dramatically lower than usual in Ireland, see Figure C2. The usual diurnal production profile is also displayed, Figure C3. Figure C4 shows the production duration curve

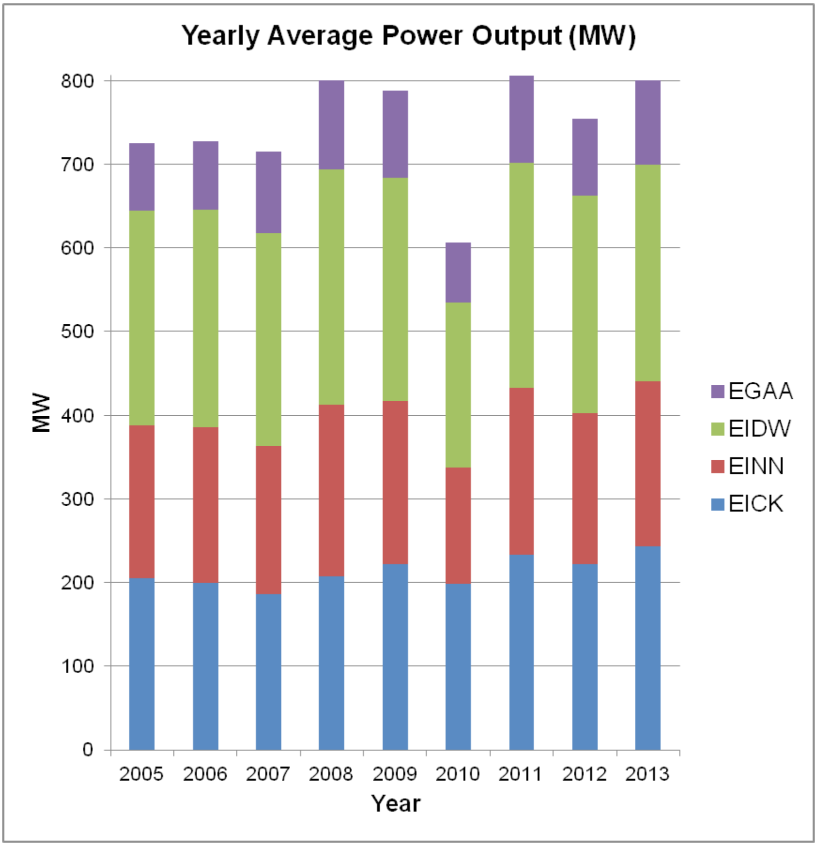

Figure C2 Yearly production from the Irish wind system

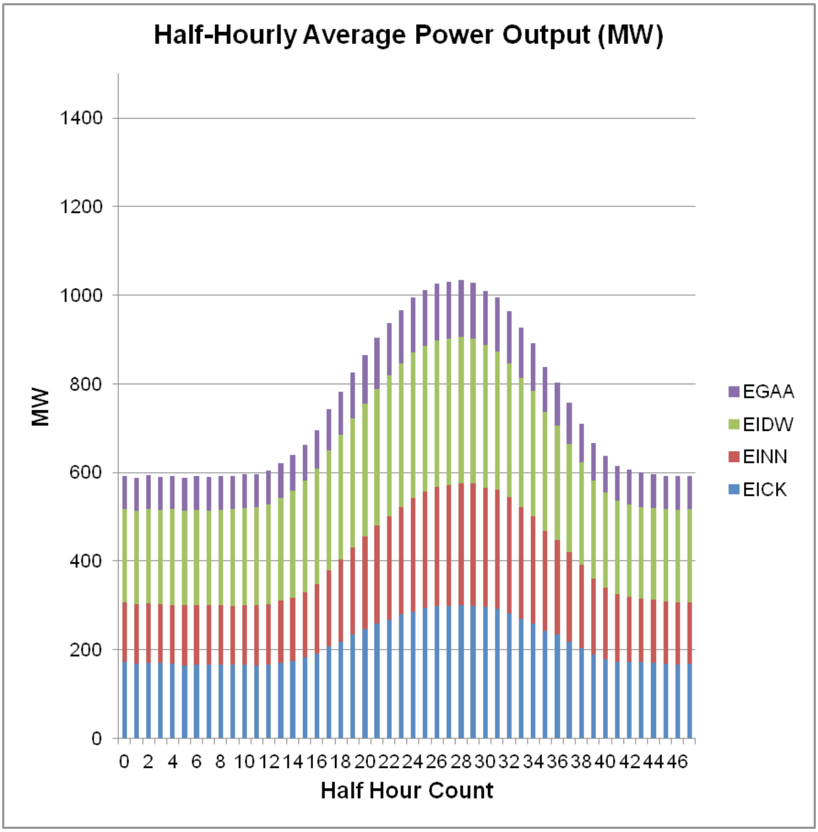

Figure C3 Diurnal variation of wind output.

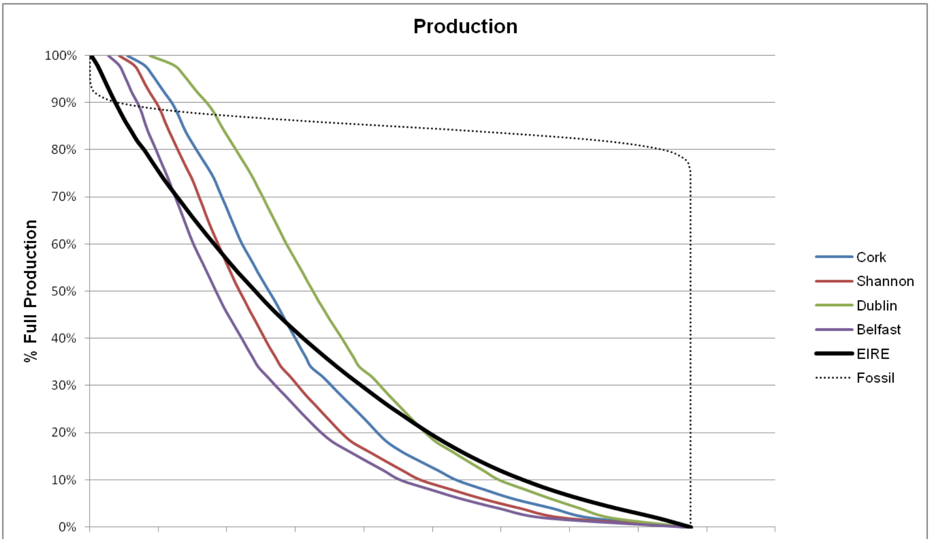

Figure C4 Irish Wind production duration curves