Wind Energy Biography: A Review of Wind Turbine Technology and Economics

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Table of Contents

Figures and Tables

1 Introduction

Wind energy is widely acknowledged as one of the most sustainable sources of electricity: environmental impacts are relatively low, further reductions in production costs are expected, the distribution of global wind resources is diverse, and the potential for market expansion is large. Life cycle greenhouse gas emissions per unit of wind energy are approximately ninety percent less than emissions from conventional fossil fuel power sources, and bird population impacts and of noise pollution have been reduced significantly in recent years. For these and other reasons, a range of policies have been adopted in various countries to promote wind energy development.

A combination of technological improvements, cost reductions, and economic incentives has made wind energy the fastest growing source of electricity, with installed global capacity doubling approximately every three years over the last decade. The state of the art turbine in 1989 was a 300 kW unit with a rotor diameter of 30 meters. By 1999, 1.5 MW wind turbines with 70 meter rotor diameters were available, and today 4 to 5 MW turbines are under development. Total installed global wind capacity was 4,844 MW by the end of 1995, and had increased over threefold to 17,706 MW by the end of 2000 (Ackerman and Söder 2002). Today's production costs are one-sixth the costs seen in the early 1980's, averaging around \$0.04 to \$0.06 per kWh, and production costs are projected to drop to \$0.027 to \$0.045 per kWh by 2030 (this report).

A variety of technological and economic issues underlie these impressive developments in wind energy. Several extensive reviews of wind energy technology have recently been published and cover these developments from various perspectives. Ackerman and Söder (2002) review recent global developments and major wind power characteristics. A recent book by Manwell, McGowan and Rogers (2002) provides detailed information on the theory and analysis of wind turbine design and operation. An updated version of Hau's book on wind technology (2000) provides a detailed account of a range of issues, including turbine design, manufacturing and economics.

This report is intended as a general primer on wind energy technology, with a focus on technological characteristics and how they relate to the economics of wind energy. It draws upon the three major sources mentioned above, as well as a variety of additional sources, to provide a concise survey of four wind energy topics: 1) characteristics and extent of wind resources, 2) fundamentals of wind turbine technology, 3) intermittency of wind energy and the roles of transmission and storage, and 4) the economics of wind energy. Within these topics, there is an emphasis on the theoretical aspects of converting wind energy into electricity, was well as subsequent conversion of electricity into hydrogen.

2 Wind Energy Resources

The future of wind power depends upon the extent and type of known wind resources. While many wind locations with economically favorable characteristics have already been developed, large reserves remain untapped. Wind energy resources can be characterized in terms of their average wind speeds, temporal variability and geographic distribution. Sections 2.1 and 2.2 review characteristics of known wind resources and current wind energy development patterns in terms of installed wind capacity.

2.1 Wind resource characteristics

Estimates of economically exploitable wind resources in the United States vary, and depend upon a range of assumptions, such as land use practices, utility deregulation trends, anticipated advances in wind turbine technology, and proximity of existing transmission lines. In general, wind resources are classified according to wind Classes, which corresponds to the average annual wind speed in a given location or region as measured at a particular height (see Figures 2-1, 2-2, 2-3 and Table 3-1). Class 4 or higher winds are typically considered economically viable using today's wind turbine technology. A 1991 study by Elliot et al. estimated that wind turbine technology could deliver over 1200 GW of power from Class 4 or higher winds. Of this total, 80 percent was Class 4, 12 percent Class 5, and 8 percent Class 6. To account for potentially conflicting land use practices, the researchers excluded all wilderness and urban areas, 50 percent of forest areas, 30 percent of farm areas, and 10 percent of barren and range land areas.

Variations from average annual wind speeds are an important aspect of characterizing wind resources. Manwell et al. (2002, 26) discuss temporal variations in wind power occurring on four scales: short-term, diurnal, annual and inter-annual variations. Short-term variations include turbulence, defined as relatively small fluctuations about the mean wind speed, and gusts, defined as wind speeds deviating significantly from the mean speed for short periods of time. Diurnal or daily variations mostly occur in response to the daily radiation cycle, and tend to follow a pattern of low speeds from midnight to sunrise and higher speeds during the day. In addition, diurnal fluctuations tend to be wider in the spring and summer and smaller in the winter. Annual wind speed fluctuations vary by geographic region, with winter and early spring maximums occurring over the eastern third of the U.S., and spring and summer maximums occurring in the windy locations of Oregon, Washington, and California. Meteorologists suggest that at least five years of data are required to determine reliable estimates of annual wind speeds, and that up to thirty years of data are needed to determine long-term variations (also see: Archer and Jacobson 2003).

Variations in wind resources by geography are shown in Figures 2-1, 2-2 and 2-3. Figure 2-1, based upon 1987 data described in the Elliot et al. 1991 study, indicates two major expanses of economically viable wind resources of Class 4 and higher. One expanse is an area sweeping from North and South Dakota into Northern Nebraska and Iowa, and another stretches from Southern Kansas into the panhandles of Oklahoma and Texas. Many of the high speed wind areas scattered across the Rocky Mountains are difficult to access, and are therefore less valuable for large-scale production (i.e. large wind farms). One apparent feature of this geographic distribution is that most large expanses of valuable inland wind resources are some distance from the major demand centers along the coasts and in the Chicago region.

Recent wind resource mapping efforts have significantly improved the resolution of wind resource maps, but thorough remapping has only been completed for some states. For example, Figure 2-2 compares an updated map of wind resources in North and South Dakota to the previous 1987 mapping effort. A notable feature of this updated map is that the overall land area characterized as having Class 4 winds has decreased, but a greater amount of land is now characterized as having Class 5 or better winds. Schwartz and Elliot (2002) note that this higher resolution mapping has resulted in increased interest in wind power in states that have been re-mapped. Figure 2-3 is a recent map of offshore wind potential in New England, indicating Class 5 or greater winds along most of the coast (also see: Rogers at al. 2002).

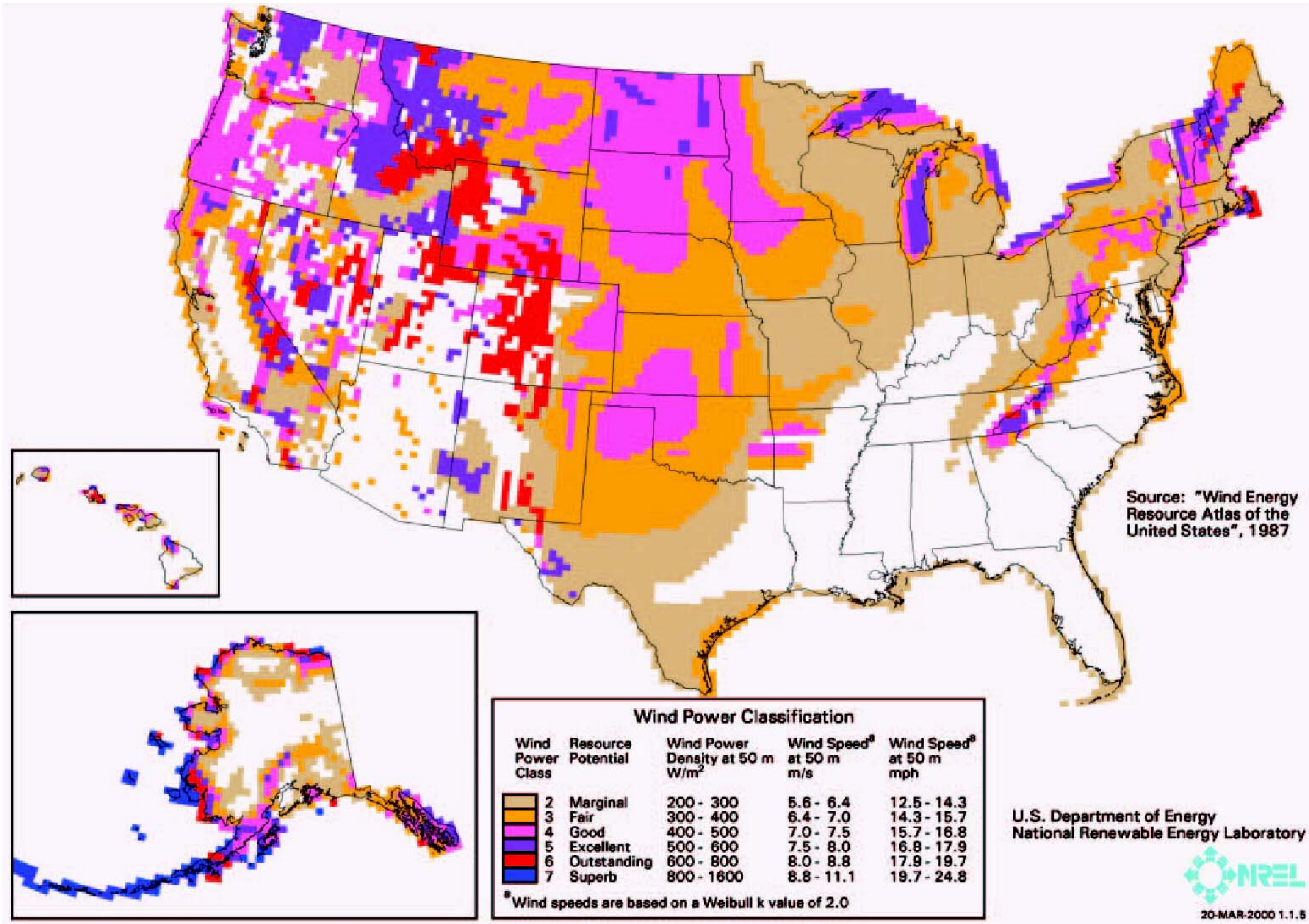


Figure 2-1 Wind resources by wind Class in the United States (DOE 2004).

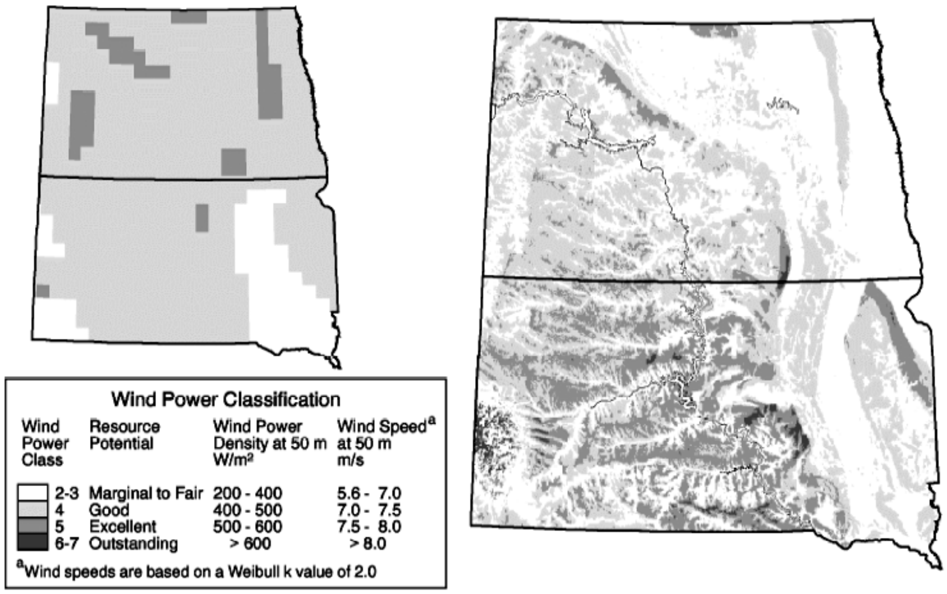


Figure 2-2 Comparison of year 1987 and 2000 wind maps of North and South Dakota with 25- and 1-miles resolutions, respectively (Schwartz and Elliot, 2001).

