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An appraisal of wind energy conversion systems for agricultural enterprises.

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AN APPRAISAL OF WIND ENERGY CONVERSION SYSTEMS FOR AGRICULTURAL ENTERPRISES

Susan Macmillan B.Sc.(Hons), Dip. Surv.

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CONTENTS

Note: Tables and Figures appear at the end of the relevant chapters; lists of the Tables and Figures appear at the start of each chapter.

ABSTRACT

AN APPRAISAL OF WIND ENERGY CONVERSION SYSTEMS FOR AGRICULTURAL ENTERPRISES

Susan Macmillan

A detailed wind prediction model is developed which predicts wind regimes and energy outputs from wind turbine generators at locations remote from sites where long-term wind data is available. The model accounts for the local, directional influences on the wind flow of topography and surface characteristics. The model for the validation runs performs well and predicts energy outputs over several months to generally within 7% of the actual energy outputs.

Experience is described of a 60kW wind turbine generator connected at a pig farm in the NE of Scotland with respect to the wind regime, performance, farm energy consumption pattern and overall economics.

Long-term economics are assessed by simulating different scenarios of wind turbine generators connected at farms. The different scenarios account for a realistic range of wind regimes, wind turbine generators, farm types and tariffs, all applicable in particular to the NE of Scotland but valid for many other areas in the UK. It is concluded that the main factors affecting economic feasibility of grid connected wind installations at farms are wind regime, local utilisation of wind generated electricity and availability of capital grants. Other factors include the choice of tariff and maintenance costs.

The wind prediction model is shown to be a useful tool in assessing economic feasibility of wind installations on farms as both the wind regime and utilisation are dependent on accurate wind speed predictions.

DECLARATION

The candidate has not, while registered for this C.N.A.A. Ph.D. submission, been registered for another award of the C.N.A.A. or of a university during this research programme.

None of the original material contained in this thesis has been used in any other submission for an academic award. Acknowledgements for assistance received are given under the heading ACKNOWLEDGEMENTS, and any excerpt from other work has been acknowledged by its source and its author.

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Director of Studies : Dr G S Saluja, MEng, PhD, CEng, MInstE, MCIBSE

Second Supervisors : Prof S H Baxter, FRICS, FIAS, MRSH, Dip. Phil.

I G Mackenzie, BSc(Hons), MSc, AFIMA

Dr P Robertson, BSc(Hons), PhD, MSIAD, MInstE, FRMetS

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1. INTRODUCTION

Contents

1.1 HISTORICAL PERSPECTIVE

There are indications that windmills existed in China and Babylon as long ago as 2000 B.C. (1). By the middle of the 7th century A.D. windmill building was a well recognised craft in Persia. They were mainly vertical axis designs replacing animal- or man-drawn beams for grinding grain and pumping water.

There are no records of the so-called European windmills with the sails mounted on a horizontal axis until the 13th century when the Dutch were the early pioneers. In Britain the first examples of windmills are located in the eastern and south-eastern corn growing and low-lying counties of England. The need for power at a certain location was thus more important than a good wind site.

In Scotland they appear as prominent landmarks in some 17th and 18th century engravings. They were mainly used to pump water, grind grain and drive sawmills. In 1757 William Robertson of Leven designed and built the great Dundee windmill (2). None of these early windmills have survived intact but as many as sixty two ruined towers can still be seen around Scotland. Some of the best remaining examples are to be found on farms.

With development of the steam engine through the nineteenth century followed by internal combustion engines there has been little incentive to further develop the traditional windmill as a means of power generation.

In the post-war years interest was rekindled due to the increase in demand for power, the poor economic and political situation making a country depend more on its own energy resources and the greatly increased knowledge of aerodynamics, with the development of the propeller type rotor to replace the traditional canvas and timber sails. Development in electricity generation and supply earlier in the century also supported the practical possibility of generating electricity on a large scale using the power in the wind. The first large electricity producing windmill was the 1250kW Smith-Putnam experimental machine at Grandpa's Knob in Central Vermont, U.S.A.

One wind turbine generator built in Scotland in the post-war years was a 100kW rated machine of John Brown manufacture, installed at Costa Head, Orkney in 1950. This unit was not a technical success and as cheap oil became available interest waned again in wind energy.

The oil crisis of 1973 drew attention to the need for research into renewable forms of energy and interest in wind energy was revived. Denmark, with negligible energy resources of its own, supported considerable wind energy research and in the 1980's are world leaders in wind turbine generator manufacture. However by 1987 still less than 1% of the total generating capacity of Denmark is by wind (3).

In California the tax incentives in the early 1980's for installing wind plant are largely responsible for the huge capacity of wind power there. Approximately 90% of all machines installed in the world are in California (4). The installed capacity in 1988 is 1,420MW.

Britain were somewhat slow to appreciate the potential of wind energy despite it being one of the windier countries in Europe. The installed capacity in Britain is 8.5MW in 1989 excluding any of the proposed CEGB wind farms but including the 1MW Howden machine at Richborough.

1.2 CURRENT WIND ENERGY SCENE IN SCOTLAND

The oldest working example of a grid connected wind turbine generator in Scotland is a 22kW 10m diameter machine at Berriedale Farm on S. Ronaldsay, Orkney installed by the North of Scotland Hydro-Electric Board (NSHEB) in 1980 (5, 6). The NSHEB is one of the two electricity utilities in Scotland.

The main current NSHEB wind energy project is that on Burgar Hill in Orkney where there are now three machines, two in the 200-300kW range and a recently commissioned machine which is rated at 3MW (7, 8). The three Burgar Hill machines are all prototypes and are mainly public-funded.

Another large scale NSHEB project is the recent installation of a 750kW machine on Susetter Hill in the Shetlands (9).

On the small scale one of the most successful projects has been that on Fair Isle where 20 households are supplied with electricity from a 55kW machine in conjunction with a small diesel grid (10). High wind speeds, high machine availability and community participation in load control have all contributed to the success of this project.

The South of Scotland Electricity Board (SSEB) have never become as involved as the NSHEB in wind energy. However they have supported a couple of projects at the two Agricultural Colleges at Auchincruive and Penicuik (11). The later machine was poorly designed and was never operational but the 15kW machine at Auchincruive has been a relative success though with fairly poor availability.

In the NSHEB area of Scotland there are a number of privately owned machines. In 1983 DP Enterprises Ltd in Aberdeen became agents for a Dutch wind turbine manufacturing company, Polenko. In the Grampian area grid-connecting machines were sold to individual farms at Hill of Fiddes, Mains of Bogfechel and Eastertown. The machines at Eastertown and Mains of Bogfechel, which are both intensive pig farms, are rated at 60kW. The Hill of Fiddes machine is rated at 15kW. These three Polenko machines are the first examples of privately owned wind turbine generators connected to farms.

From 1985 machines from a Danish company, Vestas, have penetrated the market initially in Scotland and then the rest of the UK. There are 75kW machines of this make connected to a large estate farm at Berriedale in Caithness and to a salmon fish farm at Inganess near Kirkwall in Orkney. Others are in the planning stages. The machine at the fish farm is used to power four 18kW water pumps. An older design is the 55kW machine of which there used to be one at Scalloway in the Shetlands supplying a dozen holiday chalets. Unfortunately it was damaged beyond repair in a storm after only three years operation. However quite a large amount of valuable information was collected from it while it was operational (12, 13, 14).

1.3 AIM OF STUDY

In the early 1980's there existed an apparently favourable economic climate for the connection of privately owned wind generators to farms. There are still grants available to certain farms from the Government for the purchase of innovative cost-cutting agricultural machinery and wind turbine generators are included in this (15). Also, although this advantage was not realised until later, wind generators connected at farms are exempt from local authority rates (16).

Most of the machines which have been installed in the 1980's have been mainly prototypes paid for by the Government, the NSHEB and large multinational companies. The focus of the projects was mainly on the machine design, energy capture and operational experience rather than on economic feasibility as in commercial projects. Being owned by the electricity utility the effect of the varying electricity tariffs is of no consequence. Site selection for optimal wind speeds was not of primary concern either as most of the sites were selected from other criteria such as land ownership and only then was the wind resource assessed through extensive on-site monitoring.

In commercial projects such as privately owned machines at farms it is not economically viable to do on-site monitoring. In addition to the little information available on the wind resource and likely energy capture, the problems of load assessment of the enterprise installing the wind turbine generator and the complicated tariff structure if the machine is grid-connected, all contribute to the difficulty of estimating the subsequent economic implications of a wind generator installation.

As the wind speed is very much locally affected by height above ground, topography and surface roughness, using near-by Meteorological Office data without any correction can quite often introduce large errors in the wind resource estimate at the wind generator site. As the energy extractable from the wind is approximately proportional to the cube of the wind speed the resultant error in the estimated power output will be in the region of three times the error in the wind speed. Hence an accurate wind prediction model which takes these local effects into account is vital.

At the start of this study little information was available on the energy demand patterns at various types of agricultural enterprises. They have to be assessed before the farm load and the energy from the wind can be brought together and the surplus or deficit of energy with the alternative source can be calculated. The alternative source is normally the national grid but in an autonomous system it could be a diesel generator or an energy storage scheme. Only the national grid option is considered in this study. A method of deriving the savings made by using wind generated electricity to replace electricity imported from the grid is developed. Finally life cycle costing techniques are used to determine pay-back periods and rates of returns of the wind generator installation.

The three privately owned Polenko wind turbine generators in the NE of Scotland were identified at the initial phase of this study as being valuable, previously unpublished sources of information for the study of wind turbine generators on farms. In particular detailed data were collected from the Eastertown 60kW machine and are used throughout the study.

To summarise, the study "An appraisal of wind energy conversion systems for agricultural enterprises" has the following objectives:

(1) To develop a wind prediction model which gives good estimates of energy output from a wind turbine generator at a site where there is no data available.

(2) To assess energy usage for various types of agricultural enterprise with a view to utilising wind energy.

(3) To assess the economics and practicalities of a wind energy installation at an agricultural enterprise.

The layout of the thesis is shown in a flow chart format in Fig 1.1.

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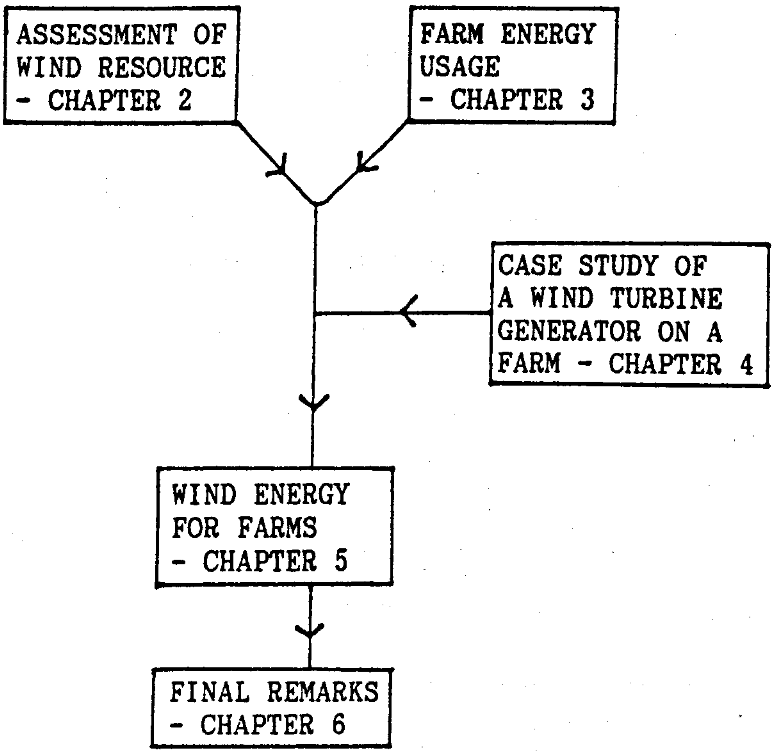

Fig 1.1 Layout of thesis

2. PREDICTING WIND

Contents

LIST OF TABLES FOR CHAPTER 2

LIST OF FIGURES FOR CHAPTER 2

2. PREDICTING WIND

In assessing the overall feasibility of a wind generator one of the main problems that arises is how to accurately predict the wind and expected energy output levels. On-site wind monitoring will give indications of turbulence intensities, wind shear across the blades and maximum gusts which are useful inputs for design of larger machines. It is more difficult to gain information from short-term on-site monitoring on long-term diurnal, monthly and annual mean wind speeds. The accuracy of any long-term energy predictions from on-site data will of course very much depend on the duration of the data at the site and in most cases it is best to at least statistically correlate the data with long-term data from the nearest available meteorological station.

If no on-site data is available, as is the norm unless there are plans to install a large machine or a wind farm, the wind regime must somehow be predicted. If nearby meteorological data are used as reference data, wind shear alone can have a substantial effect on the wind speeds since the hub height of the wind generator is generally above the standard height of 10m for meteorological data collection. Variations in topography and surface roughness characteristics will also have a strong effect on the wind flow between two relatively close sites. The prediction process must therefore somehow model all these local factors that affect the wind flow.

2.1 LITERATURE SURVEY

In Britain initial attempts at modelling the geostrophic wind with the view to extrapolating down to the wind turbine hub height range were made by MOORE et al (1, 2). The geostrophic wind is the free horizontal air movement determined by the balance of the varying pressure gradient force and the Coriolis force. It is the wind at such a height that it is unaffected by retardation due to the earth's surface. The pressure gradient force pushes air from high to low pressure in an attempt to reduce the pressure gradient. Differential heating of the earth's atmosphere maintains these horizontal pressure gradients. The Coriolis force accounts for the rotation of the earth and acts normal to the direction of motion. The layer between the geostrophic wind and the ground is referred to as the planetary boundary layer.

MOORE et al used long-term upper air data from radiosondes at approximately 950m height which is around about the 900mbar layer to model the geostrophic wind. Wind speeds in the height range 10-100m at the centre of the squares of a 10km grid covering the whole of the UK and its offshore area were derived using ratios of these upper air wind speeds with those measured near the surface from a few selected stations and previously determined surface drag coefficients. Separate formulations take account of the different roughness of land and sea surfaces. Interpolation is used in the transition from one to the other although the development of an internal boundary layer at the coast is ignored. The short-comings of this model are that it does not take account of variable topography and surface roughness characteristics. However it is a useful guide for coastal and offshore long-term wind speeds.

Two models which do attempt to model the wind flow in topographically complex areas are NOABL (3) and COMPLEX (4). In these models an initial wind field is established over the test area by means of a weighted interpolation between each of the grid points and the limited number of existing data stations. The model then vertically extrapolates the wind speeds at each grid point using a surface roughness dependent height correction. In NOABL this is done by means of a power law correction for up to 200m above ground level (AGL). Above that and up to the assumed planetary boundary layer top of 1000m either a linear function of the wind speed derived from limited upper air data or a constant wind speed is used. In COMPLEX the geostrophic wind calculated from sea-level pressure data represents the boundary layer top wind. The wind profile is assumed to be logarithmic from ground to boundary layer top. Either model then adjusts this resultant flow field between the terrain surface and the boundary layer top by an iterative procedure in order to minimise local divergence and to satisfy the continuity equation.

The NOABL model was applied to a 98 x 84 km area in SW Scotland for the purpose of site selection. Validation of the model was by comparison of the NOABL output for three stations in the area where real data is available. Only one station was used to initiate the flow field. Four station initialisation was tried but give similar results in strong and intermediate winds which most affect wind generator power output. The model was run twelve times for each of twelve direction sectors. The predicted and actual annual mean wind speeds were different by 16% at

Abbotsinch, 2% at Ardrossan and 8% at Eskdalemuir, all three sites being Meteorological stations. However the authors claim that despite large errors at individual points the model is still useful for selecting sites in an area of complex terrain where high winds are to be expected.

The COMPLEX model was applied to eight candidate sites in North Carolina. Data from four surrounding sites were used to initiate the model. The differences between actual and predicted annual mean wind speeds ranged from 1% to 25% for the eight sites.

A comparison of the performance of the two models was carried out in the relatively complex area of Devon (5). In their original forms the NOABL and COMPLEX models generated seasonal mean wind speeds which differ respectively by up to 30% and 26% from the actual observations. Some improvements were made to the COMPLEX model by introducing a momentum consistency condition into the final adjusting process. The resultant seasonal differences are reduced to less than 5%. The COMPLEX model generally performed better than NOABL and this is thought to be due to the different surface roughness dependent height corrections used.

Probably the most significant work in the area of wind energy prediction is that done by the Department of Meteorology and Wind Energy at Risø National Laboratory in Denmark (6, 7). In the Danish Wind Atlas the climatological time series of geostrophic wind is estimated from surface pressure data. The stability of the atmosphere, which affects wind variation with height, is derived from long-term measurements of wind speed and temperature from one very high meteorological mast at Risø. The atmospheric stability is then regarded as constant across Denmark since the greatest proportion of variation is due to daily and seasonal trends which are essentially the same over the entire country.

From this time series and from the employment of the geostrophic drag law which relates the frictional force at the earth's surface to the geostrophic wind speed, the climatology is established for each of eight direction sectors in terms of the frequency distribution of wind speed for different heights and types of terrain.

Although some very simple corrections were suggested in order to allow for the effect of topography the Danish Wind Atlas can only really be applied with certainity to areas of similar flatness as Denmark.

Due to the problems of collecting and analysing pressure data and the errors introduced when reducing the data to sea level, the "double-vertical extrapolation method" or the Risø WA^{S}P (Wind Atlas Analysis and Application Program) model was adopted for use in conjunction with the European Wind Atlas (8, 9). This model is available as a user-friendly computer program. In the European Wind Atlas the climatology of the geostrophic wind is established from long-term surface (10m AGL) wind speed records from 175 European stations. Any effect of sheltering from nearby buildings and trees at these stations is eliminated so that the resultant data appears as if from over homogeneous terrain. The geostrophic wind speed is then estimated and horizontally interpolated or extrapolated over distances of the order of 50-100km and then extrapolated downwards again at a prediction site to a specified height AGL and specified roughness length.

The Risø WAsP model incorporates a topographic model which is based on work done by the Canadian Environmental Services (10) and the International Energy Agency-sponsored Askervein Hill Experiments (11) in which both parties were involved. The first step of the model is calculating the potential flow perturbation induced by the terrain. Then the potential flow solution has to be modified to allow for the effects of surface friction. Risø have adapted the model to their needs by using a polar grid centered on the point of interest and a higher grid resolution.

The Canadian Environmental Services have also developed their own guidelines for estimating wind speeds which are available as a computer program (12). The guidelines provide an estimate for the wind velocity upstream of the prediction site by using the geostrophic drag law at the reference site. This assumes that the geostrophic wind is constant over the area. The model only allows for the effect of terrain features which lie between the upstream and prediction sites. The upstream site should be chosen close to the reference site to eliminate wind speed variations due to topographic effects. A direction is specified in the input but is not used in any of the subsequent calculations. The term 'upstream site' is a little misleading as it will only be truely upstream from the prediction site when the reference wind direction is the prevailing wind direction. Turning of the wind due to topographic features cannot be described by the model. The program must be re-run for each reference wind direction. The output is in the form of one mean wind speed and turbulence intensity for each height and reference wind direction at both the prediction site and the upstream site.

Application of the guidelines to Prestwick to derive a climatology at Myres Hill (13) resulted in predicted turbulence intensities close to those measured. However the estimated wind speeds at various heights were generally poor. To account for several transitions in roughness between the reference site and the prediction site the model must be re-run for each change. However it gives much better results than when the model assumes only one transition in roughness.

Work currently being carried out in Britain on wind prediction at the University of East Anglia in Norwich (14, 15) uses a theory developed by Weiringa (16) which is based on extrapolating the 10m recorded wind data to the so-called 'meso-winds' at 60m. A 3km radius circle is drawn around both sites and is divided into twelve 30° sectors. Within each of the twelve sectors the proportion of the area of different roughness lengths is evaluated and an area weighted sector roughness value is calculated. No account is taken of internal boundary layers that might develop due to a transition in roughness.

To obtain the 60m meso-wind Weiringa height extrapolation factors are derived at the reference site which are dependent on the directional, area weighted roughness length. Topography is taken account of in a similar manner to the Canadian Environmental Services guidelines.

The results to date of the East Anglian model present the predicted topographic-free, roughness-free wind speeds derived from two sites 5km apart in the North Pennines. Work on this model is not complete so it is difficult to assess its worth.

2.2 THE NATURE OF WIND DATA

The majority of the meteorological stations in Britain record the wind speeds and directions continuously from a 10m mast, sited in open level terrain, onto an anemograph chart recorder which has dual pens tracing the outputs from the anemometer and wind vane onto precalibrated chart paper. In cases where there is nearby obstruction present (within 100m) the height of the anemometer is often raised so that the effective height is 10m. Most of the stations now run Digital Anemograph Logging Equipment (DALE) which records the data, previously extracted from the charts, onto magnetic tape in computer-compatible format. The charts are still written at these stations but cease to be analysed except in the case of a DALE failure. The data used in this project are the hourly mean wind speeds and directions. If a long-term prediction is required the Meteorological Office can provide long-term wind speed and direction frequency tables in order to reduce the amount of data processing.

The variability of hourly wind speeds over a period of one day from Dyce, Peterhead and Eastertown which are within 50km of one another in the NE of Scotland is demonstrated in Fig 2.1. Dyce and Peterhead are both meteorological stations on or near the coast and Eastertown is a monitored wind generator site near Old Meldrum. The location of the three sites is shown in Fig 2.2. They are fairly close to one another compared to the size of a passing weather system. Thus the variation is mainly caused by factors other than those due to passing weather systems and it is these factors which the prediction process must attempt to quantify.

Atmospheric turbulence ie. small scale irregularities in the overall wind flow caused by interaction with the uneven surface of the earth, lead to wind speed variations predominantly with periods of seconds up to a few minutes. As the variations decrease with height above ground and are spatially averaged over the rotor blade swept area, the effect on wind generator output is reduced except in the case of small machines on short towers. The measure of intensity of turbulence is the ratio of speed variance over mean speed. On a hill-top site in the Shetlands for averaging periods of one hour the turbulence intensity was 0.074 at 35m and 0.086 at 10m (17). This is considered low, but with these figures the resultant error in energy output of the wind generator using hourly means is for 35m in the region of 1.6% and at 10m is in the region of 2.2%. However, it is of great importance in the design process of a wind generator as it has a critical impact on the fatigue lifetime of the structural components.

Diurnal variation in the wind speeds is due to differential heating and cooling of the earth's surface between night and day. It is particularly significant at coastal sights where the sea has a high specific heat capacity and thus heats up and cools down slower than the land. During the day, due to heating of the land from the sun's rays, warm air rises above the land and cold air rushes in from the sea. The reverse process happens at night, though to a lesser extent, when the sea is losing its heat to the air above and causes a land to sea breeze. Diurnal variation in wind speeds is due to the more rapid heating of the land relative to the sea during the day thus resulting in higher day-time wind speeds, particularly in mid-afternoon. At Prestwick Meteorological Office on the west coast of Scotland the mean diurnal range is 1.3m/s with maximum speeds experienced between 12noon and 3pm. The range is greater in the summer than in the winter and decreases with an increase in height above ground (18). The effect of diurnal variations on overall wind generator economics can be quite high especially if there is a marked difference in the tariffs between night and day. This difference in tariff reflects the higher demand on the national grid during the day than at night.

Individual monthly mean wind speeds are influenced by short-term local weather events and thus can vary considerably from the long-term monthly data as can be seen in Fig 2.3 for Lerwick. Therefore for the long-term prediction of energy output from a wind generator it is preferable to use long-term monthly means.

In a study carried out by HALLIDAY (18) the maximum deviation of one year's mean wind speed from a ten year mean speed for fourteen stations was 13% and was on average 8.5%. According to PALUTIKOF et al (19) the long-term temporal trends in wind speeds are significant to merit consideration in the estimation of wind power potential at a potential site. However current machines have design lifes of 20-25 years and over that period long-term temporal trends are insignificant.

The Weibull probability distribution suitably represents non-zero wind speed data. One shortcoming of using the Weibull distribution is that, in its usual form, it does not take account of the correlated nature of the wind. The Weibull probability distribution is given by

$$f(v) = (k/c)(v/c)^{k-1} \exp-(v/c)^{k} \qquad 2.1$$

f(v) is the probability of the wind speed being v m/s, k is the shape parameter which determines the sharpness of the distribution and is inversely related to the variance and c is the scale parameter which is approximately proportional to the mean. The parameters are computed by a least squares process. An example of a Weibull probability distribution compared to actual data is shown in Fig 2.4.

2.3 THE PREDICTION MODEL

The method of prediction adopted in this project uses wind data from the nearest available meteorological station, otherwise referred to as the source site, and transposes it to the prediction site using direction dependent factors. These factors function so as to eliminate effects of upstream transitions in surface roughness and topography at the meteorological station, to transfer the data to the prediction site by accounting for the difference in general elevation above sea level of the two areas, and to incorporate the effects due to local surface characteristics and topography at the prediction site. Vertical wind shear is accounted for if the prediction height differs from the height above ground at which the recorded data is taken.

The method incorporates procedures which were mainly developed in Denmark (20, 21, 22) to deal with fairly level terrain where only the surface characteristics have an effect on the wind flows. However in Scotland, where there is considerable potential for wind energy utilization, the terrain is doubly complicated. Firstly, by having a large coast/land area ratio both the meteorological stations and the prediction sites are often near the coast with varying diurnal cycles superimposed on the wind flow. In addition they are often in areas of complex surface roughness characteristics. Secondly, the terrain in Scotland is topographically complex with more than 50% of the land area over 200m above sea level (ASL) with a common occurrence of fairly steep gradients.

If an hour by hour prediction is being carried out as in most of the validation runs, it is preferable if the source site and the prediction site are within approximately 50km of one another so that the two sites experience the same weather systems simultaneously and the same geostrophic wind speed. This is not so important if long-term predictions are being done as the difference in the geostrophic winds above the two sites will average out to be near zero.

The method is geared towards making maximum use of the long-term, joint wind speed and direction frequency distribution tables which are readily available from the meteorological stations. The data in these tables, which is either number of hours or percentage time, comes by default in twelve directional divisions. For the purposes of this project it was felt that this should be reduced in order to eliminate some of the time-consuming manual work which is required in the prediction model such as drawing topographic cross-sections. Eight sectors, coinciding with the cardinal points of the compass, ie. N, NE, E etc, would have been the most suitable but it is not possible to reduce the joint frequency data from twelve sectors to eight sectors. Six sectors are used instead as this data is obtainable from the twelve sector data simply by doubly up the joint wind speed and direction frequencies for two consecutive directional divisions.

Another adaptation to the prediction method to cope with these long-term, joint frequency tables is the use of the Weibull probability distribution. The tables, by default, use the historical Beaufort Scale numbers for the wind speed divisions. The Beaufort Scale is based on visual observations of sea conditions. The bin size varies thus making it difficult to extract mean wind speeds. As the duration of the data is generally over several years it is expected that the Weibull probability distribution would give good fits. Also the data has already been reduced to a form which is useful for extracting Weibull parameters.

For validation purposes, where simultaneous data is required at both sites, mean hourly data is normally used because of the lack of long-term data at most of the prediction sites.

The correction which is applied to the representative wind statistic be it a mean wind speed or Weibull distribution scale parameter, is a mean of the six directional correction factors weighted by the number of hours the wind is from each direction sector. Each directional correction is made up of five factors, F_i. The functions of the factors is as follows :

F_1 : eliminate upstream tangential surface roughness transitions near the source site and to transfer the data to prediction height above ground level (AGL)

F_2 : eliminate topography-induced effects in the vicinity of the source site

F_3 : account for the difference in general elevation above sea level (ASL) of the two areas surrounding the source site and the prediction site

F_4 : incorporate the effect of local topography at the prediction site

F_5 : incorporate the effect of surface roughness and any nearby transitions at the prediction site.

For any one sector, if v_i represents the wind speeds after factor F_i has been applied, then $v_i = F_i v_{i-1}$ where $v_0 = v_h$, the recorded data.

2.3.1 Description of the first factor

The first factor F_1 eliminates from the recorded data the effect of one surface roughness transition that is within a 2km radius of the source site for the sector in question. For instance any effect on the wind flow due to a nearby built-up area or a nearby expanse of water is eliminated. A guideline to roughness lengths is given in Table 2.1. Roughness length is formally the height above ground level where the wind speed becomes zero supposing a logarithmic profile such as that in equation 2.5 is applicable. The roughness lengths in Table 2.1 have been determined from experiments where the variation in mean wind speed with height has been measured and the profiles extrapolated to zero velocity.

Suppose, in one sector, the anemometer of height h is in an area of surface roughness length z_y and upstream at a distance D there is a transition to roughness length z_x. The situation is illustrated in Fig 2.5.

An internal boundary layer - a boundary layer forming within the planetary boundary layer (see section 2.1) - forms downstream from the discontinuity, the height of which, h_2, is dependent on the distance D to the transition and the greater of the two surface roughness lengths (23). The height increases with downstream distance. Thus if $z_x > z_y$:

$$h_2 = 0.7\, z_x\, (D/z_x)^{0.8} \qquad 2.2$$

where h_2 is the height AGL of the internal boundary layer
z_x is the roughness length beyond the transition
D is the distance to the transition.

If $z_y > z_x$:

$$h_2 = 0.7\, z_y\, (D/z_y)^{0.8} \qquad 2.3$$

where z_y is the roughness length in the vicinity of the site.

Above h_2, in zone 3 of Fig 2.5, the recorded wind speed is affected by the upstream roughness length z_x only. A correction must be made to eliminate the effect of the upstream roughness characteristics.

Beyond 2km a change in surface characteristic will have little effect on the wind flow. This can be seen by letting D=2000m in equation 2.3 for a variety of roughness lengths and comparing the height h_2 of the top of the internal boundary layer developing from a transition in roughness length, with the expected range of wind generator hub heights, H. If h_2 is higher than H the upstream roughness length beyond the transition at 2km will not have any effect on the wind speeds.

Within the internal boundary layer there is a transition zone, which is zone 2 in Fig 2.5. In the absence of experimental work the vertical wind speed profile within the transition zone is assumed to be a weighted mean of the profiles in zones 1 and 3, the weights being dependent on how high the anemometer extends into the transition zone (23). A correction must be applied to reduce the data so that it effectively lies in zone 1 where the wind speed profile is unaffected by the upstream roughness length z_x.

The lower limit of the transition zone is determined by the height h_1 (23) which is given by

$$h_1 = 0.7\ 10^{-8}\ z_y^{0.3}\ D^3 \qquad 2.4$$

Below this height, in zone 1, the wind speed profile is affected by surface roughness length z_y only and no correction is required to account for the upstream roughness transition.

The corrections to apply to the data if the anemometer is in zones 2 and 3 are fairly complex. However, what is essentially required is a relationship between wind speeds over terrain of different surface roughness lengths but same height above ground. Equation 2.5 represents the wind profile at a height h over ground of roughness length z_y in neutral stability conditions.

$$v_h(z_y) = (u_{*y}/K)\ln(h/z_y) \qquad 2.5$$

where $v_h(z_y)$ is the horizontal wind speed at height h over roughness z_y

u_{*y} is the friction velocity for roughness length z_y

K is von Karman's constant (= 0.4)

h is the height of the anemometer above ground level

z_y is the surface roughness length in the vicinity of the anemometer

Atmospheric stability is determined by the vertical gradient in temperature. It varies with time of day, surface radiation, wind speed and cloud cover. It affects the mixing processes in the boundary layer and hence modifies the wind profile. However, when considering a mean profile over a month or longer, the stability is assumed to average out to be neutral. Thus, this profile is generally not applicable to instantaneous wind speeds, especially if recorded at night-time or on high insolation days in summer when the stability of the atmosphere is changing most rapidly. Also, by assuming neutral stability conditions the derived profiles will be most accurate for moderate to strong winds which affect a high proportion of the energy output of a wind generator, whereas in lighter winds the stability is more likely to depart from neutral.

The geostrophic drag law links surface friction velocity, surface roughness, stability and the geostrophic wind speed. However there exists a simple approximation for neutral conditions :

$$u_{*y}/G = 0.5/\ln(G/fz_y) \qquad 2.6$$

where G is the mean geostrophic wind speed derived from radiosonde data (Fig 2.6)

f is the Coriolis parameter (= 1.21 $10^{-4}s^{-1}$ at 56^oN)

Equations 2.5 and 2.6 are combined to eliminate the friction velocity to obtain an expression for $v_h(z_y)$:

$$v_h(z_y) = [0.5\ G \ln(h/z_y)] \ / \ [K \ln(G/fz_y)] \qquad 2.7$$

A similar expression may be obtained for $v_h(z_x)$, the wind speed at the same height but over surface roughness length z_x beyond the transition. Thus a relationship may be established between wind speeds at constant height above ground but different surface roughness lengths :

$$v_h(z_y) = v_h(z_x)\ [\ln(G/fz_x)\ \ln(h/z_y)]\ /\ [\ln(G/fz_y)\ \ln(h/z_x)] \qquad 2.8$$

If the anemometer is in zone 1, ie. $h < h_1$, then the recorded wind speeds represented (ie, could be the mean wind speed or the Weibull scale parameter) by v_h are unaffected by the transition and thus

$$v_h(z_y) = v_h \qquad 2.9$$

If the anemometer is in zone 2, ie. $h_1<h<h_2$, the representative recorded mean wind speed v_h is a weighted mean of the equivalent wind speeds (ie same height) in zones 1 and 3 and is given by :

$$v_h = w_x v_h(z_x) + w_y v_h(z_y) \qquad 2.10$$

where the weights w_x and w_y are given by

$$w_x = \ln(h/h_1)\ /\ \ln(h_2/h_1) \quad \text{and } w_y = 1 - w_x \qquad 2.11$$

$v_h(z_y)$ is the required unknown, the wind speed at height h over surface roughness length z_y without the transition.

From equation 2.8 $v_h(z_x)$ can be expressed in terms of $v_h(z_y)$:

$$v_h(z_x) = v_h(z_y)\ F(z_x, z_y, h) \qquad 2.12$$

where $F(z_x, z_y, h) = \ln(G/fz_y)\ln(h/z_x) / \ln(G/fz_x)\ln(h/z_y)$ 2.13

Substituting equation 2.12 into equation 2.10 gives :

$$v_h = [w_x\, v_h(z_y)\, F(z_x, z_y, h)] + [w_y\, v_h(z_y)] \qquad 2.14$$

and making $v_h(z_y)$ the subject of equation 2.14 gives :

$$v_h(z_y) = v_h / [F(z_x, z_y, h)\, w_x + w_y] \qquad 2.15$$

If the anemometer is in zone 3, ie. $h > h_2$, where the profile is solely determined by the upstream roughness length z_x then $v_h = v_h(z_x)$. Substituting into equation 2.8 gives :

$$v_h(z_y) = v_h\, [\ln(G/fz_x)\, \ln(h/z_y)] / [\ln(G/fz_y)\, \ln(h/z_x)] \qquad 2.16$$

The next step is to account for the difference in height between the source site and the prediction site. The well known logarithmic profile derived from equation 2.5 is used :

$$v_H(z_y)/v_h(z_y) = \ln(H/z_y) / \ln(h/z_y) \qquad 2.17$$

where $v_H(z_y)$ is the mean wind speed (or Weibull scale parameter) at prediction height over a large expanse of ground of roughness length z_y

H is the prediction height

It is necessary for the wind speed distribution to be transferred to prediction height prior to taking account of the effect of any roughness transitions at the prediction site. This is because if there are any transitions in the surface roughness at the prediction site the resultant effect at prediction height will differ from that at source height. It is the effect on the wind flow at prediction height that is of interest.

$v_H(z_y)$ is the required representative wind speed, having applied the first correction factor F_1. Thus $v_1 = v_H(z_y)$.

To summarise the first correction factor, **if the anemometer is in zone 1**, then :

$$F_1 = \ln(H/z_y) \,/\, \ln(h/z_y) \qquad 2.18$$

If the anemometer is in zone 2, then :

$$F_1 = \ln(H/z_y) \,/\, [\ln(h/z_y)(F(z_x,\ z_y,\ h)w_x + w_y)] \qquad 2.19$$

using equation 2.13 for $F(z_x, z_y, h)$ and equation 2.11 for w_x and w_y.

If the anemometer is in zone 3, then :

$$F_1 = \ln(G/fz_x)\ln(H/z_y) \,/\, [\ln(G/fz_y)\ln(h/z_x)] \qquad 2.20$$

2.3.2 Description of the second factor

The second factor F_2 eliminates the effect on the wind flow of local topography in the surrounding 2km radius area of the source site. In theory it should rarely be necessary to apply this factor as usually the source site is a meteorological station which should be sited in open flat terrain. However in practice this is often not the case. At Dyce meteorological station near Aberdeen where the anemometer is sited at a seemingly flat site at an airport (see Fig 2.7) it can be seen from the long-term wind rose that there are two distinct predominant directions which are both within the prevailing south-westerly air flow (Fig 2.8). The drop between the two peaks cannot be attributed to weather so therefore must be due to some local effect. The most likely cause is Tyrebagger Hill due SW of the meteorological station.

The prediction method eliminates the effects of topography at the source site by applying an "inverse topography factor" which takes the form :

$$F_2 = 1 - T_o \qquad 2.21$$

where T_o is dependent on the approximate maximum gradient in the direction sector in question. This gradient is calculated from the cross-section, drawn from a 1:25,000 map, which bisects the direction sector. For each cross-section a base height ASL is established by the following criteria.

If the site is on or near a distinct topographic feature such as a hill or a valley or a ridge, the base height level is the lowest line (or highest in the case of valley sites) that can be drawn such that little or no land is above (or below in valley site case) it except for the feature itself.

If the site is in undulating terrain (maximum gradient for cross-section is less than 0.05) the base height should be the mean height of the cross-section and if possible should be close to the actual height ASL of the site so that no correction is required.

Having established the base height level the next step is to calculate the maximum gradient for the cross-section. The correction factor F_2 depends on the magnitude of the maximum gradient, g.

If $g < 0.05$, then

$$T_o = K/1000 \tag{2.22}$$

where K is the height of the site in metres above or below the base height level. Thus

$$F_2 = 1 - K/1000 \tag{2.23}$$

This correction is equivalent to a 1% difference in wind speeds per 10m of site altitude above (or below) the base height. This is the correction applied for undulating terrain (24).

If $0.05 < g < 0.3$, then

$$T_o = 2sK/L \tag{2.24}$$

where s is a coefficient depending where on the topographic feature the site is (25). It is determined from Fig 2.9 and takes values between s = 0, where topography has no effect, to s = 1 near the ground at the summit or crest of the feature. K is the height of the topographic feature above (or below for valley sites in which case K is negative) the base height level and L is the upwind half-width of the topographic feature. Thus

$$F_2 = 1 - 2sK/L \qquad 2.25$$

If $g > 0.3$, then

$$T_o = 0.6s \text{ for +ve K and } T_o = -0.6s \text{ for -ve K} \qquad 2.26$$

s is established from Fig 2.9 (25). Thus

$$F_2 = 1 - 0.6s \text{ for +ve K and } F_2 = 1 + 0.6s \text{ for -ve K} \qquad 2.27$$

2.3.3 Description of the third factor

The third factor F_3 accounts for the difference in general elevation above sea level (ASL) between the source site and the prediction site. This is done by applying a 1% increase (or decrease) to the wind speeds per 10m rise (or fall) of the base height at the prediction site above (or below) the base height at the source site (26). Thus

$$F_3 = 1 + [0.01(X_2 - X_1)] \qquad 2.28$$

where X_1 is the base height level above sea level (ASL) in metres of cross-section at the source site and X_2 is the base height level ASL of cross-section at the prediction site.

2.3.4 Description of the fourth factor

The fourth factor F_4 accounts for the effect of local topography at the prediction site. It takes the form :

$$F_4 = 1 + T_o \qquad 2.29$$

where T_o is determined in exactly the same manner as in equations 2.22, 2.24 and 2.26.

2.3.5 Description of the fifth factor

The fifth and final factor F_5 accounts for the effect of local surface roughness and nearby transitions at the prediction site. For any one sector, if the roughness in the vicinity of the prediction site is different from that at the source site and/or there is a nearby transition in roughness, a correction for the surface roughness at the prediction site must be applied. Otherwise no correction is required at this stage.

Suppose that the prediction site is in an area of roughness length z_{y1} with an upwind transition to roughness length z_{x1}. The situation is similar to that in Fig 2.5.

If the prediction height H is in zone 1, ie is less than h_1, then from equation 2.8 :

$$F_5 = \ln(G/fz_y)\ln(H/z_{y1}) \,/\, [\ln(G/fz_{y1})\ \ln(H/z_y)] \qquad 2.30$$

In equation 2.30 if $z_{y1} = z_y$, ie. the roughness lengths in the immediate vicinities of the prediction site and the source site are the same, then $F_5 = 1$.

If the prediction height is in zone 2, ie $h_1 < H < h_2$ then from equation 2.10 :

$$v_H = w_{x1}v_H(z_{x1}) + w_{y1}v_H(z_{y1}) \qquad 2.31$$

where w_{x1} and w_{y1} can be determined from equation 2.11 and $v_H(z_{x1})$ and $v_H(z_{y1})$ can be determined from equation 2.8 replacing $v_h(z_x)$ with v_4 on the right hand side. Thus

$$F_5 = \ln(h/z_y)\ [w_{x1}(\ln(G/fz_{x1})/\ln(h/z_{x1})) + ..$$

$$w_{y1}(\ln(G/fz_{y1})/\ln(h/z_{y1}))]\ /\ \ln(G/fz_y) \qquad 2.32$$

If the prediction height is in zone 3, ie. $H > h_2$, then from equation 2.8 :

$$F_5 = \ln(G/fz_y)\ln(H/z_{x1})\ /\ [\ln(G/fz_{x1})\ln(H/z_y)] \qquad 2.33$$

A constraint on the fifth factor is introduced to allow for the effect of topography dominating over that of surface roughness when the site is on an elevated location. The elements of surface roughness are at a lower elevation than the prediction site and are therefore not in the immediate upwind fetch of the prediction site. They will therefore not have their normal effect on the wind speeds at the prediction height. Thus if the fourth factor is greater than unity, ie if $F_4 > 1$, implying that the prediction site is elevated above the base height level, the fifth factor is forced to equal unity unless the surface in the vicinity is of extreme roughness in one of two ways. The extremes of roughness are (a) the surface is sea or sand where the roughness length is 0.001m or smaller, and (b) partially built-up areas where the roughness length is 0.25m or greater.

The final directional correction factor is the factor required to transpose v_h, the source wind data, to v_5, the predicted wind regime. Thus if F_k is the correction factor for direction sector k = A, B, C, D, E or F then

$$F_k = F_1.F_2.F_3.F_4.F_5 \qquad 2.34$$

2.3.6 Wind and energy output prediction

The final correction factor is a weighted mean of the six directional correction factors, the weights being functions of the time the wind is in each direction sector. It is applied to the all-direction recorded mean wind speed or the scale parameter fitted to non-zero winds at the source site. In the Weibull curve-fitting process where $\ln[-\ln(1-F(v))]$ is linearly regressed with $\ln(v)$ the shape parameter k is the gradient of the regression line and the scale parameter c can be be found from the intercept with the y-axis, $\ln(c^{-k})$.

For validation purposes the predicted wind speed is compared with the actual mean wind speed recorded at the prediction site for a simultaneous period of time. If the Weibull distribution is being used the shape parameter is transposed to the prediction site without any correction. The predicted distribution with the corrected scale parameter but unchanged shape parameter is compared with the recorded Weibull distribution.

The long-term predicted energy output is calculated from the predicted Weibull distribution using a realistic power curve which has the wind speeds at the prediction height. The probabilities and hence the number of hours that the wind speed is in 1m/s bins is computed from the Weibull distribution. For each bin the number of hours is multiplied by the power output at the midpoint wind speed. Summation then gives the total energy output for the prediction period. This predicted energy output is compared with the energy output calculated from the recorded wind speed distribution by the same method.

2.4 APPLICATION OF THE PREDICTION MODEL

The prediction methodology is applied to a number of data sets from six source sites as given in Table 2.2. The site selection criteria was essentially dictated by the availability of wind data for validation purposes. The location of all the sites used in the prediction process are shown in Fig 2.10. The data from Dyce, Peterhead, Lerwick and Prestwick have been collected by the Meteorological Office, the data from Eastertown have been collected by the monitoring system set up by Energy Design and run by the author (see section 4.3), the data from Scroo and Susetter Hills on the Shetland Isles have been collected by Rutherford Appleton Laboratory (27) and the data from Myres Hill have been collected by the National Wind Turbine Test Centre under the auspices of the National Engineering Laboratory (28).

A computer program which derives the correction factors has been written using a spreadsheet package. Runs of the program are shown in Table 2.3 for the Lerwick to Susetter Hill prediction showing the input requirements for the model, and Appendix A. Lerwick meteorological station is a fairly complicated site from a prediction point of view as it is a hilly area with some steep gradients and there are nearby transitions in roughness for five out of six sectors due to the coastal location and the nearby buildings.

2.4.1 Predicting long-term wind speeds and energy outputs

The only set of sites which could provide good long-term data for validation is Dyce meteorological station and Peterhead meteorological station. The final correction factor, derived from the long-term wind direction distribution, is applied to the scale parameter of the Weibull distribution fitted to data recorded at Dyce over a period of 22 years. The shape parameter remains unchanged. The percentage time calm can be thought of as a separate parameter and this is also transposed to the prediction site without any alteration. In order to make all the results comparable via one parameter representing the predicted wind regime, the predicted annual mean wind speed is calculated from the predicted Weibull distribution.

The data set that is available from Myres Hill for this project has a duration of ten months. The correction factor from Prestwick to Myres Hill is applied to the Weibull scale parameter representing the ten months' data.

2.4.2 Predicting monthly wind speeds and energy outputs

The duration of the data sets that fall within the category of monthly wind speeds varies from 20 days to 71 days. Twelve separate data sets from a variety of sites are used for validation. As in the long-term predictions the correction factors are applied to the Weibull scale parameters and the mean wind speeds are computed from the predicted Weibull distribution to give one parameter by which all the results can be compared. At Eastertown, although there is a monitored 60kW machine at the site (see chapter 4) the manufacturer's power curve is used to calculate the actual output as well as the predicted output. This is because the actual performance of the machine is lower than the manufacturer's power curve, especially in 1986 before the alteration to the switch-over wind speed (see section 4.5.1).

2.4.3 Predicting diurnal wind speeds

The only data set used for predicting diurnal variations is the Prestwick - Myres Hill set. Two approaches are used. Both approaches make use of the data from the highest wind speed month and the lowest wind speed month from the ten months of data available. The first approach is to calculate mean hourly correction factors for each hour of the day, and apply them to the mean hourly wind speeds. Thus the correction factor applied to the 10am data is different than the factor applied to the 10pm data due to the different direction distributions at the source site for these two hours. At Prestwick the wind direction varies quite significantly with time of day due to its coastal location and thus the correction factors will vary considerably with time of day. The second approach is to apply the monthly correction factor to the mean hourly wind speeds. Thus the same factor is applied to all twenty four mean hourly wind speeds.

2.4.4 Predicting hourly wind speeds

The purpose of applying the prediction model to hourly wind speeds is to illustrate its possible use in simulating time series of wind data. Again, the Prestwick - Myres Hill data set is used and the prediction is done for the highest and lowest wind speed months.

2.5 RESULTS

Each prediction can be classified as a low terrain or high terrain prediction. A low terrain prediction is one where both the source site and the prediction site are in areas where topography plays a generally insignificant role compared to that of surface roughness. A high terrain prediction is one where the topographic factors are much greater than the roughness factors.

2.5.1 <u>Long-term predictions</u>

The results of long-term predictions are shown in Table 2.4. The energy output is not calculated for Peterhead due to the physical impossibility of actually installing a wind generator at the site. There is also a difficulty in determining the effective height of the recorded wind data. For the mean wind speed predictions at this site, an effective height of 18m is taken. This is derived using the Meteorological Office code (29) applicable when the anemometer is on an isolated building and is on a mast at least half the height of the building. The later condition is not satisfied at Peterhead as the anemometer is on a 6m mast on a 24m building. However the code states that the effective height may be taken to be about the height of the mast plus half the height of the building.

Despite this problem at Peterhead the long-term annual mean wind speed is predicted, using long-term Dyce data, to within 0.2m/s of the actual.

At Myres Hill the prediction model gives very good results. The mean wind speed prediction is 0.03m/s from the recorded mean speed for a ten month period and the energy prediction is within 3% of the actual energy output.

2.5.2 Short-term predictions

The results of the short-term wind speed and energy predictions are shown in Table 2.5. At Scroo Hill it can be seen that although the mean wind speeds are over-predicted the resultant energy predictions are generally under-predicted. This is because the predicted wind speed distribution reaches above the cut-out wind speed of the machine or, in the case of the 20m predictions where a stall-regulated power curve is used, the wind speed distribution reaches above rated wind speed of the machine.

A further result, not included in Table 2.5, is the prediction of long-term mean wind speed at anemometer height at Lerwick with the effects of topography and local transitions in roughness eliminated. It is approximately 10% below the recorded long-term mean wind speed. This means that the coastal hill-top (as seen by the wind in some sectors) site of the anemometer at Lerwick is such that it enhances the wind speeds.

For the two hill top sites in Shetland the method predicts a 26% increase in long-term mean wind speeds at 20m above ground level (AGL) on Susetter and a 52% increase at Scroo Hill from the wind speeds recorded at Lerwick. At 35m AGL the method predicts a 37% increase at Susetter Hill and a 64% increase at Scroo Hill from wind speeds recorded at Lerwick.

The results of applying the model in Grampian area are also shown in Table 2.5 for Eastertown and Peterhead. The method is used on 706 hours of data from Dyce and Peterhead to predict the corresponding mean wind speed and energy output at Eastertown. The use of the two source sites gives different energy results by 25%, Dyce giving considerably better results with less than a 1%

error from the actual energy output than Peterhead. However the performance of the model is not consistent as in 1987 the energy prediction at Eastertown using Dyce as a source site is an underestimate of the actual energy output by 35%.

2.5.3 Diurnal predictions

The results of diurnal predictions for Myres Hill using the first approach, whereby diurnal correction factors are applied to the mean hourly data, are shown in Figs 2.11 and 2.12. It can be seen that the predicted mean hourly wind speeds exaggerate the diurnal variation at Myres Hill. This can be attributed to the stronger diurnal variation in wind speeds and directions (Fig 2.13) at Prestwick. However in the second approach, whereby for each month a single correction factor is applied to all the mean hourly data, the predicted diurnal variation at Myres Hill is closer to the actual diurnal variation (Figs 2.14 and 2.15). Clearly this is the better approach as the stronger diurnal variation at the source site in the wind speeds, not the wind directions, is transposed. The wind direction distribution has its effect on the correction factor which in turn is applicable to the wind speeds.

2.5.4 Hourly predictions

An example of predicting time series of hourly data is shown in Fig 2.16 for Myres Hill. The error in individual hourly wind speeds ranges from 0 to 13m/s, however the mean absolute error is 2.2m/s. This is most probably due to the temporal variation in the wind flow between the source site and the prediction site which are present when comparing simultaneous hourly data over distances up to 50km. Also, on an hourly basis the atmospheric stability will frequently deviate from neutral stability conditions.

2.6 CONCLUSIONS

The results for the long-term and short-term predictions are generally satisfactory for the purposes of an economic analysis of a proposed wind turbine generator. However the following cautionary notes on the limitations of the prediction model should be taken into consideration when assessing the results especially where there is no data at the prediction site available for validation.

One limitation of the model which affects all predictions whether they be over long or short periods or are low terrain or high terrain predictions is the inability of the model to predict a change in direction distribution between the source site and the prediction site. This will affect the weighting of the directional correction factors. The wind direction correlation between the source site and the prediction site is illustrated by calculating the square root of the mean square difference, taking suitable action when errors of greater than 180^{o} occur. These are shown in Table 2.6. It can be seen that the direction differs from Lerwick more at Susetter Hill than at Scroo Hill. It can also be seen that there is a fairly large mean difference of 36.5^{o} between Prestwick and Myres Hill directions, this being due to the strong diurnal variation that exists at Prestwick. However the effect of the difference between the direction distributions on the long-term results at Myres Hill is negligible as the directional correction factors are all very similar. The factors are 1.446, 1.326, 1.326, 1.344, 2.020 and 1.342 for sectors A to F respectively and for both Prestwick and Myres Hill the percentage time that the wind is in sector E with the correction factor that most deviates from the mean is approximately the same

(25.3% and 27.1%). The inability of the method to predict wind directions may explain the poorer short-term results such as those at Eastertown. Unfortunately the wind direction is not recorded at Eastertown and thus it is difficult to draw firm conclusions. To overcome this problem of direction change would require considerable more research on the effect of topographic features on long-term wind directions.

Three limitations of the model as regards low terrain predictions have been identified. Firstly, if the site is inland the wind speeds are generally low ie. annual mean wind speeds of less than 5m/s. The consequence of this is that the assumption of neutral stability used in deriving the roughness correction equations is more doubtful at low wind speeds.

Secondly, if the site is near the coast it is most likely that there will be some sort of diurnal cycles superimposed on the wind flows. These variations will vary in magnitude and direction depending on time of day and year. From the results of the diurnal predictions in section 2.5.3 it can be seen that the predicted wind speeds have the diurnal variation from the source site simply superimposed on them rather than predicted independently. In this prediction, the only example of predicting diurnal variation, it was by chance that a fairly strong diurnal range existed at both the source site and the prediction site. However in another situation this may not be the case. Thus this inability to account for these cycles separately at either the source site or prediction site is one of the limitations of the prediction model.

Thirdly, for low terrain sites the accuracy of the final result greatly depends on the accurate determination of the roughness length. Table 2.1 has been compiled from a number of sources but there still remains considerable guesswork since roughness length is not a measurable quantity.

There is one other limitation of the model that has been identified but it concerns only the processing of the raw wind data to extract representative figures rather than the derivation of the correction factors. Where a Weibull distribution is being used in the case where an energy prediction is required errors can arise if the duration of the data is short, ie. a month. This can lead to errors in fitting a Weibull distribution caused by the effect of individual weather systems on the recorded wind speeds. In long-term data the effects of individual weather systems are averaged out. Errors in fitting Weibull distributions to short-term data are demonstrated in Fig 2.17, a plot of the mean square error of the regression fit versus the sample size. It can be seen that the general trend is for mean square error to decrease with an increase in sample size.

The absence of a correction to the shape parameter of the Weibull distribution used in the short and long-term predictions is possibly another shortfall of the prediction model. The recorded shape factor at the source site is transposed to the prediction site without any alteration. However it is known that shape factors generally increase with height above ground, depending on the surface roughness (30), and that shape factors on hill sites are generally higher than those on low terrain sites (Table 2.5). However the consequence of an incorrectly estimated shape factor on the energy output of a machine is normally quite small although it does depends on the shape of the power curve and the mean wind speed (Fig 2.18).

However despite these theoretical limitations the prediction process has, for the high terrain sites, given energy estimates to generally within 7% of the actual energy output. On an hour-to-hour basis the prediction process is not so reliable due to the temporal variation in the wind flow between the source site and the prediction site and the deviation from neutral stability conditions. More validation of the process is desirable, especially with more sets of sites in a wider variety of surface roughness characteristics and topography, however it is difficult to find two sites within 50km of one another where wind data has been collected. In addition the majority of prediction sites only have short-term data and not long-term data available for validation.

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Table 2.1 Roughness length guideline

Terrain description	Roughness length (m)
Large expanse of water	0.0005
Rough sea	0.001
Mown grass eg airports, parks and football pitches	0.01
Short grass with few bushes and isolated trees	0.05
Farmland with scattered hedges, trees and buildings	0.1
Farmland with many hedges, trees and buildings	0.2
Suburbia, forests and woodland	0.6

Table 2.2 Basic site descriptions for source sites and prediction sites

SOURCE SITE DESCRIPTION	PREDICTION SITE DESCRIPTION	DISTANCE	POSSIBLE PROBLEMS
DYCE - anemometer at 10m AGL at airport with hill rising to 250m ASL to W and built-up area to E nearby. Site is 58m ASL and is NW of Aberdeen in NE Scotland.	EASTERTOWN - anemometer at 12m AGL on top of farm building in gently undulating farmland with a 245m ridge to N. Site is 105m ASL NW of Old Meldrum in Aberdeenshire.	22km	(1) deflection of winds round hill to W of Dyce - long-term wind rose gives evidence of this. (2) anemometer site at Eastertown on top of building.
DYCE - as above.	PETERHEAD - anemometer on 6m mast on top of 24m harbour building in centre of Peterhead in NE Scotland.	42km	(1) deflection of winds round hill to W - long-term wind-rose gives evidence of this. (2) anemometer at Peterhead on top of building with town to W and sea to E.
LERWICK - anemometer at 10m AGL on rough moorland site, 80m ASL with coast at 0.6km. Site is S of Lerwick on E side of Shetland.	SCROO HILL - anemometers at various heights on mast on top of exposed rounded hill at 248m ASL in hilly area S of Lerwick.	11km	(1) Lerwick anemometer in non-flat area with 80m rise from nearby coast. (2) two hills near to Scroo Hill which rise to over 290m ASL.
LERWICK - as above.	SUSETTER HILL - anemometers at various heights on mast on top of a fairly isolated elongated hill 170m ASL in a hilly area N of Lerwick.	25km	(1) Lerwick anemometer in non-flat area with 80m rise from nearby coast. (2) possible funnelling effects due to sea inlet and valley S of hill.
PETERHEAD - anemometer on 6m mast on top of 24m harbour building in Peterhead in NE Scotland.	EASTERTOWN - as above.	38km	(1) anemometer at Peterhead on top of building with town to W and sea to E. (2) Eastertown anemometer on top of building.
PRESTWICK - anemometer at 10m AGL at airport with built-up area of Prestwick and coast to W. Prestwick is on W coast of Scotland.	MYRES HILL - anemometers at various heights on mast on top of hill 332m ASL in area of surrounding high moorland SW of East Kilbride.	29km	(1) Prestwick anemometer is at a coastal location with a strong diurnal variation which is outwith the modelling capabilities of this prediction method.

