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WP 3

Wind power
- status and development possibilities[1]

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Introduction

Within the last 15-20 years wind power has on a global scale developed incredible fast. In 1990 total installed capacity of wind power in the World amounted to approx. 2.0 MW – by the end of 2004 this capacity has increased to 48 GW. An increase of twenty-four fold, equalling an annual growth rate of almost 25%. However, although wind power never before has witnessed so rapid an expansion, the use of wind for energetic purposes is not new.

People have used technology to transform the power of the wind into useful mechanical energy since antiquity. Along with the use of waterpower through water wheels, wind energy represents one of the world's oldest forms of mechanised energy. Though solid historical evidence of wind power use does not extend much beyond the last thousand years, anecdotal evidence suggests that the harnessing of mechanised wind energy pre-dates the Christian era. The use of wind power is said to have its origin in the Asian civilisations of China, Tibet, India, Afghanistan, and Persia. The first written evidence of the use of wind turbines is from Hero of Alexandria, who in the third or second century BC described a simple horizontal-axis wind turbine. It was described as powering an organ, but it has been debated as to whether it was of any practical use other than as a kind of toy. More solid evidence indicates that the Persians were harnessing wind power using a vertical-axis machine in the 7th century AD (Shephard, 1990).

From Asia the use of wind power spread to Europe. Historical accounts date the use of windmills in England to the 11th or 12th century. Witnesses also spoke of the German crusaders bringing their windmill-making skills to Syria around 1190 AD. From this, one can assume that windmill technologies were generally known around Europe from the Middle Ages on. Early windmills and water wheels were used for simple low-energy processes such as water pumping and grain grinding; and they continue today to be used for this purpose in many parts of the world, particularly in developing countries. Variations in windmill styles developed from place to place, with perhaps the most famous being the traditional Dutch style. Several Mediterranean islands are also known for their picturesque old windmills.

With the advent of the steam engine in the 18th century the world's demand for power gradually shifted to techniques and machines based on thermodynamic processes. The advantages of these machines over wind became particularly evident with the introduction of fossil fuels such as coal, oil, and gas. As a result, the importance of wind energy declined during the 19th century and even more so during the 20th century. However, work on wind turbines continued to a wider extent than is commonly

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[1] This paper is an edited and updated version of previously published materials and mainly based upon Redlinger et al. (2002) and Jamasb et al. (2005)

assumed. Though it is often assumed today that interest and research in wind power vanished due to overwhelming competition from fossil energy sources, this is in fact not the case. Around the world, theorists and practitioners continued to design and construct electricity-producing wind turbines throughout the 20th century.

In 1891 Poul la Cour and a team of scientists at Askov Folk High School in Denmark installed the world's first electricity-producing wind turbines and established a test station for wind turbines, funded by the Danish government. As a result of this and the fuel shortage during World War I, by 1918 one quarter (120) of all Danish rural power stations used wind turbines for generating electricity. In America the Jacobs brothers manufactured battery-charging wind turbines in the 2.5 - 3 kW range in large numbers from 1925 to 1957. The famous 1250 kW Smith-Putnam wind turbine was erected in 1941 at a place called Grandpa's Knob in Vermont, USA. Also, in the 1920s and 1930s the Frenchman F. M. Darrieus and the Finn S. J. Savonius designed and tested new concepts for vertical axis wind turbines (VAWT), though these designs have never succeeded in gaining significant market share.

On the theoretical research side as well, efforts have continued throughout the 20th century. la Cour carried out groundbreaking empirical observations using a primitive wind tunnel around the turn of the century. One of la Cour's students was J. Juul who was employed by the power utility SEAS and after World War II headed a research and development programme on wind energy utilisation. This R&D effort formed the basis for Juul's pioneering design of the modern electricity producing wind turbine, the 200 kW Gedser turbine, installed in 1957 and in operation until 1967. In the 1920s the German professor Albert Betz of the German aerodynamics research centre in Göttingen made groundbreaking theoretical studies on wind turbines in the light of modern research. Also in the 1920s H. Glauert provided an aerodynamic theory for wind turbines. These theoretical contributions of Betz and Glauert remain the foundation of today's rotor theory, as discussed in the following section. Other important contributors to the development of wind power theory include the Austrian engineer Ulrich Hütter who worked in the late 1930s as chief engineer at the state-owned Ventimotor wind turbine firm in Weimar outside Berlin. In 1942 he received his doctoral degree from the University of Vienna through a theoretical study on wind turbines; and in the 1970s he was called upon again by the West German government to lead a research effort in wind power techniques.

Hence, research in wind power utilisation did not die due to competition from fossil fuels, but rather made steady progress over the past 100 years. The revival of more widespread interest in wind power after the oil crises of the 1970s did not require starting from scratch and was able to build on a solid foundation of theories and practical experiences. By the time the new era of wind energy began in the 1970s and 1980s, new materials and technologies had also become available. As composite materials such as fibreglass proved highly suitable for wind turbine rotor blades, blade design has become increasingly sophisticated; and electronic controls for wind turbines also continue to advance

Market development

On a global scale wind power has succeeded in achieving growth rates of 20-25% for quite a number of years. However, European countries dominate the wind power scene. In 2004, a little more than 72% of total installed wind turbine capacity was established in Europe, and the only major contributors outside Europe were the US with a total installed capacity of approximately 6.8 GW and India with 3.0 GW (BTM-consult, 2005).

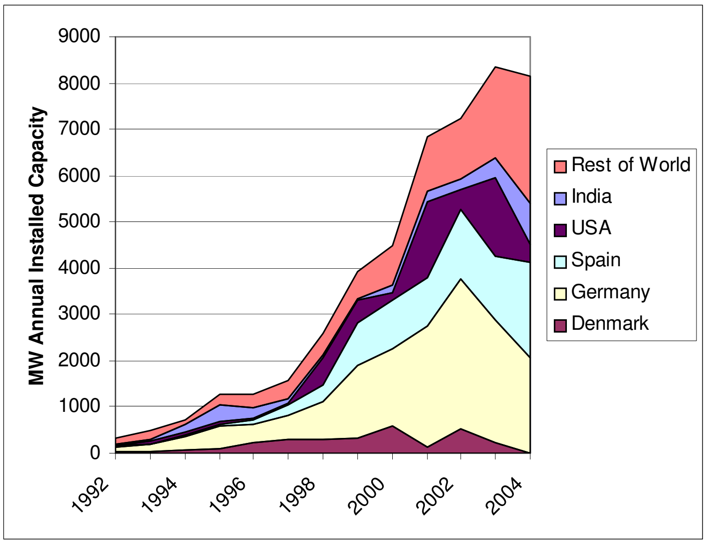


Figure 1: Annual increase in global installed wind power with special emphasis on Germany, Spain, US, India and Denmark. Source: BTM-consult, 2005.

But a few countries are the dominant ones, even within Europe: Germany, Spain and Denmark account for more than 80% of the total accumulated capacity in Europe. Germany has especially had a rapid development. In 1991, their total accumulated capacity was approximately 100 MW; by now, the annual capacity increase is approximately 2000 MW and total installed wind power capacity is almost 17 GW. A similar development is found in Spain, which in 2004 was the country installing most wind power, almost 2.1 GW. By the end of 2004 Spain has in total installed approximately 8.3 GW wind power. Denmark has by now a total installed capacity of almost 3.1 GW but in recent years the development has stalled in Denmark, now mostly concentrating on offshore turbine development.

The main reasoning behind the development in these three above-mentioned dominant countries in Europe (i.e. Germany, Spain and Denmark) is a fast improvement of the cost-effectiveness of wind power during the past ten years, combined with long-term agreements on fixed feed-in tariffs (at fairly high levels), altogether making wind turbines some of the most economically viable renewable energy technologies today. And the national policies of fairly high buy-back rates and substantial subsidies from governments to a certain extent reflect the need for a development of renewable energy technologies to cope with the greenhouse gas effect. According to the Kyoto protocol the European Union has agreed on a common greenhouse gas (GHG) reduction of 8% by the years 2008-12 compared with 1990. And all the three above-mentioned countries have adopted a policy of GHG-limitations in accordance with the agreed burden sharing in EU.