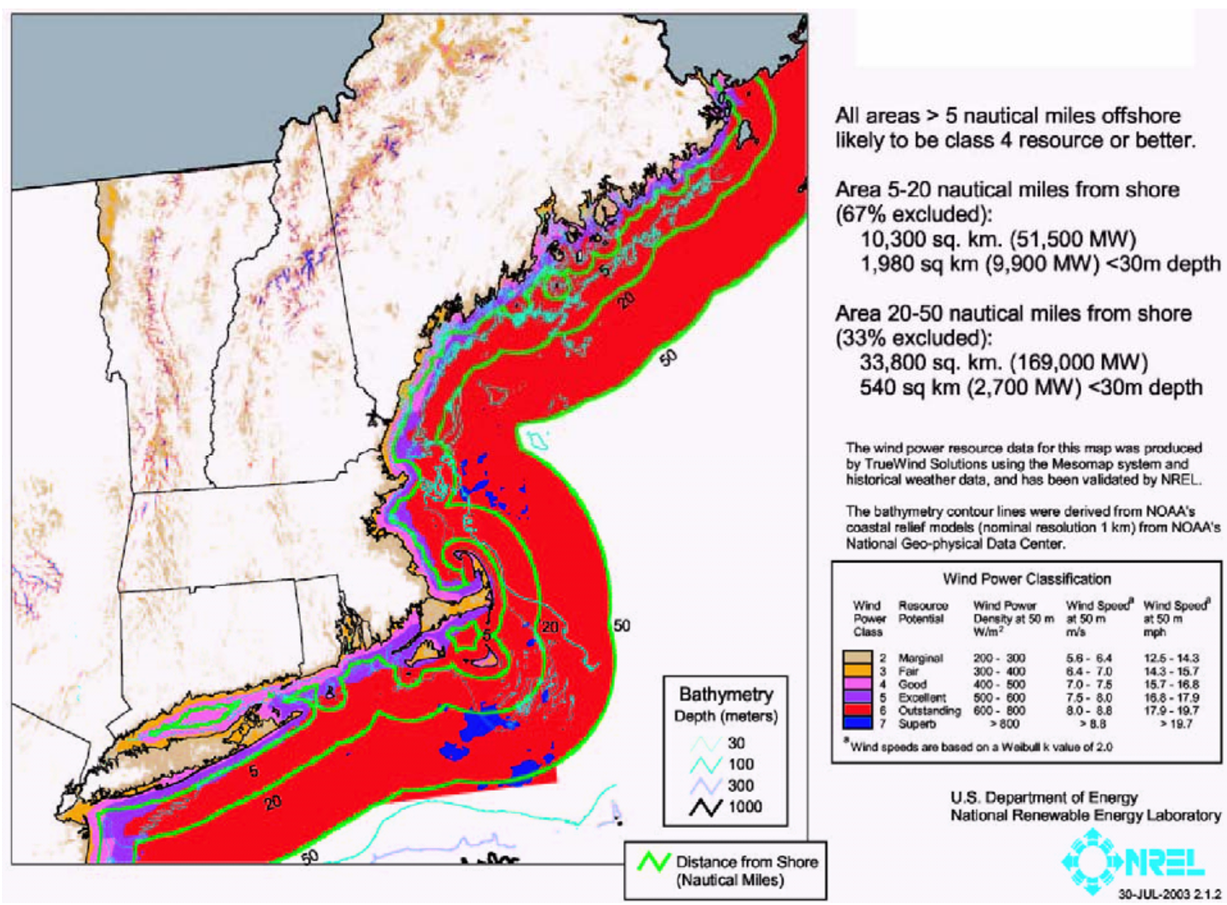


Figure 2-3 New England offshore wind resource potential (DOE 2004).

2.2 Installed wind capacity

By 2001, over 83 percent of global wind capacity was installed in five countries: Germany, the United States, Denmark, India and Spain. Most of the growth in wind power over the past decade has occurred in Europe. Installed wind capacity in Europe exceeded that of North America in 1994, and between the end of 1995 and 1999, 75 percent of all new grid-connected wind capacity was installed in Europe. At the end of 2001, total global installed wind capacity exceeded 23 GW, with 16.4 GW installed in Europe and 4.4 GW installed in North America (Ackerman and Söder 2002).

The existence of a production tax credit in the United States resulted in significant growth between 2000 and 2003. Installed wind capacity had reached about 6.3 GW by 2003, with wind farms located in 32 states. Figure 2-4 shows the distribution of existing wind capacity by state. The states with the largest installed capacity, California and Texas, account for, respectively, 32 percent and 20 percent of total capacity. Most of today's wind farms are located in regions with wind resources rated as Class 6 or higher (DOE 2004).

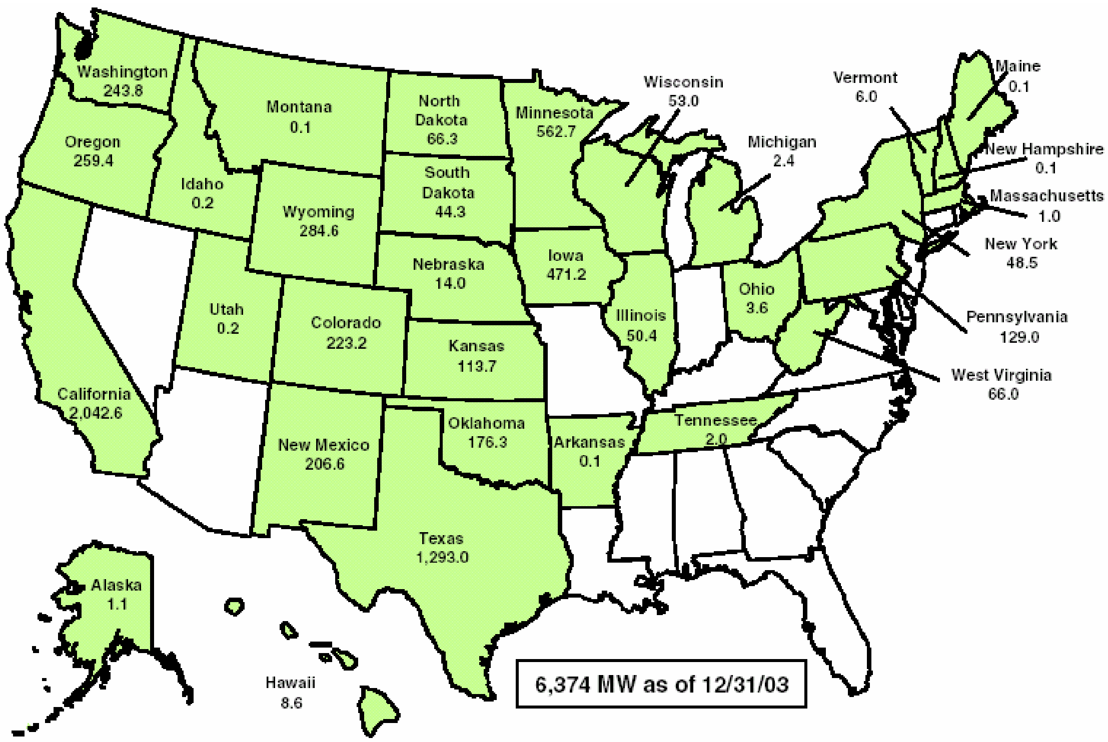


Figure 2-4 Installed U.S. wind capacity in 2003 (DOE 2004).

3 Wind Turbine Technology

This section discusses the physics of wind energy conversion and the major characteristics of wind turbine technology, including classifications, major components, performance metrics and life cycle impacts. This material provides a foundation for topics in Section 4, intermittency, transmission and storage, and Section 5, wind energy economics.

3.1 Physics of wind conversion

The energy content of wind and the manner in which it is transferred to the blades of a wind turbine can be explained in terms of basic physics. The kinetic energy of wind moving at a given velocity can be expressed as:

$$KE = 1/2\, mV^2 \tag{1}$$

Where m is the mass of the air (kg) and V is the wind speed (m/s). The power of wind flowing through an area A depends upon the mass flow rate, which can be expressed in terms of velocity, area and the density of air:

$$\dot{m} = \rho VA \tag{2}$$

Where $\dot{m}$ is the mass flow rate (kg/s), ρ is the air density (1.225 kg/m^3 at 15ºC and sea level) and A is the area (m^2). This equation can be substituted into Equation 1, resulting in an expression for the rate of wind kinetic energy passing through an area per unit time:

$$P_{Wind} = \frac{1}{2}\rho AV^3 \tag{3}$$

Only a fraction of this kinetic energy may be captured by the blades of a wind turbine. Conceptually, translating all of the kinetic energy of an air mass to the blades of a spinning turbine (i.e., 100 percent conversion) would involve bringing the air mass to a complete halt (i.e., $V = 0$). This is clearly infeasible, as air must continue to pass through the swept area of the blades during operation. In 1926, Betz derived an expression for the theoretical optimum power that can be extracted from wind:

$$P_{Wind} = \frac{1}{2}\rho AV^3 C_p \tag{4}$$

Betz determined that the power coefficient, C_p, has a theoretical optimum value of 0.59, meaning that no more than 59 percent of the energy contained in wind can be extracted by a wind energy conversion device.[1] The Betz factor has been derived in Hau 2000 (59) and Manwell et al. 2002 (84) using elementary momentum theory. As discussed in more detail in following sections, Equation 4 is also

[1] Ackerman and Söder (2002) note that in his derivation, Betz did not take into account potential reductions due to swirl losses, which are significant in turbines with low tip-speed ratios (V_{tip}/V_{wind}). A tip-speed ratio of approximately unity, typical of an American farm windmill, would reduce the Betz limit to about 0.42. For aerodynamic turbines with tip-speed ratios greater than 3, swirl losses are relatively small.

useful in assessing wind conversion in general, in which case the power coefficient C_p is used as a general efficiency term that depends on a variety of factors, such as blade design, rotor speed, and the efficiency of wind turbine components.

Wind turbine blades are designed to efficiently capture wind energy and convert it into the mechanical energy of a spinning rotor. The conversion concept, as well as the rigorous engineering models used to design rotor blades, is based upon aerodynamic analysis methods developed in the 1920s and 1930s for airplanes. As shown in Figure 3-1, the cross section of a rotor blade has the shape of an airfoil. The length of an airfoil, called the chord (c), is measured along a line (the chord line) connecting the leading and trailing edges of the airfoil. The position of the airfoil relative to the incoming wind direction is called the angle of attack, α, and is the angle between the wind velocity vector and the chord line. As in airplanes, the angle of attack significantly influences the resulting forces transmitted from the passing air mass to the airfoil.

As the oncoming air mass passes across the blade, various forces are distributed along the different surfaces of the airfoil. In general, increased flow velocity across the convex or 'suction' side of the airfoil results in lower pressure, and resistance on the concave or 'pressure' side of the airfoil results in higher pressure. As shown in Figure 3-1, the resulting force of these various pressures can be resolved in terms of two force vectors and a moment: lift force, drag force and the pitching moment. Each of these is shown applied at a single point along the chord line, at a distance from the leading edge that is one quarter the length of the airfoil chord ($c/4$). By definition, the lift force is perpendicular to the direction of the oncoming wind, and results primarily from unequal pressure on the convex and concave airfoil surfaces. The drag force is defined as parallel to the wind direction, and results from both friction along the airfoil surface and unequal forces on the forward and rear sides of the airfoil. The pitching moment is shown in Figure 3-1 as a clockwise rotation about an axis perpendicular to the cross section of the airfoil.

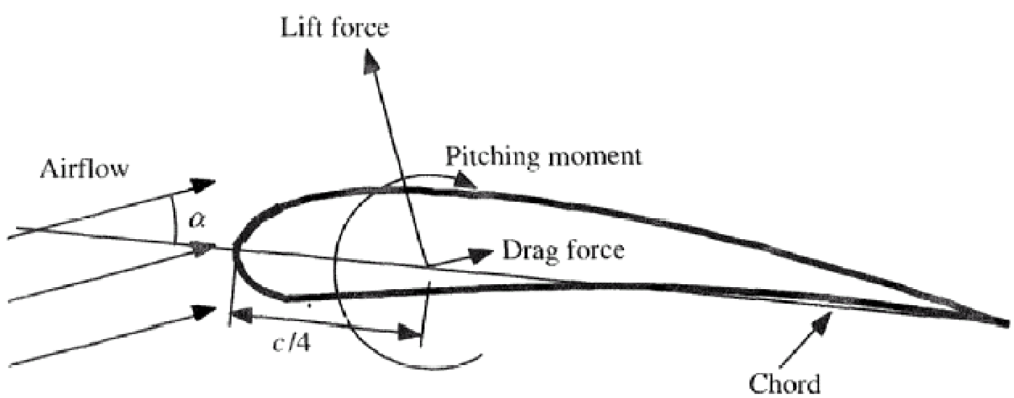


Figure 3-1 Drag and lift forces on an airfoil (Manwell et al. 2002, 97).

Wind turbines translate the lift force into the mechanical rotation of the turbine rotor system, which consists of the rotor hub and blades (see Fig. 3-4). Ideally, the airfoil is oriented to the wind direction such that a significant portion of the combined lift and drag forces is parallel to the plane of rotation of the turbine rotor. The angle of attack is an important parameter in determining the magnitude of this translated force, and correlates with the efficiency of converting the kinetic energy of the air mass to the mechanical energy of the spinning rotor.

The orientation shown in Figure 3-1 depicts a stationary airfoil. However, because the rotor blade velocity increases towards the tip of the rotor blade, the relative orientation to the oncoming wind changes, and the angle of attack is reduced. For this reason, turbine blades are designed with increasing twist along the length of the blade away from the rotor hub. The optimal degree of twisting depends upon the design rotation velocity of the turbine.

Turbine blades can be designed to allow for aerodynamic power control. At high rotation velocities, the angle of attack becomes large enough that laminar airflow across the convex side of the blade is disrupted, resulting in reduced lift force. This mode of operation, called stall, is used as a means of aerodynamic power control in two types of turbines: 1) fixed speed turbines, where stall automatically occurs when a certain wind speed threshold is reached and slows the rotor speed accordingly, and 2) blade pitch control turbines with active stall, where the blade attack angle can be mechanically adjusted to induce stall, typically by rotating the entire blade about its longitudinal axis. Both turbine designs are discussed in more detail in the following section on wind turbine types.

