Science & Global Security, 1993, Volume 4, pp.65–109
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Printed in the United States of America

Wind Energy: Current Status and Future Prospects

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Field operation of more than 17,800 wind turbines in Denmark and California during the past 10 years has thoroughly tested and proven the present generation of wind turbine technology. Reliability is now satisfactory; in addition, wind farm operation and maintenance procedures have been mastered. Unit size has increased by a factor of 10 during the past decade: wind turbines rated at 0.5 megawatts are now available commercially from several manufacturers. Moreover, advances in wind turbine technology in the next 20 years (such as advanced materials for airfoils and transmissions, better controls and operating strategies, and improved high-power-handling electronics) will substantially reduce capital costs as well as operation and maintenance costs. In areas with good wind resources (450 watts per square meter [m^{-2}] wind power density at hub height), wind turbines now generate electricity at a cost of $0.053 per kilowatt-hour (kWh^{-1}) (6 percent interest, all taxes neglected). With a mature wind turbine technology, the cost is expected to decline to less than $0.03 kWh^{-1}, rendering wind-generated electricity fully competitive with electricity from coal-fired generating stations. In addition, economically exploitable wind resources (wind power density > 300 watts m^{-2} at 50 meters) are extensive and widely distributed, and, in general, wind-generated electricity can be easily integrated into utility grids without provision for storage. As a result, the development of economically competitive wind turbines should have a profound impact on energy production industries in many parts of the world.

INTRODUCTION

During the past 20 years outstanding progress has been made in the technology used to convert wind energy to electrical energy. More than 15,000 wind turbines in California and 2,800 in Denmark have been integrated into existing utility grids. In California the cost of wind-generated electricity has decreased substantially during the last several years (see figure 1).[1] Installed capital costs have also dropped sharply, and wind turbine utilization efficiency has improved considerably (see figure 2), indicating that manufacturing techniques and wind farm operating methods are maturing rapidly.

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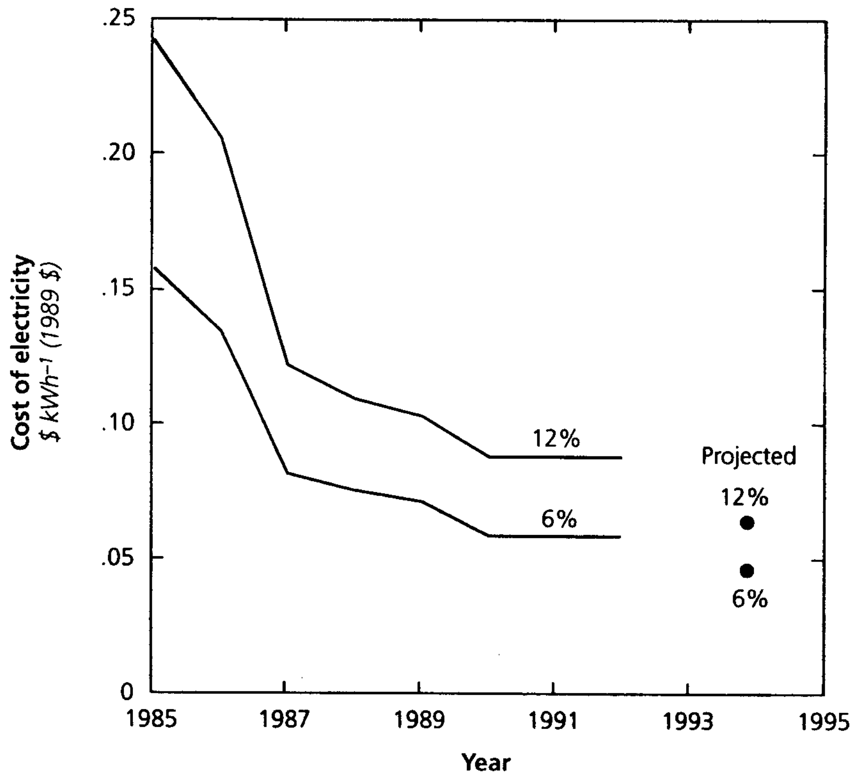

Figure 1: Declining cost of electricity from wind turbines in California; data for 1994 are estimates,[2,3] for real discount rates of 12 percent and 6 percent. The average wind energy density in the California mountain passes is typically greater than 450 watts m^{-2}.

California and Denmark now produce 1.1 and 2.5 percent, respectively, of their average electricity consumption with wind turbines, and Denmark intends that wind turbines will supply 10 percent of its electricity by the year 2005.

The wind resources of California and Denmark are by no means unique. Similar and even higher quality resources are available in many other regions of the world. A study[4] based on work by the World Meteorological Organization and the Pacific Northwest Laboratories[5] estimated that global wind energy potential is several times global electricity consumption. Even after factoring in land use, environmental, and system integration constraints, wind energy could supply 20 percent of global electricity demand.[6] In the United States, with reasonable system assumptions and land use restrictions for wind turbine siting,[7] the wind electric potential of two states, North Dakota and South Dakota, is estimated to be 80 percent of present United

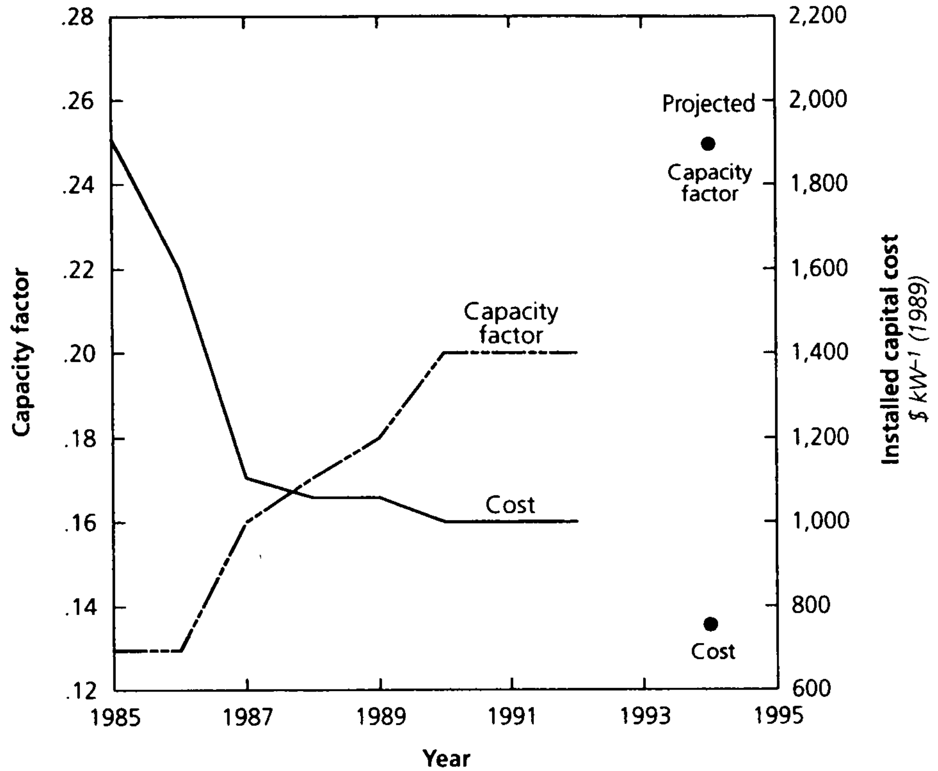

Figure 2: Wind turbine use, as indicated by the capacity factor (which is the ratio of the annual average power output to the rated power output (see "Power Output" on page 76)) and installed capital cost for wind turbines in California. The 1994 estimated cost and capacity factor for a US Windpower 33M-VS variable-speed turbine (see "Variable-Speed Wind Turbines" on page 84) are based on public filings by US Windpower. The capacity factor for 1990 is an average for all wind farms in California. Excluding obsolete machines in the Altamont Pass, the capacity factor for wind farms in this area is 0.24. The capacity factor for San Gorgonio Pass is 0.24 and for Tehachapi Pass is 0.19.[3]

States electricity consumption.[8] Clearly, expansion of the wind power industry is not limited by the physical availability of wind resources.

There are many examples of skillful exploitation of wind energy in recent and ancient history. For example, simple windmills were used to pump water in China about several hundred years BC. As early as 200 B.C., vertical-axis windmills were employed to grind grain in the Middle East. Windmills were subsequently introduced to Europe in the 11th century by merchants and veterans returning from the Crusades.[5] Windmill designs were improved first by the Dutch, and later by the English.[9, 10, 11] The greatest use of windmills occurred in the 18th century, when more than 10,000 in the Netherlands alone were used to grind grain, pump water, and saw wood. Eventually, the mills were unable to compete with the low cost, convenience, and reliability of fossil fuels, and were replaced by steam engines. In the United States, windmills are best known for their role in the development of the American West. Windmills supplied water for cattle and small-scale irrigation and worked as standalone systems to generate electricity for isolated homesteads.[12, 13] Wind machines were also used to supply water for the railroads.

Today's wind turbines are more likely to be coupled to a utility grid that is also supplied by other types of generators. Large numbers of wind turbines can be integrated into a utility grid with little or no need for storage. Wind turbines that are isolated from the utility grid require an auxiliary backup (rechargeable batteries in small systems, diesel engines in multikilowatt systems), which is both expensive and inconvenient.

Although wind energy technology demands careful attention to scientific and engineering detail, it is well within the capabilities of most if not all countries and is becoming economically competitive in many regions around the world.

WIND CHARACTERISTICS

The energy flux, or wind power density in watts m^{-2}, of a stream of air of density ρ moving with velocity v is given by:

$$P_w = \frac{\rho v^3}{2} \tag{1}$$

Not all of the wind power density is available for useful work. The maximum power[14] that can be extracted from a wind stream is $^{16}/_{27} \cdot P_w = 0.593 \cdot P_w$; this quantity is referred to as the Betz limit.[15] (See appendix A for details.)

Because wind power density varies as the cube of the wind velocity, a wind turbine must be able to function over very large variations in P_w to accommodate typical variations in wind speed. For example, if an area has a characteristic average wind velocity (v_{avg}), for wind speeds of $0.5 \cdot v_{avg}$ the available power density is only one eighth that at v_{avg}, while at $2 \cdot v_{avg}$ the power density is eight times that at v_{avg}. Wind velocities that are less than the average yield little useful power, while velocities much above the average can overstress turbine components. Thus, the technical challenge is to design a wind turbine that can function efficiently and reliably over a large variation in P_w with a minimum amount of maintenance for as low an initial capital cost as possible. This has proved to be a demanding task.

