ASIA ALTERNATIVE ENERGY PROGRAMME (ASTAE) WORKING PAPER

STATISTICAL ANALYSIS OF WIND FARM COSTS AND POLICY REGIMES

This working paper presents the results of a statistical analysis to identify the main factors that affect the cost of electricity generated by wind. It is published to encourage discussion and comment within the wind energy community and for dissemination to parties interested in wind power development in Asia and other countries.

The findings, interpretations and conclusions expressed in this paper should not be attributed in any manner to the World Bank, to its affiliated organizations, or to members of its Board of Executive Directors or the countries they represent. The World Bank does not guarantee the accuracy of the data included in this publication and accepts no responsibility whatsoever for the consequence of their use.

STATISTICAL ANALYSIS
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PREFACE

This paper has its origins in a request made by the Government of China to the World Bank for information on the factors that affect the cost of electricity generated by wind. The request stemmed China's interest in developing its wind resource and from the observation that there appeared to be a wide range of costs among countries leading the large-scale development of wind. The first version was prepared by David Milborrow, consultant, using his own and published sources. In the next phase, the databases were expanded and developed into their current form drawing on information from a variety of publications and the new data incorporated into the paper. This work was undertaken by Tobias Wiesenthal, during an internship at the World Bank. The final version of the paper, which is presented here, incorporates further statistical and economic analysis undertaken by Peter Meier, consultant. The work was supervised by Susan Bogach and Richard Jeremy Spencer and reviewed by Noureddine Berrah and Charles Feinstein. It has been funded by the World Bank's China Country Department (under the China Renewable Energy Scale-up Program) and the Asia Alternative Energy Program.

Our interest in publishing this paper is, first, to get what we feel is important and useful information into the public domain, second, to solicit feedback and, third, to find and compare the results of similar studies. We are particularly aware that the correlations identified in the paper are not necessarily indicative of the causal relationships: however the data and the analysis strongly support our research hypothesis that competitive policy regimes bring about lower wind electricity costs .Nevertheless, we regard the paper as 'work in progress' and, we hope, a contribution to the debate on where wind costs are headed and what the best means is of getting them there. Comments may be sent to meierpeter@compuserve.com, sbogach@worldbank.org or rspencer@worldbank.org and we will also publish them on the ASTAE web site. We will take these comments into consideration as we design the next phase of the activity.

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ABSTRACT

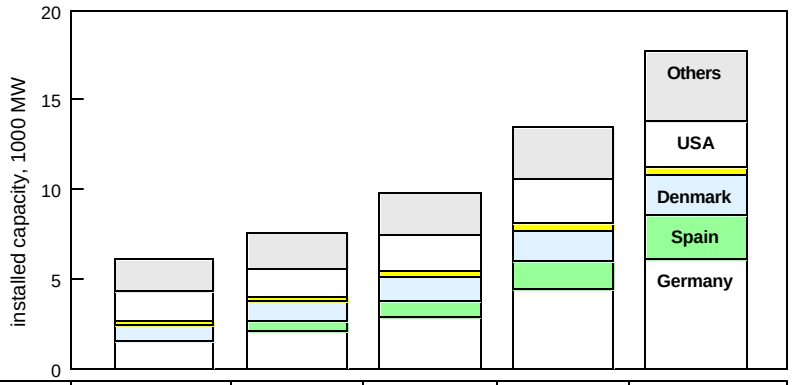
This paper presents the results of a statistical analysis of wind farm costs and prices based on a database of published worldwide wind farm costs. While past studies have demonstrated general "learning curve" effects, these do not identify the individual contributions of technological innovation, scale economies of project size, scale economies of machine and order size, as a function of the policy regime. While recognizing the problems with published data, we show that in the competitive policy regimes of the UK, USA and Australia, the data are consistent with a classical economic theory: learning curve, scale economies of project size, turbine size, and turbine order explain 81% of the variation of reported project costs. By contrast, the German project cost data, and the set of data from the rest of the world, reveal no statistically significant relationship between these factors and reported project costs. However, published German turbine list prices do reveal learning curve, turbine size, and turbine order size economies, though the explanatory power of the model is lower (R^2=0.61). The results demonstrate that only in competitive policy regimes are the benefits of learning curve and scale economies passed to the consumer; while in Feed-in Law regimes (Germany, Spain) the principal beneficiary is the developer.

1. INTRODUCTION

1.1 Background

World wind energy capacity doubled every three years from 1990 to 2000. It is doubtful whether any other energy technology is growing, or has grown, at such a remarkable rate. Installed capacity in 2000 grew by 30% so that total world wind turbine capacity at the end of the year was around 17,600 MW (see Figure 1). Germany, with over 6,000 MW, has the highest installed capacity but Denmark, with over 2,000 MW, has the highest level per capita and wind production accounts for about 13% of Danish electricity consumed. Wind provided 21% of the electricity consumed in Western Denmark in February 2001.

Figure 1: Growth in Worldwide Wind Installed Capacity



	1996	1997	1998	1999	2000
Germany	1545	2080	2874	4445	6113
Spain	2	512	834	1530	2402
Denmark	857	1116	1450	1742	2297
UK	270	320	334	356	409
USA	1590	1590	1952	2492	2555
Others	1819	1963	2378	2879	3896

It is generally acknowledged that the extraordinary growth in German wind power is attributable to a very favorable policy regime (the so-called "Feed-in Law") that guarantees fixed prices – as much as 9 US cents/kWh -- for wind energy. The resulting growth in the equipment market has provided incentives for technological innovation in turbine design, and for the exploitation of scale economies at the project and equipment manufacture scale – just in the past five years, the typical rated capacity of a wind turbine has grown from 600kW to over 1MW. On the other hand, the lowest wind energy prices have occurred in countries where the policy regime emphasizes competitive structures, notably in the UK where the competitive Non-Fossil Fuel Obligation (NFFO), Scottish Renewables Obligation (SRO) and Northern Ireland NFFO (NI-NFFO) process resulted in prices as low as 3-4 US cents/kWh by 1998.

Policy regimes vary widely across countries: Table 1 (and Box 1) summarises those in five leading wind power countries: those of other countries reveal further diversity in support mechanisms. There are two fundamentally different support mechanisms: those where the Government sets the price (or a fixed level of subsidy), and the market determines quantity offered (as under the German Feed-in Law or the US production tax credit); and those where the Government sets the

quantity, and the market sets the price (Mandated Market Share/Renewable Portfolio Standard systems, or the UK NFFO).

But while the influence of policy regime on market size and price is generally understood in qualitative terms, little quantitative evidence has been presented to date. A few studies have sought to demonstrate "learning curve effects," [1] but to our knowledge none have attempted to distinguish between the relative importance of technological innovation, scale economies of project size, scale economies of machine and order size, as a function of the policy regime. It is the goal of this paper to fill some of these gaps by a statistical analysis based on published worldwide data.[2]

Table 1:
Policy Regimes

	Denmark	Germany	Spain	UK	USA
Price established by:	Feed-In Tariff (Transition to Portfolio Standard); EUR 0.044/kWh	Fixed Feed-In Tariff: 0.178 DM/kWh (EUR 0.091) for 5 years depending on the site(1)	Feed-In Tariff of 0.063 EUR/kWh OR market pool plus bonus of 0.029EUR/kWh	Competitive market through bidding, under NFFO up to 1998 and under the Renewables Obligation from 2002	Competitive market BUT Production Tax Credit of 17 cents/kWh
Other incentives	Production subsidy of Euro 0.036/kWh for private owners Tax incentives	Cheap loans through federal interest rate subsidy Tax incentives	Subsidized loans Tax incentives	None	Federal: Accelerated depreciation In some States: - Renewable Portfolio Standard - Net metering - Systems Benefit Charges

See Box 1 for further details[3]
(1) The original Stromeinspeisungsgesetz ("Electricity Feed-in Law") was replaced on 1st April 2000 by the Erneuerbarer Energie Gesetz ("Renewable Energy Law"), which provides payments for wind energy that are a function of "location quality" [4]

Classical economic theory suggests that the cost of wind farms and of wind-generated electricity should be strongly linked to learning curve effects (decrease in costs over time as experience with a relatively new technology and overall market size grows), and scale economies (of project size, of unit machine size, and of machine order size). We hypothesise that the extent to which these linkages can be demonstrated is dependant upon the extent to which competitive market regimes

[1] See, e.g., C. Wene, Stimulating learning investments for the "250MW Wind Programme, WMEP Jahresauswertung, 1998.

[2] Unfortunately, there remain many gaps in our database, which we hope to remedy in the coming months.

[3] L. Harrison and D. Milborrow: Commercial Reality kept at bay in Europe, Windpower Monthly, September 2000.

[4] For details and typical tariffs at representative locations in Germany, see, e.g., WMEP Jahresauswertung 1999/2000, University of Kassel, 2001.

are in place. In this paper we use standard multivariate statistical analysis techniques to test for these relationships,[5] using three databases assembled for this study:

1. A database of manufacturers list prices for single wind turbines in Germany for 1995-2001, derived from an annual German publication.[6]
2. A database of reported prices and details of turbine purchases assembled from journals such as Windpower-Monthly, internet-newsletters such as www.iwr.de, wind energy associations and information published by manufacturers (40 projects).
3. A database from the same sources that contains information at the *project* level (126 projects). There are some significant gaps in this database: for example, although Denmark accounts for a significant share of the worldwide installed capacity, no Danish projects are included: we hope to rectify this (and some other) data gaps in the near future.

The cost data were adjusted for inflation with the relevant indices for manufacturing[7] or – in cases where they were not available – with the GDP deflator, and then converted into year 2000 US dollars.

Box 1**:**
Windpower Policy Regimes

Different market support mechanisms are established, designed to achieve different aims, such as a high deployment of wind energy or an important price reduction. All incentives must be embedded in the legal and fiscal context. The most common incentives are fixed price tariffs which are in place in Denmark, Spain and Germany and competitive compulsory renewables quota like the "Renewables Portfolio Standard" in the United States and "Renewables Obligation" in the UK (replacing NFFO).

Denmark: The Danish support system is currently under transition from a market with a Feed-in Tariff to a market regulated by quotas. The aim of the National Plan "Energy 21" is to increase the share of renewables in total energy consumption to 12-14% by the year 2010. This shall be achieved by a Renewable Portfolio system. For a limited transition time, a production subsidy of Euro 0.036/kWh is paid to private wind turbine owners.

The buy-back rates have been related to the utilities' production costs (tariffs) until 1999. From 2000, the buy-back is Euro 0.044/kWh until the turbine is 10 years old. In addition to the Feed-in Tariff, favorable taxation for wind turbine owners is common.

Germany: Germany intends to double the share of renewable energy sources in total energy consumption by the year 2010. The main financial support is a guaranteed Feed-in Tariff, regulated in the Renewable Energy Sources Act from April 01, 2000: The utilities are obliged to pay the generator of wind electricity DM 0.178/kWh for at least five years. From the sixth year, the tariff for turbines at good coastal sites will drop to DM 0.121/kWh, resulting in an average payment over 20 years of operation of DM 0.148/kWh, according to calculations from the German Wind Energy Association BWE. In an inland site with lower wind speeds, the 20 years average is DM 0.173/kWh.

Additionally, wind turbine developers might get soft loans with federal subsidized interest rates at 1-2% below normal market rates. These are provided by the state-backed Deutsche Ausgleichs Bank and the effective real rate for a complete project has varied between 5% and 8%. Typical loan terms are 10 – 12 years. About 90% of wind turbine projects completed in Germany in 1999 benefited from cheap loans from the Deutsche Ausgleichsbank [see reference 4]. Some Länder (States) offer supplementary cheap loans and other financial support such as direct funding through capital subsidies.