3.2 Wind turbine types

Wind turbines types can be divided into various categories. The first major categorical distinction is between turbines that rely primarily upon drag forces and turbines that rely primarily upon lift forces. Drag turbines, where the resistive force of the wind is ‘captured’, have much lower theoretical C_p values, typically about 0.16, and are generally not being pursued for modern power applications (Ackermann and Söder 2002, 84). The Savonius Rotor turbine, shown in Figure 3-2, is an example of a drag turbine. Drag also occurs in lift turbines, being an unavoidable form of friction, but lift turbine blades are designed to minimize the influence of drag forces (see Section 3.1).

The second major categorical distinction concerns the orientation of the rotor axis, and includes two general turbine types: horizontal axis wind turbines and vertical axis wind turbines (HAWT and VAWT). Vertical axis turbines typically involve curved airfoils rotating in a horizontal plane about a vertical axis. Three major types of VAWTs are shown in Figure 3-2, the Savonius, Darrieus and H-Rotor turbine designs. Most VAWTs are capable of collecting wind from any direction, and are configured with the gearbox and generating equipment close to the ground and therefore more accessible than in HAWTs. However, other restrictions on these turbines, such as the inability to regulate speed in high winds and the lack of a self-starting capability, have slowed research on this type of wind turbine (Ackermann and Söder 2002, 84).

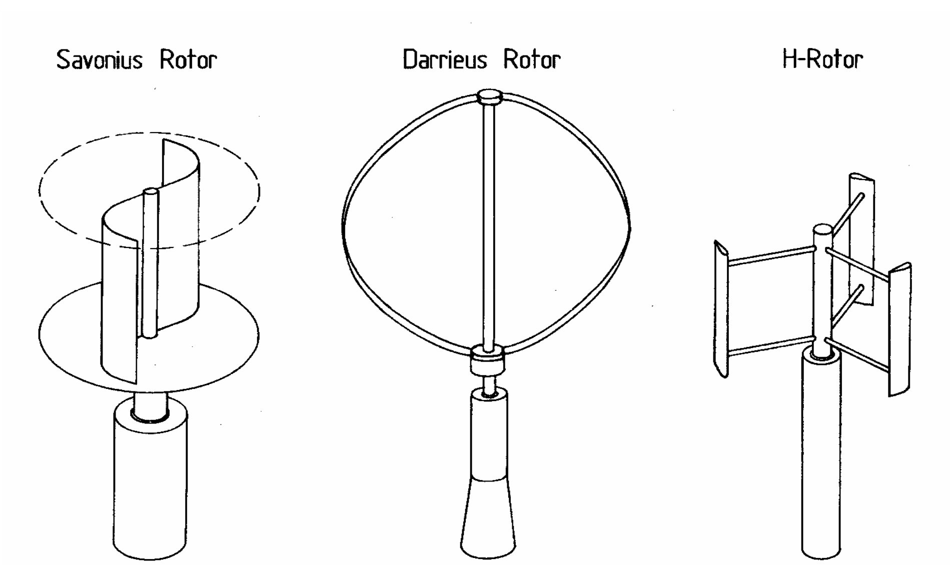
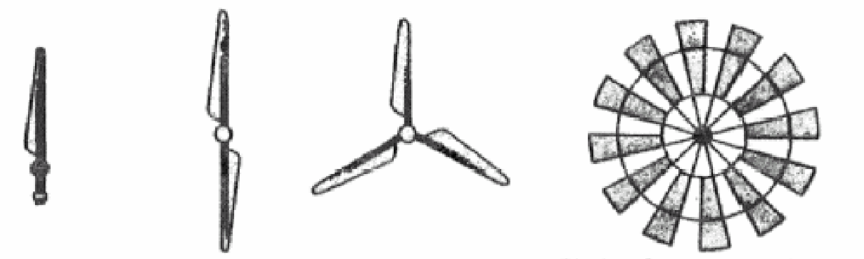
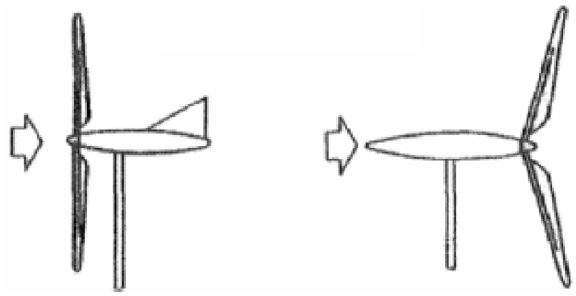


Figure 3-2 Types of vertical axis wind turbines (Hau 2000, 46).



Single blade   Double blade   Three-bladed   U.S. Farm Windmill (multi-bladed)



Up-Wind   Down-Wind

Figure 3-3 Types of horizontal axis wind turbines (Manwell et al. 2002, 9).

Various configurations of HAWTs are possible, as shown in Figure 3-3. The most common modern turbines are HAWTs designed with three rotor blades positioned upwind from the turbine tower, called 'up-wind' configuration. Downwind turbines, with the rotor blades positioned downwind from the tower, have an advantage in terms of not requiring motor assistance to follow wind directions. However, downwind turbines suffer from increased drag on the rotor blades due to the wake produced by the tower. In addition, the passing of blades through this wake increases noise production and introduces harmonics that are translated to the mechanical drivetrain and generator. In upwind HAWT configurations, the orientation of the turbine is controlled by a mechanical yaw system, located between the nacelle and the top of the tower (see Fig. 3-4). Because they are the most promising and commonly manufactured turbine type, HAWT systems are reviewed in detail in Sections 3.2.1 and 3.2.2.

3.2.1 Horizontal axis wind turbine components

As shown in Figure 3-4, major HAWT components include the rotor, nacelle, tower, and foundation, as well as sub-components contained within the nacelle (rotor shaft, gearbox, rotor brake, generator, electric controls, and nacelle bed plate) and the sub-components of the rotor system (hub, blades and blade pitch mechanism). Much analysis and engineering work has focused on rotor blade design, but the performance and cost effectiveness of HAWTs depends on each of the components shown in Figure 3-4. For example, tower costs compose a significant fraction of total turbine capital costs, and reducing the mass of components contained within the head or top of the turbine can result in reduced tower costs. A variety of turbine configurations are feasible, but the system shown in Figure 3-4 is typical of most modern HAWTs. Each turbine component is discussed in more detail below.

Rotor Blades. The rotor blades are the most distinctive component of a wind turbine. While all other turbine components are derivatives of components found in other mechanical or electronic systems, wind turbine rotor blades have evolved as a unique application of wing theory within aeronautical engineering. Rotor blade design faces many of the challenges found in aircraft engineering; the blades must withstand a highly variable load spectrum, material aging, and vibration stresses over a lifetime of 20 to 30 years.

These challenges have largely been overcome through a combination of elaborate mathematical modeling methods and unique material development and manufacturing methods.
In theory, various blade materials are possible, including aluminum, titanium, steel, fiber composites or wood. In practice, the first three are typically disregarded for reasons of manufacturing cost (aluminum), material cost (titanium) and weight (steel). Carbon fiber-reinforced composite materials, while expensive, prove favorable due to their light weight and strength, and are typically combined with glass fiber material. Rotor blade manufacturing methods most closely resemble modern boat building methods, rather than the more expensive methods of traditional aircraft engineering. The availability of mass-produced, durable and well-designed rotor blades is a precondition for the economic success of many turbine manufacturers (Hau 2000, 183).

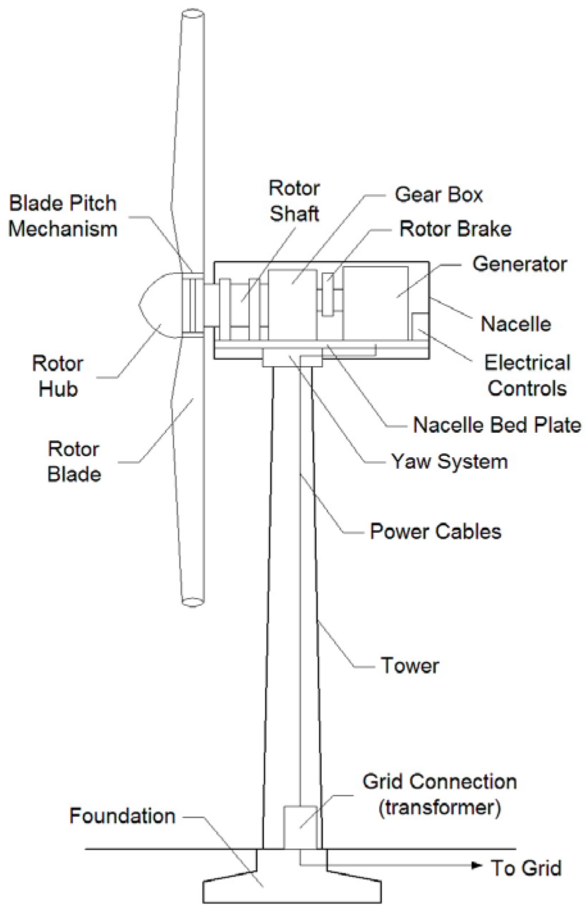


Figure 3-4 Major components of an up-wind, horizontal axis wind turbine.

Rotor Hub. The rotor hub transmits the rotational energy of the blades to the rotor shaft, and is therefore one of the most highly stressed components of the turbine system. The sphere-like shape of the hub can be seen in Figure 3-5, where it is shown without its outer shell. Material and manufacturing issues are very important for hub strength, and most mass produced hubs are made from cast or forged steel. These manufacturing methods are expensive, and experimental or limited production turbine hubs are therefore typically of welded steel design.

Pitch Control Mechanism. If a turbine design includes blade pitch control, as most large turbines do, the pitch control mechanism will typically be contained within the rotor hub at the base of each rotor blade. The pitch control mechanism allows for very controlled rotation of the rotor blade about its longitudinal axis, changing the magnitude of the lift force experienced by the blade. Pitch control mechanisms have traditionally been powered hydraulically, but electric motors are becoming more common (Hau 2000, 227). In addition to providing a means of power control through small rotations (less than 20 to 25 degrees), the pitch mechanism may allow for approximate 90 degree rotations to a 'feathered' position when aerodynamic breaking is required. Some turbines employ partial span pitching, where the blades are fixed directly to the rotor hub and only the end portion of the blade is capable of pitch control.

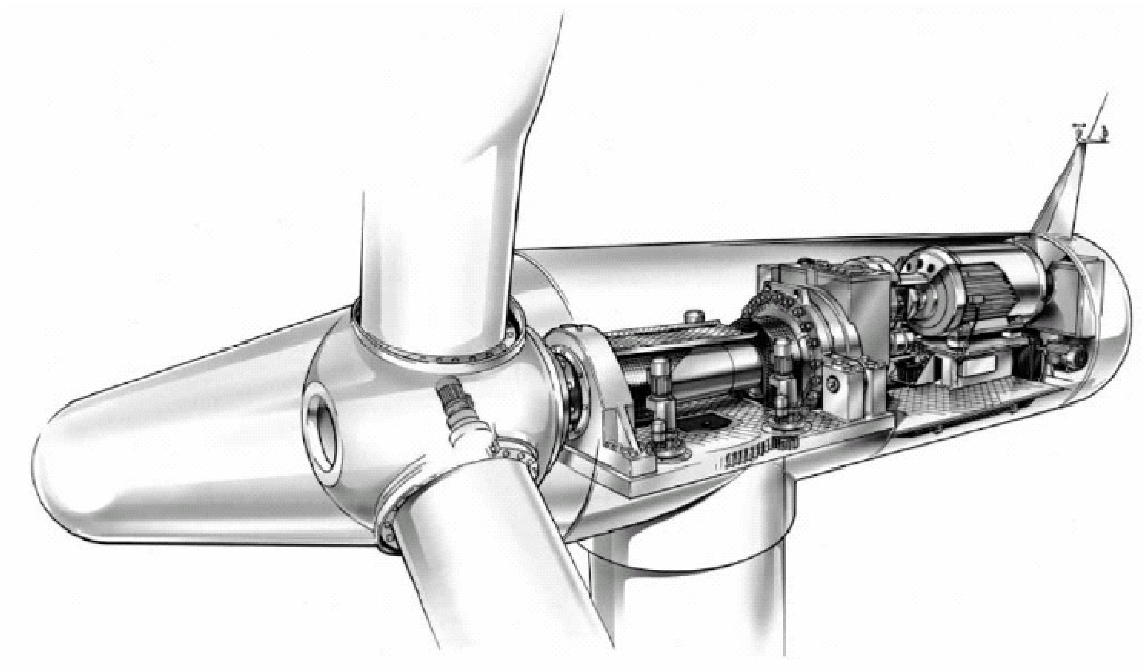


Figure 3-5 Internal components of the BONUS 1 MW nacelle. BONUS Energy A/S, Denmark (Ackerman and Söder 2002, 93).