Wind speed in any given region is not constant but varies over periods of

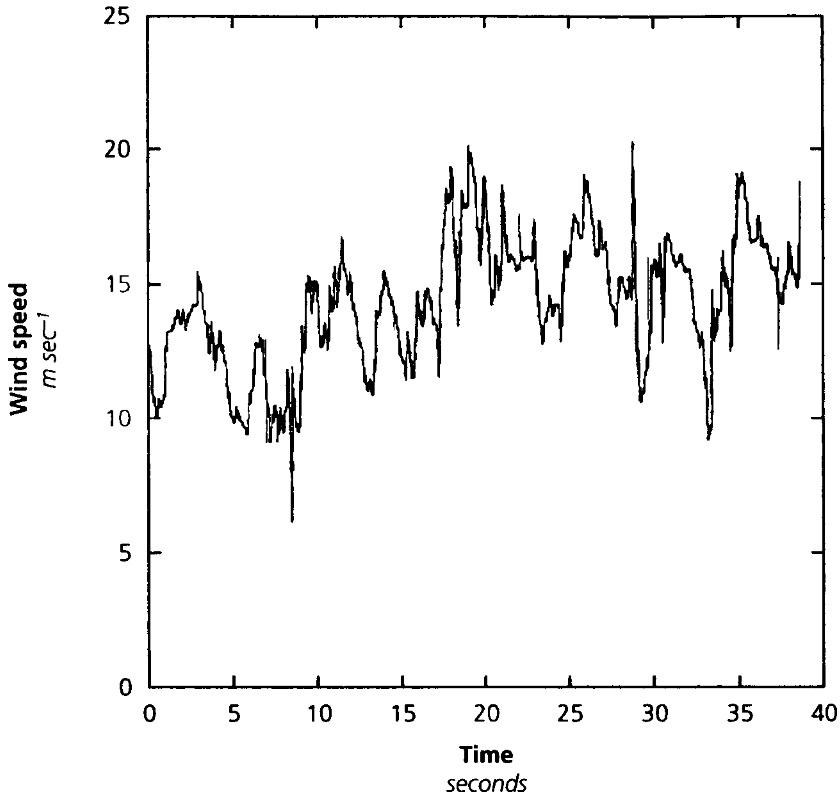

Figure 3: Wind speed as a function of time measured near the center of an array of 600 wind turbines in the San Gorgonio Pass, California. Measurements were made with a sonic anemometer with a 10-hertz frequency response. Turbines are spaced two rotor diameters (*D*) apart in rows 6*D* apart and are perpendicular to the prevailing wind. Average wind velocity is 13.3 m sec^{-1}, and the standard deviation is 3.85 m sec^{-1}. For this site the turbulence intensity is 0.29.

seconds, hours (diurnal variation), days, and months (seasonal variation). The frequency at which different wind velocities occur is described by a wind speed frequency distribution, $f(v)$. If information on the frequency distribution is not available, a Rayleigh distribution (see figure 4) is often assumed. (See appendix A for details.) Large changes in wind speed can be encountered by a wind turbine (see figure 3). Fluctuations in velocity that occur over seconds or minutes are referred to as turbulence and can cause fatigue and failure of wind turbine components (blades, transmissions, and generators). Turbulence levels are characterized by the turbulence intensity, which is the ratio of the wind speed standard deviation to average wind speed. A site with an intensity greater than 0.5 is considered too turbulent for a wind turbine.[16]

Additionally, wind speed increases with elevation. Usually, wind measurements are made at a single elevation, often near 10 meters, which is very different from the probable hub height (25 to 50 meters) of modern wind turbines. Wind speed at hub height is calculated by assuming that wind speed increases as the one-seventh power of the elevation (see appendix A). The one-seventh power rule means that for a Rayleigh distribution, the wind power density at 50 meters is twice that at 10 meters. This rule was developed from a synthesis of many data sets and should be applied with caution. This rule is critical to estimates of wind energy potential when detailed site-specific data are lacking.

Wind-speed distribution will also vary with elevation—winds are usually steadier at higher elevations. Over large regions of the North American Great Plains strong night winds at higher elevations (a nocturnal jet[17]) substantially enhance the wind-electric potential. It is essential to measure $f(v)$ for at least one year at several different elevations at a given site in order to predict with confidence energy production and turbulence levels at that site.

Wind frequency distributions measured at 10 meters at the Altamont Pass in California and Bushland, Texas, are shown in figure 4.[16] The average wind velocity at this Altamont Pass site is about 6.4 m sec^{-1}. Winds with three times this velocity, and thus 27 times the power density, are encountered only one percent of the time. The additional cost and weight of a turbine needed to capture all this energy at these very high wind speeds are not justified by the value of the extra energy obtained. To optimize energy capture as a function of turbine cost, turbines are designed to limit the energy captured above the rated wind velocity (see appendix B). At very high velocities, usually above 25 m sec^{-1}, the turbine must be stopped completely to protect it from damage.

A wind power density greater than 400 watts m^{-2} at 50 meters elevation is typical of many areas of the world, including the northern coast of Europe, the United Kingdom, and Ireland. At this power density, about 3,700 wind turbines rated at 0.5 megawatts each (35 percent capacity factor) would have to be deployed over an area of about 400 km^2 to generate an average of 650 megawatts-electric, which is comparable to the average output of a large coal or nuclear power plant. Although this may at first seem unreasonable, only one to five percent of the land area on which wind turbines are deployed is needed for tower foundations, access roads, and electrical substations. Apart from the visual impact, the land itself is almost completely undisturbed and can still be used as rangeland, farmland, or for some other purpose, while royalties from energy production significantly enhance land value.

Estimating Wind Resources and Wind Energy Potential

Wind resources of many regions of the world have been evaluated in some

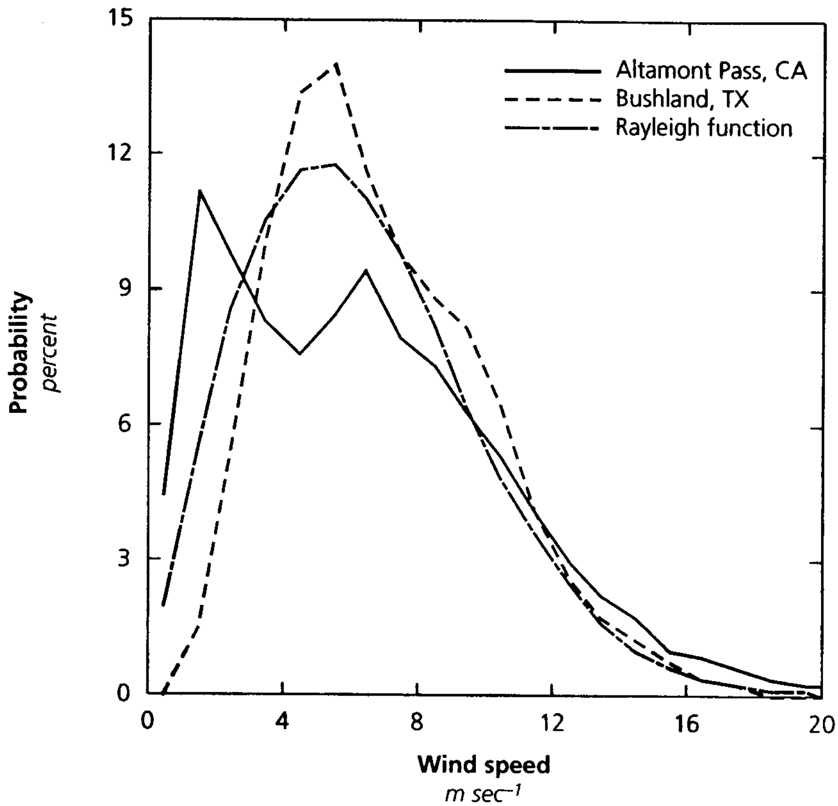

Figure 4: The wind frequency distribution at 10 meters elevation for Altamont, California, and Bushland, Texas (v_{avg} (Altamont) = 6.4 m sec^{-1}, v_{avg} (Bushland) = 7.0 m sec^{-1}). A Rayleigh probability density function for v_{avg} = 6.4 m sec^{-1} is shown for comparison (53). The wind power density for this distribution is 305 watts m^{-2}, compared to 380 watts m^{-2} computed from the measured Altamont data. The Rayleigh function is not a good fit to the Altamont data with the same average velocity. The distribution at Bushland has a shape typical of that at a Great Plains site. Here the wind speed varies with elevation to the one-seventh power during the day and to the one-fourth power at night, indicating the presence of strong night winds at higher elevations (a nocturnal jet). The average wind power density is greater than 750 watts m^{-2} at 50 meters elevation, indicating an excellent site. The distribution at Altamont has relative maxima at 1.5 m sec^{-1} and 6.5 m sec^{-1}, reflecting the unusual nature of these winds. They are driven by the temperature differential between the hot California Central Valley and the cool Pacific Ocean; the air in the Central Valley is heated and rises upward to be replaced by sea air flowing through an opening in the mountain range that separates central California from the coast. Wind speed is twice as high in the summer as in the winter and much higher in the early evening than in the late morning, following the temperature rise and fall in the Central Valley. These substantial periods of low wind give rise to the double maxima in the distribution. In addition, wind speed is independent of height in Altamont Pass, which is also a reflection of the driving mechanism.[18]

detail based on the physical characteristics of the wind and weather data from military bases, national weather services and commercial ships. These surveys indicate that substantial wind resources exist in many parts of the world.

The data collected in the US, Caribbean,[19] and European surveys are of good quality, although relatively sparse with respect to the areas covered. This lack of detail can have important consequences. For example, the windy mountain passes in California were overlooked in the first national survey and were only properly documented due to the efforts of the California Energy Commission.[20]

The world wind resource survey[21] is based on data of much poorer quality. There were uncertainties in the calibration, exposure, and height above ground level of the anemometers in many areas. The authors of the survey state that the surface wind data "...was used very cautiously and with many misgivings." Thus, the results should be taken as indicative only.

Using these wind resource surveys, the wind electric generating potential of different regions can be estimated given the following technical assumptions.

- Hub height above ground level is 50 meters.
- Average turbine spacing: 5 rotor diameters (D) apart in a direction perpendicular to the prevailing wind, and 10 rotor diameters apart in the direction parallel to the prevailing wind ($10D \times 5D$).
- Total conversion efficiency (turbine efficiency × array and system efficiency) is 26 percent (e.g., turbine efficiency of 35 percent, array and system losses of 25 percent).

When estimating wind potential from wind resources, environmental exclusions must be taken into account. "First order land exclusions" exclude densely populated, environmentally sensitive, and inaccessible areas;* wind electric potential in the remaining areas is the "first order potential." "Second order land exclusions" are those based on political judgements and traditions; wind electric potential in the remaining areas is the "second order potential." For Denmark, which has had its wind resources carefully evaluated, the first order potential is a factor of 20 lower than the gross potential, while the sec-

* Many high-wind areas are extremely remote from load centers and experience severe weather conditions. For example, the high wind areas in Russia are located in the far north bordering the Arctic Ocean, while in Canada the best area is located between the Arctic Ocean and the north of Hudson Bay. It may be possible one day to exploit these resources, however, long distance transmission and the attendant reliability and grid stability issues will first have to be addressed.

ond order potential is a factor of 78 lower than the gross potential.

The estimated second order wind electric potential for the world is 53,000 terawatt hours per year, compared to global electricity consumption of 10,600 terawatt hours per year.[6] Thus, even these crude estimates show that wind-generated electricity has the potential to make a significant contribution to world energy needs.

Wind Energy Potential in the United States

The wind resources of the US and its overseas territories have been evaluated by Elliott and co-workers and are cataloged in the *Wind Energy Resource Atlas of the United States.*[22] The wind resource is graded in seven classes, ranging from class 1 (P_w < 200 watts m^{-2}) to class 7 (P_w > 800 watts m^{-2}) at 50 meter elevation. Large areas of the Great Plains, the Appalachian Mountains and the East Coast are shown to have significant (wind class 4 or greater) wind resources. Table 1 shows US wind energy resources.

Even for the case of severe land use restrictions, the wind electric potential of the United States is 2.3 times the 1990 US electric generation by tapping land resources of wind class 3 and greater. This is enormous; most of this potential, however, is in the Great Plains, far from the load centers.*

Wind Energy Potential in the European Community

The wind resources of the European Community are summarized in the *European Wind Atlas.*[23] Wind resources of selected European countries, as computed from the *European Wind Atlas* and other wind resource surveys, are shown in table 2. The United Kingdom and Denmark have excellent wind electric potentials that are significant relative to current consumption. The European Community has a first and second order wind electric potential of 26 percent and 7 percent, respectively, of the 1989 electricity consumption of 1,600 terawatt hours per year, not including offshore potential. Thus, even in Europe, with its severe siting constraints compared to the United States, wind-generated electricity could contribute a substantial fraction of the total electricity needs.

Because of the high population density in Europe, onshore sites are somewhat difficult to obtain, and so offshore resources[24] may assume greater importance. There is already a small (11 wind turbines, 450 kilowatts each)

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* The wind electric potential of California, where virtually all of the wind energy development in the US has taken place, is seven GW_e for moderate land use restrictions. Almost all of the best sites have been exploited; the wind electric output of about 2.8 billion kilowatt-hours in 1991 is equivalent to 0.32 $GW_{e,avg}$.

Table 1: Continental US wind energy resources, assuming 35 percent turbine efficiency, 25 percent field losses, and 50 meter hub height.[a]

	Percent of US land area	Wind electric potential	
		TWh year^{-1}	*Percent of US generation, 1990*
No land-use restrictions			
Wind classes ≥ 5	1.2	1,960	71
Wind classes ≥ 3	21.0	23,380	834
"Environmental" restrictions[b]			
Wind classes ≥ 5	0.8	1,260	46
Wind classes ≥ 3	18.0	20,000	713
"Moderate" restrictions[c]			
Wind classes ≥ 5	0.6	980	35
Wind classes ≥ 3	13.6	15,120	538
"Severe" restrictions[d]			
Wind classes ≥ 5	0.4	700	24
Wind classes ≥ 3	5.7	6,440	231

a.