[5] Ordinary Least Squares (OLS), using the t-test for statistical significance of individual variables in the model.

[6] Windkraftanlagenmarkt: *Typen, Technik, Preise*; Issues 1995-2001. This database includes information for rated capacity (kW), hub height, and swept area.

[7] OECD, Main economic indicators, Issues 2001 and 1999.

Spain: Spain aims to have a contribution of the renewable energies to total energy demand of at least 12% for the year 2010. The Royal Law 2066/99 provides two choices to electricity producers from renewables: either their electricity receives a fixed Feed-in Tariff or it is sold for a variable price, calculated from the average price of the market-pool, plus a bonus per kWh produced. The fixed price and the bonus will be updated every year according to the annual variation of the market price to obtain 80-90% of the consumer price. Currently, the Feed-in Tariff for each kWh generated is 0.063 EUR/kWh and the bonus per kWh produced is 0.029EUR/kWh. Other actions to promote renewable energy include the availability of subsidized low-interest loans through state-backed financial institutions. They are usually 1.25 –1.75% below normal markets rates with payback periods of 10-12 years. Furthermore, capital subsidies of up to 40% (or Euro 2m) are available.

UK: The English market enablement strategy aimed to give renewables the opportunity to compete equitably with other energy technologies in a self sustaining market. In a series of rounds of bidding under NFFO, wind (and other renewable) energy prices were set by competitive bids in order to achieve fast and important price reductions. Developers were required to submit bids on the basis that the price they received would alone be sufficient to make their project pay if offtake was guaranteed for 15 years; there was no additional support. This resulted initially in rates of return of 10-12%. Later developments probably had rates of return of around 7%, as the intense competition favored large power companies with the ability to finance the developments themselves.

USA: The target of the American policy is to achieve a share of at least 5% of the nation's electricity by wind in 2020 and to increase the number of states with more than 20 MW installed to 16 by 2005, and to 24 by 2010. Market support mechanism occurs on two different levels; the federal level with the DoE's Wind Energy Program and at the State level. The main instruments at the federal level are the Production Tax Credit (PTC), in combination with accelerated depreciation for wind energy projects. The PTC is a payment supplement, whereby companies are allowed to offset existing tax liabilities for electricity production from specified renewable sources of energy. The credit is currently set at 1.7 c/kWh and is allowable for ten years after the plant begins operation. On the state level, the most important incentives are the Renewable Portfolio Standard (RPS), which is implemented in 9 states; and net metering (23 States). Under RPS, the supplier of electricity must fulfill a certain quota of renewables in their electricity, but are free to choose the developers on the competitive market. With an SBC, project proposers bid for funds from a pool financed by a levy normally raised from electricity sales to consumers.

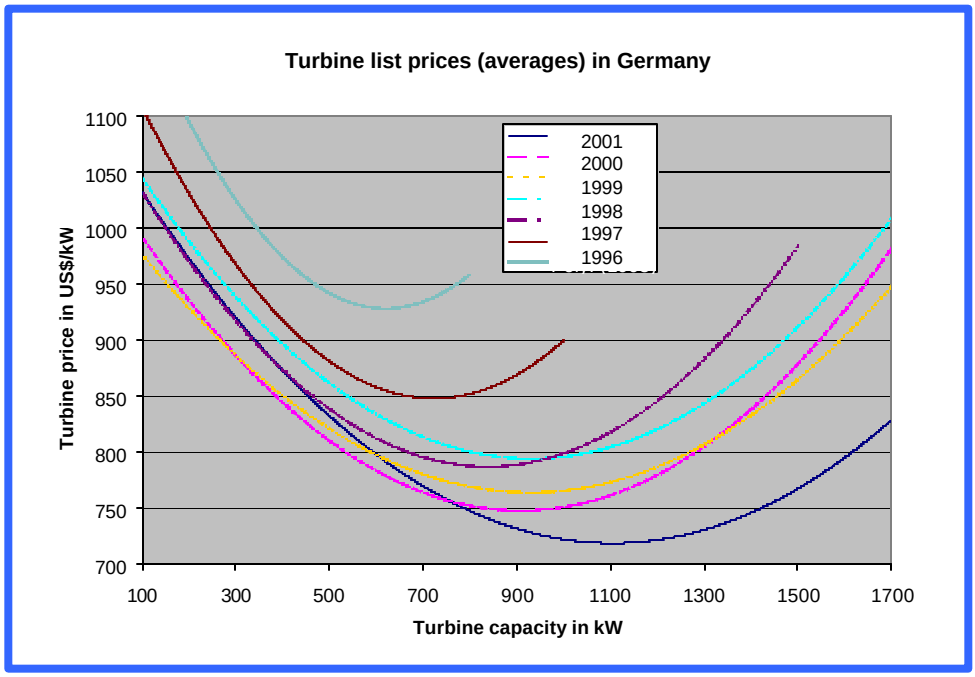
2. TRENDS IN TURBINE PRICES

2.1 Evidence from German List-price Data

The results of our analysis of the German manufacturers' list price data are shown in Figure 2, displayed as the trend lines of all price quotations for each year. The trends are evident: in each year there is a minimum price for the machine size that reflects the dominant market share. Prices for larger machines (at the cutting edge of technology in any year) will be higher, as will prices for smaller machines (for reasons of diseconomies of scale). Thus in 1996, the minimum was for 600kW machines (at 930$/kW), by 2001 this had fallen to $720/kW for 1100kW machines.

Whilst Figure 2 provides a general indication of the trends, there is considerable variation around the trend lines, as indicated in Figure 3 for 2001 data.[8] Moreover, list prices are quoted not just by kW, but also by hub height (which are shown to the right of each point in the Figure). Hub height explains about 10% of the observed variation (for a given kW rating).[9]

Figure 2: Turbine List Price Trends

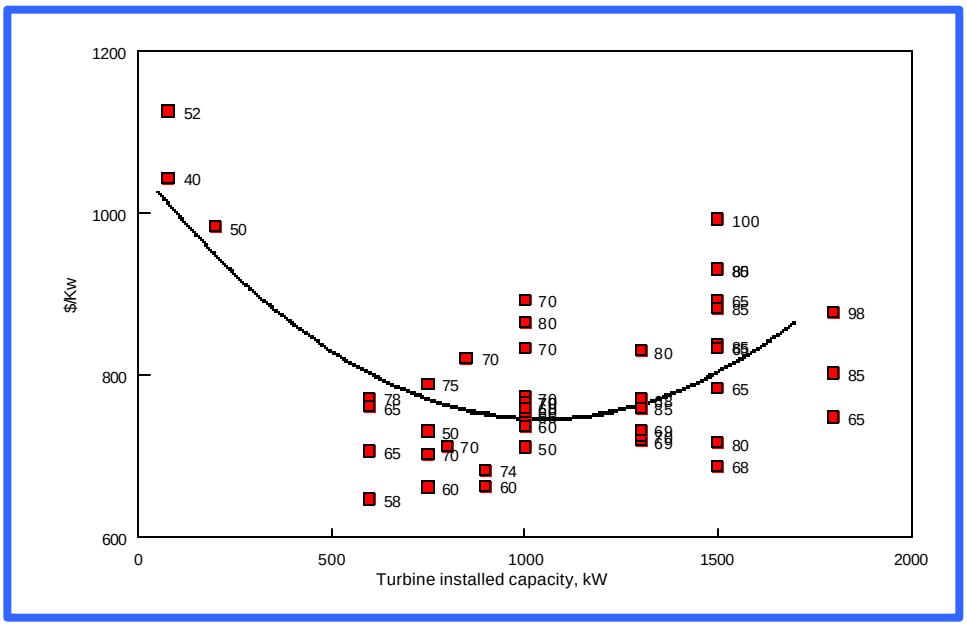


Source: Windkraftanlagenmarkt: Typen, Technik, Preise; Issues 1995-2001

[8] The trend line shown is the second order polynomial [$/kW]=1054 - 0.587[kW] + 0.000281[kW]^2; R^2=0.401

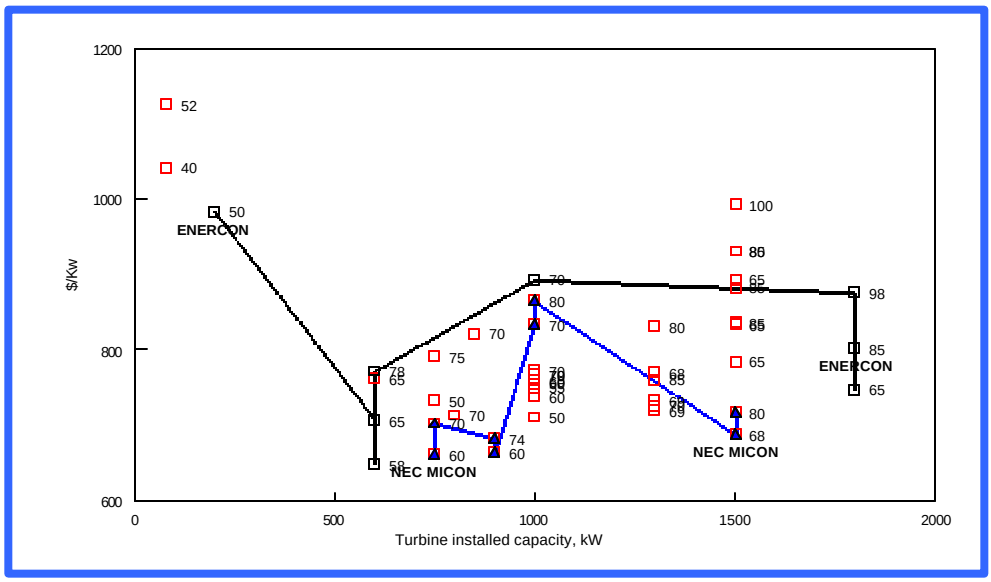
[9] When hub height is added as an independent variable, R^2 increases from 0.401 to 0.50.

Figure 3: List Price Data for 2001, All Manufacturers



An analysis of the prices quoted by individual manufacturers is instructive: Figure 4 shows the data for ENERCON and NEC MICON. It is evident that they follow very different pricing strategies, which explains the low statistical correlation between cost/kW and rated capacity for the data as a whole.[10] It also points to the inherent problem with published list prices, for these may themselves have little relationship to the prices actually negotiated with developers (which are often not in the public domain). Moreover, as noted below, order size plays a further role.

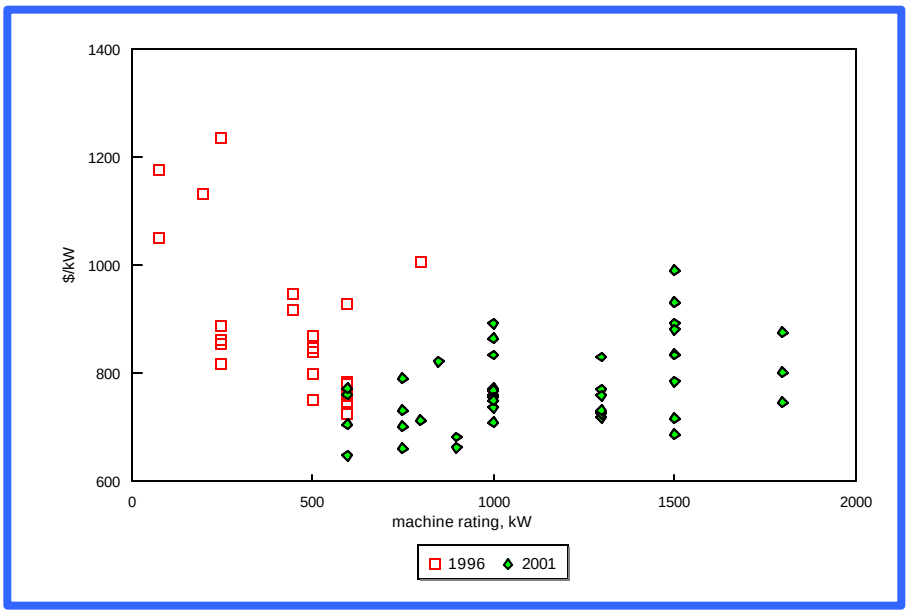
Figure 4: 2001 Prices for Individual Manufacturers



[10] To make the statistical relationships more meaningful, each data point should be weighted by its sales volume. However, this data was not available.