Rotor Shaft. The rotor shaft delivers the rotational energy of the rotor to the drivetrain, and therefore must be firmly attached to the nacelle. Due to very high torsion stresses, the rotor shaft is made of forged steel. Rotor shafts are hollow, and hydraulic or electrical supply lines pass through it to connect hub and rotor mechanisms to the rest of the turbine. In Figures 3-4 and 3-5, the rotor shaft is shown directly connected to the nacelle bedplate.

Nacelle. The nacelle structure encloses all turbine components behind the rotor system and above the tower. The most common nacelle designs today include a welded steel bedplate and a non-supporting hood-like housing, typically made of glass-fiber reinforced composite material (Hau 2000, 262). Housing structures are usually designed to completely enclose all internal components, and provide important functions of temperature insulation and shielding of noise generated from the gearbox. The nacelle structure can impose significant capital costs, and recent trends are to reduce the overall size, allowing only minimal interior room for assembly and maintenance accessibility requirements. Nacelle shape is largely an issue of aesthetics, and has negligible influence on turbine aerodynamics because of its position downwind from the rotor.

Nacelle Bed Plate. The bedplate supports all drivetrain components, and must transfer all rotor forces to the tower. In alternative designs, bedplate size and mass may be reduced for simplicity and cost reduction. For example, the rotor shaft or generator may be more closely integrated with the gearbox, allowing the weight of these components to be translated structurally through a smaller, cheaper bedplate or through the gearbox itself. In an extreme design, both the rotor shaft and generator are structurally connected to the gearbox, though this may introduce operational complexity and structure flexibility issues. Mass-produced cast bedplates can result in cost reductions.

Gearbox. Gearboxes have undergone significant advances during the evolution of modern wind turbines. The gearbox has the challenging task of matching the variable and intense mechanical loads of the rotor to the input requirements of the generator. Modern gearboxes have ratios of up to 1:100, and durable and efficient off-the-shelf gearboxes used for a variety of applications are available for use in wind turbines. While small turbines may employ belt or chain gear systems, toothed-wheel gears are required for larger power systems.

Rotor Break. A rotor brake is required to bring the rotor to rest during maintenance or downtime. Turbines often have two brakes, one on either side of the gearbox, but large turbines may have a single brake positioned on the fast side of the gearbox (between the gearbox and the generator). This reduces the size and mass of the braking system, but may result in increased stress or wear on the gearbox. Depending on the size and aerodynamic breaking capability of the turbine, rotor brake requirements can sometimes be large. Mechanical disc brakes are typical, and they are often augmented with locking bolt systems. In addition to keeping the rotor at a standstill, the rotor brake can be used as a means to reduce rotor speed.

Generator. Most turbine manufacturers today utilize variable speed induction (asynchronous) generators, though the more expensive synchronous generators also have advantages and are preferred by some manufacturers. Synchronous generators are the standard for the power industry, mostly because they allow for variable reactive power production, or voltage control. On the other hand, induction technology dominates the electric motor industry, due to robust operation and low maintenance costs. In theory, both types of generators are possible, but induction generators, supplemented with capacitor systems to compensate for lack of variable reactive power production, tend to be more widely used (Ackerman and Söder 2002, 91). In general, the challenge of designing an appropriate generator system for wind turbines involves matching wind loads to the requirements of the local grid or electricity demand system. Depending on specific conditions, either induction or synchronous generators may be appropriate when used in conjunction with variable speed capability, capacitors, and frequency inverters (Hau 2000, 280). The generator system must also operate in conjunction with the grid connection system or transformer, shown located at the base of the tower in Figure 3-4.

Some design flexibility exists in how a generator is integrated with the mechanical drivetrain, though the configuration shown in Figure 3-4 is the most common. In large turbines, the generator is typically connected to the gearbox through a high speed shaft: 1500 rpm for 50 Hz systems and 1800 rpm for 60 Hz systems (assuming two pole pairs in each case). As mentioned previously, the generator can be structurally coupled to the gearbox to reduce the nacelle bedplate mass. However, wind turbine nacelles undergo significant stresses, and flexible and detachable shaft connections are typically used to reduce risk of damage and wear. Assembly and serviceability are also less cumbersome with a flexible and detachable shaft connection. Alternatively, some turbine configurations do away with the gearbox altogether by connecting the rotor shaft directly to the generator, significantly reducing mass and cost (Ackerman and Söder 2002, 93). Recent advances in direct rotor-driven generators using single-stage permanent magnet drivetrain designs have been achieved by Global Energy Concepts and Northern Power Systems (DOE 2004).

Yaw system. In order to direct the rotor and nacelle into the wind, the head of the turbine must be able to swivel in a horizontal plane atop the fixed tower. The yaw system, located between the nacelle and the top of the tower, allows for this controlled rotation. As shown in Figure 3-6, subsystems within the yaw systems of large turbines include an azimuth or yaw bearing system, a hydraulic or electric yaw drive system, and a breaking system. Bearing systems typically utilize roller bearings, though some small turbines may employ resistance bearings. Wind turbines have historically employed hydraulic yaw drive systems, but improvements in variable-speed drives and control systems have led to increased use of electric drives. The braking system is usually applied continuously to some degree to dampen changes in rotational momentum, which would otherwise result in significant mechanical stress on yaw system components. The drive system must therefore be oversized to work against this frictional dampening. Large turbines typically employ two braking systems, one on the nacelle side of the yaw system and one on the tower side (Hau 2000, 264).

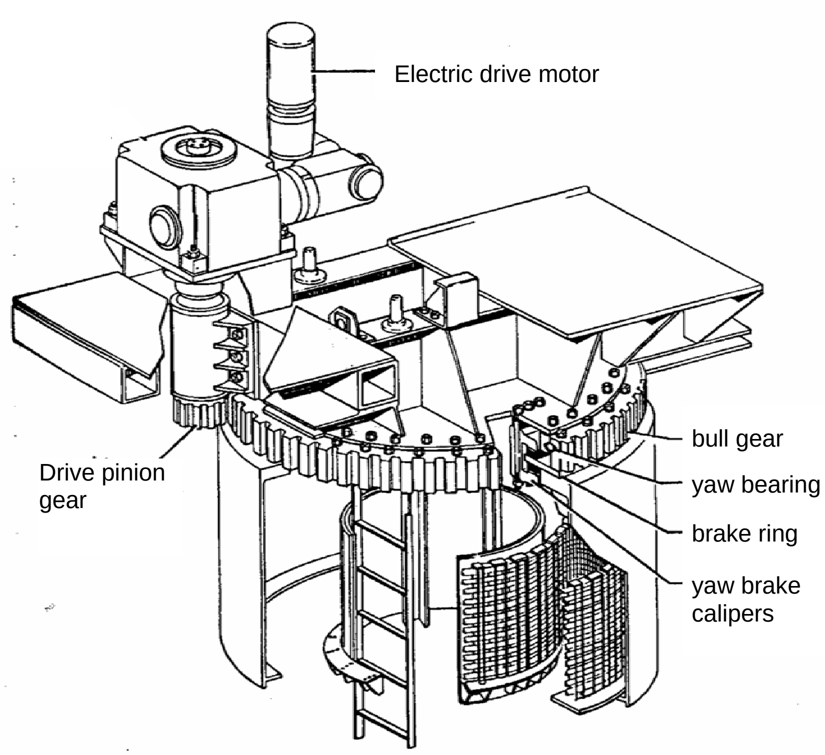


Figure 3-6 Yaw system with electric drive for the Westinghouse WTG-0600 (Hau 2000, 265).

Tower. Height, strength and stiffness are the most important characteristics of a turbine tower. Increased height results in increased yields due to higher average wind speeds at higher elevations. However, tower costs also increase rapidly with height, especially with large turbines. Tower costs can account for 18 to 25 percent of total turbine capital costs (DOE 2004). A balance must therefore be found between increased yield and the cost of additional height, and characterization of wind speeds at greater heights is needed to determine this balance for any given site. Tower strength must be adequate to endure extreme wind events and must be proportional to the weight of both the turbine head and the tower itself. The maximum force experienced by the rotor system during extreme wind events, when the rotor is at standstill, depends upon the blade pitching capability. For example, fixed blade designs will experience greater maximum forces than blades capable of pitching, requiring greater tower strength and therefore costs.

Tower stiffness must be taken into consideration when determining the natural frequencies inherent to a turbine design. Stiffness is generally described in terms of stiff or soft towers, corresponding to designs in which the natural frequency is either higher or lower than the blade passing frequency. Other natural frequencies must be taken into consideration, but resonance between the blade passing frequency and the first natural frequency of the tower poses the greatest risk of tower damage (Hau 2000, 351).

Modern turbine towers are typically of tubular steel design, with modular sections being bolted together. Access to the nacelle is achieved via internal ladders for towers over about 15 meters in height. At greater heights, intermediate platforms are positioned between ladder lengths, and for towers higher than about 50 meters internal elevators become the most practical option for accessibility.

Foundation. Wind turbine foundations are constructed of steel-reinforced concrete, and may involve pile extensions in locations with poor soil support, such as marshes or sandy regions. As is the case with the tower, the foundation must be designed to endure the maximum loads experienced during extreme wind speed events. The care required to precisely level the anchor ring connecting the tower to the concrete foundation becomes extreme with very large turbines, where even small deviations would result in significant tower tilt.

3.2.2 Power control methods

Wind turbines are designed to extract power from a limited range of wind speeds. Very high wind speeds or gusts can impose excessive stresses on turbine components, and it would not be economically practical to design turbines capable of harnessing high wind speeds that occur only infrequently. Such designs would result in increased costs and would lower conversion efficiencies at more frequently occurring wind speeds. Economic and energetic inefficiencies would also result from turbines optimized to capture very slow wind speeds.

A variety of methods are available to moderate wind turbine power under excessive wind speed conditions, including: pitch control, stall regulation, active stall regulation, aerodynamic breaking and yaw control. The most common method for large turbines is blade pitch control, which allows for rotation of the blade about its longitudinal axis, reducing the lift force. For turbines with fixed blades and constant rotational speed (achievable with a grid-connected induction generator), rotor blades can be designed for stall regulation. This type of passive power control occurs during high wind speeds, when the air flow across the blade becomes turbulent on the convex side of the blade, resulting in reduced aerodynamic force on the blade. This power control method was popular in older Danish turbines (Hau 2000, 87), and is still used in some large modern turbines (Ackerman and Söder 2002, 88). Stall regulation is also possible in turbines with blade pitch control, in which case it is termed active stall regulation. Turbines with fixed blades cannot rely upon stall regulation alone, and aerodynamic breaking is typically employed as backup speed control. Breaking mechanisms include brake flaps, spoilers that open along blade surfaces, and rotating blade tips. Finally, small turbines with yaw control mechanisms are able to reduce turbine power by rotating the nacelle out of the direction of the wind. Use of this control mechanism requires a very robust yaw system to endure significant rotational stresses. Ackerman and Söder state that yaw control is only used in turbines of 5 kW or less (2002, 91).

Wind turbine power output can also be controlled on the farm or multi-unit level. Groups of turbines are controlled by supervisory control and data acquisition (SCADA) systems, which communicate with the control systems of each individual turbine and can initiate or shut down individual turbines as needed (Manwell et al. 2002, 323). This level of power control becomes important when integrating power from large wind systems into existing power grids.

3.3 Wind turbine performance

Two important metrics that describe wind turbine performance are the *power rating* and *energy yield*. The power rating is dependent upon turbine design, while energy yield depends upon both turbine design and the wind resource available at a particular location.

3.3.1 Power output and rating

The rated power of a wind turbine should not be confused with power ratings assigned to conventional power plants. While the power output of a conventional power plant (e.g., a pulverized coal plant) is directly coupled to the plant's economic performance, this is not necessarily the case for wind turbines. The parameter with greater economic significance for wind turbines, as well as for solar energy technologies in general, is the size of the energy collector. In the case of wind energy, the rotor is the energy collector, and its diameter is important in determining energy yield. However, the rated power of a wind turbine is a meaningful parameter, and its definition, though sometimes poorly articulated, provides insight into how wind turbines function.

As a theoretical expression for wind energy conversion, Equation 4 is a representation of turbine power output. Values for the power coefficient, C_p, are directly correlated with turbine power output and conversion efficiency, and will vary with wind speed and be determined either empirically or analytically for any particular turbine. Many turbine design issues focus on optimizing the power coefficient for particular wind regimes, rotor speeds and generator sizes (Manwell et al. 2002, 83, Hau 2000, 381). For example, increasing the rotor speed design of a turbine tends to increase power coefficient values at large wind speeds, and increasing the size of the generator allows for higher energy conversion rates at large wind speeds.