ASL = above sea level AGL = above ground level

NON-	:Source site	Lerwick	(distance 25km)
DIRECTIONAL	:Prediction site	Susetter Hill	
INPUT DATA	:Ht.of anemometer h	10m	
	:Ht.of prediction H	35m	

ALL LENGTHS/HEIGHTS ARE IN METRES		Sector A 345-045	Sector B 045-105	Sector C 105-165	Sector D 165-225	Sector E 225-285	Sector F 285-345
INPUT DATA	:ZY	0.200	0.010	0.010	0.010	0.010	0.200
AT SOURCE	:D1	650	1500	850	1250	N/A	150
SITE	:ZX	0.010	0.001	0.001	0.001	0.010	0.010
	:X1	80	0	0	0	80	80
	:F2	1.120	0.893	1.000	0.872	1.000	1.227
INPUT DATA	:X2	130	80	100	70	142	152
AT	:ZY1	0.010	0.010	0.010	0.010	0.010	0.010
PREDICTION	:D2	N/A	N/A	N/A	N/A	N/A	N/A
SITE	:ZX1	0.010	0.010	0.010	0.010	0.010	0.010
	:F4	1.040	1.300	1.243	1.133	1.224	1.160
COMPUTATION	:Factor if ZX=ZY, no transition					1.181	
OF F1	:Ht.base of transition zone h1	1.186	5.934	1.080	3.434	N/A	0.015
	:Ht. top of transition zone h2	90.289	96.821	61.466	83.681	N/A	27.937
	:Weighting factor if h1<h<h2	0.492	0.187	0.551	0.335		0.864
	:Factor if h1<h<h2	1.086	1.137	1.060	1.104		0.958
	:Factor if h>h2						
	:Factor if h<h1						
COMPUTATION	:Factor if ZX1=ZY1	1.286	1.000	1.000	1.000	1.000	1.286
OF F5	:h1 (site)	N/A	N/A	N/A	N/A	N/A	N/A
	:h2 (site)	N/A	N/A	N/A	N/A	N/A	N/A
	:Weighting factor at site						
	:Factor if h1<H<h2						
	:Factor if H>h2						
	:Factor if H<h1						
	:Roughness factor	1.286	1.000	1.000	1.000	1.000	1.286
	:Roughness factor if F4>1	1.000	1.000	1.000	1.000	1.000	1.000
	:Roughness factor if F4<=1						
FINAL	:F1	1.086	1.137	1.060	1.104	1.181	0.958
FACTORS	:F2	1.120	0.893	1.000	0.872	1.000	1.227
	:F3	1.050	1.080	1.100	1.070	1.062	1.072
	:F4	1.040	1.300	1.243	1.133	1.224	1.160
	:F5	1.000	1.000	1.000	1.000	1.000	1.000
RESULTS	:Directional correction factor	1.329	1.426	1.449	1.167	1.536	1.462

INPUT VARIABLES FOR EACH SECTOR

ZY	roughness length near source site
D1	distance to transition at source site
ZX	roughness length beyond transition at source site
X1	base height level ASL of cross-section at source site
F2	inverse topography factor applicable at source site (see section 2.3.2)
X2	base height level ASL of cross-section at prediction site
F4	topography factor applicable at prediction site (see section 2.3.4)
ZY1	roughness length near prediction site
D2	distance to transition at prediction site
ZX1	roughness length beyond transition at prediction site

Table 2.4 Results of long-term predictions

SOURCE SITE	PREDICTION SITE	PERIOD OF PREDICTION	CORRECTION FACTOR FOR PERIOD	PREDICTED MEAN SPEED	ACTUAL MEAN SPEED	PREDICTED SHAPE PARAMETER	ACTUAL SHAPE PARAMETER	MACHINE TYPE	ENERGY PERCENT ERROR*
Dyce	Peterhead	long-term AMWS	1.066	5.15	4.97	1.77	1.58		
Prestwick	Myres Hill	7344 hrs Mar-Dec'87	1.514	6.53	6.56	2.16	2.29	1	-2.3

* percentage error = 100 x (predicted - actual) / actual

MACHINE TYPE 1 has a rating of 60kW at a wind speed of 12m/s

Table 2.5 Results of short-term predictions

SOURCE SITE	PREDICTION SITE	PERIOD OF PREDICTION	CORRECTION FACTOR FOR PERIOD	PREDICTED MEAN SPEED	ACTUAL MEAN SPEED	PREDICTED SHAPE PARAMETER	ACTUAL SHAPE PARAMETER	MACHINE TYPE	ENERGY PERCENT ERROR*
Dyce	Eastertown	706 hrs in '86	0.994	5.16	5.25	2.22	1.95	1	-0.7
Dyce	Eastertown	1701 hrs in '87	0.960	3.88	4.34	2.28	1.94	1	-35.2
Peterhead	Eastertown	706 hrs in '86	0.878	4.62	5.25	1.94	1.95	1	-25.6
Dyce	Peterhead	706 hrs in '86	1.151	5.96	5.25	2.22	1.95		
Lerwick	Scroo 35m	1361 hrs Sep-Nov'85	1.671	12.94	12.11	1.97	2.30	2	-5.5
Lerwick	Scroo 35m	678 hrs Apr-May'86	1.627	13.26	11.38	2.95	3.38	2	14.4
Lerwick	Scroo 35m	1107 hrs Sep-Nov'86	1.662	13.69	12.95	2.21	2.53	2	-4.1
Lerwick	Scroo 20m	1107 hrs Sep-Nov'86	1.546	12.74	12.37	2.21	2.46	3	-4.2
Lerwick	Susetter 35m	920 hrs Sep-Oct'85	1.394	9.25	9.59	2.60	2.76	2	-2.6
Lerwick	Susetter 35m	476 hrs May'86	1.370	11.36	10.58	2.81	3.30	2	2.7
Lerwick	Susetter 35m	1100 hrs Sep-Nov'86	1.371	11.26	11.71	2.21	2.33	2	-4.8
Lerwick	Susetter 20m	1100 hrs Sep-Nov'86	1.267	10.42	11.27	2.21	2.24	3	-6.6

* percentage error = 100 x (predicted - actual) / actual

MACHINE TYPES

1 machine rating is 60kW at a wind speed of 12m/s
2 machine rating is 750kW at a wind speed of 14m/s
3 machine rating is 80kW at a wind speed of 14m/s

Table 2.6 Mean differences in wind direction between source site and prediction site

PREDICTION (Tables 2.4 & 2.5)	HOURS	SQ.ROOT(MSE)
Scroo Sep-Nov'85	1361	11.3^{o}
Scroo Apr-May'86	678	9.4^{o}
Scroo Sep-Nov'86	1107	8.1^{o}
Susetter Sep-Oct'85	920	17.9^{o}
Susetter May'86	476	13.8^{o}
Susetter Sep-Nov'86	1100	11.6^{o}
Dyce-Peterhead '86	706	18.7^{o}
Prestwick-Myres '87	7344	36.5^{o}

MSE = mean square error

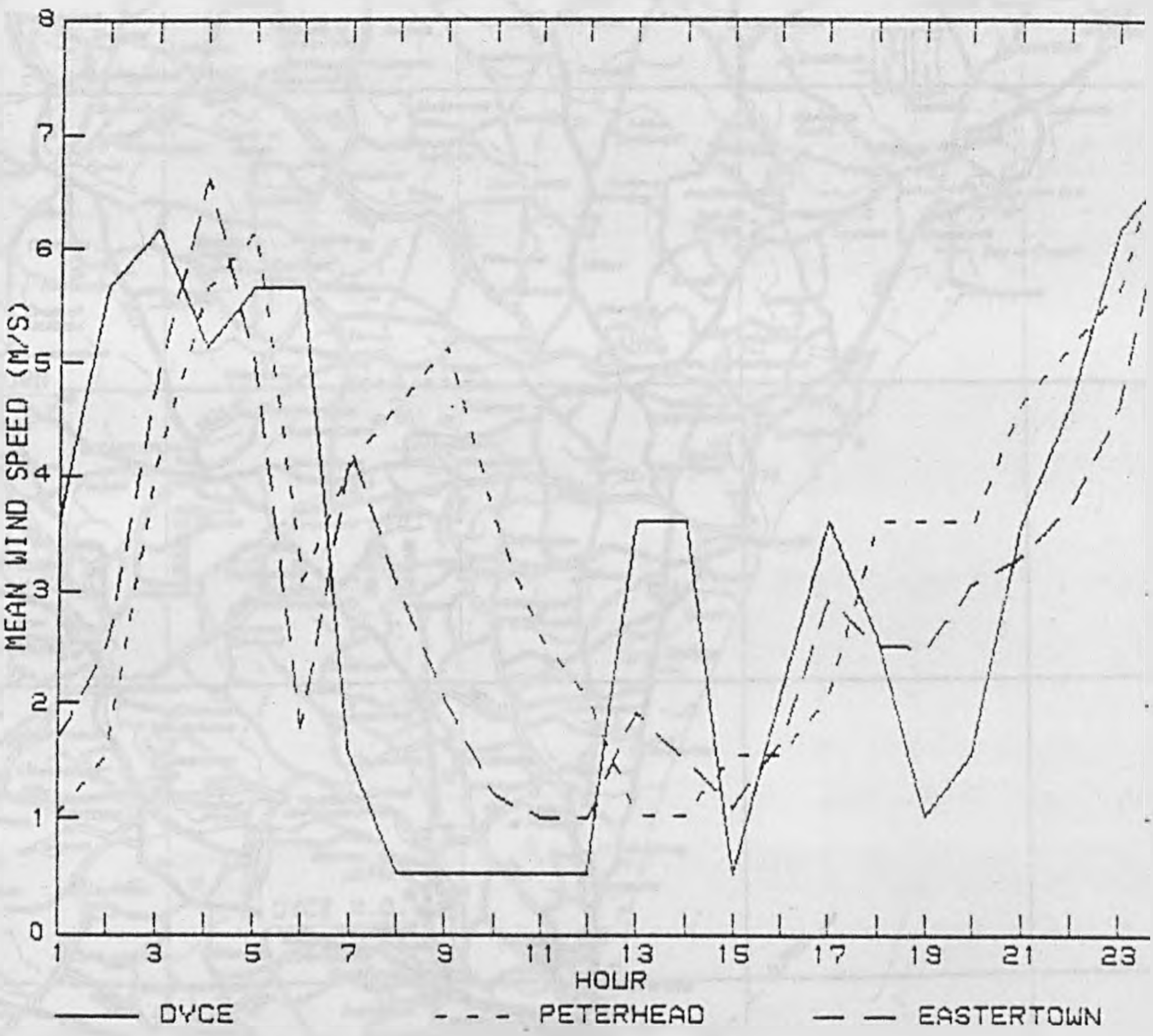

Fig 2.1 Simultaneous hourly wind speeds for three sites within 50km of each other

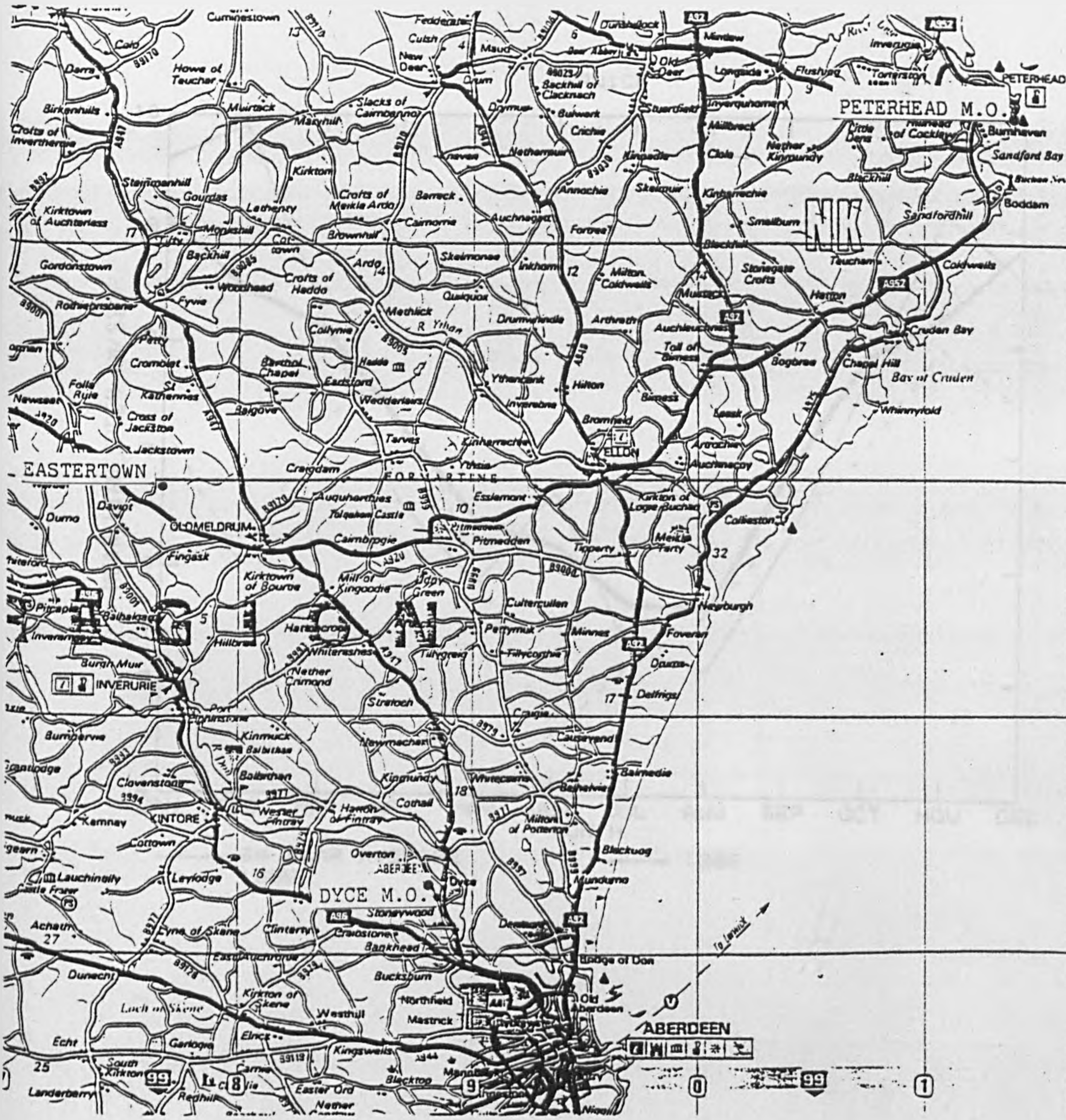

Fig 2.2 Location of Dyce, Peterhead and Eastertown in the NE of Scotland (scale 1" to 4 miles)

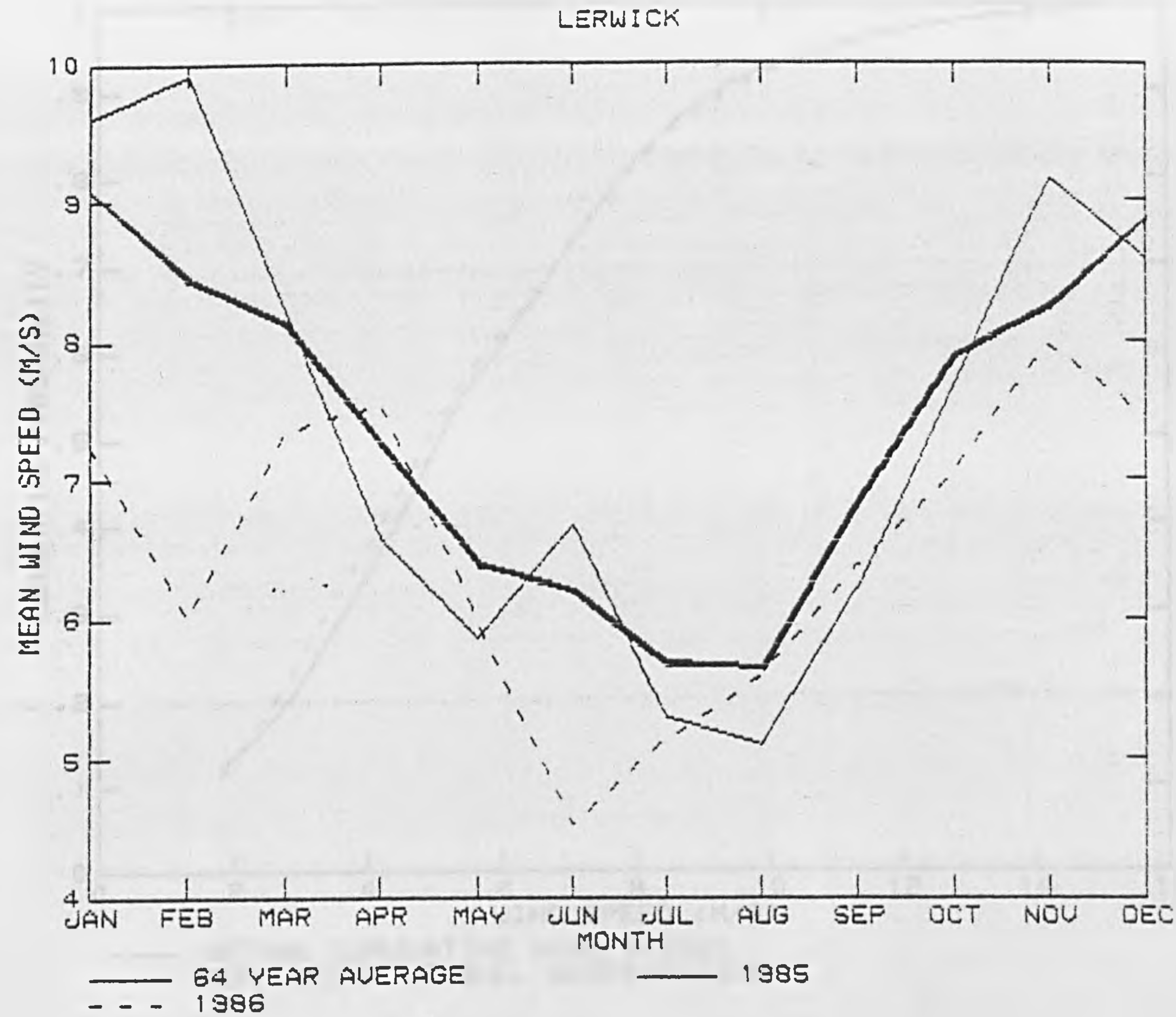

Fig 2.3 Long-term monthly mean speeds compared with monthly mean speeds from 1985 and 1986 for Lerwick

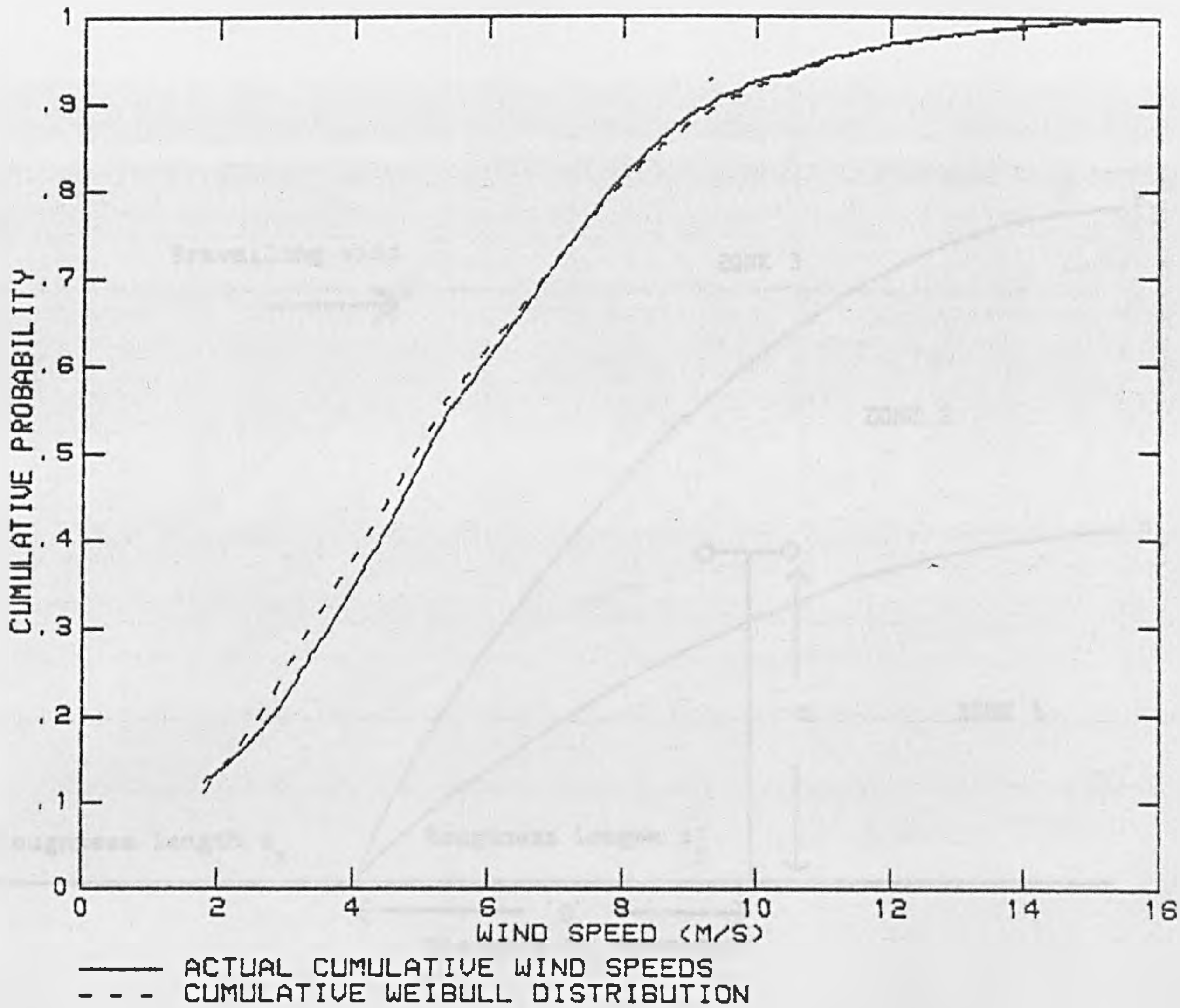

Fig 2.4 Example of a Weibull cumulative probability curve and actual data for Dyce wind speeds 1961-80

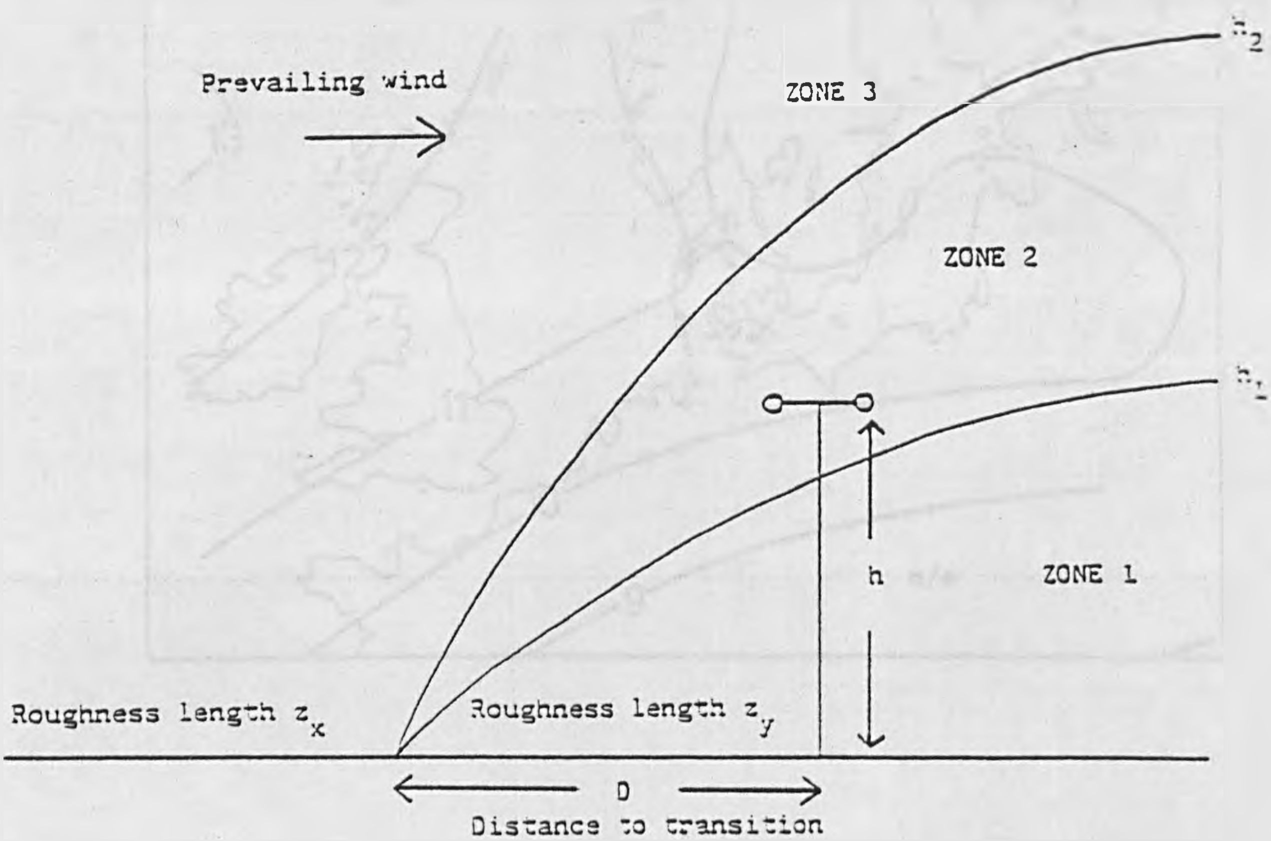

Fig 2.5 The formation of an internal boundary layer at a transition in surface roughness (ref 6)

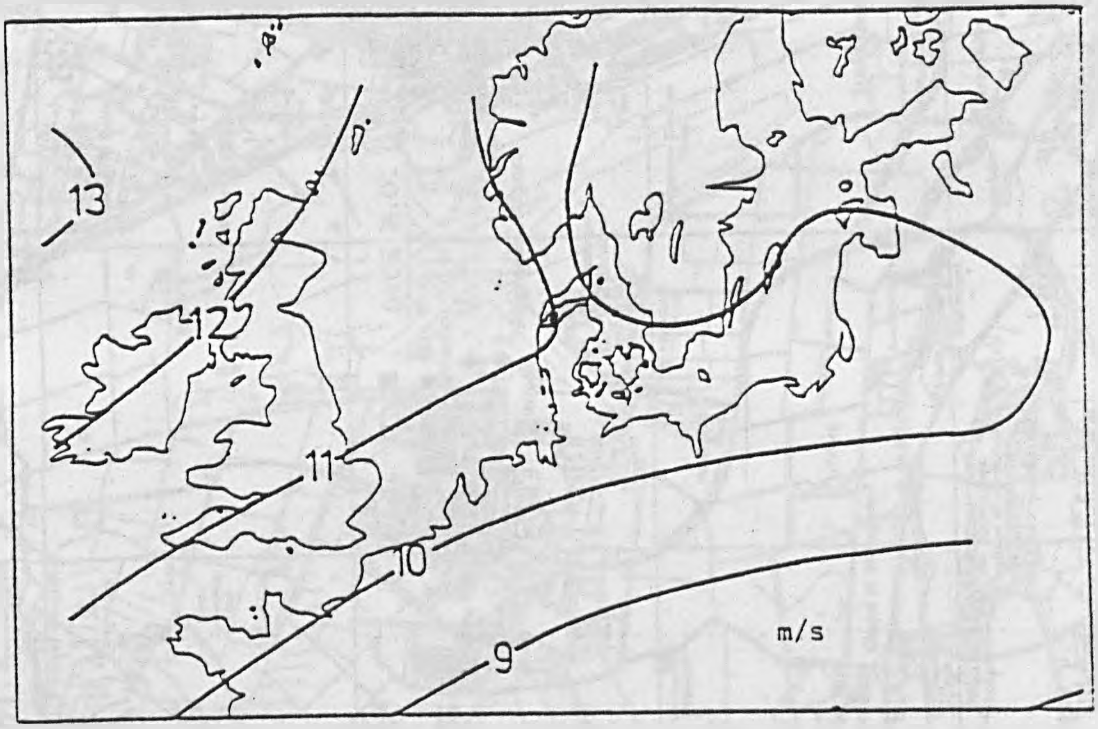

Fig 2.6 The average geostrophic wind at 850mb over Northern Europe (ref 6)

Fig 2.7 Location of Dyce meteorological station in its surroundings (scale 1:25,000)

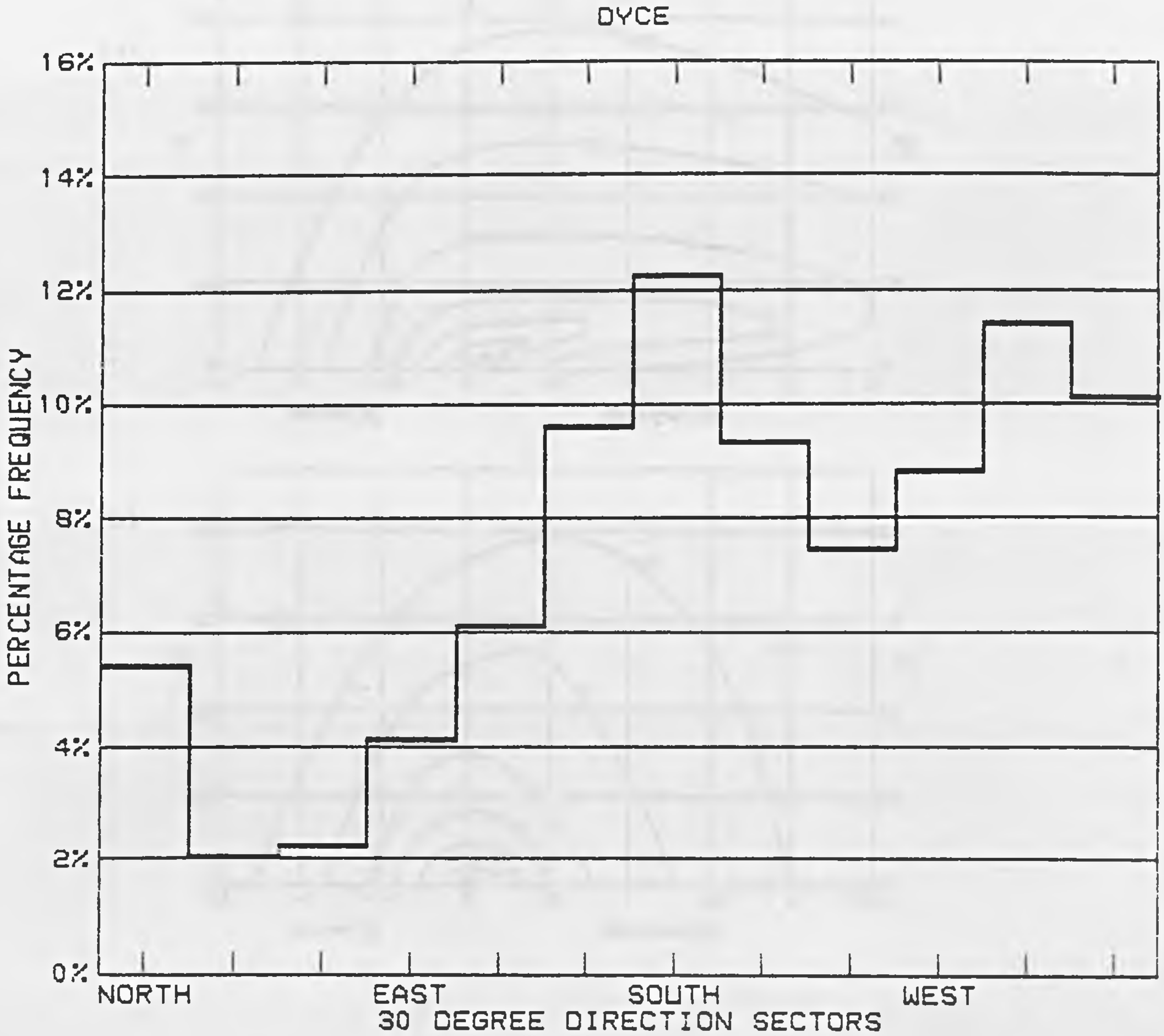

Fig 2.8 Long-term wind direction distribution for Dyce

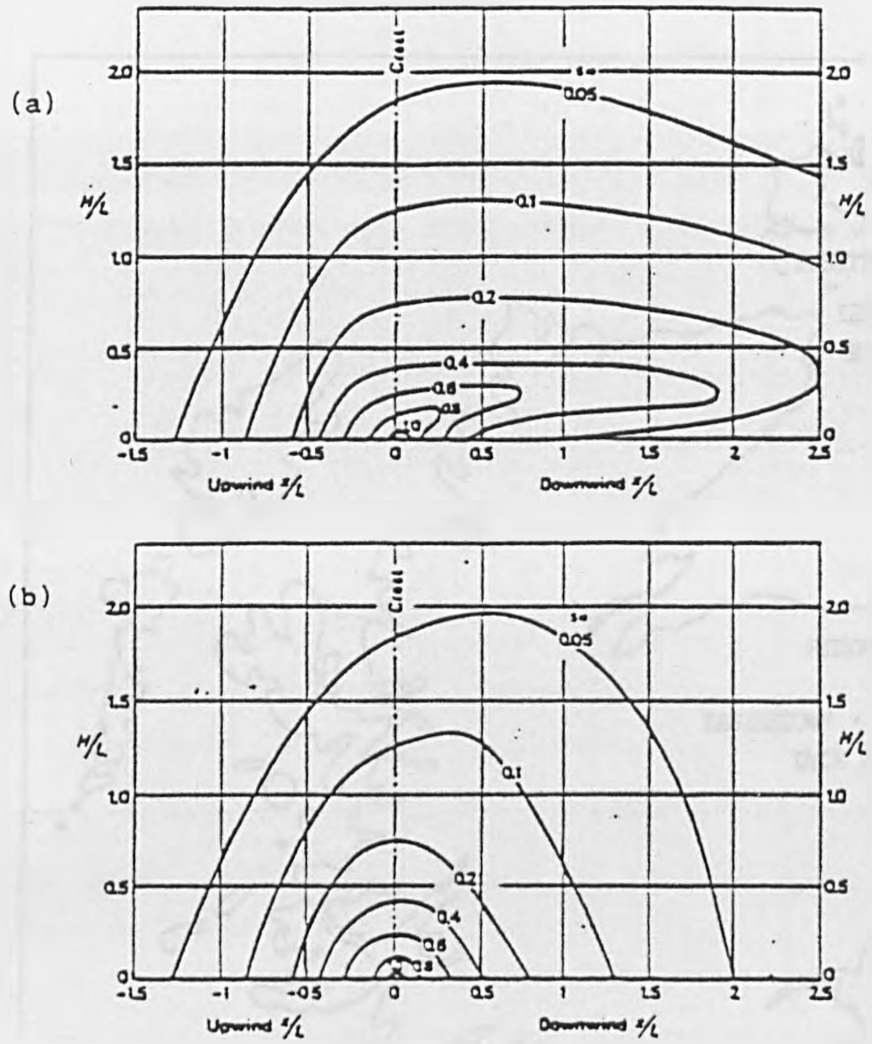

Fig 2.9 Speed increment coefficients for
(a) cliff and escarpment
(b) ridge and hill

x denotes horizontal distance from crest of topographic feature
H denotes height above ground
L denotes upwind half-width of feature (ref 24)

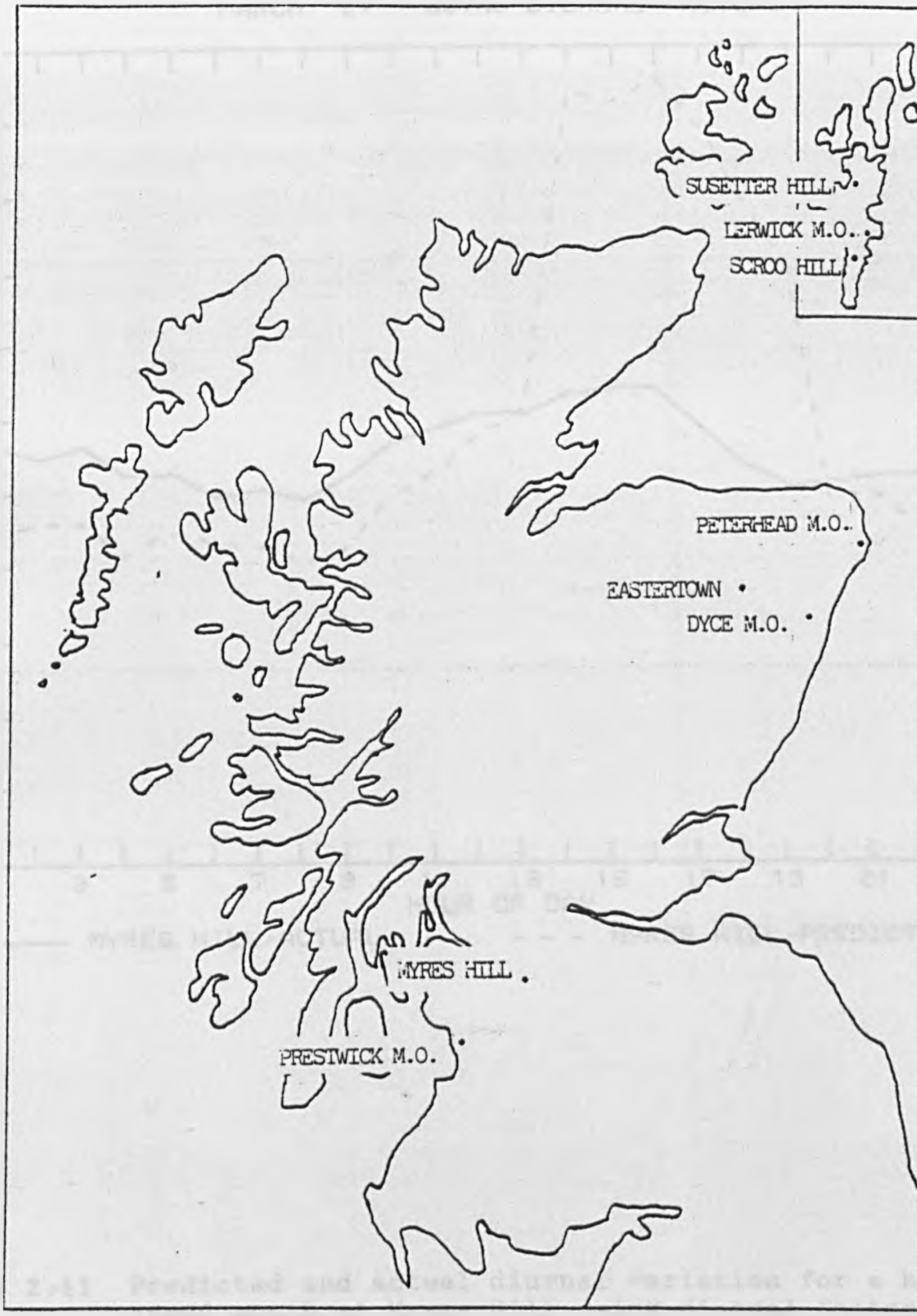

Fig 2.10 Locations of all source sites and prediction sites in Scotland

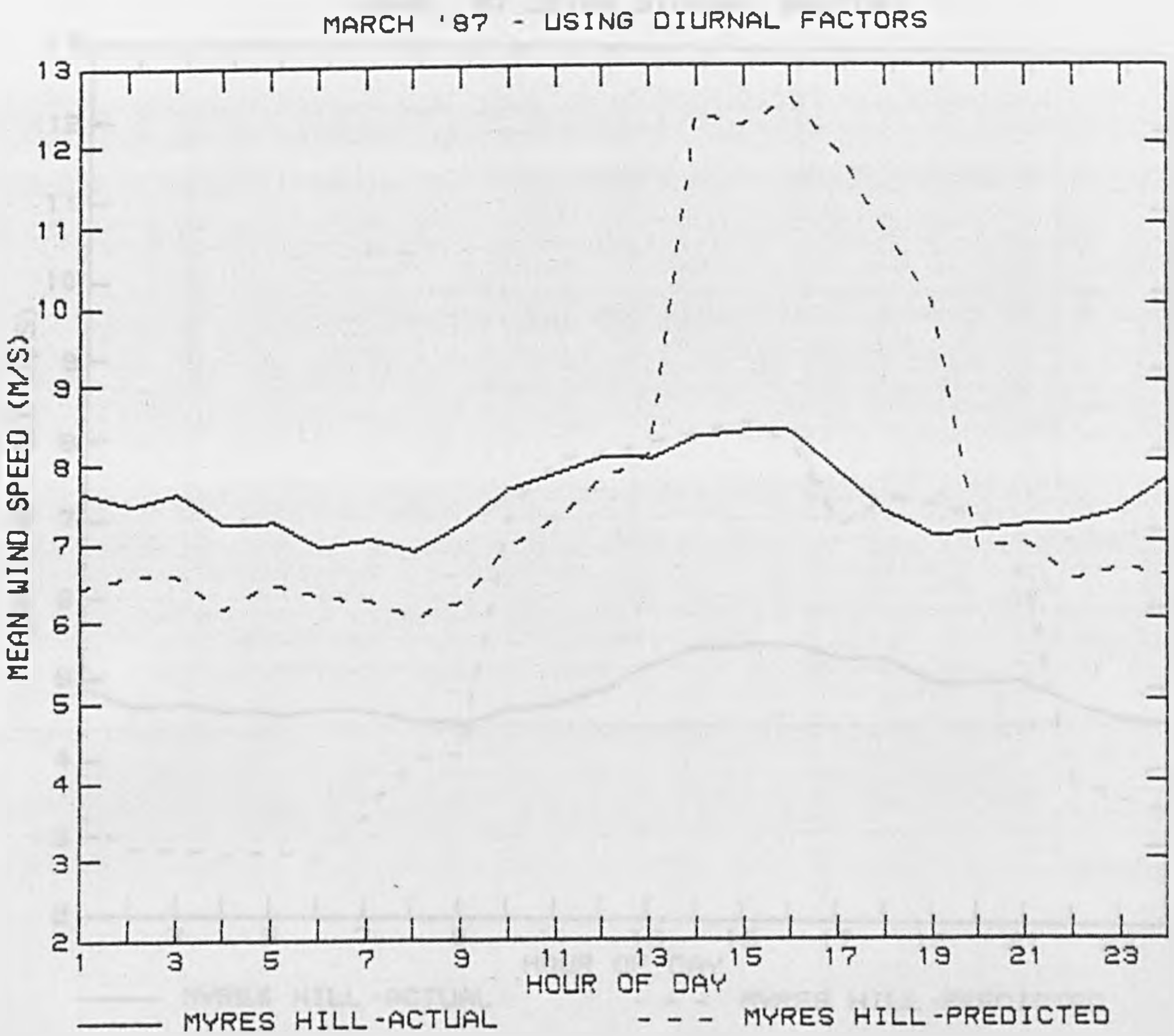

Fig 2.11 Predicted and actual diurnal variation for a high wind speed month at Myres Hill using diurnal factors

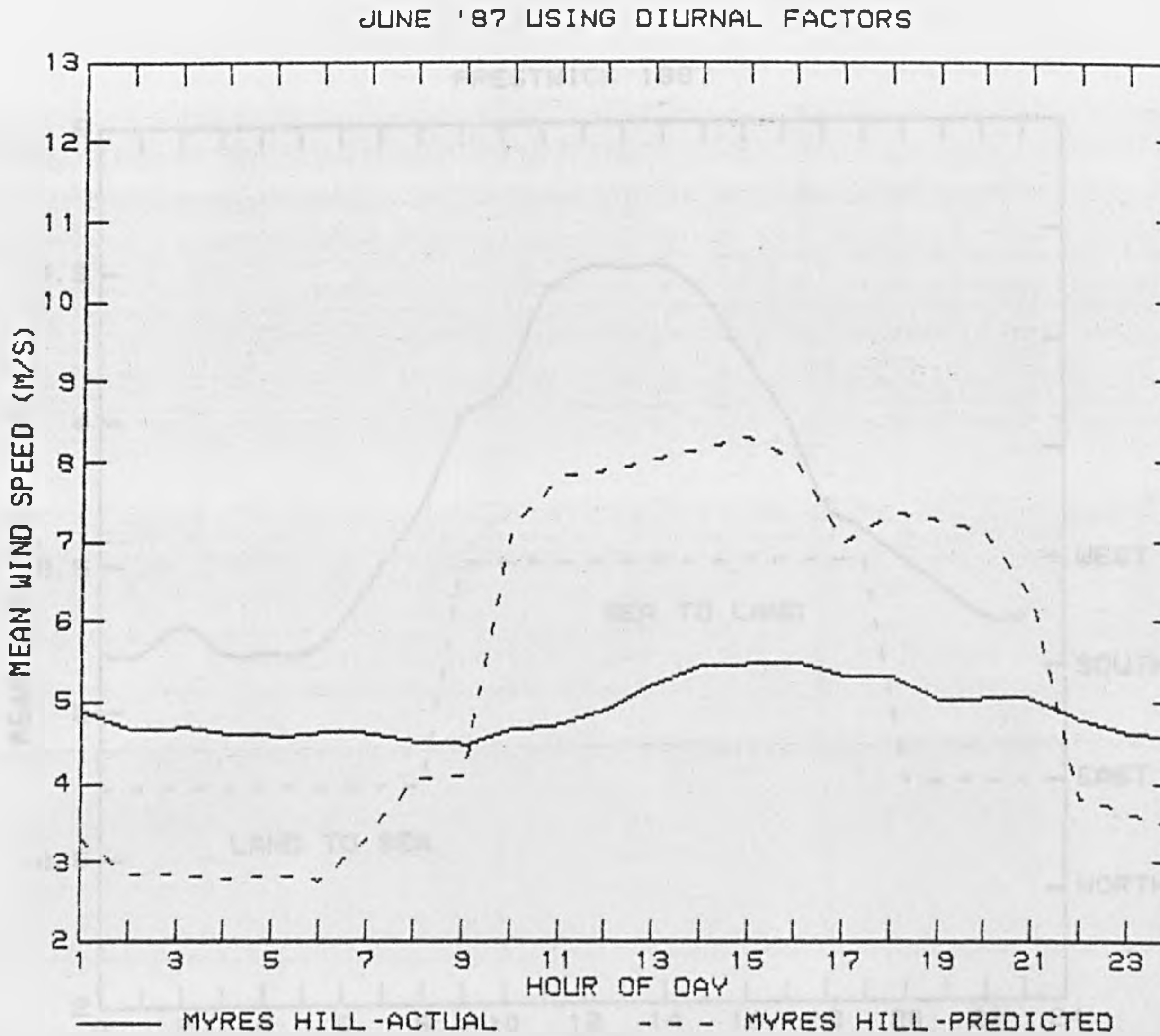

Fig 2.12 Predicted and actual diurnal variation for a low wind speed month at Myres Hill using diurnal factors

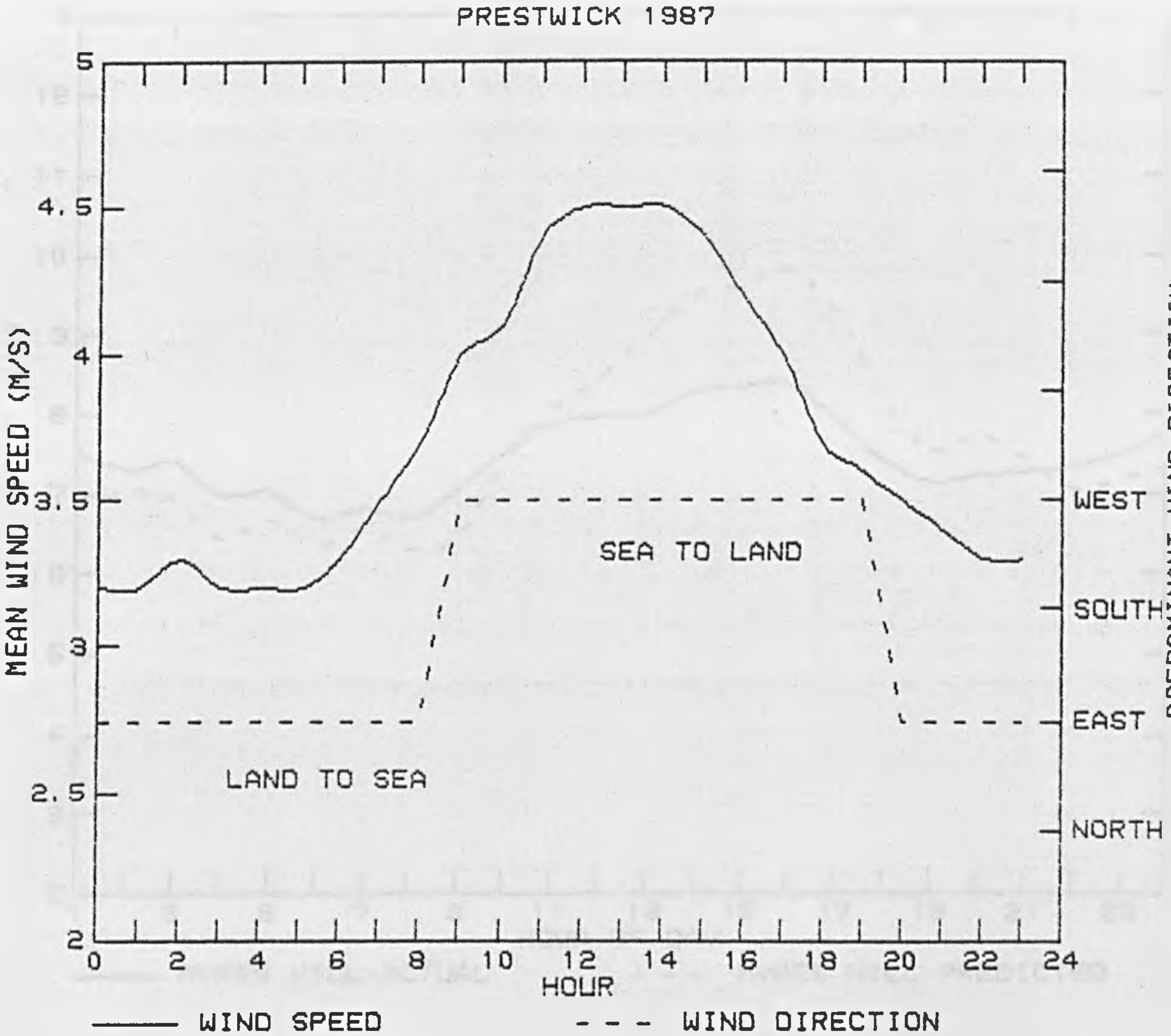

Fig 2.13 Diurnal variation in wind speeds and directions at Prestwick

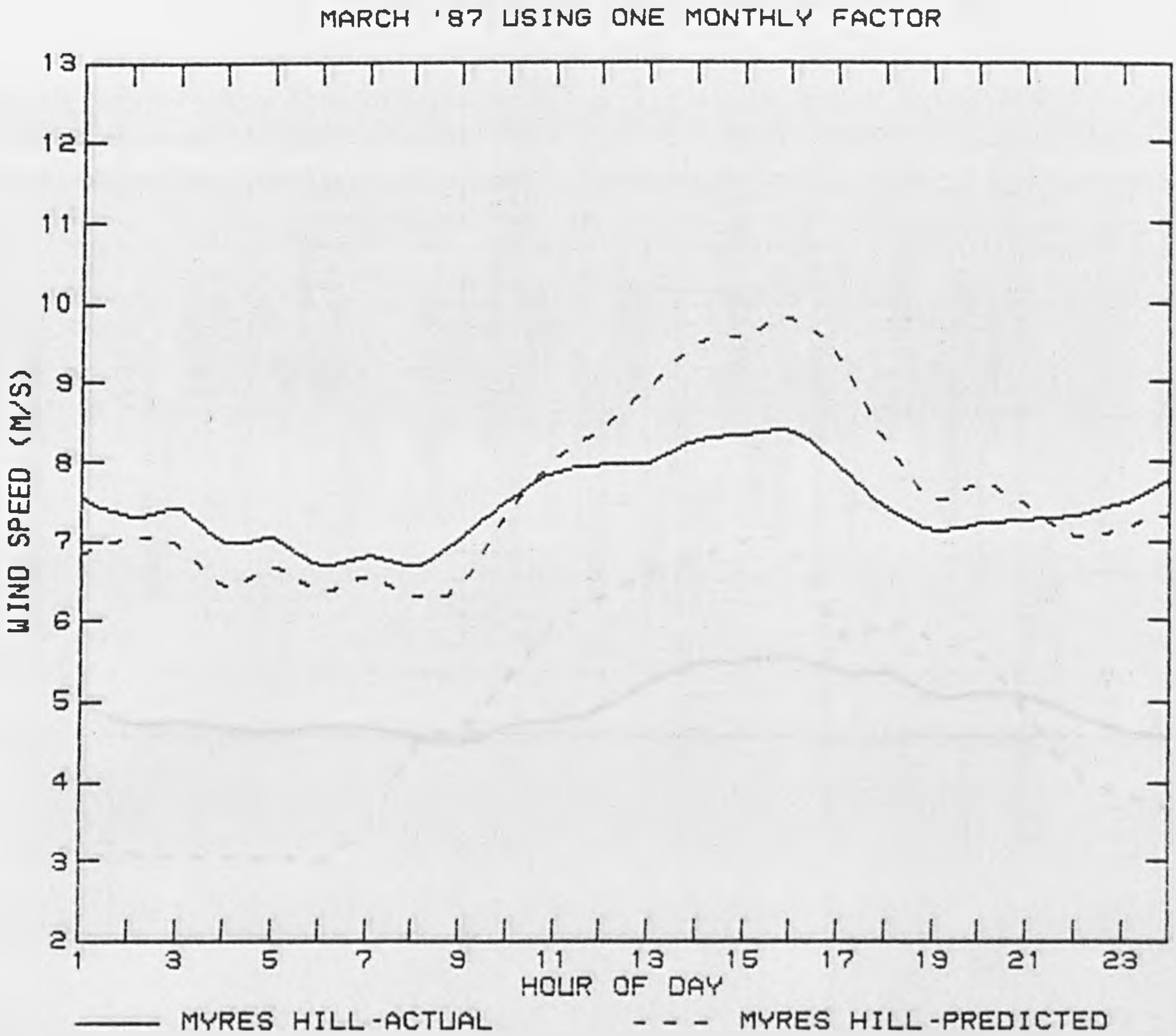

Fig 2.14 Predicted and actual diurnal variation for a high wind speed month at Myres Hill using a monthly factor

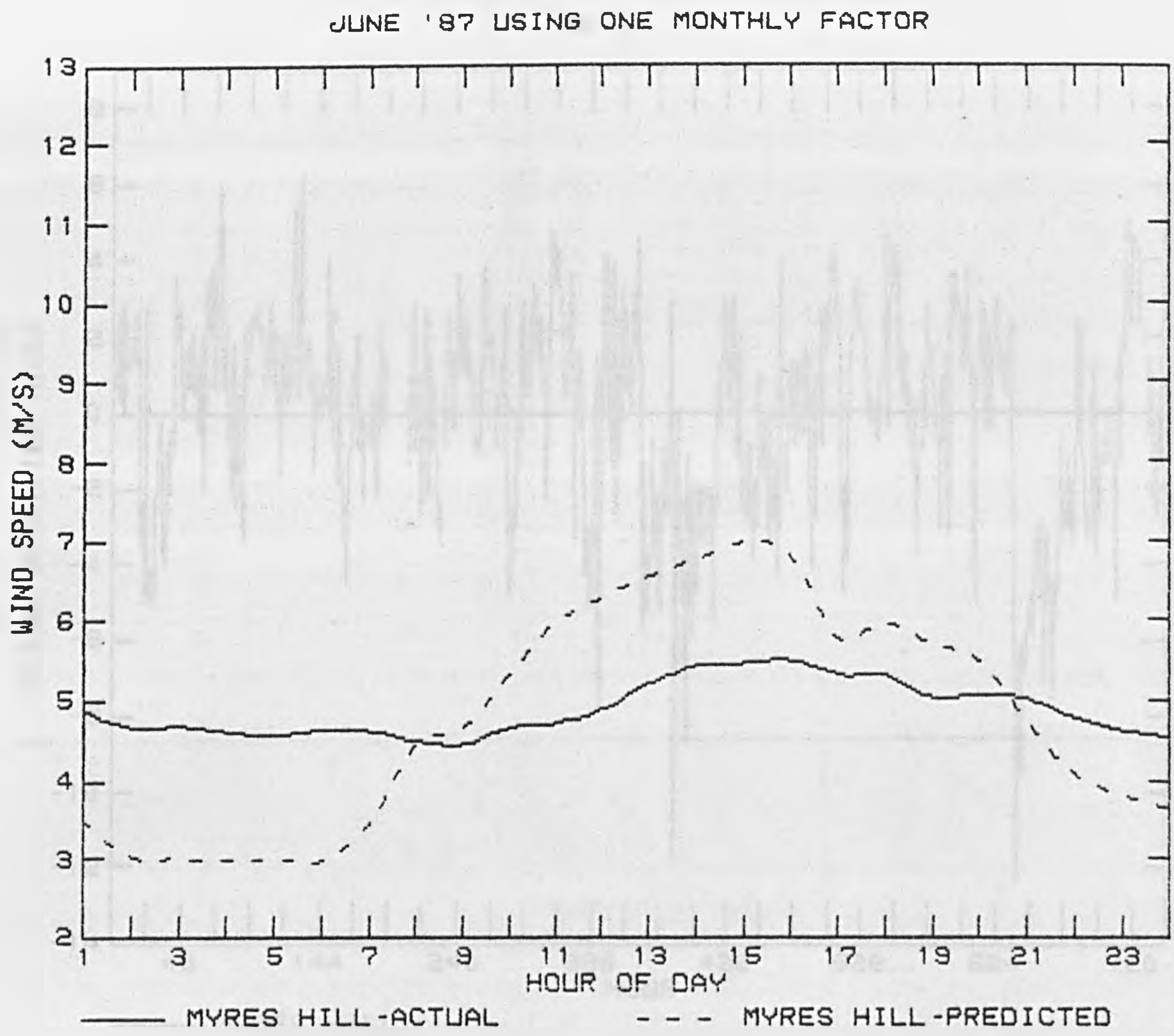

Fig 2.15 Predicted and actual diurnal variation for a low wind speed month at Myres Hill using a monthly factor