But quite a number of new countries have laid eyes on wind power. Within Europe especially Italy, the Netherlands and UK have had a rapid expansion within the last years, but as shown on Figure 2 many other countries are moving along the wind power line.

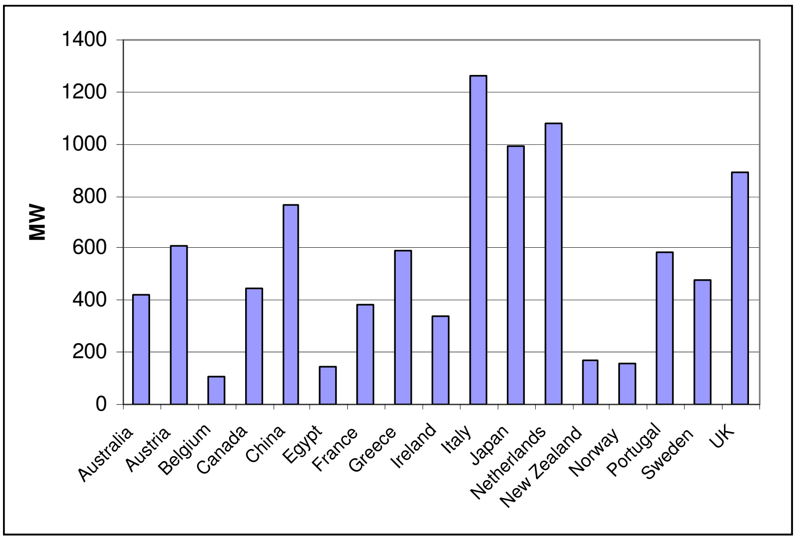


Figure 2: Countries with an installed capacity above 100 MW excluding those of figure 1. Source: BTM-consult, 2005.

That the development of renewable energy resources is expected to play an important role in the implementation of these GHG-targets is reflected in the EU policy as well. In its White Paper on a strategy for the development of renewable energy the EU-Commission has launched a goal of covering 12% of the European Union's gross inland energy consumption by the year 2010 by renewable sources, that is mainly by biomass, hydro power, wind energy and solar energy. Next to biomass wind energy is foreseen to be the main contributor with regard to future importance (European Commission, 1997). Moreover the European Commission has agreed on a directive on the promotion of renewable energy technologies, including a proposal on the share of renewables in the individual member states in 2010, based on the percentage of each country's consumption of electricity (European Commission, 2000). Although not binding it seems that these targets by now are accepted by the EU member states. Thus the directive signals the need to include wind power as one of the serious options in achieving the targets for GHG-reductions.

Offshore turbine development

In a number of countries, offshore turbines are getting an increasingly important role in the development of wind power, particularly in the north western part of Europe. Without doubt, the main reasons are that on-land sitings are limited in number and that the utilisation of these sites to a certain extent is exposed to opposition from the local population. This seen in relation to an unexpected high level of energy production from offshore turbines compared to on-land sitings (based on the experiences gained until now), has paved the way for a huge interest in offshore development.

As for onshore turbines, the wind regime, where the offshore turbines are sited determining the production of power, is the single most important factor for the cost per generated unit of power. In general, the wind regime offshore is more stable than onshore, with less turbulence and high average wind speeds. At the Danish Horns Reef wind farm, a wind speed corresponding to a utilisation time of more than 4200 hours per year were measured (adjusted to a normal wind year), thus giving a capacity factor close to 50%, which is comparable to many smaller conventional power plants. For most offshore wind farms, a utilisation time of more than 3000 hours per year is to be expected, significantly higher than for onshore sited turbines and, therefore, to a certain extent compensating for the additional costs of offshore plants.
At present, a number of offshore wind farms are in operation in the northern part of Europe, the largest ones in Danish waters. The World's largest offshore wind farm is situated at the West Coast of Denmark, Horns Reef, situated approximately 20 km West of the coast of Jutland, was established in

2002 and has a total capacity of 160 MW, consisting of 80 2 MW turbines. The Nysted project at Rødsand close to the isle of Lolland in Denmark was finalised in 2003 and has a total capacity of approximately160 MW consisting of 72 2.2 MW turbines. Middelgrunden East of Copenhagen was put into operation in 2001. The total capacity is 40 MW consisting of 20 2 MW turbines. Samsø offshore wind farm situated South of the Isle of Samsø was put into operation in 2003 and consists of 10 2.3 MW turbines. Finally, the Danish Parliament has decided to tender for two new offshore wind farms, each of a size of approximately 200 MW. These two are expected to be in operation by 2007-8.

Moreover, in a number of other countries, offshore wind power projects are in the planning and implementation phase, among these to be mentioned are Germany, Ireland, the Netherlands, and the UK.

Wind resources

Theoretical principles of wind resources

To give a basic understanding of the physical properties of energy in the wind and of how to estimate wind resource availability, this section provides a brief introduction to some basic principles of energy extraction from the wind.

The kinetic energy of a volume of air *V*, moving at the speed *u* is:

$$KE = ½\, \rho\, V\, u^2$$

where:
KE = kinetic energy, (kg m^2/sec^2, or joules)
ρ = air density, (kg/m^3)
V = volume of air, (m^3)
u = air speed, (m/sec)

Power is expressed in terms of work per unit time, or in other words, the change in kinetic energy per unit time, $\frac{d(KE)}{dt}$. To obtain the expression for power, we can re-write the equation as:

$KE = ½\, \rho\, (Area \cdot dx)u^2$, such that the volume of air *V* is expressed by an A*rea* perpendicular to the wind flow multiplied by the horizontal displacement in the direction of wind flow, *dx*. The power, or change in kinetic energy per unit time is then expressed by:

$$Power = \frac{d(KE)}{dt} = \frac{d}{dt}\left[½\, \rho\, (Area \cdot dx)u^2\right] = ½\, \rho \left(Area \cdot \frac{dx}{dt}\right)u^2$$

Since $\frac{dx}{dt}$ is in fact the wind speed *u*, power can be expressed as $Power = ½\, \rho \cdot Area \cdot u^3$.

When seeking to extract energy from the wind, it is this power passing through the fixed area of the wind turbine rotor which is of interest. The power (or kinetic energy flux), expressed per unit of area (of the rotor), is known as the power density *P*:

$$P = \tfrac{1}{2}\,\rho\, u^3$$

The power density is expressed in terms of watts per square meter. From this equation, we see that the power density is a function of the cubed wind speed, meaning that an increase in wind speed by a factor of 2 leads to an increase in power density of $2^3 = 8$. This exponential relationship, between wind speed and the power which can be potentially extracted by a wind turbine, highlights the paramount importance of wind speed when selecting locations for wind power plants.

Naturally, wind speed in the atmosphere is not constant, but varies over time, expressed mathematically as $u = u(t)$. Figure 3 shows an example of half-hourly averages of wind speed and a wind turbine's power output over the course of 6 months.

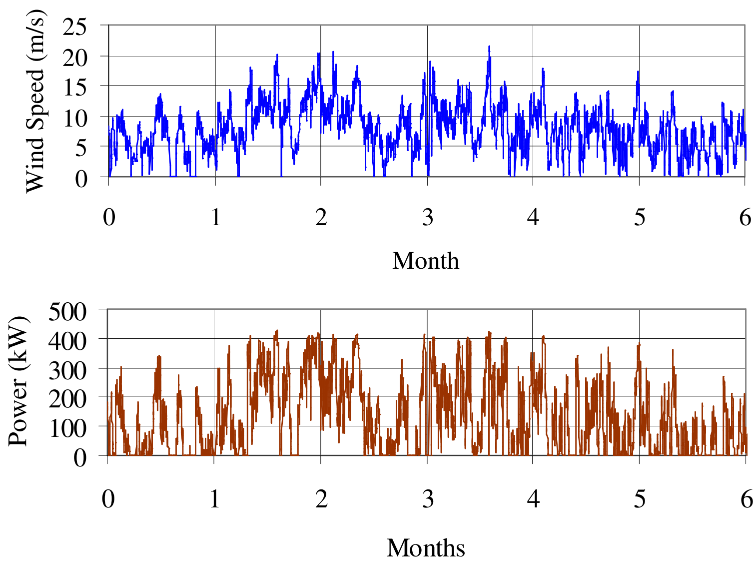


Figure 3 30-minute averages of wind speed and wind turbine power output over 6 months.