Rank of resource	$P_{w,avg}$ watts m^{-2} at 50 meters	Wind class (US Wind Atlas) (22)	Wind speed m sec^{-1} at 50 meters assuming Rayleigh distribution
Poor	0–200	1	0–5.6
Marginal	200–300	2	5.6–6.4
Useful	300–400	3	6.4–7.0
Good	400–500	4	7.0–7.5
Very Good	500–600	5	7.5–8.0
Excellent	600–800	6	8.0–8.8
Superb	> 800	7	> 8.8

b. Excluded are 100 percent of environmentally sensitive lands

c. Excluded are 100 percent of environmentally sensitive and urban lands, 50 percent forest, 30 percent agricultural and 10 percent range lands.

d. Excluded are 100 percent environmentally sensitive, urban, forest and agricultural lands, and 10 percent range lands.)

wind farm four kilometers off Denmark in water six meters deep. Although the output of the wind farm is expected to be 50 percent greater than from the same installation at an inland location the cost of electricity is projected to be 50 percent greater due to the much higher installation costs.[25] Unfortunately, offshore resources are not included in the *European Wind Atlas.*

Table 2: Wind electric potentials of selected countries in Europe.[a]

Country or region	Gross wind electrical potential TWh year^{-1}	Population density km^{-2}	First order potential TWh year^{-1}	Second order potential TWh year^{-1}	1989 electricity production TWh year^{-1}
Denmark	780	120	38	10 onshore 10 offshore	26
United Kingdom	2,600	235	760	20–150 onshore 200 offshore	285
Netherlands	420	360	16	2	67
EC[b]	8,400	140	420	107	1,600
Norway		13.1	32[c]	12[d]	109
Sweden	540[e]	19		7 onshore 23 offshore	140
Finland		14.7	30[f]	10	51

a. See reference 6.
b. Exclusion factors as for Denmark; see page 9.
c. For the whole Norwegian coast, including small island-cliffs (see reference 26).
d. Using only the best sitings along the coast (see reference 26).
e. Includes southern Sweden only, and only areas with mean annual wind power densities higher than 450 watts m^{-2} at 100 meters. Offshore sitings at 6 to 30 meters depth and more than three kilometers from land are also included (see reference 27).
f. Including some offshore sitings (see reference 28).

WIND TURBINE TECHNOLOGY

Aerodynamics

Modern wind turbines extract energy from the wind stream by transforming the wind's linear kinetic energy to the rotational motion needed to turn an electrical generator. This change is accomplished by a rotor, which has one, two, or three blades or airfoils attached to a hub; wind flowing over the surfaces of these airfoils generates the forces that cause the rotor to turn.

Air flowing smoothly over an airfoil (called laminar flow) produces two forces: lift, which acts perpendicular to the flow; and drag, which operates in the direction of the flow (see figure 5). Lift and drag can be resolved into forces F_1 in the direction of airfoil translation and F_2 in the direction of the undisturbed wind. The force F_1 is available for useful work, while the tower and structural members of the wind turbine must be designed to withstand F_2 (which is termed the rotor thrust). If the flow becomes unattached from the airfoil surface, the lift is reduced and the airfoil is said to stall. Both lift and drag are proportional to the density of the air, the area of the airfoil, and the square of

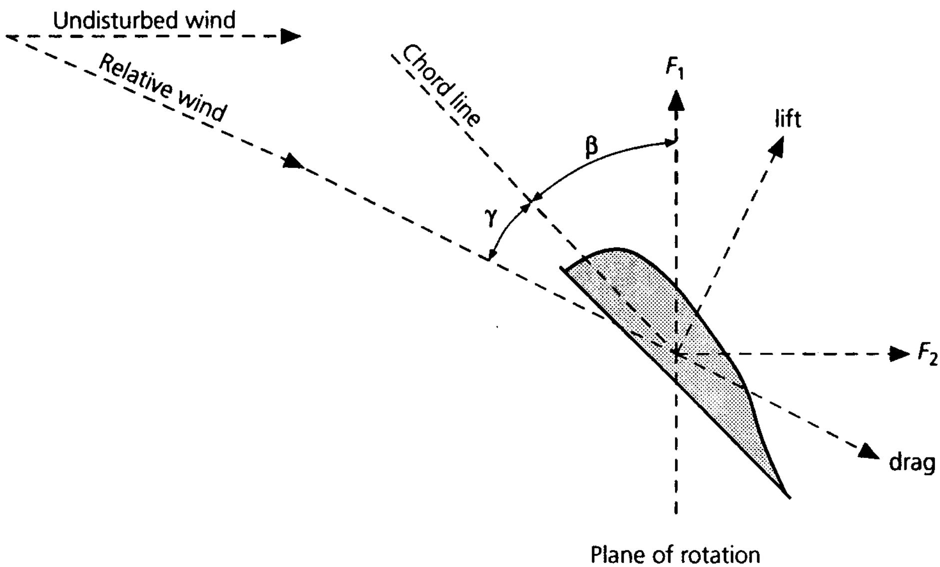


Figure 5: Lift, drag, angle of attack (γ,), and pitch angle (β,) of a wind-turbine airfoil. The force F_1 is in the direction of motion of the airfoil; the force F_2 is referred to as the rotor thrust. The velocity of the end of the airfoil is typically four to eight times the wind velocity and the angle of attack is typically less than 20°. Thus the diagram is indicative of a position far from the airfoil tip.

the wind speed for laminar flow, and are maximized at a single value of the angle of attack γ (the angle between the relative wind velocity and the chord line). (The vectorial addition of the wind velocity and the airfoil velocity is usually termed the relative velocity.) Since blade velocity increases with distance along the airfoil, the angle of attack must also change along the airfoil, i.e., the airfoil must be twisted to obtain maximum efficiency.

Power Output

The power output (P_{out}) of a wind turbine is:

$$P_{out} = C_e \frac{A \rho v^3}{2} = \varepsilon_1 \varepsilon_2 C_p (v, \omega, \beta) \frac{A \rho v^3}{2} \tag{2}$$

The fraction of power extracted from a wind stream by a wind turbine is denoted by C_e, which is the machine's coefficient of efficiency. Here C_p, the coefficient of performance of the airfoil, is a function of the wind velocity, the angular velocity of the rotor ω, and the pitch angle β (the angle between the airfoil chord line and the direction of translation of the airfoil; see figure 5) and also the airfoil shape and number of blades; ε_1 and ε_2* are the generator and transmission efficiency, respectively; and A is the rotor area. Since an airfoil has optimum values of lift and drag for one angle of attack γ, or equivalently for one value of relative wind speed, C_p for a wind turbine with fixed blades and operating at a fixed angular velocity will also have a maximum value that decreases at higher or lower wind speeds. For existing airfoils, the maximum value of efficiency occurs at a ratio of blade-tip velocity to wind velocity that is between four and eight.† For example, a three-blade 100 kilowatt machine (USW-56-100, made by US Wind Power) that is widely used in the Altamont Pass (v_{avg} = 6.4 m sec^{-1}) has a blade-tip velocity of 67 m sec^{-1} (150 mph).

There is a trade-off among several factors in choosing the number of blades: cost of the blades and transmission (the most expensive parts of a wind turbine), energy capture, and speed of rotation. A single-blade machine (with counterweight) will have lower energy capture than a multiple-blade machine but it will rotate at high angular velocity. Because the rotor must turn a generator at 1,500 to 1,800 rpm to produce electrical power at 50 or 60 hertz, a higher rotor angular velocity permits the use of a transmission with a low gear ratio that is lighter, less expensive, and has lower losses than the transmission needed for a lower-angular-velocity rotor (see appendix B). A three-blade machine has higher energy capture and better stability with respect to orientation in the wind stream but will have higher blade and transmission costs. Although most wind turbines now being manufactured do have three blades, it is not clear that this is the optimum choice for lowest overall cost of electricity.

The measured power output and coefficient of efficiency as functions of wind velocity of a commercially available wind turbine are shown in figure 6. This machine uses stall control (see appendix B) to limit the maximum power extracted from the wind and has a constant angular velocity (i.e., the rotation velocity of the blades is locked to the grid frequency of 50 or 60 hertz). Power begins to be produced at three to four m sec^{-1} (the start-up velocity, v_u), and rated power‡, P_r, is produced at about 10 m sec^{-1}(v_r). When wind velocities exceed 25 m sec^{-1} (the machine shutdown velocity, v_d) the turbine is stopped to protect it from damage. P_{out} increases by about a factor of seven (from 17 to

* $\varepsilon_1 \approx 0.95$; $\varepsilon_2 \approx 0.95$ at rated output power.

† If the ratio of blade-tip velocity to wind velocity is low, the blade simply deflects the windstream, increasing turbulence and extracting little power. If the ratio is high drag becomes important, reducing power extraction.

‡ There is no generally accepted way of defining the rated power of a wind turbine; this term, therefore, is somewhat arbitrary. A more cumbersome but precise classification scheme is the specification of the expected energy production in a given wind regime from a given wind turbine.

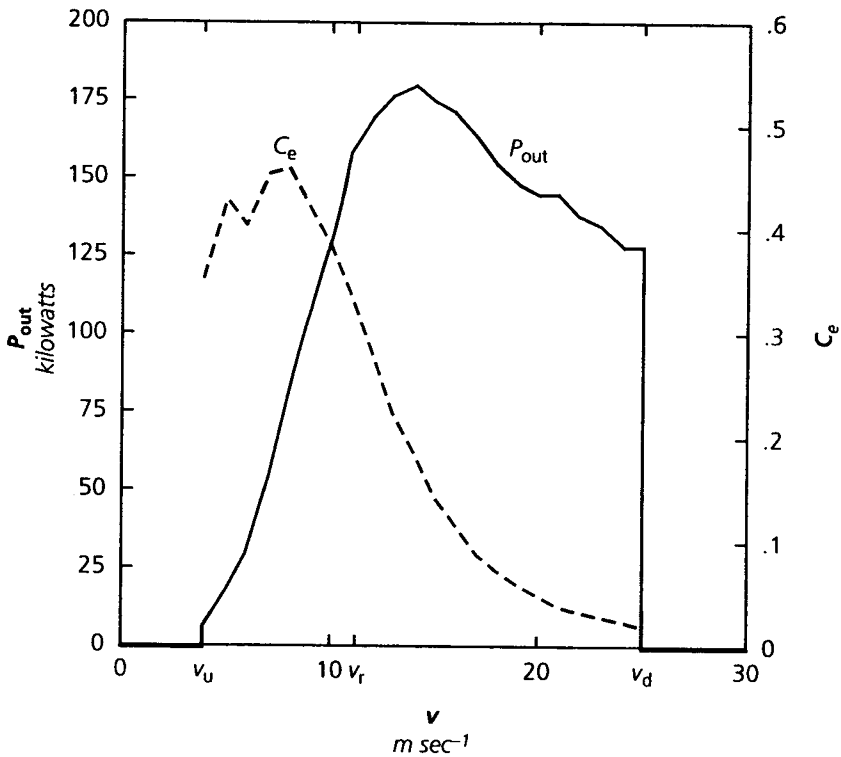


Figure 6: Power output P_{out} and coefficient of efficiency C_e for a 150 kilowatt stall-regulated turbine (29), as a function of wind velocity, v. Note the double relative maxima in the coefficient of efficiency, which result from two-speed rotor operation. Since maximum airfoil efficiency is obtained at one value of γ, for maximum turbine efficiency the angular velocity of the rotor should change as the wind velocity changes. In practice such a change is difficult to achieve, and variable-speed turbines are only now being commercialized (see "Variable-Speed Wind Turbines").

130 kilowatts) as the wind velocity increases by a factor of two (from 5 to 10 m sec^{-1}), indicating a very efficient machine. This high efficiency is obtained by having two-speed rotor operation. At low wind speed the rotor turns at lower angular velocity, while at high wind speed the angular velocity of the turbine is increased by about 50 percent, keeping the angle of attack (γ) and thus C_p of the airfoil approximately constant over this operating range. For wind speeds greater than 11 m sec^{-1}, C_p decreases rapidly due to the onset of stall, which limits the maximum power extracted from the wind stream.