Whatever the uncertainties surrounding individual corporate pricing strategies, when we compare the aggregate change in price relationships over a five-year period, the profound changes that have occurred in the costs of wind machines are unmistakable. In Figure 5 we show the data points for 1996 and 2001, eliminating for the year 2001 the few data points for machines less than 500kW.

Figure 5: Comparison of 1996 and 2001 Costs and Machine Ratings.



In 1996 the data reveal strong scale economies of unit size, with the largest machines (600kW) costing only 60-70% of the smaller sizes – an expected result in the earliest stages of machine size development. But by 2001, the relationship is altogether different: while overall price levels have come down, the trend line for 2001 is, in fact, slightly upward, with the larger machines (1,500kW) quoted at generally higher prices per installed kW than 600kW machines.

2.2 Evidence From Reported Turbine Orders

The second database contains information on actual turbine orders, and covers 40 projects from 1998 to 2001. While hub heights and swept area are not reported, this database does contain information on the number of machines in each project, which permits a statistical analysis. The hypothesis to be tested by the statistical analysis is that price decreases occur as a result of some combination of the following factors:

- Learning curve effect (the more recent the project, the lower the cost);
- Scale economies of total project size (the larger the project size, the lower the project cost);
- Scale economies in manufacture (the larger the number of units per order, the lower the unit cost);
- Scale economies of unit size (the larger the individual machine, the lower its unit cost).

Unfortunately, this database does not record the total project cost, only the total cost of the equipment order. Table 2 shows the correlations among the independent variables: note that the correlation between project size and unit machine size is weak (0.32), and much smaller than project size and number of machines (0.85) – suggesting that bigger machines *per se* have had relatively little effect on project size.

Table 2:
Simple Correlations

Independent Variable	As a proxy for:	Time	Project Size	Number	Unit Size [kW]
Time	Learning curve		0.14	0.10	0.08
Total project size	Project size scale economies	0.14		0.85	0.12
Number of machines in a project	Manufacturing scale economies	0.10	0.85		0.32
Unit size of machine	Unit size economies	0.08	0.12	0.32	

Values shown are correlation coefficients.

As one may expect, the plots of $/kW against the individual independent variables show considerable variation. Nevertheless, the learning effect is clearly evident from the data of Figure 6, as the curves shift downward over time. With regard to the relationship with machine size (the figure to the right of each point shows the rated power) – the raw data suggest *dis*economies of scale – for example, in 1998, the unit cost ($/kW) of a 1.5MW machine was twice that of a 600kW machine. However, this simply reflects the fact that major advances in machine size are initially priced above the main market (until such time as the market as a whole shifts to larger machines, at which point their price also decreases).

Figure 6: $/kW v. Time

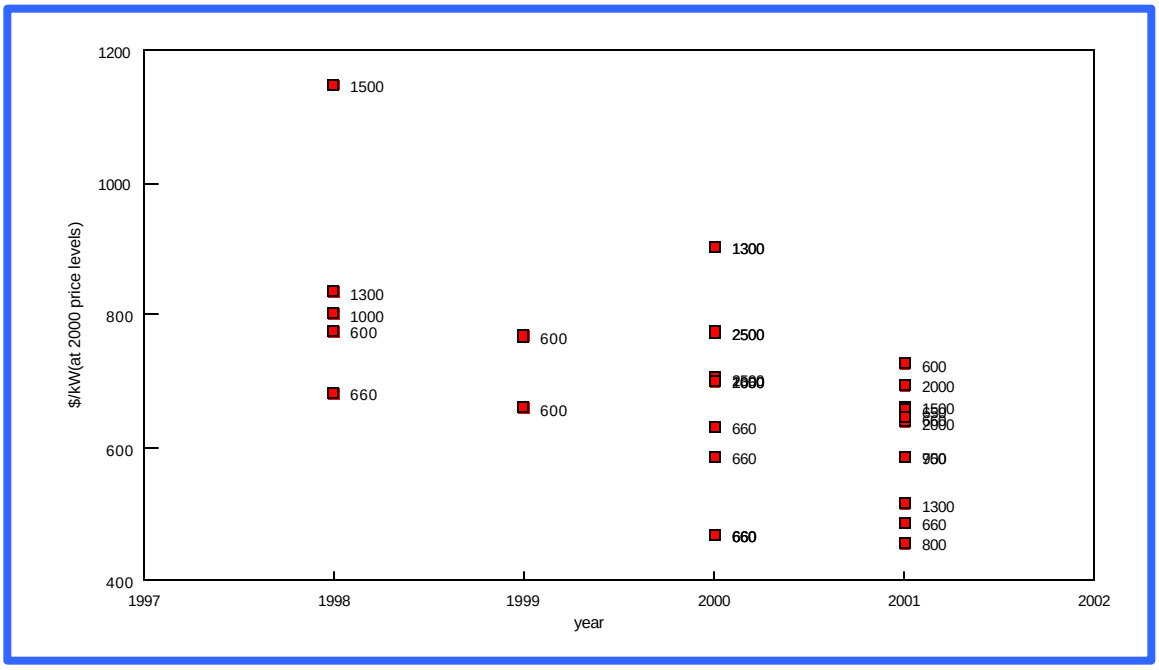
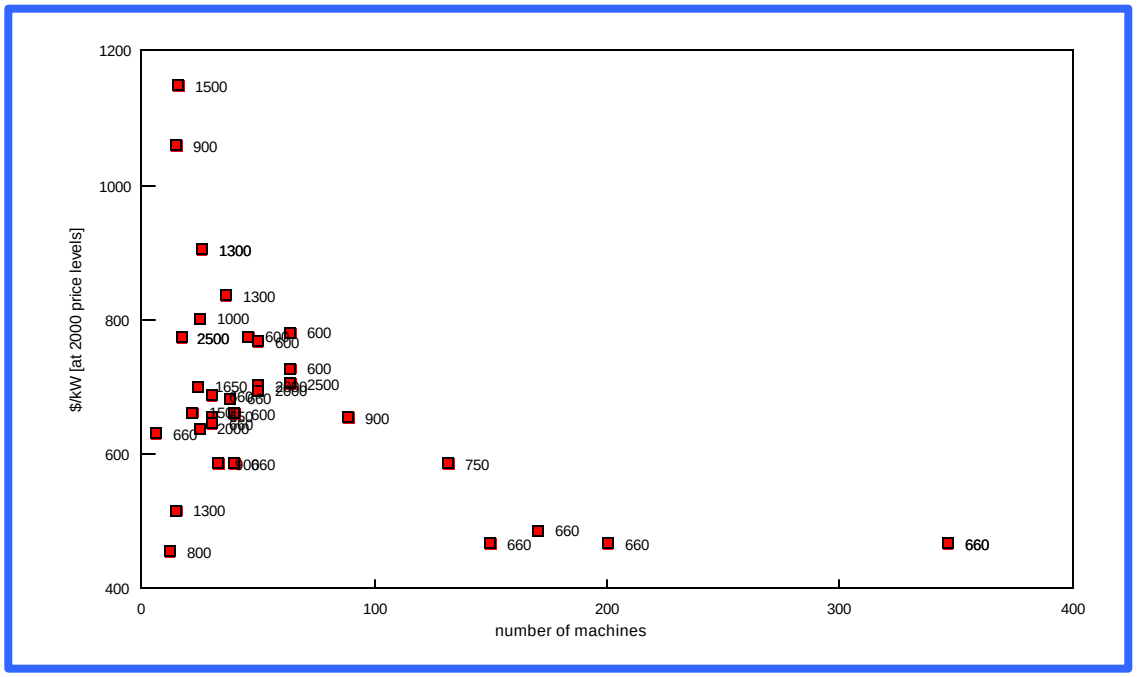


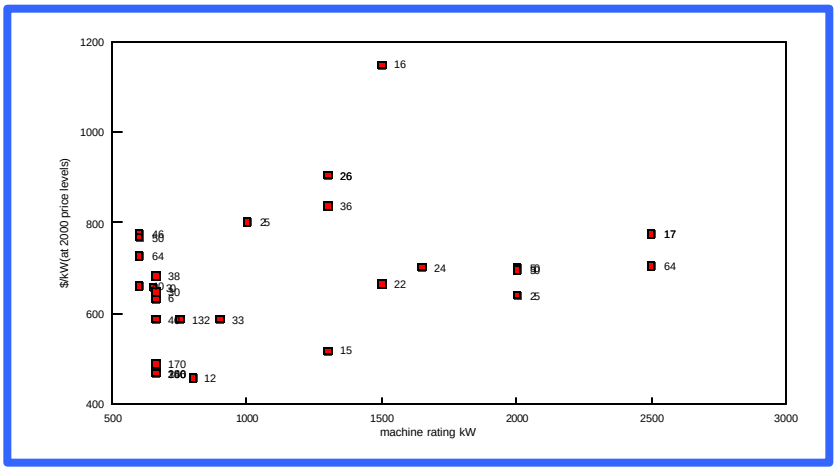
Figure 7 shows the corresponding relationship of cost/kW as a function of the number of machines per order, and Figure 8 cost/kW as a function of machine size. Figure 8 reveals very little correlation between machine size and cost/kW, and certainly is not suggestive of strong scale economies.

Figure 7: $/kW v. Number of Machines Per Order



(numbers at each point show unit machine size)

Figure 8: $/kW v. Machine Size



(numbers at each point show order size, number of machines)

However, even though these simple plots show little evidence of scale economies, this is more a matter of the limitations of simple bivariate plots (and their qualitative interpretations). As we see below when we apply more rigourous multi-variate statistical models, scale economies are indeed a feature of the data.

Note that the data of Figure 8 show a very different relationship to that of the list-price data of Figures 2 and 3. This emphasizes the point that actual prices negotiated between developer and manufacturer (or as revealed in international competitive bidding) depend upon a range of additional factors that are not apparent from data in the public domain: notably the state of each

manufacturers' order books, competitive pressures, and the relative negotiating skills of the parties involved (in the case of MoU or non-competitively bid projects where considerable haggling typically occurs among the parties in a developer's consortium).

Table 3 summarises the statistical analysis.[11] Among the single variable models, the strongest correlation is the learning curve effect, with average prices decreasing $78/kW per year – though even for this best model, the R^2 is only 0.3.