Given the variability of wind speed, a realistic measure of the available wind power resource is provided by the long-term mean power density $\overline{P}$:

$$\overline{P} = \frac{1}{T}\int_0^T \tfrac{1}{2}\,\rho\, u(t)^3\, dt \quad = \quad \int_0^\infty \tfrac{1}{2}\,\rho\, u^3 f(u)\, du$$

where T is the time over which the average is taken. T should be large, such as one year, or even better, 10-20 years. This is because wind speed varies significantly during the year, and even the annual average wind speed may vary by up to 10-20 percent between different years. The function $f(u)$ is the frequency distribution of wind speed, that is, the probability of the wind speed being within a given (unit) interval at any given time.

The mathematical Weibull two-parameter frequency distribution can provide estimated wind speed probability distributions which have proven to fit well with measured wind speed data. The Weibull distribution is defined as follows:

$$f(u) = \left(\frac{k}{A}\right)\left(\frac{u}{A}\right)^{k-1} \exp\left(-\left(\frac{u}{A}\right)^{k}\right)$$

where:
$f(u)$ = the estimated frequency of occurrence of wind speed u
A = the scale parameter ($A > 0$)
k = the shape parameter ($k > 1$)
u = wind speed ($u \geq 0$)

The Weibull scale and shape parameters vary by location, depending on climate and terrain conditions. The two Weibull parameters are determined from measurements when these are available for an actual site. If no measurements are available, the Weibull parameters can be estimated through the 'wind atlas' methodology discussed subsequently in this section.

The Weibull shape parameter k defines the shape of the wind distribution and varies with the actual climate. In typically low wind areas such as the arctic regions and the tropics, the value of k is close to 1. In climatic regions dominated by the Westerlies such as in north-western Europe, the value of k is approximately 2, indicating a Rayleigh distribution of wind speeds. In areas near the equator dominated by constant trade winds, k can be on the order of 3 or higher, approaching a normal distribution of wind speeds.

As an approximation, the scale parameter is related to the annual mean wind speed as follows[2]:

$$\bar{u} = \frac{1}{T}\int_0^T u(t)\,dt = \int_0^\infty u\, f(u)\, du \approx 0.89 \cdot A$$

A measured histogram of wind speed data is shown in Figure 4, together with the Weibull fit. The figure is typical of the Westerlies wind regime and represents a shape factor of approximately 2. Figure 4 demonstrates that, with good estimates of the scale and shape parameters, close approximations of the actual wind speed probability distribution can be obtained, allowing good estimates of mean power density.

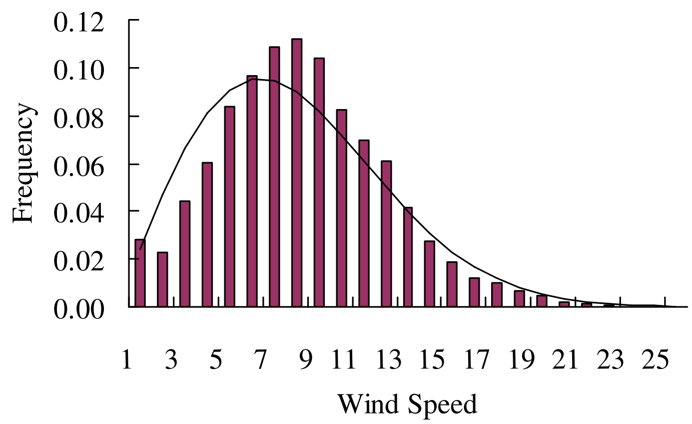


Figure 4 Measured wind speed frequency distribution (columns) and Weibull fit (line) to the measurements.

[2] 'Annual mean wind speed' is a standard term applied based on 'long-term average', as opposed to 10 minute or half-hourly averages.

Wind resource assessment

Wind resource assessment for a site or area is based on two elements: high-quality nearby wind measurements (preferably on-site) and a micro-siting model, which can estimate the spatial distribution of the wind resource over the entire area.
The most widespread micro-siting models are based on the physical laws governing wind flow. An example of the physical approach is the 'wind atlas' methodology, but other models exist as well. The wind atlas methodology has been used for wind resource assessment and siting around the world, and present day state-of-the-art models are able to predict the wind resource with good accuracy in many areas.[3]

Wind speeds measured at a meteorological station are determined mainly by two factors: regional overall weather systems, which often have an extent of several hundred kilometres, and the local topography around the site in question (a few tens of kilometres from the station). The wind atlas methodology (Troen and Petersen, 1989) is a comprehensive set of models for horizontal and vertical extrapolation of wind speeds measured at a meteorological station (for example, at an airport) for estimation of wind resources at a nearby site (for example, a planned wind farm).

The models are based on physical principles of flows in the atmospheric boundary layer, and they take into account:
1. Terrain roughness (for example, desert surface, farm land, water surface),
2. Sheltering effects (due to buildings and other obstacles), and
3. Orography (terrain height variations such as hills and escarpments).

Terrain roughness is often standardised into roughness classes. Roughness class 0 covers smooth surfaces such as sand or desert surfaces. Roughness class 1 represents open farmland with very few buildings. Roughness class 2 represents more closed farmland with some trees and/or bushes. Roughness class 3 is characterised by more sheltered terrain, suburbs, and so on.

For each meteorological station the wind atlas tables provide calculated Weibull A- and k- parameters for 12 sectors of the wind rose[4], 5 heights, and 4 roughness classes. In addition, the sector-wise distribution of wind speed is given in percent for each roughness class. A summary table gives estimated annual mean wind speed and mean power density for each of the five standard heights and four roughness classes. This is illustrated in Table 1.Based on such information, the wind atlas methodology is able to extrapolate the wind resources from meteorological stations onto nearby wind turbine sites.

Table 1 Summary wind atlas table for Hurghada on the Egyptian coast of the Gulf of Suez.

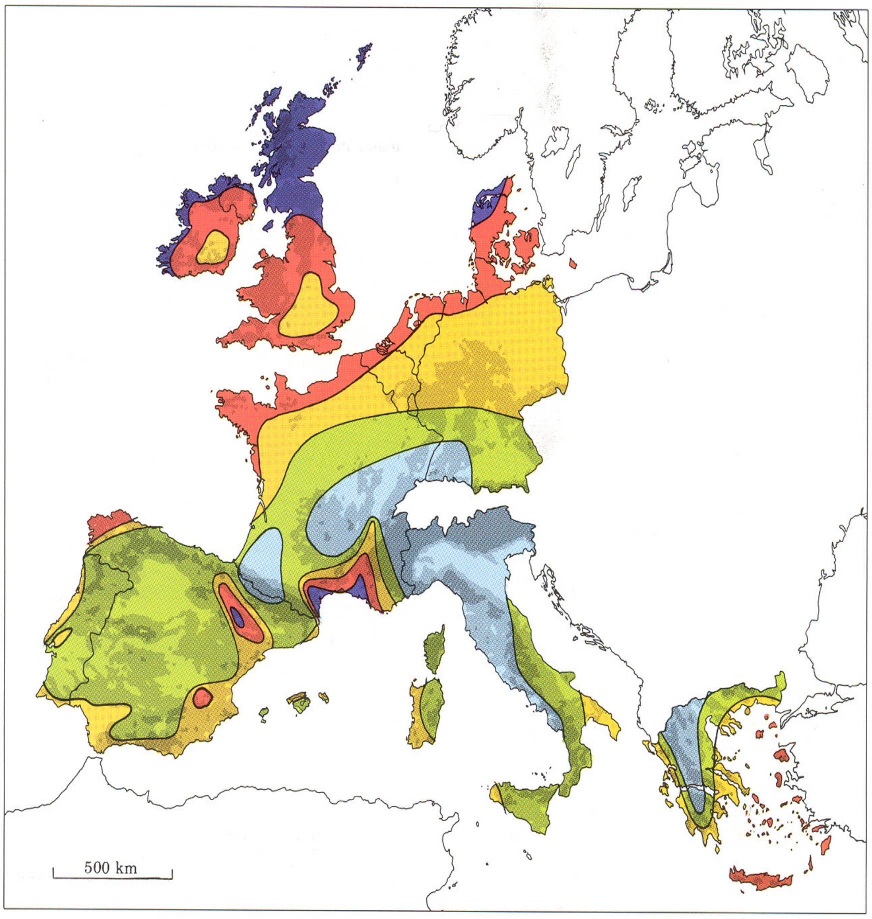
z refers to height above terrain, U is the estimated annual mean wind speed, and E is the estimated annual mean power density in the wind.