The maximum coefficient of efficiency of 0.46 (attained at a wind speed of about eight m sec^{-1}) is nearly 78 percent of the theoretical maximum coefficient of 0.593 (the Betz limit). Thus, turbine blades are already relatively efficient for a narrow range of operating conditions, although possibilities for significant improvement still exist (see "Future Developments").

The average power output, P_{avg}, of a wind turbine for any time period of interest is determined by the power output at a given wind velocity multiplied by the probability of occurrence of that velocity summed over all possible wind velocities. The equation is written as:

$$P_{avg} = \int_{v} P_{out}(v) \cdot f(v)\,\mathrm{d}v \tag{3}$$

Furthermore, if P_{out} is written as $P_{out} = P_r \cdot g(v)$, then:

$$P_{avg} = P_r \cdot \int_{v} g(v) \cdot f(v)\,\mathrm{d}v \tag{4}$$

The integrated quantity is the ratio of the average power output to the rated power of the turbine. This is defined as the maximum attainable capacity factor (*CF*) and is an important parameter that can be used to calculate the cost of energy from wind turbines.

Capacity Factor

Capacity factor is a function of both wind turbine and wind characteristics. Several factors can contribute to a reduced capacity factor, such as unscheduled maintenance, blade soiling problems, and wake effects. In a normal operating regime, maintenance should have minimal impact on turbine availability if scheduled during periods of low wind speed. Reduced capacity factor may also be caused by the interaction between upwind and downwind turbines in a large array. Because a wind turbine extracts power from the wind stream, wind power density behind the turbine is decreased. Power density is gradually restored to its unperturbed level by the diffusion of energy downward from the wind stream above the array. The disturbed region behind the turbine is known as the wake; both the increased turbulence and reduced power density in the wake can degrade the performance of downwind turbines (i.e., turbines located at the center of an array relative to turbines on the array edge). For this reason, wind turbines cannot be too close together.

The scale length of the turbulence, which can be thought of as the average size of the eddies or vortices in the wind stream, will almost always be less than the distance between turbines in a large wind farm, so that fluctuations in the output of individual turbine output are uncorrelated if turbines are spaced properly. Thus, the power output of a large wind farm will be much more constant than that of an individual wind turbine. For a wind farm with N independent turbines, the wind farm output fluctuations are reduced by $1/\sqrt{N}$ compared to that of a single turbine.

The performance of an array of turbines relative to that of a single turbine is referred to as the array efficiency and is a function of turbine spacing and turbine efficiency. Array efficiency has been studied theoretically[30] and with wind tunnel models.[31] Theoretical results indicate that for a machine spacing of $10D \times 10D$, wind velocity at the center of a large array is reduced by about a factor of 0.8 compared with the unperturbed velocity for wind turbines operating at the Betz limit. In practice, wind turbines will operate below the Betz limit, and the reduction in the average output of an array will be much smaller than would be expected from this result. Results from an empirical model[6] indicate that a 10×10 array of turbines spaced 9 rotor diameters apart would have an efficiency of 87 percent.

In the California mountain passes,[32] where winds are essentially unidirectional, machines are usually spaced 2.5 rotor diameters apart in rows perpendicular to the prevailing winds, with a row spacing of eight rotor diameters. Wake effects have caused problems at some wind farms, and there have been systematic field studies to measure these effects in detail.[33]

Wind Turbine Design History

Recent History of HAWTs

There are two fundamentally different types of wind turbines (see figure 7). The first is the horizontal axis wind turbine (HAWT), which has the axis of rotation of its rotor parallel to the wind stream; the second is the vertical axis wind turbine (VAWT), which has the axis of rotation of its rotor perpendicular to the wind stream.

Although the HAWT has long been used for small-scale applications, such as pumping water and non-utility electricity generation (see "Introduction"), its development for large-scale power production began in the United States in 1941 with the installation of the 1.25 megawatt Smith–Putnam[34] machine in Vermont. This machine was shut down in 1945 after several hundred hours of operation and was the last utility-scale wind development in the United States until 1975. In Europe, research continued after World War II in Denmark, France, the United Kingdom, and Germany. In Denmark, development of the Gedser Wind Turbine,[35] a rugged and simple machine built to withstand the imposed wind loads, was continued until the early 1960s (by J. Juul) under the sponsorship of the Danish Utility Association.[36] In Germany, Ulrich Hutter[37] built a series of sophisticated machines that attempted to reduce component

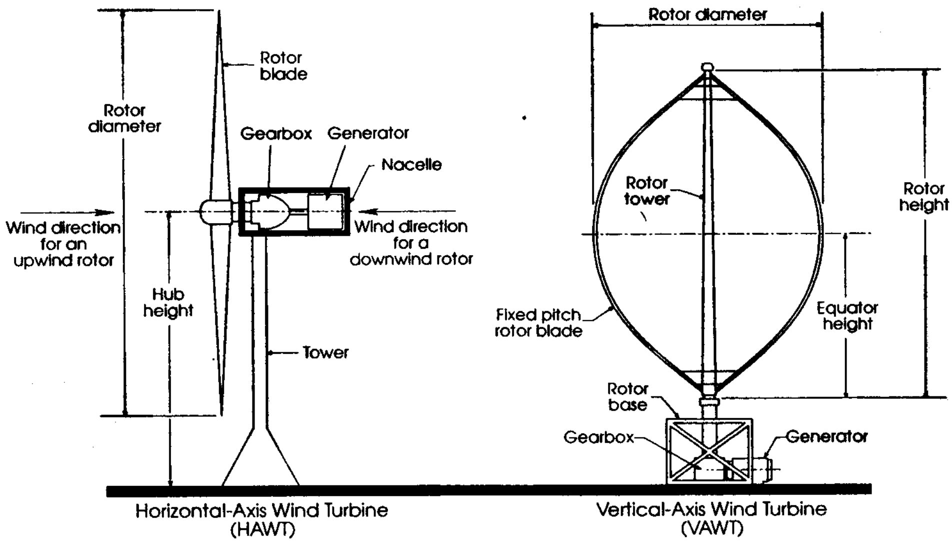


Figure 7: Two basic wind turbine configurations are shown: the horizontal axis wind turbine (HAWT) and the vertical axis wind turbine (VAWT). Upwind and downwind operation of the HAWT is indicated. Most modern machines operate upwind to avoid shadowing of the blade by the tower, which can generate objectionable noise levels and increase stress on the blades. In practice, the hub height is approximately equal to the rotor diameter. The VAWT (a Darrieus turbine) has its gearbox and generator at ground level, which simplifies routine maintenance, but cannot easily take advantage of greater wind speed and lower turbulence at higher elevation. It is supported by several guy wires fixed to the top of the rotor tower (not illustrated).

failures by using a moveable or teetered hub to shed aerodynamic loads (see appendix B); these experiments ended in 1968. Both design philosophies, load withstanding and load shedding, are reflected in the designs of present-day horizontal axis wind turbines.

The 1973 oil crisis focused the attention of governments in Europe and the United States on problems of energy supply security, and resulted in a large increase in funding for energy-related research. One of the many programs initiated at this time in the United States was a wind energy conversion research project. It was decided, based on earlier work,[38, 39] that very large-capacity machines (of the order of five megawatts-electric [MW_e] or more) were needed if wind-generated electricity were to become competitive with fossil fuel power plants. Beginning in 1975,[40] a series of successively larger machines, which attempted to implement advanced concepts of load shedding and variable-speed operation were built (see "Variable-Speed Wind Turbines" on page 20).[41]

It is now thought that the optimum machine size is between 0.2 and 0.5 megawatts, based on the simple argument[42, 43] that energy capture increases with the square of rotor diameter, while the wind turbine mass, and thus cost, increases as the cube of the diameter for current designs. This rule is derived from the extensive experience of the aircraft industry, which has found that mass increases with size to the 2.7 power.

In Denmark, development of smaller machines was based on the extensive experience obtained with the Gedser Wind Turbine. A wind turbine testing station was established at the Risø National Laboratory. Starting small has proved to be the best strategy for wind turbine development, in large part because field experience can be gained quickly, which in turn dictates rapid design improvements.

Recent History of VAWTs

The modern vertical axis wind turbine was invented in the 1920s by the French engineer G.M. Darrieus[44] and his version is called the Darrieus turbine. Major development work on this concept did not begin until the 1960s when the turbine was reinvented by two Canadian engineers. The Darrieus turbine has several advantages compared to the HAWT. First, it does not need a yaw system (see appendix B) to turn it into the wind. In addition, its drive train, generator, and controls are located at ground level where they are accessible and can be easily maintained. Because the rotor blades operate under almost pure tension, relatively light and inexpensive extruded aluminum blades can be used. Finally, it is about as efficient as a horizontal axis turbine.

Darrieus wind-turbine development has been extensively pursued by Sandia National Laboratories[45] for the US Department of Energy (DOE), the laboratories which built a 500 kilowatt, 34-meter-diameter research machine at Bushland, Texas. The blades have both a variable chord length and a variable cross section to optimize performance. The use of a variable-speed system in which the rotor speed can vary between 25 and 40 rpm to increase energy capture is currently being investigated.

The Darrieus VAWT may prove to be cost effective in some applications, but it is limited because, unlike the HAWT, it cannot take advantage of the higher wind velocity and lower turbulence at higher elevations. Other types of vertical axis machines which have hub heights tens of meters above ground level have been built and tested. Their technical and economic feasibility is uncertain at this time.[46] The vast majority of wind turbines in use today are horizontal axis machines, and these will be the focus of this discussion.

Modern Wind Turbines

Robert Lynette[47] made a detailed evaluation of the operation and maintenance of 4,500 wind turbines that were installed between 1981 and 1987 in California. The study documents many of the problems encountered with a relatively

Table 3: A selection of wind turbines available in 1991 (machines have rotor upwind of tower unless noted).

Company	Model	Hub height *meters*	Rotor diameter *meters*	Rating *megawatts*
US Windpower	USW 56-100[a]	18	17	0.1
	USW 33M-VS[b,c,d]	30	33	0.4
Nordtank	NTK-150[e]	32.5	24.6	0.15
	NTK 450/37[e]	35	37	0.45
Micon	M530-250[e]	30	26	0.25
Vestas	V27-225[c]	31.5	27	0.225
	V39-500[c]	40	39	0.5
Bonus	150 Mk III[e]	30	23.8	0.15
	450 Mk II[e]	35	35.8	0.45

a. Variable pitch, downwind.
b. Variable speed.
c. Variable pitch.
d. Prototype; production in 1993.
e. Stall-controlled.

new technology: the average capacity factor at the time of Lynette's review (1987 data) was 0.13. Yet by 1990, the capacity factor had almost doubled to 0.24.[3] Clearly, the technology associated with small- to medium-sized (50 to 250 kilowatt) machines has matured significantly. Many components or subsystems that had failed originally, such as mechanical brakes or tip brakes, were redesigned or upgraded. The environments in which the machines function vary from the relatively mild conditions of the Danish countryside to the desert extremes of the southern California mountain passes, where sandstorms and temperature variations of –15°C to +35°C test the limits of reliability and durability.

A selection of wind turbines available in 1991 is given in table 3. The organizations listed have each manufactured more than 1,500 machines, all of which represented state-of-the-art equipment in 1991. US Windpower, Inc. has built and operates more than 3,400 wind turbines in Altamont Pass, California. About 50 percent of the approximately 15,000 wind turbines installed in California were built by such Danish firms as Micon, Bonus, Nordex, Vestas, and Danwin. Although other manufacturers are also currently producing state-of-the-art equipment, they have not yet achieved such high production volumes.

Variable-Speed Wind Turbines

Currently installed wind turbines operate at a constant rotation frequency that is locked to the utility grid frequency. However, in decoupling the rotor angular velocity from the grid frequency, there is an increase in annual energy output; the quality of the power supplied to the grid is improved, and structural loads are reduced. The disadvantage is the increased cost associated with the power-handling electronics.

The increased energy output is a consequence of adjusting the rotor speed to increase the rotor efficiency at a given wind velocity. Rotor efficiency is highest when the ratio of the rotor tip velocity to wind velocity is between four and eight. By varying the rotor angular velocity to attain this ratio, annual energy output can be increased by about 10 percent.[48] In addition, the quality of the power supplied to the grid can be improved by using the power-handling electronics to control the power factor[49] and to suppress harmonic currents. Finally, structural dynamic load reduction can be obtained by controlling the rotor angular velocity to avoid resonant interactions among wind turbine components, particularly the rotor and the tower. This last advantage can be realized only if the interaction of the components is understood over the operating range of rotor angular velocity. Carefully designed control programs are therefore required to use this feature.