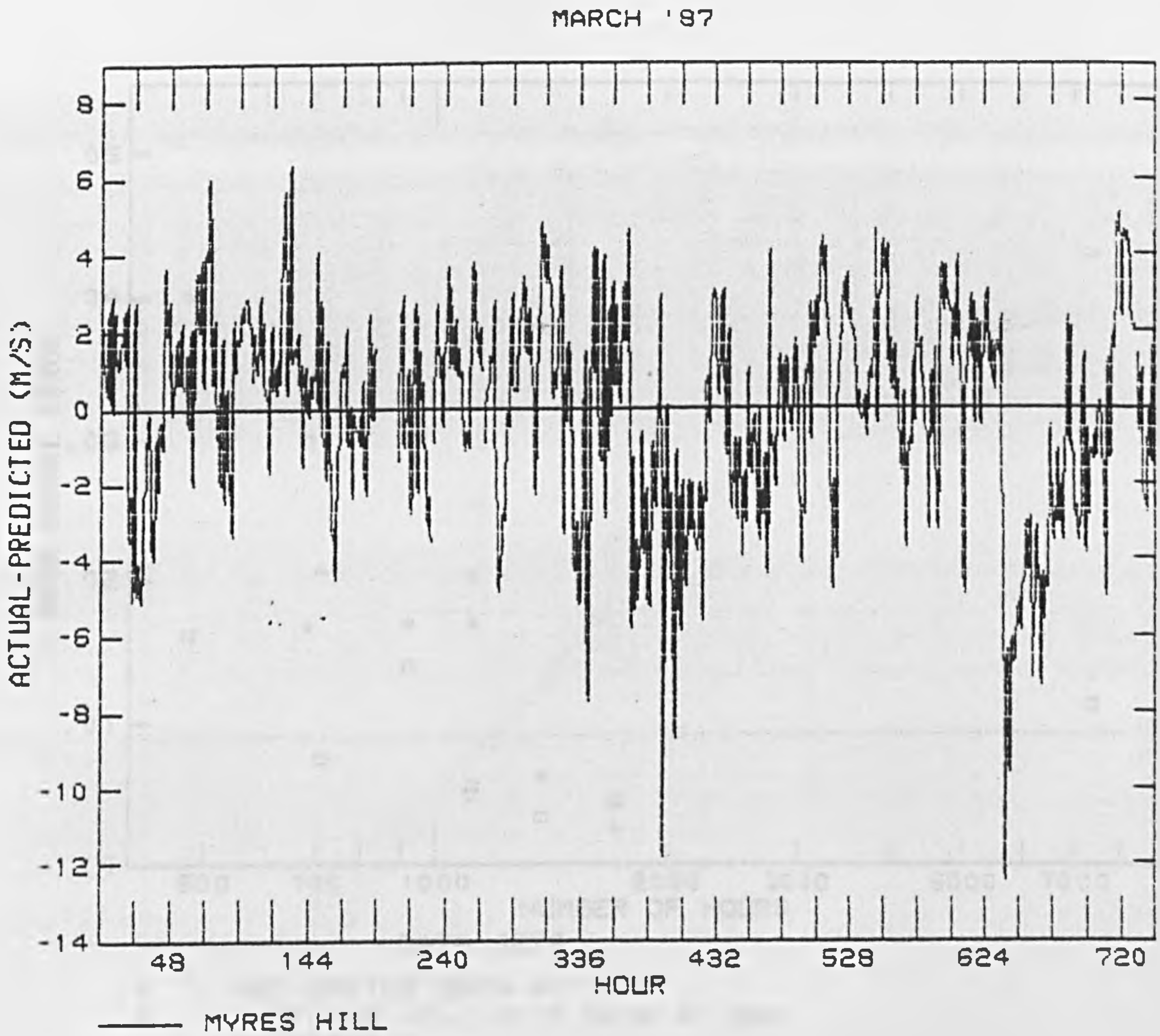

Fig 2.16 Results of predicting hourly wind speeds at Myres Hill

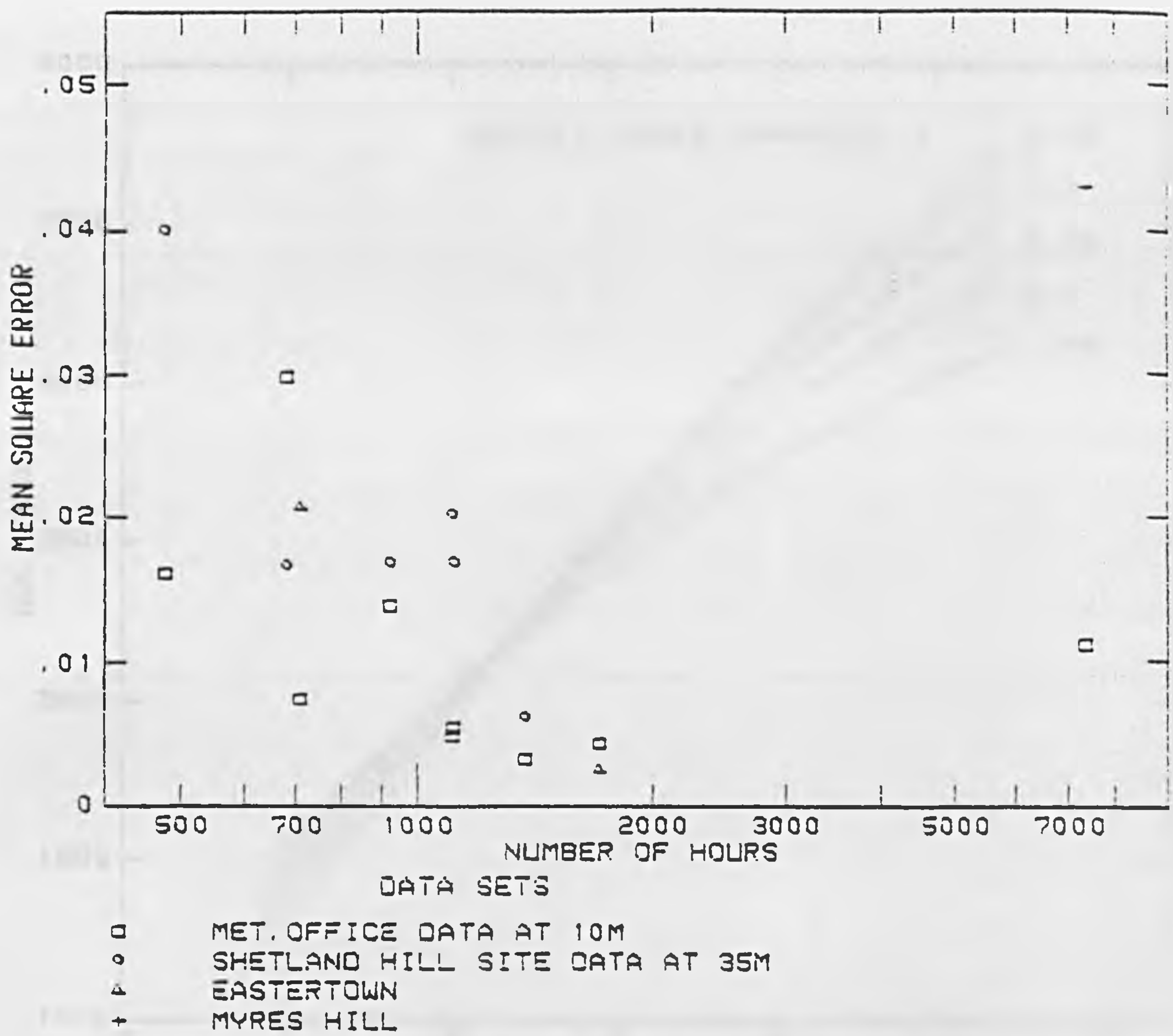

Fig 2.17 Mean square error of Weibull fit for various data sets

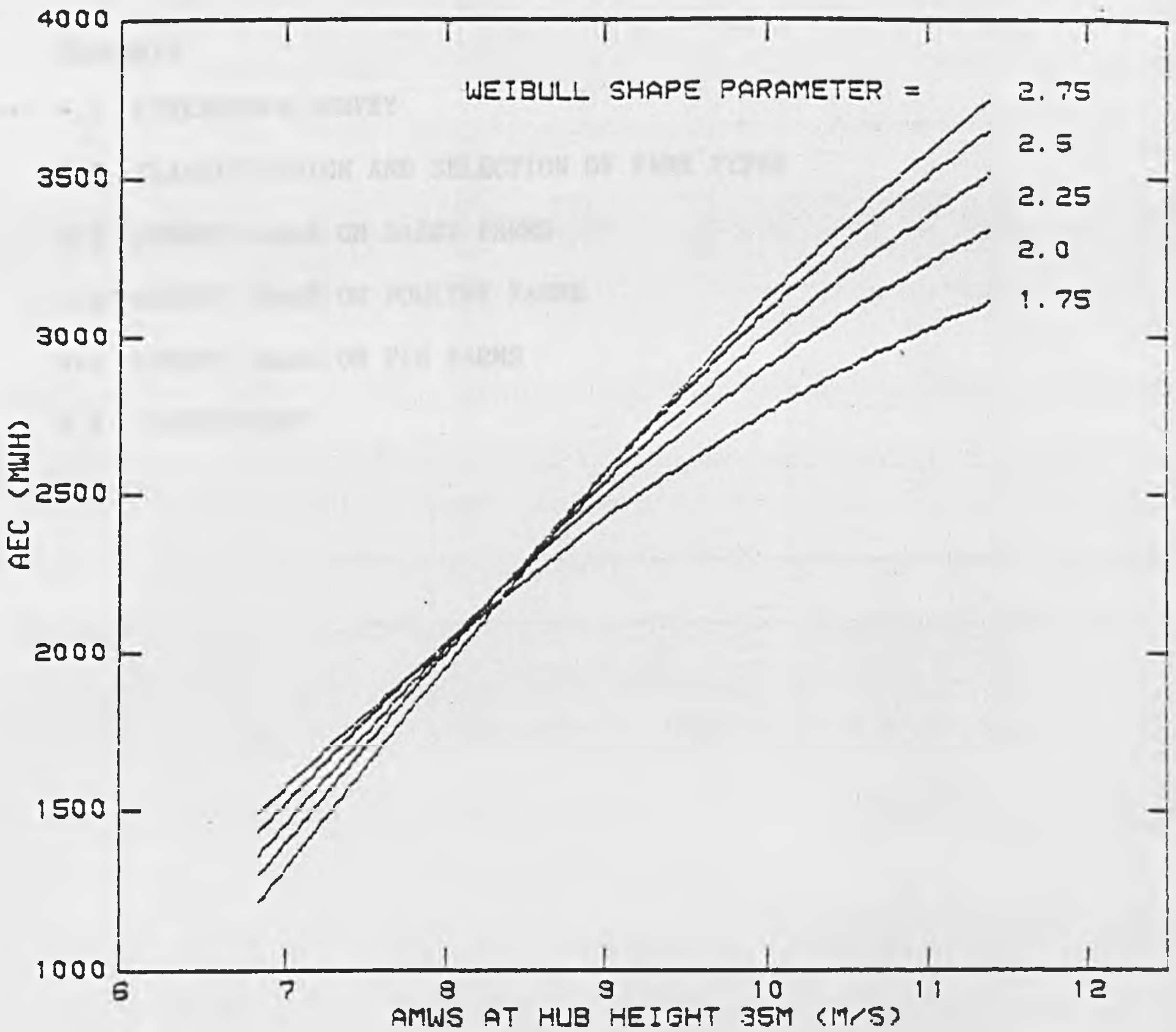

Fig 2.18 Variation of annual energy capture with annual mean wind speed and shape parameter for a 750kW machine

3. FARM ENERGY USAGE

Contents

LIST OF TABLES IN CHAPTER 3

LIST OF FIGURES IN CHAPTER 3

3. FARM ENERGY USAGE

The overall aim of this section as mentioned in chapter 1 is

"to assess energy usage for various types of agricultural enterprise with a view to utilising wind energy"

The most common method nowadays of utilising wind energy from a rotating rotor is by generation of electricity. Thus when considering the application of wind energy in agricultural enterprises, the sample of farm types where wind energy could be utilised is immediately reduced to those which could use electricity as the main energy source on the farm.

3.1 LITERATURE SURVEY

The majority of previous research on electricity usage in agriculture is either of a very broad nature with only global values being evaluated, or of a very specific nature whereby detailed minute by minute data are collected or simulated for load management purposes. However, one study that is of particular relevance for this project is that by ERA Technology Ltd (1, 2) which researches the application of grid-connected wind turbine generators for eight simulated farms. The electrical load profiles are simulated for dairy, poultry, pig and horticulture farms of different sizes. For each farm type a list is drawn up of machinery and other equipment using electricity and their respective electrical ratings with the help of Electricity Council publications (3), and periods of use through an average day and year. Before introducing the wind these electrical loads are summed to produce a table for each farm with the mean hourly loads on a monthly basis. Some of these tables are used later in this section. It was felt that this approach was satisfactory in that it gave a broad idea of the mean electricity consumption on a mean hourly basis for each month but ignored some potentially large effects on electricity consumption such as prevailing climate, preferences of individuals working the farm and building design.

An example of a study taking a more global approach to farm energy use is that by the Canadian Ministry of Supply and Services (4) whereby data is collected for 7,000 farms across Canada with a view to evaluating energy expenditure and quantities consumed for various farm uses by type of energy, characteristics of energy using machinery and energy management and conservation practices. It is found that 75% of energy expenditure for all types of farms is for mobile farm machinery and transportation and 15% is for environmental control of buildings and the remaining 10% for "other" uses. Of the 15% expenditure on energy for environmental control, 58% is due to expenditure on electricity. Similarly, of the remaining 10% expenditure on "other" uses, 55% is due to electricity. Thus for all farms in the sample expenditure on electricity as a percentage of total expenditure on energy is 14.2%. The main disadvantage of this type of approach to farm energy usage is that costs of different types of energy are not equivocal. Also it is very much specific to the Canadian situation and neither does it attempt to classify farms into different types apart from small, medium and large as according to total agricultural receipts received.

For Scotland overall energy data for farms are available from the Scottish Agricultural Colleges (5) but energy consumption is only a small aspect of the total data collected.

A survey on energy use in rural areas undertaken in the Grampian area in Scotland (6) revealed that electrical consumption constituted approximately 15% of total energy use in rural areas inclusive of the domestic sector. However the hypothesis presented in this study was that there existed considerable potential for a greater degree of rural energy autonomy, and thus only total electrical consumption was ever evaluated in the various surveys undertaken as part of this study.

An example of research on detailed electrical load management on farms is the work done by the American Society of Agricultural Engineers (7) where centrally controlled management of electrical equipment is used to reduce total consumption and electrical peaks on a grain farm. Demand patterns using an averaging period of five minutes are plotted for the farm under study for one month for use in the stochastic simulation model which is required in the electrical load management system. The emphasis of the study is on peak reduction and assessing the load interuptions with different set points.

Research into conservation of energy on farms (8), in particular dairy farms (9, 10, 11) and grain drying (12) is the predominant focus of the remaining existing work on electrical energy usage on farms in the UK. But again the actual electrical consumption levels before conservation measures are taken are not necessarily quantified on a time of day and year basis.

3.2 CLASSIFICATION AND SELECTION OF FARM TYPES

One problem is that individual farms are difficult to classify by type and size especially with regard to electrical consumption. Many farms operate as mixed farms with varying degrees of emphasis on each agricultural practice and corresponding electrical equipment.

In the first instance farms are classified by the system adopted in the "Agricultural Atlas of Scotland" (13). Table 3.1 shows this classification with the corresponding summarised definitions and the main energy requirements. The definitions of energy requirements are duplicated below.

<u>Definitions of descriptions used in energy portfolios</u>

field op.	:	energy required for field operations and general transport normally in the form of diesel and petrol
environmental	:	energy required for environmental control in buildings such as heating, ventilation and lighting
processing	:	energy required in processing foodstuffs, drying grain, milking, hot water, refrigeration, conveyors
animal feed	:	chemical energy required for feeding animals
plant feed	:	chemical energy required for feeding and controlling plant growth

As mentioned in the preliminary words of this chapter, the only farm types that can be potential users of wind energy are those which use electricity as their main source of energy. The farms in Table 3.1 which have their predominant energy requirements in field operations, animal feed or plant feed cannot use electricity for their main energy source. On this basis, hill sheep, upland, rearing with arable and part-time enterprises are dispensed with as regards utilising wind energy.

The remaining farm types all have a main requirement for energy in environmental control and processing, both of which are static energy users and are thus able to be met by electricity. The domestic house is not included in the farm energy portfolios in Table 3.1 as it's energy requirements can be considered as independent and able to be met by electricity regardless of farm type.

As the electricity consumption for farm type 4 in Table 3.1, rearing with intensive livestock, is for environmental control of the intensive livestock and processing of feed, this farm type can be considered as a subgroup of farm type 8, intensive. In a similar manner farm type 5, arable rearing and feeding, can be considered as a subgroup of farm type 6, cropping, as in both cases the electricity component is due to crop processing such as grain drying.

The wind speed varies most significantly with time of year and, depending how far from the coast, with time of day. In order to ascertain the degree of energy match between consumption and wind turbine generator production it is necessary to assess the monthly and daily variations in electrical consumption for the selected farm types.

An initial intelligent estimate can be made of the patterns of consumption for farm types 6, 7 and 8, cropping, dairy and intensive respectively. Schematic variations in daily and monthly electricity consumption profiles for these farm types are illustrated in Figs 3.1 to 3.3. They include the electricity consumption profile of a domestic house.

In Fig 3.1, the hourly and monthly profiles for a cropping farm, the base load is very low and due mainly to the base load within the domestic house consumption profile. The peak in the monthly profile is due to the very high processing requirements in grain drying.

In Fig 3.2, the profiles for a dairy farm, the hourly profile is dominated by the two periods of milking, one early morning, one mid-afternoon. High processing requirements account for these two peaks and they are due to milking machinery, hot water and refrigeration. The shape of the monthly profile is dominated by the environmental requirements of the domestic house as the effect of outside temperature on hot water requirements in the dairy unit cancels its effect on refrigeration requirements.

In Fig 3.3, the profiles for an intensive farm, the hourly profile is dominated by a high base load due to environmental requirements for the livestock such as heating and ventilation. Processing requirements such as feeding mechanisms account for the high consumption in the daytime. On a monthly basis the profile is affected by outside temperature.

In practice the amount of electricity used on a farm depends not only on predominant farming type but also on size and design of farm buildings, number of livestock, prevailing climate and specific practices used on the farm.

Fig 3.4 shows a typical wind power density profile on the same basis as Figs 3.1 to 3.3. The profile is power available in the wind per unit area and does not include the loss of power due to wind turbine generator inefficiencies which vary with wind speed. It can be easily seen that the intensive farming profiles of Fig 3.3 correlate most with the wind energy profiles. The profiles for cropping match the least with the wind energy profiles. Cropping is therefore dispensed with partly on this basis and partly because although grain drying is able to be done using electricity it is quite often done by other means such as diesel generators or gas.

Thus dairy and intensive farms are identified as potential users of wind energy. A more detailed analysis is now presented using what little literature is available and some data collected by the author. As separate data and literature is available on pig and poultry farming, intensive farms are subdivided into these two main groups.

3.3 ENERGY USE ON DAIRY FARMS

Electricity is required on the farm dairy unit for milking and transfer of milk, cooling and storage of milk and water heating. Minor uses of electricity in the dairy unit include lighting, washing of bulk tank and pumping of water for cleaning the parlour. Besides the dairy unit itself the farm may have mill and mix plant for feed preparation and/or a fan and conveyor for hay production. If 100 tonnes or more feed is required by a farm per annum the purchase of the necessary equipment can usually be justified in the farm's overall accounts compared to buying in ready prepared feed compounds. It is likely therefore that farms with dairy herds of sizes greater than 100 will have their own mill and mix plants, especially if there is also some beef cattle.

Milk is extracted from the udder and transferred to a receiver jar by a vacuum pump, normally rated 1-4kW. From the receiver jar the milk is transferred to the bulk tank sometimes by gravity but normally by a milk pump of 0.5-1kW rating.

Milk must be cooled rapidly in the bulk tank to less than $5^{o}C$ requiring a reduction in temperature of approximately $30^{o}C$ (14). The refrigerated bulk tank may be one of two kinds - indirect or direct. In the direct system the milk is only cooled when the refrigeration plant is in operation. The indirect system utilises ice-bank storage and hence the condenser is much smaller in size but is two thirds as efficient as the direct system due to maintaining the ice-bank when not required. If the farm is on an economy tariff the ice-bank for the morning milking can be built up overnight using cheap rate electricity. For example a 680 litre indirect tank would require a condensing unit of 0.5kW whereas a direct expansion tank of the same size would require a unit of 2.25kW. But the indirect tank being two thirds the efficiency, would have to be on for three times longer than the direct tank.

Milk cooling can consume up to 50% of the total electricity to the dairy unit and will vary seasonally according to the ambient temperature. Reduction in the amount of electricity used for cooling can be achieved by installing a pre-cooling system which reduces the temperature of the milk prior to storage and final refrigeration in the bulk tank. It comprises of a plate heat exchanger with cold mains water as the cooling medium. Milk outlet temperature is dependent on the water inlet temperature and the water-to-milk flow ratio. At the North of Scotland College of Agriculture at Craibstone, where approximately 100 cows are milked per day, pre-cooling saves around 13,000kWh per annum. The saving is greater in the winter due to the colder mains water temperature. An increase of 10 ^{o}C in the mains water temperature which was normal between winter and summer, results in an approximate decrease by 50% of the litres of milk cooled/kWh. A by-product of pre-cooling is a raised water temperature in the header tank, providing further energy savings in water heating.

Water heating is the other high energy user in the dairy unit. Warm water at about 50 ^{o}C is required for udder washing and the amount used is very much dependent on the preference of the herdsmen. Hot water is also required for cleaning of the plant. This may be done either by circulation cleaning requiring water at about 70 ^{o}C or by acidified boiling water (ABW) which requires almost boiling water. Both methods require approximately the same volume of water. At Craibstone approximately 200 litres of water is used per day for udder washing and 330 litres per day for plant cleaning which is by the acidified boiling water method. In addition there may be other small hot water requirements around the dairy such as hand washing and calf feeding.

Water heating can consume up to 60% of the total electricity used on the unit but on average is about 40% (15). It will vary over the year according to mains water temperature. However, unlike the pre-cooler, it will decrease with an increase in water temperature. If there is a pre-cooler installed the seasonal variation in water heating costs will be reduced.

To reduce water heating costs the water can be heated during the night in a special time-controlled, insulated tank provided the farm is on an economy tariff (16). Another alternative is to install a heat recovery unit (HRU). This comprises of an insulated water tank with a copper coil, through which hot refrigeration gas passes from the bulk tank. At Craibstone it was found that approximately 5,800kWh per annum can be saved with a heat recovery unit.

Employment of an indirect bulk tank, a pre-cooling system, circulation cleaning, a time-controlled insulated water tank and a heat recovery unit all serve to spread the electrical load over the whole day and to reduce the peaks at milking time which are both desirable if a wind turbine generator is being considered.

The overall consumption in the dairy unit is very much dependent on herd size, geographical location, milk yield, the cooling system, the method of plant cleaning and on whether pre-cooling or heat recovery are employed. Mean annual consumption figures from various sources are shown in Table 3.2. The figures for the North of Scotland College of Agriculture (NOSCA) at Craibstone are calculated from a meter reading sheet with readings dating from 1976. For a herd size in the range 89-100 the mean annual consumption on a the dairy unit ranges from 26,600kWh to 75,700kWh. The two NOSCA figures are for one specific dairy unit over a number of years (1976 - 1987) whereas the Milk Marketing Board figures are means for many farms for one specific year (1971). Differences in herd size, milk yield, cooling system used and the method of cleaning account for some of the variation. The Craibstone figures are high despite energy conservation equipment being installed. The cold climate in the NE of Scotland and the high milk yield may be responsible for this.

A surprising result was found by NORMAN (17) in the study on 12 dairy farms where the electricity use per unit volume of milk was calculated from 24 months of data. It was found that small family units with herd sizes of about 60 and units with conservation equipment installed were the most efficient. The three farms in the sample which were under institutional control had higher electricity use per unit volume of milk than the rest. This can also be seen in the figures in Table 3.2 where the dairy unit at Craibstone run by the North of Scotland College of Agriculture has high annual electrical consumption.

Fig 3.5 shows the consumption profile for the simulated dairy farm by ERA Technology Ltd (18). Handbooks and leaflets by the Electricity Council were the main source of information for this simulation. It can be seen that consumption peaks between 6 and 8am and between 4 and 6pm as would be expected. There is no pre-cooling, heat recovery or night water heater on the simulated farm. The high consumption in June and July is due to electric fan hay drying - this has been eliminated from the annual consumption figure in Table 3.2. The maximum demand is 45.1kW due to hay drying and the base load is 1kW due to ice-bank build up.

The approximate seasonal variation for the Craibstone dairy unit before and after installation of the pre-cooling and HRU systems is shown in Fig 3.6 and the interannual variation at Craibstone is shown in Table 3.2. It can been seen that there is a substantial drop in the electricity consumption after installing the energy saving equipment.

The actual cost of the electricity will depend very much on whether the farm is on an economy tariff or not. Most dairy farms are on the economy tariff as the cheap night rate can be used for ice-bank build up and water heating. In fact the majority of the 300 or so farmers in NE Scotland who are on the economy tariff are dairy farmers (19).

3.4 ENERGY USE ON POULTRY FARMS

The main enterprises on a poultry unit are egg production, broiler production and sometimes turkey production. Pullet rearing for small farm and home requirements is often done at the larger units.

In any unit the main electricity using activities are ventilation, automatic feeding and manure disposal, incubating and lighting. Heating is required for the chicks during the first three weeks, thereafter no further heating is required. On egg production enterprises eggs are incubated perhaps only twice a year so heating is required for approximately six weeks in total per annum. However for broiler production eggs are continuously incubated so at any one time up to one third of the stock require heating. During the first three weeks a chick is attracted to heat by brooder lights.

A market survey of the broiler industry in England and Wales has shown that heating for broiler production is normally done by liquid petroleum gas or oil; electricity has virtually no penetration as a heating fuel (20). At Parkhead Poultry Unit at NOSCA, Craibstone in Aberdeen the broiler house is heated by gas, but some of the other rearing buildings are heated by electricity.

In Figs 3.7 and 3.8 the electrical consumption profiles are shown for an egg production unit and a broiler production unit respectively. In these farms simulated by ERA Technology Ltd (21) all heating is assumed to be done by electricity.

From Fig 3.7 for the egg production unit it can be seen that the consumption is relatively constant throughout the year except in March and September. These two very high consumption periods can be attributed to the incubating, followed by three weeks heating for the young chicks. Maximum demand in these two months is 124kW due to feeding mechanisms whereas for the rest of the year it is only 31.5kW.

The base load is 3.4kW and this is due to a minimum ventilation rate. Ventilation rate is dependent on temperature and feed intake. The higher electrical consumption during the day is due to artificial lighting (lighting encourages the laying of eggs) the feeding mechanism and the manure disposal system. Layers do not require heating.

The load profile for the broiler unit in Fig 3.8 is much more constant although considerably higher due to a continuous through-put of stock, thus heating is required all the time for approximately one third of the stock. The annual consumption is 179,647kWh. The profile varies with time of year depending on ambient temperature. The maximum demand is 62.8kW due to feeding mechanisms and the base load is 45.7kW, this being due to the continual use of the incubator, heating, lighting (to attract chicks to heat) and ventilation. The small peaks in consumption during the day is due to the feeding mechanisms.

A real example of a poultry unit is Parkhead Poultry Unit where there are 12,000 layers, 20,000 broilers and 4,300 turkeys produced per annum. There is also pullet rearing for home requirements.

The large broiler house with 13,000 birds is heated by gas and most of the remaining heating requirements is provided by electricity. In some of the buildings, for instance one of the percheries, there is mechanically controlled ventilation. Most of the ventilation however is done electrically and is temperature controlled. It's purpose is also to remove moisture, disease organisms, carbon dioxide and ammonia (22).

From five years of electricity bills the mean annual consumption is 141,901kWh excluding the office and the broiler house. The office and the broiler house are separately metered by sub-meters and have annual mean consumptions of 17,015kWh and 15,791kWh respectively.

The seasonal variation for the whole unit (incl. office and broiler house) is shown in Fig 3.9. As expected there is a higher electrical consumption in the winter.

The inverse relationship between heating and ventilation is illustrated in Fig 3.10 where the interannual variation for the main poultry unit at Parkhead and the rearing house are shown. 1984 was a high consumption year for the broiler house where the base load is controlled by minimum ventilation rates. Heating in the rearing house is by gas. However, at the main unit 1984 was a relatively low consumption year where the base load is mainly determined by heating requirements.

3.5 ENERGY USE ON PIG FARMS

A pig farm is generally based upon breeding pigs (sows and gilts), fattening pigs and piglets being reared. Electricity is used predominantly for environmental control ie. heating and ventilation, with a small amount used for feeding, cleaning and lighting.

Unlike broiler farms the majority of pig farms are heated by electricity. Heating and ventilation are required during farrowing and post-weaning (23). These environmental energy requirements are closely related to the ratio of body surface area to volume of pig. This ratio is at its highest when the pig is at its smallest and the thus the heat and moisture loss is at its highest. The environmental input energy serves to replace this loss and is thus at its highest when the pig is at its smallest in the farrowing accommodation. The ratio decreases with an increase in size of pig, and thus in the post-weaning accommodation the energy input is reduced. In the fattening accommodation the environmental energy input is reduced even further so that there is only a ventilation requirement and no heating.

The heating is sometimes done by underfloor heating cables (24) but more often done by infra-red (IR) heating lamps. Artificial lighting is required during farrowing as it stimulates milk production (25). It also acts as an attraction to a heated area in the weaner accommodation. The IR heating lamps have the advantage in that they can provide both heating and lighting.

In intensive units the sows have two or more litters per year and the demand for farrowing and weaning accommodation is fairly constant through the year. As can be seen from Fig 3.11, the electrical consumption profile for a simulated pig farm by ERA Technology Ltd (26), the load is fairly constant throughout the year with a slight drop in summer due to less heating. On a daily basis the load again is fairly constant with a peak in the morning and in the afternoon due to the feeding mechanism being switched on. The base load of 3.7kW is due to minimum ventilation rates and lighting.

The shape of the simulated pig farm load profile agrees quite closely with that of Eastertown pig farm (see 4.6). However the simulated annual consumption is 57,530kWh compared to an annual consumption in the range 350,000-400,000kWh for Eastertown. The actual mean consumption for 1985 to 1987 inclusive is 380,506kWh at Eastertown. Eastertown has 330 breeding pigs whereas the simulated pig farm has 230 breeding pigs. Even having taken account of this in a simplified manner assuming linear scaling the simulated annual consumption is only 82,543kWh whereas a real example of a pig farm in the the NE of Scotland has an annual consumption over 350,000kWh. This can be mainly explained by the use of underfloor heating cables at Eastertown which are less efficient than IR heating lamps. With underfloor heating cables there is an extra requirement for lighting which also contributes to the high energy consumption. Also, at the simulated farm there is no separate post-weaning accommodation, the piglets being kept with their mothers until they are ready for the fattening house. This is not the case at Eastertown. Another possible cause for the large difference is the colder climate in the NE of Scotland. Different farming practices may also contribute to the difference. For instance higher feeding levels of the pigs in the simulated farm will reduce the heating requirement. Also they may be better designed buildings on the simulated farm with more insulation and natural ventilation. None of this information is available for the simulated farm.

Another real example, apart from Eastertown pig farm, is Tillycorthie Farm, near Udny, which is part of the North of Scotland College of Agriculture (NOSCA). Each pig building is individually monitored with a sub-meter. The sub-meters have been read at the start of each month since July 1985.

The seasonal variation in the farrowing and weaning accommodation at Tillycorthie is shown in Fig 3.12. It can be seen that the farrowing accommodation requires almost twice as much electricity as the weaning accommodation due to higher heating requirements as previously mentioned. The seasonal variation is relatively small in the farrowing accommodation due to continual heating and use of artificial lighting for milk stimulation. In the weaning accommodation the seasonal variation is more significant due to the more open nature of the building giving rise to passive heating and lighting from the sun. The annual consumption levels for the pig enterprise at Tillycorthie could not be obtained as the whole place, which besides the pig houses includes feed mechanisms and ventilation for indoor beef and sheep, a freezer room, washing machine, heating in laboratories, mill and mix plant, and a potato store, is under two Electricity Board meters and although there are a number of sub-meters most of them are not read unless there is an experiment going on.

3.6 CONCLUSIONS

The overall objective of this section is

"to assess energy usage for various types of agricultural enterprise with a view to utilising wind energy".

It has in general been fulfilled for farms where there is a static energy requirement. Other farms are excluded since they would not be able to use the wind energy.

From the literature survey it was found that, apart from one study, very little data have been collected or simulated for farm energy usage at the hourly and monthly time interval of relevance to this project.

From that one study by ERA Technology Ltd, simulated data are used to obtain average values of daily, seasonal and annual electricity consumption for three types of farming, namely dairy, poultry and pigs which all have a relative high static energy requirement. Very little real data were found to be available to demonstrate and validate these trends. Little consistency can be found in the simulated figures and the few real examples of farms in the NE of Scotland with suitable data. For instance mean annual consumption levels are summarised below for the three types of energy intensive farms from both the literature survey and the real examples in the NE of Scotland.

Farm type	simulated	real examples
Dairy	65,512kWh	75,700kWh (Craibstone)
Poultry		
(eggs)	179,647kWh	141,901kWh (Parkhead)
(broilers)	447,167kWh	N/A
Pigs	82,543kWh	380,506kWh (Eastertown)

The exact quantity of electricity consumed by an enterprise will not only depend om farm type but also on building design, the number of livestock, farm-specific practices and climate. It will vary considerably from one farm to the next.

If the electricity profiles from the simulated data are compared with the schematic energy consumption profiles in Figs 3.1 to Fig 3.3 produced by intelligent guesswork, little difference can be detected. This shows that either the intelligent guesswork was intelligent indeed, or that a certain degree of intelligent guesswork constituted the simulated profiles.

Although broiler units appear to be the most favourable candidates for utilising wind energy in practice the majority of poultry units are heated using liquid petroleum gas. The real examples of pig farms in the NE of Scotland indicate that intensive pig farming has very high and fairly constant heating and ventilation requirements throughout the day and the year. Intensive pig farms thus are the most favourable candidates for utilising wind energy. Dairy farms have a peaky demand with low base load though the peaks can be reduced with the use of ice-bank build up in the refrigeration unit and insulated time-controlled night water heaters.

The expense of setting up monitoring systems at different farms has precluded it as an option for assessing farm electrical energy requirements in this study. Monitoring would be a farm-specific approach and thus would include the effects of building design, farm-specific practices and prevailing climate. However it would not necessarily be possible to differentiate these effects and the end objective of assessing energy usage with the view to utilising wind would be fulfilled for only the monitored farms.

It is recommended that the patterns of electricity consumption derived in this section should be used with confidence but a farm-specific approach should be used to evaluate total annual electrical consumption. This should be straightforward information to obtain, the electricity bills being the most likely source. The patterns can then be scaled up and down according to annual consumption.

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Table 3.1 Classification of farm types with corresponding energy portfolios (ref 1)

FARM TYPE	FARM DESCRIPTION	ENERGY PORTFOLIO
1. hill sheep	grazing ratio > 90% crop ratio < 15% sheep smd > 0.35(total smd)	field op. animal feed
2. upland	crop ratio < 30% or crop ratio > 55% and grazing ratio > 75%	field op. animal feed
3. rearing with arable	crop ratio < 55% intensive ratio < 25% sale crop ratio < 25%	field op. animal feed plant feed
4. rearing with intensive livestock	intensive ratio > 25%	environmental animal feed processing
5. arable rearing with feeding	crop ratio > 55% or crop ratio > 45% and sale crop ratio > 25%	field op. processing animal feed
6. cropping	crop ratio > 75% or crop ratio > 50% and sale crop ratio > 25%	field op. plant feed processing
7. dairy	registered milk selling farms with more than 4 cows in milk and cow smd > 0.25(net smd)	production field op. animal feed
8. intensive	intensive ratio > 60%	environmental animal feed processing
9. part-time	total smd < 250	field op.

KEY TO TABLE 3.1

Definitions for farm descriptions

total smd	: all standard man days
net smd	: total smd less those devoted to pigs and poultry
grazing ratio	: percentage of total area in rough grazing seven years old and over
intensive ratio	: percentage of total smd devoted to horticulture, pigs and poultry
crop ratio	: percentage of net smd devoted to crops (incl horticulture)
sale crop ratio	: percentage of net smd in wheat, barley, potatoes, sugar beet and horticulture

Definitions of descriptions used in energy portfolios

field op.	: diesel and petrol required for field operations
environmental	: energy required for environmental control in buildings such as heating and ventilation
processing	: energy required in processing foodstuffs, drying grain, milking, hot water and refrigeration
animal feed	: chemical energy required for feeding animals
plant feed	: chemical energy required for feeding and controlling plant growth

Table 3.2 Mean annual electrical consumption for various dairy farms

SOURCE OF INFORMATION	HERD SIZE	YIELD	INDIRECT(I) OR DIRECT(D)	CIRCUL. OR ABW	PRECOOL OR HRU	ANNUAL MEAN
NOSCA, Craibstone	100	680,000l	I	ABW	no	75,700kWh
NOSCA, Craibstone	100	680,000l	D	ABW	both	50,800kWh
Milk Marketing Board 1971	89	unknown	I	circul.	no	26,600kWh
Milk Marketing Board 1971	89	unknown	I	ABW	no	31,750kWh
Simulated by ERA Technology Ltd	100	474,500l	I	ABW	no	65,512kWh

I - indirect system of cooling milk, usually by ice-bank build-up
D - direct system of cooling milk
CIRCUL. - circulation of hot water for cleaning of plant
ABW - acidified boiling water for cleaning plant
PRE-COOL - precooling of milk before final refrigeration
HRU - heat recovery unit recovering heat from the milk for water

Table 3.3 Annual trends in electricity consumption at Craibstone dairy unit

YEAR	ANNUAL CONSUMPTION	NOTES
1976	67,504kWh	smaller herd
1977	78,465	
1978	74,150	from July 78 to Jan 81 the pre-cooling
1979	75,852	system and the HRU were in operation
1980	74,616	intermittently for trial tests
1981	67,236	
1982	61,154	
1983	58,606	in Aug 83 a new bulk tank with direct
1984	53,199	expansion and a water cooled condenser
1985	51,704	was installed - previously the tank was
1986	48,284	of the ice-bank build up type

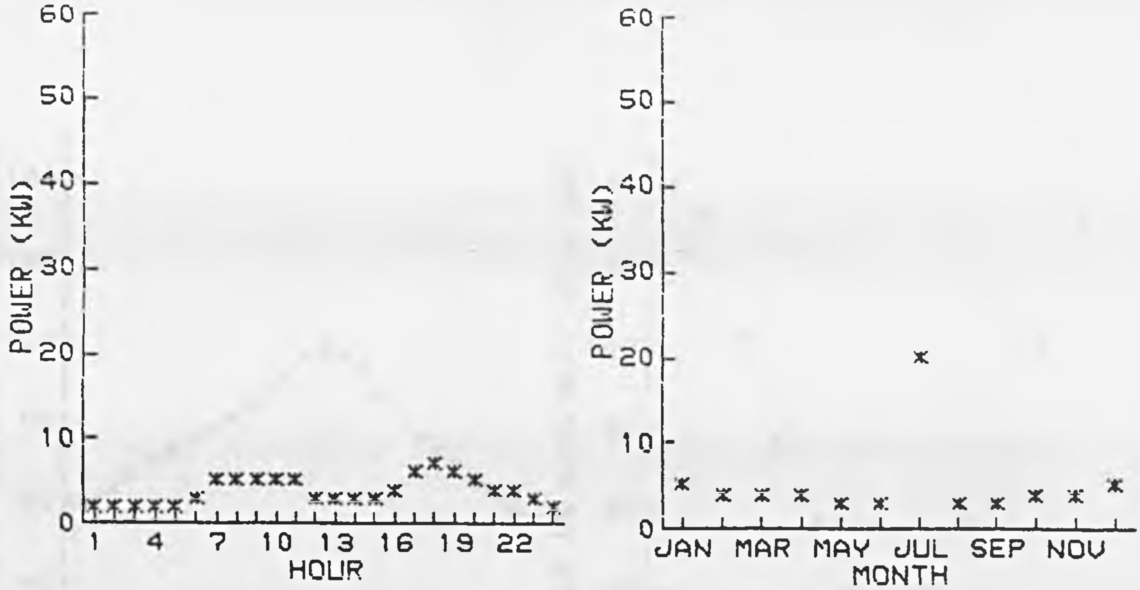

Fig 3.1 Schematic variation in electrical consumption profiles for a cropping farm

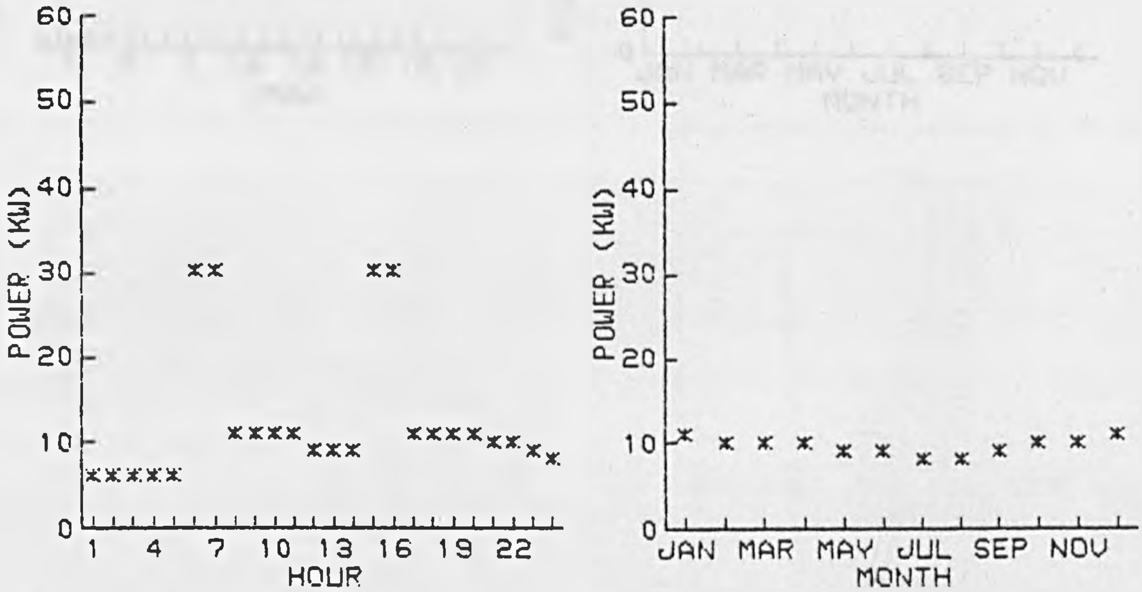

Fig 3.2 Schematic variation in electrical consumption profiles for a dairy farm

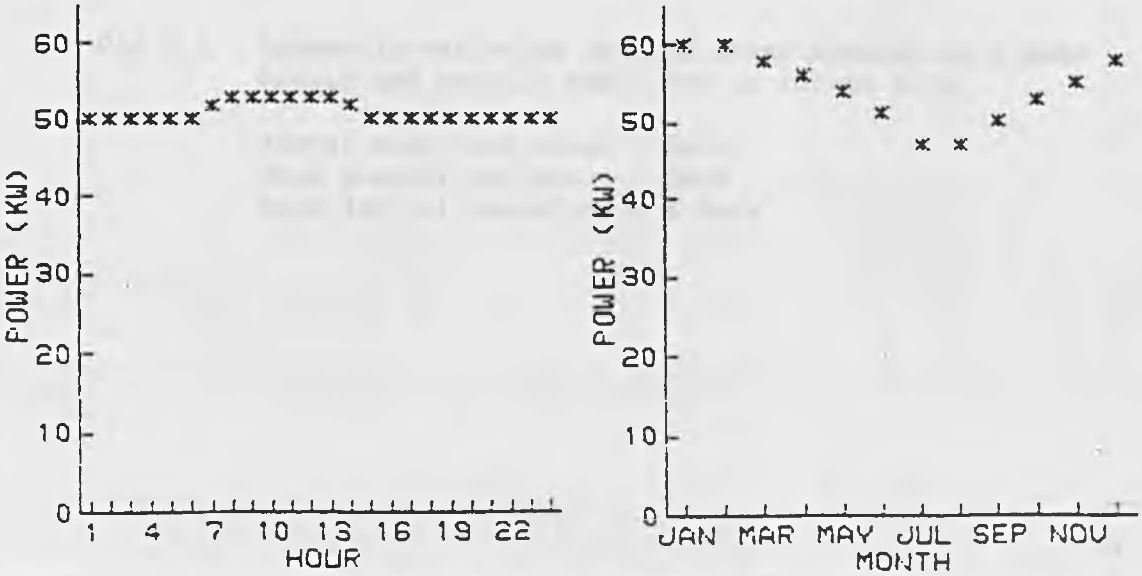

Fig 3.3 Schematic variation in electrical consumption profiles for an intensive farm

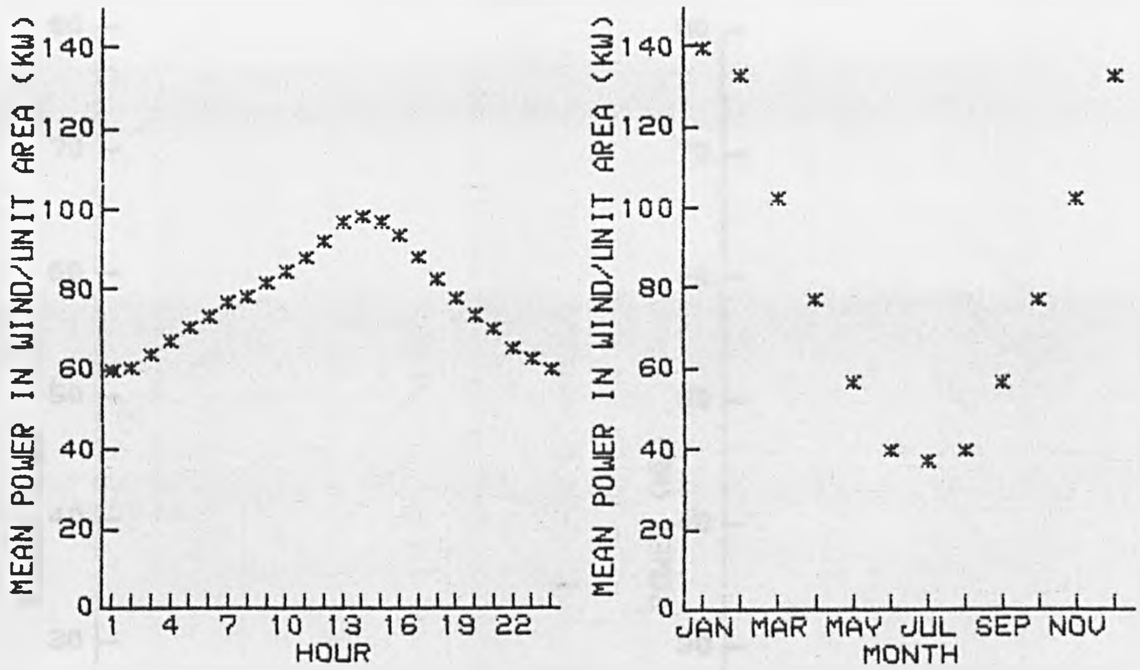

Fig 3.4 Schematic variation in wind power density on a mean hourly and monthly basis for an inland site

Annual mean wind speed = 5m/s
Mean monthly variation = 2m/s
Mean diurnal variation = 0.8m/s

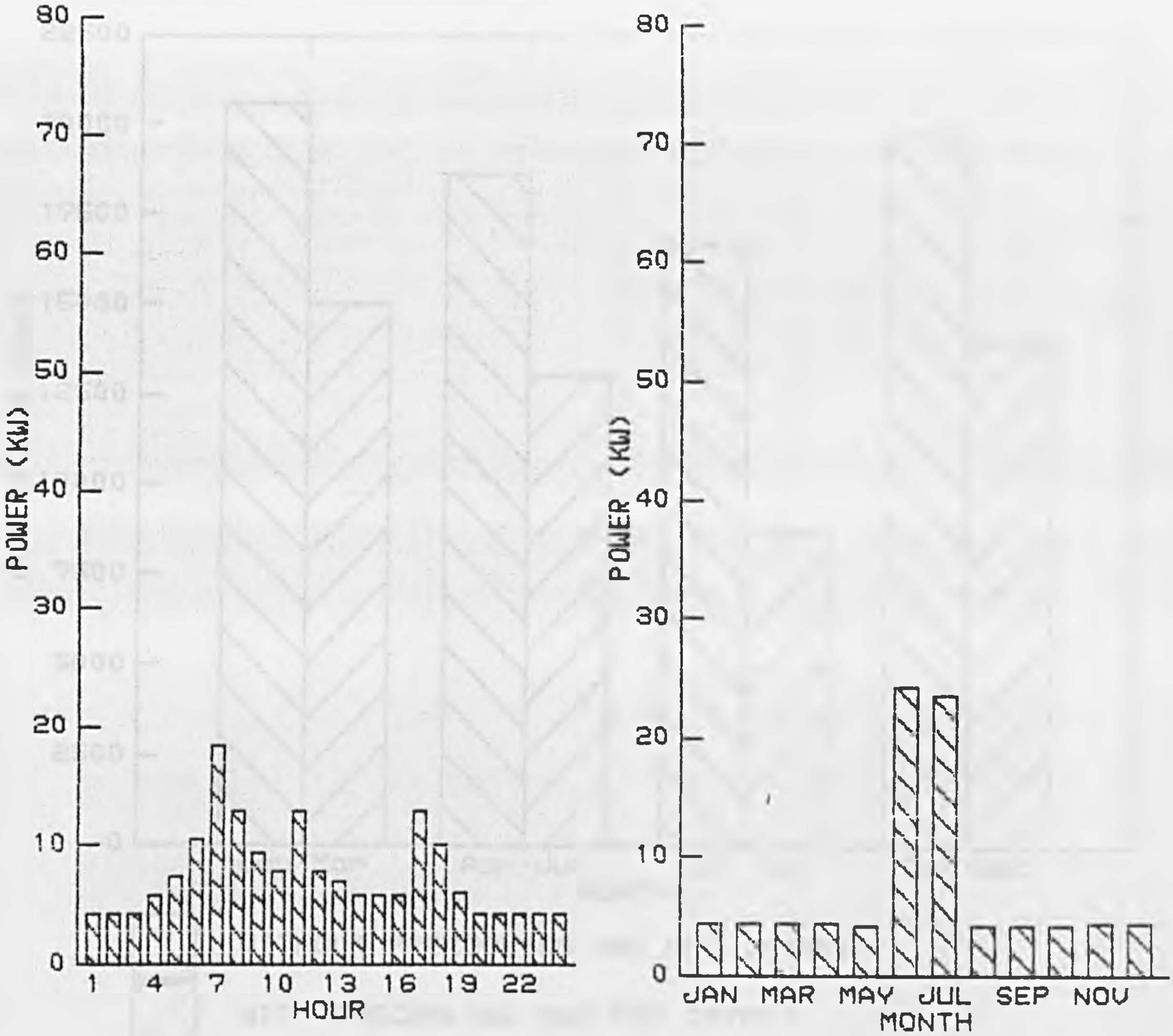

Fig 3.5 Simulated daily and monthly electrical consumption profiles for a dairy farm

Annual consumption = 65,512kWh
Herd size = 100, milk yield = 474,500 litres p.a., ice-bank build up refrigeration, acid boiling water cleaning and no pre-cooling or heat recovery

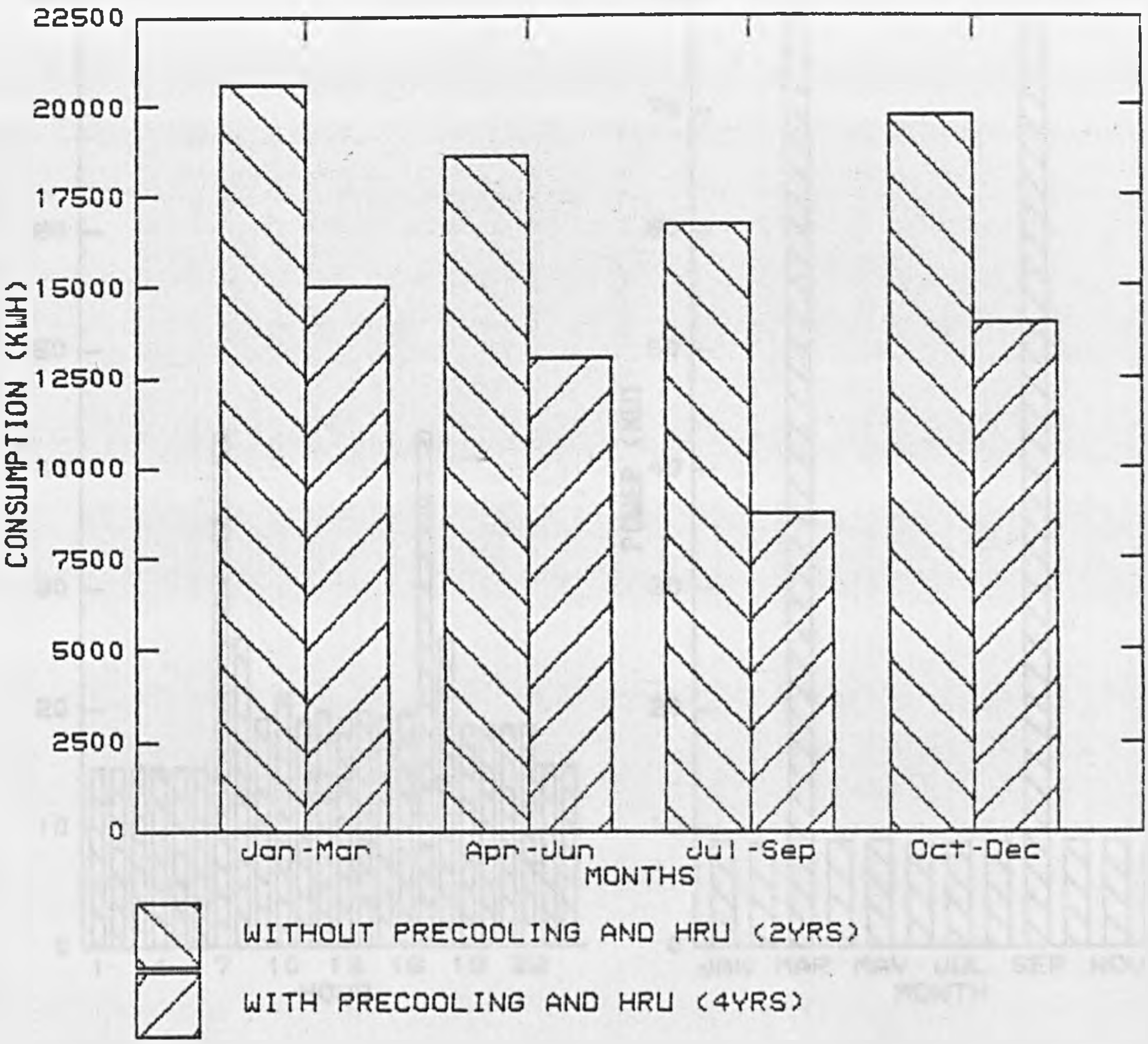

Fig 3.6 Seasonal electrical consumption at Craibstone dairy unit before and after installation of precooling and heat recovery equipment in 1978

Herd size = 100, milk yield = 680,000 litres p.a., ice-bank build up refrigeration, acid boiling water cleaning

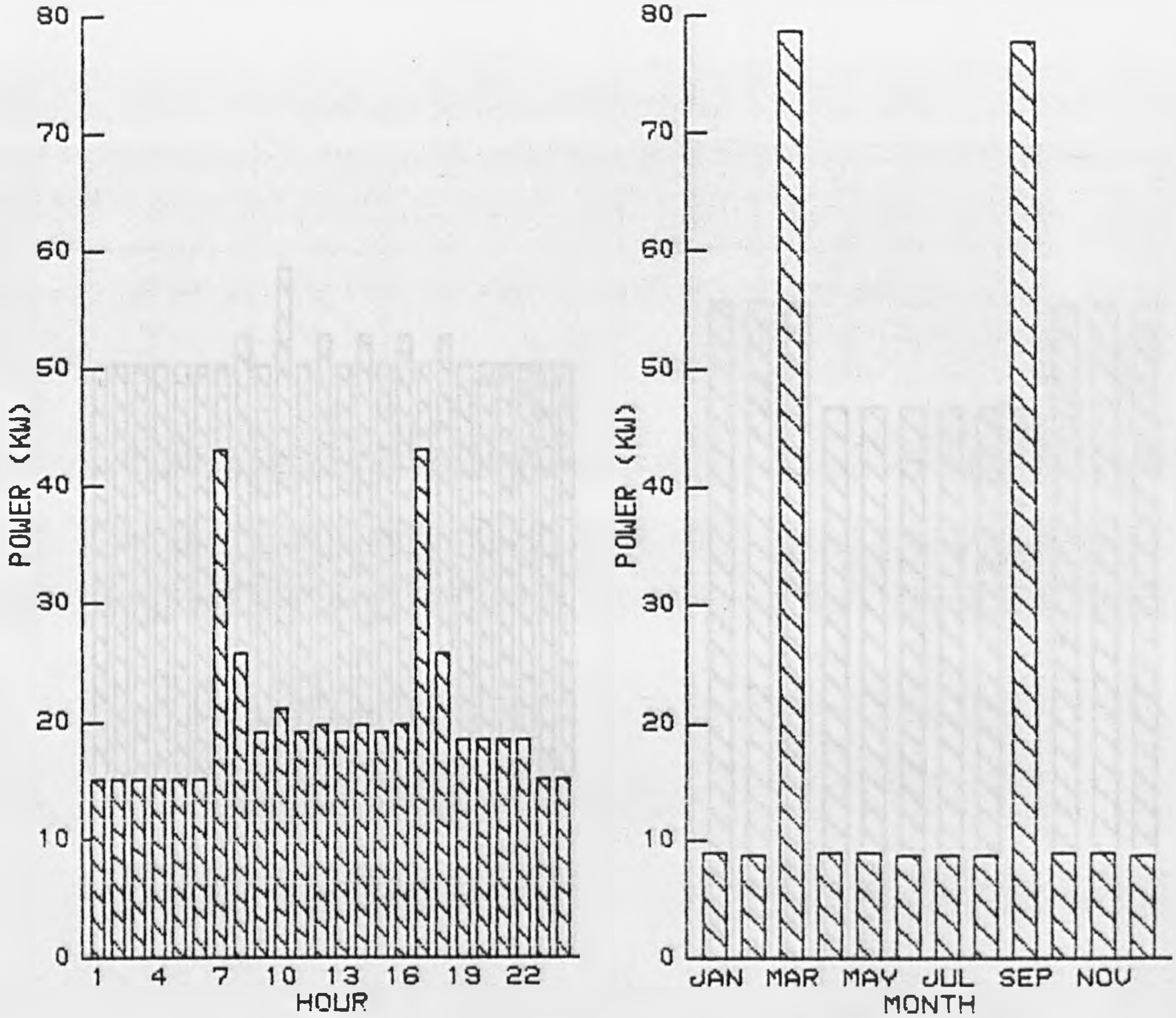

Fig 3.7 Simulated daily and monthly electrical consumption profiles for an egg production unit