z	Roughness Class 0		Roughness Class 1		Roughness Class 2		Roughness Class 3	
(m)	U (m/s)	E (W/m^2)	U (m/s)	E (W/m^2)	U (m/s)	E (W/m^2)	U (m/s)	E (W/m^2)
10	6.9	327	5.7	203	4.8	121	4.2	80
25	7.6	422	6.7	300	5.8	197	5.2	143
50	8.2	516	7.6	415	6.7	285	6.1	218
100	8.8	667	9.0	698	7.9	463	7.2	353
200	9.8	926	11.4	1 447	9.8	910	8.9	676

Source: Mortensen and Said, 1996.

[3] For a complete description of the wind atlas methodology, see Troen and Petersen, 1989.
[4] The wind rose is a graphical representation of the relative frequency, average wind speed, and energy content of the wind from each direction: north, north-west, east, south-east, and so on. The wind rose is typically drawn with 12 sectors, each sector representing an arc of 30 degrees on the compass.

The potentials for Europe are shown in Figure 5, where wind resources are mapped according to the European Wind Atlas.



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

1. The resources refer to the power present in the wind. A wind turbine can utilize between 20 and 30% of the available resource. The resources are calculated for an air density of 1.23 $kg\,m^{-3}$, corresponding to standard sea level pressure and a temperature of 15°C. Air density decreases with height but up to 1000 m a.s.l. the resulting reduction of the power densities is less than 10%.
2. Urban districts, forest and farm land with many windbreaks (roughness class 3).
3. Open landscapes with few windbreaks (roughness class 1). In general, the most favourable inland sites on level land are found here.
4. The classes pertain to a straight coastline, a uniform wind rose and a land surface with few windbreaks (roughness class 1). Resources will be higher, and closer to open sea values, if winds from the sea occur more frequently, i.e. the wind rose is not uniform and/or the land protrudes into the sea. Conversely, resources will generally be smaller, and closer to land values, if winds from land occur more frequently.
5. More than 10 km offshore (roughness class 0).
6. The classes correspond to 50% overspeeding and were calculated for a site on the summit of a single axisymmetric hill with a height of 400 metres and a base diameter of 4 km. The overspeeding depends on the height, length and specific setting of the hill.

Figure 5: European Wind Resources mapped using the Wind Atlas Method. Measured at 50 meters above ground level. Source:Risø National Laboratory

Wind Turbine Technology

Principles in extracting power from the wind

A basic understanding of the theoretical possibilities and limitations for extracting energy from the wind is helpful for understanding the fundamentals of wind power technology. The deductions of Betz (1920), though not directly applicable to practical engineering computations today, help illustrate the forces at work around a wind turbine propeller and are highlighted here in a slightly altered form. shows a wind turbine with a rotor radius (blade length) r_R, exposed to a uniform, non-turbulent flow. The undisturbed velocity has a magnitude u_0 and a direction perpendicular to the rotor. Behind the rotor, a circular wake with a uniform speed deficit au_0 expands. In other words, '*a*' represents the fractional loss of wind speed through the rotor. By assumption, the wake at the point of creation has a radius equal to the rotor radius r_R, increasing to r some distance downstream. Outside of this area impacted by the wind turbine, the wind speed is assumed to have the free stream value u_0.

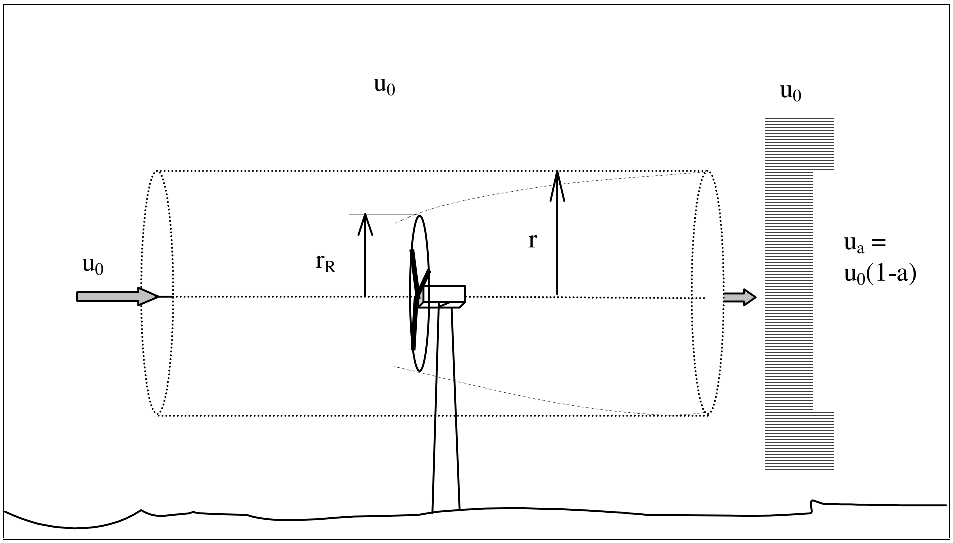


Figure 6 Control volume for momentum and energy balance.

A cylindrical control volume is devised so that it starts in the undisturbed upstream flow (to the left in Figure 6) and has a radius, r, coinciding with the wake radius, where it ends (to the right). Thus, the flow speed is $u_a = u_0 - au_0 = u_0(1-a)$ at the right end of the cylinder, and the uniform flow speed outside the control volume is u_0.

As described in the previous section, the kinetic energy of the wind is expressed by:

$$KE = ½\, \rho\, V\, u^2$$

where:
KE = kinetic energy, (kg m^2/sec^2, or joules)
ρ = air density, (kg/m^3)
V = volume of air, (m^3)
u = air speed, (m/sec)

The volume of air V in the cylinder is equal to the cross-sectional area πr^2 multiplied by the horizontal displacement, dx. By setting the horizontal depth of the air volume equal to the distance travelled by

u_a per unit of time dt, the horizontal displacement dx equals u_a. Thus, the volume of air V is equal to $\pi r^2 u_a$, and the kinetic energy of the air volume at any given time is equal to $½ \rho \pi r^2 u_a u^2$.

Thus, power equals the change in kinetic energy over time. At the left end of the cylinder in Figure 6, the wind speed is u_0, and the kinetic energy is $½ \rho \pi r^2 u_a u_0^2$, while at the right end of the cylinder, the wind speed is u_a, and the kinetic energy is $½ \rho \pi r^2 u_a u_a^2$.