The most publicized variable-speed machine currently offered commercially (for delivery in 1993) is the US Windpower 33M-VS (see table 3); the US DOE and a number of European research groups are also pursuing variable-speed turbines. The 33M-VS is the result of a five year, $20 million project funded primarily by US Windpower, with contributions from the Electric Power Research Institute, the Pacific Gas & Electric Corporation, and the Niagara Mohawk Power Company. That this development effort is privately funded is an indication of the growing capabilities of the wind power industry.

Several variations[50] in the basic 33M-VS turbine design, such as a two-blade teetered rotor stall-regulated blades (see appendix B), were considered but rejected after detailed analysis. The present design incorporates a three-blade variable-pitch rotor, a parallel shaft transmission with dual generator output, and an active (upwind) yaw system. A power conversion module rectifies each generator output and converts it to power at the utility frequency. US Windpower claims[51] that, when the 33M-VS is available in 1993, it will be able to generate electricity for less than \$0.05 kWh^{-1} [52] in areas where the average wind speed at hub height is 7.2 m sec^{-1} (16 mph, wind power density $\approx$ 450 watts m^{-2}, Rayleigh wind speed distribution).

Table 4: Selected European large-scale research wind turbines (1991).

Country	**Model**	**Hub height** *meters*	**Number of** blades	**Rating** *megawatts*
Germany	Monopteros 50[a,b]	60	1	0.65–1.0
	WKA-60[a,c]	50	3	1.2
Italy	Gamma 60[a,b,c,d]	60	2	1.5
Netherlands	NEWCS 45[a,c]	60	2	1.0
Sweden	Nasudden-II[c,e]	≈80	2	3.0

a. Variable speed.
b. Teetered hub.
c. Variable pitch.
d. Yaw controlled power.
e. Carbon fiber/glass fiber composite blades.

Future Developments

Wind turbine research and development programs are currently under way both in the United States and in the European Community. The European Community program[46] focuses mostly on turbines with a rated output of more than 750 kW_e .Such large machines may be well suited to offshore locations and to regions with a limited number of sites. In view of the high population densities and attendant siting restriction, and the excellent offshore wind resources in Europe, the development of larger machines is a reasonable strategy. Some of these large research machines are listed in table 4. Note they are much larger than the wind turbines currently available commercially and they incorporate advanced features such as variable-speed and teetered rotors.

In the United States, DOE wind-program researchers work closely with turbine manufacturers to improve the moderately sized machines now in use, while also investigating innovative technology that can be implemented by 2000. Advanced airfoil development and testing, structural-dynamics analysis, and modeling fatigue are major areas of activity. Two conceptual designs, the variable-speed wind turbine and stall-controlled wind turbine, have been analyzed for the US DOE to estimate the potential benefits that could be achieved through incremental improvements.

The expected impact of advances in wind turbine technologies and siting strategies in the near term for these two development paths are significant (see table 5). For example, taller towers (40 versus 18 meters, baseline) that can take advantage of higher winds at higher elevations will increase system cost by eight percent and increase energy capture by 25 percent.

Table 5: Estimated near-term percentage improvements in performance and cost relative to 1990 baseline design (see appendix B), for variable-speed wind turbines and stall-controlled turbines (53).

Technical advances	Systems cost *percent improvement*	Energy capture *percent improvement*	O&M improvement *$ kWh^{-1}*
Computer simulations			
Structural	5	–	–
Fatigue	5	–	–
Micrositing	0	6	–
Variable-speed machines			
Power electronics	–10	10	0.00
Control systems	–1	5	0.002
Advanced airfoils	0	10	0.001
Drive train	4	–	0.001
Tall tower (40 meters)	– 8	25	0.0001
Rotor hub	5	–	0.001
Total	**0**	**56**	**0.0051**
Stall-controlled machines			
Aerodynamic controls	2	3	0.001
Control systems	–1	5	0.0015
Advanced airfoils	2	10	0.0015
Drive train	2	–	0.001
Tall tower (40 meters)	–8	25	0.0001
Rotor hub	5	–	0.001
Total	12	**49**	**0.0061**

Most impressive are estimates that a variable-speed turbine on taller towers and other advances will increase energy capture by 56 percent and decrease operation and maintenance costs by \$0.0051 kWh^{-1}. Use of better stall-controlled blades in conjunction with taller towers and other improvements will also increase energy capture by 49 percent and reduce maintenance by \$0.0061 kWh^{-1}. Both approaches hold forth the promise of reducing the cost of electricity from typical sites in the Great Plains to less than \$0.05 kWh^{-1} by the mid-1990s.

Although US Windpower is vigorously promoting its choice of a variable-speed turbine, it is not clear at this time which of these approaches will prove superior.

The evolution of wind turbine technology depends to some extent on progress in fields such as materials science and high-power electronics. Important areas of wind turbine improvement not listed in table 5 include:

- Incorporation of advanced materials and alloys into lighter, stronger components.
- Development of damage-tolerant rotors, by adapting aerospace techniques for manufacturing composite structures.
- Better understanding of micrositing effects on wind characteristics such as turbulence and wind shear, allowing for the optimum placement and height of individual turbines in large arrays or on complex terrain.
- Elimination of the gearbox to allow the rotor to drive the generator directly.

Airfoil Improvements

Present airfoils are based on designs used on aircraft and have marked drawbacks. New families of so-called thick and thin airfoils have been designed[54, 55] that have the performance characteristics required for stall-regulated wind turbines. The low-drag thin airfoil family is best suited to fiberglass rotors 10 to 20 meters in diameter. The thick airfoil family, having slightly more drag, can meet the more demanding structural requirements of fiberglass or wood composite rotors 23 to 30 meters in diameter. Both thin and thick airfoil families have performance characteristics that change from the blade tip (95 percent rotor radius) to blade root (30 percent rotor radius).

To control peak rotor power in high winds, the tip region of the blade must have a maximum lift coefficient (C_{lmax})* that is about 25 percent less than typical aircraft airfoils, while the root region of the blade must have a high C_{lmax} to aid rotor start-up and energy production at medium wind speeds.[56, 57] Unlike previous wind turbine blades, the new airfoils have a C_{lmax} that increases continuously from blade tip to blade root. The new design permits the use of

* The maximum lift coefficient $C_{lmax} = F_{lift}/(0.5 \langle \rho v^2 \cdot cB)$, where F_{lift} is the maximum lift force, $0.5\ \rho v^2$ is the kinetic energy per unit volume in the unperturbed wind stream, c is the distance between the front edge and the rear edge of the blade, and B is a unit length transverse to the flow (along the length of the blade).

rotors that have a 15 percent greater sweep area for a given generator size, thus resulting in greater energy production.

In addition, the airfoil is designed to be less sensitive to surface roughness (caused by the accumulation of insects or dirt). The blade is shaped so that the airflow changes from laminar to turbulent on both the lower and upper surfaces of the blade as its maximum lift coefficient is approached.

Such calculated blade improvements have been verified[56] in side-by-side field tests; the new blades were found to produce from 10 to 30 percent more energy annually than conventional blades.

The mid-term goal of the United States Wind Energy Program is to reduce the levelized cost of electricity from areas with a wind speed of 5.8 m sec^{-1} at 10 meters elevation to \$0.04 kWh^{-1} by 2000. The targeted hub height of the turbines would be 40 meters; the wind speed at hub height is estimated to be 7.1 m sec^{-1}. Approximately six percent of the area of the continental United States has average wind speeds greater than or equal to this value, if the exclusions outlined in reference 7 are applied.

ECONOMICS OF WIND ENERGY

The cost of electricity (*COE*) generated from wind is computed neglecting taxes and assuming real discount rates of 6 percent and 12 percent. The former rate corresponds approximately to the real cost of money in the industrialized world, and the latter approximately to the real cost of money in the developing world. Costs are levelized, or spread out over the assumed lifetime of the facility using standard economics concepts of present value and a uniform series of payments. The elements that contribute to the total cost of wind electricity are the installed capital cost, operation and maintenance, land rental, and transmission. In addition to cost, factors such as tax policy, the attitude of the local utilities to which wind electricity must be sold, public acceptance of wind turbines, and government policy are also of central importance.

Installed Capital Costs

The total installed capital cost of a wind farm includes not only the cost of building the wind turbines but also the balance-of-system costs, including roads, cables and controls, and the utility grid substation. Balance-of-system costs represent about 20 percent of total costs for an onshore wind farm in the United States and Europe. (Balance-of-system costs may be higher in other areas due to lack of skilled labor and remote locations.) The capital costs are levelized over the assumed 25-year life of the generating unit. The average yearly contribution of the cost of capital (*WTLC*–wind turbine levelized cost) to the total cost of electricity in \$ kWh^{-1} is then:

$$WTLC = \frac{ICC \cdot CRF}{P_{avg} \cdot 8,766} \tag{5}$$

Here *ICC* is the total installed capital cost in dollars, *CRF* is the capital recovery factor,[58] P_{avg} is the average yearly power output of the wind turbine in kilowatts, and 8,766 is the number of hours in one year.

Operation and Maintenance

Lynette[47, 59] estimates that the annual average O&M cost, including direct and indirect costs, will be about \$0.008 kWh^{-1} for well-designed and built wind turbines of the type installed in the early to mid-1980s (see table 4). If major periodic overhauls were to become necessary, the cost would increase to \$0.013 kWh^{-1}. These figures are based on actual direct maintenance costs of \$0.005 to 0.010 kWh^{-1} incurred at operational California wind farms, and computed indirect maintenance costs of \$0.003 kWh^{-1}. Operating expenses include the cost of monitoring the power output and other parameters of the working turbines. Such monitoring is done routinely and remotely at all wind farms.

As with any machinery that must function reliably without intervention for long periods of time, it is essential that routine maintenance be done thoroughly at the intervals prescribed by the manufacturer. The labor and materials required for routine maintenance of a typical 150 kW$_e$ wind turbine are very modest—similar in most respects to routine automobile maintenance, mainly grease, hydraulic fluid, and oil changes twice a year or so.[60]

Maintenance costs can be calculated, both for routine operations and for blade or generator replacement, directly from the information given by the manufacturer and a knowledge of the local labor rates.

Insurance and Land Rental

In the United States, insurance costs as well as land rental costs are included in levelized cost calculations. Insurance expenses account for approximately 0.5 percent of the capital cost per year. (The insurance charge is often added to the capital recovery factor as a component of the annual capital charge rate.) Land rental costs in the Altamont Pass are a fixed percentage of the price of electricity paid by the utility to the wind farm operator; at a typical royalty rate of four percent and a price of electricity of \$0.08 kWh^{-1}, this is about \$0.003 kWh^{-1}.

Load/Resource Compatibility and Capacity Credit

The above computations take into account only the most immediate and obvious costs in relation to total annual energy production, but other wind characteristics strongly influence its economic value. The first is the diurnal and seasonal patterns in wind-speed distribution relative to the utility load characteristics (load/resource compatibility). For example, the winds in the Altamont Pass are strongest in the summer, when demand on the local utility (Pacific Gas & Electric Company) is highest. However, the utility peak load occurs around mid-afternoon (3–4 PM) while the winds reach maximum velocity around midnight. Depending on how the power purchase agreement is worded, such a mismatch could have a major impact on the price paid by a utility for wind electricity. (This is not the case in California.)

Another factor in a utility's evaluation of a new generating unit is that unit's capacity credit: the amount of 100 percent reliable generating capacity that can on average be attributed to a given installed capacity. Intermittent sources that contribute a small fraction (up to 10 percent) of the average annual consumption have a capacity credit equal to the capacity factor times the rated capacity.[61] At this level, an intermittent generator can be considered to be a negative load, and can easily be integrated onto a utility grid without provision for storage. At higher fractions of intermittent supply, capacity credit becomes an increasingly important issue.[62] For example, one detailed study[63] of the Great Plains found a capacity credit of 30 to 50 percent of wind turbine installed capacity for a Kansas location, which is lower than the capacity credit for other technologies but not zero as is often assumed.[64]

All types of generating units are characterized by a capacity credit (expressed as a percent of installed capacity) which is less than 100 percent. For example, the capacity credit for large coal-fired power plants is 75–81 percent. For large nuclear units the average capacity credit is 68 percent; on a yearly basis individual units can have a capacity factor of less than 50 percent to greater than 90 percent.[65]

Summary: Generation Costs at Busbar

Table 6 shows US Department of Energy estimates for generating costs based on a wind-speed distribution corresponding to k=2 (see appendix A) and a wind power density of 450 watts m^{-2} at 50 meters. Table 7 summarizes costs of wind arrays in California and Denmark in 1991.