Table 3:
Statistical Models: Dependent Variable: $/kW(at 2000 prices)

		Variables included (and result)	n	R^2
	Single variable models			
1	Learning curve	Time (-78$/kW/year)	1	0.30
2	Manufacturing scale economies	Order size	2	0.28
3	Unit size economies	Rated kW/machine	2	0.20
4	Total project size	Total MW (-1.1[$/kW]/MW)	1	0.14
	Two-variable models			
5		Time, order size	2	0.53
6		Time, unit size	2	0.53
7		Time, total project size	2	0.40
8		Order size, unit size	2	0.34
9	**Three-variable model**	Time, order size, unit size	2	0.61

n=Order of polynomial (e.g., n=1>linear; n=2>quadratic)
(all models shown are statistically significant)

The two-variable models show that the learning curve effect (time variable) is strongly significant, for its exclusion (model 8) significantly reduces the explanatory power (from 0.53 to 0.34). The best model involves the three variables time ((***TIME),*** order size (***O***), and unit size (***MW***), for which the estimated form is[12]

$$[\$/kW] = 722 - \underset{[t=4.21]}{76.5(TIME)} - \underset{[2.3]}{0.663\,O} + \underset{[1.83]}{321\,[MW]} - \underset{[1.46]}{85.3\,[MW]^2} \qquad R^2=0.61$$

The learning curve variable (***TIME***) is the most significant. Nevertheless, it is evident that we can explain only 61% of the variation in cost/kW Clearly there is a great deal of information not in the public domain that may explain the remaining variation.

In any event, other literature supports the general conclusions of scale economies: A detailed study for the Electric Power Research Institute suggests savings for a 25-unit wind farm, compared with a single machine, of the order 25-30%.[13] That study is now dated – although the general principles are valid – but a more recent German study[14] showed that wind farm costs were lower than "single machine" costs by between 2 and 12%.

[11] For which we use here the smallest-order polynomial that is statistically significant.

[12] The t-statistic is shown immediately below the coefficients. All the variables are significant at α=4% or smaller, except the quadratic term in unit size (significant at α=7%)

[13] Bechtel Group Inc, 1983. Cost Estimates for large wind turbines. EPRI Report AP-3276.

[14] Holger, E, Keuper, A and Veltrup, M, 1993. The Operator's Guide to Wind Energy Use. DEWI Magazin No 3, 5-36

3. TRENDS IN PROJECT COSTS

3.1 Project Scale Economies

We now turn to the third database, which contains details of a total of 140 individual projects, and total project cost rather than equipment cost data. The dramatic changes in the level of costs, the numbers of projects, and project size are illustrated in Figures 9 and 10, intentionally plotted on the same axes. In 1998, the USA was the location of the highest unit-cost projects; in 2001, the USA and Canada were the location of the lowest unit cost projects

Figure 9: Unit Cost ($/kW) v. Total Project Size: Projects to be Completed in 1998

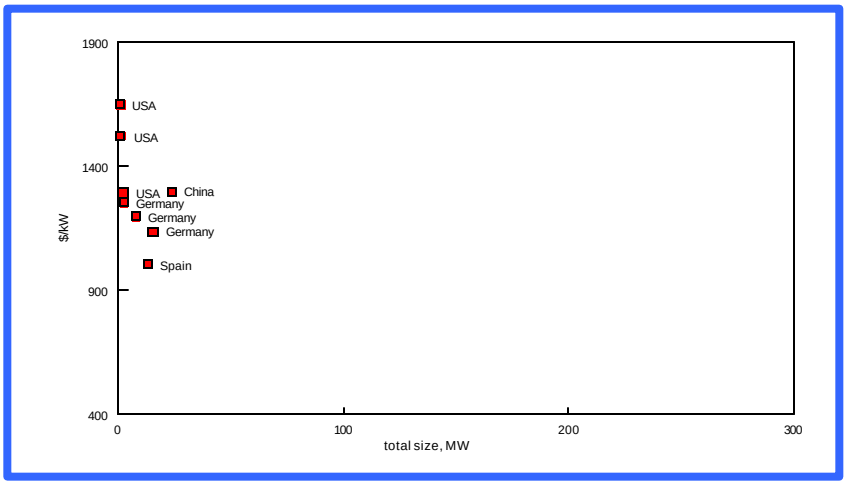
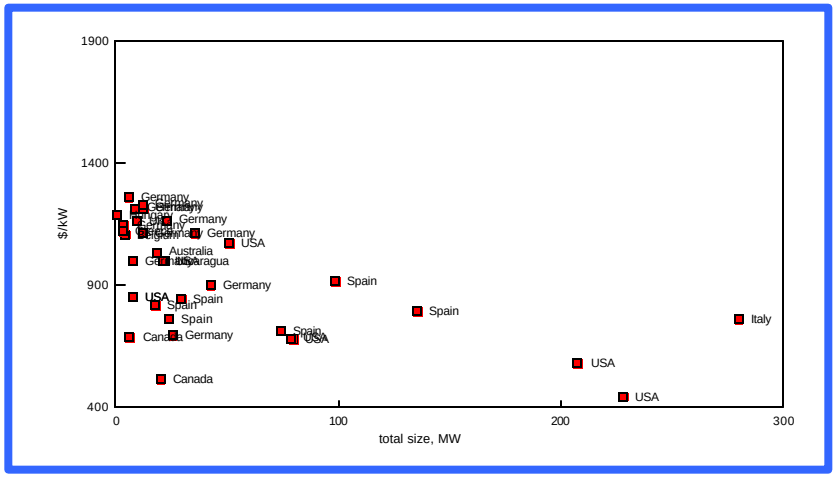


Figure 10: Unit Cost ($/kW) v. Total Project Size: Projects to be Completed in 2001



Large developments tend to have lower capital costs per unit of capacity as they:

- Attract substantial discounts from wind turbine manufacturers. For example, representations to the UK Parliament's Welsh Affairs Committee included estimates that

"100 units may be 20-30% less than 10 units"[15]. The turbine prices shown in Figure 10 provide confirmation of this.

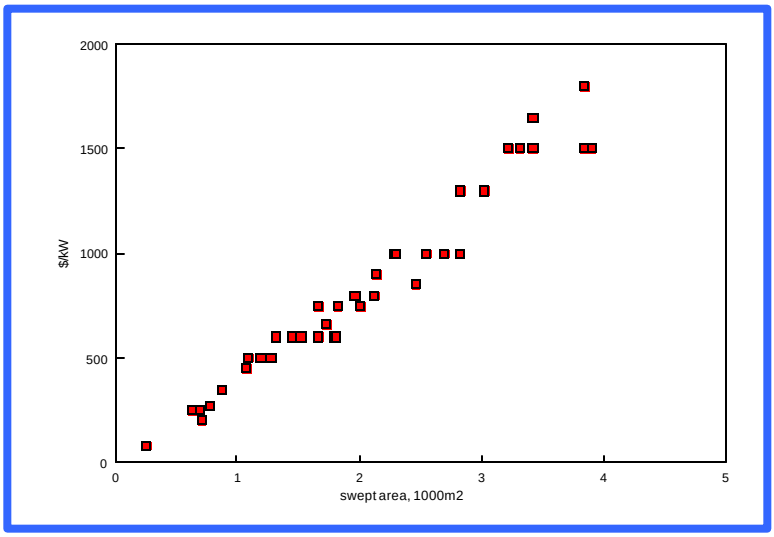
- Enable site infrastructure costs to be spread over a large number of machines, reducing the unit cost;
- May secure lower interest loans; and financing costs - per kW - are likely to be lower.

Data from the UK Non Fossil Fuel Obligation (NFFO) also suggests that larger projects offer cheaper electricity prices (which in capital intensive projects are highly correlated with project cost). In NFFO3, for example, the average bid price of the "small" wind projects (<1.6MW) which were offered contracts was 1p/kWh higher (about 25%) than the "large" (>1.6MW) project energy costs. This effect has also been stated by the American Wind Energy Association AWEA,[16] which expects an even higher cost reduction resulting from scale economy.[17] Electricity prices are analyzed further in Section 4.

Even if Figures 9 and 10 suggest a strong project scale economies, there is considerable scatter in the data presented. Possible reasons for this include:

- Although wind turbine and wind farm costs are conventionally expressed in $/kW, it should be noted that this convention introduces some scatter as manufacturers vary in their rating philosophies. Some 1000 kW wind turbines, for example, have rotor diameters of 50 m and others have diameters of 54 m and the latter will cost more - but deliver significantly more energy. However, as shown in Figure 11, rated kW and swept area are highly correlated, so there would be little change to the previously observed relationships were swept area rather than kW used as the independent variable.

Figure 11: Swept Area (m^2) v. kW Rating



- Differences in sites. High wind sites often demand turbines with high survival wind speeds (which cost more).

[15] House of Commons, (UK) Welsh Affairs Committee, Second Report, 1994. Wind Energy. Evidence by Mr Ishii, para 1512

[16] American Wind Energy Association, 2001. *Comparative Cost of Wind energy and Other Energy Sources.*

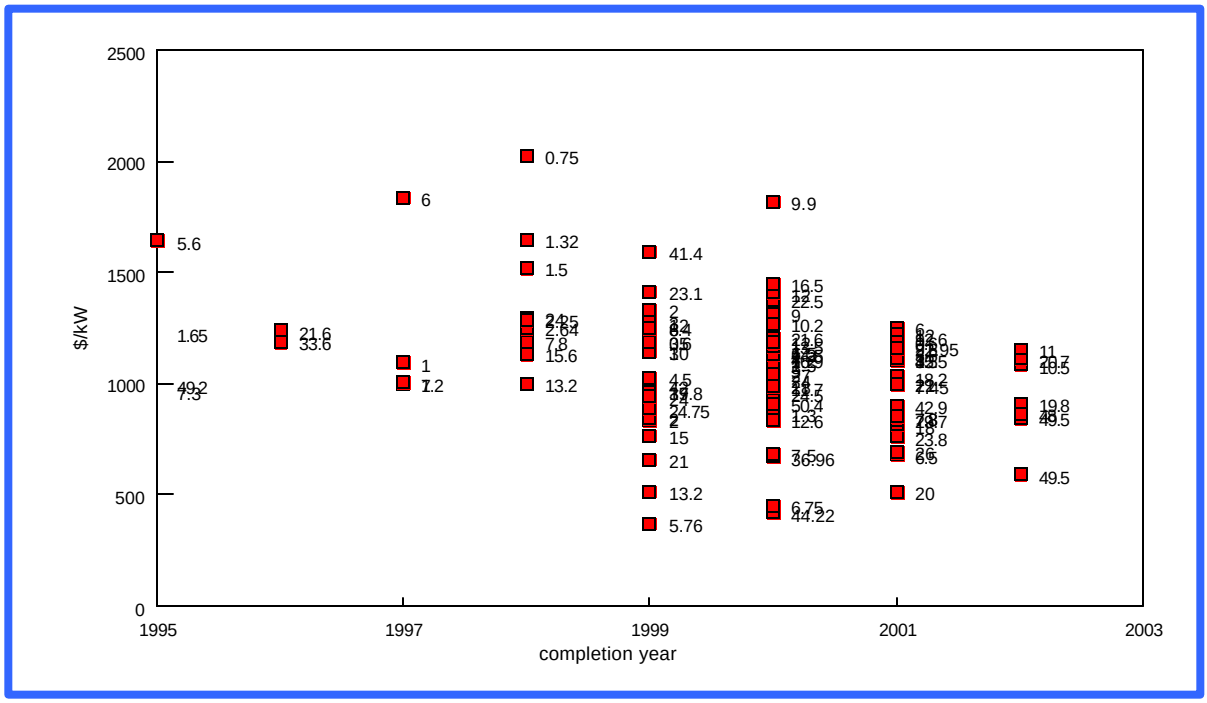
[17] The AWEA says that "a 3-MW wind plant generating electricity at 5.9 cents per kWh would, all other factors being equal, generate electricity at 3.6 cents/kWh if it were 51 MW in size."