Therefore, the power extracted by the wind turbine, represented by the change in kinetic energy through the cylinder, is given by:

$$P_{wt} = ½ \rho \pi r^2 u_a (u_0^2 - u_a^2)$$

By convention, power is often expressed in terms of the free wind speed u_0, the swept rotor area, defined as the area of the circular disc 'drawn' by the blade tips (πr_R^2), and the so-called power coefficient c_P, representing the fraction of the wind's kinetic energy extracted by the turbine. Expressed in this way, power is given by:

$$P_{wt} = ½ \rho \pi r_R^2 \, c_P \, u_0^3$$

In order to finalise Betz' deductions, we make the additional commonly held assumption that the speed deficit of the flow when passing through the rotor is half of what it finally becomes downstream. With this assumption, continuity in the wake steam tube[5] (starting with the rotor disc to the left and coinciding with the end of the control volume to the right, see Figure 6) yields

$$\pi r_R^2 u_0 (1 - ½ a) = \pi r^2 u_0 (1 - a) \quad \Rightarrow \quad \frac{r_R^2}{r^2} = \frac{1-a}{1-½ a}$$

Combining the three abovementioned equations allows the derivation of the following expression for the power coefficient c_P :

$$c_P = ½ (2-a)^2 a$$

Again, a represents the fractional loss of wind speed through the turbine. Since a is unknown, this result does not appear very useful in determining the potential power yield from a wind turbine. However, by differentiating this equation with respect to a, the upper limit of the power coefficient can be determined:

$$\frac{dc_P}{da} = \tfrac{3}{2} a^2 - 4a + 2 = 0 \quad \Rightarrow \quad a = \tfrac{2}{3} \quad \Rightarrow \quad \max\{c_P\} = \frac{16}{27}$$

In other words, the wind turbine can utilise up to a theoretical maximum of 16/27 ≈ 59 percent of the kinetic energy passing through its swept rotor area. This maximum is called the *Betz Limit* and has become a virtual mantra in the wind energy community. Many would claim that, despite the simplicity and other weaknesses in the deductions, the Betz Limit of 59 percent cannot be exceeded. Practical experience with wind turbines tends to support this claim, and modern wind turbines currently operate at efficiencies of 45-50 percent.

[5] The stream tube is defined by the stream lines following the edge of the wake. Therefore, there is no flow perpendicular to the streamlines.

However, by mounting vanes on the blade tips or other devices that concentrate the flow, it is possible to augment the efficiency. Using such vanes, one could say that the swept area is effectively increased without increasing the actual projection of the rotor contours on the vertical plane. In economic terms, such flow concentrators appear to be only partly feasible since they tend to increase loadings, and hence costs, relatively more than they increase efficiency.

Principal components of a wind turbine

Wind turbines come in two broad categories: the horizontal axis turbine whose blades appear similar to aeroplane propellers, and the vertical axis turbine whose long curved blades are attached to the rotor tower at the top and bottom and have the appearance of an eggbeater. Vertical axis turbines have not lived up to their early promise, and today virtually 100 percent of existing turbines use the horizontal axis concept. This chapter therefore focuses exclusively on horizontal axis machines. The principal components of a modern horizontal axis grid-connected wind turbine are illustrated in Figure 7 and are described below.

- **Rotor**. The rotor includes the blades and hub. The rotor can rotate either at near-fixed speed, or at variable speed, depending on the design concept. With fixed-speed operation, the rotational speed is typically 20-25 rpm for a 700 kW wind turbine, though this is dependent on design criteria. Larger turbines with longer blades have slower rotations, while small turbines with short blades rotate more quickly. For a 3-bladed turbine, optimum power output is typically achieved when the ratio of blade tip speed to wind speed is approximately four-to-one.

- **Blades**. The blades are attached to the hub. They can be attached in one of two ways: 1.) in a fixed, angular position, known as stall regulation, or 2.) on bearings so that the whole blade can be pitched at different angles depending on wind speed, known as pitch regulation. The cross section, or profile, of the blade is designed to fulfil several requirements including high efficiency and good stall properties. Current wind turbines most often have three blades, but two blade models are also common. Under stall regulation, the blade angle is set such that the blade automatically loses its lift under very high wind conditions, thus passively restricting the amount of torque on the rotor. Under pitch regulation, the angle of the blade is modified based on wind speed to provide more optimal power output over a wider range of wind speeds.

- **Hub**. The hub connects the blades to the main shaft. Hydraulic, mechanical or electrical equipment to drive the pitch setting of blades or emergency aerodynamic brakes are often mounted in the hub.

- **Nacelle**. The box-like structure located behind the rotor blades is known as the nacelle. The nacelle contains the gearbox, the generator, and various control and monitoring equipment. The nacelle is attached to the tower through the yaw drive.

- **Gearbox**. The gearbox increases the slow speed of the main shaft to a speed suitable to the generator. Thus, the speed of the rotor, which is typically well below 100 rpm, is increased up to the 1200-1800 rpm range required by the generator to produce grid-quality electricity.

- **Generator**. The generator is typically of the induction type, operating at near-fixed speed. Other generator types are being applied in newer turbine concepts as outlined in the following section.

- **Yaw Drive**. The yaw drive aligns the nacelle so that the rotor axis points as accurately as possible toward the wind. Wind turbines may face either upwind or downwind. The downwind configuration is more common among small turbines and uses passive yaw control, similar to a weather vane. The upwind configuration is used in most large modern turbines and requires active yaw control, in which the yaw motor is controlled by a wind vane on top of the nacelle.

- **Tower**. The tower is typically of tubular design, particularly for large turbines. It is most often made of steel or, less frequently, of concrete. Lattice steel towers are also used but are today more common for smaller turbines.

- **Control System**. The computer-based central control panel of the wind turbine is typically mounted inside the tower (if tubular). The control system monitors gearbox and generator temperature, wind speed (if wind speed is above some set limit, the wind turbine may be stopped for safety reasons), vibration, and so on. If the wind turbine is part of a wind farm, the turbine is connected to a central monitoring computer.

- **Foundation**. The tower is bolted to the foundation, typically made of concrete.

- **Transformer**. The low voltage electricity output from the generator is stepped up to grid level through the transformer. From the transformer, a high voltage cable or overhead line feeds into the main grid.

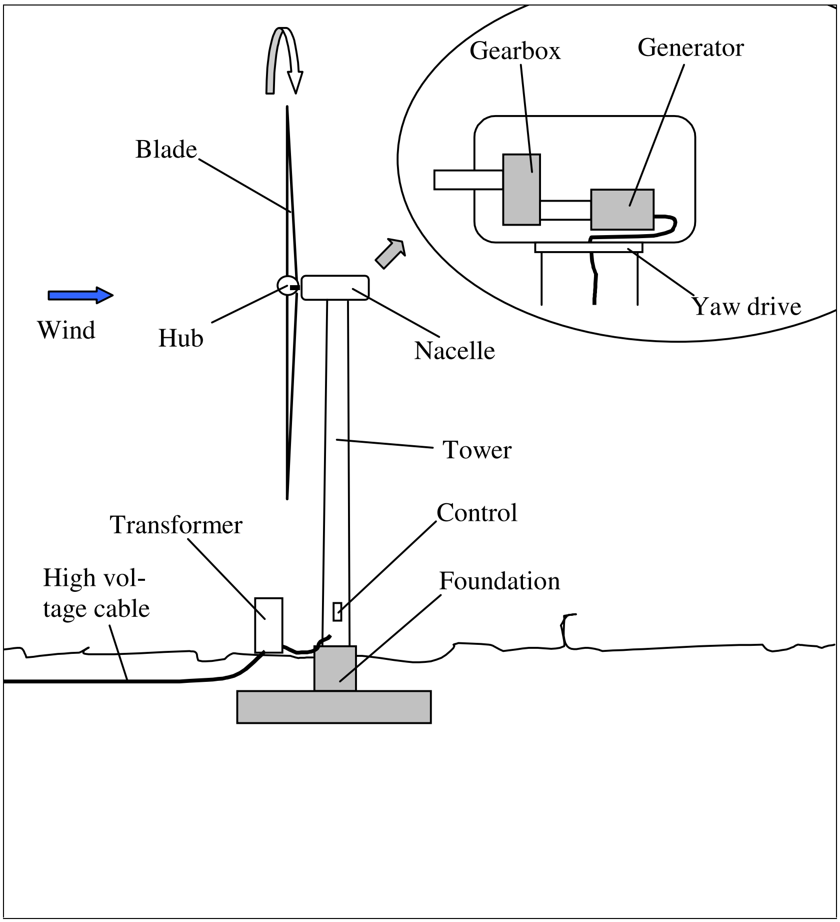


Figure 7 Principal components of a wind turbine. Pictured here is an upwind horizontal axis wind turbine.