Figure 3-7 is a simplified schematic of various wind turbine efficiency losses across a range of wind speeds, represented as reductions in the power coefficient. The outer edge of the power coefficient profile shown in Figure 3-7 represents theoretical maximum values, as determined through aerodynamic analysis. The power coefficient values associated with efficiently designed rotor blades would be only slightly less than these theoretical values. However, two additional losses significantly reduce overall wind turbine efficiency: 1) mechanical friction and electrical losses from internal turbine components, and 2) power limitation losses due to the size of the turbine generator. As shown in Figure 3-7, mechanical and electrical losses dominate at lower wind speeds, and are a relatively small compared to power limitation losses at high wind speeds. In this profile, the rated power is defined by the size of the generator and is shown occurring at a wind speed of about 12 m/s. Partial loads occur below this power rating, and full load operation occurs above this power rating. Power limitation losses begin at full load, when wind speeds provide more than sufficient energy for maximum or rated power output. Note that the power coefficient profile shown in Figure 3-7 would be a turbine designed for optimal efficiency at wind speeds ranging from about 6 to 12 meters per second. The power coefficient reduction to zero at 24 m/s is associated with the turbine design cut-out rate, as discussed below.

With the power coefficient characterized in this manner, it is possible to determine the turbine power output by accounting for the wind speed component of Equation 4, V^3. The exponential increase of this term more than compensates for declining power coefficient values at higher wind speeds. The result is a power curve such as the one shown in Figure 3-8 (Figs. 3-7 and 3-8 do not represent the same turbine, however). Figure 3-8 portrays turbine output as a function of the wind speed occurring at the height of the turbine hub. Three important power ratings are highlighted: 1) the cut-in power at which the turbine begins to produce power, 2) the maximum or rated power of the turbine, and 3) the cut-out rate at which the turbine shuts down and produces no power. Note that a turbine would generate electricity at its rated power output only during optimal wind speeds. Some manufacturers report a rated power output slightly lower than the maximum, and this ambiguity has often been a source of controversy and confusion (Hau

2000, 381). As shown in Figure 3-8, the output from stall-regulated turbines drops after reaching rated power, while turbines with pitch control are able to maintain a constant output at high wind speeds (dotted line in Fig. 3-8). Cut-out rates are dependent upon turbine design capacity and component stress considerations, and turbine systems shut down when wind speeds exceed this limit.

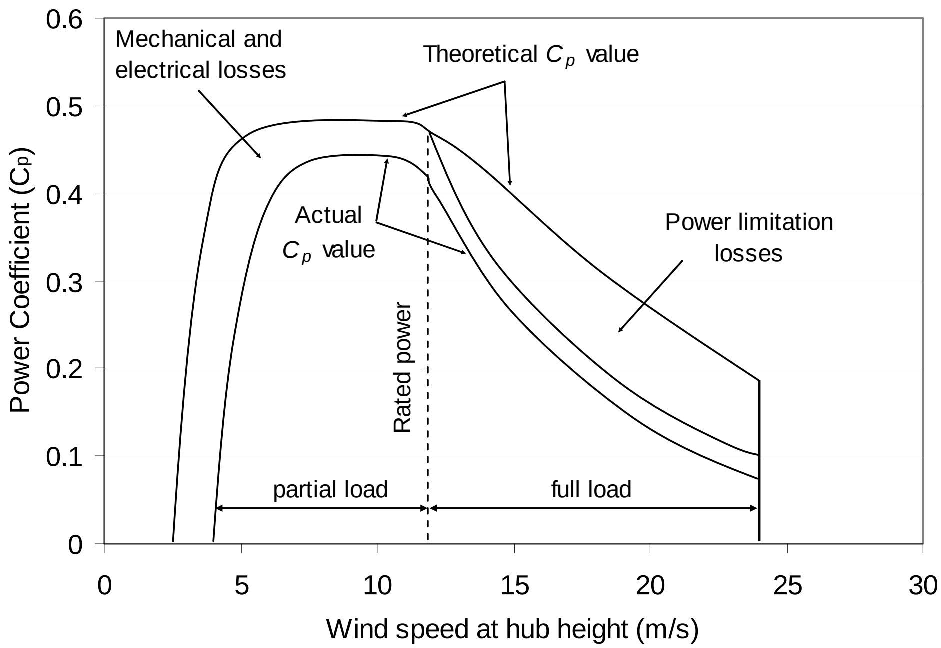


Figure 3-7 Reductions from theoretical power coefficient values due to various turbine losses. (Derived from Figure 13.4 of Hau (2000, 385) and based on the WKA-60 turbine)

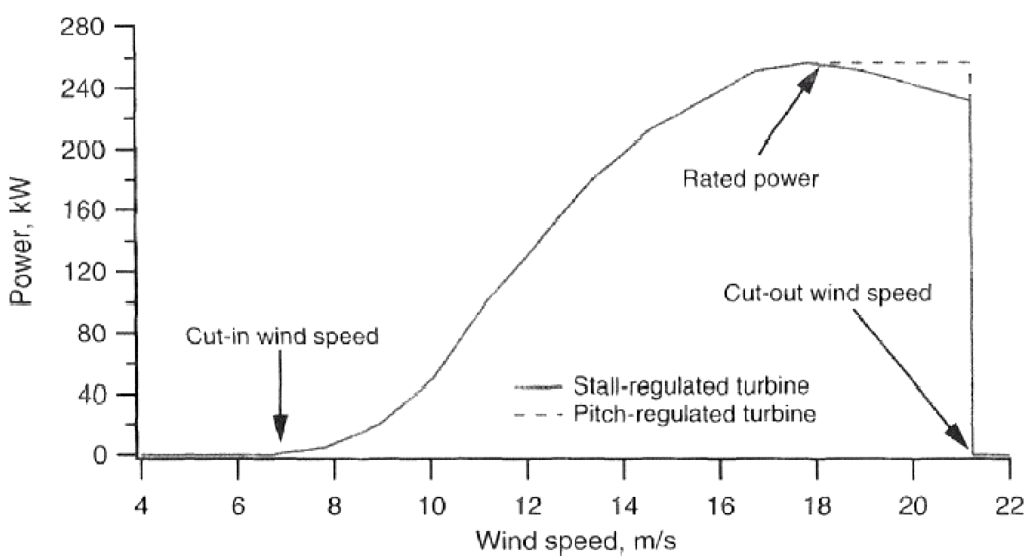


Figure 3-8 Power curve for a typical wind turbine (Manwell et al. 2002).

3.3.2 Average energy yield

The average energy yield parameter, typically expressed in kWh per year, is more closely associated with the economic performance of a turbine than is the rated power. Figures 3-7 and 3-8 characterize the performance of particular turbines across a range of wind speeds, but in order to determine the average annual energy yield of a turbine, this information must be combined with a quantitative representation of the wind regime at a particular location. One might be tempted to assume that the average annual wind speed at a location, say 8 m/s, can be used to determine the average turbine power output, and therefore the annual power production. However, this assumption would significantly underestimate the actual energy yield, typically by a factor of about 2. This is due to the cubed velocity term in Equation 4, which results in higher than average wind speeds accounting for a major portion of wind energy available at any given site. An accurate estimation of annual energy yield must therefore take into account the frequency of various wind speeds at the location in question. Theoretical probability distributions are often formulated as Rayleigh distributions:

$$\phi(U) = \frac{\pi}{2}\left(\frac{U}{\overline{U}^2}\right)\exp\left[-\frac{\pi}{4}\left(\frac{U}{\overline{U}}\right)^2\right] \tag{5}$$

Where U is the wind speed, and $\overline{U}$ is the average wind speed at the site (Manwell et al. 2002, 56). The frequency distribution curve indicates the probability that any given wind speed will occur, with the total area under the curve equal to unity. Figure 3-9 shows a theoretical wind speed frequency distribution, modeled as a Rayleigh distribution with an average wind speed of 8 m/s. The corresponding wind energy density, in W/m^2, is shown for comparison (calculated using Equation 4 with a C_p value of unity). In determining the wind energy available to a turbine at a given location, the frequency of any given wind speed is weighted by the corresponding wind power density. The average annual power output is therefore significantly higher than the output associated with the average annual wind speed. If the wind speed frequency profile were skewed to the left or the right, the average annual wind energy available would decrease or increase, respectively.

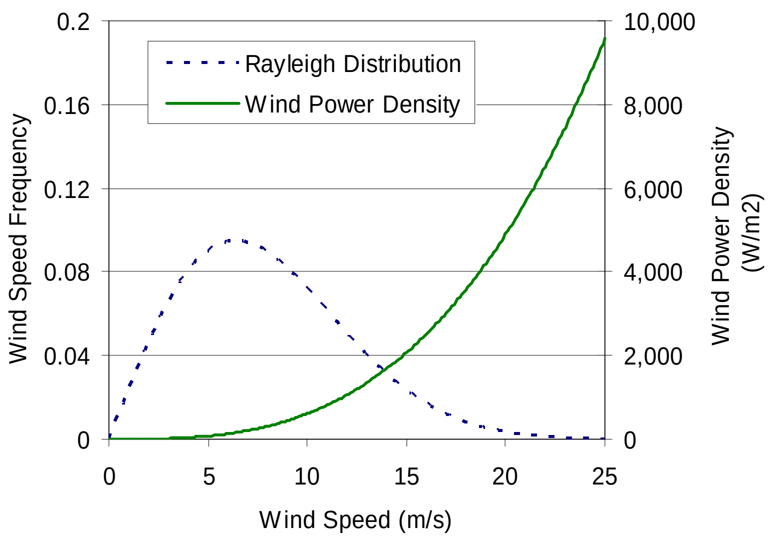


Figure 3-9 Wind power density for a Rayleigh probability distribution with average wind speed of 8 m/s.

Given the power curve for a particular turbine and a wind frequency distribution for a particular location, it is possible to estimate the annual energy yield utilizing the following expression:

$$E = \frac{8760}{100} \sum_{V_{CI}}^{V_{CO}} P_{el}(V_W)\,\Delta\phi \tag{6}$$

Where V_{CI} and V_{CO} are wind velocities associated with the turbine cut-in and cut-out power ratings, $P_{el}(V_W)$ is the turbine power as a function of the wind speed, and $\Delta\Phi$ is the wind speed frequency distribution function in percent. The summation is typically made over a range of wind 'bins' of different velocities. Assuming 8760 hours in a year (100 percent availability), units are in kWh/year.

Figure 3-10 is a productivity curve indicating total wind power and actual turbine output distributed across the total hours of operation. The difference between these two curves is marked as aerodynamic losses, and the area under the turbine power curve represents total energy captured. The distribution shown is typical, and demonstrates that losses associated with low-wind cut-in and high-wind shut down limitations, as well as the limitation of rated power (2.5 MW in this case), restrict turbines from capturing only a fraction of the total available wind power.

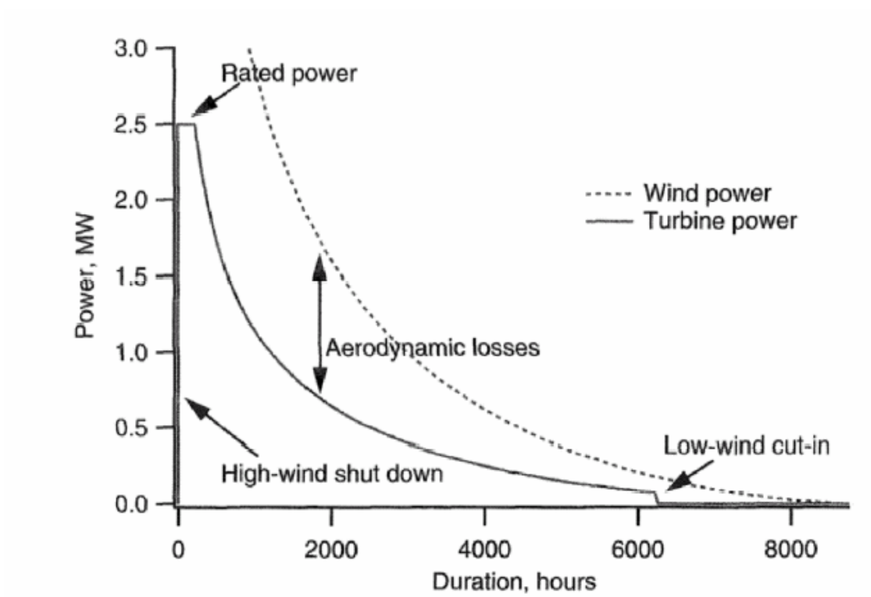


Figure 3-10 Turbine productivity curve (Manwell et al. 2002, 55).

A number of turbine design and operation parameters influence total energy yield, including rotor speed, hub height, rotor area, generator capacity, the capacity for pitch regulation, etc. In most instances, it is not feasible to optimize all parameters in a specific application. Such multi-parameter optimization would require custom designing each turbine to suit the wind profile of any given location, sacrificing important economies of production. Hau (2000, 401) notes that of these various parameters, rotor diameter is one of the least flexible, due mostly to manufacturing and cost constraints. It is therefore common to design turbine components to operate as efficiently as possible given a particular rotor diameter. Of the remaining parameters, rotor speed and pitch regulation have only a small influence on annual yield, while hub height will have a significant influence in most wind regimes.