- The accessibility of the site in general has a high impact on the costs. The difficult nature of the terrain in some high wind speed sites - often remote hilltops - raises construction costs.
- The common standard of what items are included in the total project costs differ across countries. In Denmark, for instance, the utility pays for grid reinforcement and, for projects of more than 1.5 MW, the grid connection from a junction point at the border of the wind park area.[18] Appendix 1 shows some comparisons of cost breakdowns in different countries.
- In some countries land is owned by the developers whereas in others it is standard practice to lease the land (and therefore to include the lease in the operation and maintenance cost rather than in the capital costs).
- Grid connection is usually paid by the developers but might by subject of negotiation for windfarms in Germany, the UK, Spain and the USA. In the UK, the developer is also responsible for grid reinforcement, if necessary.

3.2 Learning Curve Effects

Prices are falling with time, as suggested by Figure 12. In order to eliminate the influence of size-effects, only projects with capacities smaller than 50 MW are shown. The data reflects the so-called learning of the new technology: with an increase in the cumulative capacity installed worldwide – and therefore over time, there is a considerable gain of experience, which results in cost reductions.[19] Nevertheless, as before, the scatter is great and occurs for the same reasons already noted. In particular, there are large differences in cost due to significant differences in site accessibilities in e.g. between Germany and Australia.

Figure 12: Project Costs Over Time (for projects of 50MW or less)



[18] Information provided by the Danish Wind Turbine Manufacturer's Association.

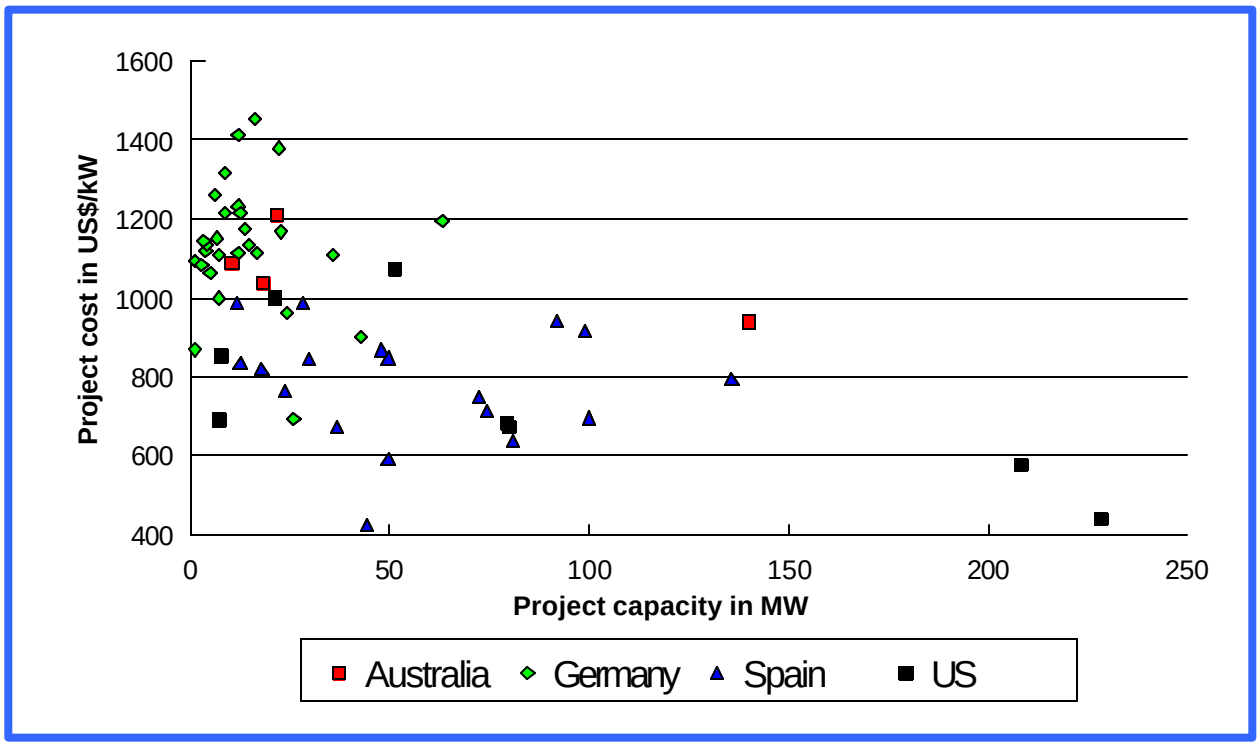
[19] For further discussion on experience curves and their political relevance see, e.g., International Energy Agency *Experience Curves for Energy Technology Policy*, 2000.

3.3 Effect of National Support Mechanisms on Capital Costs

Sections 3.1 and 3.2 show the influence of project size and of learning over time on the cost of wind projects. But the high variation in the unit costs leads to a further hypothesis: that capital costs might be influenced by national policy market support mechanisms.

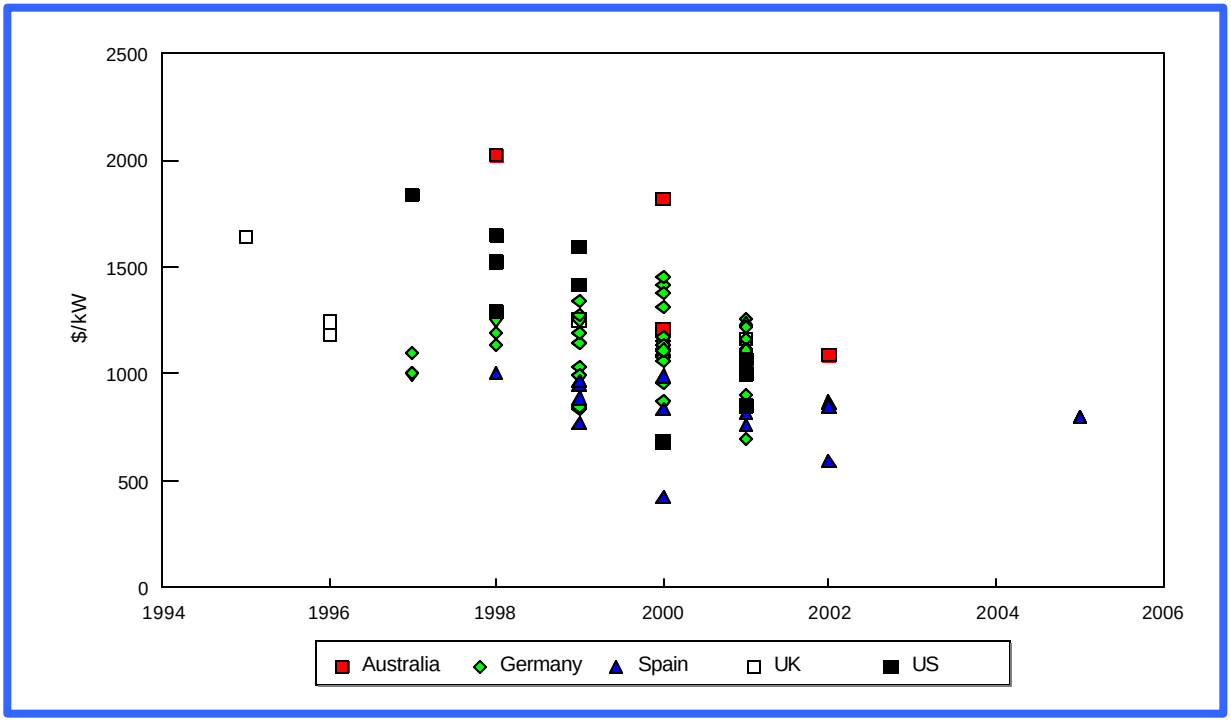
As indicated in Box 1, there are different ways to promote a new technology, depending on the main objective of the incentives. The most important policy decision to be made is whether to support wind energy in a competitive market (i.e. UK, USA and Australia) or to lower risks by guaranteeing a fixed price paid per kWh generated. This last approach is in place in Germany and Spain. The effect of project size on the project costs in Australia, Germany, Spain and the USA is shown in Figure 13. In order to disaggregate the two different effects of scale and time, this chart includes only projects from the years 2000-2002. Even though there are only limited data available, it is evident that there is little evidence of cost reductions with increasing project sizes in Germany and Spain, whereas these can be observed in the USA and (more weakly) in Australia.

Figure 13: Effect of Project Size on Relative Project Cost; Year 2000-2002



The time-dependent cost development for Australia, Germany, Spain, UK and USA is shown in Figure 14. Only projects with total capacities smaller than 50 MW have been taken into consideration in order to eliminate the size effects.

Figure 14: Cost Decrease Over Time in Different Countries, Project Size < 50 MW



Again it is difficult to identify clear trends from such simple bi-variate plots. We therefore turn in the next section to more formal multi-variate models.

3.4 Statistical Evidence

Application of our statistical model to the entire dataset yielded no useful insights.[20] However, when the data was split into four separate sets: Germany; Spain; the competitive regimes of USA, UK and Australia; and the rest of the world, the results were striking, as shown in Table 4.[21]

[20] No statistically significant model was found using all of the projects in the data set. Even when we added country dummy (0/1) variables (for Spain and Germany) , no useful relationships were found. However, time limitations prevented an exhaustive study of alternative model hypotheses. Alternative models using log and log-log relationships are currently being studied.

[21] The ***time*** variable is simply the reported completion date-1995 (the year of the first project in the database); thus projects completed, for example, in year 2001 thus have a time value of 6.

Table 4:
Results of Statistical Analysis (R^2 of ordinary least squares against dependent variable: $/kW, normalized to 2000 price levels)

	USA + UK + Australia	Spain	Germany	Rest-of-world
number of projects	26	18	60	19
Single variable models				
Time	**.40**	0.03	0.00	0.00
Machine size (kW/machine)	**.47**	0.08	0.01	0.07
project size (total MW)	**.43**	**0.24**	**0.16**	0.05
Number of turbines	**.35**	0.08	0.01	0.05
Multivariate models				
Machine size, time	**0.54**	**0.17**	0.04	
Machine size, total MW	**0.69**	**0.33**	0.17	
Machine size, total MW, time	**0.70**	0.33	0.17	
Machine size, total MW, time, number	**0.72**			
+dummy for UK (remove total MW)	**0.79**			
+dummy for Australia (remove total MW)	**0.81**			

Boldface indicates statistically significant relationships

Germany has the least competitive regime, and wind power operates under a generous Feed-in Law system. Among the single-variable models, only total project size (MW) had any significant influence on cost/kW, albeit weak (R^2=0.16). However, for the rest-of-the world, no statistically significant relationships could be found – which, given the diversity of these countries, the fact that many of these are first demonstration projects (as in the case of Sri Lanka), and/or funded under bilateral grants that generally operate under favored-nation procurement (or other non-competitive or only partially competitive) arrangements, is hardly surprising. Spain, with a considerably less generous Feed-in Law provision than Germany, at least shows a slightly stronger correlation with project size (R^2=0.24), but again both time and machine size variables are not significant. But for the competitive regimes, all of the single-variable models are statistically significant.

These individual relationships carry through into the multivariate models – in the case of Germany, addition of time and machine size variables to total MW is not statistically significant, and the R^2 of the best multivariate model is a modest 0.33. But in the case of the competitive regimes, the results of the multivariate model are surprisingly good: the best model is[22]

$$\textit{Project cost[\$/kW]} = 2544 - \underset{\textbf{[t=1.93]}}{1569\,[\textit{turbine size,kW}]} + \underset{[1.4]}{530\,[\textit{turbine size, kW}]^2} - \underset{\textbf{[2.4]}}{84.6\,[\textit{time}]}$$
$$- \underset{\textbf{[3.66]}}{2.38\,[\#\textit{turbines}]} - \underset{\textbf{[2.13]}}{271\,[\textit{UK}]} + \underset{[1.7]}{261\,[\textit{Australia}]};\quad R^2 = 0.81$$

[22] All the t-values are significant at α=0.05 except the quadratic term for turbine size, and the Australia variable, significant at which are significant at α=0.1.