Transmission

Finally, the cost of transmission of electricity must in general be included in

Table 6: Estimated cost (in 1989 dollars) of wind-generated electricity,[a] array losses and transmission costs neglected.[b]

	Units	1990	1995	2000	2010	2020	2030
Hub height	*meters*	25	30	40	40	50	50
v_{avg} at hub height	*m sec*$^{-1}$	6.6	6.8	7.0	7.0	7.3	7.3
P_w at hub height	*watts m*$^{-2}$	333	360	408	408	450	450
System rating	*kilowatts*	100	300	500	500	1,000	1,000
Installed cost	*\$ kW*$^{-1}$	1,100	1,000	950	850	800	750
Rotor diameter	*meters*	18.3	33	40	40	51.7	51.7
Capacity factor		0.2	0.28	0.3	0.33	0.34	0.35
O&M	*\$ kW*$^{-1}$	0.017	0.013	0.01	0.008	0.006	0.006
COE at 6 percent	*\$ kW*$^{-1}$	0.072	0.05	0.043	0.036	0.031	0.029
COE at 12 percent	*\$ kW*$^{-1}$	0.103	0.07	0.061	0.050	0.046	0.041

a. v_{avg} = 5.8 meters per second at 10 meters, (wind class 4 in the *US Wind Atlas* (reference 22)) Rayleigh wind-speed distribution; wind speed at 10 meters scaled to hub height using the one-seventh power rule; includes insurance at 0.5 percent of installed cost, and land rental, $0.003 per kWh.
b. See reference 64.

Table 7: 1991 Cost of wind-generated electricity
6 and 12 percent real discount rates, neglecting array interference effects.

Location	P_w at hub height *watts m*$^{-2}$	Capacity factor	O&M *\$ kWh*$^{-1}$	Capital cost *\$ kW*$^{-1}$	COE *\$ kWh*$^{-1}$	
					6%	*12%*
California[a]	450	0.24	0.01	1,000	0.052	0.076
California[b]	450	0.25	0.011	760	0.042	0.063
Denmark[c]	475	0.267	0.01	1,300	0.055	0.084

a. The cost of electricity from wind farms in California's Altamont Pass. The installed capital cost and the capacity factor are based on data supplied to the California Energy Commission (see reference 3). A 25-year turbine lifetime, insurance costs of 0.5 percent of installed capital costs, and land royalty payments at $0.003 per kWh are assumed.
b. USW 33M-VS variable-speed wind turbine.
c. The cost of wind-generated electricity in Denmark (see reference 67) is computed for a recently built wind farm of 29 machines with a maximum output of 225 kilowatts each at an installed cost of 1,028 ECU per kW_e. The O&M costs are estimated to be 1.75 percent of installed costs. Royalty payments are not included. The energy flux is estimated for a wind speed at hub height (31.5 meters) of 7.4 meters per second, assuming a Rayleigh wind speed distribution.

the cost of energy calculations. This cost has been negligible up to now both in Denmark and in California since the wind resources have been close to the load centers or to existing transmission lines, and transmission capacity has been available. However, the best resources nearest to consumers have been exploited. If wind is to make a significant contribution to total energy consumption, particularly in the United States, long distance, multi-gigawatt transmission line will be necessary. In Denmark[66] a serious dispute between wind turbine owners and utilities over transmission access and cost has only recently been resolved, clearing the way for further development.

The situation in the United States is especially striking. The wind electric potential is estimated[8] to be more than 1,200 GW_{avg}, compared to the average annual consumption of 320 GW; over 94 percent of this potential is located in the Great Plains, many hundreds or thousands of miles from the centers of population. We estimate the impact long distance transmission will have on wind energy costs, through an illustrative wind farm in central Kansas supplying power over a 2,000 kilometer, 2 gigawatt transmission line to southern California or northern Florida.[68, 69]

The transmission line levelized cost ($TMLC$, \$ kWh^{-1}) is given by:

$$TMLC = \frac{TMCC \cdot CRF}{CF \cdot 2 \cdot 10^6 \cdot 8,766 \cdot (1 - L)} \tag{6}$$

Here $TMCC$ is the transmission line capital cost in dollars, and L is the transmission losses (taken to be five percent).

Long distance transmission line technology has advanced substantially over the past 10 years. Large blocks of power are routinely transferred thousands of kilometers at low cost with low losses and excellent reliability. For this example, high voltage direct current (HVDC) transmission has been chosen: for distances greater than about 400 kilometers it is the lowest cost option[70] and it eliminates concerns about low frequency electromagnetic stray fields.

The capital cost of a 2,000 kilometer, 2 gigawatt HVDC transmission line would be about \$1.52 billion, based on the costs experienced in the construction of the James Bay-Boston HVDC link. This is a ±450 kV, 2 gigawatt DC transmission line linking a hydroelectric dam on the James Bay in Canada with the Boston metropolitan area. The cost per mile of transmission line was about \$1 million, and the cost of the AC-DC converter stations was \$320 million for this project, which took about 10 years to design and build.[71]

The cost of electricity delivered to market, including array losses, trans-

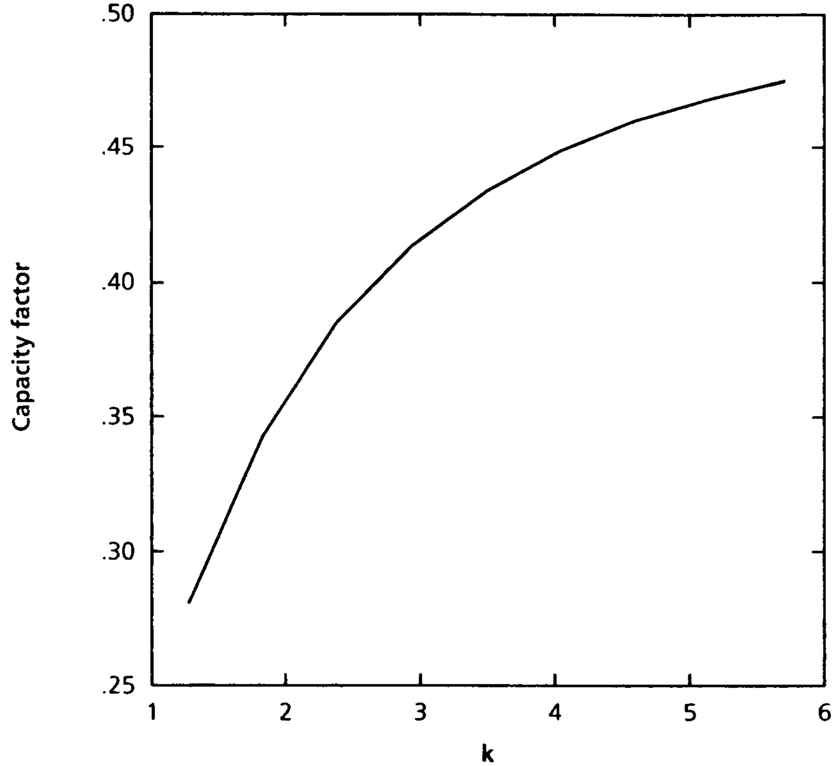


Figure 8: Wind turbine capacity factor as a function of the k parameter of the Weibull wind frequency distribution (see appendix A). The capacity factor is computed for a wind power density of 440 watts m^{-2} using the published power output characteristic of the Vestas[72] V27-225 (27 meter rotor diameter, 225 kilowatt maximum power output) wind turbine.

mission and operation and maintenance costs, is:

$$COE = (WTLC) \cdot (1 - A)^{-1} + TMLC + O\&M \qquad (7)$$

The array loss (A) is assumed to be 15 percent and the operation and maintenance costs ($O\&M$) are taken to be \$0.01 kWh^{-1}.

Given the extremely high cost and long design and construction times of the transmission line, it is essential to utilize the transmission capacity to the maximum extent that is practical and economical. One way to do this is to locate the wind farm in an area where, for a given wind power density, the winds are steadiest. The steadiness of the wind resource is indicated by the Weibull k factor (see appendix A): the effect of different k factors on the average power output (capacity factor) of a wind turbine is shown in figure 8. In the northern US Great Plains k=2.25 is typical, while in the region chosen for

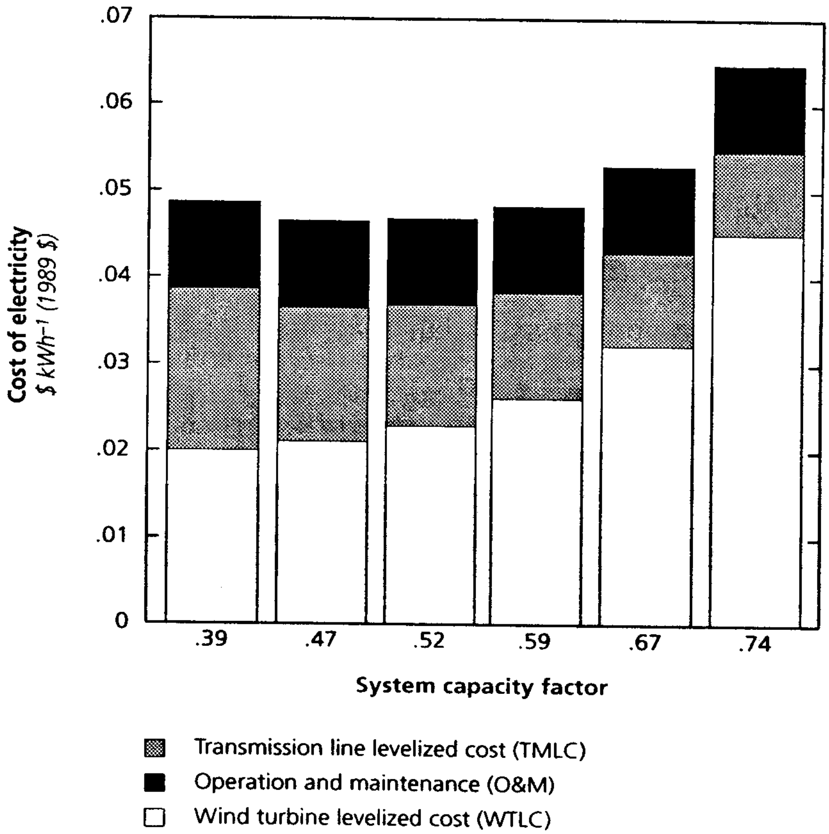


Figure 9: Levelized cost of electricity versus capacity factor for a 2 gigawatt wind farm, and a 2 gigawatt transmission line system. The length of the HVDC transmission line is 2,000 kilometers; the wind power density is 440 watts m^{-2}; the Weibull k factor is three; the interest rate is six percent; and insurance is 0.5 percent. The levelized cost of energy is approximately constant up to a capacity factor of about 60 percent, as the increased cost of additional wind turbines is counterbalanced by a decrease in transmission costs on a per kilowatt basis.

this example, central Kansas, k=3 is appropriate. Compared to the normal assumption of a k=2 wind speed distribution (see table 7), a 20 percent higher capacity factor is obtained in a k=3 region.

Transmission line utilization can also be increased by another strategy. In a conventional wind farm transmission line system, the peak output of the wind farm is matched to the transmission line capacity. For an average wind farm capacity factor of about 0.4, the two gigawatt transmission line could carry the maximum power generated by about 10,000 wind turbines, each with a maximum output of 225 kilowatts. In this base case the cost of transmission is about one third of the total cost of delivered power (see figure 9).