Design decisions regarding rotor area and generator capacity are closely coupled, and are often discussed jointly in terms of the rated power per rotor swept area (W/m^2). Typical values range from 300-500 W/m^2 for small turbines to 500-600 W/m^2 for larger turbines. Taylor (1996, 302) reports that a typical value is about 450 W/m^2, or about 2.2 m^2 of swept area per rated kW. Figure 3-11 portrays the relative heights, rotor diameters and rated power per swept area for various wind turbines ranging in size from 50 to 5000 kW. The Washington Monument at 170 meters shown for reference. In general, increased generator capacity leads to higher yields in regions with high average wind speeds. However, increasing the rated power per area may result in diminishing or even decreasing returns in regions with average wind speeds lower than about 7 m/s (the lower bound on Class 4 winds), as suggested by Figure 3-12. In determining the most appropriate generator size for a given rotor swept area, additional costs must be weighed against increased yield. In a recent presentation, Lyons (2004) suggests an optimal capacity of about 2 MW.

Actual wind speed frequency distributions vary from location to location, but some form of the Weibull distribution typically provides a good representation of empirical data. By convention, a Weibull distribution with shape parameter of 2 (therefore a Rayleigh distribution) is used to provide a consistent representation of wind speed frequency distribution for a range of average wind speeds. The result is the wind classification system shown in Table 3-1 and used to characterize wind resources in Figures 2-1, 2-2 and 2-3. These classes are based upon average wind speeds occurring at a hub height of 50 m.

Table 3-1 Wind speeds and power densities for wind Classes 1-7 (McGowan and Connors 2000).

Wind Class	Average Wind Speed (m/s)	Wind Power Density (W/m^2)
1	0 - 5.6	0 - 200
2	5.6 - 6.4	200 - 300
3	6.4 - 7.0	300 - 400
4	7.0 - 7.5	400 - 500
5	7.5 - 8.0	500 - 600
6	8.0 - 8.8	600 - 800
7	8.8 - 11.9	800 - 2000

Note: Speed and power densities at 50m height

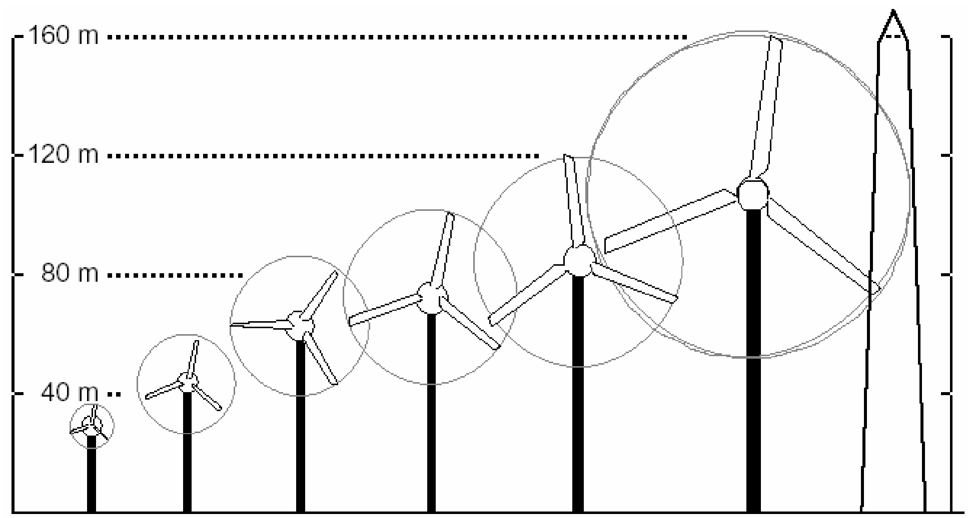
The power density values shown in Table 3-1 can be used to make a simple estimate of the average power output of a turbine, and therefore its annual yield. The following equation bypasses detailed information on wind speed frequencies and variations in power coefficients by assuming a general wind turbine efficiency:

$$P_{ave} = \eta A F \tag{7}$$

Where F is the power density of the wind class (W/m^2), A is the swept area of the rotor (m^2), and η is a generalized efficiency term, equal to approximately 26 percent according to Grubb and Meyer (1993, 186). This efficiency term is somewhat less than half the Betz limit, and takes into account a range of losses, including variations in wind speed, losses due to the wind turbine drivetrain, losses due to neighboring wind turbines, etc. This simplified expression provides a reasonable estimate of power output and energy yield for a turbine of a given size located in a specific wind class. For example, a turbine with a 60 meter diameter in a Class 4 wind location would have an average power output of:

$$P_{ave} = 0.26 \cdot \pi \left(\frac{60m}{2} \right)^2 \cdot 450 W/m^2 = 330\ kW \tag{8}$$

This corresponds to an annual yield of 2.9 GWh/year, assuming 100 percent availability. Section 5 utilizes this estimation in an economic analysis of a wind turbine located in a Class 4 wind region.



Rated Capacity (kW):	50	300	750	1000	2000	5000	Washington
Rotor diameter (m):	15	34	48	60	72	112	Monument
Tower Height (m):	25	40	60	70	80	100	170 m
Power/rotor area (W/m^2):	280	330	415	355	490	510	

Figure 3-11 Representative sizes and performance parameters for various wind turbine capacities (Adapted from McGowan and Connors 2000, 18).

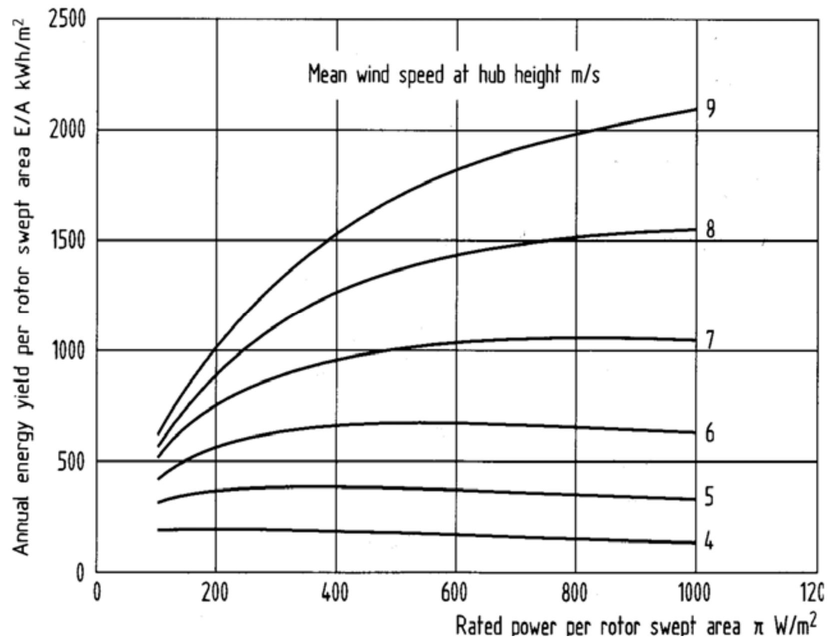


Figure 3-12 Rated power per rotor swept area vs. energy yield for various wind speeds (Hau 2000, 407).

3.4 Wind turbine life cycle analysis

Several studies of wind turbine life cycles have been carried out to better understand the 'cradle to grave' performance and environmental burdens of wind power. Material and energy resource requirements from a number of these studies are shown in Table 3-2 on a per rated capacity basis. The table also shows total greenhouse gas emissions per rated power and carbon intensity per GJ of wind energy supplied. The turbines range in size from 50 kW to 2 MW.

Three turbines are land-based, and two are offshore turbine systems. Comparisons between these studies reveal some basic trends, but a thorough examination of the assumptions supporting each study is beyond the scope of this paper, and the trends are therefore only suggestive. In terms of completeness of data, the NREL and Hassing papers are probably the least detailed, and the Schleisner paper is the most detailed. In addition, the Schleisner study examines both land-based and offshore turbines. In general, total primary energy use ranges from 3.5 to 8.8 GJ per kW of rated power, and life cycle carbon emissions range from 253 to 826 kg CO_2 eq. per kW of rated power. Primary energy use due to concrete is shown on a per rated capacity basis for comparison.

Only one wind turbine in Table 3-2 is very large, the 2 MW turbine analyzed by Hassing. This study reported relatively small quantities of concrete for the offshore turbines, resulting in lower energy and carbon intensities per kW of production capacity than for the other turbines. This is somewhat unfortunate, as the results might otherwise reflect economies of scale rather than an alternative design. Concrete was a major contributor to the large primary energy value shown for the offshore Schleisner turbine. Schleisner assumed than an offshore turbine would require twice the concrete of a land-based turbine. Disregarding the offshore Schleisner turbine, total primary energy requirements for turbine production ranged from 3.5 - 5.2 GJ per kW capacity. For every turbine except the low concrete Hassing turbine, coal for concrete and steel production dominates primary energy use.

Table 3-2 Material, energy, and carbon metrics from four wind turbine LCA studies.

Characteristic	Units	Turbines				
		NREL, 2001	Schleisner 2000	Pembina, 2000	Schleisner 2000	Hassing, 2001
Turbine Type		Land	Land	Land	Offshore	Offshore
Rated Power	kW	50	500	600	500	2000
Materials						
Concrete	kg/kW	245.03	565.00	72.07	1,130.00	8.80
Iron/Steel	kg/kW	158.10	129.40	106.44	161.20	32.00
Aluminum	kg/kW	-	2.80	3.08	2.80	0.80
Copper	kg/kW	-	0.70	1.67	5.86	-
Sand	kg/kW	-	4.20	-	4.20	-
Glass	kg/kW	-	2.20	-	2.20	-
Plastics	kg/kW	-	4.00	12.50	4.00	-
Lead	kg/kW	-	-	-	6.72	-
Other	kg/kW	-	1.60	0.42	2.68	-
Water	kg/kW	7,035	-	-	-	-
Energy						
Primary Energy**	GJ/kW	4.58	5.20	-	8.77	3.51
Coal	GJ/kW	2.43	4.62	-	7.33	1.58
Oil	GJ/kW	1.05	1.33	-	2.13	0.59
Natural Gas	GJ/kW	0.44	0.07	-	0.20	1.18
Gasoline	GJ/kW	-	-	-	-	0.15
Due to concrete*	GJ/kW	0.91	2.09	0.27	4.18	0.03
Greenhouse Gases						
GHG emissions	kg CO_2 eq/kW	524.58	426.44	704.17	826.40	252.70
Carbon intensity	kg CO_2/GJ	114.52	82.08	-	94.18	72.09

** Calculated assuming concrete production requires 3.7 MJ/kg. ** Primary energy for Schleisner turbines is larger than the sum of the fuel energies because the fuel energies reflect production energy only, while the total primary energy value reflects credits from recycling metals during the end of life stage.*

An interesting life cycle metric not included in Table 3-2 is the net energy ratio, defined as the total useful energy produced over the life cycle of the system divided by the total non-renewable or fossil energy consumed. For renewable systems, the net energy ratio is typically greater than one, while ratios for fossil-based systems are always less than unity due to conversion inefficiencies. A recent study by Wagner and Pick (2004) examined two turbines, 1.5 and 0.5 MW in size, located in various wind regimes. The authors determined that net energy ratios for these turbines ranged from 40 to 70, with the wind regime being the most important variable. Another recent life cycle study carried the wind fuel cycle through to hydrogen production via electrolysis, and found a net energy ratio of 13.2, representing the energy content the hydrogen produced divided by the life cycle fossil energy consumed by the system, including compression to 20 MPa and high pressure gaseous storage (Spath and Mann 2004).

4 Intermittency, Transmission and Storage

Reductions in wind power production costs, combined with availability of vast wind resources, suggests a very positive outlook for wind power. However, wind power appears more limited from an economic perspective when the additional costs of supply intermittency and transmission investments are taken into consideration. Due to its intermittent nature, wind power is not always available during peak electricity demand periods when the market value of electricity is high. Furthermore, backup power units may be needed to shore-up installed wind capacity to ensure grid reliability, or 'firm' capacity. Inability to deliver either of these capabilities, supplying power during peak power periods and ensuring firm capacity, can result in significant economic penalties for installed wind capacity. Furthermore, many areas that are rich in wind resources are not located near existing transmission lines. Installing new transmission lines to access these remote areas, or even upgrading existing transmission lines to accommodate increased supply, can increase the cost of wind energy for end users.

Several strategies have been proposed to address the potential costs of intermittency. Three of these strategies concern system operation and design, and include flexible operation of existing power units, aggregation of multiple farm outputs, and forecasting of wind speeds. Each of these is addressed in Section 4.1.

A fourth strategy involves the introduction of storage technologies to temporarily store electricity produced from wind turbines. Adding storage capacity give wind energy systems a degree of 'dispatchability' – the capacity to provide power on demand. Storage can also be used to smooth out fluctuations in wind energy output by storing energy during high wind speed periods and feeding electricity back into the gird or transmission system during low wind speed periods. Increased dispatchability will typically improve the value of wind energy in electricity markets, as well as facilitate its integration into existing grid systems by reducing demand for backup power. Energy storage at the wind farm also allows for more efficient utilization of transmission lines by allowing increased average line loadings. Theses and other advantages must be weighed against the additional costs of wind energy storage. Transmission is discussed in Section 4.2, and Section 4.3 reviews two promising energy storage methods: compressed air and hydrogen energy storage. For additional discussions of intermittency, see Hirst and Hild (2004), Asmus (2003) and presentations from a recent IEA workshop (IEA 2004).