Annual consumption = 179,647kWh
20,000 layers, electrical heating

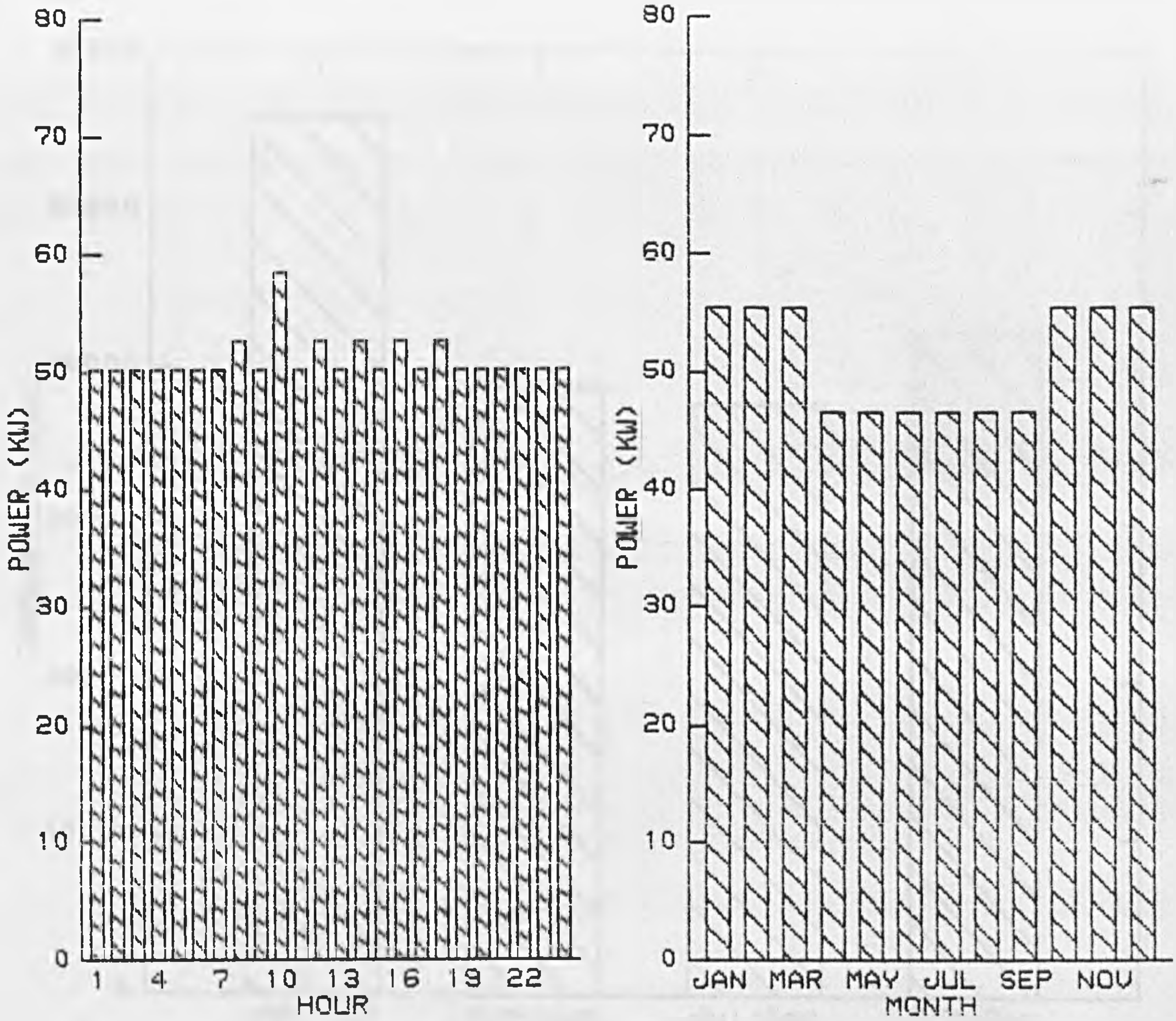

Fig 3.8 Simulated daily and monthly electrical consumption profiles for a broiler production unit

Annual consumption = 447,167kWh
30,000 broilers, electrical heating

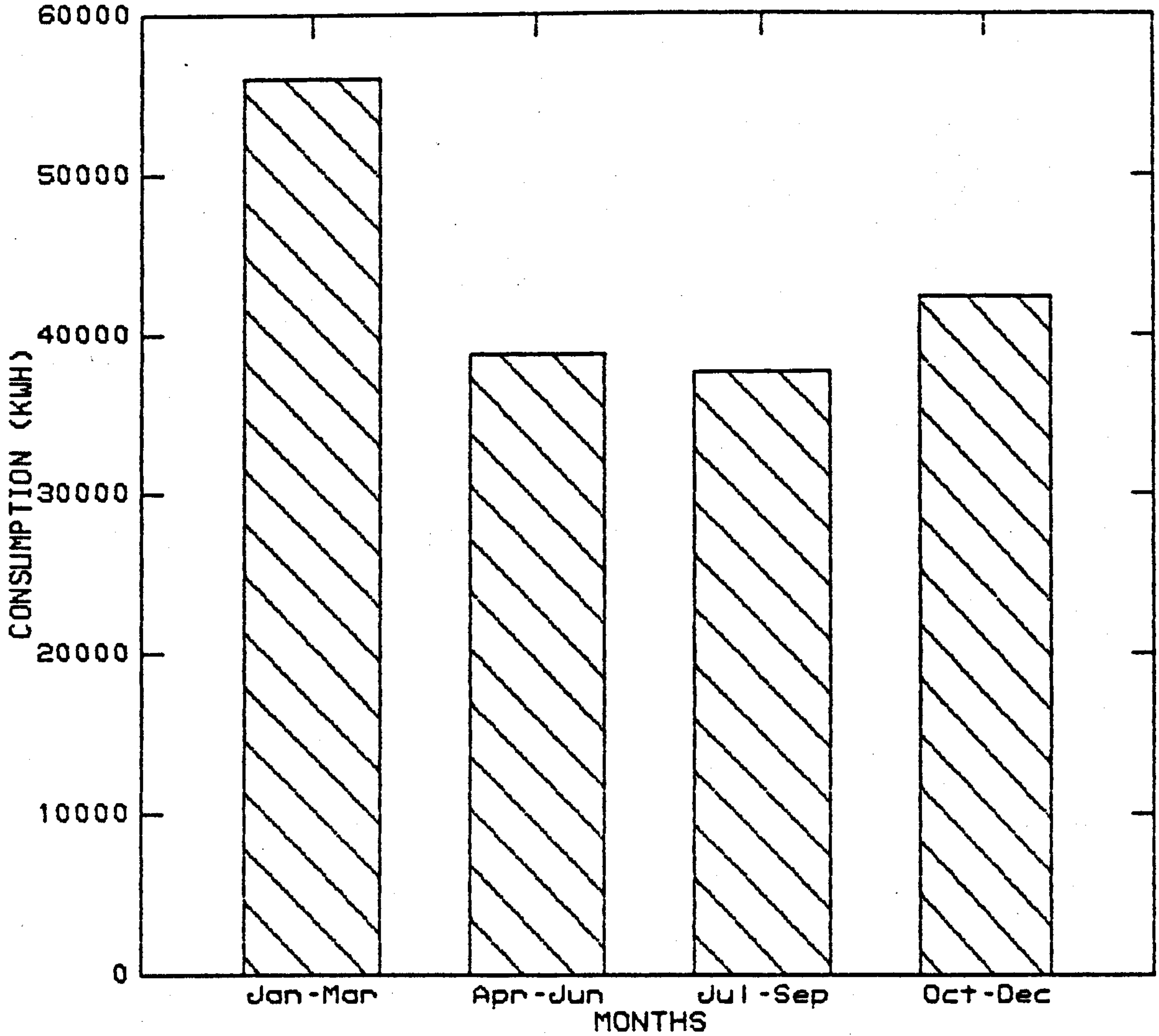

Fig 3.9 Seasonal variation in electrical consumption at Parkhead poultry unit (1982 - 1987)

20,000 broilers, 12,000 layers, 4,300 turkeys

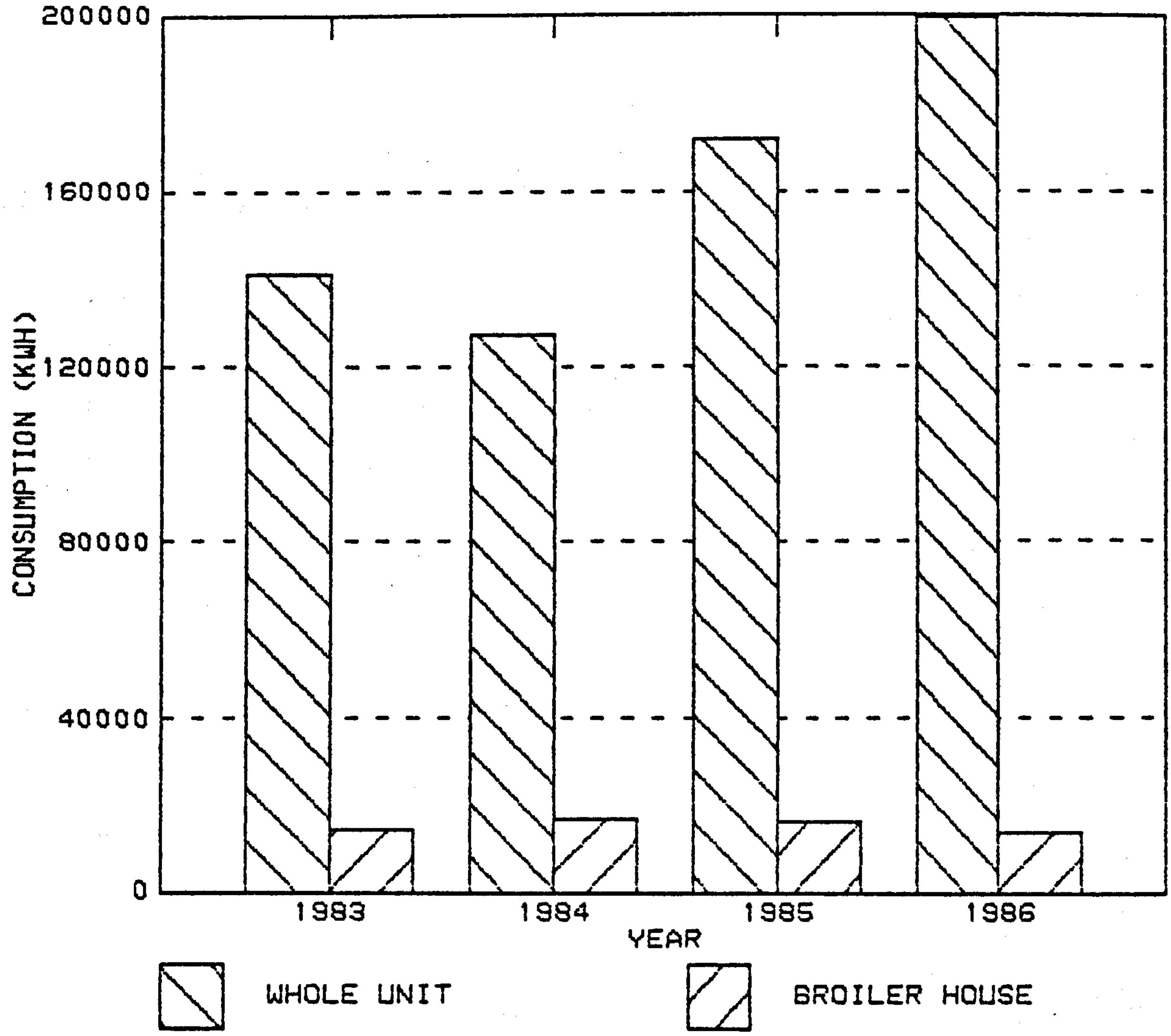

Fig 3.10 Annual electrical consumption (1983 - 1986) for the whole of Parkhead poultry unit and the broiler house (gas heated)

13,000 broilers in broiler house

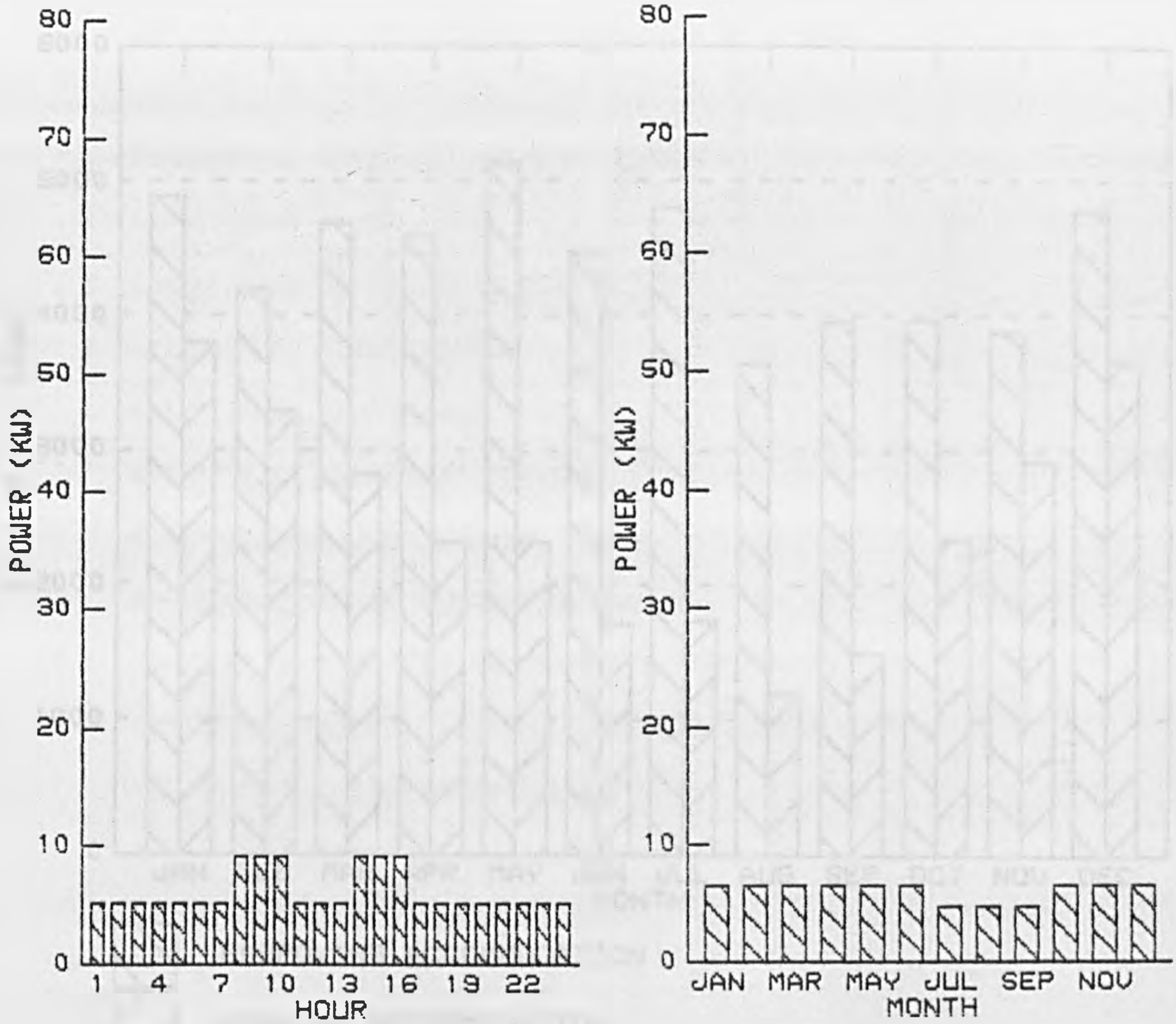

Fig 3.11 Simulated daily and monthly electrical consumption profiles for a pig unit

Annual consumption = 57,530kWh
230 breeding pigs, 3910 piglets reared p.a. and 1770 fattening at any one time. Heating by thermostatically controlled IR strip heaters and ventilation by automatically controlled fans

Fig 3.12 Monthly variation in electrical consumption in farrowing and weaning accommodation at Tillycorthie farm based on data from July 1985 to October 1987

4. CASE STUDY OF A WIND TURBINE GENERATOR ON A FARM

Contents

LIST OF TABLES FOR CHAPTER 4

LIST OF FIGURES FOR CHAPTER 4

4. CASE STUDY OF A WIND TURBINE GENERATOR ON A FARM

As described in section 1.2 wind turbine generators have been operating in Scotland since 1980 with varying degrees of success. Most of them are utility owned experimental machines but in 1983 three commercial machines were installed in the NE of Scotland. This section analyses the performance of one of these machines connected to an intensive pig farm at Eastertown near Old Meldrum.

The large pig unit at Eastertown farm uses entirely electricity as its energy source for environmental control of the various stages in pig rearing and fattening. All the other static energy requirements on the unit such as hot water and feeding mechanisms are also met by electricity. Prior to 1983 the annual electricity bill was in excess of £14,000, assuming similar consumption levels as in the years from 1983 to 1988. In an attempt to reduce the bills, a Polenko 60kW grid-connected wind turbine generator was installed and commissioned in January 1983. Unfortunately during the first half of 1984 it was severely damaged in a storm and a number of components including the rotor were replaced and it was restarted at the beginning of October 1984. Since then it has been operating satisfactorily.

One of the other commercial machines in the area is of the same design and is about 10km away at Mains of Bogfechel pig unit near Whiterashes in Aberdeenshire. The third machine is a Polenko 15kW machine at Hill of Fiddes farm near Udny. The locations of the three machines is shown in Fig 4.1. Polenko is a Dutch company which is now part of a larger company called Holec.

DP Enterprises Ltd of Aberdeen supplied these three machines. The maintenance is mainly carried out by a local electrical engineering company, however no official maintenance contract has been drawn up with them.

A detailed monitoring system was set up at the farm in March 1986 by the collaborating establishment for this project, Energy Design of Aberdeen. From March 1986 to March 1988 twenty eight weeks of detailed hourly data has been collected. The data capture is not continuous but is spread throughout the period thus giving some indication of the seasonal variation. In addition to the detailed hourly data, an employee on the farm has been recording the weekly output of the wind generator since October 1984. This data is of great value in assessing the long-term performance of the machine.

There is obvious interest in the machine, especially from the wind energy fraternity with a well attended British Wind Energy Association (BWEA) visit in November 1987 and several people have asked for performance details mainly for studies carried out at educational establishments. Outside it is more difficult to assess the interest but a feature made by BBC Northern Ireland for farming programmes broadcasted in Ireland in February '89 and in Scotland in September '89 indicates some interest from the farming fraternity. There is a good photograph of the original machine on the cover of a leaflet published by the North of Scotland College of Agriculture in 1984 (1) which would have had circulation around the local farming community.

The three Polenko machines in the NE of Scotland are the oldest privately owned wind turbine generators in the UK (2). In fact at the start of 1983 only two or three other machines above 20kW rating were operating in the UK.

4.1 DESCRIPTION OF WIND TURBINE GENERATOR

The machine is of Polenko manufacture, model WPS 16e A60 (Fig 4.2). It has three fixed pitch blades of 16m diameter with control flaps at the tips and it has a 20m high stiff tubular concrete tower. The rotor is upwind of the nacelle. The nacelle is accessible from within. The blades are made of twin-walled steel and are polyurethane-foam filled. It has electrical yaw drive to turn it into the wind and has power limitation by means of aerodynamic stall and micro-processor regulated control flaps at the tips of the blades. In the event of over-speed of the rotor a hydraulic brake is applied, automatically or manually, to the main shaft. There is an anemometer and vane on top of the nacelle which send signals to the control unit.

Transmission is by means of a shaft-mounted gearbox and V-belt drive. As the aerodynamic characteristics of a rotor require that, for maximum efficiency, it operates at a constant tip speed ratio, that is the ratio of the blade tip velocity to the wind velocity, it is desirable that the rotor speed varies with wind speed. However as a machine is normally generating into a grid system of constant frequency, speed or frequency conversion equipment is necessary and this is normally expensive. One compromise between the variable speed and the fixed speed operation is to have several fixed speeds. This may be achieved in several ways, for instance a multi-speed mechanical gearbox or electrical speed changing by switching the stator windings or using dual windings in an induction generator. In the Polenko machine at Eastertown the solution to multi-speed operation was to use two separate generators. It has two induction generators, the smaller being rated at 15kW/1000rpm and the larger being rated at 60kW/1500rpm. Being simple induction generators they draw lagging kVAR (kilovolt-ampere reactive) power from the grid. At wind speeds up to 6.5m/s the smaller generator is used at a speed of 1000rpm, and above 6.5m/s the 60kW generator is used at 1500rpm, the wind speeds being rated at a height of 10m. The machine starts up at a wind speed of 3.5m/s and cuts out at approximately 20m/s. As a guideline a manufacturer's power curve is shown in Fig 4.3. This power curve is only an approximation for three reasons :

(1) A piece-wise linear power curve such as in Fig 4.3 does not exist except possibly for zero turbulence conditions or to some extent, variable pitch machines.

(2) The exact specifications for the model at Eastertown are unobtainable.

(3) The details of the origin of this power curve are not known. It is unlikely that it is based on measurements taken out in the field as at the time of manufacture wind turbine test stations were not common. It is more probably taken from a purely theoretical estimate.

All the wind turbine generator's functions are controlled by a micro-processor control unit positioned within the farm buildings. The wind turbine generator is about 3m from the buildings. The control unit coordinates all the production and safety functions of the machine. It displays the current status of the braking and yawing systems and gives the output in amperes from either generator and the rpm of the high-speed shaft. The machine is designed to last 20 years.

The maintenance and inspection manual contains information and instructions necessary to perform most of the wind turbine generator's maintenance and inspection tasks. The tasks are arranged by codes based on divisions of the various main systems of the machine. The manual is divided into sections on general safety procedure, task descriptions, frequency schedules and task instructions with photographs and information on equipment required. Information on how the machine operates is not contained within this manual. Examples of task descriptions are given in Table 4.1. It can be seen that there is quite a lot involved if the machine is to be well maintained. It should be checked every three months.

4.2 DESCRIPTION OF THE SITE

The site of the wind turbine generator is at Accredicross Seghers Hybrid Ltd pig rearing unit at Eastertown near Old Meldrum. It is 105m above sea level and 25km from the east coast of Scotland. Fig 4.4 shows the location of the Eastertown machine at an enlarged scale.

The machine is sited at about 3m from SE corner of the farm building complex, some of the buildings rising to a height of 15m. The surrounding terrain is gently undulating farmland with scattered bushes and buildings. To the north there is a hill which rises to 245m which causes sheltering at the wind generator site when the wind is from this direction. It is not an ideal site with an annual mean wind speed of approximately 4.6m/s, estimated from the prediction method (see chapter 2) using data recorded at Dyce meteorological station 22km away from 1960 to 1981, during which time the average recorded annual mean wind speed at Dyce is 4.8m/s.

4.3 DESCRIPTION OF THE MONITORING SYSTEM

A low cost data collection system was installed at the farm by Energy Design in March '86 to monitor the machine's performance and its integration with the farm's electricity supply from the national grid.

The layout of the monitoring system is shown in Fig 4.5. The production, import, export and reactive energies are very simply monitored by means of photo-diodes stuck to the outside of the meters, aimed at the dial inside, thus complying with the Electricity Board's requirements of not interfering with the internal workings of the meters. Every pass of the black band on the dial in the diode's path sends a signal to the computer. The monitoring program in the computer accumulates the signals over an hour, calibrates them and outputs the hourly production, import, export and reactive power drawn.

The wind speed is recorded by a cup anemometer manufactured by Vector Instruments Ltd, type A100M, which is on a mast approximately 4m above an 8m high building. The anemometer is a pulse output type with an accuracy of 2% $\pm$ 0.1m/s and a length constant of 5m. The wind speed is sampled every 12 seconds. The hourly mean, variance, maximum and minimum are recorded by the computer program.

The pulse signals from the sensors are fed into a frequency to voltage converter and then are transferred into an INTERBEEB interface to be converted into decimal numbers which can be read by an Acorn designed BBC microcomputer and put onto floppy disk storage. The whole system is powered from the mains electricity supply. Altogether twenty eight weeks of hourly data were collected during the periods shown in Table 4.2. The data is spread throughout the year so an idea of the seasonal variations can be obtained. The system could theoretically be left to run for one month at a time before the floppy disk was filled to capacity, however in practice it was generally left to run for only a week at a time due to some of the technical problems outlined below. At most weekly visits the actual accumulated readings on the four meters were recorded in order to compare with the automatic monitoring system.

(1) Rebooting of the monitoring system after a power failure. this problem was mainly due to large birds in the area, in particular migrating geese, flying through the electricity distribution cables and causing an instantaneous short due to their large wing spans. The program reloaded automatically but it required an initial starting time typed in before it would run. There was no-one at the farm who knew how to operate the computer and it was thus necessary to go to the farm once per week.

(2) The photodiode head not aimed correctly at the dial inside the meter resulting in 2-3 pulses being received by the computer for one pass of the black mark on the dial. This problem was quickly detected by comparing the accumulated reading taken by the program with the actual reading on the electricity meter. It was solved simply by repositioning the sensor.

(3) The clock inside the computer lost 20-40 seconds in each hour resulting in up to two hours lag over a week in the monitoring program. The clock was reset during the weekly visits.

(4) If the dial inside a meter is wavering backwards and forwards for instance in the situation of very low power output, more passes of the black mark on the dial in front of the photodiode are registered thus giving a higher reading on the computer than what actually appears on the meter.

Errors can be classified under three main headings - gross errors, systematic errors and random errors. Gross errors are generally the largest and easy to detect and thus easy to remove. Systematic errors are those which occur according to some regular pattern. Therefore their occurrence can be modelled mathematically and such a model can then be used to compensate for the errors. Random errors are those variations remaining in observations after gross errors and known systematic effects have been removed. Probability models are used to cope with these errors.

The first two problems are gross errors and are easily detected and the data eliminated. The clock error is a systematic error which can be modelled simply and used to compensate for the errors.

The fourth error however is more difficult to classify. It can be considered as a systematic error as it is known to occur at low rotational speeds of the dial. Although this happens in situations of low output, reactive power etc, the increase in the number of pulses received will itself make detection of this error difficult. It can also be considered as a random error because the black mark which triggers a pulse may not be in front of the photodiode when the dial is going backwards and forwards.

Also, although the hourly reading for the dial may indicate reasonably high levels of rotation of the dial when averaged over the hour, in reality the dial could have been rotating fairly fast for most of the hour and wavering to and fro for the remainder of the hour.

In practice as only the accumulated error can be quantified the differentiation and elimination of the two "non-gross" errors would thus be difficult. The largest error occurs in the production meter as this is the slowest running meter apart from the export meter which very rarely moves at all. The mean accumulated error in the production monitor for all the data files is -5% of the actual readings for the production meter.

4.4 ANALYSIS OF WIND RESOURCE

4.4.1 Mean wind speeds

The recorded mean wind speed for the total time of data capture, amounting to 4364 hours taken between March 1986 and March 1988, is 4.7m/s which is marginally higher than the estimated long-term wind speed of 4.6m/s at the anemometer site. The mean speed for data obtained in the winter months (October to March inclusive) is 5.05m/s and for the summer months, 4.64m/s.

4.4.2 Wind speed distributions

The wind speed distribution at Eastertown is shown in Fig 4.6 for all the hourly data collected. A Weibull distribution is fitted with a scale parameter of 6.0m/s and a shape parameter of 1.7 (see section 2.2). The data was then split approximately into winter and summer data and in Fig 4.7 a comparison is made between the fitted Weibull distributions. It is interesting to note from Fig 4.7 that there is a much greater spread in the wind speeds during the winter than the summer with a higher frequency of both low and high wind speeds during the winter. The higher frequency of high wind speeds for the winter data can be seen in Fig 4.7 but for the low wind speeds this observation cannot be made from the Weibull fits as the Weibull probability distribution is only appropriate for non-zero wind speeds. However from the actual data the percentage calm, ie. less than 1m/s, is 22.5% for winter and 8% for summer. The shape parameter for the data taken during the winter months is 2.0 and for the summer months it is 1.6.

4.4.3 Diurnal variation

The diurnal cycle and the difference in it between winter and summer can be seen clearly in Fig 4.8. The wind speeds are generally at their highest between 11am and 2pm. The cycle is more marked in the summer than in the winter. The magnitude of variation is 2.2m/s in the summer while it is only 1.5m/s during the winter. It can also be seen that the wind speeds generally increase quite sharply at sunrise and this, of course, happens later in the day in winter than in the summer.

As the site is 25km from the coast the diurnal variation is unlikely to be due to land/sea breezes (see section 2.2). It is more likely to be due to a nearby south facing slope of a hill. During the day this will heat up and the cold air which has accumulated in the valley during the night will rush up the side of the hill to replace the warm air rising off the slope.

4.4.4 Turbulence and maximum speeds

The mean hourly turbulence intensity (see section 2.2) for the whole monitoring period is 0.375. Turbulence intensity is the standard deviation divided by the mean wind speed for the same period. This high level of turbulence is due to three factors.

(1) Nature of site. The closeness of the anemometer to the irregular farm building roof and the wind turbine generator will increase the recorded variance and thus the turbulence intensity.

(2) Sampling rate. The wind speed is sampled every 12 seconds and this is close to a localised peak in the turbulence spectrum at 0.07Hz (3) which is equivalent to sampling once every 14.3 seconds.

(3) Averaging period. It has been observed by other researchers that turbulence intensity increases with an

increase in averaging period (4). This observation is supported by an analysis of turbulence data on two hill sites in Shetland (5).

The relationship between turbulence intensity and wind speed for all the data collected is shown in Fig 4.9. As the wind speed increases the turbulence generally decreases.

In Fig 4.10 the summer/winter mean turbulence intensity is plotted as a function of time of day. As expected, turbulence is higher at night-time when the air is unstable. Also, the turbulence is higher in the winter than in the summer. This is partly due to the high occurrence of low wind speed periods for the data recorded in the winter months as mentioned in section 4.4.2. Also, the occurrence of very high instantaneous wind speeds during winter is more common. The highest instantaneous wind speed recorded at the site is 32.9m/s and this occurred on 28th February 1988 at 10am.

4.5 ANALYSIS OF WIND TURBINE GENERATOR PERFORMANCE

4.5.1 Availability of wind turbine generator

As it was not possible to record automatically on the existing monitoring set-up the down-times of the wind turbine generator, an approximate method is adopted to assess the availability of the machine. This consists of selecting the hours when the mean energy output is less than 1kWh when the corresponding mean wind speed is greater than the cut-in wind speed of 3.5m/s. During these hours the machine is designated unavailable. Fig 4.11 shows percentage time non-availability versus time of day for summer and winter. The actual percentage time of non-availability is liable to be higher than calculated because the hours where the wind speed is less than 3.5m/s are essentially eliminated. However this may be offset by the number of hours incorrectly included in the non-availability figure because of occurrences of hours with a persistent wind at 3.5m/s with little variation around the mean thus allowing the machine to cut in. The constraints of 3.5m/s and 1kWh were selected so that these two factors might cancel one another out so that the resultant figure for non-availability might be close to the actual one.

It can be seen from Fig 4.11 that the percentage time non-availability is generally higher in the winter than in the summer. There is no determinable pattern on a time of day basis. The mean availability by this method of calculation is 92.5% for the whole monitoring period.

4.5.2 Power curve determination

The manufacturer's power curve given in Fig 4.2 is only included in this analysis as an approximate guideline - there is no degree of certainity in it as mentioned in section 4.2. There are some known design alterations, for instance it is known that the rotor speed was reduced at the time of replacing the rotor after storm damage in 1984. The rpm in the original design is 38rpm but was reduced to 34rpm in 1984. Rotor speeds affect optimal rotor solidity (ratio of blade area to swept area), operational torque level, gearbox ratio and system dynamic response (6). The reduction in rpm is an attempt to increase the machine's efficiency at low wind speeds prevalent at the site but at the sacrifice of some of the power available at higher wind speeds. The laws of similarity for wind turbine rotors states that the peak power of the rotor varies as the cube of the speed of rotation (7). Thus the decrease in power output at higher wind speeds is considerable, almost 40% for a reduction from 38rpm to 34rpm. It is uncertain whether this is offset by increased production at low wind speeds at Eastertown as there is no detailed data available before the change in the rotational speed.

Another change from the initial design is the setting within the micro-processor of the switch-over point between the small and large generators. This point is determined by the recorded wind speed at the nacelle and it has the function of switching the machine onto the larger generator if the wind speed is high enough. The change was made in December 1986. Prior to this the machine was not switching onto the large generator until wind speeds of approximately 9.5m/s. This can be seen in Fig 4.12. Only data points for hours of fairly persistent winds, identified by mean hourly turbulence intensity being less than 0.2, are used in plotting Fig 4.12. The hours where the turbulence levels are higher show greater variability in power outputs and any patterns are more difficult to identify. This can be seen in Fig 4.13 where hourly power outputs over a period of one typical week (after alteration to switch-over wind speed) for three levels of turbulence are plotted.

In Fig 4.14 the mean power outputs for 1m/s wind speed bins are plotted at two levels of turbulence intensity. This analysis excludes the designated unavailable hours as defined in section 4.5.1. The seemingly arbitrary division at turbulence intensity 0.17 used in Fig 4.14 was used in preference to a turbulence intensity closer to the mean value of 0.375 for the whole monitoring period. Otherwise there would not have been enough data points in the higher turbulence level at high wind speeds to produce a valid power curve. It has already been established (Fig 4.9) that turbulence decreases with an increase in mean wind speeds. According to the International Energy Agency's recommendations for power curve determination (8) there should be a minimum of ten points in each 1m/s bin. Even by dividing the data into only two turbulence levels, above and below 0.17, this requirement is not fulfilled as in some of the higher wind speed bins at the higher turbulence level there are only three data points which make up the mean. However in Fig 4.14 it can be seen that an increase in the mean hourly turbulence intensity increases the corresponding mean hourly power output. This can be explained by the following mathematical consideration.

The mean power density of the wind over time T is

$$[P]_T = 0.5p[V]_T^3 \tag{4.1}$$

where p is the air density, assumed constant, and $[V]_T$ is the wind speed averaged over time T. Thus

$$[V]_T = \frac{1}{T}\int_0^T V\,dt \tag{4.2}$$

The instantaneous wind speed V can be written as a mean value $[V]_T$ and a deviation V'.

$$V = [V]_T + V' \tag{4.3}$$

Straightforward operations using equations 4.2 and 4.3 give

$$\begin{aligned}
[V']_T &= \frac{1}{T}\int_0^T V'\,dt \\
&= \frac{1}{T}\int_0^T (V - [V]_T)\,dt \\
&= \frac{1}{T}\int_0^T V\,dt - \frac{1}{T}\int_0^T [V]_T\,dt \\
&= [V]_T - \frac{[V]_T}{T}\int_0^T dt \\
&= [V]_T - \frac{[V]_T}{T} \cdot T \\
&= 0
\end{aligned} \tag{4.4}$$

In a similar manner

$$[V'^2] = \frac{1}{T}\int_0^T V'^2 \, dt$$

$$= \frac{1}{T}\int_0^T (V - [V]_T)^2 \, dt$$

$$= \frac{1}{T}\int_0^T (V^2 - 2V[V]_T + [V]_T^2) \, dt$$

$$= [V^2]_T - 2[V]_T^2 + [V]_T^2$$

$$= [V^2]_T - [V]_T^2 \qquad 4.5$$

And similarly

$$[V'^3]_T = \frac{1}{T}\int_0^T V'^3 \, dt$$

$$= \frac{1}{T}\int_0^T (V - [V]_T)^3 \, dt$$

$$= \frac{1}{T}\int_0^T (V^3 + 3V[V]_T^2 - 3V^2[V]_T - [V]_T^3) \, dt$$

$$= [V^3]_T + 3[V]_T^3 - 3[V^2]_T[V]_T - [V]_T^3$$

$$= [V^3]_T - 3[V]_T \left([V^2]_T - [V]_T^2\right) - [V]_T^3$$

$$= [V^3]_T - 3[V'^2]_T[V]_T - [V]_T^3 \qquad 4.6$$

For the sake of clarity the following symbols are introduced

$$M = [V]_T \qquad \text{mean}$$
$$S^2 = [V'^2]_T \qquad \text{variance} \qquad 4.7$$
$$K = [V'^3]_T \;/\; S^3 \qquad \text{skewness}$$

The mean power density of the wind in equation 4.1 can be expressed in terms of M, S and K.

$$[P]_T = 0.5pM^3 \left(1 + 3(S/M)^2 + K(S/M)^3\right) \qquad 4.8$$

As turbulence intensity is the ratio of standard deviation over the mean, ie. S/M, it can be seen that the last two terms in the parenthesis in equation 4.8 represent contributions to the average power density from turbulence intensity in the time interval considered. The curved section of a typical wind turbine generator power characteristic where the power output approximates to the above power density equation. Thus in the lower turbulence level in Fig 4.14 where the mean turbulence intensity is 0.157 an increase in the power output on the curved section of the power curve in the region of 7.4% can be expected from zero turbulence conditions. Skewness is estimated to be 0.1 for averaging period of one hour. At the higher level the mean turbulence intensity is 0.346 and an increase in power output of 36.3% from zero turbulence conditions can be expected. A difference of 28.9% of zero turbulence conditions can thus be expected in the two power curves for low and high turbulence levels. If as an approximation we calculate the actual differences between the data points making up the two power curves in Fig 4.14 as percentages of the data points on the lower power curve rather than on the the nonexistent zero turbulence power curve, the mean difference is 32.2%. Only the wind speed bins between 3m/s and 13m/s where the power curve will approximate to the power density equation 4.1 are used. In order to calculate the actual power output equation 4.1 and 4.8 would have to include a coefficient of performance term. This varies with wind speed and is evaluated in the next section.

Typical monthly machine performances on an hourly basis for all levels of turbulence are shown in Figs 4.15 for September and October '87. In general there is a large degree of scatter in the plots and there a general lack of data at high wind speeds making it difficult to validate the effect of reduction of rpm above rated speed as mentioned at the start of this section.

In Fig 4.16 mean power outputs for each 1m/s wind speed bin for all turbulence intensities are plotted using all available data before and after the alteration to the switch-over wind speed except the hours where the machine is designated as unavailable as defined in section 4.5.1. It can seen that the measured power curve does not attain the levels of output suggested by the manufacturer. Neither does it appear to flatten out at higher wind speeds. Possible reasons for this are as follows :

(1) Poor aerodynamic stalling of rotor.

(2) High turbulence site causing rounding of the power curve at rated wind speed (9).

(3) Lack of data at high wind speed bins. For instance in the wind speed bin 18 - 19m/s only six data points make up the mean value.

The major problem in determining the power curve for the

Eastertown wind turbine generator is the non-representivity of the measured wind speeds for the driving wind speeds. This is due to the anemometer not being at hub height, being too close to the wind turbine generator and its siting on top of a building. It is within or near two rotor diameters distance of the machine which is the minimum anemometer-to-wind generator distance recommended by the International Energy Agency (10). The nearness of the anemometer to the tower of the wind generator and to the roof of the farm buildings will cause a decrease in the wind speeds recorded and higher levels of turbulence.

Another problem is an error that occurs in a mainly random manner in the production sensor as mentioned in section 4.3. The dial inside the production meter at low rotational speeds sometimes wavers backwards and forwards. More passes of the black mark on the dial in front of the photodiode are registered thus giving a higher accumulated reading on the computer than what actually appears on the meter. As the error cannot be quantified separately from the clock error and is not linear over the period of one week between meter readings it is difficult to eliminate it. However the mean error for the production monitor is only 5% of the meter reading for all the data sets.

Another problem associated with determining the actual power curve is the well known problem of over-speeding of the anemometer (11) especially prevalent at turbulent sites such as at Eastertown. When the wind speed fluctuates, the cups have to accelerate and decelerate under the influence of the moment induced by the difference between the present wind speed and the wind speed corresponding to the present speed of rotation. This induced moment is non-linear around zero moment and causes the anemometer to run too fast.

4.5.3 Efficiency of wind turbine generator

The approximate efficiency of the machine in converting wind energy to electrical energy before and after the alteration to the switch-over wind speed is shown in Fig 4.17. The efficiency is calculated from the following formula.

$$\text{efficiency at wind speed V} = 100 * C_p = 100 * \frac{\text{output at wind speed V}}{0.5 * p * A * V^3} \qquad 4.9$$

where p = standard air density = 1.225kg/m^3

A = swept area of rotor

C_p = coefficient of performance

The coefficient of performance C_p takes account of all the losses such as aerodynamic losses, gearbox losses and generator losses. The output at wind speed V is taken from Fig 4.16 of the machine performance before and after alteration to the switch-over wind speed.

It can be seen from Fig 4.17 that after the alteration the maximum efficiency is approximately 28% at a wind speed of 5.5m/s. This is a low efficiency by any standard; the maximum efficiency of most up-to-date machines is in the region of 35% (12). The dip in the efficiency curve prior to the alteration demonstrates the loss of power due to the machine not switching generators until too high a wind speed.

The total efficiency of the wind generator for all wind speeds before the alteration is 18% and afterwards it increased to 26%. This is calculated from the actual recorded wind speed distributions and the efficiency curves in Fig 4.17.

Ideally, from a design point of view, the machine should have its maximum efficiency within the modal wind speed bin, ie the wind speed bin with the largest number of entries, for the site. From Fig 4.6 it can be seen that the bin 4-5m/s has the largest number of entries apart from 0-1m/s which is of no interest from an energy point of view. From Fig 4.17 the maximum efficiency after the alteration to the switch-over wind speed occurs in the range 4.5-6.5m/s.

4.5.4 Variation in power output

The daily variation in the power output as a result of the diurnal variation in the wind speeds can be seen in Fig 4.17. The hours where the machine is designated unavailable (section 4.5.1) are excluded from this analysis.

It is interesting to compare Fig 4.17 with Fig 4.8 which shows the diurnal variation in wind speeds. It can be seen that between 8am and 6pm although the mean hourly wind speeds in summer are much the same as in winter, the corresponding power output is considerably higher in winter than in summer. As can be seen in Fig 4.10 turbulence is higher in winter than in summer. From Fig 4.14 it is known that the power curve rises with an increase in mean turbulence level. The higher turbulence in the winter explains why, for the same mean wind speeds the mean power outputs are higher in winter than in summer. However varying air densities may also contribute to some of the anomaly.

4.5.5 Annual energy capture

The annual production figures and corresponding load factors since installation of the second, redesigned machine are shown in Table 4.3. These figures are from meter readings taken as close as possible to the 1st January. The load factor is given by

load factor = (production in h hours)/(rated power x h) 4.10

In Table 4.3 it can be seen that there is a large increase in output between 1985 and 1987 when the annual wind speeds are much the same. This is partly due to the improvement in machine performance due to the alteration made to the switch-over wind speed as mentioned in section 4.5.1. However it also demonstrates the potential errors that can arise in calculating annual energy captures from annual mean wind speeds.

The long-term annual energy capture for the Eastertown machine is estimated to be 56,171kWh. This is calculated from the long-term (1960 - 1981) Weibull distribution, estimated using the prediction method on the long-term data from Dyce (see section 4.4.2), and the power curve after alteration to switch-over wind speed as in Fig 4.16. A 92.5% machine availability is used (see section 4.5.1). The long-term predicted annual wind speed (section 4.4.1) at the anemometer site is 4.6m/s.

The load factor for the detailed monitoring period is 0.120. This corresponds to an mean hourly output of 7.2kWh.

The machine generates for, on average, only 57% of the time. This is calculated in an arbitrary manner by summing <u>all</u> the hours where the hourly production is over 1kWh.

4.6 ANALYSIS OF ENERGY CONSUMPTION ON THE FARM

The pig unit is fairly large with 330 breeding pigs. The electrical energy consumption on the pig unit is high, averaging 380,506kWh from 1985 to 1987 inclusive. All the energy requirements on the unit are supplied by electricity. The energy is used for heating required during farrowing and weaning, for ventilation during all stages of pig rearing, and for feeding mechanisations, cleaning and lighting. The heating is by underfloor cables and the ventilation is by fans in the roof. There are over seventy fans in the fattening shed alone.

The consumption is calculated from the detailed hourly data using the following equation.

$$\text{consumption} = \text{import} + \text{production} - \text{export} \qquad 4.11$$

The daily consumption pattern for the monitoring period is shown in Fig 4.19. There is a very high base load due to high heating and ventilation rates and artificial lighting in the weaning accommodation to stimulate milk production. The hourly energy consumption ranges from 40kWh to 44kWh over an average day in the summer and from 41kWh to 47kWh in the winter. There are a number of small peaks. The small peak at 1am is most probably a boost in the heating. The peaks at 8am and 2pm can be attributed to the feeding mechanisation which consists of a pump and an auger. Shortly after the feeding mechanisation is switched on in the morning the cleaning process is started and this consists of two pressure water pumps, one of which uses hot water.

The difference between the winter and summer consumption rates are small with on average 1-2kWh higher consumption per hour in the winter, this being due to the higher heating requirement. Between the hours of 7am and 12 noon the difference increases to 5kWh per hour, this being due to higher hot water and feed requirement. The seasonal difference is small due to the constant demand on the farrowing and weaning accommodation throughout the year due to the intensive nature of the unit.

4.7 INTEGRATION OF WIND GENERATED ELECTRICITY ON THE FARM

For the whole monitoring period the utilisation factor is 0.984. This means that 98.4% of the wind generated electricity is used on the farm, the remainder being exported to the grid. A slightly higher utilisation factor is reported for the summer months showing that the energy mismatch between production and consumption profiles is minimised during the summer. The utilisation factor is calculated from

$$\text{utilisation factor} = (\text{consumption} - \text{import})/\text{production} \qquad 4.12$$

The penetration factor for the monitoring period is 0.157. Thus the wind generator supplies 15-16% of the pig unit's total energy requirements with a higher percentage being supplied during the day and in the winter when the wind is higher. The remainder of the energy requirement comes from grid as imported units. The penetration factor is calculated from

$$\text{penetration factor} = (\text{consumption} - \text{import})/\text{consumption} \qquad 4.13$$

In Fig 4.20 the difference in the mean production and consumption levels is shown on an hour of day basis using all the data available from the monitoring. For later use with the electricity tariffs which change at 0730 and 2330 hrs GMT, from Fig 4.18 it can be calculated that 75% of the production occurs between 0730 and 2330 hrs which constitutes 66.6% of the time and the remainder at night-time.

As most of the electricity is used to supply active power such as that required by the underfloor heating, the annual reactive component drawn from the grid is usually only about 54,600kVArh. This can be attributed to the wind generator and the ventilation fans and other motors which require motive power and thus drawing reactive current.

4.8 ECONOMIC ASSESSMENT

The pig unit is connected to the NSHEB grid and is on a farm economy tariff with an installed capacity of 100kVA. The structure of this tariff along with the other tariffs available to the pig unit is shown in Table 4.4 with the rates of charge as from 1st April 1988.

Since 1983 the tariffs have usually increased on April 1st with the exception of April '83 and April '87 when the tariffs increased on August 31st instead. From April 1st 1986 to August 31st 1987 there was a 0.15p/unit fuel rebate on all units imported from the grid.

4.8.1 Savings on electricity bills

As the electricity meter readings are taken approximately every three months (quarterly) an economic assessment based on the electricity bills has been done since October 1984. A record of the actual electricity bills paid is available since January 1983 when the original machine was erected, however from January '83 to October '84 there are no production figures available, although after this date weekly production figures are available. Without production figures the electricity consumption on the farm cannot be calculated and hence neither can the electricity bill without a wind generator be calculated. The saving is calculated by subtracting the actual bill from an estimated bill without a wind generator based on a farm economy tariff with a three phase supply.

All the information extractable from the weekly production readings and the quarterly electricity bills are shown in Tables 4.5 to 4.10 along with an estimate of the savings made each quarter. As the meters are read at rather irregular intervals it should be noted that the quarters tend to vary in length.

As the number of imported units at Eastertown is always high it has never been necessary to make a charge for reactive units used. This charge is only made if the number of reactive units is in excess of half the number of import units.

From section 4.7 it is known that 75% of the machine's production occurs during the hours 7.30am to 11.30pm GMT when the day tariff applies and the remainder at the lower night tariff. This figure is used in Tables 4.5 to 4.10 to calculate the day/night consumption.

From these tables it can be calculated that the mean saving per kWh produced from 20/9/84 to 3/3/88 is 4.7p. The total saving for that period is £8,642. This saving excludes any capital expenditure on the wind generator and any running costs. Not all this saving is due to the wind generated electricity penetrating the farm's demand; some of the saving is due to the lower cost of importing electricity from the grid when on a private generator tariff. This can be seen from Table 4.4. Considering that the penetration of wind generated electricity on the farm is only 14% it is as valid to consider saving per kilowatt-hour consumed and for the same period this is 0.64p.

It can be seen from Tables 4.5 to 4.10 that 1985 is a poor year economically. This can be attributed to a poor wind year and malfunctioning of the machine due to the error in the switch-over wind speed in the micro-processor as mentioned in section 4.5.2.

For the monitoring period the average saving made per kilowatt-hour produced is also 4.7p. It is based on the tariff that is in operation at the time of recording the data. This is equivalent to a saving of 34p per hour. The saving in the winter months is considerably higher at 40p per hour whilst in the summer it is 28p per hour. This is mainly because maximum penetration of wind generated electricity on the farm load generally occurs during the day in winter thus saving on the more expensive day import units.

In Figs 4.21 to 4.23 the mean saving per hour is plotted against the mean hourly wind speed, production, consumption and direct use, production and consumption being plotted on the same graph. Direct use is defined as follows:

$$\text{direct use} = \text{consumption} - \text{import} \qquad 4.14$$

and is related to penetration factor as follows:

$$\text{direct use} = \text{penetration factor} \times \text{consumption} \qquad 4.15$$

From Fig 4.21 it can be seen that if the mean hourly wind speed increases from 3m/s to 6m/s the savings/hour increase from 11p to 50p although this will be dependent on the consumption at the farm. From Fig 4.22 it can be seen, as expected, that the saving increases more sharply with an increase in production than in consumption. Fig 4.23 demonstrates in a simpler manner than in Fig 4.22 that not all the saving is due to penetration of wind generated electricity on the farm. Even if the direct use is zero, ie zero production, a saving of 5p/hour can be made (Fig 4.22 and 4.23) provided the mean power consumption is greater than 38.5kWh per hour. This minimum constraint is computed by transposing the marginal case of 5p/hour saving to the regression equation fitted to the saving and consumption data in Fig 4.22.

The long-term mean hourly power is 6.41kW (see section 4.5.5) and from the regression equation fitted to production vs saving data the mean saving/hour at normal production levels is 31p/hour. Thus the contribution to the saving due to the different import charges is approximately 16%.

The mean penetration factor for the period 20/9/84 to 3/3/88 is 0.136 whereas the mean percentage savings on the electricity bills for the same period is 16.1%. This again demonstrates, as mentioned previously, that a component of the saving is due to the more favourable tariffs for importing electricity from the grid when on a private generator tariff.

4.8.2 Long-term economics

A life cycle cost model is set up for the Eastertown wind generator as in Table 4.11. For the purposes of comparison with other power plants the life cycle cost model using discounted cash flow and net present values is preferred to an internal rate of return approach (13). For an internal rate of return calculation the lifetime of the machine must be known.

The actual capital outlay for the machine is estimated to be £20,000 (14). This includes the cost of the foundations and a 33% grant from the Department of Agriculture and Fisheries for Scotland. It excludes a cash compensation received from the manufacturers because the machine did not attain its guaranteed annual output. The amount of compensation was not disclosed by the owner.

For the annual outlays a figure of £200 is assumed to be paid out annually for general maintenance. As the machine is for an agricultural application it is exempt from a rates charge. This is crucial to the project's success as the annual rates bill has crippled some other wind generator projects. For instance at Scalloway in the Shetland Isles where from 1985 to 1988 there was a 55kW machine supplying twelve holiday chalets, the annual rates bill for the financial year 1988-89 was £4,465.80 (15).

Every three years the annual maintenance bill is assumed to be in the region of £1000 to allow for replacement cost of components. Information on maintenance costs proved to be very hard to obtain and in the circumstances only estimates based on figures mentioned in various conversations with people at the farm could be used.

The annual income from the machine is equally difficult to forecast. The long-term saving at the current year's tariff must be calculated. The data necessary to calculate the long-term annual saving at the April '88 tariff (Table 4.4) is shown below.

	Day	Night
Mean annual consumption (1985 to 87 incl.)	253,531	126,975kWh
Mean annual import (" ")	214,967	114,153
Mean annual export (" ")	350	150
Annual saving at 1988 tariff	£2,814.59	

The main problem with doing a life cycle costing model for a wind generator is that the annual income, in other words the saving made on the electricity bills, can vary to a large extent depending on the wind speeds and the availability of the machine and also on the tariff structure for the year in question. This last factor is immediately evident from the above calculation where the annual saving, calculated using three yearly annual means of import, export and consumption figures and the 1988 tariff, is higher than the mean of the annual savings made in these three years which is £2,421.41.

In the life cycle costing analysis in Table 4.11 the mean annual saving using the 1988 tariff is used as the long-term annual income from the machine. Even if future tariff structures don't increase this annual income as they have done in 1988 there may be a slight increase due to different inflation rates on energy than on labour and materials. The component of the annual income which is due to penetration of wind generated electricity on the farm may increase over the years as it is influenced by marginally higher inflation rates than labour and materials which make up the outflow figures. This is assuming that production levels remain constant. From 1970 to 1983 the price of electricity in the domestic sector inflated at a rate of 2.6% p.a. over the general rate of inflation (16). However this was mainly due to the oil crises of 1973 and 1979. The higher the difference in inflation rates the more favourable it is for wind energy.

The discount rate used in calculating present value factors in Table 4.11 has the effect of discounting future cash to give its present value. For instance if one has £1 in pocket today and the inflation rate is 6%, then in one year's time one will have £1.06 in pocket. However, if the pound had been invested at a bank with 8% interest rate, it would be worth £1.08 in one year's time which is a 2p gain. The discount rate can be thought of as a real rate of return available on the "best alternative use of funds" and in this case it is 2%. However the "best alternative use" is often difficult to define. For the purposes of life cycle costing in wind energy it is set at 5%. This is the rate recommended by the UK Treasury for all projects considered by nationalised industries in Great Britain, net of inflation and is that used by the BWEA (17). It must be emphasised that the discount rate is not the rate at which industry or private individuals borrow money from the Government or from the lending banks.

From Table 4.11 the machine is feasible if it lasts longer than twelve years and if it keeps within the prescribed outflows and attains the annual savings. Assuming the machine attains its twenty year design life this is equivalent to an internal rate of return of 9.2%. Without the 33% grant the machine would take over nineteen years to pay for itself.

A pessimistic scenario would be an annual maintenance bill of £300 with £1.000 every three years and annual savings of only £2,000. The wind generator in these circumstances would not pay for itself in its design life of twenty years.

Another pessimistic scenario is that where a farmer becomes liable for rates for the addition of a wind turbine generator to his farm. For this to come about would first require a massive change in Government agricultural policy as at present a farmer even exempt for rates for his land. However, assuming that the Eastertown machine is evaluated in a similar manner as the Scalloway 55kW machine (18) whereby the rateable value is 9% of the installed cost, the Eastertown machine would probably receive an annual rates bill in the region of £1,800. The machine cannot ever hope to pay itself off as the maximum annual net income is only £815.

An optimistic scenario is one where the wind turbine generator does attain its guaranteed output of 100,000kWh p.a. and has annual maintenance bills of £200 with £1,000 every three years for component replacements as before. Using an estimated value for the day and night export per annum of 700 and 300 units respectively, and using the mean consumption levels for 1985 to 1987, the annual saving at the 1988 tariff is £4,772 and the pay-back period is six years.

4.9 CONCLUSIONS

This study carried out on the Polenko 60kW machine at Eastertown has been mainly based on hourly data collected over a non-continuous period of twenty eight weeks from a low cost monitoring system. Electricity bills and weekly production figures were also available since commissioning of the second machine in September '84 for the long-term economic assessment. The amount of information extracted from this apparently limited monitoring is considerable.

The site of the machine is poor with a predicted long-term annual mean wind speed, using Dyce as a source site, of 4.6m/s at the site of the anemometer 4m above an 8m building very close to the wind turbine generator. The mean hourly turbulence intensity is 0.375 for the monitoring period. The high turbulence and low mean wind speeds has made the determination of the power curve difficult. However power curves for different turbulence levels have been calculated, the higher the mean turbulence the higher the mean power output. For mean turbulence intensities of 0.157 and 0.346 it is demonstrated theoretically and validated experimentally that a difference occurs in the power outputs on the curved sections of the two power curves in the region of 30% of the power curve at the lower turbulence level.

On average the machine provides about 15% of the pig unit's electrical requirements and is expected to pay for itself within thirteen years. This is equivalent to an internal rate of return of 9.2% with a twenty year lifetime. The pay-back period is most dependent on future production levels of the wind turbine generator and future maintenance bills. However future tariff structure policy is also important as it is calculated for the

Eastertown situation that approximately 16% of the annual income from the machine is due to the different costs for units imported from the grid with and without a private generator connected.