However, if the number of wind turbines in the wind farm is increased, the

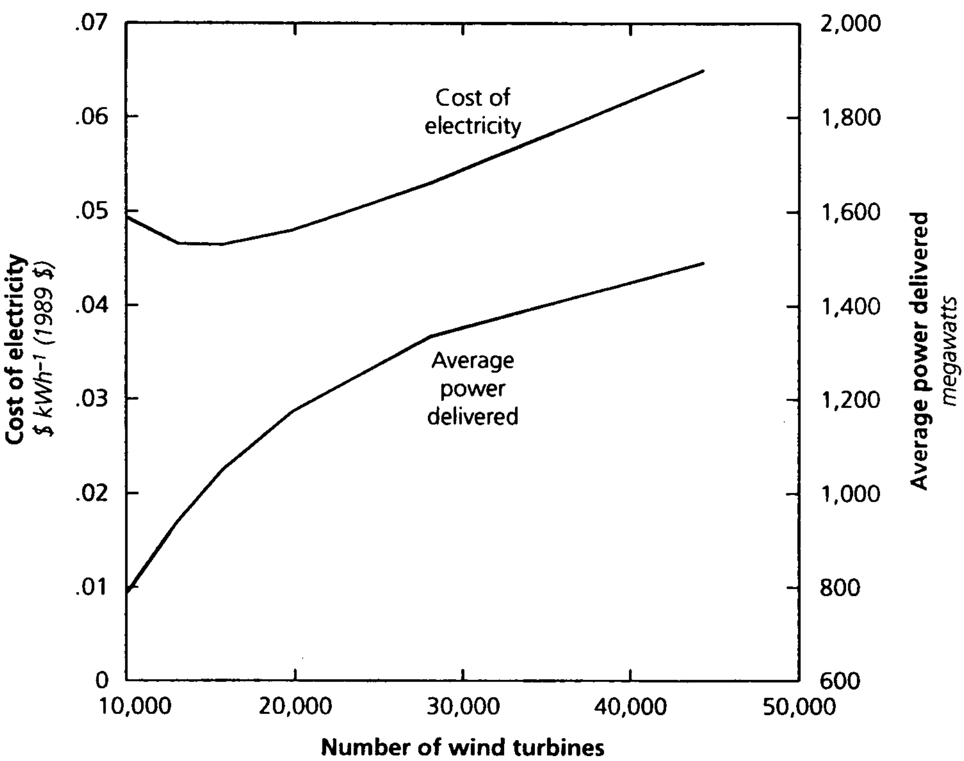


Figure 10: Cost of electricity (1989 $) and average delivered power as a function of the number of wind turbines in the wind farm supplying the 2 gigawatt HVDC transmission line. By doubling the number of wind turbines in the wind farm, about 50 percent more power is transmitted for the same unit cost of energy. Still higher utilization of the transmission line is possible by a further increase in the size of the wind farm, but at an increase in average cost of energy.

amount of energy delivered, and thus the capacity factor of the transmission line can be increased (see figures 9 and 10). The additional turbines produce more power when the wind speed is below the rated wind velocity where the winds blow most frequently. At higher velocities some of the turbines will have to be shut down due to the limited capacity of the transmission line. However, since these higher wind speeds occur much less often, the net result is an increase in the average power transmitted. The increased cost of the additional wind turbines is counterbalanced by a decrease in transmission cost and an increase in the capacity factor of the system as seen by the utility taking delivery of the power. Not only is the transmission line much better utilized, but the higher capacity factor means that the power is much easier to integrate into a utility grid.

In this example, the increase in the wind turbine capital cost is balanced by a decrease in transmission costs up to the addition of 10,000 turbines, and up to a system capacity factor of 60 percent. Beyond this point, the cost of electricity begins to increase. It is interesting to note that, in this case, a 67 percent capacity factor (approximately equal to the average capacity factor of nuclear power plants) can be obtained for an increase in the cost of electricity of about 10 percent above the base case.

The ability of wind-energy-transmission systems to offer an increase in capacity factor at no increase in the cost of electricity will be central to determining how large a fraction of the total load can be supplied by this intermittent renewable technology.[73]

WIND ENERGY POLICY

There are numerous obstacles to a growing wind power industry. To begin with, the conventional fossil fuel technology used in large central power stations is well-understood by industry and government. In addition, the discovery, extraction, refining and transportation of fossil fuels is an immense enterprise that employs hundreds of thousands of people and will use all means to maintain its market. Finally, the nuclear industry, with the implicit and explicit support from many governments, is still a formidable competitor. Given these obstacles, major initiatives from outside the electric utility industry are necessary if wind energy is to be accepted as an equal with more familiar technologies. However, a well-formulated energy policy will allow the advantages of wind energy to be demonstrated, and will permit fair competition among all of the alternatives.

The experience of the wind industry in Denmark and California suggests various policies which could be effective in opening markets up for wind energy systems.

In California, acceptance of wind technology was accomplished with three separate yet coincidental federal governmental actions and two acts passed by the state of California. The federal initiatives were the Public Utility Regulatory Policy Act (PURPA) of 1978, the Crude Oil Windfall Profits Act of 1980, and the Economic Recovery Tax Act of 1981. In California state tax credits and generous long-term contracts were provided.

PURPA is the most important, for it created a new class of electricity providers, the small power producers. According to PURPA, local utilities were required to purchase the output of independent producers at the cost the utility could save by not providing this power itself. Independent producers could generate up to 30 (80 in 1993) MW_e and still be exempt from federal and state utility regulations and be eligible for energy tax credits. This basically ended the monopoly power the utilities had previously enjoyed.

The Economic Recovery Tax Act allowed for an accelerated (five-year) depreciation of the wind turbines. The Windfall Profits Act provided federal tax credits for producers using renewable energy, including wind—a 15 percent energy tax credit in addition to the normal 10 percent investment tax credit could be taken. These expired at the end of 1985. California allowed a 25 percent solar energy tax credit against state income taxes, which ended in 1986.

In addition, California utilities offered a creative and innovative long term power purchase agreement for renewable energy, the standard offer number 4 (SO4) contract. This type of contract addressed the major financial problems associated with capital-intensive, renewable energy technologies: the need for long-term contracts and the inability of non-utility power producers to borrow money for longer than a 10 year term. The SO4 was a 30 year contract. The initial purchase price of electricity was \$0.08 kWh^{-1}, with an escalation adjustment that raised the price to about \$0.14 kWh^{-1} at the end of the first 10 years; thereafter, the price dropped to the avoided cost to the utility. This allowed the developer to pay off the large debt needed to finance the renewable energy power plant in the first 10 years of the contract. Once the equipment was paid for, the much lower operation and maintenance charges could presumably easily be covered by the much lower avoided cost price. The program ceased after the collapse of oil prices in 1985.

The net effect of these tax laws was that wind farms were sometimes operated as "tax farms" by a few unscrupulous promoters. Untested designs were rushed into production, and many wind farms had severe reliability problems and produced less than 50 percent of the power promised in the initial promotional material. However, a few legitimate and technically competent companies used the tax incentives and the SO4 contracts to lay the foundations for the successful industry that now exists in California.

The Danish government has adopted a much more methodical and systematic approach to developing its wind resources.[20] Beginning in 1979, private citizens who installed wind turbines were reimbursed 30 percent of a turbine's purchase price plus part of the installation costs. Only wind turbines tested and approved at the Risø National Laboratory were eligible for this subsidy, which has now been eliminated. This facility has been of prime importance in establishing the reliability of Danish wind turbines and a major factor in the success of Danish wind turbine manufacturers.

In addition, Danish utilities are obliged to purchase electricity generated by privately owned turbines at a rate of 70–80 percent of the net utility price to residential customers.

As a result of these initiatives, the Danish energy plan—Energy 2000—foresees a total installed wind turbine capacity of 800 to 1,350 megawatts by the year 2000 and 2,800 megawatts by the year 2030. This could provide 5 to 8.5 percent and 17.5 percent, respectively, of 1990 electricity consumption. It is a substantial increase over the 1990 installed capacity of 320 megawatts. As such it is an ambitious but realistic plan.[74]

The experiences of California and Denmark suggest the value of the following factors in promoting wind energy:

- High-quality national and regional wind surveys.
- Government certification and testing of wind turbines.
- Government–industry research coordination.
- Long-term contracts (e.g., SO4) which guarantee a fair rate of return to investors in wind energy technology.
- Market strategies (e.g., investment tax or production tax credits* or generous utility purchase price agreements) that allow wind to compete with heavily subsidized fossil fuel and nuclear alternatives.
- Transmission line access and construction to allow the exploitation of distant wind resources.

CONCLUSIONS

Advances in wind turbine technology and the associated reduction in cost of wind-generated electricity that have occurred during the past 20 years are dramatic. This development will have a profound impact on energy production industries around the world. The policies that need to be put in place in order for wind energy to contribute a significant (10 percent) fraction of the electricity supply over the next 20 years in the United States and the European Community are clear, but the question remains as to whether such rapid growth is possible. The recent utility industry experience with nuclear energy is instructive. This technology contributed little to electricity supplies in 1970, yet in 1991 contributed about 22 percent, or 70 $GW_{e,avg}$ to total electricity demand, an impressive rate of growth indeed. If such a complex technology could increase its market share so quickly, it is not at all unreasonable to believe that the much

* The Comprehensive National Energy Policy Act (HR776) of 1992 provides for a \$0.015 kWh^{-1} production tax credit for wind-generated electricity, and allows the Federal Electric Regulatory Commission to mandate transmission line accessibility.

less intricate technologies associated with wind energy can grow at least as rapidly, assuming the institutional and social challenges are met.

Appendix A: Fundamentals of the Wind Resource

The kinetic energy, U, of a sample of air of volume, $A(\delta x)$, and density, ρ, moving with velocity, v, where A is a unit area perpendicular to the wind stream and δx is parallel to the wind stream, is:

$$U = \frac{\rho A (\delta x) v^2}{2}$$

The energy flux, P_w, or wind energy density, is given by the time rate of change of U/A:

$$P_w = \frac{dU}{dt} \cdot \frac{1}{A} = \frac{\rho}{2}\left(\frac{\delta x}{\delta t}\right) v^2 = \frac{\rho v^3}{2}$$

The density of air must be calculated for the temperature, T, and pressure, P, at the location of the wind turbine as follows:

$$\rho = \frac{P}{RT}$$

where R is the gas constant. This correction can be substantial for summertime high altitude locations, relative to standard conditions (normally 15°C and 1 atm). For example, at Medicine Bow, Wyoming (altitude 2,000 meters), wind power density is 21 percent less than at sea level due to the higher elevation. At a temperature of 30°C, there is an additional five percent decrease in energy flux.

The limit on energy extraction from a wind stream (the Betz limit) can be derived using conservation of energy, mass and momentum. The overall bounds of the problem are clear: if the wind velocity is reduced to zero by the wind turbine, there is no mass flow and no power extracted. If however, the wind velocity is unchanged, there is again no power extracted. Maximum power extraction occurs between these two limits, and can be determined from the above conservation laws.

The Rayleigh probability density function (see figure 4) has the form:

$$f(v) = \frac{\pi v}{2} (v_{avg})^{-2} \cdot \exp\left[-0.25\pi\left(\frac{v}{v_{avg}}\right)^2\right]$$

For this function, $(v^3)_{avg} = 6/\pi\ (v_{avg})^3$, which illustrates the importance of high wind speeds in contributing to the average wind power density.

This is a special case of the Weibull distribution,[40] which fits a wide variety of wind speed data from many different locations. The Weibull function is a two-parameter probability density function of the form:

$$f(v) = \frac{k}{c} \cdot \left(\frac{v}{c}\right)^{k-1} \cdot \exp\left[-\left(\frac{v}{c}\right)^k\right] \quad (k > 1, v \geq 0, c > 0)$$

Here c is the scale parameter and k is the shape parameter. The scale parameter c has dimensions of velocity and for most practical values of k is about 1.1 times v_{avg}. For k

close to one, the probability density as a function of velocity is relatively flat: this describes a wind regime that is quite variable. For $k > 2$, the probability density becomes more peaked and so describes a wind regime where the wind speed is relatively constant. Weibull density functions with different shape parameters can have the same v_{avg} but quite different $(v^3)_{avg}$ and wind power densities.