All the coefficients have the expected (negative) sign.[23] Note that once the dummy variables are added, total project size is no longer statistically significant, because much of the size effect in the dataset is attributable to country differences (average size in the UK is 12.1MW, Australia 15.8MW as against 51MW in the USA). The effectiveness of the NFFO regime in the UK is particularly evident, given that a UK location lowers average costs by $261/kW.

To be sure, there is another 19% of the cost variation not explained by these variables, but it is hard to avoid the conclusion that in the Feed-in Law regimes, nearly all the benefits of learning curve effects and scale economies of machine size have been captured by developers and manufacturers, not consumers. It is hardly surprising that developers have found these regimes very attractive, and that Spain and Germany have accounted for the bulk of the new wind capacity installed over the past few years.

Although there are doubtless some problems with the database, the following conclusions may reasonably be drawn from this analysis:

- The type of support mechanism employed has great importance for the reduction of capital costs. The evidence that the greatest capital cost reductions have occurred in the competitive markets of Australia, the USA and the UK, and the lack of any observable trend in project costs in Spain and Germany, is compelling.
- The lack of cost reduction at the project level in Germany is even more remarkable given the evidence of cost reductions in German *equipment* (noted in Section 2):[24] It is of course true that there are an increasing number of less favorable sites in Germany, as these have spread from the high wind speeds in Northern and coastal Germany into the South. But lower wind speeds and lower energy yields (and capacity factors) would normally result in higher average costs per kWh, not higher capital costs per kW. However, given the additional incentives given in the new German Renewable Energy Law to wind energy produced at poorer sites, it is hardly surprising that this leads to higher capital costs (e.g. very tall towers to reach higher windspeeds available at the greater heights).

[23] In the case of the turbine size variable, the positive sign for the second order term reflects the parabolic form of the relationship described in Section 2 for *turbine* prices: it is interesting to note that this same relationship is found in the *project* level data as well.

[24] It is recognized that UK sites may have better capacity factors than in Germany, and may therefore have lower unit *energy* costs. But lower capacity factors *per se* do not explain lack of progress in reducing *capital* costs.

4. WHAT DETERMINES WIND ELECTRICITY PRICES?

Prices paid for wind-generated electricity show wide variations, from a minimum of about 3 c/kWh (in the United Kingdom), to around 9 c/kWh (in Germany):

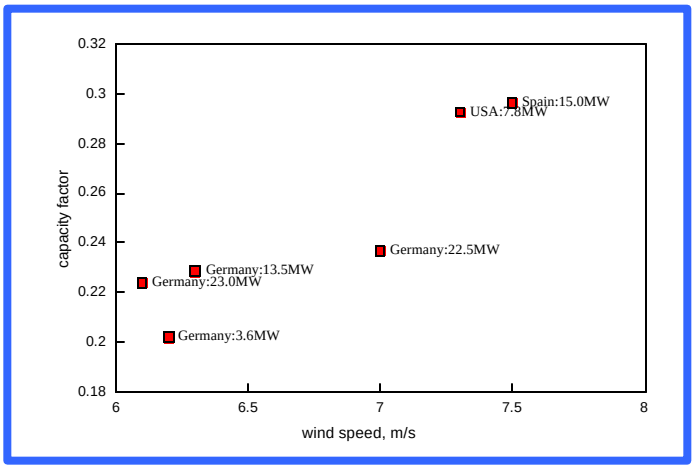
- British prices were set by competitive bidding, whereas German prices are fixed by law
- Wind speed variations: the best wind speed sites in Germany are on a par with the poorest in Britain
- Institutional factors: The UK NFFO guaranteed prices for 15 years, but most German developments rely on loans from a state-backed bank, with 10-year terms the norm.

Other factors that may influence installed costs of wind farms are the state of maturity of the technology in the country concerned, which is affected by historical factors, such as the length of time incentives have been in place. Moreover, there are differences in capital and operating costs, given that the windiest sites tend to be most difficult to reach.

4.1 The Influence of Site Characteristics on Wind Energy Prices

There is very little *empirical* data on how site characteristics affect wind costs and prices. In our database of 128 windfarms, only seven[25] record both wind speed and annual capacity factor, as shown in Figure 15 – certainly too small a sample to draw generalised conclusions.[26]

Figure 15: Capacity Factor v. Wind Speed



Moreover, only 48 projects in our database record annual energy (from which capacity factors can be derived), whose frequency distribution is shown in Figure 16. It does seem evident that capacity factors in Germany are below the average, and those of the UK significantly above the average (which reflects the general view that the wind regime in the UK is among the best in Europe). But how well actual production figures match these reported design energy values is unknown.

[25] The two USA projects shown in the graph are essentially identical, and overlap.

[26] The data in Figure 15 show energy capture rather than instantaneous power (which varies as the cube of wind speed). Indeed, a cubic relationship could be also be demonstrated (with an R^2 of 0.861); but this is statistically indistinguishable to a linear fit (R^2=0.849), which is another way of saying that seven data points are insufficient to say anything meaningful.

Figure 16: Capacity Factors

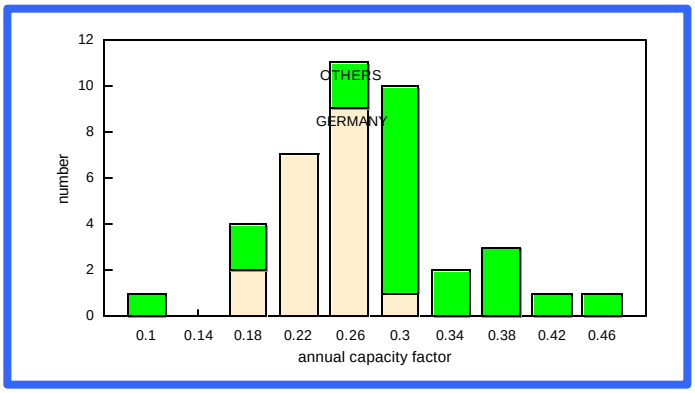


Table 5:
Average Capacity Factors

Country	N	
USA	4	0.256
Spain	10	0.275
UK	4	0.380
Germany	19	0.216
All	48	0.252

What does seem clear (from the previous discussion of the German list price database) is that hub height has a significant influence on capital cost of the WTG. For a given site, higher hub heights permit exploitation of the higher wind speeds available at the greater height. But while poor wind speeds may explain higher than average energy prices (because for given capital outlay, less energy is generated), all other things equal, lower wind speeds would generally be associated with *lower* (not higher) capital costs (given that high windspeed sites are generally reported as being associated with more difficult terrain and are more remote).[27] It may of course be true that higher towers are used at sub-optimal sites in Germany[28] in an attempt to benefit from the better windspeeds at higher height (which developers can afford because of the fixed prices offered).[29] However most of the German projects in our database are in the higher windspeed sites in the North. Clearly this question merits further research, because the data suggest that the present Renewable Energy Law results in a misallocation of capital (because the incentives reward the use of wind resources that are on points in the wind resource supply curve that lie far above the avoided externality cost).[30] In this further work we plan to correlate new German operating data

[27] However, even this widely quoted generality seems to be disproved by the actual UK data: as we have seen in the previous section, the higher wind-speed UK projects have *lower* capital costs. It appears that the discipline of a competitive market forces greater care in site optimization.

[28] For example the 1997 EWEA Strategy paper on costs, prices and values claims that " . . . the more accessible - and cheaper - sites in Germany were used up in the early years of the wind programme and later construction has had to use more expensive sites."

[29] This is certainly true under the new German Renewable Energy Law, under which guaranteed prices for poor sites are higher!

[30] The effect of the extra reward for poor sites is largely to reward equipment manufacturers with larger hardware orders than would otherwise be the case. For further discussion of wind resource supply curves and avoided externality

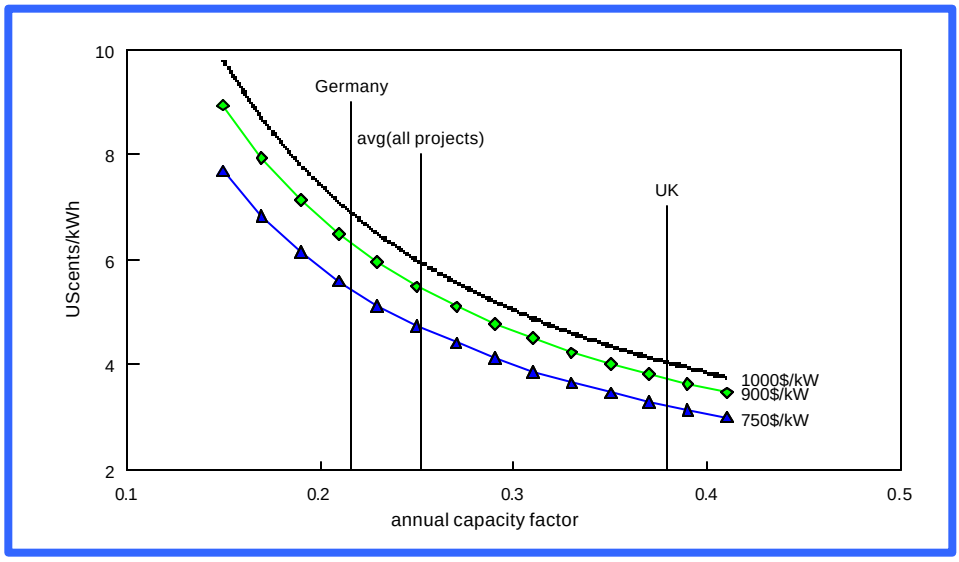
with the reported project cost data already in our database (that will provide a clearer picture of the relationship between windspeeds and capital costs).

4.2 Economic Costs

Figure 17 shows the relationship of *economic* cost and capacity factor under different capital cost assumptions, using a discount rate of 9%[31] and an economic life of 20 years. We make the following assumptions:

- Capital costs: Several commentators suggest that the world average cost of wind farms is about $ 1000/kW, which will be our standard value. Nevertheless, the most recent orders for wind turbines show prices around $500/kW (see Figure 4). Taking a conservative figure of $250/kW for "balance of plant costs" therefore suggests large wind farms can now be built (at least in the USA) for around $750/kW.
- Operation and maintenance costs assumed as a fixed annual amount of $15/kW installed/year plus a variable cost per kWh of 0.3 c/kWh. These are a conservative "best average" values, drawn from a wide range of sources.

Figure 17: Economic Costs of Wind Generated Electricity v. Annual Capacity Factor



4.3 Impact of Financing Package

A complete analysis of the relationship of price to the financing arrangements lies beyond the scope of this paper.[32] However some indication of the differences of financing packages across countries is evident from the sample of windfarm projects shown in Table 6, which draws together

costs, see, e.g.., P. Meier, China Renewable Energy Scale-up Program: Economic Analysis of a Mandated Market Share Policy, World Bank, April 2001.

[31] This corresponds to typical weighted average costs of capital, assuming 13.5% return on equity, a 27.5% equity share, and debt at 7% (which computes to 8.88%). Developing country opportunity costs of capital are typically higher at 10-12%.