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Table 4.1 Examples of maintenance task descriptions for Polenko WPS 16e A60 wind generator

Main system	Example of a task description	Frequency	Special equipment
Rotor blades and control flaps	check bolts	once/year	crane or mobile platform
Rotor hub and flap control system	check bolts	4 times/year	spanners
Rotor blocking system	check functioning and lubrication	2 times/year	grease gun
Transmission	change oil in gear box	once/3 years	oil
Brake and safety system	check wear of brake lining, replace or re-adjust	4 times/year	spanners, feeler gauges
Yaw system	grease slewing ring	4 times/year	grease gun
Tower	check anchor bolts	once/year	spanner
Electrical system	check all wiring and cables, control cabinet functions	4 times/year	
General	check entire tower and rotor for corrosion	once/year	paint if necessary

Table 4.2 Periods of hourly data capture at Eastertown

```
     Jan Feb Mar Apr May Jun Jul Aug Sep Oct Nov Dec
    |-----------------------------------------------|
1986|              *** * **                         |
    |-----------------------------------------------|
1987|                   **  *********************   |
    |-----------------------------------------------|
1988|    *****                                      |
    |-----------------------------------------------|
```

Table 4.3 Annual production figures, load factors and wind speeds at Eastertown

	Annual production	Load factor	Site mean wind speed
1985	40,282kWh	0.077	4.2m/s
1986	59,995	0.114	5.0
1987	50,746	0.097	4.2

Table 4.4 North of Scotland Hydro Electric Board Tariffs from 1st April 1988

Charges per month	STANDARD Dom/Farm WECS	STANDARD Dom/Farm No WECS	ECONOMY Dom/Farm WECS	ECONOMY Dom/Farm No WECS
Basic/Availability				
240V 1-ph		# 2.81		# 3.57
(up to 10kVA)	#13.82	(Dom 1-ph)	#13.82	(Dom 1-ph)
415V 3-ph		# 4.47		# 5.36
(up to 20kVA)	#25.07	(Farm 1-ph)	#25.07	(Farm 3-ph)
+/excess kVA	# 0.77	# 6.98	# 0.77	# 7.91
		(Farm 3-ph)		(Farm 3-ph)
Import/kWh				
24 hrs	4.52p	5.18p		
2330-0730 hrs			2.02p	2.02p
0730-2330 hrs			4.78p	5.43p
Export/kWh				
24 hrs	-1.86p			
2330-0730 hrs			-1.50p	
0730-2330 hrs			-2.04p	
Reactive/kVArh	0.47p		0.47p	
(in excess of half the number of total import units)				

Table 4.5 Analysis of electricity bills and weekly production figures in 1983 for Eastertown

	1983				
	Quarter 1 12/1-11/3	Quarter 2 11/3-10/6	Quarter 3 10/6-14/9	Quarter 4 14/9-12/12	Annual 12/1-12/12
Day import kWh	40,100	58,550	53,840	57,260	209,750
Night import kWh	21,500	27,770	21,090	21,660	92,020
Total import kWh	61,600	86,320	74,930	78,920	301,770
Total export kWh	180	520	990	1,220	2,910
Actual electricity bill	£2,191.53	£3,128.99	£2,787.35	£2,947.66	£11,055.53
% of bill for availability	0	0	0	0	0

Note : no charge was made for availability

Table 4.6 Analysis of electricity bills and weekly production figures in 1984 for Eastertown

	1984				
	Quarter 1 12/12-14/3	Quarter 2 14/3-19/6	Quarter 3 19/6-20/9	Quarter 4 20/9-17/12	Annual 12/12-17/12
Production kWh				13,173	
Load factor				0.104	
Day consumption kWh				62,880	
Night consumption kWh				32,723	
Total consumption kWh				95,603	
Day import kWh	58,310	65,440	68,720	53,290	245,760
Night import kWh	27,610	33,820	35,060	29,480	125,970
Total import kWh	85,920	99,260	103,780	82,770	371,730
Day export kWh				290	
Night export kWh				50	
Total export kWh	310	10	0	340	660
Utilisation factor				0.974	
Penetration factor				0.134	
Actual electric bill (1)	£3,118.43	£3,557.23	£3,833.82	£3,030.41	£13,539.89
% of bill for availability	0.0	0.0	7.6	8.1	4.0
Est'd bill - no WECS (2)				£3,587.54	
% of bill for availability				0.5	
Saving in £'s				£557.13	
% saving (100*(2-1)/2)				15.5	

Table 4.7 Analysis of electricity bills and weekly production figures in 1985 for Eastertown

	1985				
	Quarter 1 17/12-12/3	Quarter 2 12/3-6/6	Quarter 3 6/6-10/9	Quarter 4 10/9-5/12	Annual 17/12-5/12
Production kWh	12,140	10,214	7,748	10,180	40,282
Load factor	0.099	0.082	0.056	0.082	0.077
Day consumption kWh	66,655	59,031	61,141	56,915	243,742
Night consumption kWh	31,415	30,404	31,547	28,115	121,481
Total consumption kWh	98,070	89,434	92,688	85,030	365,222
Day import kWh	57,570	51,400	55,340	49,370	213,680
Night import kWh	28,380	27,890	29,610	25,630	111,510
Total import kWh	85,950	79,290	84,950	75,000	325,190
Day export kWh	20	30	10	90	150
Night export kWh	0	40	0	60	100
Total export kWh	20	70	10	150	250
Utilisation factor	0.998	0.993	0.999	0.985	0.994
Penetration factor	0.124	0.113	0.083	0.118	0.110
Actual electric bill (1)	£3,194.49	£2,926.93	£3,261.61	£2,918.91	£12,301.94
% of bill for availability	7.7	8.4	7.9	8.8	8.2
Est'd bill - no WECS (2)	£3,738.60	£3,363.01	£3,661.14	£3,384.32	£14,147.07
% of bill for availability	0.5	0.6	0.6	0.6	0.6
Saving in £'s	£544.11	£436.08	£399.53	£465.41	£1,845.13
% saving (100*(2-1)/2)	14.6	13.0	10.9	13.8	13.0

Table 4.8 Analysis of electricity bills and weekly production figures in 1986 for Eastertown

	1986				
	Quarter 1 5/12-6/3	Quarter 2 6/3-6/6	Quarter 3 6/6-3/9	Quarter 4 3/9-12/12	Annual 5/12-12/12
Production kWh	13,480	21,020	7,949	17,546	59,995
Load factor	0.116	0.159	0.062	0.122	0.114
Day consumption kWh	70,020	61,605	57,582	65,590	254,796
Night consumption kWh	33,380	32,425	28,847	32,457	127,109
Total consumption kWh	103,400	94,030	86,429	98,046	381,905
Day import kWh	59,910	46,130	51,660	52,500	210,200
Night import kWh	30,010	27,230	26,860	28,130	112,230
Total import kWh	89,920	73,360	78,520	80,630	322,430
Day export kWh	0	290	40	70	400
Night export kWh	0	60	0	60	120
Total export kWh	0	350	40	130	520
Utilisation factor	1.000	0.983	0.995	0.993	0.991
Penetration factor	0.130	0.220	0.092	0.178	0.156
Actual electric bill (1)	£3,468.70	£2,806.05	£3,040.13	£3,107.67	£12,422.55
% of bill for availability	7.4	9.1	8.0	8.3	8.2
Est'd bill - no WECS (2)	£4,122.44	£3,683.44	£3,450.39	£3,911.60	£15,167.86
% of bill for availability	0.5	0.6	0.6	0.6	0.6
Saving in £'s	£665.43	£895.61	£417.58	£820.09	£2,798.70
% saving (100*(2-1)/2)	16.1	24.2	12.1	20.9	18.4

Table 4.9 Analysis of electricity bills and weekly production figures in 1987 for Eastertown

	1987				
	Quarter 1 12/12-18/2	Quarter 2 18/2-3/6	Quarter 3 3/6-3/9	Quarter 4 3/9-3/12	Annual 12/12-3/12
Production kWh	11,384	22,589	11,423	9,984	55,380
Load factor	0.116	0.149	0.086	0.076	0.108
Day consumption kWh	57,328	83,222	61,357	60,148	262,055
Night consumption kWh	26,906	43,717	30,786	30,926	132,335
Total consumption kWh	84,234	126,939	92,143	91,074	394,390
Day import kWh	48,830	66,500	52,890	52,800	221,020
Night import kWh	24,080	38,220	27,930	28,490	118,720
Total import kWh	72,910	104,720	80,820	81,290	339,740
Day export kWh	40	220	100	140	500
Night export kWh	20	150	0	60	230
Total export kWh	60	370	100	200	730
Utilisation factor	0.995	0.984	0.991	0.980	0.987
Penetration factor	0.134	0.175	0.123	0.107	0.139
Actual electric bill (1)	£2,873.36	£3,919.44	£3,125.67	£3,205.42	£13,123.89
% of bill for availability	8.9	6.5	8.2	7.9	7.8
Est'd bill - no WECS (2)	£3,407.56	£5,026.70	£3,683.90	£3,626.14	£15,744.30
% of bill for availability	0.6	0.4	0.6	0.6	0.6
Saving in £'s	£524.20	£1,107.26	£558.23	£420.72	£2,620.41
% saving (100*(2-1)/2)	15.7	22.0	15.2	11.6	16.6

Table 4.10 Analysis of electricity bills and weekly production figures in 1988 for Eastertown

	1988				
	Quarter 1 3/12-3/3	Quarter 2	Quarter 3	Quarter 4	Annual
Production kWh	15,463	Bills are not available for these quarters.			
Load factor	0.118				
Day consumption kWh	72,137				
Night consumption kWh	33,526				
Total consumption kWh	105,663				
Day import kWh	60,590				
Night import kWh	29,670				
Total import kWh	90,260				
Day export kWh	50				
Night export kWh	10				
Total export kWh	60				
Utilisation factor	0.996				
Penetration factor	0.146				
Actual electric bill (1)	£3,586.00				
% of bill for availability	7.0				
Est'd bill - no WECS (2)	£4,406.38				
% of bill for availability	0.5				
Saving in £'s	£820.38				
% saving (100*(2-1)/2)	18.6				

Table 4.11 Life cycle costing model for Eastertown wind turbine generator

	Cash flows (£) Outflow	Inflow	Net (1+2)	PV factor at 5%	Present value (3*4)	Net present value
	(1)	(2)	(3)	(4)	(5)	(6)
0	-20,000	0	-20,000	1.000	-20,000	-20,000
1	-200	2,500	2,300	0.952	2,190	-17,810
2	-200	2,500	2,300	0.907	2,086	-15,723
3	-1,000	1,845	845	0.864	730	-14,993
4	-200	2,799	2,599	0.823	2,138	-12,855
5	-200	2,620	2,420	0.784	1,896	-10,959
6	-1,000	2,815	1,815	0.746	1,354	-9,605
7	-200	2,815	2,615	0.711	1,858	-7,747
8	-200	2,815	2,615	0.677	1,770	-5,977
9	-1,000	2,815	1,815	0.645	1,170	-4,807
10	-200	2,815	2,615	0.614	1,605	-3,202
11	-200	2,815	2,615	0.585	1,529	-1,673
12	-1,000	2,815	1,815	0.557	1,010	-663
13	-200	2,815	2,615	0.530	1,387	724
14	-200	2,815	2,615	0.505	1,321	2,044
15	-1,000	2,815	1,815	0.481	873	2,917
16	-200	2,815	2,615	0.458	1,198	4,115
17	-200	2,815	2,615	0.436	1,141	5,255
18	-1,000	2,815	1,815	0.416	754	6,009
19	-200	2,815	2,615	0.396	1,035	7,044
20	-200	2,815	2,615	0.377	985	8,030

INTERNAL RATE OF RETURN = 9.2%

Fig 4.1 Location of the three Polenko wind turbine generators in the NE of Scotland (scale 1" to 4 miles)

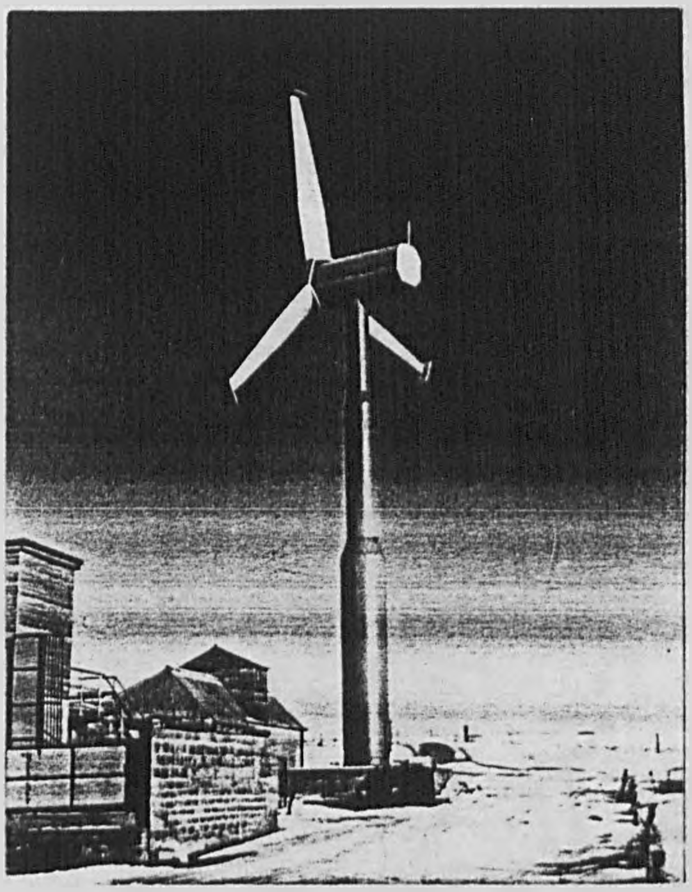


Fig 4.2 Polenko 60kW wind turbine generator at Eastertown

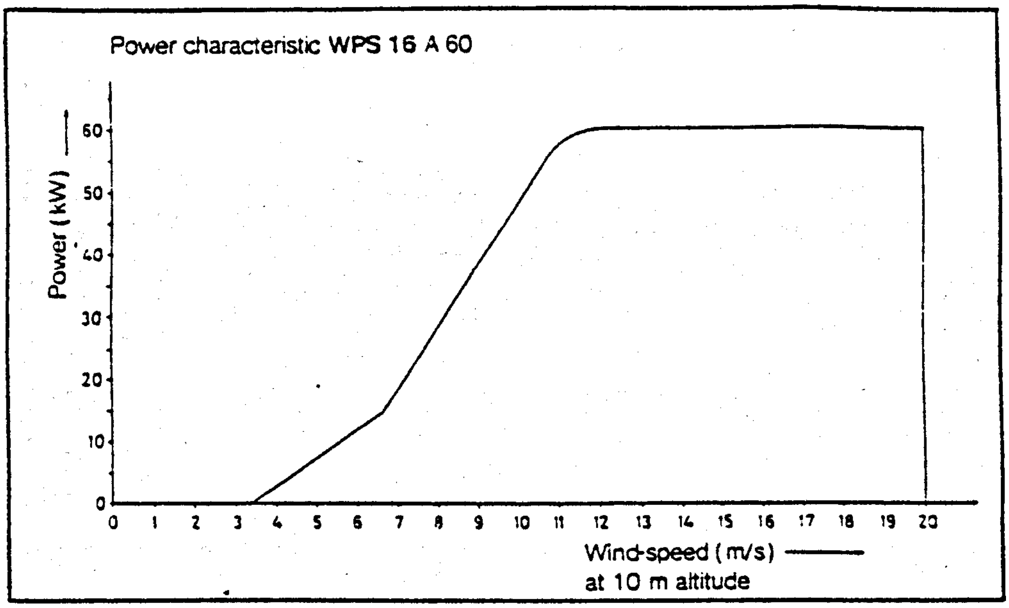


Fig 4.3 Manufacturer's power curve for Polenko 60kW wind turbine generator

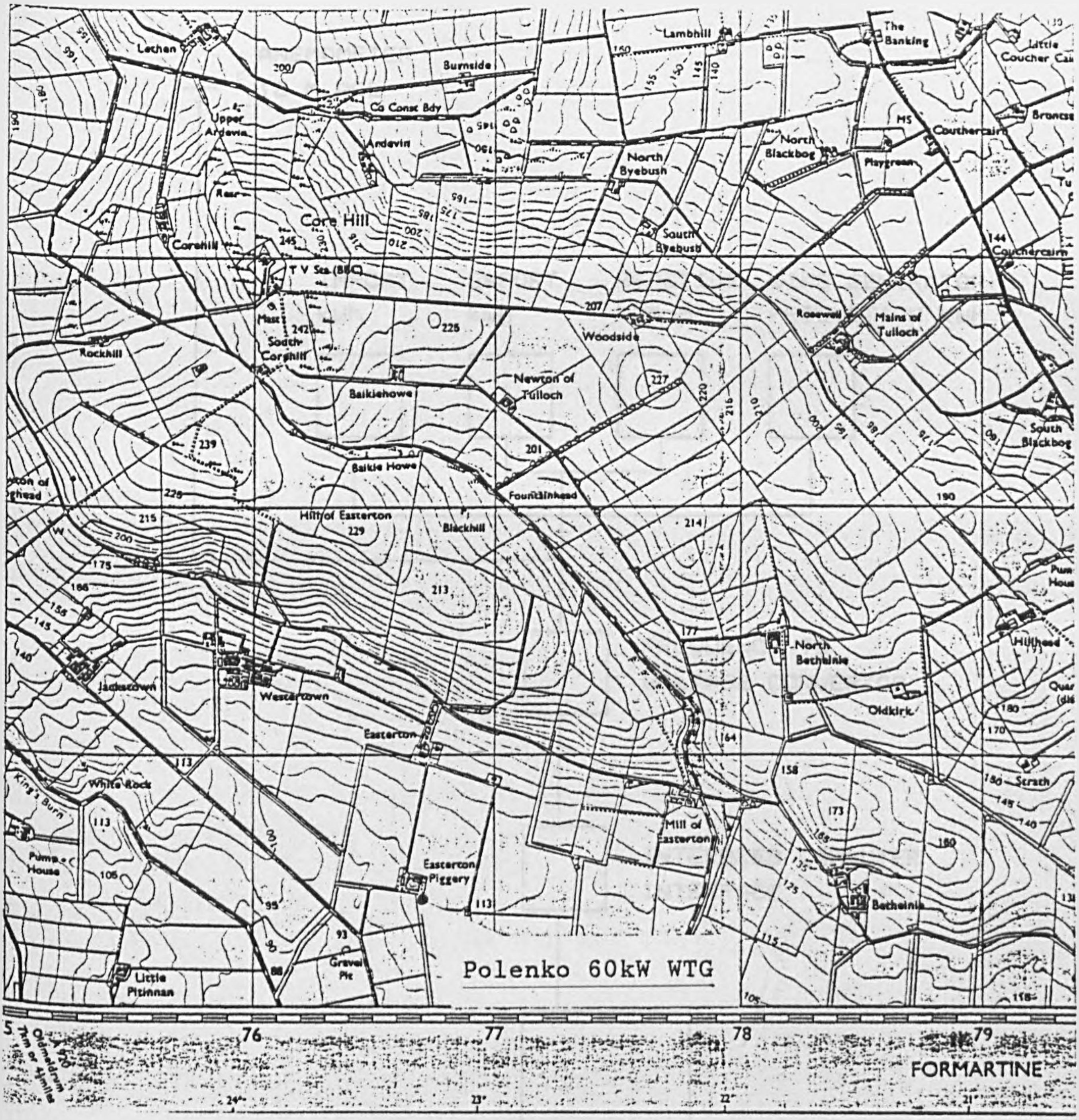


Fig 4.4 Location of the Polenko wind turbine generator at Eastertown (scale 1:25,000)

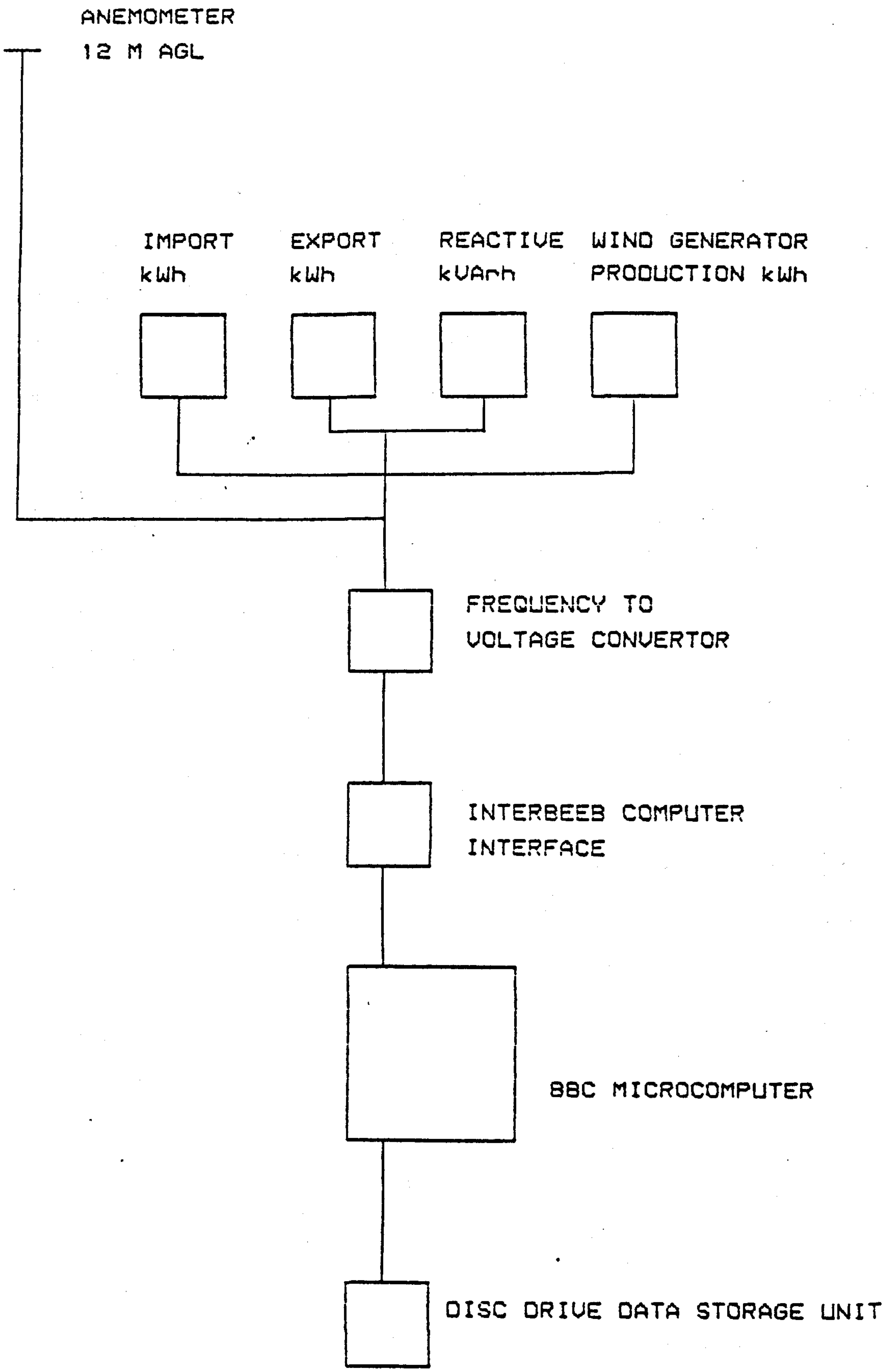


Fig 4.5 Layout of monitoring system at Eastertown

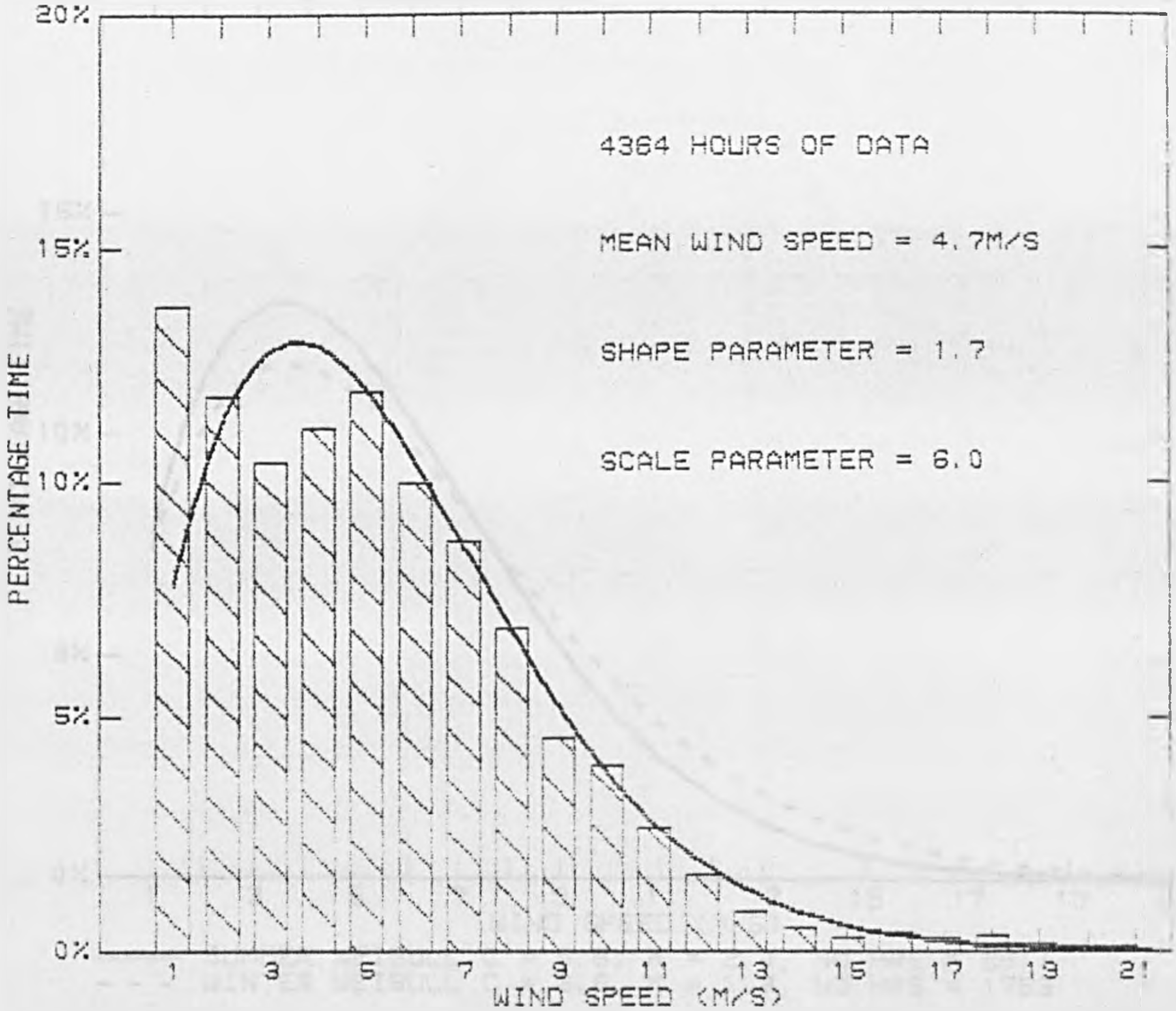


Fig 4.6 Actual and Weibull distribution for wind speeds at Eastertown

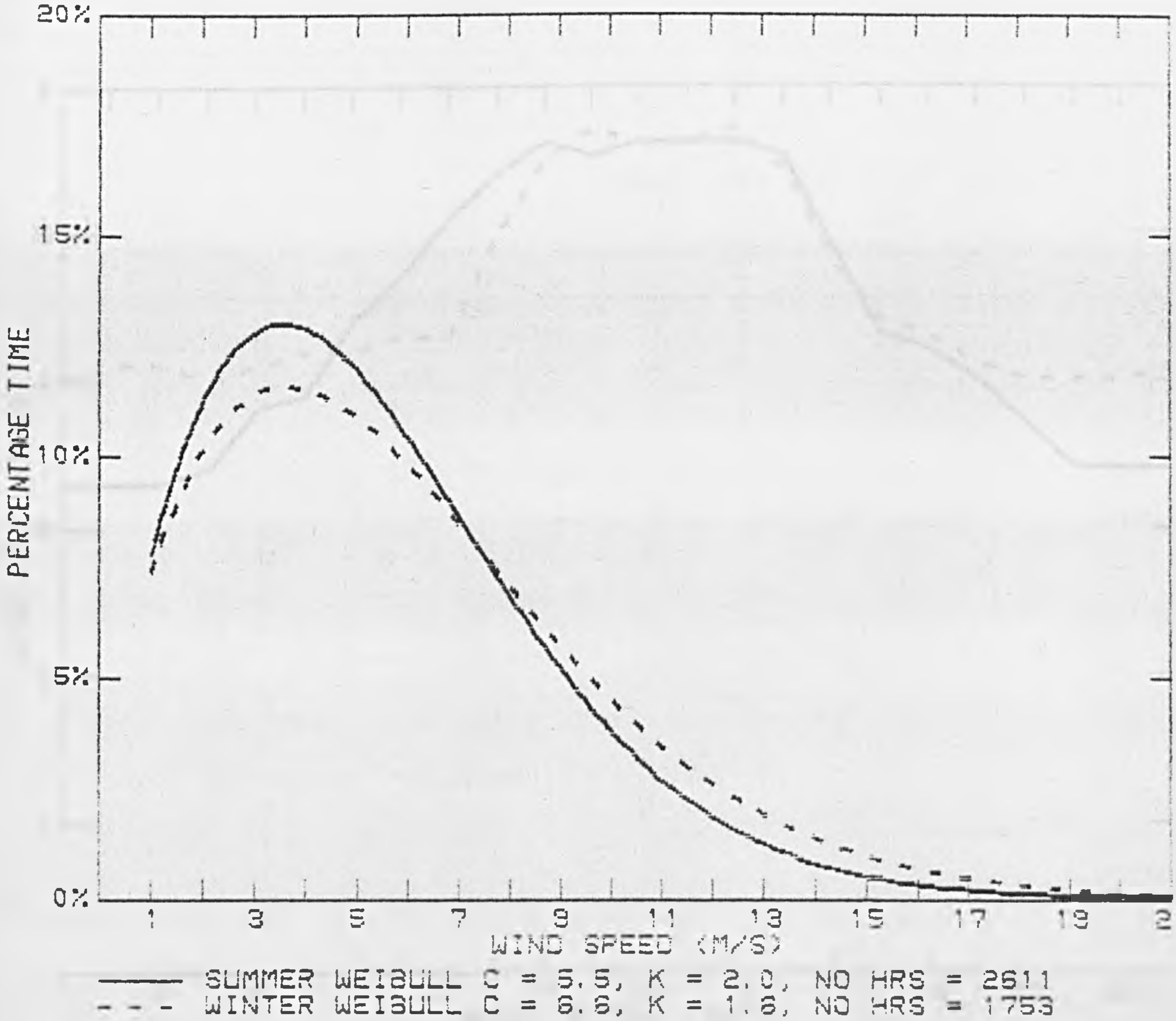


Fig 4.7 Summer and winter Weibull distributions fitted to recorded wind speed data at Eastertown

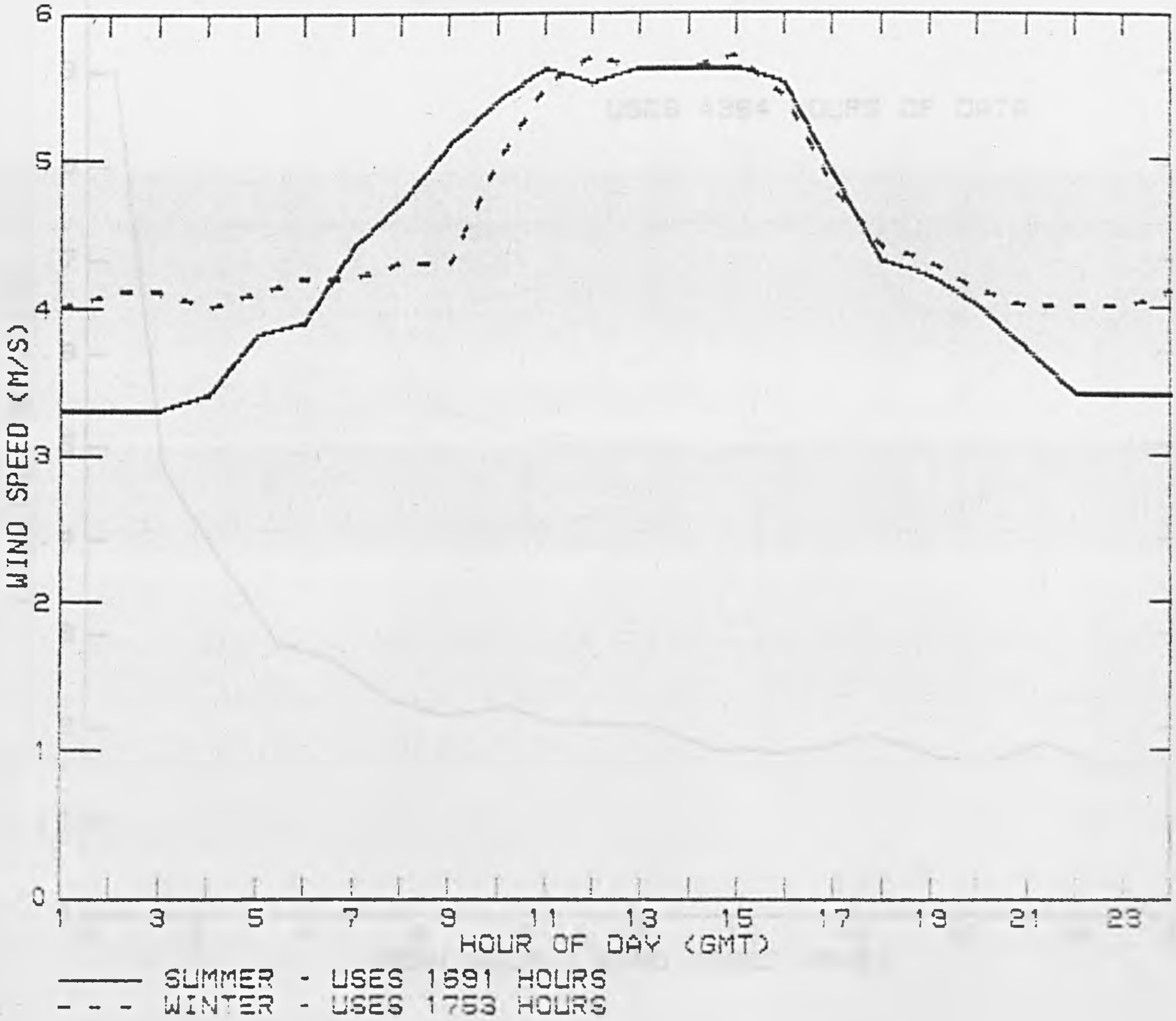


Fig 4.8 Summer and winter diurnal variation in wind speeds at Eastertown

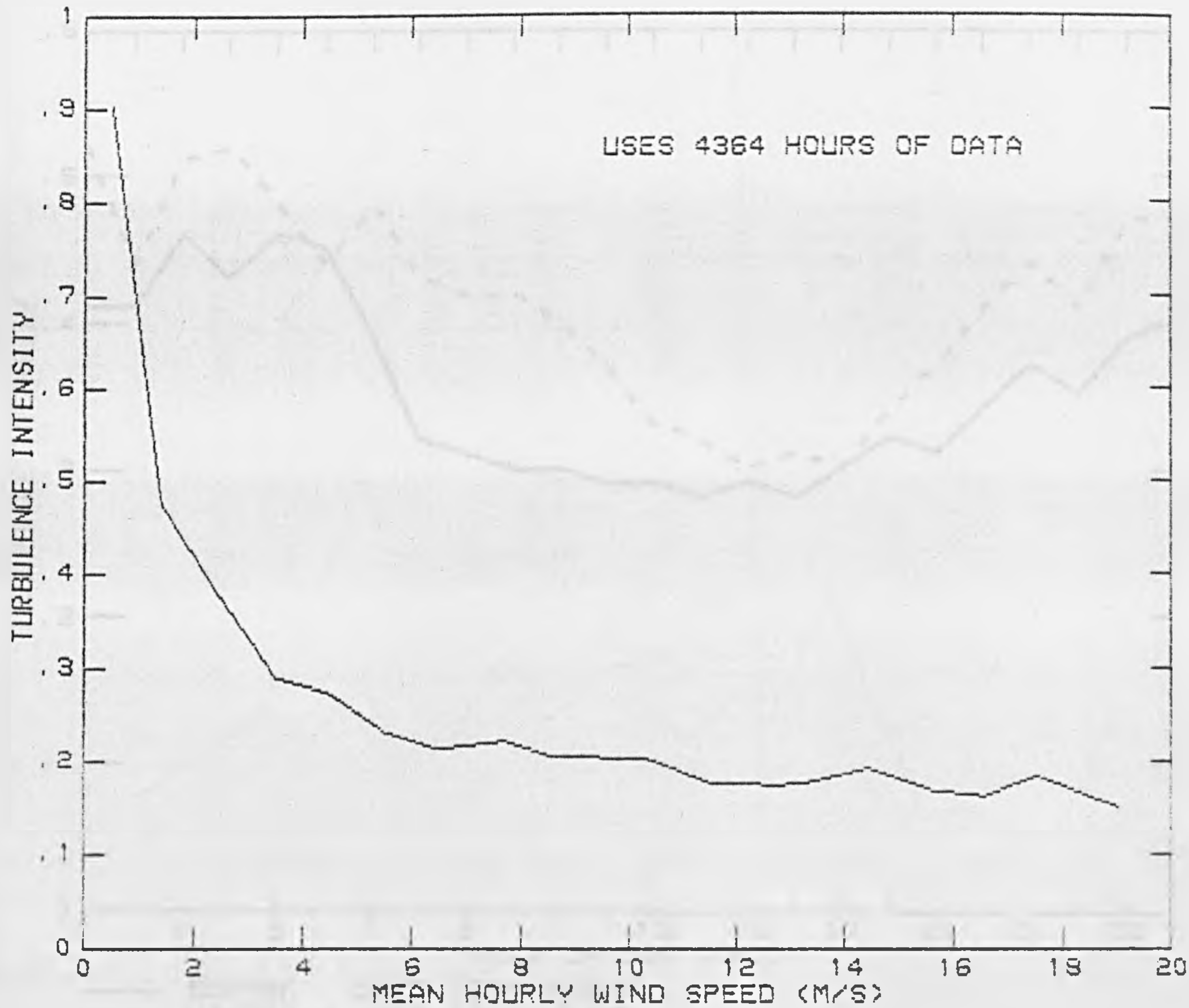


Fig 4.9 Variation of mean hourly turbulence intensity with wind speed at Eastertown

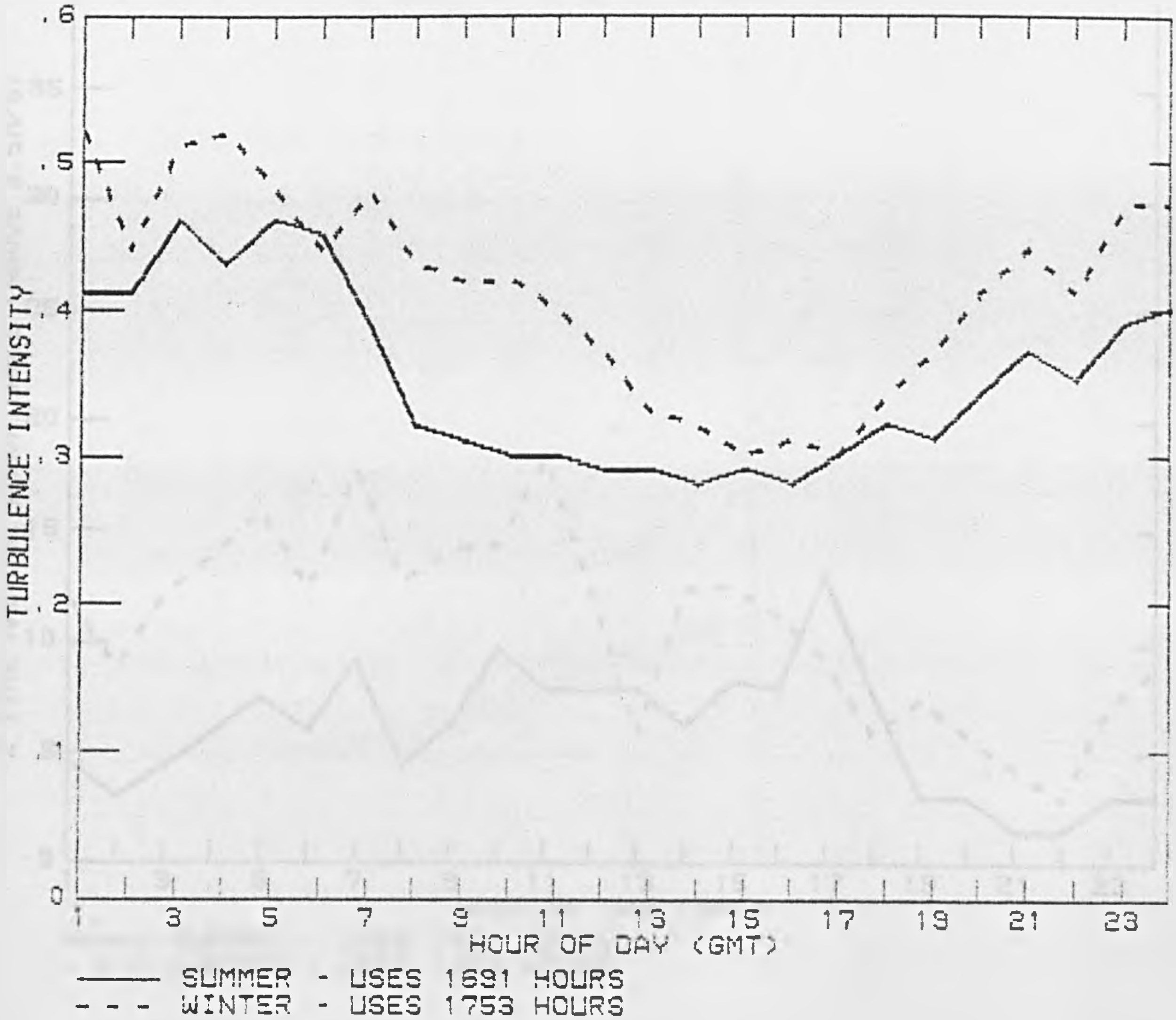


Fig 4.10 Summer and winter diurnal variation in turbulence intensities at Eastertown

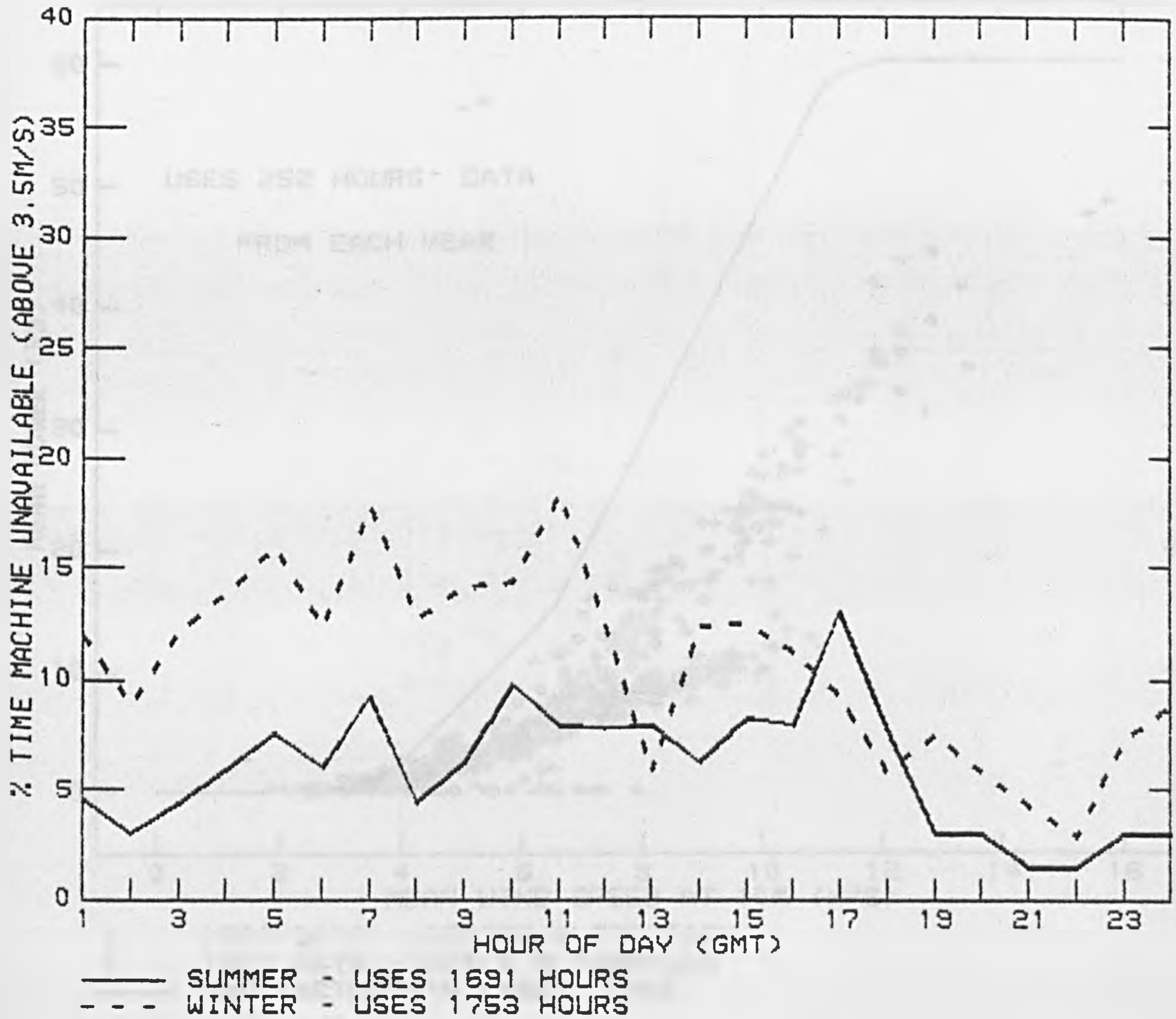


Fig 4.11 Summer and winter diurnal variation in machine non-availability above 3.5m/s wind speed

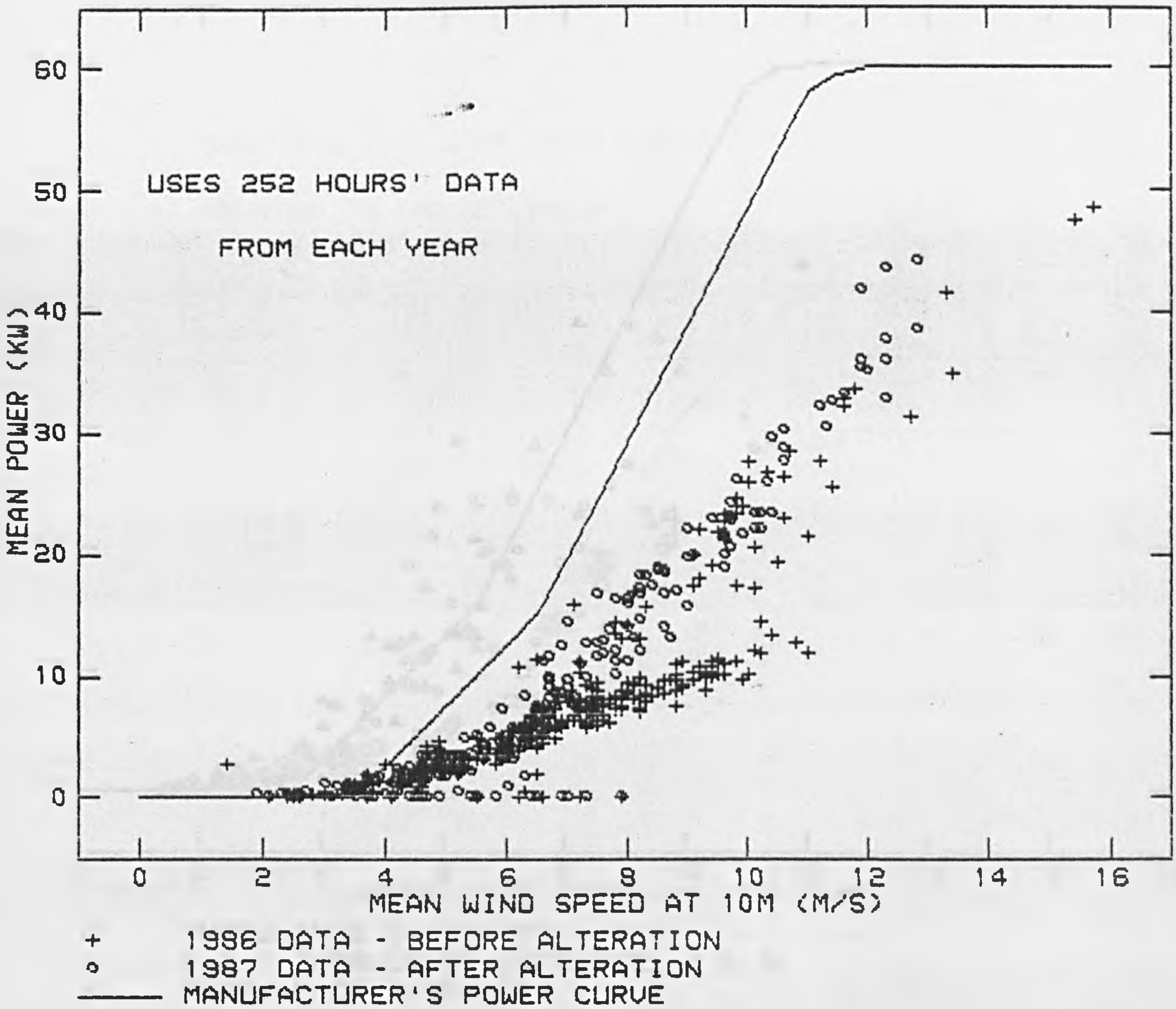


Fig 4.12 Machine performance on an hourly basis before and after alteration to switch-over wind speed at turbulence intensity less than 0.2

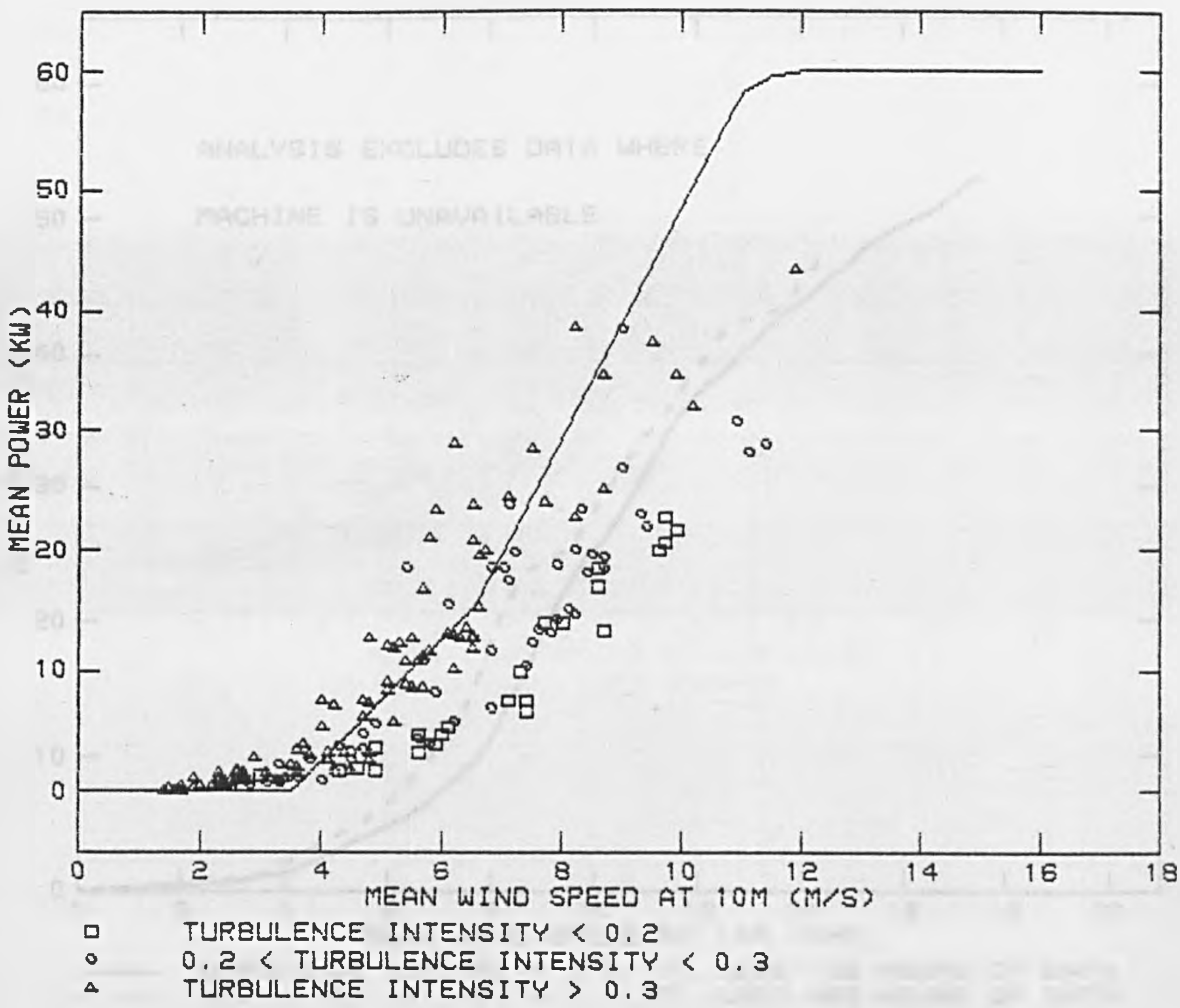


Fig 4.13 Machine performance for a typical week on an hourly basis at different turbulence levels after alteration to switch-over wind speed

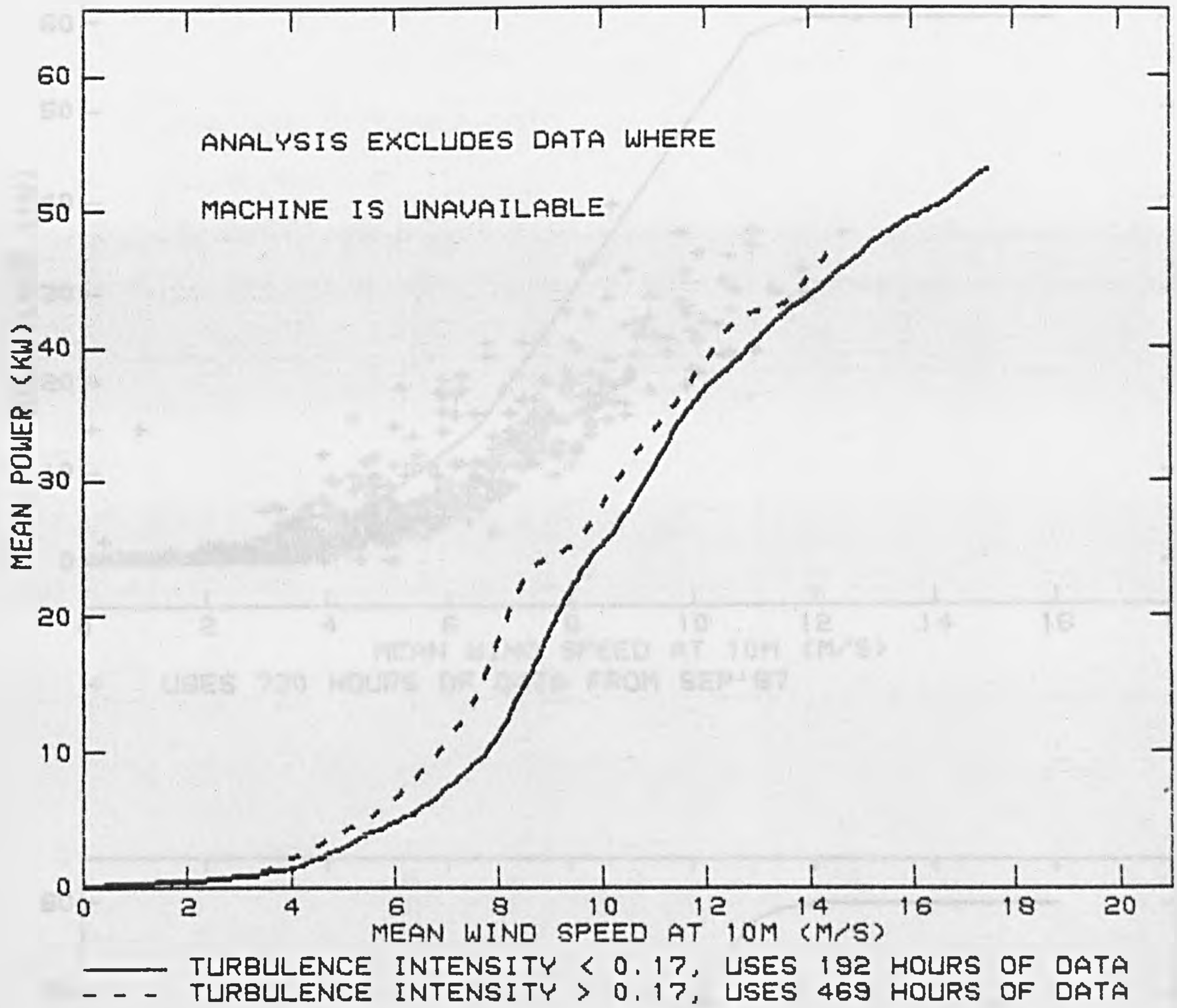
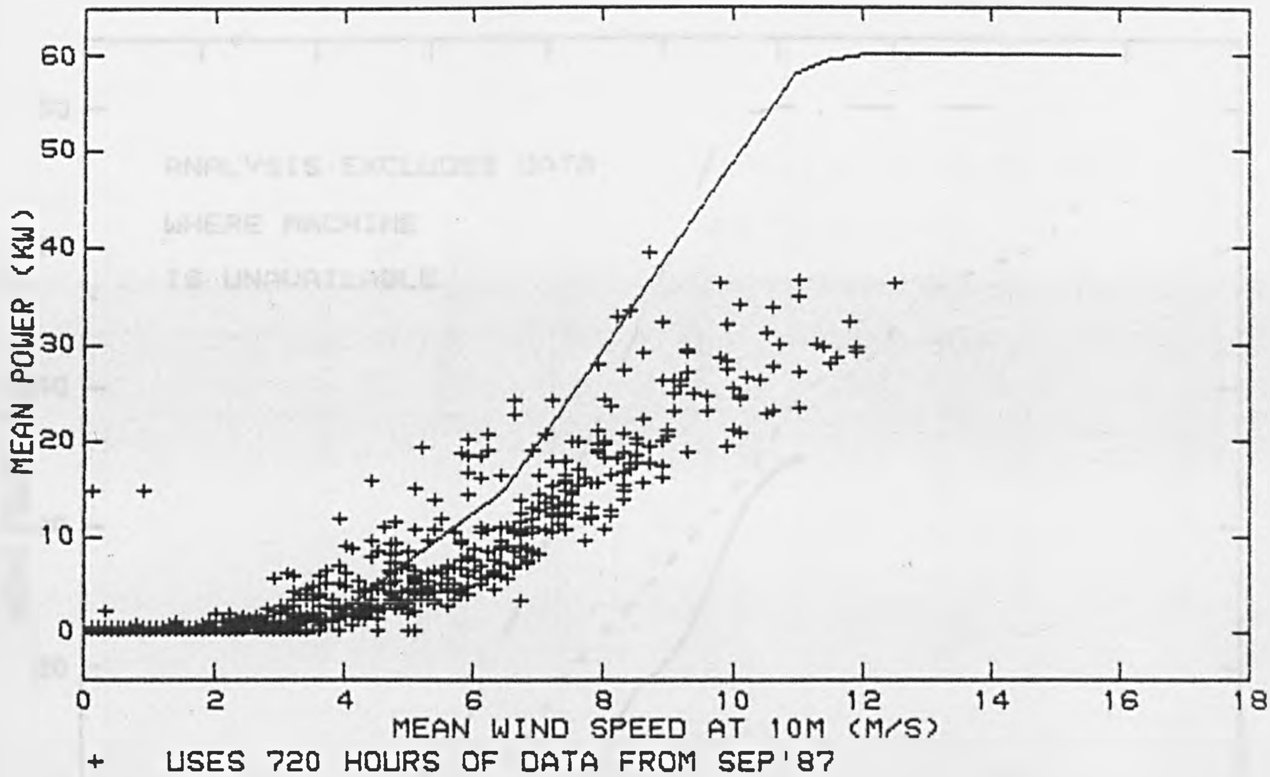