What has been described above is the 'standard concept' as of 1998. New concepts are also under development and are discussed in the following section.

Technological trends

The following section outlines the structure and development of land-based wind turbines' technological and efficiency trends. In general, three major trends have in recent years dominated the development of grid-connected wind turbines:

1) The turbines have grown larger and taller – thus, the average size of turbines sold at the market place has substantially increased;
2) The efficiency of the turbines' production has steadily increased;
3) In general, the investment costs per kW have decreased.

Figure 8 shows the development of the turbine size. In the beginning of the 80's the 55 kW was a very popular and reliable machine, which was sold in several thousands. Around 2000 the MW-machines really took off, to a certain extent because of the offshore development.

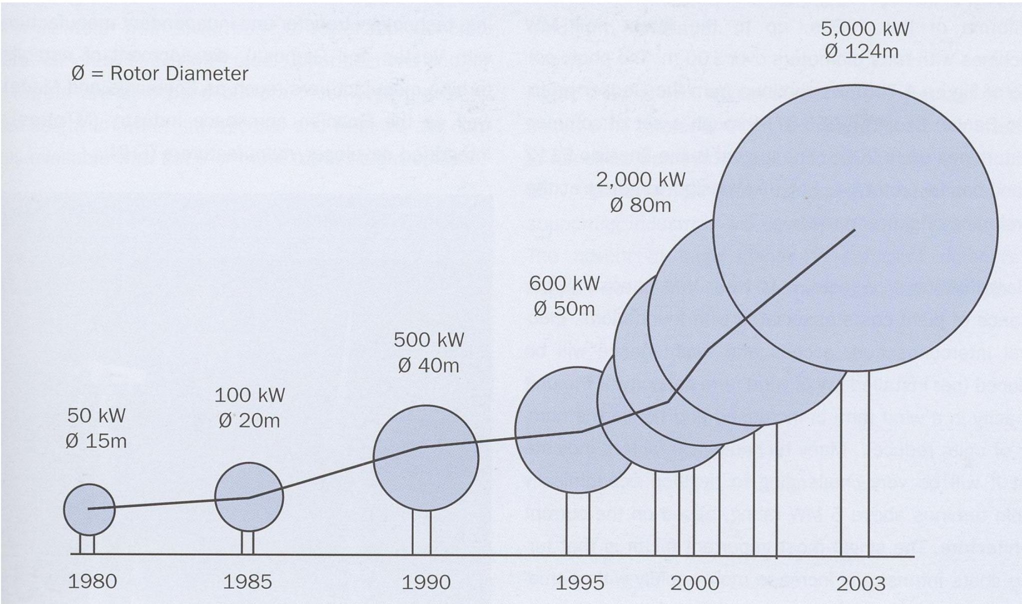


Figure 8: The increase in size of new turbines. Source: EWEA, 2004.

Figure 9 shows the development of the average size of wind turbines sold each year for a number of the most important wind power countries. As illustrated in Figure 9, average annual size has increased significantly over the last 10-15 years, from approximately 200 kW in 1990 to approximately 2000 kW in Germany, the UK and Denmark in 2004. But as shown, there is quite a difference between the individual countries. In Spain, the average size installed in 2004 was approximately 1100 kW, significantly below the level in Denmark and Germany of 2200 kW and 1700 kW, respectively. In recent years, the large increase in Denmark and the UK stems mainly from establishing offshore wind farms that are mostly equipped with 2 MW turbines or larger.

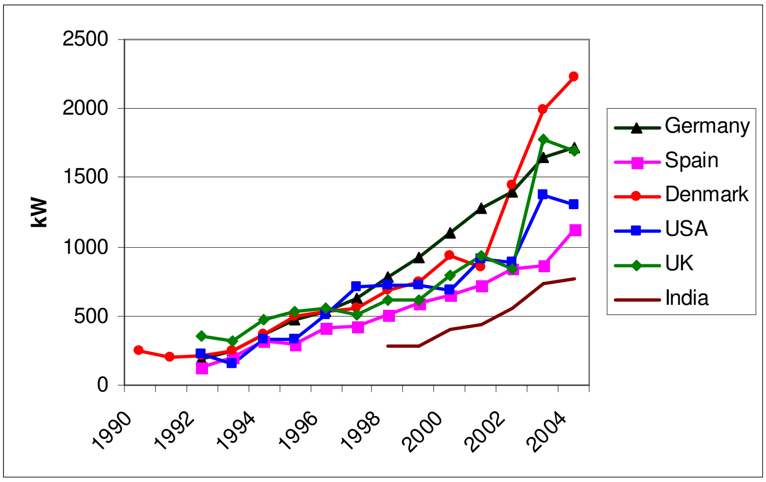


Figure 9 Development of the average wind turbine size sold in different countries. Source: BTM-consult.

In 2004, the best-selling turbines on the World market had a rated capacity of 1.5 MW and more, and these machines had a market share of more than 40%. But turbines with capacities of 1 to1.5 MW are still important having a market share of almost 30%. Finally, the smaller turbines with capacities of 750 to 1000 kW had a market share of 23%.

The development of electricity production efficiency owing to improved equipment design measured as annual energy production per swept rotor area (kWh/m^2) at a specific reference site has correspondingly improved significantly over the last years. Taking into account all the three mentioned issues of improved equipment efficiency, improved turbine-siting and higher hub height, the overall efficiency has increased by 2-3% annually over the last 15 years.

In general most turbines are developed on the basis of the original "Danish Concept", a stall regulated fixed speed turbine with a gearbox. In recent years quite a number of improvements have been added to this concept, most turbines today being pitch-regulated with variable speed. But also new concepts have been taken in use, as the gearless direct drive turbine. Figure 10 summarises the development. The different concepts have different pros and cons at by now it is still not to be said, if direct drive versions will take the lead in the future or the improved Danish concept will stand the ground. No doubt this will mainly be a question of the economics and reliability of these different machines.

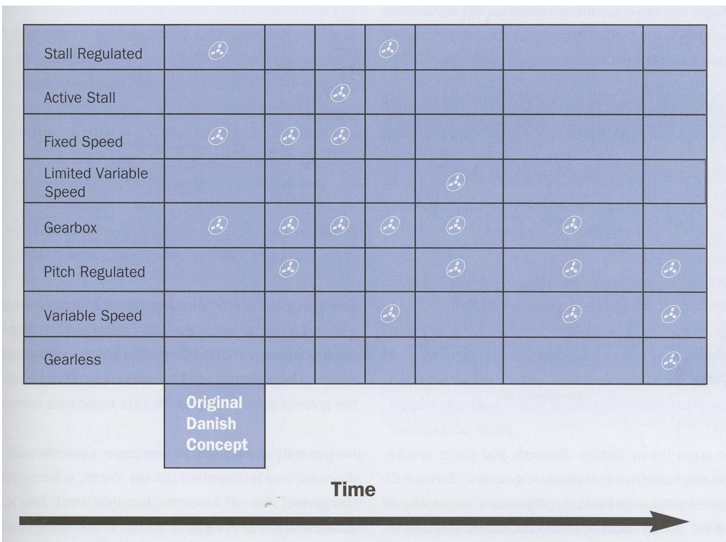


Figure 10: Development of turbine technology over time. Source: EWEA, 2004.

Economics of Wind Energy

Wind power is used for a number of different applications, including both grid-connected and stand-alone electricity production, as well as water pumping. This section analyses the cost and investment structures of on-land wind power, primarily in relation to grid-connected turbines that account for the vast bulk of the market value of installed turbines. Offshore turbines gain an increasingly important role in the overall development of wind power and, thus, an overview is given in a separate section at the end of this chapter.