The average wind power density for a given area with a characteristic probability density function $f(v)$ is:

$$P_{w,avg} = \frac{1}{2}\rho\int_v v^3 f(v)\,dv = \frac{1}{2}\rho\,(v^3)_{avg}$$

The increase of wind velocity with elevation, h, (above ground level) is usually termed wind shear; it is in general a function of surface roughness, wind speed, and atmospheric stability. Based on data from many locations, for areas of low surface roughness this is often approximated by:

$$v(h_2) = v(h_1) \cdot \left(\frac{h_2}{h_1}\right)^{1/7}$$

The *European Wind Atlas*[23] uses a different methodology to estimate wind shear, with results that are roughly equivalent to the one-seventh power rule for seacoast and open-plain sites. That rule is:

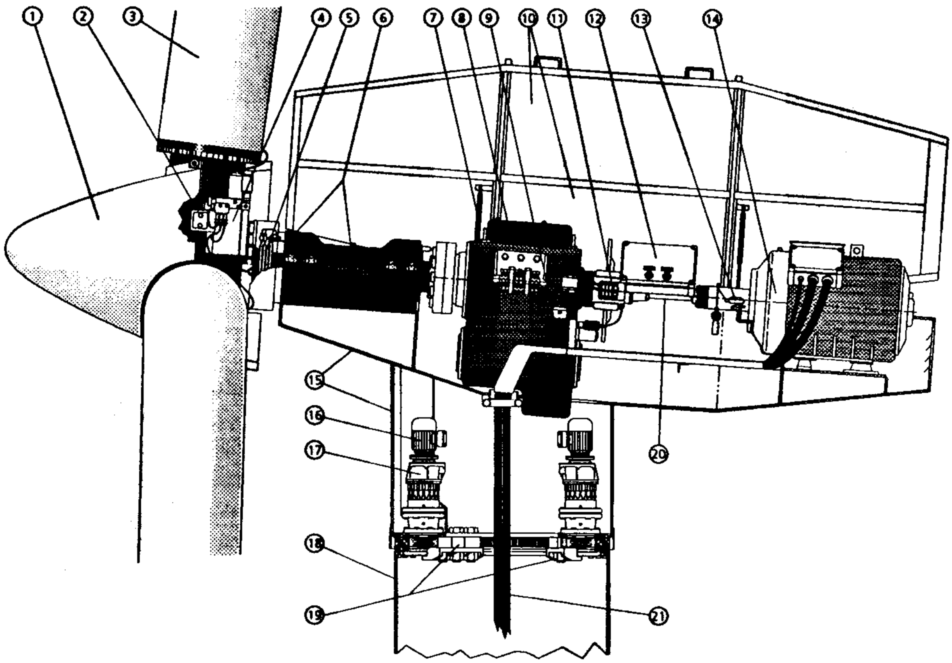
$$\frac{v(h_2)}{v(h_1)} = \frac{ln\left(\frac{h_2}{z_0}\right)}{ln\left(\frac{h_1}{z_0}\right)}$$

Here z_0 is the surface roughness, which is a mathematical construction and has nothing to do with the size of the surface features. Some values for z_0 are: 0.1–0.01 centimeters (sand); z_0 = 1–4 centimeters (low grass); z_0 = 4–10 centimeters (high grass). This expression is valid in dry air if thermal convection can be ignored. However, there are important exceptions to these formulations. For example, the wind shear at the Altamont Pass is zero and negative at Solano County, California.

Appendix B: Wind Turbine Subsystems

A modern horizontal-axis wind turbine (HAWT) is composed of six basic subsystems:

- The rotor, which consists of one, two, or three blades mounted on a hub and may include aerodynamic braking systems and pitch controls.
- The drive train, including gearbox or transmission, hydraulic systems, shafts, braking systems and nacelle, which encases the actual turbine.
- The yaw system, which positions the rotor perpendicular to the wind stream.
- Electrical and electronic systems, including the generator, relays, circuit breakers, droop cables, wiring, controls, and electronics and sensors.
- The tower.



1. Nose cone
2. Hub
3. Blades
4. Hydraulics
5. Slew ring system
6. Main shaft
7. Shock absorber
8. Coaxial gearbox
9. Hydraulics
10. Nacelle
11. Brake
12. Controls
13. Vibration sensor
14. Generator
15. Bed plate
16. Yaw motor
17. Yaw gear
18. Tower
19. Yaw system
20. Transmission shaft
21. Power cables

Figure B-1: A modern 150 kilowatt wind turbine, showing components.[29]

- Balance-of-station systems including roads, ground-support equipment, and interconnection equipment.

The basic components (excluding balance-of-station systems) are illustrated in figure B-1; the relative simplicity of a wind turbine assembly is remarkable. Initially, off-the-shelf industrial components (gearboxes, drive shafts, and generators) that had been developed for other applications were installed in wind turbines, a strategy that allowed the industry to grow very quickly. Now that a market has been established, components specifically adapted and designed for wind turbine applications are being built. These are expected to increase turbine efficiency and reduce maintenance costs.

Rotors

The rotor, which converts the wind's kinetic energy to kinetic energy of rotation, is a unique and critical part of a wind turbine. It is exposed to the full force of the elements and the full range of the variation in wind speed, direction, turbulence and shear (the change in the wind velocity with elevation). Because loads on the rotor are complex and difficult to model, they often cannot be simulated in a laboratory environment. For these reasons, this component represents the greatest engineering challenge in this field.

The rotor can be characterized as being rigid, with fixed (stall-controlled), or variable, pitch to limit maximum turbine output, or teetered, with fixed or variable pitch. In a teetered rotor, the rotor plane of rotation may vary a few degrees in a direction perpendicular to the average wind velocity. This additional degree of freedom reduces stress on the drive train by uncoupling pitching moments at the hub;[47] but it requires a design that can accommodate complicated dynamic loads and increased cost and complexity.

The rotor is also used to control the amount of energy extracted from the wind stream. Rotors with either variable-pitch blades or stall-controlled blades are commonly employed. With variable pitch, rotating the blade about an axis along its length alters the pitch angle and thus the lift and drag forces on the blades. Variable pitch not only limits maximum energy capture but also reduces start-up speed and provides aerodynamic braking of the turbine. Such pitch control mechanisms, however, are subject to high loadings and must be carefully designed.

Stall-controlled blades, which limit the maximum energy capture of a turbine by loss of lift at high wind-speed, are attractive in their simplicity. At low wind velocity, airflow around the blade is laminar and the flow streamlines follow the blade's contour. At high wind velocities, the streamlines separate from the blade contour, causing the net force on the blade (F_1 in figure 5) to first level off and then decrease with increasing wind velocity. (This type of behavior is evident in figure 6, which shows power output of a stall-regulated wind turbine as a function of wind speed.) The velocity at which flow begins to separate from the blade is controlled by precisely shaping the blade contour.

Stall-controlled blades, although an elegant technique to limit energy capture, have the following limitations:[75]

- Stall-induced turbulence may create additional structural loads.
- Wind-speed fluctuations about the stall speed can induce large fluctuating loads on the turbine.
- Rotor thrust (force F_2, figure 5) increases above the stall velocity, while it decreases with pitch control.
- Aerodynamic or mechanical brakes are needed to stop the rotor should loss of connection to the grid or transmission failure occur.

The most common type of braking system on stall-controlled machines is a movable tip brake, which deploys automatically when the rotation velocity exceeds some critical value. Because the tip brakes slow the rotor down by abruptly increasing drag, they increase loads on the other components of the turbine. Although early versions had reliability problems, modern systems have overcome the failings of their predecessors. Tip brakes can now bring the rotor to a complete rest, with the mechanical brake used only as a parking brake. Today's tip brakes are spring loaded, fail-safe, hydraulically controlled, and deploy simultaneously.

The blades for most existing wind turbines are based on aircraft airfoils and thus were designed to function in operating regimes other than those encountered by wind turbines. While such borrowed technology facilitated the rapid deployment of wind systems, the blades were later found to severely compromise wind turbine performance under some circumstances. Wind turbines with these blades have had the following problems:

- Generator failure resulting from excess energy capture in high winds.
- Degraded energy capture as the result of blade soiling by dust or insect build-up.
- Higher array losses due to the generation of higher levels of turbulence.

Advanced airfoils designed specifically for wind turbine applications have solved these problems (see "Wind-Turbine Technology: Future Developments").

Drive Trains

The major components of the drive train are the low- and high-speed shafts, the mechanical braking system, bearings, couplings, gearbox, or transmission, and the nacelle. The gears of the drive train increase the angular velocity of the rotor, which is normally 0.5 to 2 hertz (30 to 120 rpm), to the output shaft rotational speed of 20 to 30 hertz (1,200 to 1,800 rpm), which is required by most generators to produce power at 50 to 60 hertz. For example, a 1,200 rpm generator requires a two- or three-stage gearbox with a ratio of 10:1 to 60:1 for typical rotor angular velocities. (The maximum ratio per stage is 6:1 and gearbox losses are 2 percent per stage at rated power.[40]) Because existing wind turbines are locked to the grid frequency and thus operate at nearly constant angular velocity, the drive train must also partially dampen torque fluctuations caused by turbulence and shear. Loads are highly variable and cyclic, with peak loads as high as 10 times normal operating loads. Nonetheless, provided that a sufficient safety margin is allowed, commercially available units may be used.

Yaw-Control Systems

Horizontal-axis wind turbines fall into two categories: upwind machines (the wind-stream encounters the rotor first) or downwind machines (the wind-stream encounters the tower first). Yaw systems are used to orient the plane of the rotor perpendicular to the wind-stream.

Downwind machines rely on a passive yaw-control system, which exploits the weather-vane action of the wind forces to position the rotor. This downwind system, while mechanically uncomplicated, has an intricate dynamic operating regime. These machines can oscillate about a stable position, which imposes high cyclic loads on the turbine's other components.

In contrast, upwind machines have an active yaw system. The yaw system drive-trains are subjected to very high loads because of wind turbulence. In older designs, all of the forces were taken up on one or two gear teeth, which led to fatigue-induced failures. Recent designs have eliminated this problem, however, by using yaw system brakes to hold the nacelle in position when the yaw drive is not activated.

Electrical Systems

Almost all modern wind turbines have induction generators, which consist of a stator, or stationary coils, and a generator rotor. The power output of this type of generator varies rapidly with the difference between the line frequency and the generator rotor angular velocity. Maximum power output is attained when this difference is a few percent above the line frequency; thus, the wind-turbine rotor angular velocity is locked to the line frequency. Induction generators can convert electrical energy to mechanical energy or vice versa at efficiencies between 94 to 97 percent. Thus the overall conversion efficiency of wind kinetic energy to electrical energy is excellent in modern wind turbines.

The electrical equipment in a wind turbine, which includes electronic controls and sensors as well as the generator, must operate with minimum maintenance under a wide variety of harsh climatic conditions.

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$$CRF = \frac{r}{1-(1+r)^{-n}}$$

where r is the interest rate and n the assumed life of the installation. For a 25-year lifetime, if r = 6 percent, CRF = 0.0782; for r = 12 percent, CRF = 0.1275. If the assumed lifetime is 15 years instead of 25 years, the CRF increases by 32 percent (r = 6 percent) and 15 percent (r = 12 percent).

59. Indirect costs are calculated using the following assumptions: 1) 100 megawatt station rating, 110 kilowatt machines 2) 4,500 operation hours, zero wind shear, 3) capacity factor of 0.29 at 97 percent availability, 4) capital recovery factor of 15 percent 5) burdened labor rate (includes all overhead etc.) $25 per hour.

Lynette also indicates that turbines of higher output rating should have lower O&M costs, although in 1987 there was no evidence that this was true, perhaps because the larger turbines had less time in the field.

The Lynette report discusses the actual operational problems and maintenance costs, as well as actual versus projected power production, availability, capacity factor, and reliability and increase in reliability for a large number of wind farms in California. There was a significant decrease in O&M costs and an increase in reliability of the wind turbines during the period covered by the report (1981–1987), indicating a rapidly maturing industry.

Lynette's estimate of the average O&M cost is close to that for a recently installed wind farm of twenty-nine 225 kW_e machines in an area with a wind speed of 7.4 m sec^{-1} at hub height (31.5 meters) in western Jutland, Denmark (see reference 67). The estimated O&M costs were 1.75 percent of the installed cost of the turbine, or about 0.008 European Currency Unit (ECU) ($0.01) per kWh (based on the extensive experience of the wind turbine manufacturer). (One ECU = $1.27, December 1991).

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73. H. Kelly and C.J. Weinberg, "Utility Strategies for Using Renewables,"in *Renewable Energy: Sources for Fuels and Electricity,* T.B. Johansson, H. Kelly, A.K.N. Reddy, and R.H. Williams, editors (Washington DC: Island Press, 1993).

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