Fig 4.14 Machine performance after alteration at two levels of turbulence



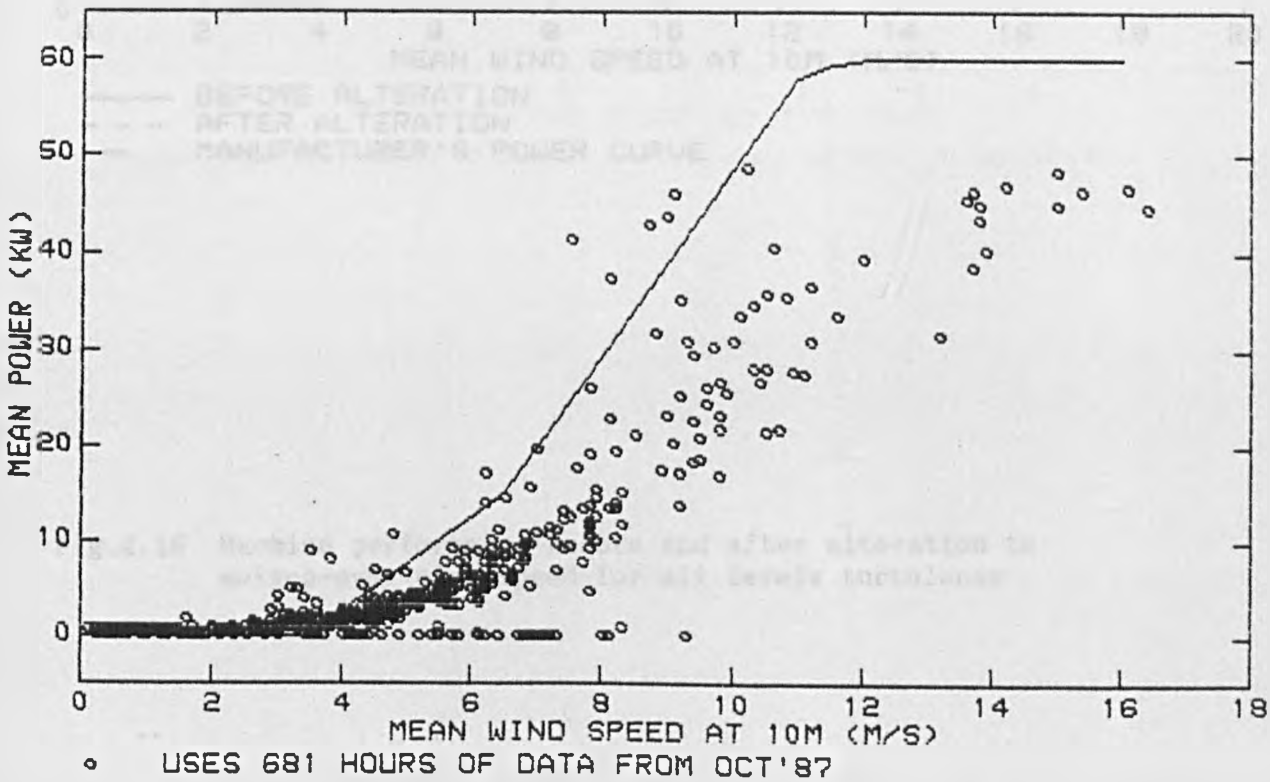


Fig 4.15 Machine performance on an hourly basis for September and October '87

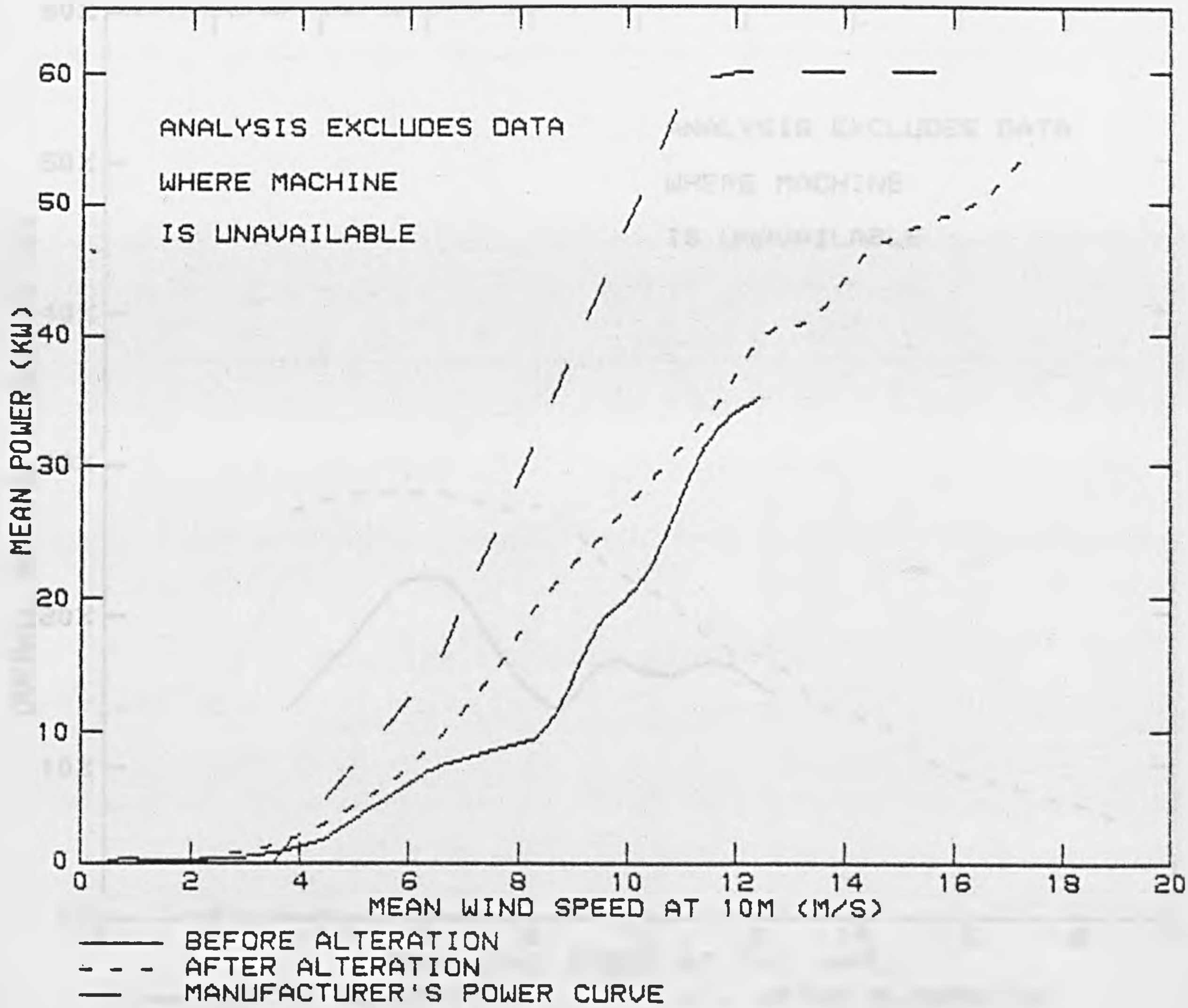


Fig 4.16 Machine performance before and after alteration to switch-over wind speed for all levels turbulence

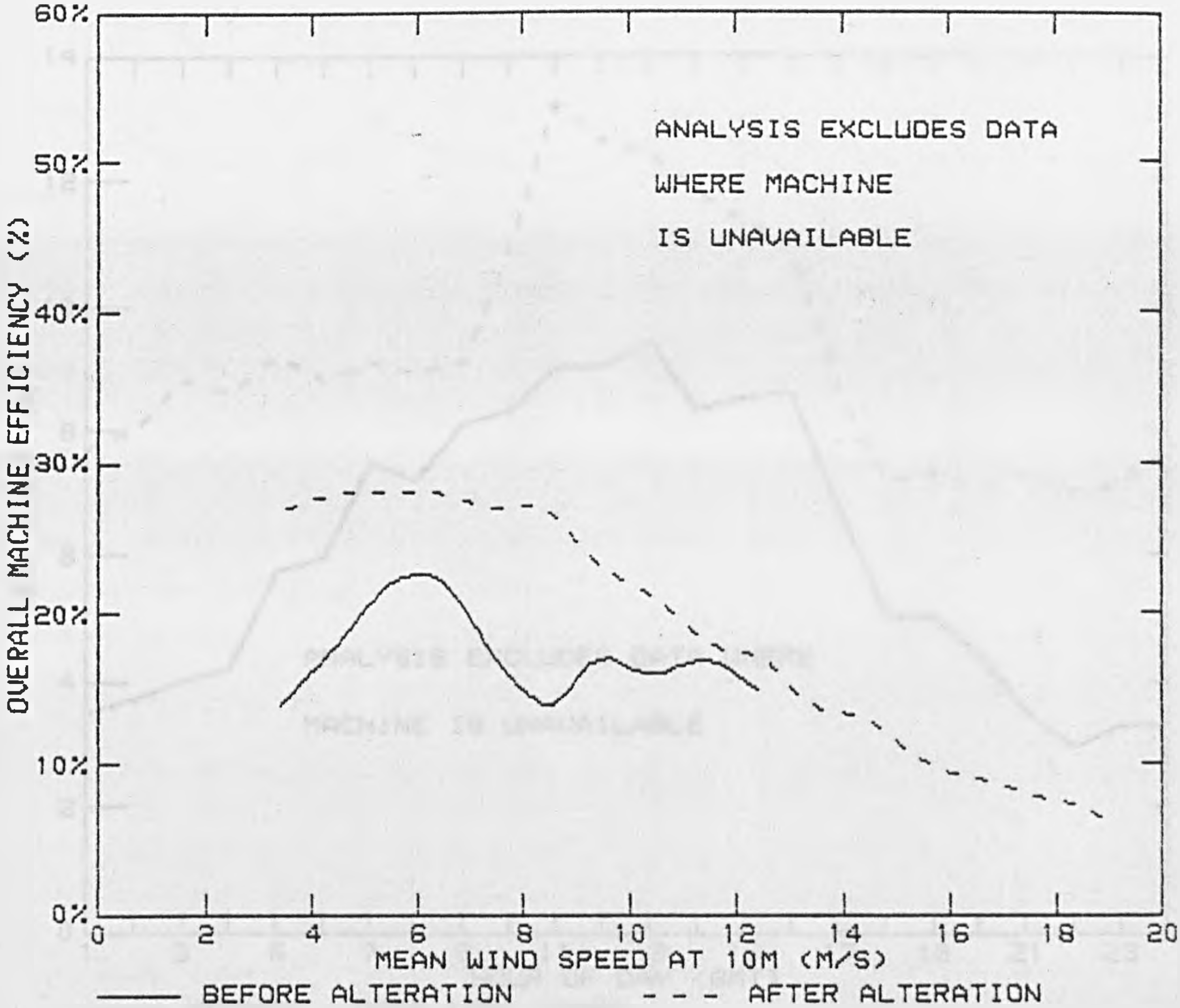


Fig 4.17 Overall efficiency of machine before and after alteration to switch-over wind speed

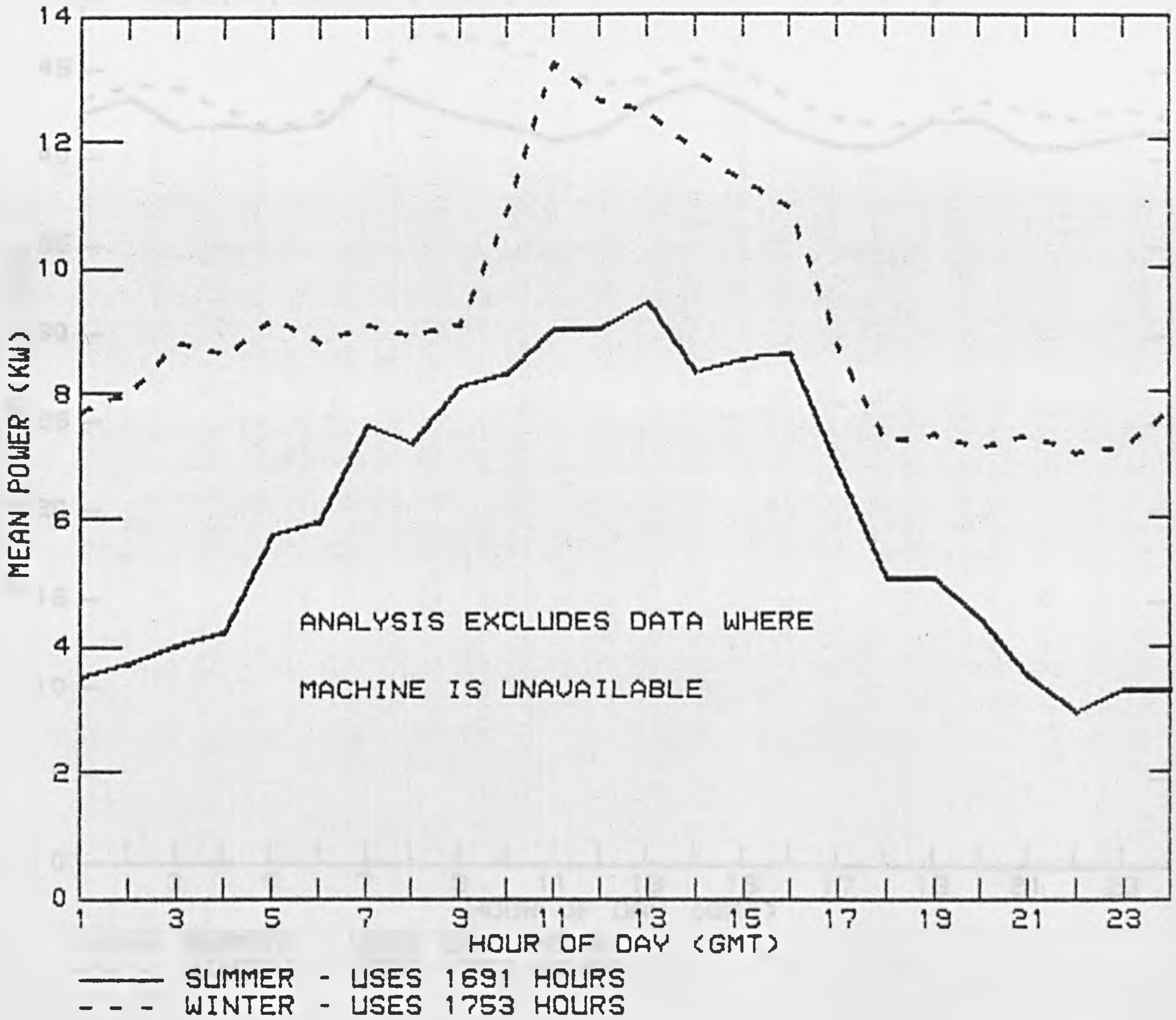


Fig 4.18 Summer and winter diurnal variation in power outputs at Eastertown

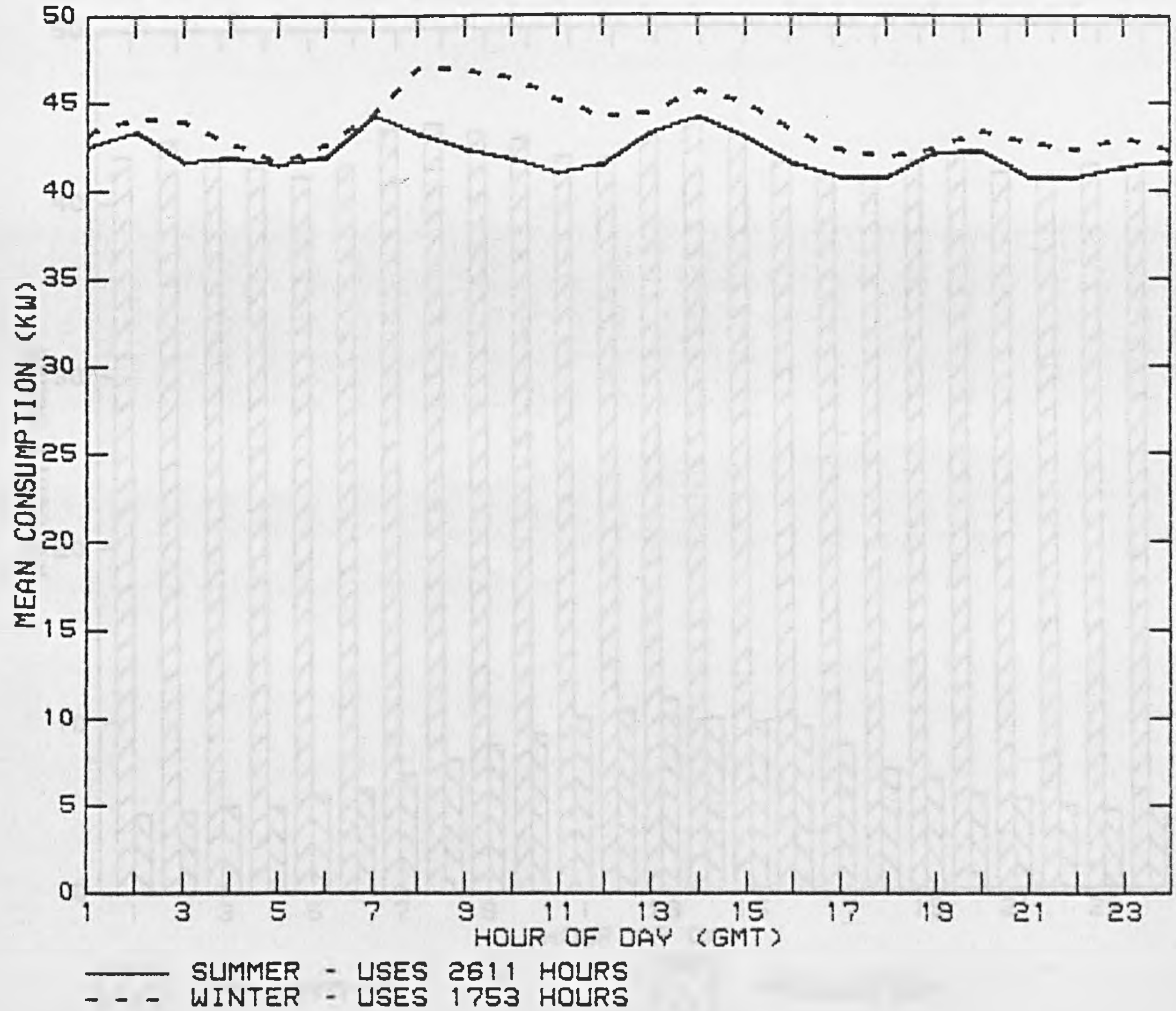


Fig 4.19 Summer and winter diurnal variation in consumption at Eastertown

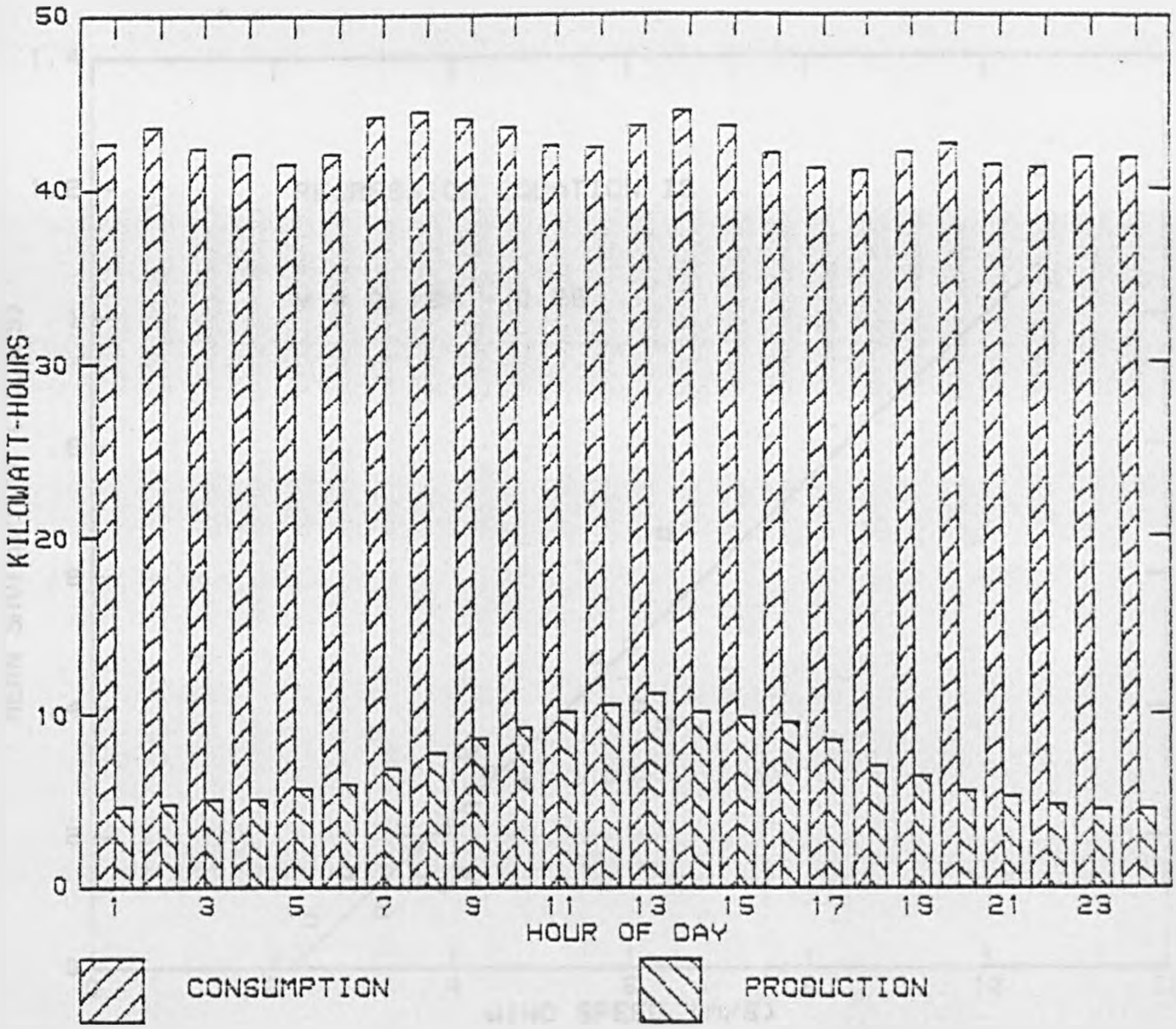


Fig 4.20 Annual diurnal variation in production and consumption at Eastertown using all data available after alteration to switch-over speed (3444 hours)

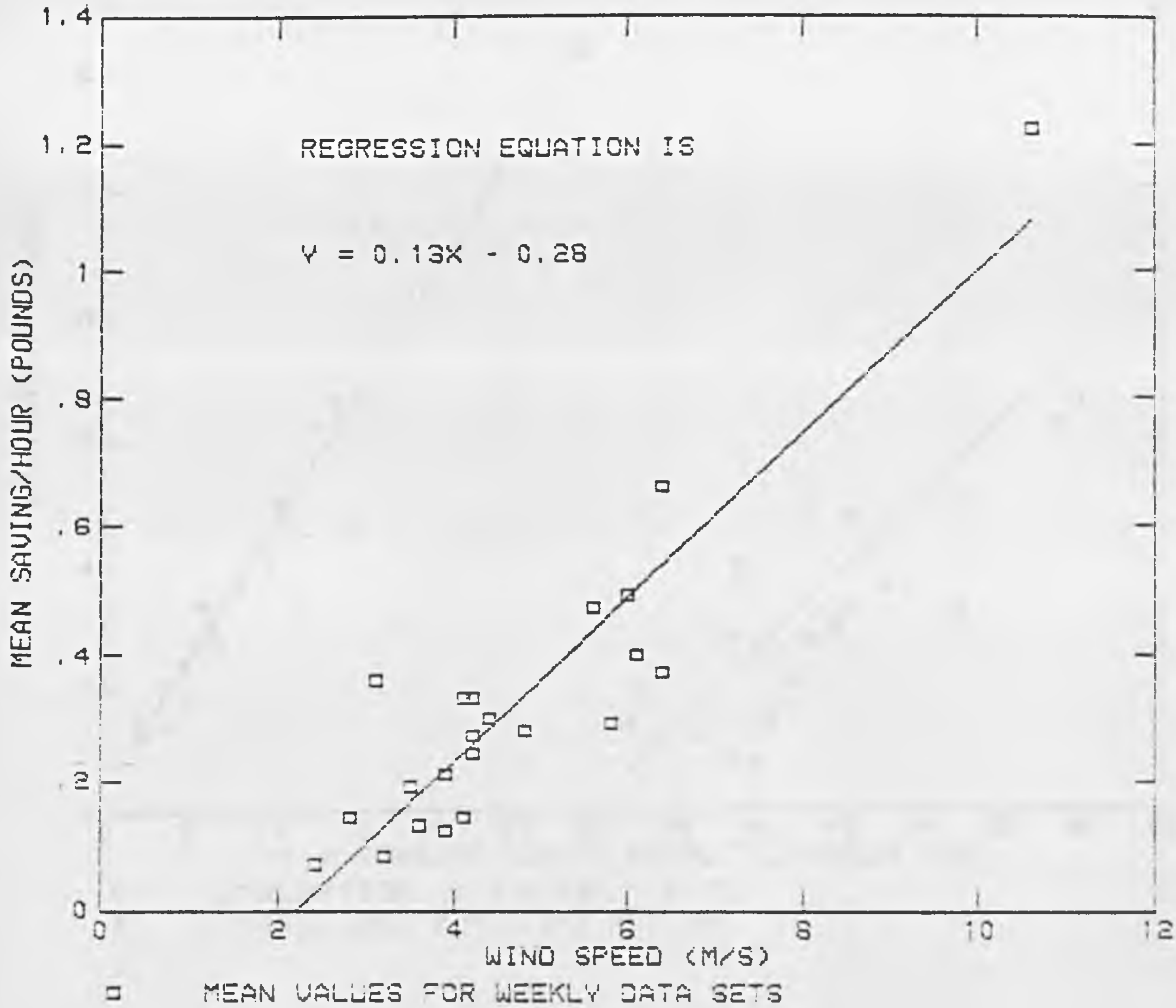


Fig 4.21 Variation of monetary saving with wind speed using all available data

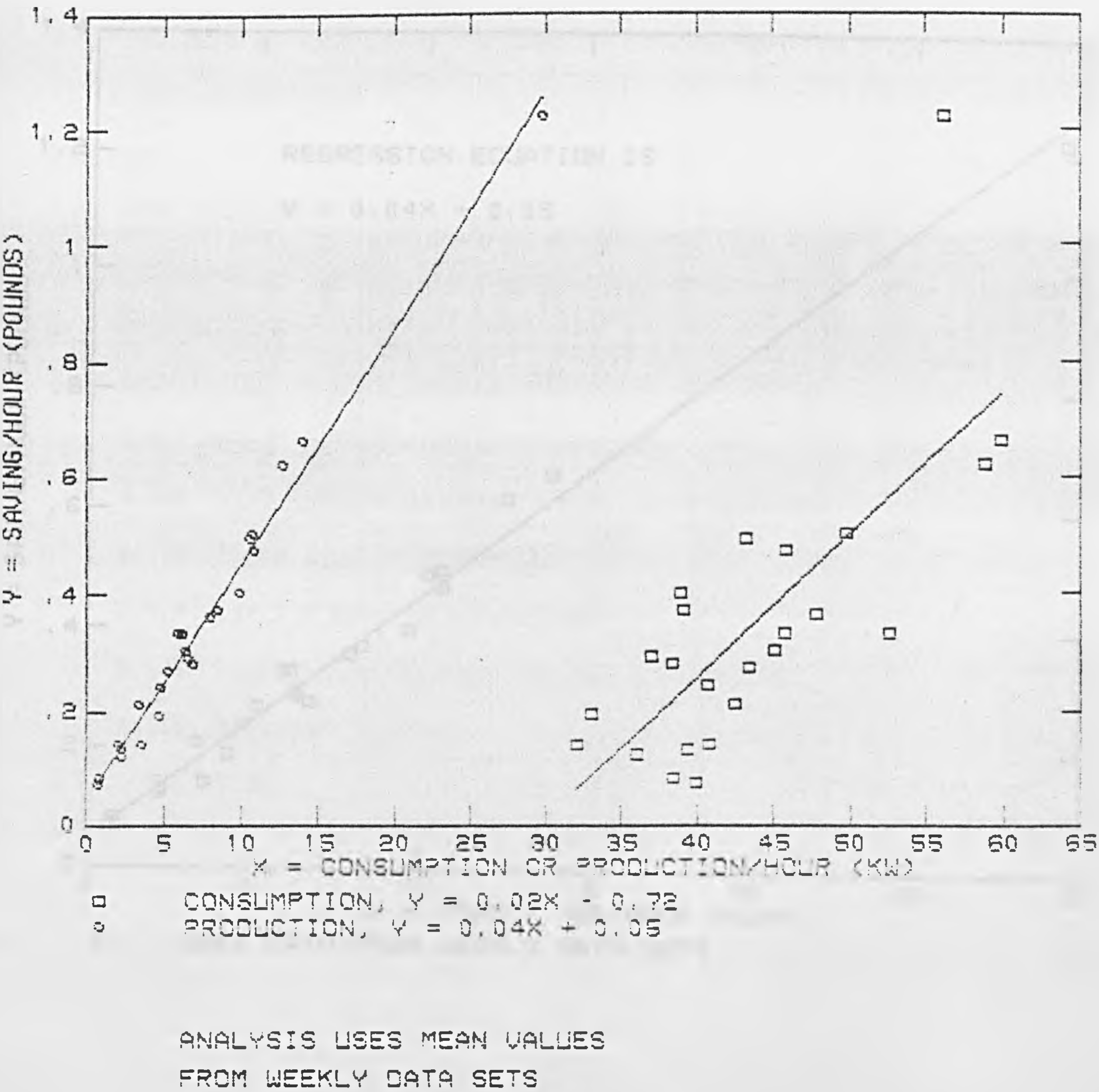


Fig 4.22 Variation of monetary saving with production and consumption using all available data

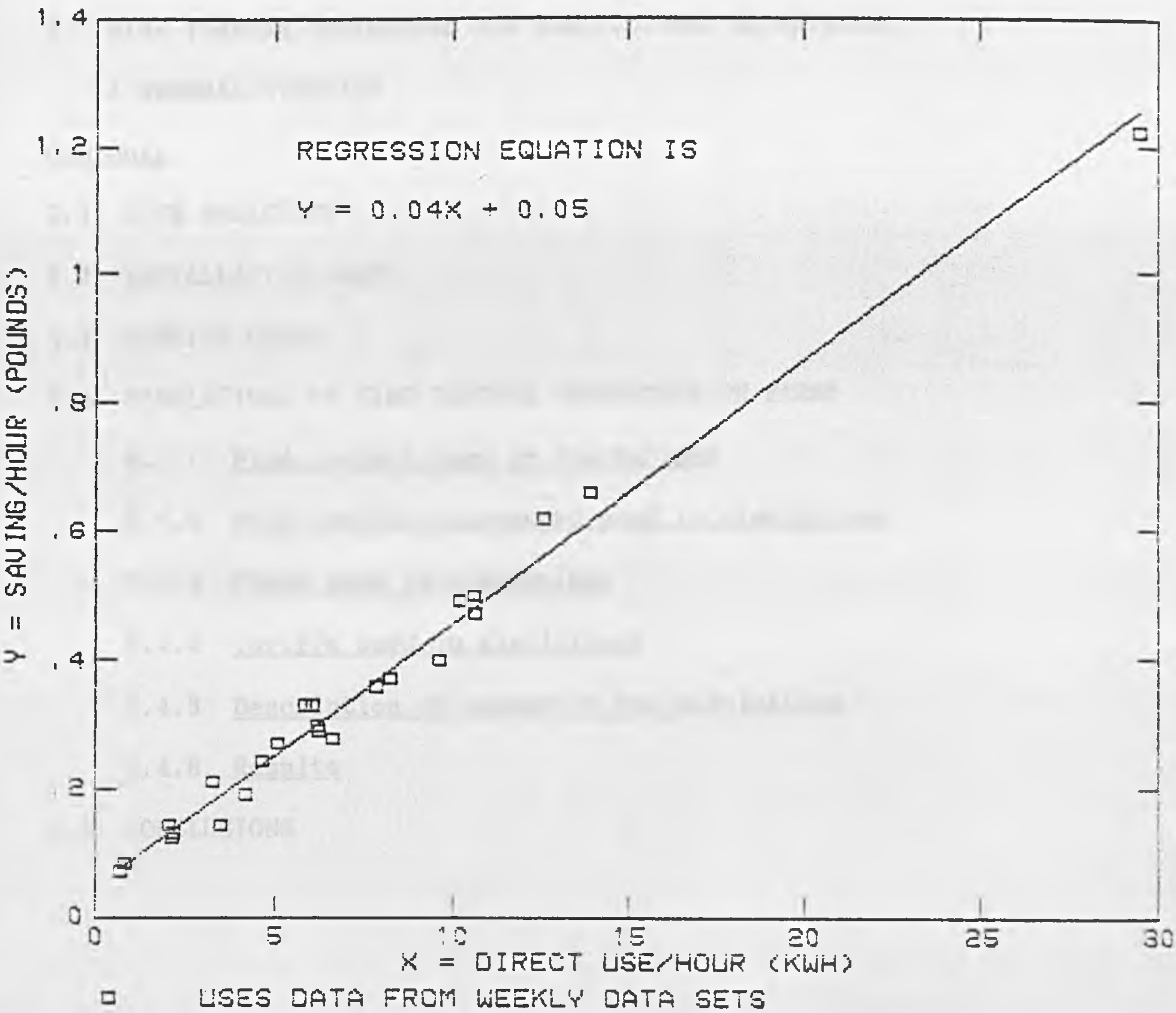


Fig 4.23 Variation of monetary saving with direct use using all available data

5. WIND TURBINE GENERATORS FOR AGRICULTURAL ENTERPRISES - A GENERAL OVERVIEW

Contents

LIST OF TABLES FOR CHAPTER 5

LIST OF FIGURES FOR CHAPTER 5

5.1 SITE SELECTION

Selecting the optimum site for a wind turbine generator is not necessarily a case of determining the best wind site in the area. Many other site-dependent factors affect the economic viability of a wind installation besides the wind regime. For instance a good wind site may pose difficult access problems for a crane for installation and a maintenance team for repair of machine as it is likely to be on top of a hill and may be be some distance from the existing electricity distribution network giving rise to high connection charges.

An ideal site should be on elevated ground with low roughness length (see Table 2.1) and with no obstructions such as trees and buildings. There should be no sharp gradients such as crags or cliffs in the vicinity as this will give rise to turbulence. The highest possible tower option should always be selected for the wind turbine generator as mean wind speeds increase with height above ground while turbulence intensity and diurnal variation decrease with height above ground. Although it is shown in section 4.5.2 that turbulence increases the power output of a wind turbine generator on the cubic section of the power curve, it also results in fatigue loading on the rotor which may be detrimental. A site with low turbulence is most desirable. The gust factor for the site (mean of the ratios of maximum 3 second gust in hour to mean hourly wind speed) is closely related to the turbulence intensity and this will also be reduced if a low turbulence site can be found. The diurnal variation in the wind speeds, depending on the farm type and the daily pattern of electrical consumption, may improve the economics.

Charges for connecting a wind turbine generator to the local distribution network can be considerable. Assuming that the farm is already connected to the national grid it is preferable for the connection of a wind turbine generator that the supply is three phase and that there are no other client's take off points between the wind turbine generator and the transformer. An individual transformer is normally required for clients who are at a distance of 350m or more from the High Voltage (HV) supply, otherwise the voltage drops on the Low Voltage (LV) cables are outwith the tolerance level which is approximately 3% (1). Any disturbances in the electricity supply due to the wind turbine generator are normally only noticed on the LV side of the transformer and therefore only the farm's imported and exported electricity is affected. As the farmer is the main beneficiary of the machine his tolerance levels of light flicker may be higher. However this has not been a reported problem at Eastertown or Scalloway. These variations in the electricity supply are negligible on the HV side of the transformer for the size of machines likely to be installed on farms.

The wind turbine generator should not be located close to habitation. Apart from the effect of the reduction in mean wind speeds and increase in turbulence caused by the buildings on the output of the wind turbine generator, the machine itself may cause hazards for the occupants. These are unacceptable noise levels (2), aesthetic acceptability (3) and risk of blade loss. The problem of electromagnetic interference (4) is another siting variable if the proposed site is in the vicinity of a radio station.

The main siting variables are as follows:

(1) Wind regime - mean wind speeds and turbulence intensities.

(2) Distance to suitable cables and transformer.

(3) Distance to existing tracks.

(4) Geology and soil type of ground for foundations.

(5) Distance to habitation.

5.2 INSTALLATION COSTS

The main cost of installing a wind turbine generator is the ex-works cost of the machine itself. It generally constitutes about 80% of the total installed cost (5). The four early commercial machines in the NE of Scotland and Scalloway in the Shetland Isles (chapter 4 and reference 6) were very competitively priced in an attempt to break into the UK market. In addition, 33% grants were secured from the Scottish Department of Agriculture and Fisheries for the commercial machines connected to farms in the NE of Scotland and a Commission of the European Community grant was secured for the Vestas machine at Scalloway. Polenko also offered high guaranteed production rates, which if not attained, were compensated for.

Other costs at installation are transportation of machine from factory to site, foundations, erection and grid connection charges. Typical costs as a percentage of ex-works cost for a 23m diameter machine are 2.7%, 6.8%, 2.7% and 5.5% respectively (7). However for the Eastertown installation the foundations cost in the region of £3,000, constituting 11.5% of the ex-works cost without the grant. For the Scalloway installation the foundations cost £3,450, constituting 11.1% of the ex-works cost without grant. Grid connection charges for the Scalloway installation were in excess of £6,000 though this included upgrading of transformer. This constitutes 20.2% of the total installation cost. These high percentages can be attributed entirely to the low ex-works costs for these machines, as previously mentioned, in order to break into a new market.

5.3 RUNNING COSTS

The main running costs of a wind turbine generator are the maintenance costs. A simulation of annual maintenance costs from information on annual down-time, service rate and duration and failure rates of major components of 700 grid connected wind turbine generators in Denmark revealed that annual repair costs are likely to be greater than the commonly used figure of 2% (8) and possibly as high as 8% of the capital cost (9). In Table 5.1 the annual maintenance cost for wind turbine generators of different sizes and ages are shown. Thus, for the more established designs in the size range 50-90kW the annual maintenance costs are in the region of 2 to 4% of the capital cost of the machine in the first 7 years of operation. For larger machines annual maintenance costs are likely to be higher.

Three other main running costs are applicable for wind turbine generators connected to the grid in the UK. These are grid availability charge, reactive power charge and local taxation (rates).

The grid availability charge is for provision, maintenance, operation, administration and depreciation of the assets involved in the electricity network. For the consumer it depends on his authorised capacity of supply expressed in kilovoltamperes (kVA) either requested by him and authorised by the Board or such higher capacity as may be determined from the recorded maximum demand in kilowatts in the month of account or any of the previous eleven months, whichever is greater, and the average power factor in the same month (8). The wind turbine generator affects the overall power factor for the farm due to its demand for reactive power.

The reactive power charge is dependent on the power factor characteristics of the wind turbine generator and the machinery on the farm. All rotating machinery draws wattless current for excitation of the windings, this is expressed in kilovoltampere hours (kVArh). A grid connected wind turbine generator with an induction generator normally produces three phase voltages (415/240V) and its frequency is controlled at 50 cycles per second (50Hz) by using electricity from the grid to excite the generator's field windings. Although the quantity of electricity for excitation is small, the wind turbine generator causes the supply voltage and current to become out of phase. The Board penalises for this if a wind turbine generator is installed, however they accept the burden of reactive units drawn if the farm is on a normal farm tariff and make no charge (11). The case is different for maximum demand tariff but this option is not considered in this study as it is generally only very large consumers of electricity that are on this tariff. Installation of a capacitor can reduce reactive power charges and this was successfully done at the Scalloway installation (12).

A charge is only made if the total reactive units is in excess of half the number of units imported from the grid. Thus if a wind turbine generator is installed the number of imported units will drop but the number of reactive units used will increase.

Unless a wind turbine generator is fitted with an expensive synchronous generator which does not require any reactive power from the grid, it cannot be considered as a stand-by source of electricity in the event of grid failure. Even if reactive power could be supplied from another source besides the grid the Board does not allow this as it may cause danger to linesmen working on the grid line fault.

Local taxation is based on capital cost and life of machine and currently in the UK can constitute approximately 5% of capital cost (13). Wind turbine generators on farms are in the fortunate position of being exempt from local taxation.

5.4 SIMULATIONS OF WIND TURBINE GENERATORS ON FARMS

In this section simulated pay-back periods of wind turbine generators are calculated for different combinations of wind regime, wind turbine generator, farm type and tariff. The simulations are of realistic situations in the NE of Scotland but are also applicable for all areas in the UK. Only the grid-connected option is considered in detail but in the case of a farm isolated from the grid and thus relying solely on a diesel generator set for its electricity supply it may well be feasible to integrate a wind turbine generator for a wind/diesel system or a wind/hydro system. The operating cost of a small diesel plant can be relatively high, figures of 15 - 30p/kWh are typical (14). The main problems are caused by the varying nature of the wind and the resulting power fluctuations. This in turn results in frequent stops and starts of the diesel set which raises fuel consumption and increases wear and tear on the diesel engine. On Fair Isle where there is a successful wind/diesel system this problem is partly overcome by the use of load control, partially implemented automatically and partially by community co-operation (15). In the third year of operation the diesel generator supplied only one tenth of the total energy requirements on the island. However they do have a dump and for the same year 15.4% of the wind generated electricity had to be dumped. Batteries can be used to store a limited amount of excess energy but are an expensive option. The use of hydraulic accumulators and flywheel energy storage are currently being investigated for the short-term storage of excess wind energy.

5.4.1 Wind regimes used in simulations

Two different wind regimes are used in the simulations. They are both realistic wind regimes for sites in the North of Scotland Hydro-Electric Board (NSHEB) area as it is the NSHEB tariffs that are used in the simulation. The wind regimes are represented by mean hourly wind speeds for each month. Each mean hourly wind speed is the average of the hourly wind speeds for a particular hour in a particular month. The effect of the diurnal and monthly variation on the economics of the wind installation can thus be assessed. The wind regimes are for the standard reference height above ground of 10m.

The first wind regime is for an inland site with a mean annual wind speed 5m/s, a mean monthly variation of 2m/s and a mean annual diurnal variation of 0.8m/s. Therefore the mean difference between the highest wind speed month and the lowest wind speed month is 2m/s. The mean diurnal variation and the mean monthly variation for an inland site are shown in Fig 5.1. The annual wind speed distribution of individual hourly wind speeds is a Weibull distribution with scale parameter of 5.6m/s and shape parameter of 2 (see section 2.2). This is equivalent to a Rayleigh distribution.

The second wind regime is for a coastal site with a higher annual mean speed of 6m/s, a mean monthly variation of 2m/s and a larger mean diurnal variation of 1.3m/s. It is also shown in Fig 5.1. The annual wind speed distribution of individual hourly wind speeds is a Weibull distribution with a scale parameter of 6.8m/s and a shape parameter of 2.

Seasonal trends in the diurnal variation are accounted for in the data which make up Fig 5.1 (see section 2.2). There is a larger variation in the summer months than in the winter months.

In both the inland and coastal wind speed profiles it is assumed that localised topographic effects at the two sites are the same. If the inland site is located on top of a hill the wind speeds could be considerably higher and similarly, if the coastal site is located very close to the sea, the wind speeds could be considerably higher. The prediction model in chapter 2 should be used to accurately assess the annual mean wind speed at the proposed site.

It is assumed that the mean hourly turbulence intensity (standard deviation/mean) is 0.15 at 20m height above ground at both the inland site and the coastal site. This is a typical level of turbulence at 20m for Burgar Hill in Orkney (16). It also seems a compromise between the low levels of mean hourly turbulence quoted for a hill in Shetland in section 2.2, ie 0.086 at 10m AGL, and the high levels of mean hourly turbulence found at Eastertown in section 4.4.4, which is 0.375 at 4m above an 8m high building. Turbulence decreases with height above ground.

Turbulence intensity varies with mean wind speed as shown in Fig 4.9. The Eastertown plot of turbulence versus wind speed (as in Fig 4.9) is reduced in such a manner that the overall mean turbulence intensity is 0.15 for an inland wind speed distribution. The resulting variation of turbulence with wind speed is shown in Fig 5.2. There is no evidence that turbulence decreases or otherwise for coastal regions so the same turbulence variation with wind speed is assumed for both inland and coastal sites.

5.4.2 Wind turbine generators used in simulations

Three different wind turbine generators are used in the simulations. They are real examples of wind turbine generators currently available on the market. Their rotor diameters are 16.6m, 20.6m and 21.8m and rated outputs are 60kW, 110kW and 150kW respectively. Their capital costs ex-works mid-1988 are £43,000, £61,500 and £97,100 respectively. Their power curves are shown in Fig 5.3. It is assumed that these power curves are determined using the International Energy Agency's recommendations (17) which stipulate an averaging period of ten minutes. However in these recommendations the wind speeds are to be corrected to hub height. In the brochures for the three machines this correction is not made and the wind speeds are those measured at 10m above ground level. In the simulations therefore, 10m is the preferred working height. Corresponding measurements of turbulence are not recommended and there were certainly no indications of what turbulence conditions the power curves had been measured under in the brochures for the machines. The power curves are corrected to standard air density. It is assumed that the power curves were determined by measurement at the Risø test site in Denmark as the three machines are of Danish manufacture. At this site the average ten minute turbulence intensity is about 0.15 (18) and is assumed to have a similar variation with mean wind speed as in Fig 5.2.

Additional capital costs as mentioned in section 5.2 are for transportation, foundations, erection and grid connection. The total installed capital costs therefore become £50,611, £72,386 and £114,287 respectively. The mean annual maintenance costs, using Table 5.1, are respectively £1,118, £2,768 and £4,370. The mean power factor for all three machines is 0.84; this is used in calculating the reactive power charge.

The effect of grants to reduce the capital expenditure is included in the simulations. Grants are available from the Department of Agriculture and Fisheries for supply and installation of renewable energy equipment and from February 1989 the rate for businesses outside less favoured areas is 15% while for businesses inside the less favoured areas the rate is 25% (19). However there are limits depending on the number of labour units employed on the farm, each labour unit being equivalent to 2200 hours per year. In most circumstances the upper limit of total project expenditure over six years amounts to £35,000 per labour unit. This is subject to a maximum of £74,000 per business in any six year period. Businesses that are eligible must be based mainly on agriculture or horticulture or fresh water fish farming and have a net income in excess of £10,000 per labour unit. There are restrictions for dairy enterprises in that only small units with a maximum of 60 dairy cows are eligible.

For a business in a less favoured area employing more than 2.1 labour units, each earning in excess of £10,000 per annum net, the maximum grant is £18,500 assuming the total installed cost of the wind turbine generator is in excess of £74,000 and provided that it can be shown that the wind turbine generator has increased the earned income of each labour unit after six years. This latter requirement may prove difficult as it is very rare that a wind installation will pay for itself within six years, excluding the grant. However right from the beginning of a project the annual income from the machine (savings on electricity bills) exceeds the annual expenditure on the machine (maintenance costs) and if it can be shown in the accounts that the farmer has the capital, fulfilling the six year criterion should not pose a problem.

The annual production for each machine is calculated for each site from the annual Weibull distribution with shape parameter 2 using 0.5m/s bins. 95% availability is assumed. They are shown below.

SITE (AMWS)	MACHINE	PRODUCTION p.a.
INLAND(5m/s)	60kW	63,755kWh
INLAND(5m/s)	110kW	145,175kWh
INLAND(5m/s)	150kW	158,097kWh
COAST(6m/s)	60kW	105,551kWh
COAST(6m/s)	110kW	224,237kWh
COAST(6m/s)	150kW	266,908kWh

5.4.3 Farms used in simulations

Four types of farms with their respective consumption profiles are used in the simulations, namely dairying, egg production, broiler production and pig farming. These are taken from chapter 3 for the farms simulated by ERA Technology Ltd. The mean hourly consumptions for each month which make up Figs 3.5, 3.7, 3.8 and 3.11 are used. Information on the size and nature of the farms accompanies these figures. The annual electrical consumptions are 65,545kWh, 178,254kWh, 447,163kWh and 52,529kWh respectively.

5.4.4 Tariffs used in simulations

Four tariffs are considered. They are all farm tariffs, all for NSHEB area and all for 3 phase supply. Tariffs for other areas in the UK have the same structure in that they are made up of an availability charge and a unit charge, though the the actual costs vary considerably from one Board to another.

A standard tariff (unit charge constant with time of day) and an economy tariff (two sets of unit charges for 0730-2330 and 2300-0730), both with and without a wind turbine generator, are considered and details of the 1988 rates valid to April 1989, which are used in the simulations are shown in Table 4.4. In these tariffs the wind turbine generator supplies the farm and any surplus electricity is fed to the grid. If there is a shortfall between the wind turbine generator and the farm electricity is imported from the grid.

The availability charge for each farm when a wind turbine generator is connected is dependent on the installed capacity which, for the simulations, is calculated from from the mean hourly maximum demand MD and an estimate of the corresponding power factor PFMD. It is then rounded up to the nearest 10kVA. Thus

$$\text{installed capacity (kVA)} = MD * PFMD \qquad 5.1$$

For instance the mean hourly maximum demand for the dairy farm is 45kW and this is due to a combination of machinery all requiring wattless current for excitation. The power factor is estimated at 0.8 and the installed capacity, rounded up to the nearest 10kVA, is 60kVA. For egg production the mean hourly maximum demand is 124kW due to heating in the incubators. A power factor of 0.9 is estimated resulting in an installed capacity of 140kVA. For broiler production the mean hourly maximum demand is

62.8kW due to heating. The installed capacity is estimated at 70kVA. For pig farming the maximum demand of 9.5kW is due to feeding mechanisms with an estimated power factor of 0.8 resulting in an installed capacity of 20kVA.

The availability charge without a wind turbine generator connected are constant and do not depend on maximum demand and corresponding power factor. It is considerably less than the availability charge in the tariffs with wind turbine generators connected.

The total reactive units drawn by the farm is calculated from the annual production AP of the wind turbine generator, its corresponding power factor which is 0.84 in all three cases, the annual imported units AI and a machine factor MF for each type of farm which is a factor of the total consumption due to machinery with a power factor of 0.8. Thus

$$\text{total reactive units (kVArh)} = (AP/0.84)+(MF*AI/0.8) \tag{5.2}$$

The machine factor for dairy farms is 0.7, for egg production 0.2, for broiler production 0.2 and for pig farms 0.1. A charge is made only if the total reactive units drawn exceeds half the number of imported units. There is reactive power charge when a wind turbine generator is not connected.

5.4.5 Description of procedure for simulations

The first step is, for each combination of site and machine, to calculate the mean hourly production of the wind turbine generator. The power curves for the three machines are adjusted to include the effect of the coefficient of variation between one hour in a day and the thirty hours or so in each month that the mean hourly wind speed represents. From the spectral density function in Fig 5.4 (20) showing the distribution of variance in wind speeds as a function of time, it is calculated that, by roughly estimating the area under the spectrum, that the variance lost is approximately 0.6 between one day and one month. The corresponding coefficient of variance assuming a mean wind speed of 5m/s is 0.15. Excluded from the variance analysis is the effect of varying monthly mean wind speeds. The diurnal variation within one day is already accounted for in the wind regimes. Zero skewness in the wind speeds is assumed at this stage of determining the hourly power outputs; the skewness of the annual mean hourly wind speed distribution is taken into account later.

The theory developed in section 4.5.2 concerning the effect of turbulence on power outputs is applied here to account for the coefficient of variation between one day and one month. The turbulence is a coefficient of variation within the hour, this is substituted in equation 4.8 by a coefficient of variation within one month:

$$P_{0.15}(V) = P(V)\,(1+3(0.15)^2) \qquad 5.3$$

where $P_{0.15}(V)$ is the mean hourly power output at wind speed V and corresponding coefficient of variance estimated at 0.15. P(V) is the power output at wind speed V read from Fig 5.3.

Equation 5.3 is only applied to power outputs on the section of the power curve that approximately follows a cubic relation with wind speed ie. within cut-in and rated wind speed. Once the wind is above rated wind speed no adjustment is made to the power curve to account for variations of wind speed between the mean value and the individual hourly values. The so-called "spectral gap" in the spectral density function in Fig 5.4 between ten minutes and one hour means that no adjustment need be made to the power curves to account for the fact that the power outputs are determined using an averaging period of ten minutes and the simulations use hourly values. A real example to support this are turbulence levels measured at Burgar Hill using averaging periods of one hour and ten minutes (21). The recorded turbulence intensities differ only by 0.03 and this has a negligible effect on power output (using equation 4.8 the increase in power outputs on the cubic section of the curve will be approximately 0.27%).

The mean hourly production for each month is then calculated from the mean hourly wind speeds and the adjusted power curves. The annual production is computed from the mean hourly production figures. The difference between it and the annual production calculated from the annual distribution of individual mean hourly wind speeds in section 5.5.2 is then distributed evenly over all the mean hourly productions. This action takes account of the skewness of the wind speed distribution over long periods of time, viz. one year.

The mean hourly mismatch with the farm load is then computed by subtracting mean hourly production from mean hourly consumption. If the resultant mismatch is positive the deficit production is imported from the grid and if it is negative the surplus production is exported to the grid.

The annual import and export for day-time hours (0730-2330) and night-time hours (2330-0730) and hence the bills for each combination of site, machine and farm type with and without a wind turbine generator on a farm standard tariff and a farm economy tariff are computed.

A simple life cycle costing model, as applied in section 4.8.2, is applied to each machine for each combination of site, farm and tariff taking into account all the capital costs, grants and the annual maintenance costs as in Table 5.1. Maximum grants for both favoured and less-favoured areas have been used assuming the farms employ more than 2.1 labour units, net income per labour unit is in excess of £10,000 per annum and that the problem of showing economic return within six years can be overcome (see section 5.4.2). The annual savings of all the combinations, calculated by subtracting the annual bill with a wind turbine generator from the equivalent bill without a wind turbine generator, are transposed to the life cycle costing model as annual incomes. Pay-back periods are evaluated assuming a 5% discount rate (section 4.8.2).

5.4.6 Results of simulations

The summarised results of the simulations are shown in Tables 5.2 to 5.5 for each farm type. The annual savings for each combination of site, machine, and tariff are shown by bar charts in Figs 5.5 to 5.8 for each type of farm. In all cases the standard tariff gives higher annual savings than the economy tariff. This can be attributed to the fact that the cost of importing electricity from the grid at night-time on the economy tariff is the same whether or not a wind turbine generator is installed. Even during the day on an economy tariff the saving per imported unit is only 0.65p whereas with the standard tariff the saving is 0.66p per imported unit. Also the tariff structure is such that, as regards exporting electricity to the grid, the economy tariff is less favourable due to the generally higher day-time utilisation factors which can be seen in Tables 5.2 to 5.5. The higher day-time production is more than absorbed by the higher day-time consumption except in most of the dairy farms scenarios. The result of this is that less electricity is exported to the grid in the day-time.

Once the life cycle costing model is applied, taking into account the capital costs and the running costs, the only scenario that is feasible is where a wind turbine generator is connected to a broiler production farm. Even when different levels of grant are applied none of the other scenarios are economically feasible.

On the simulated broiler farm, if a 25% grant is applicable, all three machines have pay-back periods within the design life of twenty years provided the farm is on a standard tariff. The one exception to this is a 150kW machine installed at an inland site. If the farm is on an economy tariff only the 60kW and 110kW machines pay for themselves within the design life regardless of rate of grant (Table 5.4). For a broiler farm which can use all the wind generated electricity locally, the pay-back period is reduced by nine years if the site is coastal with an annual mean wind speed of 6m/s and a mean annual diurnal variation of 1.3m/s rather than inland with a mean wind speed of 5m/s and diurnal variation 0.8m/s.

Dairy farms, despite reasonable levels of utilisation and penetration give the worst economic returns (Table 5.2). As simulated dairy farm had a herd size of 100 it is not eligible for grant aid. Apart from this, the poor economic performance of wind turbine generators on dairy farms can be attributed partly to utilisation not being 100% and partly to availability charge and reactive charge. The penetration and utilisation factors for the simulated wind turbine generator on a dairy farm agree closely with a real example of a 22kW machine with an annual production of 57,114kWh in 1987, connected to a dairy farm in Berriedale in Orkney (22) with an annual consumption of 60,260kWh. The resultant penetration and utilisation factors for the corresponding year are 0.47 and 0.50 at Berriedale while in the simulated case with annual production of 63,755kWh and annual consumption of 65,545kWh, the factors are 0.495 and 0.511 respectively.

The peaky nature of the consumption profiles for both dairy and egg production are disadvantages for these types of farms considering a wind installation. This has the effect of decreasing penetration and increasing availability charges.

The poor results for pig farms can be attributed to the low annual consumption (Table 5.5). As mentioned in section 3.5 the simulated pig farm has an uncharacteristically low consumption compared to real examples in the NE of Scotland. As the consumption is not too peaky and due mainly to heating, it is very similar in shape to that for broiler farms. A direct scaling up of the consumption profile is thus possible to make it more realistic for the NE of Scotland and would result in improved pay-back periods. From section 4.8.2 the Eastertown 60kW machine located in an inland wind regime on a pig farm with annual consumption of 380,506kWh, on an economy tariff, has an estimated pay-back period of twelve years with a 33% grant.

The average annual availability charges are £670, £1,410, £763 and £301 for dairy, eggs, broiler and pigs respectively. In fact if the availability charge is eliminated in the egg production case which is the highest, the economics improve considerable although the pay-back periods still do not come within the design life of the machines. The most feasible case for egg production farms with the availability charge eliminated is for the 110kW machine in a coastal region; the resultant pay-back period is 21 years with a 25% grant.