The main parameters governing wind power economics include the following:

- Investment costs, including auxiliary costs for foundation, grid-connection, etc.;
- Operation and maintenance costs;
- Electricity production/average wind speed;
- Turbine lifetime;
- Discount rate.

Of these, the most important parameters are the turbines' electricity production and their investment costs. As electricity production is highly dependent on wind conditions, choosing the right turbine site is critical to achieving economic viability.

Capital costs of wind energy projects are dominated by the cost of the wind turbine itself (ex works)[6]. Table 2 shows a typical cost structure for a 1 MW turbine in Denmark. The turbine's share of total cost is approximately 82%, while grid-connection accounts for approximately 7% and foundation for approximately 5%. Other cost components, such as control systems and land, account for only minor shares of total costs.

Table 2: Cost structure for a 1 MW wind turbine (year 2001 €)

	Investment (1000 €)	Share (%)
Turbine (ex works)	748	81.9
Foundation	44	4.8
Electric installation	10	1.1
Grid-connection	60	6.6
Control systems	2	0.2
Consultancy	8	0.9
Land	27	2.9
Financial costs	8	0.9
Road	7	0.7
Total	914	100.0

Note: Based on Danish figures for a 1 MW turbine, using average 2001 exchange rate 1€ = 7.45 DKK.

Changes in investment costs over the years are shown in Figure 11 below. All costs at the left axis are calculated per kW of rated capacity, while those at the right axis are calculated per swept rotor area. The data reflect turbines installed in the particular year shown and all costs are converted to 2001 prices. As shown in the figure, there has been a substantial decline in per kW costs from 1989 to 1999. During this period, turbine costs per kW decreased in real terms by approximately 4% per

[6] 'Ex works' means that no site work, foundation, or grid connection costs are included. Ex works costs include the turbine as provided by the manufacturer, including the turbine itself, blades, tower, and transport to the site.

annum. At the same time, the share of auxiliary costs (i.e., foundation, grid-connection, etc.) as a percentage of total costs has also decreased. In 1987, almost 29% of total investment costs were related to costs other than the turbine itself. By 1999, this share had declined to approximately 20%. The trend towards lower auxiliary costs continues for the last vintage of turbines shown (1000 kW), where other costs amount to approximately 18% of total costs.

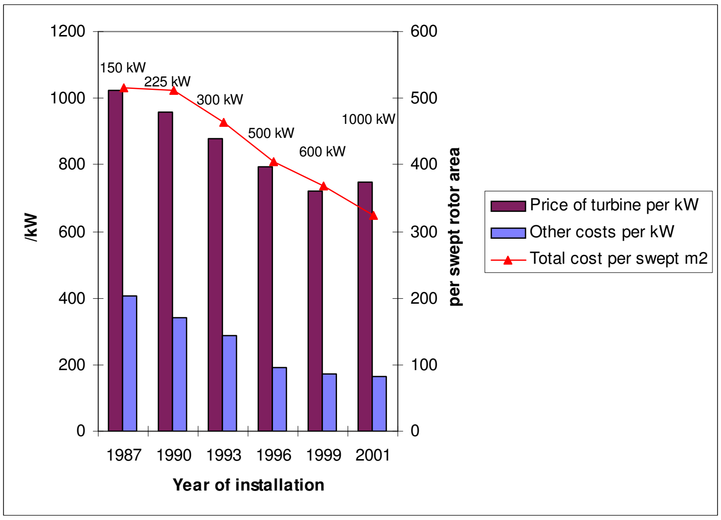


Figure 11: Left axis: Wind turbine capital costs (ex works) and other costs per kW rated power (€/kW in constant 2001 €). Right axis: Investment costs divided by swept rotor area (€/m2 in constant 2001 €).

A little surprisingly, investment costs per kW have increased for this last-mentioned machine compared to a 600 kW turbine. The reason has to be found in the dimensioning of the turbine. With higher hub heights and larger rotor diameters, the turbine is equipped with a relative smaller generator although it produces more electricity. This is illustrated in Figure 11 at the right axis, where total investment costs are divided by the swept rotor area[7]. As shown in this figure, the cost per swept rotor area has continuously decreased for all turbines considered. Thus, overall investment costs per swept rotor area have declined by approximately 3% per year during the period analysed.

The total cost per produced kWh (unit cost) is calculated by discounting and levelising investment and O&M costs over the lifetime of the turbine, divided by the annual electricity production. The unit cost of generation is thus calculated as an average cost over the turbine's lifetime. In reality, actual costs will be lower than the calculated average at the beginning of the turbine's life, due to low O&M costs, and will increase over the period of turbine use.

Figure 12 shows the calculated unit cost for different sizes of turbines based on the above-mentioned investment and corresponding O&M costs, a 20-year lifetime, and a real discount rate of 5% per annum. The turbines' electricity production is estimated for roughness classes one and two, corresponding to an average wind speed of approximately 6.9 m/s and 6.3 m/s, respectively, at a height of 50 m above ground level. A roughness class one position corresponds to a coastal and rather windy site, while a roughness class two position is an inland-siting.

[7] Swept rotor area is a good proxy for the turbines' power production.

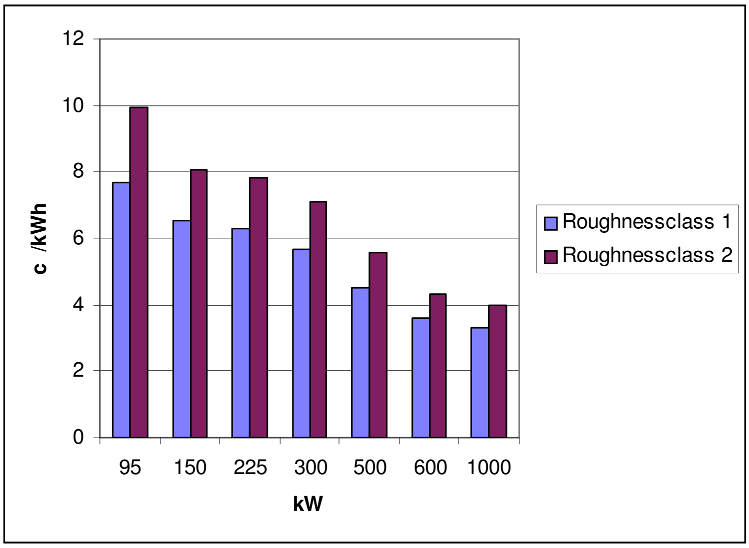


Figure 12: Total wind energy costs per unit of electricity produced, by turbine size. (c€/kWh, constant 2001 prices).

Figure 12 illustrates the trend towards larger turbines and improved cost-effectiveness. For a roughness class one site (6.9 m/s), for example, the average cost has decreased from over 7.7 c€ /kWh for the 95 kW turbine (1985) to under 3.4 c€ /kWh for a new 1000 kW machine, an improvement of more than 50% over a timescale of 15 years (constant 2001 prices).

The turbine's production of power is the single most important factor for the cost per generated unit of power. Whether a turbine is sited at a good wind location or not might totally determine if the turbine is profitable, or operates at a loss. In Europe, coastal positions (roughness class one positions) are mostly to be found at the coast of the UK, Ireland, Holland, France, Germany, Spain, Denmark and Norway. A capacity factor of 25-30% can normally be achieved at coastal positions in these areas. Medium wind areas (roughness class two positions) are mostly to be found as inland terrain in Mid and Southern Europe, i.e., Germany, France, Spain, Holland, Italy, but also as inland sites in Northern-Europe, Sweden, Finland and Denmark. Here, a normal capacity factor will be in the range of 20-25%. In many cases, local conditions do significantly influence the average wind speed at the specific site for which reason strong fluctuations in the wind regime are to be expected even for neighbouring areas.

Also the discount rate has a significant influence on electricity production costs and hence on wind projects' financial viability. For a 1 MW turbine, changing the discount rate from 5-10% per year (in real terms) increases the production cost by a little more than 30%.