4.1 Intermittency concerns

There are two main concerns about the intermittent nature of wind energy: 1) to what degree will intermittency reduce the value of wind power, and 2) can large capacities of wind power be economically integrated into a utility grid composed of multiple power sources. In the final analysis, answers to these questions will depend upon characteristics of the particular wind resource and grid system. However, some general trends can be identified.

The first intermittency concern revolves around the difference between wind power production costs and the actual market value of that power when supplied to a local or regional grid system. Even if a specific wind farm produces relatively low-cost power, the market value of this power will depend upon when it is available, what capacity it is displacing, and how reliably it can be delivered in response to changes in demand. The second intermittency concern is the reliability of wind power as a replacement for conventional baseload power, as large percentages of wind power will begin to displace baseload power in most grid mixes. To some degree, this reliability will depend upon the compatibility of wind system supply dynamics with the dynamics of other power sources feeding a particular grid.

In some regions, including some locations in California, wind energy supply correlates well with peak demand. This can significantly increase the value of wind energy capacity (Smith, D.R. 1987). However, statistical analyses have shown that this is not typically the case (Grubb and Meyer 1993, 178). Therefore, because providing power during peak demand periods is not the norm, the value of wind energy will generally correspond to its ability to provide baseload power. In theory, this reliability diminishes as the percentage of wind energy supplied to a grid system increases, due to the potential for wider fluctuations in wind energy supply and therefore greater reliance on (more expensive) backup capacity. Studies suggest that, as a general rule of thumb, significant intermittency penalties are not associated with grid penetration levels below about 10 percent (Grubb and Meyer 1993, 181). This percentage is site dependent, however, and would be lower for wind resources that correlate poorly with demand. This percentage also applies only to near-term installed capacity, and does not take into account strategies that could increase the value of future large-scale wind energy applications, such as grid management and energy storage strategies. Several grid management strategies are discussed below, and wind energy storage is discussed in more detail in Section 4-3.

Three interrelated grid management strategies can facilitate the integration of large percentages of wind energy into existing grid systems: 1) flexibility in traditional thermal plant operation, 2) geographic diversity in wind power sources, and 3) utilization of wind forecasting techniques. Existing thermal sources (i.e., coal, nuclear, natural gas) can be more easily adapted to accommodate the intermittent nature of wind energy if wind capacity is integrated slowly over time. Due to the high value placed on flexibility in an unregulated market, it is not unreasonable to assume that flexibility will generally increase in most grid systems as they become deregulated. In some cases, for example, backup power can be provided for wind energy systems without incurring additional capital costs by keeping older units in reserve. If these older reserve units have high operating costs, or long startup times, the value of additional wind power within that grid may be diminished. Determining these types of dynamics must be done on a grid-specific basis, and must take into account the entire system, not just wind turbine supply dynamics. A study by Milligan (2001) suggests that the additional backup capacity required to support wind power plants, when examined on a system-wide basis, is much smaller than previously assumed, and can be as low as about 10 percent of the rated wind capacity. Eventually, of course, all old plants must be retired, but some units can provide backup for wind power until alternative methods or systems are employed.

The second strategy involves combining output from multiple wind farms separated by some distance. Recent studies have revealed that combining outputs from geographically separated wind farms can have a significant smoothing effect on the aggregated supply. For example, a simulation of the introduction of wind farms in Iowa and Minnesota, where the turbines were spread across large geographic regions, found that hourly wind power variations could be reduced by half (Milligan et al. 2002). Figure 4-1 indicates the resulting smoothing effect, showing one week of 10-minute average output records from two geographically separated sites: Lake Benton in Minnesota and Storm Lake in Iowa. With a time lag of 9 to 12 hours between winds arriving at the two sites, the variation in total aggregate output is much less than that of either site operating in isolation. In addition to large-scale effect between farms, it should be noted that large wind farms with many turbines scattered across large areas can experience local or internal smoothing of aggregate output. In regions where these smoothing effects are significant, the dampening of power output fluctuations can result in reduced transmission costs and increased reliability.

A third strategy is the use of forecasting methods to increase the effectiveness of backup power units used during fluctuations in wind power supply. The accuracy of wind speed forecasting is relatively high when projecting one to four hours into the future. However, information becomes less reliable and less precise at greater time scales. While forecasting inevitably involves some degree of error, the magnitude of this error has been found, at least in one case, to be less than that of typical utility load forecasting when looking only one to two hours ahead (Milligan et al. 2002, 58). The availability of this quality of forecasting information brings into question the most appropriate manner in which wind power should be scheduled by utilities. Milligan et al. (2002) suggest that the use of forecasting methods under near real-time scheduling protocols would improve the market value of wind power.

The combined effectiveness of these three factors (flexibility of existing power sources, geographic diversity of wind supply, and improved wind speed forecasting) can significantly increase the percentage of wind power that can be economically integrated into particular grid systems. Grubb and Meyer (1993, 185) contend that by applying these management strategies, wind power should be able to supply from 25 to 45 percent of total grid power before experiencing prohibitive economic penalties.

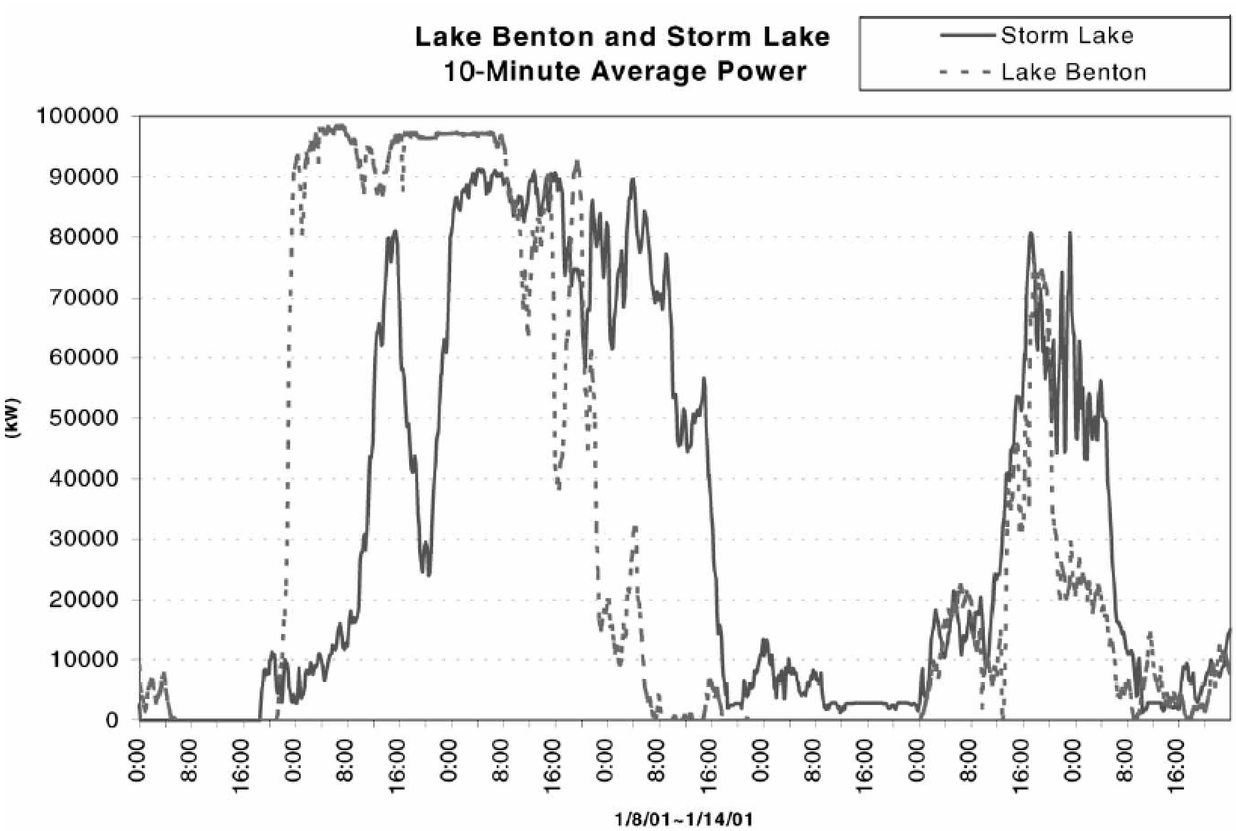


Figure 4-1 Smoothing effect in power supply due to geographic diversity (Milligan et al. 2002).

Once this limit has been reached, energy storage could be introduced to provide an additional degree of supply flexibility, allowing even higher percentages of wind power to be integrated. In theory, cheaper energy storage would allow for larger percentages of wind power integration. As is the case for thermal sources, management and effectiveness of energy storage capacity will depend upon the mix of sources in any specific grid system. In general, the ability to regulate the flow of wind energy from large farms would result in various system benefits that must be weighed against the cost of wind energy storage. Major benefits include improved quality of electricity (important for transmission), increased marked value due to firmer capacity and the ability to provide peak power, and more efficient use of transmission lines.

4.2 Transmission of wind energy

The transmission of wind power can impose significant economic costs. The capital expenditures needed for wind power transmission depend on various factors, but generally increase with distance from a load center, distance from existing transmission lines, and the degree of upgrading needed to utilize existing transmission lines. As is the case for wind power production economics, accurate estimates of transmission costs must be determined on a site-specific basis and must examine grid dynamics from a systems perspective rather than focusing just on the wind system.

A 1995 study by Parsons, Elliot and Wan examined the proximity of wind resources to existing transmission lines. Table 4-1 summarizes the results of this study, and Figure 4-2 portrays the geographic distribution of economic wind resource regions (Class 4 or better), existing 230 kV or greater transmission lines, and large urban load centers. As suggested in Table 4-1, approximately 400 GW of wind resource capacity is within 20 miles of existing transmission lines. A more detailed analysis of existing electricity transmission and distribution systems is needed to determine the economic viability of transmitting wind from various wind resource areas to load centers in the United States.

Table 4-1 U.S. Wind power capacity in proximity to existing transmission lines (NWCC 1997).

Proximity	Average Wind Capacity (MW)
Within 20 miles	401,652
Within 10 miles	284,239
Within 5 miles	175,656

4.3 Energy storage options

Options for economically storing large quantities of electricity are limited. Currently, pumped hydro storage is used routinely by many utilities. Other promising electricity storage technologies include advanced batteries, ultracapacitors, flywheels, superconducting magnetic energy storage (SMES), compressed air energy storage (CAES) and hydrogen. Table 4-2, derived from Schoenung et al. (1996), compares performance and cost parameters for each of these technologies, with the exception of hydrogen, which can be stored by various different methods. Storage technologies with small energy capacities, such as flywheels, batteries, SMES or ultracapacitors, are suitable for applications requiring power output on short timescales (i.e., seconds to minutes) to improve power quality and reliability. For extended load leveling requirements (i.e., minutes to hours), such as those needed to supply backup power for wind systems, greater energy capacities are needed. Recent models by Bathurst and Strbac (2003) and Korpass et al. (2003) suggest that energy storage can increase the market value of wind power.

Table 4-2 Performance and cost parameters for energy storage technologies (Schoenung et al. 1996).