The average annual reactive charges are £640, £477, £257 and £633 for dairy, eggs, broiler and pigs respectively. Eliminating the reactive power charges for any of the farms do not improve the economics to any considerable extent.

In the light of the poor economic results for all farms except broiler farms, the simulations are run again using the more common 2% annual maintenance costs (section 5.3) for all three machines, a site with annual mean wind speed of 7m/s at 10m and 50% utilisation of extra production over that from a coastal site. The latter factor could be brought about by re-distributing the load in order to use the extra production at the high wind speed site. Re-distributing the load may also have the effect of reducing maximum demand and hence availability charges, however this is not included in the subsequent analysis.

Excluding broiler farms, which have already been shown to be economic, pay-back periods for the other farms are considerably reduced; the best results using a standard tariff and 25% grant are tabulated below.

SCENARIO	O&M = 2%	AMWS = 7m/s	PAY-BACK PERIOD
M2, CO, F2	YES		18 yrs
M1, F2		YES	15 yrs
M2, F2		YES	14 yrs
M1, F2	YES	YES	13 yrs
M1, F4	YES	YES	20 yrs
M2, F2	YES	YES	10 yrs
M2, F4	YES	YES	15 yrs
M3, F2	YES	YES	17 yrs

KEY:

O&M - maintenance and operation costs as a percentage of capital cost
AMWS - annual mean wind speed at 10m
CO - coastal site with AMWS = 6m/s
M1 - 60kW wind turbine generator
M2 - 110kW wind turbine generator
M3 - 150kW wind turbine generator
F2 - egg production farm
F4 - pig farm

It can be seen that the benefits of a high annual mean wind speed are greater than reduced maintenance costs, but a combination of the two in conjunction with a 25% grant and utilisation of extra production at high wind speed site in excess of 50%, provides the optimum economic returns for farms other than broiler farms where utilisation is 100%.

5.5 CONCLUSIONS

A high wind regime is generally the most important factor in the economic feasibility of wind installations on farms, followed closely by high utilisation of wind generated electricity and availability of grants. Low maximum demand with corresponding high power factor, use of standard tariff rather than economy tariff and a reduction in maintenance costs are also shown to be important in the economic feasibility of a wind installation.

In particular, a reduction of nine years in the pay-back period is reported for a farm that can use all the wind generated electricity located in a wind regime with an increase in annual mean wind speed of 1m/s and in mean annual diurnal variation of 0.5m/s.

In the simulations the most economically viable machines are those connected to broiler farms.

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Table 5.1 Simulated annual maintenance costs as a percentage of capital cost (ref 2)

	WIND TURBINE GENERATOR AGE							
SIZE	1	2	3	4	5	6	7	Mean
50 - 65kW	-	0.2	1.1	2.8	1.4	1.4	2.9	2.6*
75 - 90kW	1.8	0.9	1.0	2.7				1.6
95 - 130kW	4.1	4.9	4.8					4.5
150 - 300kW	6.5	5.7						6.5

* - the mean figures are distorted due to different numbers of machines in each age group

KEY FOR TABLES 5.2 - 5.5 AND FIGURES 5.6 - 5.8

IN - Inland wind regime with annual mean wind speed = 5m/s at 10m
CO - Coastal wind regime with annual mean wind speed = 6m/s at 10m
M1 - 60kW wind turbine generator
M2 - 110kW wind turbine generator
M3 - 150kW wind turbine generator
F1 - dairy farm
F2 - egg production farm
F3 - broiler farm
F4 - pig farm

Table 5.2 Results of simulations for WTG's on dairy farms

	IN/M1/F1	IN/M2/F1	IN/M3/F1	CO/M1/F1	CO/M2/F1	CO/M3/F1
import day	20969	16399	11549	15787	7259	4114
import night	12120	9416	6627	9934	15068	4237
export day	21432	75116	77671	47913	126373	151031
export night	9683	30082	33046	17802	54195	57600
actual day cons	44039	44039	44039	44039	44039	44039
actual night cons	21506	21506	21506	21506	21506	21506
consumption	65545	65545	65545	65545	65545	65545
production	63755	145175	158097	105551	224237	266908
reactive (kVArh)	72084	136403	142980	103067	200862	228879
chargeable kVArh	55540	123496	133892	90206	189699	224704
reactive charge	261.04	580.43	629.29	423.97	891.58	1056.11
day penetration	0.524	0.628	0.738	0.642	0.835	0.907
night penetration	0.436	0.562	0.692	0.538	0.299	0.803
mean penetration	0.495	0.606	0.723	0.608	0.659	0.873
day utilisation	0.518	0.269	0.295	0.371	0.225	0.209
night utilisation	0.492	0.287	0.310	0.394	0.106	0.231
mean utilisation	0.511	0.274	0.300	0.377	0.193	0.215
standard tariff:						
bill with WTG	1848.36	461.02	61.95	1034.69	-787.36	-1776.51
bill without WTG	3479.00	3479.00	3479.00	3479.00	3479.00	3479.00
saving	1630.64	3017.97	3417.05	2444.30	4266.36	5255.50
economy tariff:						
bill with WTG	1596.17	241.35	-94.55	805.24	-1177.55	-1936.23
bill without WTG	2920.67	2920.67	2920.67	2920.67	2920.67	2920.67
saving	1324.51	2679.33	3015.22	2115.43	4098.23	4856.91
capital cost	50611	72386	114287	50611	72386	114287
annual O&M cost	1118	2768	4370	1118	2768	4370
max grant (15%)	0	0	0	0	0	0
max grant (25%)	0	0	0	0	0	0
pay-back period with no grant:						
farm standard	>30 yrs	>30 yrs	>30 yrs	>30 yrs	>30 yrs	>30 yrs
farm economy	>30 yrs	>30 yrs	>30 yrs	>30 yrs	>30 yrs	>30 yrs
pay-back period outwith less-favoured areas with 15% grant:						
farm standard	>30 yrs	>30 yrs	>30 yrs	>30 yrs	>30 yrs	>30 yrs
farm economy	>30 yrs	>30 yrs	>30 yrs	>30 yrs	>30 yrs	>30 yrs
pay-back period in less-favoured areas with 25% grant:						
farm standard	>30 yrs	>30 yrs	>30 yrs	>30 yrs	>30 yrs	>30 yrs
farm economy	>30 yrs	>30 yrs	>30 yrs	>30 yrs	>30 yrs	>30 yrs

REFER TO KEY FOR ABBREVIATIONS
ALL MONETARY VALUES ARE IN POUNDS STERLING

Table 5.3 Results of simulations for WTG's on egg production farms

	IN/M1/F2	IN/M2/F2	IN/M3/F2	CO/M1/F2	CO/M2/F2	CO/M3/F2
import day	85955	66137	61515	72015	51471	46821
import night	41881	35425	33920	38606	29495	27006
export day	6445	44880	47663	24167	90611	113763
export night	6709	23356	27603	13739	35887	47633
actual day cons	124013	124013	124013	124013	124013	124013
actual night cons	54241	54241	54241	54241	54241	54241
consumption	178254	178254	178254	178254	178254	178254
production	63755	145175	158097	105551	224237	266908
reactive (kVArh)	74008	138197	148071	106362	201314	236015
chargeable kVArh	10090	87416	100354	51052	160831	199102
reactive charge	47.42	410.86	471.66	239.94	755.90	935.78
day penetration	0.307	0.467	0.504	0.419	0.585	0.622
night penetration	0.228	0.347	0.375	0.288	0.456	0.502
mean penetration	0.283	0.430	0.465	0.379	0.546	0.586
day utilisation	0.855	0.563	0.567	0.683	0.445	0.404
night utilisation	0.648	0.446	0.424	0.532	0.408	0.364
mean utilisation	0.793	0.529	0.524	0.641	0.435	0.393
standard tariff:						
bill with WTG	6990.62	5141.90	4795.00	5944.58	3472.36	2680.39
bill without WTG	9317.33	9317.33	9317.33	9317.33	9317.33	9317.33
saving	2326.71	4175.43	4522.33	3372.74	5844.96	6636.94
economy tariff:						
bill with WTG	6179.62	4431.53	4120.52	5172.64	2834.90	2093.68
bill without WTG	7924.50	7924.50	7924.50	7924.50	7924.50	7924.50
saving	1744.88	3492.97	3803.98	2751.86	5089.60	5830.82
capital cost	50611	72386	114287	50611	72386	114287
annual O&M cost	1118	2768	4370	1118	2768	4370
max grant (15%)	7592	10858	17143	7592	10858	17143
max grant (25%)	12653	18097	18500	12653	18097	18500
pay-back period with no grant:						
farm standard	>30 yrs	>30 yrs	>30 yrs	>30 yrs	>30 yrs	>30 yrs
farm economy	>30 yrs	>30 yrs	>30 yrs	>30 yrs	>30 yrs	>30 yrs
pay-back period outwith less-favoured areas with 15% grant:						
farm standard	>30 yrs	>30 yrs	>30 yrs	>30 yrs	>30yrs	>30yrs
farm economy	>30 yrs	>30 yrs	>30 yrs	>30 yrs	>30yrs	>30yrs
pay-back period in less-favoured areas with 25% grant:						
farm standard	>30 yrs	>30 yrs	>30 yrs	>30 yrs	>30yrs	>30yrs
farm economy	>30 yrs	>30 yrs	>30 yrs	>30 yrs	>30yrs	>30yrs

REFER TO KEY FOR ABBREVIATIONS
ALL MONETARY VALUES ARE IN POUNDS STERLING

Table 5.4 Results of simulations for WTG's on broiler farms

	IN/M1/F3	IN/M2/F3	IN/M3/F3	CO/M1/F3	CO/M2/F3	CO/M3/F3
import day	256113	197859	190454	224450	137462	109659
import night	127479	104376	98624	117174	85916	71679
export day	0	0	0	0	0	0
export night	0	0	0	0	0	0
actual day cons	300615	300615	300615	300615	300615	300615
actual night cons	146548	146548	146548	146548	146548	146548
consumption	447163	447163	447163	447163	447163	447163
production	63755	145175	158097	105551	224237	266908
reactive (kVArh)	114929	170305	179054	143323	224099	253217
chargeable kVArh	0	19187	34515	0	112411	162548
reactive charge	0.00	90.18	162.22	0.00	528.33	763.97
day penetration	0.148	0.342	0.366	0.253	0.543	0.635
night penetration	0.130	0.288	0.327	0.200	0.414	0.511
mean penetration	0.142	0.324	0.354	0.236	0.500	0.594
day utilisation	1.000	1.000	1.000	1.000	1.000	1.000
night utilisation	1.000	1.000	1.000	1.000	1.000	1.000
mean utilisation	1.000	1.000	1.000	1.000	1.000	1.000
standard tariff:						
bill with WTG	18101.19	14514.04	13991.35	16204.22	11387.83	9723.31
bill without WTG	23246.80	23246.80	23246.80	23246.80	23246.80	23246.80
saving	5145.61	8732.77	9255.46	7042.59	11858.98	13523.49
economy tariff:						
bill with WTG	15580.10	12419.07	12020.94	13858.44	9597.34	8216.44
bill without WTG	19378.58	19378.58	19378.58	19378.58	19378.58	19378.58
saving	3798.48	6959.51	7357.65	5520.14	9781.24	11162.14
capital cost	50611	72386	114287	50611	72386	114287
annual O&M cost	1118	2768	4370	1118	2768	4370
max grant (15%)	7592	10858	17143	7592	10858	17143
max grant (25%)	12653	18097	18500	12653	18097	18500
pay-back period with no grant:						
farm standard	20 yrs	19 yrs	>30 yrs	11 yrs	10 yrs	20 yrs
farm economy	>30 yrs	>30 yrs	>30 yrs	17 yrs	14 yrs	>30 yrs
pay-back period outwith less-favoured areas with 15% grant:						
farm standard	15 yrs	14 yrs	>30 yrs	9 yrs	8 yrs	15 yrs
farm economy	>30yrs	27 yrs	>30 yrs	13 yrs	11 yrs	25 yrs
pay-back period in less-favoured areas with 25% grant:						
farm standard	13 yrs	12 yrs	>30 yrs	7 yrs	7 yrs	15 yrs
farm economy	25 yrs	21 yrs	>30 yrs	11 yrs	10 yrs	25 yrs

REFER TO KEY FOR ABBREVIATIONS
ALL MONETARY VALUES ARE IN POUNDS STERLING

Table 5.5 Results of simulations for WTG's on pig farms

	IN/M1/F4	IN/M2/F4	IN/M3/F4	CO/M1/F4	CO/M2/F4	CO/M3/F4
import day	3153	556	0	353	31	0
import night	627	0	0	86	92	0
export day	9643	65300	72149	38506	125171	152943
export night	5179	27655	33408	14943	46207	60352
actual day cons	38013	38013	38013	38013	38013	38013
actual night cons	14517	14517	14517	14517	14517	14517
consumption	52529	52529	52529	52529	52529	52529
production	63755	145175	158097	105551	224237	266908
reactive (kVArh)	53857	121991	132801	88698	188369	224203
chargeable kVArh	51966	121713	132801	88479	188308	224203
reactive charge	244.24	572.05	624.17	415.85	885.05	1053.75
day penetration	0.917	0.985	1.000	0.991	0.999	1.000
night penetration	0.957	1.000	1.000	0.994	0.994	1.000
mean penetration	0.928	0.989	1.000	0.992	0.998	1.000
day utilisation	0.783	0.365	0.345	0.494	0.233	0.199
night utilisation	0.728	0.344	0.303	0.491	0.238	0.194
mean utilisation	0.767	0.359	0.332	0.494	0.234	0.198
standard tariff:						
bill with WTG	440.27	-830.93	-1038.34	-257.63	-1996.22	-2612.70
bill without WTG	2804.78	2804.78	2804.78	2804.78	2804.78	2804.78
saving	2364.51	3635.71	3843.13	3062.41	4801.01	5417.48
economy tariff:						
bill with WTG	434.08	-847.47	-1047.94	-274.36	-2057.40	-2670.73
bill without WTG	2452.24	2452.24	2452.24	2452.24	2452.24	2452.24
saving	2018.17	3299.71	3500.19	2726.61	4509.64	5122.97
capital cost	50611	72386	114287	50611	72386	114287
annual O&M cost	1118	2768	4370	1118	2768	4370
max grant (15%)	7592	10858	17143	7592	10858	17143
max grant (25%)	12653	18097	18500	12653	18097	18500
pay-back period with no grant:						
farm standard	>30 yrs	>30 yrs	>30 yrs	>30 yrs	>30 yrs	>30 yrs
farm economy	>30 yrs	>30 yrs	>30 yrs	>30 yrs	>30 yrs	>30 yrs
pay-back period outwith less-favoured areas with 15% grant:						
farm standard	> 30yrs	> 30yrs	> 30yrs	> 30yrs	> 30yrs	> 30yrs
farm economy	> 30yrs	> 30yrs	> 30yrs	> 30yrs	> 30yrs	> 30yrs
pay-back period in less-favoured areas with 25% grant:						
farm standard	> 30yrs	> 30yrs	> 30yrs	> 30yrs	> 30yrs	> 30yrs
farm economy	> 30yrs	> 30yrs	> 30yrs	> 30yrs	> 30yrs	> 30yrs

REFER TO KEY FOR ABBREVIATIONS
ALL MONETARY VALUES ARE IN POUNDS STERLING

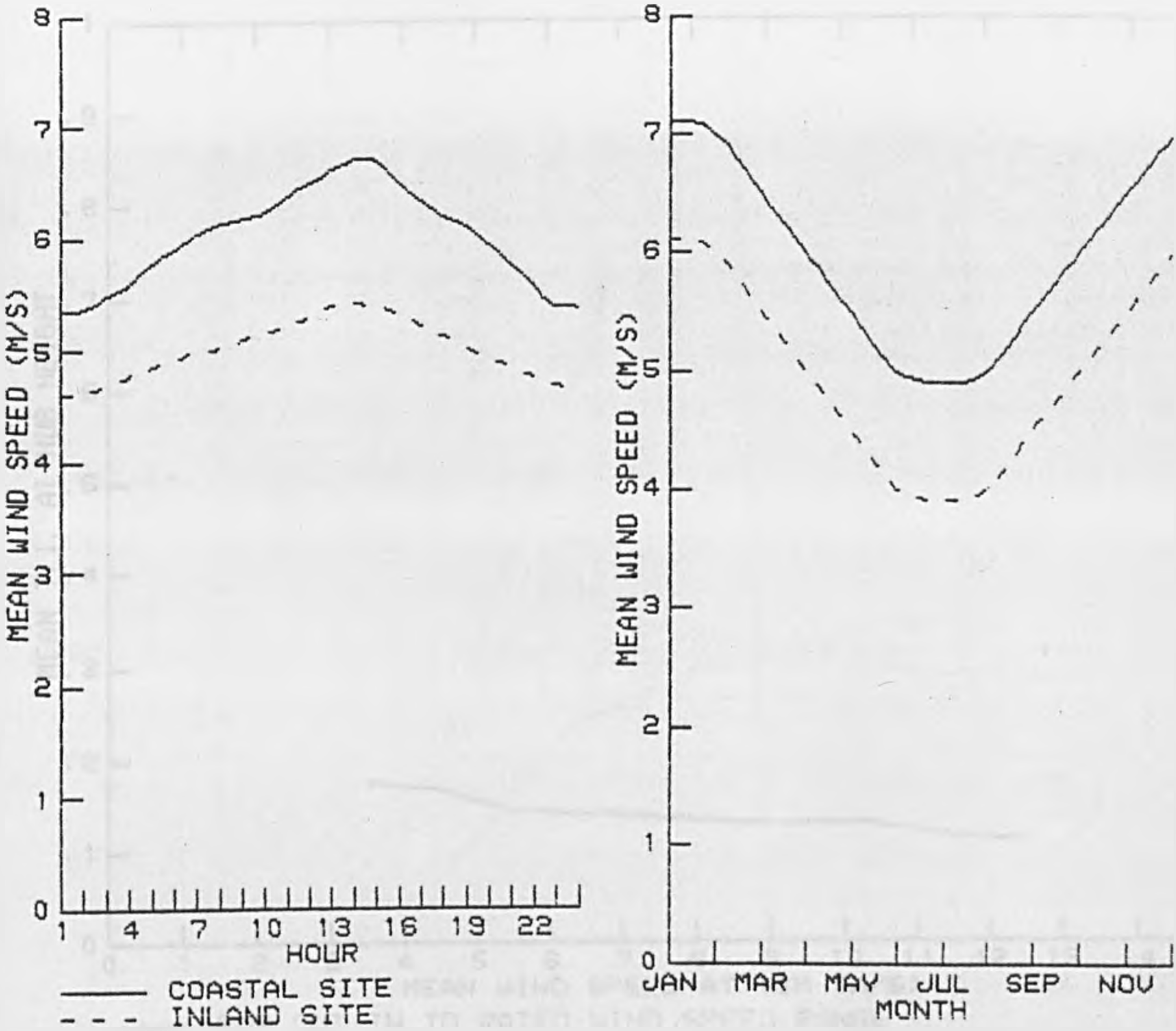

Fig 5.1 Mean hourly and monthly wind regimes used in simulations

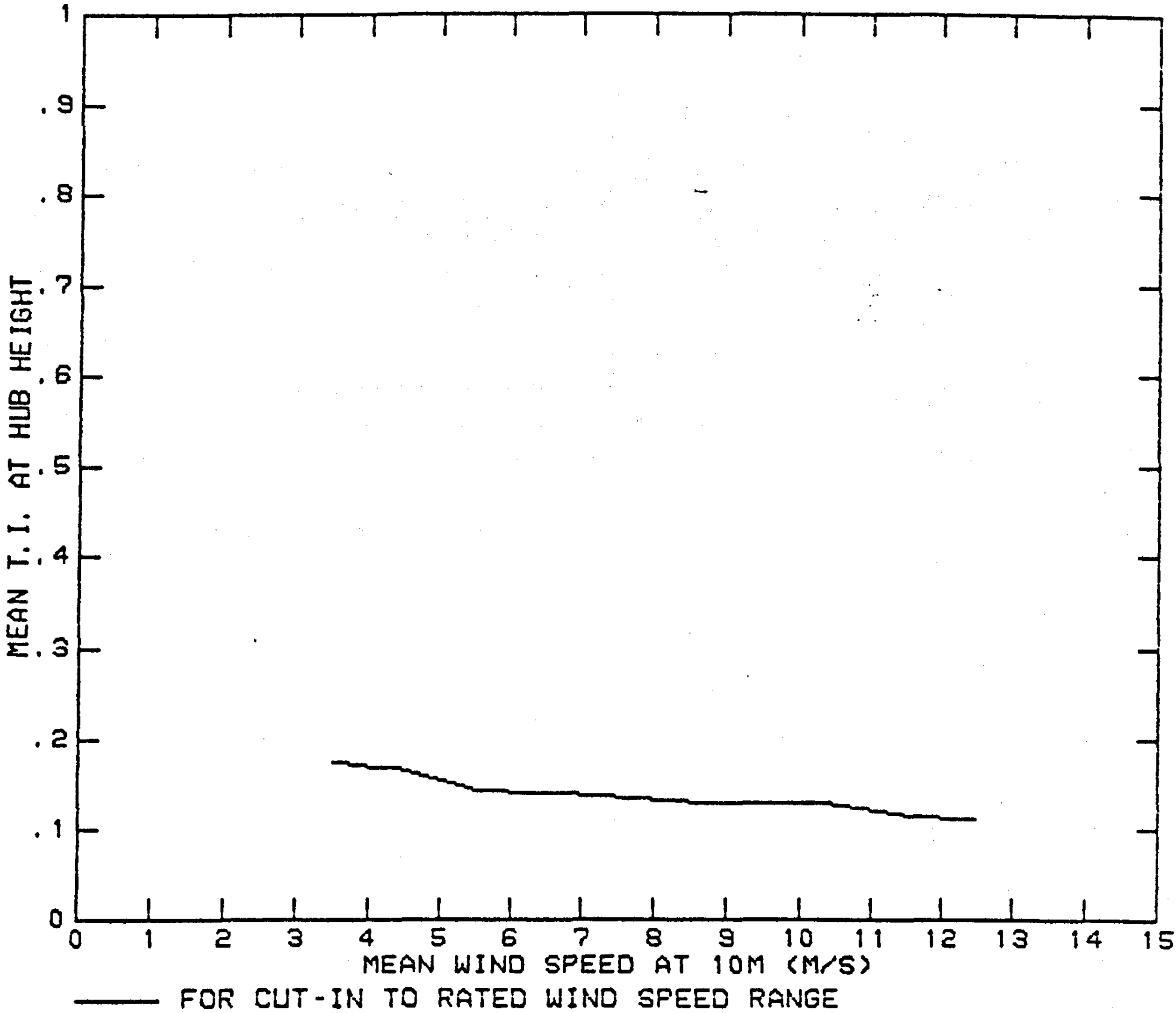

Fig 5.2 Variation of turbulence with wind speed

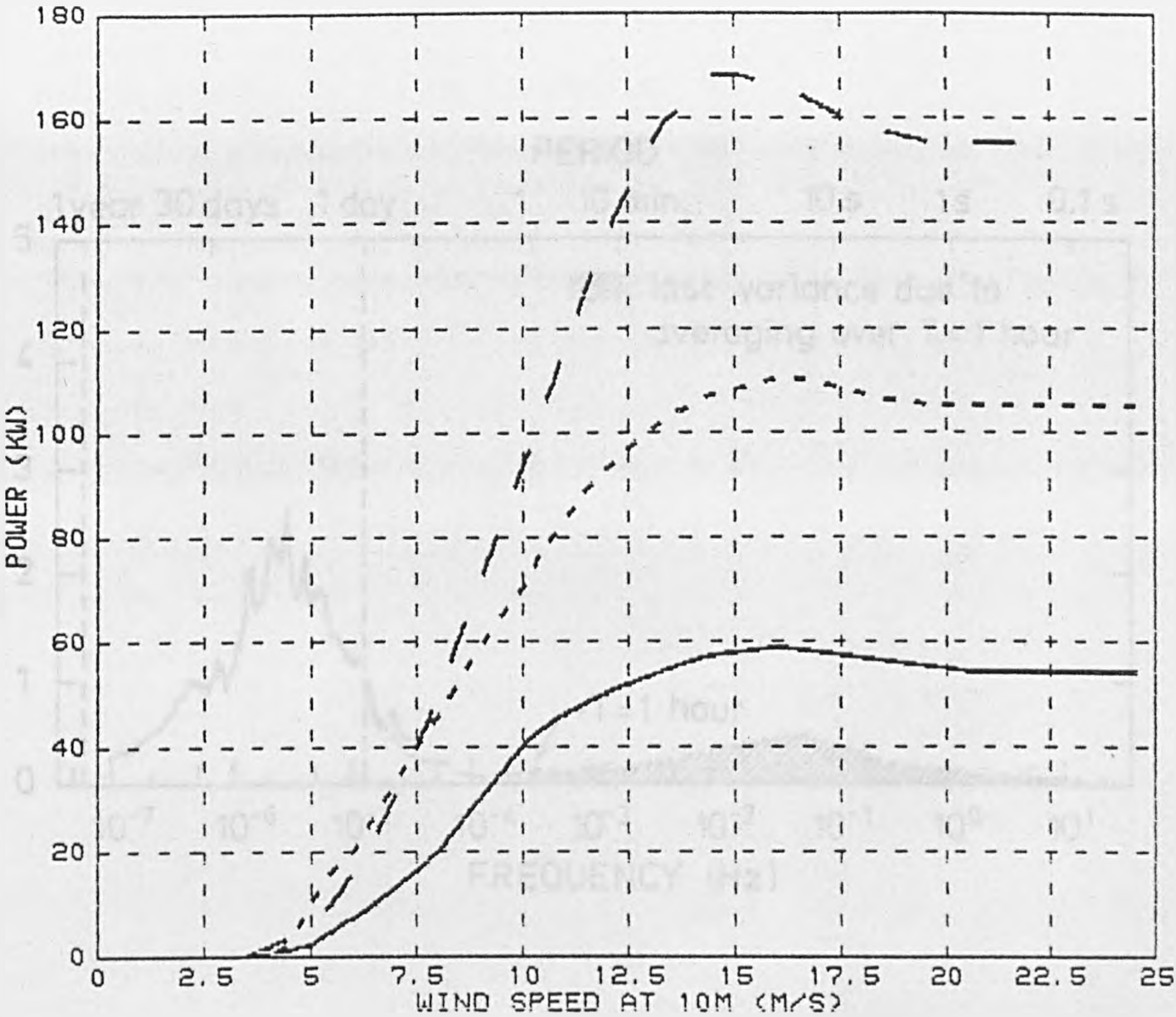

Fig 5.3 Power curves for wind turbine generators used in simulations

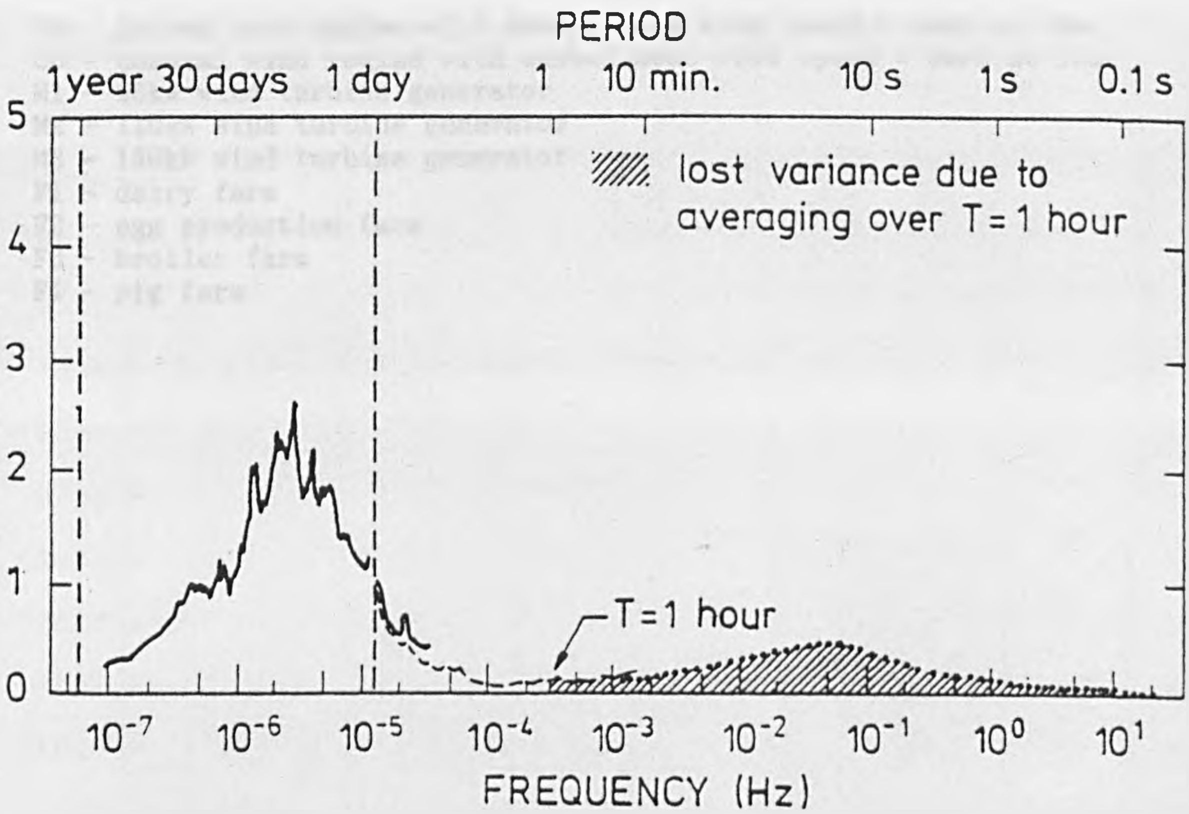

Fig 5.4 Spectral density function for wind speeds (from Windatlas for Denmark (19))

KEY FOR TABLES 5.2 - 5.5 AND FIGURES 5.6 - 5.8

IN - Inland wind regime with annual mean wind speed = 5m/s at 10m
CO - Coastal wind regime with annual mean wind speed = 6m/s at 10m
M1 - 60kW wind turbine generator
M2 - 110kW wind turbine generator
M3 - 150kW wind turbine generator
F1 - dairy farm
F2 - egg production farm
F3 - broiler farm
F4 - pig farm

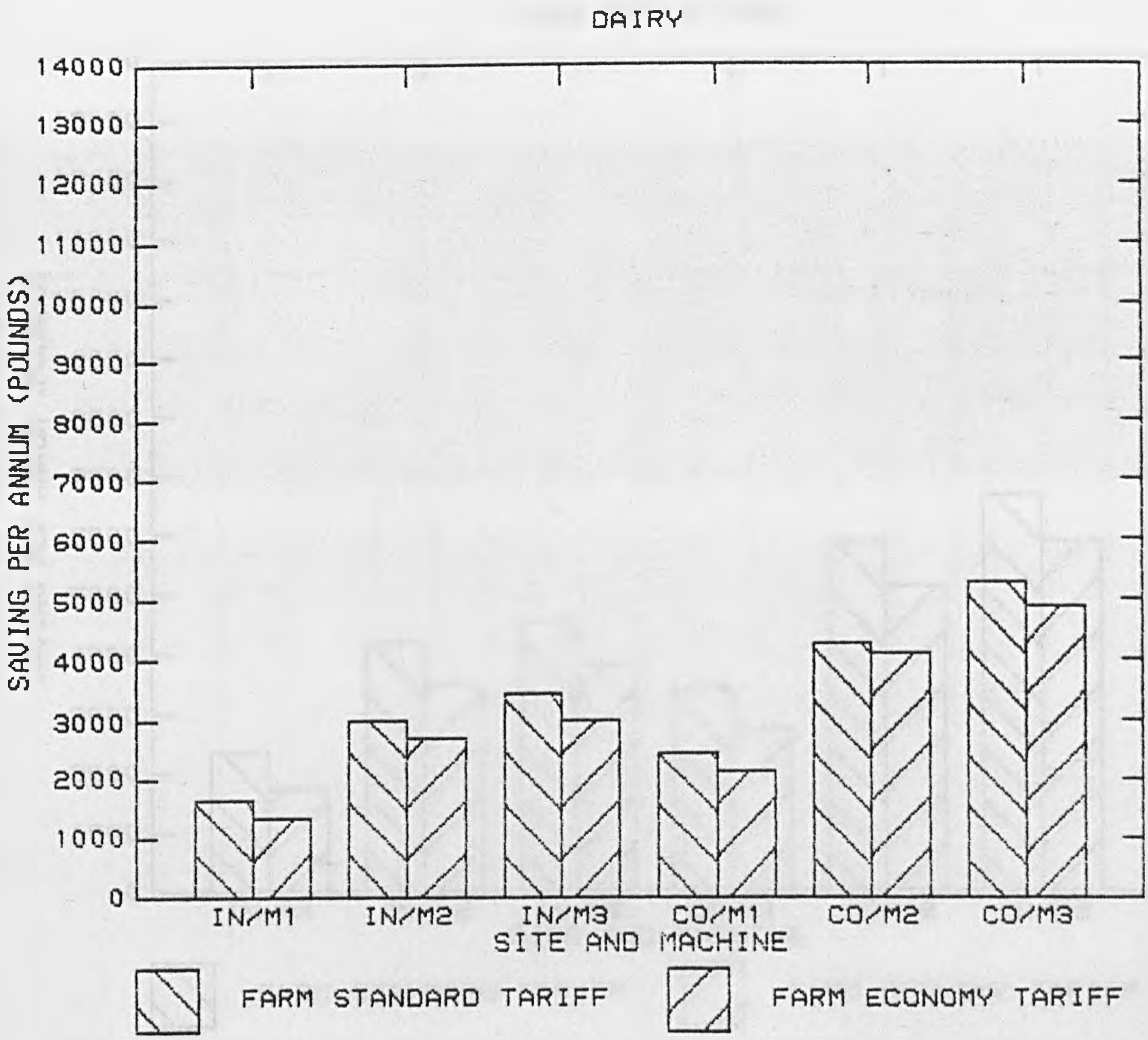

Fig 5.5 Annual savings on electricity bills for simulated dairy farms

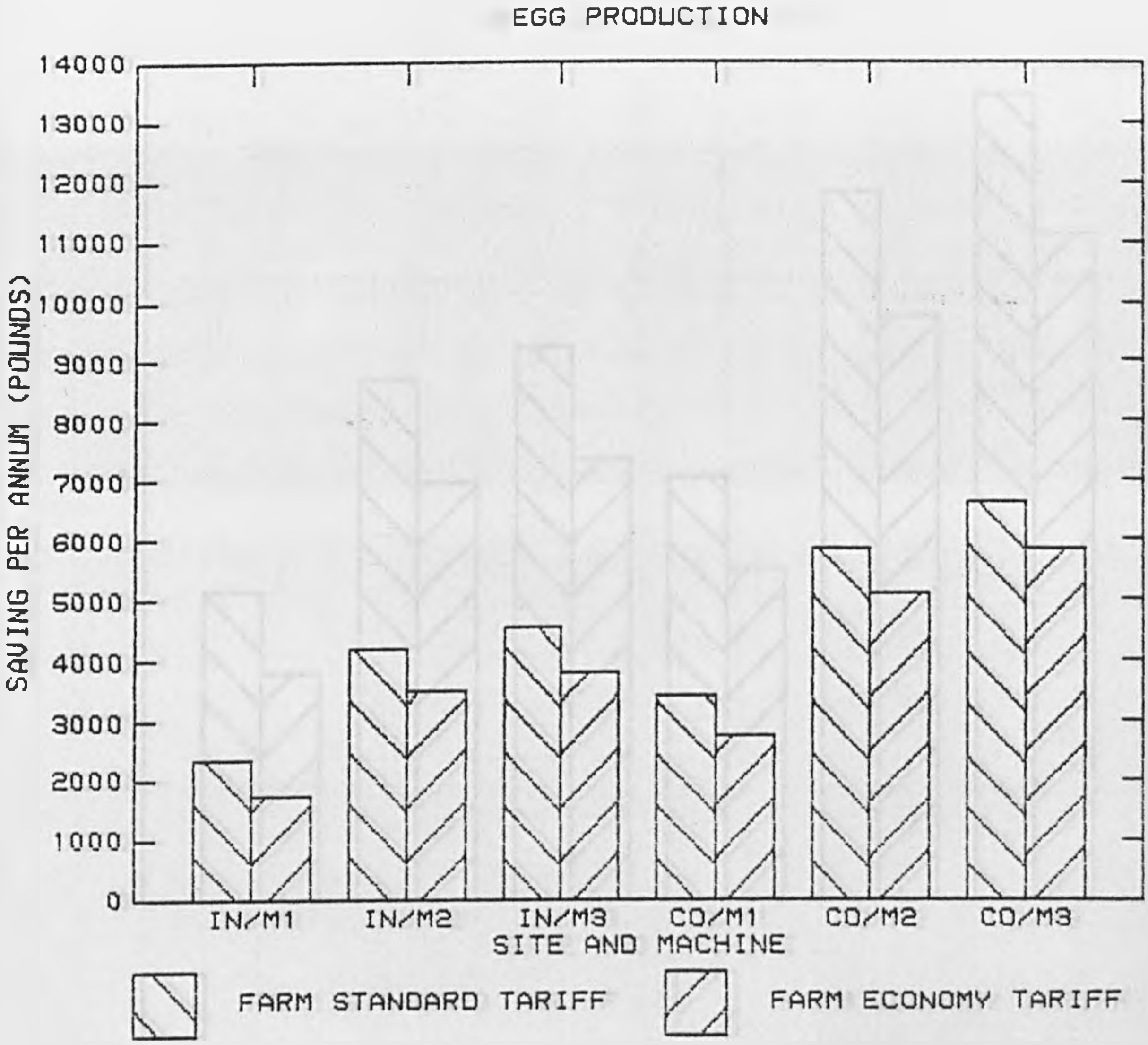

Fig 5.6 Annual savings on electricity bills for simulated egg production farms

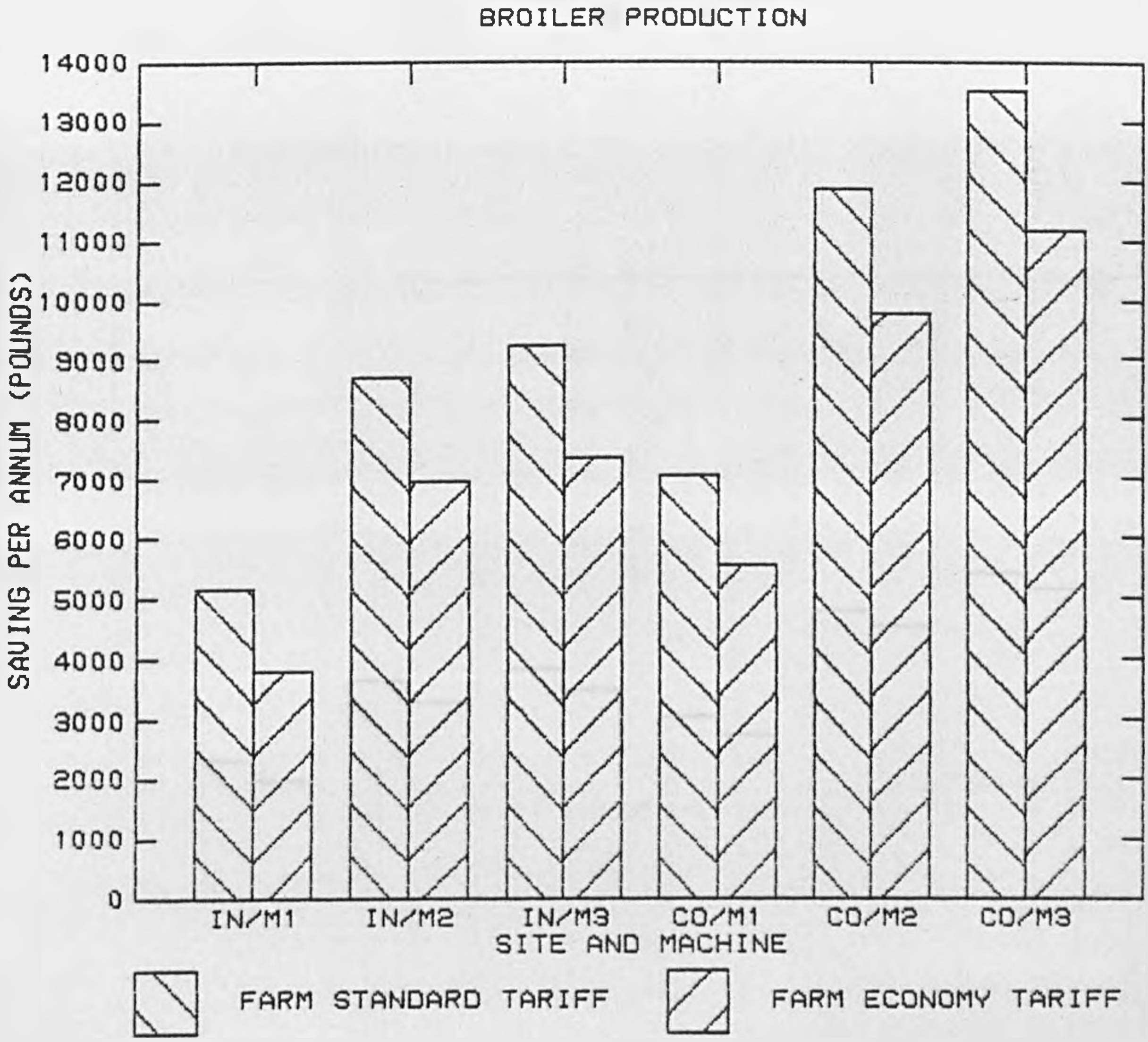

Fig 5.7 Annual savings on electricity bills for simulated broiler farms

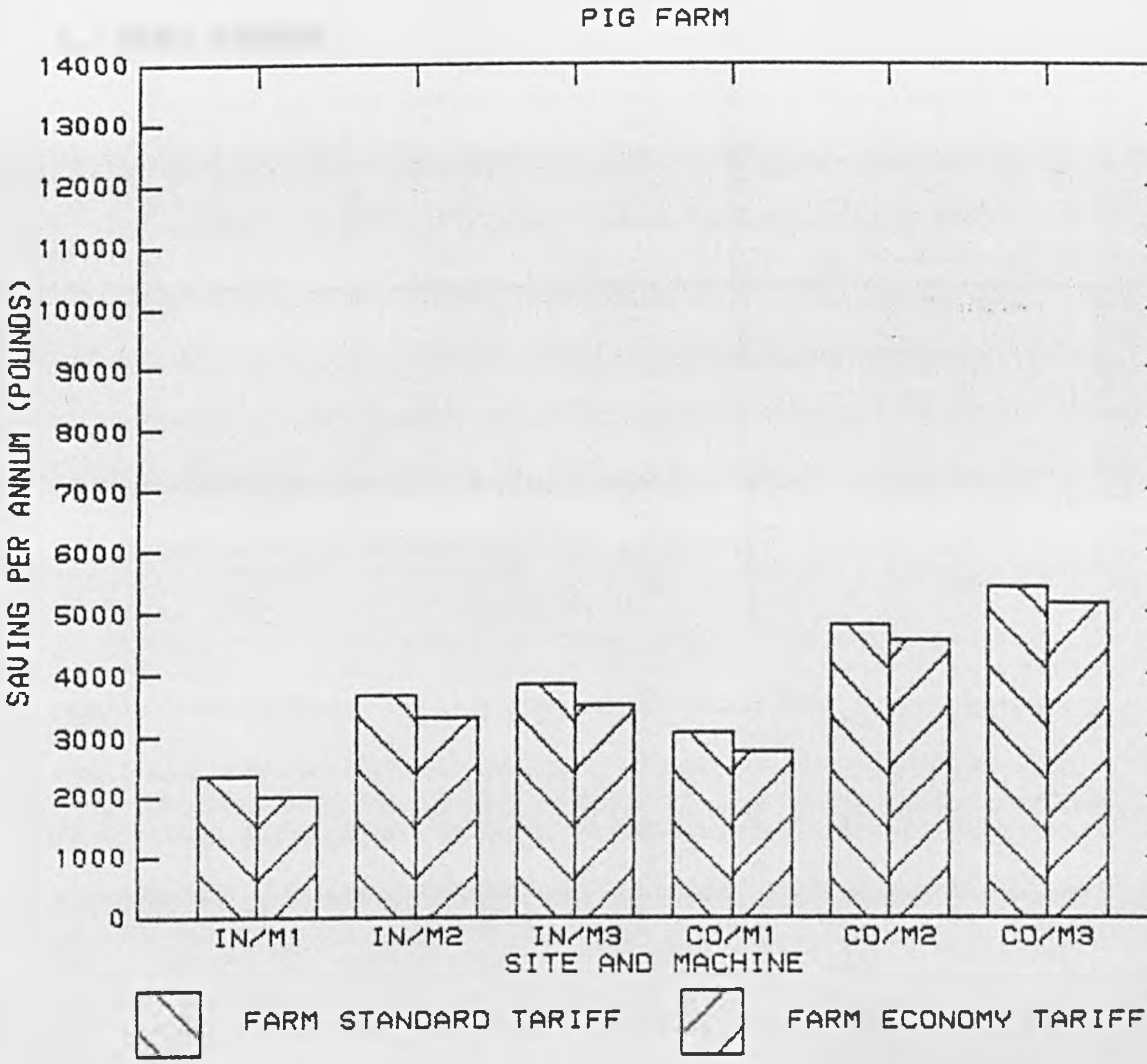

Fig 5.8 Annual savings on electricity bills for simulated pig farms

6. FINAL REMARKS

6. FINAL REMARKS

The aims of this project as stated in the first chapter are:

(1) to develop a wind prediction model which gives good estimates of energy output from a wind turbine generator at a site where there is no data available.

(2) to assess energy usage for various types of agricultural enterprise with a view to utilising wind energy.

(3) to assess the economics and practicalities of a wind energy installation at an agricultural enterprise.

A wind prediction model has been successfully developed which applies correction factors to wind data from the nearest available meteorological station. These corrections allow for directional differences in local terrain characteristics such as topography, surface roughness and altitude which affect the wind flow between the source site and the prediction site. The model is validated with real data at the prediction sites and is shown to predict long-term and monthly mean wind speeds with good accuracy.

After an initial inspection of energy portfolios for a variety of farm types, dairy and intensive animal farms such as pigs and poultry were focused on as being suitable for wind energy applications. Detailed monthly and daily electrical consumption profiles are derived using the little literature found to be available and some data collection in the NE of Scotland for these types of farms.

Experience is described of a 60kW wind turbine generator connected to a pig farm in the NE of Scotland with respect to wind regime, performance, daily consumption pattern and overall economics. The difficulties in determining the actual power curve such as non-representativity of wind speeds for driving speeds of the rotor, high turbulence at site and use of a low cost monitoring system are highlighted in this section.

In general, for wind turbine generators on farms, although a good wind regime and availability of grants are of prime importance in the overall economic viability of the installation, the ability to use all the electricity on the farm rather than sell it to the grid is also, in the present tariff structure, crucial. The lower charges for imported units if a wind turbine generator is connected can help to offset the currently poor buy-back rates for exported units. However the combination of the poor buy-back rates, high availability charges and the charge made for reactive power drawn can together be detrimental to the economics of a wind installation. Other factors which affect the economics of a wind installation on a farm are nature of load on farm, maintenance costs for wind turbine generator and choice of tariff. However it is not necessary for all the factors to contribute a positive effect as is demonstrated in the Eastertown installation. The economic feasibility of the Eastertown wind turbine generator cannot be attributed to wind regime and energy yield, but rather to the high utilisation and grant availability.

As both the wind regime and utilisation are important to the economics of a wind installation at a farm it is vitally important to be able to predict the wind regime at the site. The minimum requirement is the ability to predict annual mean wind speeds and hence annual energy outputs accurately. The prediction model can predict energy outputs to generally within 7% for the six pairs of sites used in the validation process. If, for all sites it is assumed that annual energy outputs can be predicted with certainty to within 10%, the resultant effect of a maximum error in prediction of energy output on the pay-back periods is at maximum, one and a half years. As this is short compared to the design life of a typical wind turbine generator, which is normally in excess of twenty years, the prediction model is an essential tool in assessing the economic feasibility of a wind installation on a farm.

Even if there is short-term wind data in the order of a few months available for the proposed wind turbine generator site the long-term wind speeds, which affect the economics to a greater extent, from the nearest available meteorological station in conjunction with the prediction model, will give more accurate estimates of overall economic feasibility. However there is scope for possible improvement of the prediction model by using short periods of data collected at the site to determine diurnal variations and turbulence.

The high initial capital cost nature of wind installations compared to annual running costs make them difficult to finance, and in the case of a small farmer he is dependent on the grants to reduce this initial expenditure. The initial capital expenditure could possibly be reduced if local manufacturing of wind turbine generators were encouraged; at present in Britain there are very few wind turbine manufacturers and, of the number of privately owned machines in the UK, the majority of them are manufactured on mainland Europe. This also has the effect of increasing maintenance costs. Local mass production of machines would reduce the capital costs considerably.

However, primarily, a complete overhaul of the tariff structure is required for an increase in the use of private wind turbine generators connected at farms. The Energy Act of 1983 (1) served to provide a basis for encouraging private generators to connect to the grid, however it has not succeeded as regards reasonable buy-back rates. The method of calculation of the "avoided cost" incurred by the Electricity Board which is the basis for assessing buy-back rates is suitably vague in the Act and has resulted in very poor rates. However the problem not only lies in the buy-back rates but in the inconsistent availability charges, import charges and reactive charges for farms with and without wind turbine generators. The inconsistencies are attributed to "the use of the Electricity Board's distribution network for the supply of wind generated electricity to the farm and grid", but it is still difficult to see why the charges are so high.

Wind energy in general should receive a boost in the present "greening" of the Government and in particular, in the wake of the Pearce Report (2) which proposes taxes to be levied on polluters. Perhaps in addition to this, wind energy, as an "anti-polluter", could be positively encouraged by allocation of more subsidies. These subsidies could be based on monetary values attached to the environmental benefits, amongst other social benefits, as determined by a report recently submitted to the Commission of European Communities (3). It is shown in this study that the impact of excluding social costs in electricity generation puts wind energy at a considerable disadvantage compared to the other more conventional forms of electricity generation.

REFERENCES FOR CHAPTER 6

(1) EVANS J, 1984, "The Energy Act - Statutory aspects" in BWEA, "The Energy Act and other institutional aspects of wind power generation", proceedings of the day meeting held at the University of Strathclyde, Feb 1984.

(2) PEARCE D et al, 1989, "The implications of sustainable development for resource accounting, project appraisal and integrative environmental policy", 180pp, The London Environmental Economics Centre, 4 Taviton St, London WC1.

(3) HOHMEYER O, 1988, "Social costs of energy consumption", Springer-Verlag, 125pp.