[32] For detailed analyses see. e.g., E. S. Piscitello and V. S.Bogach, Financial Incentives for Renewable Energy Development, Proceedings of an International Workshop, February 17-21, 1997, Amsterdam, Netherlands; D. Milborrow, Wind farm cost and electricity price analysis, Report to the World Bank, 2001; or P. Meier, Wind farm pricing in China, World Bank, September 2001.

performance and cost parameters from various sources and aims to give in an insight into typical numbers for capital costs, wind speed, financing regime and the electricity prices. It shows examples for typical wind energy price data in three European countries, America and China. The table clearly shows the wide variations in financing arrangements and the influence they have on electricity prices.[33] Other causes of apparent price variations arise from non-technical factors, such as the rents paid to landowners, and local taxes.

Table 6:
Sample Price Analysis

	GB	GB	DE	DE	DE	DK	USA	China
	SRO1	SRO3	Ref 2	WPM[34]	WPM[35]	Ref 5	Ref [36]	Ref [37]
Date	1997	2000	1999	2000	2000	1998	2001	2001
Comment	Project	Project	Generic	Project	Project	Average	Iowa	Proposed
Installed, $/kW**	1100	1223	986	1313	1324	809	1215	1024
Wind speed, m/s	8.6	9+*	6*	6.2*		7*	8	7.2
Production, kWh/kW	3540	3900*	2000	2317	1811	2100*	2980	-
discount rate, % (whole project)	8*	6*	5.5			5	13.25#	-
Equity, %, return, %				30, 13.9	30, -		50,18, post-tax	
Loan repayment (yr)	15	15	10			20	15	-
Energy costs (c/kWh)								-
Capital repayments	4.4*	3*	6.5			2.8*	5.3#	-
O & M cost	1.2*	0.7*	1.5			0.7*	0.8	-
TOTAL	c.5.6	2.8-3.7	8***	8***	8***	3.5	6.1	8.4

Notes: All wind speeds at hub height
** Author's estimates.*
*** Converted from money of the day to $ at the current exchange rate*
**** Price paid by German law for first 5 years (approx), 6.3 c/kWh thereafter*
 # This appears to be an actual (not real) rate, but this is not explicit; the total electricity price is quoted net of the Production Tax Credit, which has been added on here. O&M data are quoted, enabling the O&M electricity price to be derived and capital repayments to be inferred.

Trends in electricity prices are presented in Figure 18.[38] The chart compares the German and Spanish Feed-in Tariffs with the average NFFO-prices for large windfarms in the UK and contract prices in the USA. Whereas the prices in Germany and Spain are fixed by law (see Box 1 for a detailed discussion), they are subject of negotiations in competitive markets. For that reason, the prices of electricity in the USA have been collected from issues of *Windpower Monthly* and each data point represents only the price contracted for one project. For the UK, the data points present the average contract prices under the series of Renewable Obligations (NFFO).

[33] Data in the table that is not marked with an asterisk comes directly from the original source, or from published information about the energy prices paid by the appropriate support mechanism. In the first column, for example, the developer secured a contract from the first Scottish Renewables Order and quotes a contract price "about 4p/kWh". Project test discount rates in the first two columns come from published information on the cost of capital in the utility sector, although a check has been made to confirm it yields electricity prices consistent with the other information.

[34] Wind Wire, Windpower Monthly, September 2000

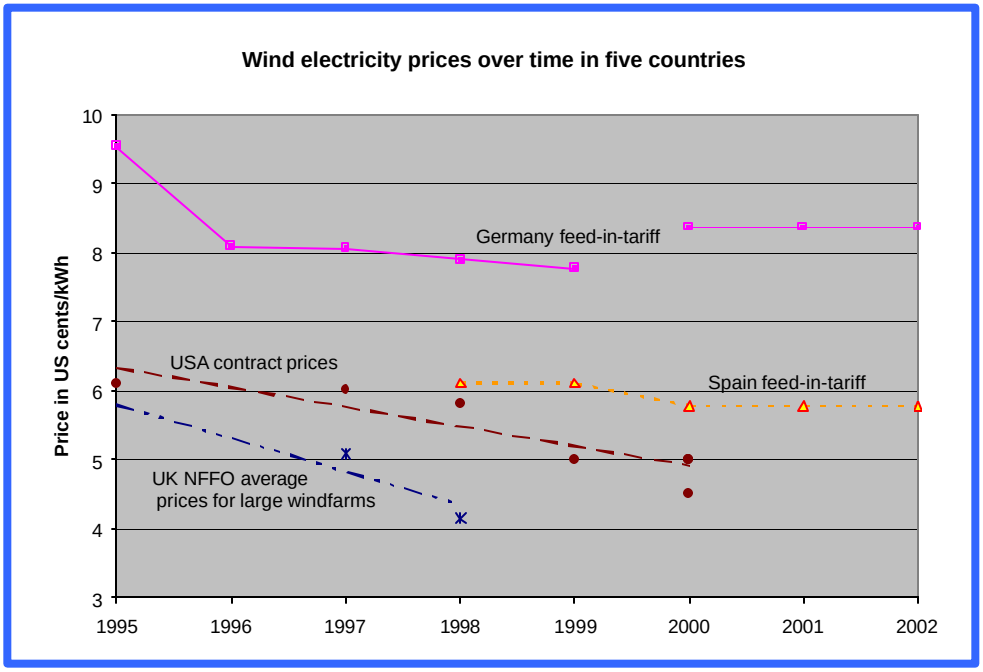
[35] Knight, S, 2001. The price of security for wind investors. Windpower Monthly, March

[36] Wind, T A, 2000. Projected impact of a Renewables Portfolio Standard on Iowa's electricity prices. Wind Utility Consulting.

[37] www.windpoweronline.com. Authenticity not verified

[38] These are not adjusted for inflation

Figure 18: Price Trends



The following conclusions are evident:

- Electricity prices are lower in competitive markets than the Feed-in Tariffs set in Germany and Spain.
- The prices in the UK decrease rapidly. The minimum bid price of the UK Non-Fossil Fuel Obligation (NFFO) practically halved between 1994 and 1998. A glance at the capital costs suggests that there must have been additional, important factors leading to this price reduction, notably the exploitation of sites with very good wind regimes and declining interest rates (from 10% to 7%) and longer repayment periods (now 15 years).
- Comparing the curve of cost reductions in all four countries, the UK has the steepest gradient, meaning the most important price reductions over time. On the other hand, the UK has much less wind power installed than Germany, Spain and the USA (see Figure 1).

5. CONCLUSIONS

While recognizing the problems with published data, we draw the following conclusions:

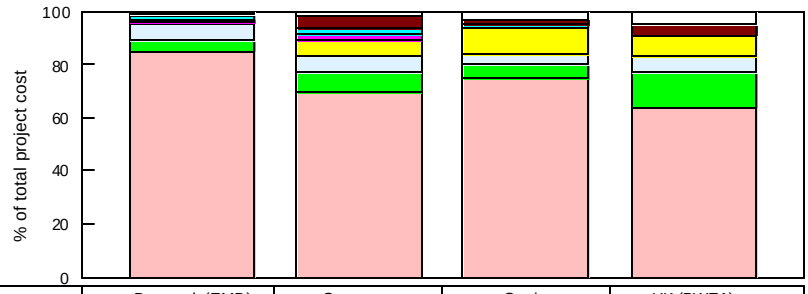
1. In the competitive policy regimes of the UK, USA and Australia, the data are consistent with classical economic theory: learning curve, scale economies of project size, turbine size, and turbine are all statistically significant in a multivariate model which explains 81% of the variation of reported project costs in these countries.
2. By contrast, the German project cost data, and the set of data from the rest of the world, reveal no statistically significant relationship at all. It would be expected the data from the rest-of-the world (which includes projects in many developing countries) does not show much in the way of cost reduction, since many of these have been developed under (largely uncompetitive) bilateral assistance.
3. Indeed, published German turbine list prices do reveal learning curve, turbine size, and turbine order size economies, though the explanatory power of the model is lower (R^2=0.61) than for the project scale model (R^2=0.81). One might have expected that these relationships carry over into project costs, but evidently that is not the case.
4. Although list prices may differ significantly from deals actually made between equipment suppliers and developers, it is much more likely that deals would be *below* the list price, than *above* the list price. Consequently it is reasonable to conclude that developers rather than manufacturers are the principal beneficiary of the generous Feed-in Law tariffs provided in Germany (though the equipment manufacturers would still benefit from the profits associated with higher volume of manufacture).
5. Our initial research hypothesis, that the evidence for learning curve and scale economy effects would be strongly dependant upon the extent of competitive market regimes is therefore confirmed.

Nevertheless, while one may criticize the Feed-in Law regimes for their generous prices, the stimulus given to technological innovation by the fast-growing German (and Spanish) wind markets has been to the benefit of wind-farm development everywhere: developers in the competitive regimes would not have been able to offer the much lower prices without the decrease in turbine prices offered by European manufacturers responding to the much larger volumes in the Feed-in Law countries.

APPENDIX 1: BREAKDOWN OF PROJECT COSTS

A further investigation of the capital costs requires the examination of the "balance of plant costs" - the difference between total installed costs and turbine costs. As part of an investigation of data published by the British Wind Energy Association BWEA,[39] Euwinet[40] and EMD, [41] a country-specific project cost - breakdown (Figure 16) had been established. The range of the balance of plant costs amount to 19-36% of the total project costs; they are naturally very site-specific and also depend on machine numbers, as several items in the "balance of plant" cost category decrease with machine numbers, especially foundation costs, electrical interconnection costs, grid connection costs and site establishment costs.

Figure 22: Capital Cost Breakdown, Selected Countries



	Denmark (EMD)	Germany	Spain	UK (BWEA)
WTG	85.1	69.5	75	64
Foundation	4	7.5	5	13
Grid	6.3	6.5	4	6
Electric	0.9	5.5	10	8
Land	1.1	2.5		
Infrastructure	1.1	2	1	
Proj.Devel.	0.5	5	2	4
Other	1	2	3	5

Comparisons of this kind are inevitably bedeviled by the use of different categories of cost. A further complicating factor is that land costs are included in some figures for installed costs but British and American practice tends towards paying landowners a rent, based on the income received by the wind farm (typically 1 to 2%). Most recent European data include grid connection costs - which can be subject to a high degree of variation - but American studies by the Department of Energy tend to omit these factors.