Finally, it should be mentioned than the energy payback time for a wind turbine is extremely short compared to other kinds of energy producing plants. Energy is only consumed for the construction and the erection of the turbine and, finally, in small amounts during the maintenance of the turbine over its entire lifetime. Calculations carried out by the author assuming the required energy input to be generated by a conventional coal-fired power plant show that the energy payback for a medium sized turbine is less than 3 month.

Future Development of the Economics of On-land Turbines

Can and will this improvement in cost-effectiveness for wind power continue in the future? Quite a number of factors are important in the future wind power development, but the single most important one is without doubt the up-scaling in the size of the turbines. As shown above, the 95 kW machine was a typical size in the mid 1980s, while an average size is by now approximately 1.5 MW. Thus, within a timescale of 15-20 years, the size of the average turbine has grown by more than a factor of 15, and it seems that this up-scaling is still one of the driving factors behind the wind power development. Quite a number of Multi-MW turbines (2-3 MW) are by now sold at the market place and larger turbines are still being developed – turbines of approximately 5 MW are currently being tested by the manufacturers and will probably be in serial production within the next year.

There is still, especially for offshore applications, a drive towards larger machines, mainly to reduce costs of foundation and cabling, which is much more expensive offshore than on land. But the large offshore machines are to an increasing extent also being used for on-land installations, especially in Germany.

An important issue in the up-scaling of turbines is to keep the weight down. This is especially essential for blades; the longer the blades, the more important weight becomes. Therefore, new construction methods are being applied to reduce weight and new materials, such as carbon fibres which are used in blade manufacturing. In a recent 3 MW construction, the manufacturer managed to reduce weight to be at almost the same level as the former 2 MW model.

But how large will the turbines become in the future? According to expert judgements (Risø 2003), there are no major physical barriers before we are above a turbine size of 20 MW. A 10 MW machine will have a rotor diameter of approximately 160 m, increasing to approximately 220 m for a 20 MW turbine. By now, the largest rotors are 110-120 m in diameter (5 MW turbine). If we can continue the technological development, especially in reducing the weight, we may see turbines of a size of 30-40 MW. The most significant future barrier might be found within the transport infrastructure.

How will a continued development of the turbine, including an up-scaling in size, influence the future cost of wind-produced energy? In this section, the future development of the economics of wind power is illustrated by the use of the experience curve methodology. The experience curve approach was developed back in the 1970s by the Boston Consulting Group and the main feature is that it relates the cumulative quantitative development of a product with the development of the specific costs (Johnson, 1984). Thus, if the cumulative sale of a product is doubled, the estimated learning rate shows one the achieved reduction in specific product costs. The experience curve is not a forecasting tool based on estimated relationships. It merely points out that if the existing trends are going to continue in the future, then we might see the proposed development. It converts the effect of mass production into an effect on production costs, and other casual relationships are not taken into account. Thus, changes in market development and/or technological breakthrough within the field may considerably change the picture.

In a number of projects, different experience curves have been estimated[8], but unfortunately mostly by using different specifications, which means that not all of these can be directly compared. To get the full value of the experiences gained, not only the price-reduction of the turbine (€/KW-specification) should be taken into account, but also the improvements in efficiency of the turbine's production. The last mentioned issue requires the use of an energy specification (€/kWh) and this approach is used in (Neij, 1997) and (Neij et al., 2003). Thus, using the specific costs of energy as a basis (costs per kWh produced), the estimated progress ratios in these publications range from 0.83 to 0.91, corresponding to learning rates of 0.17 to 0.09. That is, when total installed capacity of wind power is doubled, the

[8] See for instance (Durstewitz and Hoppe-Klipper, 1999), (Neij, 1997), (Neij, 1999) or (Neij et al., 2003)

costs per produced kWh for new turbines are reduced between 9 and 17%. In this way, both the efficiency improvements and embodied and disembodied cost reductions are taken into account in the analysis.

Wind power capacity has developed very rapidly in recent years, on average by approximately 25% per year during the last ten years. Thus, it takes at present approximately 4 years to double the accumulated capacity of wind power. The EU has set a target of 40,000 MW wind power by year 2010, compared to approximately 29,300 MW installed in the EU by the end of 2003. Thus, if the current development continues, the EU target will be by-passed in less than 2 years.

The European Wind Energy Association (EWEA) has recently published a target of 75,000 MW for Europe in 2010. This implies that a growth rate of approximately 14% per annum is required to reach the EWEA target in 2010 (doubling time of approximately 5 years). In Figure 13 below, the consequences for wind power production costs according to the following assumptions are shown:

- A learning rate of 15% is assumed, implying that each time the total installed capacity is doubled, the costs per kWh wind-generated power is reduced by 15%;

- The growth rate of installed capacity is assumed to double cumulative installations every 5 years.

The historical development of wind power costs is used as a starting point as shown in Figure 12.

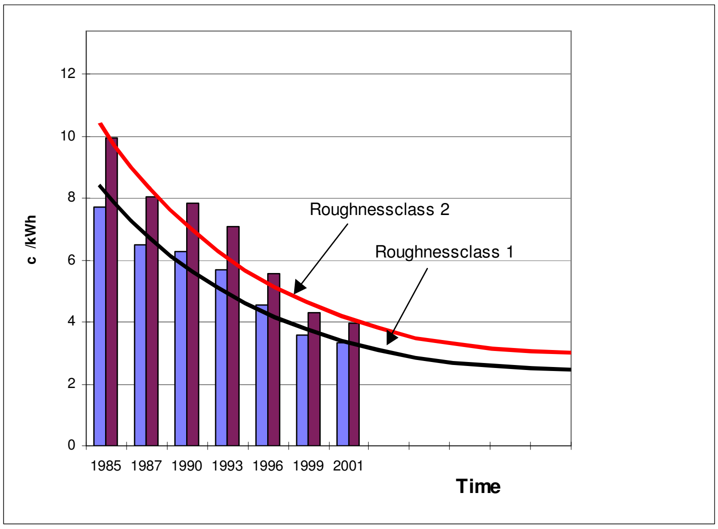


Figure 13: Using experience curves to illustrate the future development of wind turbine economics.

The consequences of applying the above-mentioned results for wind power are illustrated in Figure 13, where a roughness class 1 position corresponds to a coastal-siting, while roughness class 2 is a typical inland-siting. Thus, if accumulated capacity of wind power doubles every 5 years, the costs of wind produced power should around 2010 according to the experience curve approach be within a range of approximately 2.4 c€/kWh to 3.0 c€/kWh (constant 2001 currency). The costs of intermittency are not included in these costs; due to fluctuations in wind speed, wind power will not always be available and if supplying the produced power to a liberalised spot market, it will not always be possible for the wind turbine owner to fulfil the bid given to the market. Thus, other producers of power will have to step in, either up-regulating or down-regulating their production depending on if too little or too much wind power is produced. For the conditions at the Nordic power market, Nord Pool, the cost of regulation is estimated to an average of 0.3 c€/kWh delivered by wind turbines (Morthorst, 2003). Thus, including the cost of intermittency, the total costs of wind produced power by 2010 as estimated by the experience curve approach is expected to be in a range of approximately 2.7 c€/kWh to 3.3 c€/kWh (constant 2001 currency).

An implicit assumption of the learning curve approach is that the analysis is performed for essentially the same technology over time. For the period analysed, this assumption is clearly fulfilled for the wind turbine development, the 95 kW machine from the mid 1980s as well as the 1 MW machine from 2001, both being technically classified as members of "the Danish Concept", that is being up-wind turbines, three bladed and gearbox based machines. Thus, for the period analysed and the chosen turbine sample, no technological breakthroughs have been witnessed. But the wind turbine industry is still in its infancy. Thus, new design concepts are to be expected, the trend going towards direct drive transmission, pitch regulated, variable speed and gearless turbines. But these new concepts will only be introduced either as a requirement by the market due to grid or regulatory conditions or because they will improve the cost-effectiveness of the turbines. Thus, even if the up-scaling of turbine size as the driver towards reduced costs might slow down in the future, a considerable potential still exists for new technological developments to lower the costs per kWh for new future turbines.

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