APPENDIX A

DERIVATION OF CORRECTION FACTORS FOR ALL SETS OF SOURCE SITES AND PREDICTION SITES

1. DYCE/EASTERTOWN

2. DYCE/PETERHEAD

3. PETERHEAD/EASTERTOWN

4. LERWICK/SCROO HILL 20M

5. LERWICK/SCROO HILL 35M

6. LERWICK/SUSETTER HILL 20M

7. PRESTWICK/MYRES HILL

Non-	Source site	Dyce					
directional	Prediction site	Eastertown					
input	Distance	22km					
	Ht.of anemometer h	10	10	10	10	10	10
	Ht.of prediction H	12	12	12	12	12	12
ALL LENGTHS/HEIGHTS ARE IN METRES		SectorA 345-045	SectorB 045-105	SectorC 105-165	SectorD 165-225	SectorE 225-285	SectorF 285-345
Source site	Rg.length near anemometer ZY	0.010	0.010	0.010	0.010	0.010	0.010
topography	Distance to transition D1	5000.00	550.00	750.00	5000.00	625.00	5000.00
and	Rg.length beyond transition ZX	0.010	0.300	0.300	0.010	0.250	0.010
roughness	Base ht.of x-section X1	58.00	58.00	58.00	58.00	58.00	58.00
	Inverse topography factor F2	0.982	1.000	0.982	1.034	1.044	1.054
Prediction	Base ht.of x-section X2	105.00	105.00	105.00	105.00	105.00	105.00
site	Rg.length near site ZY1	0.050	0.050	0.050	0.050	0.050	0.200
topography	Distance to transition D2	5000.00	5000.00	5000.00	5000.00	5000.00	50.00
and	Rg.length beyond transition ZX1	0.050	0.050	0.050	0.050	0.050	0.050
roughness	Topography factor F4	0.822	0.935	1.000	1.000	0.958	0.882
Computation	Ht. of base of transition zone h1	219.790	0.293	0.742	219.790	0.429	219.790
of hub ht.	Factor if ZX=ZY, no transition	1.026	1.000	1.000	1.026	1.000	1.026
factor at	Ht. of top of transition zone h2	253.673	85.667	109.792	253.673	91.493	253.673
source site	Weighting factor if h1<h<h2	-21.553	0.622	0.521	-21.553	0.587	-21.553
eliminating	Factor if h1<h<h2	1.026	1.319	1.260	1.026	1.275	1.026
nearby	Factor if h>h2	1.026	1.319	1.260	1.026	1.275	1.026
transitions	Factor if h<h1	1.026	1.319	1.260	1.026	1.275	1.026
Computation	h1 (site)	356.204	356.204	356.204	356.204	356.204	0.001
of site	Factor if ZX1=ZY1	0.859	0.859	0.859	0.859	0.859	1.000
roughness	h2 (site)	350.000	350.000	350.000	350.000	350.000	11.601
factor	Weighting factor at site	192.965	192.965	192.965	192.965	192.965	1.003
including	Factor if h1<H<h2	0.859	0.859	0.859	0.859	0.859	0.859
effect	Factor if H>h2	0.859	0.859	0.859	0.859	0.859	0.859
of nearby	Factor if H<h1	0.859	0.859	0.859	0.859	0.859	1.000
transitions	Roughness factor	0.859	0.859	0.859	0.859	0.859	0.859
	Roughness factor if F4>1	1.000	1.000	1.000	1.000	1.000	1.000
	Roughness factor if F4<=1	0.859	0.859	0.859	0.859	0.859	0.859
Final	F1	1.026	1.319	1.260	1.026	1.275	1.026
factors	F2	0.982	1.000	0.982	1.034	1.044	1.054
	F3	1.047	1.047	1.047	1.047	1.047	1.047
	F4	0.822	0.935	1.000	1.000	0.958	0.882
	F5	0.859	0.859	0.859	0.859	0.859	0.859
Results	Directional correction factor	0.745	1.109	1.113	0.954	1.147	0.858

Non-directional input	Source site	Dyce					
	Prediction site	Peterhead					
	Distance	42					
	Ht.of anemometer h	10	10	10	10	10	10
	Ht.of prediction H	18	18	18	18	18	18
ALL LENGTHS/HEIGHTS ARE IN METRES		SectorA 345-045	SectorB 045-105	SectorC 105-165	SectorD 165-225	SectorE 225-285	SectorF 285-345
Source site topography and roughness	Rg.length near anemometer ZY	0.010	0.010	0.010	0.010	0.010	0.010
	Distance to transition D1	5000.00	550.00	750.00	5000.00	625.00	5000.00
	Rg.length beyond transition ZX	0.010	0.300	0.300	0.010	0.250	0.010
	Base ht.of x-section X1	58.00	58.00	58.00	58.00	58.00	58.00
	Inverse topography factor F2	0.982	1.000	0.982	1.034	1.044	1.054
Prediction site topography and roughness	Base ht.of x-section X2	4.00	4.00	4.00	4.00	11.00	15.00
	Rg.length near site ZY1	0.400	0.400	0.300	0.001	0.001	0.600
	Distance to transition D2	625.00	400.00	350.00	5000.00	1000.00	5000.00
	Rg.length beyond transition ZX1	0.001	0.001	0.001	0.001	0.600	0.600
	Topography factor F4	1.004	1.004	1.004	1.004	0.990	0.985
Computation of hub ht. factor at source site eliminating nearby transitions	Ht. of base of transition zone h1	219.790	0.293	0.742	219.790	0.429	219.790
	Factor if ZX=ZY, no transition	1.085	1.000	1.000	1.085	1.000	1.085
	Ht. of top of transition zone h2	253.673	85.667	109.792	253.673	91.493	253.673
	Weighting factor if h1<h<h2	-21.553	0.622	0.521	-21.553	0.587	-21.553
	Factor if h1<h<h2	1.085	1.394	1.332	1.085	1.348	1.085
	Factor if h>h2	1.085	1.394	1.332	1.085	1.348	1.085
	Factor if h<h1	1.085	1.394	1.332	1.085	1.348	1.085
Computation of site roughness factor including effect of nearby transitions	h1 (site)	1.298	0.340	0.209	110.156	0.881	750.678
	Factor if ZX1=ZY1	1.000	1.000	1.000	1.144	1.000	0.608
	h2 (site)	100.511	70.333	59.673	160.057	158.755	575.313
	Weighting factor at site	0.605	0.744	0.788	-4.848	0.581	14.022
	Factor if h1<H<h2	0.952	1.020	1.048	1.144	0.833	0.608
	Factor if H>h2	0.952	1.020	1.048	1.144	0.833	0.608
	Factor if H<h1	1.000	1.000	1.000	1.144	1.000	0.608
	Roughness factor	0.952	1.020	1.048	1.144	0.833	0.608
	Roughness factor if F4>1	0.952	1.020	1.048	1.144	1.000	1.000
	Roughness factor if F4<=1	1.000	1.000	1.000	1.000	0.833	0.608
Final factors	F1	1.085	1.394	1.332	1.085	1.348	1.085
	F2	0.982	1.000	0.982	1.034	1.044	1.054
	F3	0.946	0.946	0.946	0.946	0.953	0.957
	F4	1.004	1.004	1.004	1.004	0.990	0.985
	F5	0.952	1.020	1.048	1.144	0.833	0.608
Results	Directional correction factor	0.963	1.350	1.302	1.219	1.106	0.656

Non-directional input	Source site	Peterhead					
	Prediction site	Eastertown					
	Distance	38km					
	Ht.of anemometer h	18	18	18	18	18	18
	Ht.of prediction H	12	12	12	12	12	12
ALL LENGTHS/HEIGHTS ARE IN METRES		SectorA 345-045	SectorB 045-105	SectorC 105-165	SectorD 165-225	SectorE 225-285	SectorF 285-345
Source site topography and roughness	Rg.length near anemometer ZY	0.400	0.400	0.300	0.001	0.001	0.600
	Distance to transition D1	625.00	400.00	350.00	5000.00	1000.00	5000.00
	Rg.length beyond transition ZX	0.001	0.001	0.001	0.001	0.600	0.600
	Base ht.of x-section X1	4.00	4.00	4.00	4.00	11.00	15.00
	Inverse topography factor F2	0.996	0.996	0.996	0.996	1.010	1.015
Prediction site topography and roughness	Base ht.of x-section X2	105.00	105.00	105.00	105.00	105.00	105.00
	Rg.length near site ZY1	0.050	0.050	0.050	0.050	0.050	0.200
	Distance to transition D2	5000.00	5000.00	5000.00	5000.00	5000.00	50.00
	Rg.length beyond transition ZX1	0.050	0.050	0.050	0.050	0.050	0.050
	Topography factor F4	0.822	0.935	1.000	1.000	0.958	0.882
Computation of hub ht. factor at source site eliminating nearby transitions	Ht. of base of transition zone h1	1.298	0.340	0.209	110.156	0.881	750.678
	Factor if ZX=ZY, no transition	1.000	1.000	1.000	0.959	1.000	0.881
	Ht. of top of transition zone h2	100.511	70.333	59.673	160.057	158.755	575.313
	Weighting factor if h1<h<h2	0.605	0.744	0.788	-4.848	0.581	14.022
	Factor if h1<h<h2	0.618	0.577	0.595	0.959	1.316	0.881
	Factor if h>h2	0.618	0.577	0.595	0.959	1.316	0.881
	Factor if h<h1	0.618	0.577	0.595	0.959	1.316	0.881
Computation of site roughness factor including effect of nearby transitions	h1 (site)	356.204	356.204	356.204	356.204	356.204	0.001
	Factor if ZX1=ZY1	1.380	1.380	1.302	0.741	0.741	1.000
	h2 (site)	350.000	350.000	350.000	350.000	350.000	11.601
	Weighting factor at site	192.965	192.965	192.965	192.965	192.965	1.003
	Factor if h1<H<h2	1.380	1.380	1.302	0.741	0.741	1.517
	Factor if H>h2	1.380	1.380	1.302	0.741	0.741	1.516
	Factor if H<h1	1.380	1.380	1.302	0.741	0.741	1.000
	Roughness factor	1.380	1.380	1.302	0.741	0.741	1.516
	Roughness factor if F4>1	1.000	1.000	1.000	1.000	1.000	1.000
	Roughness factor if F4<=1	1.380	1.380	1.302	0.741	0.741	1.516
Final factors	F1	0.618	0.577	0.595	0.959	1.316	0.881
	F2	0.996	0.996	0.996	0.996	1.010	1.015
	F3	1.101	1.101	1.101	1.101	1.094	1.090
	F4	0.822	0.935	1.000	1.000	0.958	0.882
	F5	1.380	1.380	1.302	0.741	0.741	1.516
Results	Directional correction factor	0.769	0.817	0.850	0.779	1.033	1.303

Non-directional input	Source site	Lerwick					
	Prediction site	Scroo Hill					
	Distance	11km					
	Ht.of anemometer h	10	10	10	10	10	10
	Ht.of prediction H	20	20	20	20	20	20
ALL LENGTHS/HEIGHTS ARE IN METRES		SectorA 345-045	SectorB 045-105	SectorC 105-165	SectorD 165-225	SectorE 225-285	SectorF 285-345
Source site topography and roughness	Rg.length near anemometer ZY	0.200	0.010	0.010	0.010	0.010	0.200
	Distance to transition D1	650.00	1500.00	850.00	1250.00	5000.00	150.00
	Rg.length beyond transition ZX	0.010	0.001	0.001	0.001	0.010	0.010
	Base ht.of x-section X1	80.00	0.00	0.00	0.00	80.00	80.00
	Inverse topography factor F2	1.120	0.893	1.000	0.872	1.000	1.227
Prediction site topography and roughness	Base ht.of x-section X2	183.00	90.00	110.00	202.00	241.00	280.00
	Rg.length near site ZY1	0.010	0.010	0.010	0.010	0.010	0.010
	Distance to transition D2	5000.00	5000.00	5000.00	5000.00	5000.00	5000.00
	Rg.length beyond transition ZX1	0.010	0.010	0.010	0.010	0.010	0.010
	Topography factor F4	1.289	1.158	1.368	1.368	1.280	0.962
Computation of hub ht. factor at source site eliminating nearby transitions	Ht. of base of transition zone h1	1.186	5.934	1.080	3.434	219.790	0.015
	Factor if ZX=ZY, no transition	1.000	1.000	1.000	1.000	1.100	1.000
	Ht. of top of transition zone h2	90.289	96.821	61.466	83.681	253.673	27.937
	Weighting factor if h1<h<h2	0.492	0.187	0.551	0.335	-21.553	0.864
	Factor if h1<h<h2	0.969	1.059	0.987	1.028	1.100	0.854
	Factor if h>h2	0.969	1.059	0.987	1.028	1.100	0.854
	Factor if h<h1	0.969	1.059	0.987	1.028	1.100	0.854
Computation of site roughness factor including effect of nearby transitions	h1 (site)	219.790	219.790	219.790	219.790	219.790	219.790
	Factor if ZX1=ZY1	1.343	1.000	1.000	1.000	1.000	1.343
	h2 (site)	253.673	253.673	253.673	253.673	253.673	253.673
	Weighting factor at site	-16.718	-16.718	-16.718	-16.718	-16.718	-16.718
	Factor if h1<H<h2	1.343	1.000	1.000	1.000	1.000	1.343
	Factor if H>h2	1.343	1.000	1.000	1.000	1.000	1.343
	Factor if H<h1	1.343	1.000	1.000	1.000	1.000	1.343
	Roughness factor	1.343	1.000	1.000	1.000	1.000	1.343
	Roughness factor if F4>1	1.000	1.000	1.000	1.000	1.000	1.000
	Roughness factor if F4<=1	1.000	1.000	1.000	1.000	1.000	1.343
Final factors	F1	0.969	1.059	0.987	1.028	1.100	0.854
	F2	1.120	0.893	1.000	0.872	1.000	1.227
	F3	1.103	1.090	1.110	1.202	1.161	1.200
	F4	1.289	1.158	1.368	1.368	1.280	0.962
	F5	1.000	1.000	1.000	1.000	1.000	1.343
Results	Directional correction factor	1.543	1.194	1.499	1.475	1.635	1.626

Non-directional input	Source site	Lerwick					
	Prediction site	Scroo Hill					
	Distance	11km					
	Ht.of anemometer h	10	10	10	10	10	10
	Ht.of prediction H	35	35	35	35	35	35
ALL LENGTHS/HEIGHTS ARE IN METRES		SectorA 345-045	SectorB 045-105	SectorC 105-165	SectorD 165-225	SectorE 225-285	SectorF 285-345
Source site topography and roughness	Rg.length near anemometer ZY	0.200	0.010	0.010	0.010	0.010	0.200
	Distance to transition D1	650.00	1500.00	850.00	1250.00	5000.00	150.00
	Rg.length beyond transition ZX	0.010	0.001	0.001	0.001	0.010	0.010
	Base ht.of x-section X1	80.00	0.00	0.00	0.00	80.00	80.00
	Inverse topography factor F2	1.120	0.893	1.000	0.872	1.000	1.227
Prediction site topography and roughness	Base ht.of x-section X2	183.00	90.00	110.00	202.00	241.00	280.00
	Rg.length near site ZY1	0.010	0.010	0.010	0.010	0.010	0.010
	Distance to transition D2	5000.00	5000.00	5000.00	5000.00	5000.00	5000.00
	Rg.length beyond transition ZX1	0.010	0.010	0.010	0.010	0.010	0.010
	Topography factor F4	1.289	1.158	1.368	1.368	1.280	0.962
Computation of hub ht. factor at source site eliminating nearby transitions	Ht. of base of transition zone h1	1.186	5.934	1.080	3.434	219.790	0.015
	Factor if ZX=ZY, no transition	1.000	1.000	1.000	1.000	1.181	1.000
	Ht. of top of transition zone h2	90.289	96.821	61.466	83.681	253.673	27.937
	Weighting factor if h1<h<h2	0.492	0.187	0.551	0.335	-21.553	0.864
	Factor if h1<h<h2	1.086	1.137	1.060	1.104	1.181	0.958
	Factor if h>h2	1.086	1.137	1.060	1.104	1.181	0.958
	Factor if h<h1	1.086	1.137	1.060	1.104	1.181	0.958
Computation of site roughness factor including effect of nearby transitions	h1 (site)	219.790	219.790	219.790	219.790	219.790	219.790
	Factor if ZX1=ZY1	1.286	1.000	1.000	1.000	1.000	1.286
	h2 (site)	253.673	253.673	253.673	253.673	253.673	253.673
	Weighting factor at site	-12.815	-12.815	-12.815	-12.815	-12.815	-12.815
	Factor if h1<H<h2	1.286	1.000	1.000	1.000	1.000	1.286
	Factor if H>h2	1.286	1.000	1.000	1.000	1.000	1.286
	Factor if H<h1	1.286	1.000	1.000	1.000	1.000	1.286
	Roughness factor	1.286	1.000	1.000	1.000	1.000	1.286
	Roughness factor if F4>1	1.000	1.000	1.000	1.000	1.000	1.000
	Roughness factor if F4<=1	1.000	1.000	1.000	1.000	1.000	1.286
Final factors	F1	1.086	1.137	1.060	1.104	1.181	0.958
	F2	1.120	0.893	1.000	0.872	1.000	1.227
	F3	1.103	1.090	1.110	1.202	1.161	1.200
	F4	1.289	1.158	1.368	1.368	1.280	0.962
	F5	1.000	1.000	1.000	1.000	1.000	1.286
Results	Directional correction factor	1.730	1.282	1.609	1.583	1.756	1.746

Non-directional input	Source site	Lerwick					
	Prediction site	Susetter Hill					
	Distance	25km					
	Ht.of anemometer h	10	10	10	10	10	10
	Ht.of prediction H	20	20	20	20	20	20

ALL LENGTHS/HEIGHTS ARE IN METRES		SectorA 345-045	SectorB 045-105	SectorC 105-165	SectorD 165-225	SectorE 225-285	SectorF 285-345
Source site topography and roughness	Rg.length near anemometer ZY	0.200	0.010	0.010	0.010	0.010	0.200
	Distance to transition D1	650.00	1500.00	850.00	1250.00	5000.00	150.00
	Rg.length beyond transition ZX	0.010	0.001	0.001	0.001	0.010	0.010
	Base ht.of x-section X1	80.00	0.00	0.00	0.00	80.00	80.00
	Inverse topography factor F2	1.120	0.893	1.000	0.872	1.000	1.227
Prediction site topography and roughness	Base ht.of x-section X2	130.00	80.00	100.00	70.00	142.00	152.00
	Rg.length near site ZY1	0.010	0.010	0.010	0.010	0.010	0.010
	Distance to transition D2	5000.00	5000.00	5000.00	5000.00	5000.00	5000.00
	Rg.length beyond transition ZX1	0.010	0.010	0.010	0.010	0.010	0.010
	Topography factor F4	1.040	1.300	1.243	1.133	1.224	1.160
Computation of hub ht. factor at source site eliminating nearby transitions	Ht. of base of transition zone h1	1.186	5.934	1.080	3.434	219.790	0.015
	Factor if ZX=ZY, no transition	1.000	1.000	1.000	1.000	1.100	1.000
	Ht. of top of transition zone h2	90.289	96.821	61.466	83.681	253.673	27.937
	Weighting factor if h1<h<h2	0.492	0.187	0.551	0.335	-21.553	0.864
	Factor if h1<h<h2	0.969	1.059	0.987	1.028	1.100	0.854
	Factor if h>h2	0.969	1.059	0.987	1.028	1.100	0.854
	Factor if h<h1	0.969	1.059	0.987	1.028	1.100	0.854
Computation of site roughness factor including effect of nearby transitions	h1 (site)	219.790	219.790	219.790	219.790	219.790	219.790
	Factor if ZX1=ZY1	1.343	1.000	1.000	1.000	1.000	1.343
	h2 (site)	253.673	253.673	253.673	253.673	253.673	253.673
	Weighting factor at site	-16.718	-16.718	-16.718	-16.718	-16.718	-16.718
	Factor if h1<H<h2	1.343	1.000	1.000	1.000	1.000	1.343
	Factor if H>h2	1.343	1.000	1.000	1.000	1.000	1.343
	Factor if H<h1	1.343	1.000	1.000	1.000	1.000	1.343
	Roughness factor	1.343	1.000	1.000	1.000	1.000	1.343
	Roughness factor if F4>1	1.000	1.000	1.000	1.000	1.000	1.000
	Roughness factor if F4<=1	1.000	1.000	1.000	1.000	1.000	1.000
Final factors	F1	0.969	1.059	0.987	1.028	1.100	0.854
	F2	1.120	0.893	1.000	0.872	1.000	1.227
	F3	1.050	1.080	1.100	1.070	1.062	1.072
	F4	1.040	1.300	1.243	1.133	1.224	1.160
	F5	1.000	1.000	1.000	1.000	1.000	1.000
Results	Directional correction factor	1.185	1.328	1.349	1.087	1.430	1.304

Non-directional input	Source site	Prestwick					
	Prediction site	Myres Hill					
	Distance	29km					
	Ht.of anemometer h	10	10	10	10	10	10
	Ht.of prediction H	10	10	10	10	10	10
ALL LENGTHS/HEIGHTS ARE IN METRES		SectorA 345-045	SectorB 045-105	SectorC 105-165	SectorD 165-225	SectorE 225-285	SectorF 285-345
Source site topography and roughness	Rg.length near anemometer ZY	0.010	0.010	0.010	0.010	0.010	0.010
	Distance to transition D1	5000.00	5000.00	5000.00	5000.00	750.00	5000.00
	Rg.length beyond transition ZX	0.010	0.010	0.010	0.010	0.400	0.010
	Base ht.of x-section X1	11.00	11.00	11.00	11.00	11.00	11.00
	Inverse topography factor F2	1.000	1.000	1.000	1.000	1.000	1.000
Prediction site topography and roughness	Base ht.of x-section X2	265.00	317.00	317.00	281.00	290.00	272.00
	Rg.length near site ZY1	0.020	0.020	0.020	0.020	0.020	0.020
	Distance to transition D2	5000.00	5000.00	5000.00	5000.00	5000.00	5000.00
	Rg.length beyond transition ZX1	0.020	0.020	0.020	0.020	0.020	0.020
	Topography factor F4	1.153	1.015	1.015	1.058	1.258	1.064
Computation of hub ht. factor at source site eliminating nearby transitions	Ht. of base of transition zone h1	219.790	219.790	219.790	219.790	0.742	219.790
	Factor if ZX=ZY, no transition	1.000	1.000	1.000	1.000	1.000	1.000
	Ht. of top of transition zone h2	253.673	253.673	253.673	253.673	116.294	253.673
	Weighting factor if h1<h<h2	-21.553	-21.553	-21.553	-21.553	0.515	-21.553
	Factor if h1<h<h2	1.000	1.000	1.000	1.000	1.256	1.000
	Factor if h>h2	1.000	1.000	1.000	1.000	1.256	1.000
	Factor if h<h1	1.000	1.000	1.000	1.000	1.256	1.000
Computation of site roughness factor including effect of nearby transitions	h1 (site)	270.593	270.593	270.593	270.593	270.593	270.593
	Factor if ZX1=ZY1	0.940	0.940	0.940	0.940	0.940	0.940
	h2 (site)	291.394	291.394	291.394	291.394	291.394	291.394
	Weighting factor at site	-44.533	-44.533	-44.533	-44.533	-44.533	-44.533
	Factor if h1<H<h2	0.940	0.940	0.940	0.940	0.940	0.940
	Factor if H>h2	0.940	0.940	0.940	0.940	0.940	0.940
	Factor if H<h1	0.940	0.940	0.940	0.940	0.940	0.940
	Roughness factor	0.940	0.940	0.940	0.940	0.940	0.940
	Roughness factor if F4>1	1.000	1.000	1.000	1.000	1.000	1.000
	Roughness factor if F4<=1	1.000	1.000	1.000	1.000	1.000	1.000
Final factors	F1	1.000	1.000	1.000	1.000	1.256	1.000
	F2	1.000	1.000	1.000	1.000	1.000	1.000
	F3	1.254	1.306	1.306	1.270	1.279	1.261
	F4	1.153	1.015	1.015	1.058	1.258	1.064
	F5	1.000	1.000	1.000	1.000	1.000	1.000
Results	Directional correction factor	1.446	1.326	1.326	1.344	2.020	1.342

APPENDIX B

PUBLICATIONS

Paper presented at the European Community Wind Energy Conference held at Herning Congress Centre, Denmark, 6-10 June 1988.

A METHODOLOGY FOR THE PREDICTION OF WIND SPEEDS AT POTENTIAL WIND GENERATOR SITES

S Macmillan and G S Saluja

School of Surveying, Robert Gordon's Institute of Technology, Garthdee Road, ABERDEEN, AB9 2QB, SCOTLAND.

ABSTRACT

A methodology has been developed to predict the wind speed distributions at potential wind generator sites in the absence of on-site wind data. The model uses wind data from the nearest available meteorological station and transposes it to the prediction site using direction dependent factors. These factors function so as to eliminate effects of upstream transitions in surface roughness and topography at the source site, to transfer the data to the prediction site by accounting for the difference in general elevation above sea level of the two areas, and to incorporate the effects due to local surface characteristics and topography at the prediction site. Vertical wind shear is accounted for if the prediction height differs from the height above ground of the recorded data.

The aim of the model is to predict wind speed distributions and energy outputs over periods of time relevant to the overall economics of the wind generator project. The results for the flat terrain prediction sites are not very satisfactory but for the hilly terrain sites, where there is more data available for validation, the imaginary energy predictions are generally within 7% of that calculated from the recorded wind speed distributions. The problems encountered applying the prediction model are discussed.

1. INTRODUCTION

In assessing the overall feasibility of a wind generator one of the main problems that arises is how to accurately predict the expected long-term annual and monthly energy outputs. This paper presents an objective methodology to predict the wind regime and the resultant expected energy outputs at potential wind generator sites in the absence of on-site wind data. The predictions are based on wind speed and direction data from nearby meteorological stations.

The method incorporates ideas which were mainly developed to deal with fairly level terrain where only the surface characteristics have an effect on the wind flows (1, 2). However in Scotland, where there is considerable potential for wind energy utilization, the terrain is doubly complicated. Firstly, by having a large coast/land area ratio both the meteorological stations and the prediction sites are often near the coast with varying diurnal cycles superimposed on the wind flow. In addition they are often in areas of complex surface roughness characteristics. Secondly, the terrain in Scotland may be topographically complex with more than 50% of the land area over 200m above sea level (ASL) with a common occurrence of fairly steep gradients. The prediction methodology attempts to deal with wind flow over complex terrain in an objective manner by application of simple equations.

2. METHODOLOGY

The wind prediction methodology uses wind speed and direction data from the nearest meteorological station, hence referred to as the source site. The prediction process is geared towards making maximum use of the long-term wind speed and direction distribution tables which are readily available from the meteorological stations. This is the reason for applying the corrections to the Weibull scale parameters and for the slightly strange directional divisions which do not coincide with the conventional cardinal points of the compass. However, for validation purposes, where simultaneous data is required at both sites, mean hourly data is used due to the lack of long-term data at any of the prediction sites with the exception of Peterhead which is also a meteorological station.

A Weibull distribution is fitted to the non-zero mean hourly wind speeds or to the long-term wind speed frequencies by a least squares process. The correction which is applied to the Weibull distribution scale parameter is a mean of six directional correction factors weighted by the number of hours the wind is from each direction sector. Each directional correction is made up of five factors. They function on the wind flow so as to :

(1) eliminate upstream tangential surface roughness transitions near the source site and to transfer the data to prediction height above ground level (AGL)

(2) eliminate topography-induced effects in the vicinity of the source site

(3) account for the difference in general elevation ASL of the two areas surrounding the source site and the prediction site

(4) incorporate the effect of local topography at the prediction site

(5) incorporate the effect of surface roughness and any nearby transitions at the prediction site.

2.1 First factor

The first factor eliminates the effect of surface roughness transitions that are within a 2km radius of the source site. Beyond that distance a change in surface characteristic will have little effect on the wind flow. Once applied there will usually not be any radial transitions in roughness so that the resultant distribution represents the wind speeds over a uniform surface of one roughness length. However, in some cases it was found that the anemometer site had varying surface characteristics in its immediate vicinity. An example of this is Peterhead in NE Scotland (see Table I). As the method does not attempt to derive an intermediate roughness-free topography-free wind as in the method being developed by Palutikof (3) it was decided that radial transitions in roughness length were acceptable. The difference in roughness between the source site and the prediction site is accounted for in the fifth factor.

Initially it is determined whether or not the recorded data is affected by the upstream transition of roughness. This depends on the distance to the transition and the roughness lengths on either side of the transition. The equations used to eliminate the effect of the transition are derived in Macmillan and Saluja (4).

The roughness-dependent vertical wind shear is then considered in the case where the prediction height differs from the source height. A logarithmic profile is used :

$$\frac{c_H}{c_h} = \frac{\ln(H/z_y)}{\ln(h/z_y)} \qquad \ldots 1$$

where c_H is the Weibull scale parameter at prediction height, c_h is the scale parameter at source height with the effect of roughness transitions eliminated, H is the prediction height, h is the source height and z_y is the roughness length in the vicinity of the source site for the direction sector in question.

The height correction is carried out at the source site. If there are any transitions in the surface roughness at the prediction site the effect at prediction height will differ from that at source height. Also, the effect of topography will vary for different heights above ground. Therefore it is necessary for the wind speed distribution to be transferred to prediction height prior to taking account of the effect of topography and roughness transitions at the prediction site.

2.2 Second factor

The second factor eliminates the effect on the wind flow of local topography in the surrounding 2km radius area of the source site. In theory it should rarely be necessary to apply this factor as usually the source site is a meteorological station which should be sited in open flat terrain. However in practice this is often not the case. Even at Dyce where the anemometer is sited at a seemingly flat site at an airport (see Table I) it can be seen from the long-term wind rose that there are two distinct predominant directions which are both within the prevailing south-westerly air flow. The drop between the two peaks cannot be attributed to weather so therefore must be due to some local effect. The most likely cause is a nearby hill. The prediction method accounts for this by applying an "inverse topography factor" which takes the form :

$$1 - T_o \qquad \ldots 2$$

where T_o is dependent on the approximate maximum gradient in the direction sector in question. This gradient is calculated from the cross-section, drawn from a 1:25000 map, which bisects the direction sector. For each cross-section a base height ASL is established by the following criteria.

If the site is on a distinct topographic feature such as a hill or a valley or a ridge, the base height level is the lowest line (or highest in the case of valley sites) that can be drawn such that little or no land is above (or below in valley site case) it except for the feature itself.

If the site is in undulating terrain the base height should be the mean height of the cross-section and if possible should be close to the actual height ASL of the site.

Once the base height is established the upwind half-width L of the topographic feature and the height K of the feature above (or below for valley sites in which case K is negative) the base height are estimated to give the maximum gradient. Let g be the magnitude of this gradient.

If $g < 0.05$ then $T_o = K/1000$ ie. a 1% difference per 10m of site altitude above (or below) the base height.

If $0.05 < g < 0.3$ then $T_o = 2gs$ where $g = K/L$ and s is a coefficient depending where on the topographic feature the site is. It can be determined from Fig 4 of Macmillan and Saluja (4).

If $g > 0.3$ then $T_o = 0.6s$ for positive K, and $T_o = -0.6s$ for negative K.

2.3 Third factor

The third factor accounts for the difference in general elevation ASL between the source site and the prediction site. This is done by applying a 1% increase (or decrease) to the scale parameter per 10m rise (or fall) of the base height at the prediction site above (or below) the base height at the source site.

2.4 Fourth factor

The fourth factor accounts for the effect of local topography at the prediction site. It takes the form :

$$T = 1 + T_o \qquad \ldots 3$$

where T_o is determined in exactly the same manner as the second factor which eliminates the topographic effects at the source site.

2.5 Fifth factor

The fifth and final factor accounts for the effect of local surface roughness and nearby transitions at the prediction site. If there is no transition but the roughness is different from that at the source site this is taken into account.

The equations to apply here are derived in detail in Macmillan and Saluja (4).

If T > 1 implying that the prediction site is on a hill or a ridge, a roughness correction is not made unless the surface in the vicinity is of extreme roughness in one of two ways. The extremes of roughness are (1) the surface is sea or sand where the roughness length is 0.001m or smaller, and (2) partially built-up areas where the roughness length is 0.25m or greater. Otherwise the effect of topography dominates over that of surface roughness.

2.6 Mean wind speed and energy output prediction

Having derived the final correction factor, which is a weighted mean of the six directional correction factors depending on the percentage time the wind is from each direction, it is applied to the recorded scale parameter fitted to non-zero winds at the source site. The mean wind speed at the prediction site is calculated from this predicted scale parameter and the shape parameter recorded at the source site taking into account the recorded number of hours calm. For validation purposes it is compared with the actual mean wind speed recorded at the prediction site for a simultaneous period of time.

The predicted energy output is calculated from the predicted Weibull distribution using a realistic power curve which has the wind speeds at the prediction height. The probabilities of the wind speed being in 1m/s bins is computed from the Weibull distribution. These are multiplied by the total number of hours and by the power outputs for the midpoint wind speeds of the bins read from the machine's power curve. They are then summed to give the total energy output for the prediction period. This predicted energy output is compared with the energy output calculated from the recorded wind speed distribution by the same method.

3. APPLICATION

The prediction methodology is applied to six sites as given in Table I. The site selection criteria depended on the availability of wind data for validation purposes rather than on the site characteristics. Unfortunately, most of the sites are in fairly complex areas.

The output of a computer program deriving the six directional corrections for the prediction at Susetter Hill in Shetland using Lerwick meteorological station for source data is shown in Table II. Lerwick meteorological station is a fairly complicated site from a prediction point of view as it is non-flat and there are nearby transitions in roughness for five out of six sectors due to the coastal location and the nearby buildings of the Geophysical Laboratory. According to the computer program the long-term scale parameter at anemometer height at Lerwick with the effects induced by topography and local transitions in roughness eliminated, should be approximately 10% below the actual long-term scale parameter.

The other sites all have there own individual problems from a wind prediction point of view and these are summarized in Table I.

4. RESULTS

The results of all the predictions are shown in Table III. The first five predictions can be considered as low terrain predictions as both the source sites and the prediction sites are in areas where topography plays a generally insignificant role compared to that of surface roughness.

The energy predictions are not carried out for Peterhead due to the difficulty in determining the effective height of the recorded wind data. For the mean wind speed predictions at this site an effective height of 18m is taken. This is derived using the Met. Office code (5) applicable when the anemometer is on an isolated building and is on a mast at least half the height of the building. The later condition is not satisfied at Peterhead as the anemometer is on a 6m mast on a 24m building. However the code is that the effective height may be taken to be about the height of the mast plus half the height of the building.

Despite this problem at Peterhead the long-term annual mean wind speed is predicted using long-term Dyce data to within 0.2m/s of the actual.

Two problems that arise at low terrain sites are apparent. One is that if the site is inland the wind speeds are generally low ie. annual mean wind speeds of less than 5m/s. The consequence of this is that the assumption of neutral stability used in deriving the roughness correction equations is more doubtful at low wind speeds.

If the site is near the coast it is most likely that there will be some sort of diurnal cycles superimposed on the wind flows. These variations will vary in magnitude and direction depending on time of day and year. It is outwith the capability of this model to account for these cycles at either the source site or prediction site.

Additional errors are introduced at the Weibull curve-fitting stage as the time period of recorded data decreases in length. This is shown in Fig I, a plot of the mean square error when $\ln[-\ln(1-F(v))]$ is linearly regressed with $\ln(v)$ versus the sample size. $F(v)$ is the actual cumulative probability of wind speed v. The gradient of the regression line is k, the Weibull shape parameter and the intercept is $\ln(c^{-k})$ where c is the scale parameter.

The remaining predictions in Table III are for various continuous time periods at different heights for three hill sites. Although there are over 15,000 hours of data available for validation at hill sites, half of that is for Myres Hill alone where there is the longest period of data lasting ten months. The energy prediction for that site is within 3% of the actual. The remaining data is split up into shorter time periods of up to two months. At Scroo Hill it can be seen that although the mean wind speeds are over-predicted (columns 5 and 6 of Table III) the resultant energy predictions are generally under-predicted (column 10).

This is because the predicted wind speed distribution reaches above the cut-out wind speed of the machine or, in the case of the 20m predictions where a stall-regulated power curve is used, the wind speed distribution reaches above rated wind speed of the machine.

The remaining energy predictions are generally within 7% of the actual output. This small under-estimate can be partly attributed to the lack of correction made to the shape factor This can be seen by comparing columns 7 and 8 of Table III. Column 7 contains the recorded shape factor at the source site for the prediction period and is transposed to the prediction site without any alteration. Shape factors generally increase with height above ground. Also, the shape factors on hill sites are generally higher than those on low terrain sites (col 8). However the consequence of an incorrectly estimated shape factor on the energy output of a machine is normally quite small although it does depends on the form of the power curve and the mean wind speed (Fig II).

Using long-term wind direction distributions the method predicts a 26% increase in wind speeds at 20m on Susetter and a 37% increase at 35m from those recorded at Lerwick on a long-term basis. For Scroo Hill a 52% increase at 20m and a 64% increase at 35m is predicted.

The wind direction correlation between the source site and the prediction site is illustrated by calculating the square root of the mean square difference, taking suitable action when errors of greater than 180^{o} occur. These are shown in Table IV. It can be seen that the direction varies more at Susetter Hill from Lerwick than at Scroo Hill. It can also be seen that there is a fairly large mean difference of 36.5^{o} between Prestwick and Myres Hill directions, this being due to the strong diurnal variation that exists at Prestwick. The ability of the prediction methodology to take account of a shift in direction distribution therefore may be a significant problem at some sites.

5. CONCLUSIONS

For low terrain sites the results of the predictions are generally not very satisfactory. Low wind speeds and the possibility of differing diurnal variations coupled with a shortage of data available for validation make these results less conclusive. Further work is required.

At Myres Hill, where there is ten months of continuous data, the final energy prediction is within 3% of the actual. At the remaining two hill prediction sites the energy predictions are generally within 7% but this is for prediction periods of under two months.

Finally it is suggested that the long-term energy predictions should be done on a time of year and, if possible a time of day basis using long-term data from the meteorological stations. The predictions carried out in this paper are for validation purposes only and therefore simultaneous periods of data are necessary. The majority of prediction sites do not have long-term data available.

6. ACKNOWLEDGEMENTS

The authors would like to acknowledge the financial assistance received from the Science and Engineering Research Council in the form of a research studentship and a contribution towards the conference expenses. They would also like to acknowledge Ray Hunter at the National Engineering Laboratory, the North of Scotland Hydro Electric Board and Jim Halliday at Rutherford Appleton Laboratory for supplying wind data.

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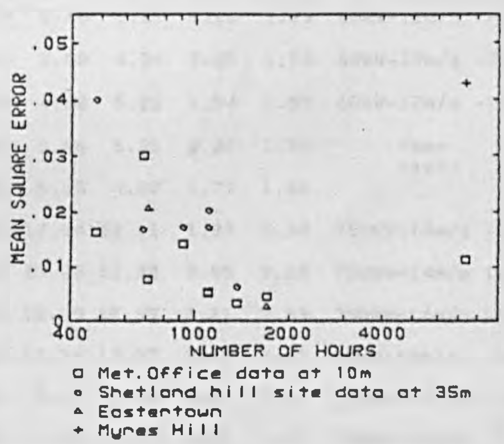

Fig. I Mean square error of the Weibull fit for various data sets.

4

Table I Basic site descriptions for anemometers.

Source site description	Prediction site description	Distance	Possible problems
DYCE - anemometer at 10m AGL at airport with hill rising to 250m ASL to W and built-up area to E nearby. Site is 58m ASL and is NW of Aberdeen in NE Scotland.	EASTERTOWN - anemometer at 12m AGL on top of farm building in gently undulating farmland with a 245m ridge to N. Site is 105m ASL NW of Old Meldrum in Aberdeenshire.	22km	(1)deflection of winds round hill to W of Dyce - long-term wind rose gives evidence of this. (2)anemometer site at Eastertown on top of building.
DYCE - as above.	PETERHEAD - anemometer on 6m mast on top of 24m harbour building in centre of Peterhead in NE Scotland.	42km	(1)deflection of winds round hill to W - long-term wind-rose gives evidence of this. (2)anemometer at Peterhead on top of building with town to W and sea to E.
LERWICK - anemometer at 10m AGL on rough moorland site, 80m ASL with coast at 0.6km. Site is S of Lerwick on E side of Shetland.	SCROO HILL - anemometers at various heights on mast on top of exposed rounded hill at 248m ASL in hilly area S of Lerwick.	11km	(1)Lerwick anemometer in non-flat area with 80m rise from nearby coast. (2)two hills near to Scroo Hill which rise to over 290m ASL.
LERWICK - as above.	SUSETTER HILL - anemometers at various heights on mast on top of a fairly isolated elongated hill 170m ASL in a hilly area N of Lerwick.	25km	(1)Lerwick anemometer in non-flat area with 80m rise from nearby coast. (2)possible funnelling effects due to sea inlet and valley S of hill.
PETERHEAD - anemometer on 6m mast on top of 24m harbour building in Peterhead in NE Scotland.	EASTERTOWN - as above.	38km	(1)anemometer at Peterhead on top of building with town to W and sea to E. (2)Eastertown anemometer on top of building.
PRESTWICK - anemometer at 10m AGL at airport with built-up area of Prestwick and coast to W. Prestwick is on W coast of Scotland.	MYRES HILL - anemometers at various heights on mast on top of hill 332m ASL in area of surrounding high moorland SW of East Kilbride.	29km	(1)Prestwick anemometer is at a coastal location with a strong diurnal variation which is outwith the modelling capabilities of this prediction method.

ASL = above sea level AGL = above ground level

Table III Results of mean wind speed and energy predictions

(1) Source site	(2) Prediction site	(3) Period of prediction	(4) Correction to scale factor	(5) Pred. mean w/spd	(6) Actual mean w/spd	(7) Pred. shape factor	(8) Actual shape factor	(9) Machine rating at w/spd	(10) Energy percent error*
(see Table I for site descriptions)									
Dyce	Eastertown	706 hrs in '86	0.994	5.16	5.25	2.22	1.95	60kW-12m/s	-0.7
Dyce	Eastertown	1701 hrs in '87	0.960	3.88	4.34	2.28	1.94	60kW-12m/s	-35.2
Peterhead	Eastertown	706 hrs in '86	0.878	4.62	5.25	1.94	1.95	60kW-12m/s	-25.6
Dyce	Peterhead	706 hrs in '86	1.151	5.96	5.25	2.22	1.95	(see text)	
Dyce	Peterhead	long-term AMWS	1.066	5.15	4.97	1.77	1.58		
Lerwick	Scroo 35m	1361 hrs Sep-Nov'85	1.671	12.94	12.11	1.97	2.30	750kW-14m/s	-5.5
Lerwick	Scroo 35m	678 hrs Apr-May'86	1.627	13.26	11.38	2.95	3.38	750kW-14m/s	14.4
Lerwick	Scroo 35m	1107 hrs Sep-Nov'86	1.662	13.69	12.95	2.21	2.53	750kW-14m/s	-4.1
Lerwick	Scroo 20m	1107 hrs Sep-Nov'86	1.546	12.74	12.37	2.21	2.46	80kW-14m/s	-4.2
Lerwick	Susetter 35m	920 hrs Sep-Oct'85	1.394	9.25	9.59	2.60	2.76	750kW-14m/s	-2.6
Lerwick	Susetter 35m	476 hrs May'86	1.370	11.36	10.58	2.81	3.30	750kW-14m/s	2.7
Lerwick	Susetter 35m	1100 hrs Sep-Nov'86	1.371	11.26	11.71	2.21	2.33	750kW-14m/s	-4.8
Lerwick	Susetter 20m	1100 hrs Sep-Nov'86	1.267	10.42	11.27	2.21	2.24	80kW-14m/s	-6.6
Prestwick	Myres Hill	7344 hrs Mar-Dec'87	1.514	6.53	6.56	2.16	2.29	60kW-12m/s	-2.3

* percentage error = 100 x (predicted - actual) / actual

Table II Derivation of directional correction factors

NON-DIRECTIONAL INPUT	:Source site	Lerwick
	:Prediction site	Susetter Hill
	:Distance	25km
	:Ht.of anemometer h	10m
	:Ht.of prediction H	35m

ALL LENGTHS/HEIGHTS ARE IN METRES		SectorA 345-045	SectorB 045-105	SectorC 105-165	SectorD 165-225	SectorE 225-285	SectorF 285-345
SOURCE SITE TOPOGRAPHY AND ROUGHNESS	:Rg.length near anemometer ZY	0.200	0.010	0.010	0.010	0.010	0.200
	:Distance to transition	650	1500	850	1250	none	150
	:Rg.length beyond transition ZX	0.010	0.001	0.001	0.001	0.010	0.010
	:Base ht.of x-section	80	0	0	0	80	80
	:Inverse topography factor	1.120	0.893	1.000	0.872	1.000	1.227
PREDICTION SITE TOPOGRAPHY AND ROUGHNESS	:Base ht.of x-section at site	130	80	100	70	142	152
	:Rg.length near site ZY1	0.010	0.010	0.010	0.010	0.010	0.010
	:Distance to transition	none	none	none	none	none	none
	:Rg.length beyond transition ZX1	0.010	0.010	0.010	0.010	0.010	0.010
	:Topography factor T (manual)	1.040	1.300	1.243	1.133	1.224	1.160
COMPUTATION OF HUB HT. FACTOR AT SOURCE SITE ELIMINATING NEARBY TRANSITIONS	:Factor if ZX=ZY, no transition					1.181	
	:Ht.base of transition zone h1	1.186	5.934	1.080	3.434	none	0.015
	:Ht. top of transition zone h2	90.289	96.821	61.466	83.681	none	27.937
	:Weighting factor if h1<h<h2	0.492	0.187	0.551	0.335		0.864
	:Factor if h1<h<h2	1.086	1.137	1.060	1.104		0.958
	:Factor if h>h2						
	:Factor if h<h1						
COMPUTATION OF SITE ROUGHNESS FACTOR INCLUDING EFFECT OF NEARBY TRANSITIONS	:Factor if ZX1=ZY1	1.286	1.000	1.000	1.000	1.000	1.286
	:h1 (site)						
	:h2 (site)						
	:Weighting factor at site						
	:Factor if h1<H<h2						
	:Factor if H>h2						
	:Factor if H<h1						
	:Roughness factor	1.286	1.000	1.000	1.000	1.000	1.286
	:Roughness factor if T>1	1.000	1.000	1.000	1.000	1.000	1.000
	:Roughness factor if T<=1						
FINAL FACTORS	:First factor	1.086	1.137	1.060	1.104	1.181	0.958
	:Second factor	1.120	0.893	1.000	0.872	1.000	1.227
	:Third factor	1.050	1.080	1.100	1.070	1.062	1.072
	:Fourth factor	1.040	1.300	1.243	1.133	1.224	1.160
	:Fifth factor	1.000	1.000	1.000	1.000	1.000	1.000
RESULTS	:Directional correction factor	1.329	1.426	1.449	1.167	1.536	1.462

Table IV Mean differences in direction between the source site and the prediction site.

Prediction	Hours	Sq.root(MSE)
Scroo'85	1361	11.3°
Scroo'86 (1)	678	9.4
Scroo'86 (2)	1107	8.1
Susetter'85	920	17.9
Susetter'86 (1)	476	13.8
Susetter'86 (2)	1100	11.6
Dyce-Peterhead	706	18.7
Prestwick-Myres	7344	36.5

MSE = mean square error

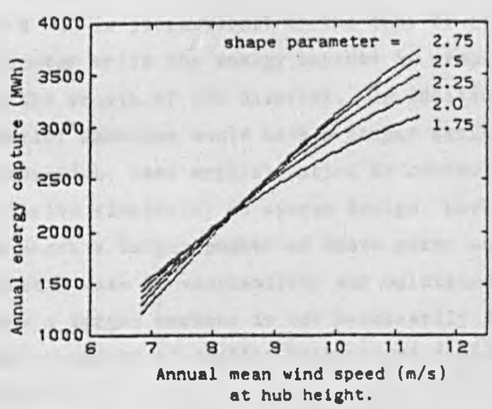

Fig. II Variation of annual energy capture with annual mean wind speed and shape parameter for a 750kW machine.

OPERATIONAL EXPERIENCE OF A SMALL (60 kW) GRID CONNECTED WIND TURBINE GENERATOR

G S Saluja* and S Macmillan
School of Surveying, Robert Gordon's Institute of Technology, Garthdee Road, Aberdeen, AB9 2QB, Scotland.
(*Now at University of Ulster at Jordanstown, Newtownabbey, Co Antrim, BT37 0QB, Northern Ireland).

ABSTRACT

Currently the focus on wind generated electricity is either on large megawatt size wind turbine generators (WTGs) or on wind farms. However, there is a considerable potential for the use of smaller (50-150 kW) single WTGs in a number of applications. Little published data is available on the operational experience of commercially produced such machines. This study presents a detailed analysis of a 60 kW grid connected WTG operating for over 5 years on an Aberdeenshire (Scotland) intensive pig farm. A low cost computer operated data logging system has been used to collect 4000 hours of data over a period of 2 years. An attempt has been made to explain the variation in energy production during summer and winter periods at similar wind speeds. As a result of the initial monitoring a faulty setting of the microprocessor was corrected, resulting in improved power output from the WTG. Over the 5 year period the WTG has operated satisfactorily, but at 60-70% of the capacity specified by the manufacturer. Based on medium term performance the system economics has been analysed and compared with two other nearby, and one remote, installations in Scotland.

INTRODUCTION

In most developed countries the focus on wind energy utilisation is almost entirely for the generation of electricity. The UK Department of Energy has categorised wind as the most promising of the renewable energy resources [1]. The emphasis is being biased towards large (MW range) utility owned WTGs and on wind farms [2]. Probably this line of action suits the utility authorities despite the lack of evidence of the economic viability of such systems. There are indicators of lower installed cost/kW rated power of smaller sized WTGs [3]. There are also definite indications that the repair costs of larger machines are considerably higher than smaller size machines [4,5]. This possibly reflects the less established nature of larger machines. It may be argued that the cost advantage of smaller systems over their giant counterparts may be short lived since the cost of one larger system is likely to be lower than that of several smaller systems. Very roughly the mass of a WTG is proportional to the cube of its diameter while the energy capture is proportional to the square of the diameter. In addition the smaller machines would have a larger series production, less sophistication in controls, relative simplicity in system design, more ability to stock a larger number of spare parts and general ease of adaptability and maintainability. Thus a larger machine is not necessarily cheaper than a number of smaller machines of equivalent capacity.

Published data on the operating experience on small sized grid connected WTGs has been limited to machines which were either forerunners of the large machines or those installed in remote areas of the microprocessor was adjusted to the correct value and, as can be seen, from the data for 1987, the performance of the machine was improved. However, the guaranteed output of 100,000 kWh per annum was never achieved. A settlement was already made by the manufacturer for this shortfall well before the commencement of monitoring. The improvement in the annual energy capture can be seen by looking into 3 years figures as given below:

Year	Production (kWh)	Mean wind speed (m/s)
1985	40,282	4.2
1986	59,995	5.0
1987	50,746	4.2

Thus an improvement of 25% from 1985 to 1987 was achieved with equal annual mean wind speeds. The estimated annual production at the long term wind speed of 4.6 m/s at the site is 62,700 kWh. Figure 2 shows the average hourly power output for October 1987 as a function of hourly mean wind speed.

Seasonal and Diurnal Variation

Seasonal and diurnal variation in wind speeds and energy production, were analysed by dividing the data into two broad "winter" and "summer" periods of October-March and April-September respectively. Figures 3 and 4 show diurnal variation in the mean hourly wind speed and the average power output for the two seasons respectively. The power output in winter was higher than in summer at similar wind speeds. Some increase in power output in winter can be expected due to higher density of air, but a large difference could not be attributed to density alone.

Although the measurement of mean hourly turbulence intensity was not ideal, it gave an indication of increased power output with increasing level of turbulence. Figure 5 shows the winter and summer diurnal variation in turbulence intensities. A further attempt was by plotting the performance of the machine on an hourly basis at three different turbulence levels, as shown in Figure 6. A significant increase in power output can be seen with increasing turbulence intensity. Since the data was limited and the turbulence measurements were not as prescribed, ie with sampling rate of one second, no further rigorous analysis was carried out.

ECONOMIC ASSESSMENT

An economic assessment can be made only after the tariff structure of the utility supply company is clearly indicated. Table 1 shows the tariff structure for small private generators applied by the utility company in question - North of Scotland Hydro Electric Board. A penalty must be paid for the reactive power, however this is related to total energy imported from the utility company. In this case the penalty was negligible due to high consumption levels.

Based on 1988 tariffs and long term performance of the WTG and diurnal variation in consumption and production rates, a life cycle costing was carried out. The cost of the machine was estimated at £20,000 after making an allowance for the agricultural subsidy of 33% available at the time of installation of the machine. The cost of maintenance was difficult to obtain, however based on past experience an annual cost of £200 and a three yearly cost of £1000 for parts replacement was assumed. A real rate of discount was assumed to be 5%. This produced an internal rate of return of 9.2% and the machine was "viable" with its life over 12 years. Without 33% subsidy the design life needs to be 18 years for the machine to be viable. All these figures are based on the energy output at only 63% of the originally guaranteed value and no account of the compensation given by the manufacturer was taken into consideration.

A comparison was made with three other WTGs in Scotland with 3-5 years of operational experience.

with limited grid capacity and managed through expert advice [6].

DESCRIPTION OF WTG, FARM ENERGY AND MONITORING

This study is focused on the Dutch wind turbine, Polenko, with three fixed pitched blades of 16 m diameter and control flaps at the tips, 20 m stiff tubular concrete tower and two induction generators rated at 15 kW/1000 rpm and 60 KW/1500 rpm. The blades are made of twin-walled steel and are polyurethane-filled. The site of the WTG is not ideal with sheltering from a north hill rising to 245 m and some of the farm buildings rising to 15 m. The installation is within 3 m from the control room located in the farm building thus incurring no extra cost for the power cable and sub-station. The long term annual wind speed at the site at 10 m height is only 4.6 m/s. The monitoring system consists of 4 photo-diodes stuck on the outside of production, import, export and reactive energy meters, a cup anemometer located approximately 4 m above a 8 m building, a microcomputer, a frequency to voltage converter and an interface.

The WTG supplies energy to the pig unit which has an annual consumption of approximately 400,000 kWh. All the energy requirements on the unit are supplied by electricity. The seasonal and diurnal consumption pattern is almost constant. With an estimated annual energy capture of the WTG at 100,000 kWh, these were the ideal conditions for the installation of such à WTG.

RESULTS OF MONITORING

There were limitations in data collection owing to the use of an inexpensive logging system. The wind speeds were sampled every 12 seconds. The microprocessor was capable of averaging the wind speeds at any interval with the multiples of the sampling rate. Most of the data was collected on hourly basis with some readings taken at 10 minutely intervals. Mean hourly turbulence intensity (standard deviation/mean wind speed) was also calculated . Sampling rate of 12 second is not ideal, it being close to a localised peak in the turbulence spectrum at .07 Hz which is equivalent to a sampling rate of 14.3 seconds [7]. However some useful information has been collected from the turbulence measurements. Data was collected during periods of April-June 1986, June-November 1987 and February-March 1988.

Initial Monitoring Results

Figure 1 shows average hourly power output of the WTG against mean hourly wind speed at 10 m height for initial periods in 1986 and a similar period in 1987. The manufacturer's power curve is also shown on the plot. A number of observations can be made at this stage. These are:

1 The power output of the WTG was much lower than the manufacturer's guaranteed values. This was known at the outset and indeed was one of the reasons for the performance monitoring.

2 The installation was completed in early 1983, but it was severely damaged in a storm in the first half of 1984 and the rotor had to be replaced. After a shut down of 4 months the machine was restarted in October 1984. The rotor speed was reduced from 38 rpm to 34 rpm by the manufacturer in an attempt to improve the energy output at low wind speeds. As will be seen later, this did not prove to be the case. It is now suspected that another reason was to protect the rotor from any further damage.

3 1986 results show that the machine was switching over to the large generator at around 9.5 m/s instead the original setting of 6.5 m/s.

Further Monitoring Results

In consultation with the manufacturer the setting

Two WTGs are located in the vicinity of the machine under study and are of Polenko make, while the third one was the ill-fated installation at Scalloway in Shetland Island, damaged and scrapped in heavy gust conditions in December 1988 [8]. The tariff structure in Shetland was more favourable as the local power generation is by diesel fuel and the export rates were almost 1p/kWh higher than the other areas under the same utility authority [9]. Table 2 summarises the results for long term economic assessment. It is interesting to note that the smaller 15 kW machine at Hill of Fiddes performed as guaranteed by the manufacturer, but it still had the worst economic record. The reason is simply a low utilisation of the wind generated electricity and poor rate of exported energy. A similar situation existed for the Scalloway machine but for the higher payment for the exported energy. In this assessment the property tax (local authority rates) have been ignored. Three WTGs installed on farms in Aberdeenshire are exempt from such rates but the Scalloway installation was subject to rates which were so high that the actual savings were equal to rates payable [9]. At the time of installation it was anticipated that no rates would be payable.

CONCLUSIONS

Small WTGs can be economically viable provided:

1 A reasonable wind regime is present.
2 A very high proportion of wind generated electricity is consumed by the customer.
3 No local authority rates are payable.
4 The performance of the WTG matches the performance curve supplied by the manufacturer.

ACKNOWLEDGEMENTS

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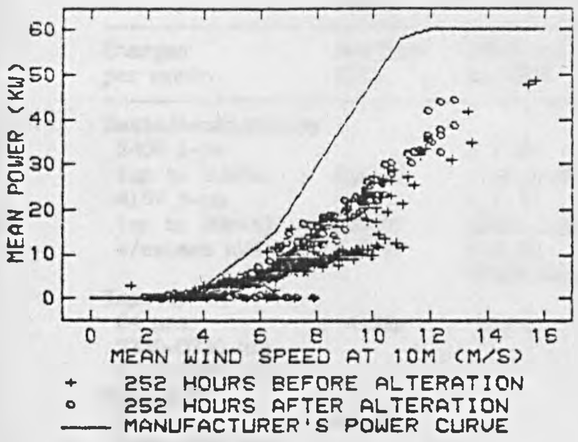

Figure 1. PERFORMANCE OF 60 kW WTG AT EASTERTOWN

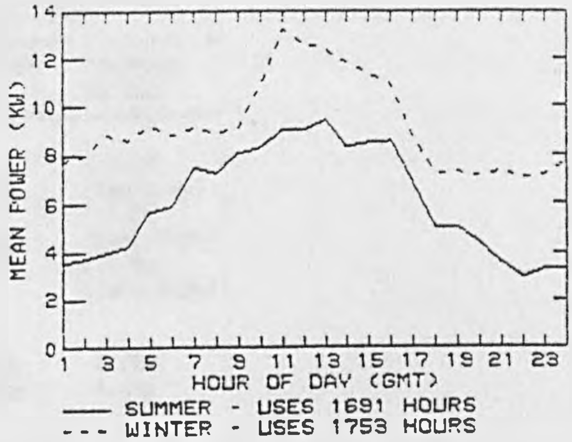

Figure 4. DIURNAL VARIATION IN MEAN POWER OUTPUT

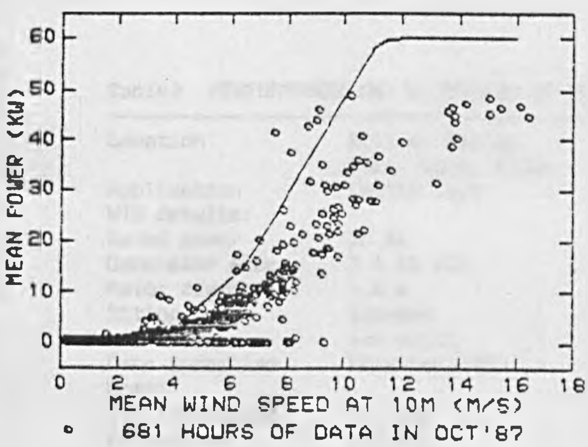

Figure 2. OUTPUT OF 60 kW WTG FOR ONE MONTH

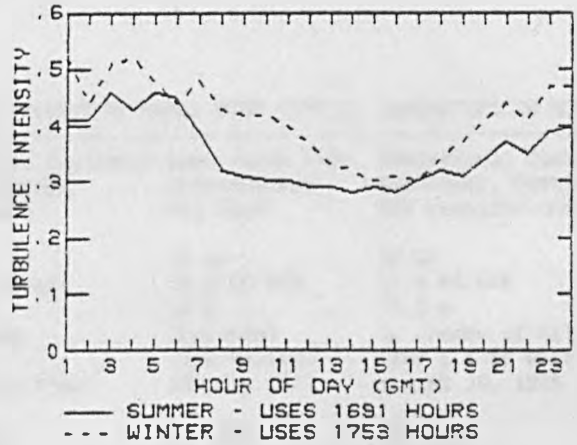

Figure 5. DIURNAL VARIATION IN MEAN TURBULENCE INTENSITY

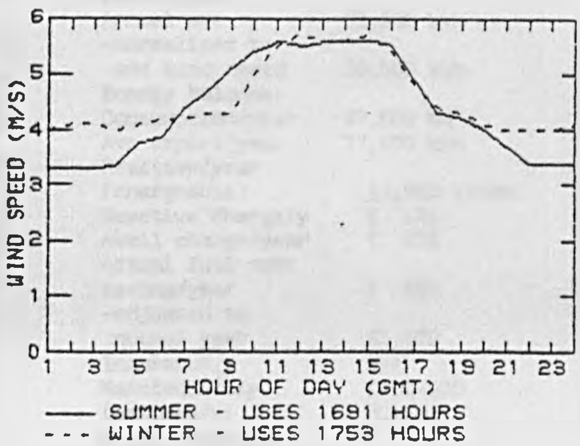

Figure 3. DIURNAL VARIATION IN MEAN HOURLY WIND SPEEDS

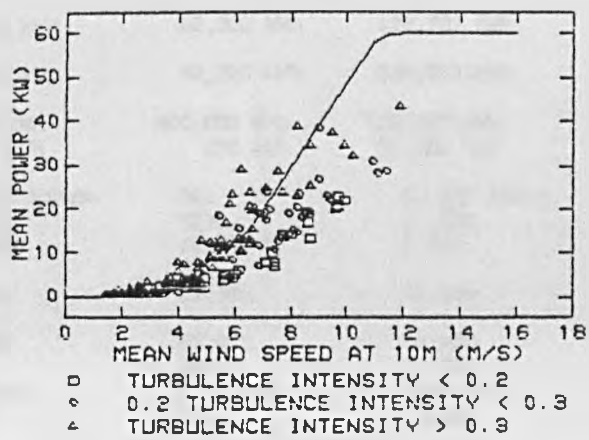

Figure 6. MEAN POWER OUTPUT AT DIFFERENT TURBULENCE LEVELS

Table 1 NORTH OF SCOTLAND HYDRO ELECTRIC BOARD TARIFFS
(FROM 1 APRIL 1988 TO 31 MARCH 1989)

Charges per month	Dom/Farm WECS	Dom/Farm No WECS	Dom/Farm WECS	Dom/Farm No WECS
Basic/Availability				
240V 1-ph		£ 2.81		£ 3.57
(up to 10kVA)	£13.82	(Dom 1-ph)	£13.82	(Dom 1-ph)
415V 3-ph		£ 4.47		£ 5.36
(up to 20kVA)	£25.07	(Farm 1-ph)	£25.07	(Farm 3-ph)
+/excess kVA	£ 0.77	£ 6.98	£ 0.77	£ 7.91
		(Farm 3-ph)		(Farm 3-ph)
Import/kWh				
24 hrs	4.52p	5.18p		
2330-0730 hrs			2.02p	2.02p
0730-2330 hrs			4.78p	5.43p
Export/kWh				
24 hrs	-1.86p			
2330-0730 hrs			-1.50p	
0730-2330 hrs			-2.04p	
Reactive/kVArh	0.47p		0.47p	

(in excess of half the number of total import units)

Table 2 PERFORMANCE AND ECONOMICS OF FOUR GRID CONNECTED SMALL WIND TURBINE GENERATORS IN SCOTLAND

Location	Hill of Fiddes Farm, Udny, Ellon	Mains of Bogfechel Whiterasnes	Eastertown Farm Rothienorman	Easterhoull Chalets Scalloway, Shetland
Application	Cattle farm	Pig farm	Pig farm	All electric chalets
WTG details:				
Rated power	15 kW	60kW	60 kW	55 kW
Generator size	5 & 15 kVA	15 & 60 kVA	15 & 60 kVA	11 & 55 kVA
Rotor diameter	9.6 m	16 m	16 m	15.3 m,
Siting	Exposed (on hill)	Exposed	Sheltered (low valley)	In shadow of hill (for E & SE wind)
Date installed	November 1983	January 1983	January 1983	August 19, 1985
Cost:				
WTG (installed)	£13,000	£27,000	£27,000	£31,000
Foundation	£ 3,500	£ 3,850	£3,092	£ 3,450
Grid Connection	£ 1,500	£ 4,259	Nil	£ 6,261
Total (Gross)	£18,000	£35,109	£30,392	£40,711
Grant	£ 5,400	£ 9,772	£10,130	£ 6,747
Nett cost	£12,600	£25,337	£20,262	£33,964
Production:				
Annual ave	32,800 kWh	59,300 kWh	53,300 kWh	129,737 kWh
-normalised to ave wind speed	38,500 kWh	69,800 kWh	62,700 kWh	138,500 kWh
Energy Balance:				
Consumption/year	37,000 kWh	575,000 kWh	400,000 kWh	110,000 kWh
Ave export/year	17,800 kWh	435 kWh	200 kWh	78,600 kWh
Reactive/year (chargeable)	27,500 kVArh	143,400 kVArh	Nil	52,320 kVArh
Reactive charge/y	£ 121	£ 631	Nil	£ 230
Avail charge/year	£ 276	£1,153	£1,033	£ 646
Actual fuel cost saving/year	£ 920	£3,646	£2,520	£4,135
-adjusted to normal year	£1,070	£4,035	£2,870	£4,440
Insurance/y	N/A	N/A	N/A	£ 250
Maintenance/y	£100-500	£250-800	£250-600	£200-300
(assumed/y)	(£300)	(£550)	(£450)	(£250)
Simple payback:				
With subsidy	16 years	7 years	8 years	8 years
Without subsidy	23 years	10 years	12 years	10 years