The example of Denmark can be seen as a best-practice case with very little balance of plant costs. The main factors leading to the small balance-of-plant costs include[42]

- low land costs as WTGs are often on "own" land
- payment of grid connection, which is mostly provided by the utilities
- low project development costs, since projects are primarily developed by the operators themselves
- low transportation costs due to the manufacture in Denmark
- extreme reduction in the cost of civil and electrical installations

[39] British Wind Energy Association; see www.britishwindenergy.co.uk

[40] European Wind Energy Network EUWINET; see http://euwinet.iset.uni-kassel.de

[41] Energi-og Miljødata (EMD), Denmark

[42] Communication with Per Nielsen, Energi- og Miljødata (EMD), Denmark, June, 2001

APPENDIX 2: DATABASE

Extract

	Source	Date published		Investor / Remarks	Total invest	Currency	Price in year	Price in year	1.1.2000 US$	Project cost	Project costs	Price in year	Price in year	Capacity	Costs in 1000	Date of inaug	costs in 1000	costs in 1000	Generated en	Manufacturer	Turbine Type	number of tur	Windspeed	capfac
n	source	date	country	remarks	totinv	curr	priceY	price2000	exch	cost	cost2000	P1	P2	MW		startup	$/kWCosty	$/kWCosts	GWh	manufact	Type	number	windspeed	capfac
1	Windpower Monthly	Apr-98	Australia	Tasmania	2.5	A $	2.02	1.52	0.6446	1.61	1.67	2.50	1.48	0.75	2229.8	1998	1978.2	2025.1		Nordex	250	3	9.7	0.000
2	Planetark	30-Jun-2000	Australia	Western Power	45	A$	45.00	26.10	0.6086	27.00	27.00	45.00	26.10	21.6	1251.3	2000	1208.2	1208.2		Enercon	1800	12		0.000
3	Windpower Monthly	Apr-2000	Australia	Blayney / Pacific Power	18	$	18.00	18.00			18.00		18.00	9.9	1818.2	2000	1818.2	1818.2		Vestas	660	15		0.000
4	Pacific Hydro & Planetark	14-Jul-2000	Australia	Codrington / Pacific Hydro L	33	A $	32.48	18.84	0.5810	18.50	18.50	33.00	19.14	18.2	1071.4	2001	1051.5	1035.0			1300	14		0.000
5	Windpower Monthly	Jun-2001	Australia	Babcock & Brown	230	A$	226.40	131.20	0.5431	124.91	124.91	230.00	122.38	140	892.2	2002	952.7	937.8						0.000
6	Planetark	28-Nov-2000	Australia	Hydro Tasmania	20	A$	19.60	11.42	0.5250	10.52	10.52	20.00	11.60	10.5	1001.7	2002	1104.6	1087.3		Vestas	1750	6		0.000
7	Windpower Monthly	May-2001	Belgium	Electrabel	5.4	Euro	5.40	4.98	0.8972	4.84	4.84	5.40	4.98	4.5	1076.6	2001	1106.5	1106.5		Enron	1500	3		0.000
8	Windpower Monthly	Nov-98	Canada	Le Nordais	180	C$	180.00	107.23	0.6353	101.65	101.65	164.36	110.67	99.75	1019.0	2000	1108.4	1080.0	149.7	NEG Micon	750	133		0.171
9	iwr	22-Feb-2001	Canada	Canadian Hydro Developers	23	DM	21.76	10.23	2.1530	10.68	10.68	23.00	10.61	20	534.1	2001	540.7	511.4		Nordex	1300	15		0.000
10	Windpower Monthly	May-2001	Canada	Hydro Developer	7	C$	6.82	4.46	0.5985	3.55	3.55	7.00	4.71	6.5	545.5	2001	725.1	685.7		Nordex	1300	5		0.000
11	Windpower Monthly / Planet	5/1/2001 & 19 apr 01	Canada	Enbridge Inc & Suncor Energ	20	C$	18.91	12.74	0.5065	10.13	10.13	20.00	13.47	11	920.9	2002	1224.2	1157.7		Vestas		17		0.000
12	Windpower Monthly	Sep-98	China	Shantou	30	$	28.58	31.13			31.13		31.13	24	1297.2	1998	1297.2	1297.2		NEG Micon	600	40		0.000
13	Nordex	24-Nov-98	China	Guangdong	15	DM	14.64	6.88	1.7010	8.82	9.15	15.23	7.16	13.2	693.3	1999	540.4	521.5		Nordex	600	22		0.000
14	Windpower Monthly	Dec-98	China	Hubei	34	NLG	33.18	13.89	1.8873	18.02	18.70	34.75	14.54	21	690.3	1999	692.2	661.0			600	35		0.000
15	Windpower Monthly	Nov-98	Costa Rica	Lake Arenal	24.5	$	24.50	24.50			24.50		24.50	24	1020.8	2000	1020.8	1020.8		NEG Micon	750	32		0.000
16	Windpower Monthly	Apr-2001	Costa Rica	Guanacaste	18	$	18.00	18.00			18.00		18.00	19.8	909.1	2002	909.1	909.1		Vestas	660	30		0.000
17	Wind Project Development		Germany	Wind Project Development	2.3	DM	2.25	1.20	1.7358	1.33	1.41	2.34	1.10	1.2	1172.7	1997	916.6	1000.2		DeWind	600	2		0.000
18	Nordex	26-Jun-97	Germany	Buergerwindpark	13.5	DM	14.98	7.84	1.7265	7.82	8.30	13.96	6.57	7	1186.3	1997	938.1	1006.4	13.8	Nordex	1000	7		0.225
19	Wind Project Development		Germany	Wind Project Development	2.1	DM	2.33	1.10	1.7358	1.21	1.28	2.14	1.00	1	1284.9	1997	1004.3	1095.9		Enercon	500	2		0.000
20	Wind Project Development		Germany	Wind Project Development	35.4	DM	37.74	17.25	1.7560	20.16	20.82	35.84	16.90	15.6	1341.0	1998	1083.2	1137.6		AN Bonus	1300	12		0.000
21	Wind Project Development		Germany	Wind Project Development	18.6	DM	19.83	9.32	1.7560	10.59	10.99	18.88	8.88	7.8	1409.2	1998	1138.3	1195.4		AN Bonus	1300	6		0.000
22	Wind Project Development		Germany	Wind Project Development	6.6	DM	7.04	3.31	1.7560	3.76	3.90	6.70	3.15	2.64	1477.4	1998	1193.4	1253.2		Vestas	660	4		0.000
23	Wind Project Development		Germany	Wind Project Development	3.5	DM	3.56	1.67	1.8490	1.89	1.93	3.52	1.66	2	967.2	1999	827.7	896.4		AN Bonus	1000	2		0.000
24	Wind Project Development		Germany	Wind Project Development	3.55	DM	3.61	1.70	1.8490	1.92	1.96	3.57	1.68	2	981.0	1999	839.5	849.3		DeWind	1000	2		0.000
25	Windpower Monthly	Feb-2000	Germany	Midlum	87	DM	88.43	41.59	1.9820	43.67	43.67	87.00	40.91	42	1039.9	1999	974.0	990.0		Enercon	600	70		0.000
26	Wind Project Development	1999	Germany	Wind Project Development	9.7	DM	9.86	4.64	1.8490	5.25	5.36	9.76	4.59	4.5	1191.3	1999	1019.5	1030.2		Enron Wind	1500	3		0.000
27	Windpower Monthly	May-99	Germany	AN Windenergie	24	DM	24.39	11.47	1.8710	12.83	13.11	24.14	11.35	10	1310.8	1999	1135.1	1147.0	20	Bonus	1000	10		0.228
28	iwr / Windpower Monthly	12/1/1999 & Feb 00	Germany	Bobilkiewicz	87	Dm	88.43	41.59	1.9377	44.90	45.88	87.00	40.91	35	1310.9	1999	1168.8	1188.0	63	Enercon	500	70		0.205
29	Wind Project Development		Germany	Wind Project Development	7.2	DM	7.32	3.44	1.8490	3.88	3.98	7.24	3.41	3	1326.4	1999	1135.1	1147.0		Enercon	1500	2		0.000
30	Wind Project Development		Germany	Wind Project Development	1.5	DM	1.52	0.72	1.8490	0.81	0.83	1.51	0.71	0.6	1381.7	1999	1182.4	1194.8		Enercon	600	1		0.000
31	Wind Project Development		Germany	Wind Project Development	15.75	DM	16.01	7.53	1.8490	8.52	8.70	15.84	7.45	6	1450.6	1999	1241.5	1254.6		HSW	1000	6		0.000
32	Wind Project Development		Germany	Wind Project Development	5.6	DM	5.69	2.68	1.8490	3.03	3.09	5.63	2.65	2	1547.5	1999	1324.2	1338.2		HSW	1000	2		0.000
33	Windpower Monthly	Jun-99	Germany	Brandenburg	32	DM	32.52	15.29	1.6972	18.85	19.27	32.19	15.13	12	1605.6	1999	1261.2	1274.5	21	Suedwind	600	20		0.200
34	Nordex	23-May-2001	Germany	Nordex	2.4	DM	2.40	1.13	2.1798	1.10	1.10	2.40	1.13	1.3	846.9	2000	868.1	868.1	1.7	Nordex	1300	1		0.149
35	Borsig Energy **	10-Sep-2000	Germany	Altenautal	50	DM	50.00	23.51	2.2105	22.62	22.62	50.00	23.51	24.5	923.2	2000	959.6	959.6				28		0.000
36	iwr	16-Nov-2000	Germany		5.77	Euro	5.77	5.32	0.8509	4.91	4.91	5.77	5.32	5	981.9	2000	1064.1	1064.1		Nordex	1000	5		0.000
37	Borsig Energy	28-Sep-2000	Germany	Husing Umwelttechnik	6.9	DM	6.90	3.24	2.2105	3.12	3.12	6.90	3.24	3	1040.5	2000	1081.5	1081.5		Suedwind	1500	2	6.3	0.000
38	Borsig Energy	18-Sep-2000	Germany	Park Ellinbau	40	DM	40.00	18.81	2.2105	18.10	18.10	40.00	18.81	16.9	1070.7	2000	1112.9	1112.9		Nordex	1300	13		0.000
39	Wind Project Development		Germany	Wind Project Development	17	DM	17.00	7.99	2.1267	7.99	7.99	17.00	7.99	7.2	1110.2	2000	1110.2	1110.2		Nordex		3		0.000
40	Wind Project Development		Germany	Wind Project Development	9.5	DM	9.50	4.47	2.1267	4.47	4.47	9.50	4.47	4	1116.8	2000	1116.8	1116.8		AN Bonus	1000	4		0.000
41	Wind Project Development		Germany	Wind Project Development	35	DM	35.00	16.46	2.1267	16.46	16.46	35.00	16.46	14.5	1135.0	2000	1135.0	1135.0		NEG Micon	1500	10		0.000
42	iwr	21-Mar-2000	Germany	H&P Windkraft	3.49	DM	3.49	1.64	2.0433	1.71	1.71	3.49	1.64	1.5	1138.3	2000	1094.0	1094.0	2.9	Enercon	1500	1		0.221
43	Wind Project Development		Germany	Wind Project Development	15.9	DM	15.90	7.48	2.1267	7.48	7.48	15.90	7.48	6.5	1150.2	2000	1150.2	1150.2		AN Bonus	1300	5		0.000
44	Wind Project Development	/14-Dec-2000	Germany	Wind Project Development	10.15	DM	10.15	4.77	2.1088	4.83	4.83	10.15	4.77	4.2	1150.4	2000	1136.4	1136.4	7.5	Enercon	600	7		0.204
45	Wind Project Development	/05-Dec-2000	Germany	Wind Project Development	33.7	DM	33.70	15.85	2.1088	16.04	16.04	33.70	15.85	13.5	1188.2	2000	1173.8	1173.8	27	Enron Wind	1500	9	6.3	0.228
46	iwr	19-Jan-2000	Germany		160	DM	160.00	75.23	2.0779	77.00	77.00	160.00	75.23	63	1222.2	2000	1194.2	1194.2	110			36		0.199
47	iwr	16-Oct-2000	Germany	Koenig & Cie	60	DM	60.00	31.03	2.3485	28.10	28.10	60.00	31.03	22.5	1249.0	2000	1379.3	1379.3	40.6	NEG Micon	1500	15	7	0.230
48	Wind Project Development		Germany	Wind Project Development	25.2	DM	25.20	11.85	2.1267	11.85	11.85	25.20	11.85	9	1316.6	2000	1316.6	1316.6		Enercon; Ve	1500	2+4		0.000
49	iwr	28-Sep-2000	Germany	Ostwind	36	DM	36.00	16.93	2.2105	16.29	16.29	36.00	16.93	12	1357.2	2000	1410.6	1410.6	24.91	Enron	1500	8		0.237
50	iwr	26-Sep-2000	Germany	Ostwind	51	DM	51.00	23.98	2.2105	23.07	23.07	51.00	23.98	16.5	1398.3	2000	1453.4	1453.4	35.2	Enron	1500	11		0.244