	Units	Flywheels	Batteries	Pumped Hydro	CAES	SMES	Capacitors
Performance							
Efficiency	%	~ 90	~ 75	~ 75	~ 70 + fuel	~ 95	~ 90
Energy Range	various	1 MJ-5 MWh	0.5-50 MWh	0.5-10 GWh	50-5,000 MWh	0.5-1,500 MWh	1-10 MJ
Power Range	MW	1-10	0.5-100	500-3,000	100-1,000	10-1,000	1-10
Costs							
Energy Capital	$/kWh	100-800	200	~ 15	10	3000	3600 $/MJ
Power Capital	$/kW	220	300	600	425	300	300
Operating costs	$/kW/yr	7.5	1.55	4.3	1.35	1	5% capital
Variable costs	¢/kWh	0.4	0.5	0.43	0.1	0.1	~ 0

CAES - compressed air energy storage
SMES - superconducting magnetic energy storage

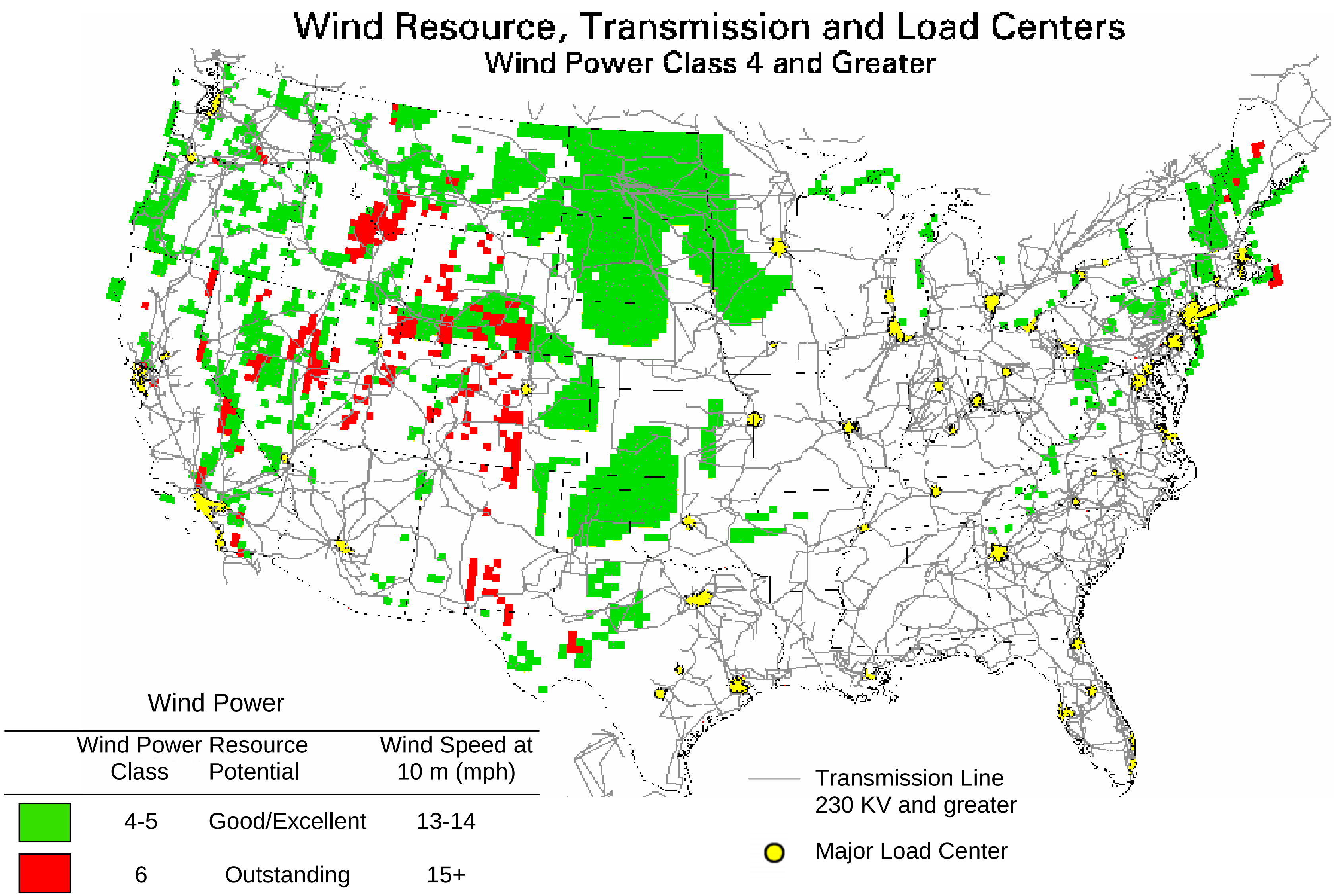


Figure 4-2 Class 4-6 Wind regions, transmission lines and load centers (Goldman 2003).

Of the technologies included in Table 4-2, only pumped hydrogen and CAES are capable of high power outputs over extended periods of time. Other high energy capacity storage options are hydrogen (discussed below) and flow batteries (see: Price, 2000, and Norris et al., 2002). Two storage options that appear well suited for integrating large percentages of wind power into electricity grids are CAES and hydrogen storage inside wind turbine towers. Each of these is discussed in detail below.

4.3.1 Compressed air energy storage

This type of energy storage relies upon the capacity of air to be compressed like a spring, typically in large underground caverns for utility scale storage systems. To utilize the energy stored in compressed air, it is released through a turbine/generator system, displacing energy otherwise needed for the turbine compressor. CAES systems are not in widespread use in the U.S. or overseas. One small system is in operation in Alabama (110 MW) and a large system is planned for Ohio (2,700 MW). However, this modest level of development is not due to lack of technological maturity, as the major components of a CAES system (compressors, turbines and generators) are all mature technologies. (Shepard and van der Linden, 2001; Schaber et al., 2004).

Figure 4-3 portrays a simplified schematic of a CAES system, with a limestone cavern as the storage reservoir and a motor and compressor filling this reservoir during off peak production periods. Unlike traditional gas turbine and combined cycle systems, the compressor in a CAES system is separate from the turbine. In a CAES system, pressurized air (~1,500 psi) used in the turbine is recovered from storage rather than being produced by a compressor powered by the turbine. As shown in Figure 4-3, pressurized air from the storage formation is preheated by exhaust heat from the turbine in a recuperator, and is then passed through a series of turbines, first a high pressure turbine and then a low pressure gas turbine where a fuel mixture is combusted. As indicated in the Figure, power from the generator is fed back into the grid system during peak demand periods. This configuration is distinct from a traditional combined cycle gas turbine, where the turbine powers both the compressor and the generator, and gas turbine exhaust heat is recovered in a boiler to produce steam for a second power cycle (Shepard and van der Linden, 2001). In a variation on the CAES configuration shown in Figure 4-3, a special clutch can be employed to allow the turbine/generator system to operate in reverse to compress the stored air. For each kWh produced by the CAES system, 0.75 kWh of compression energy and 4200 kJ of fuel are required (Stambler, 1988). For a more detailed description of CAES systems, see Najjar and Zaamout (1998).

One of the uncertainties in applying CAES for wind power storage is the adequacy or appropriateness of storage reservoirs. Three types of storage reservoirs typically considered for CAES systems include: naturally occurring aquifers, solution-mined salt caverns, and mechanically formed reservoirs. Naturally occurring aquifers are the most economical reservoirs. Williams has reported that 85 percent of U.S. land area has salt, rock or aquifer formations suitable for CAES systems (2002).

The value of CAES depends on its ability to improve the market value of produced electricity. The main cost advantage of CAES for wind systems is its potential to provide reliable baseload power over long periods of time. An additional cost advantage is the ability to in increase the average transmission line capacity, an advantage particularly important for dedicated lines connecting wind farms to distribution or other transmission systems. Cost advantages would also result from the capacity to supply power during peak demand periods. Taking these cost advantages into account, CAES has the potential to facilitate the integration of wind energy into transmission systems at very low costs (Williams 2002; cf. DeCarolis and Keith, 2005).

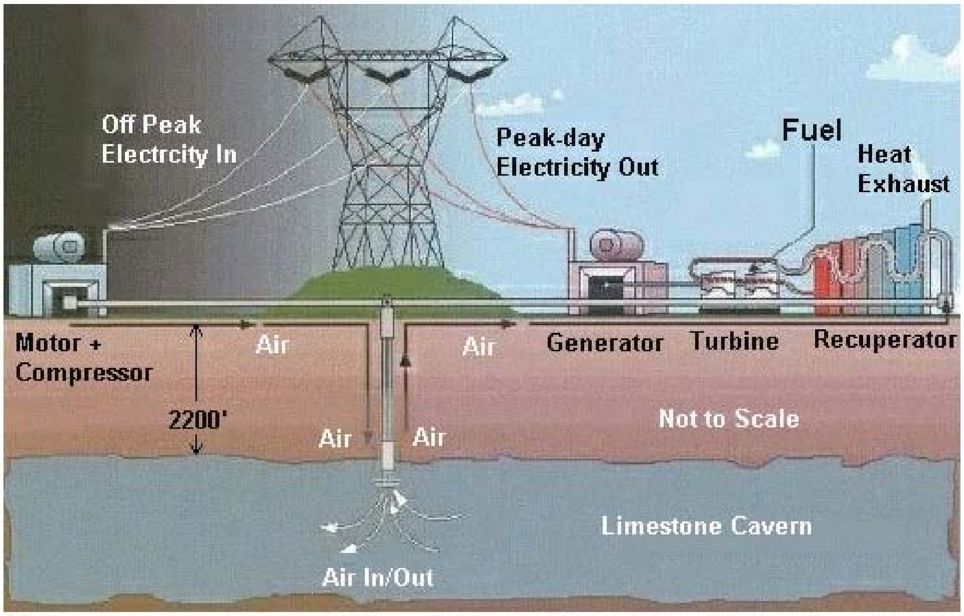


Figure 4-3 Schematic of a compressed air energy storage system (ESA, 2004).

Williams (2002) reports cost estimates for CAES from two studies (Cavallo, 1995, Shainker et al., 1993), and determines that a cost penalty ranging from \$0.005 to \$0.01/kWh would be required to improve the capacity factor of a wind farm from 36 to 90 percent. The capital costs of CAES storage reported by Schoenung et al. (1996), shown in Table 4-2, are similar to those cited by Williams (\$350-\$450/kW). This increased capacity factor would have a significant effect on the cost of transmission, as well as the ability to integrate wind power into existing grids with multiple power sources.

4.3.2 Hydrogen production by electrolysis

A second method of storing wind power is to convert it into hydrogen by way of electrolysis. The hydrogen produced can be either converted back into electricity, by way of a fuel cell, for example, or utilized in an alternative high fuel quality application, such as in automobiles. Hydrogen storage methods are numerous, but most tend to be expensive, as are current fuel cell systems. With an optimistic round-trip efficiency of a fuel cell/electrolyzer system of about 40 percent (assuming 90 and 45 percent efficiency for the electrolyzer and fuel cell, respectively), wind-hydrogen systems do not always compare favorably on an efficiency or economic basis with other storage options, such as those listed in Table 4-2. A recently proposed strategy to reduce the cost of storage in wind-hydrogen systems is to use turbine towers as storage vessels (Fingersh 2003, Kottenstette and Cotrell 2003). This innovative wind-hydrogen storage option is examined in more detail in Section 4.3.3. For examples of models of other renewable, electrolytic hydrogen storage systems, see Wen-Jei and Aydin (2001) and Vanhanen and Lund (1995).

Hydrogen production via electrolysis was a major conversion technology before production of hydrogen from natural gas became widely adopted. Today, electrolysis is used in a limited range of applications, and typically where small amounts of very pure hydrogen are required, such as semiconductor manufacturing, hydrogenation of food products and the refining of high purity metals. Padró and Putsche report that about 4 percent of the global hydrogen supply is from electrolysis (1999). Due to the relatively high cost of electricity production, electrolysis tends to be more common in countries without access to cheap natural gas.

The suffix '*-lysis*' is from a Greek stem meaning 'to loosen' or 'split up', and the electrolysis process involves the separation of a compound into its elements by an electric current. In the case of electrolytic hydrogen production, water is the compound and hydrogen and oxygen are the separated elements. The present discussion focuses on traditional alkaline electrolysis systems, which used KOH as the conductive electrolyte. In addition to alkaline systems, several advanced electrolytic hydrogen production technologies are being pursued, including reversible polymer electrolyte membrane (PEM) fuel cell systems and high temperature steam electrolysis. Water dissociation methods closely related to electrolysis include: water thermolysis, water photolysis, photoelectrochemical water cleavage, photobiological water cleavage, and thermochemical cycles. Each of these dissociation methods involve the generation of hydrogen from a water substrate, though the types of primary or secondary energy converted may vary.

Figure 4-4 is a schematic of a simple alkaline electrolysis system, where a direct electric current from a battery is conducted across two electrodes submerged in a container of water, producing hydrogen gas at the cathode and oxygen gas at the anode. As shown, the circuit is closed by the migration of hydroxyl ions (OH^-) produced at the cathode through a porous diaphragm to the anode. Upon reaching the anode, the hydroxyl ions are oxidized in the following half reaction:

$$2OH^-{}_{(aq)} \rightarrow H_2O_{(l)} + \tfrac{1}{2}O_{2(g)} + 2e^- \qquad (9)$$

which occurs on the catalytic surfaces of the anode (usually nickel), releasing electrons into the electric circuit through the conductive anode materials. Excess water is produced in this reaction, resulting in a net migration of water through the diaphragm to the cathode side of the reactor, where it is reduced in the following half reaction:

$$2H_2O_{(l)} + 2e^- \rightarrow 2OH^-{}_{(aq)} + H_{2(g)} \qquad (10)$$

Hydrogen produced by this catalytic reaction bubbles up through the reactor as a diatomic gas (H_2). The combined result of these anode and cathode half reactions is the splitting of water to form hydrogen and oxygen gases:

$$H_2O_{(l)} \rightarrow H_{2(g)} + \tfrac{1}{2}O_{2(g)} \qquad (11)$$

The conversion efficiency of the electrolysis process can be defined as the ratio of the required input electricity to the energy content of the hydrogen produced. Assuming constant temperature and pressure, the energy required is the Gibbs free energy, ΔG. Following Faraday's first law of electrolysis – that the quantity of product formed is directly proportional to the amount of electricity conducted – the amount of electric charge required to complete Equation 11 is nF, with n being the number of electrons (equal to 2), and F being Faraday's constant (96,485 Coulombs per mole). The Gibbs free energy is the energy needed to move this quantity of charge through a *reversible potential difference*, E_{rev}, under isothermal and constant pressure conditions:

$$\Delta G = -nFE_{rev} \qquad (12)$$

Under standard conditions (25° C and 1 bar), the Gibbs free energy for Equation 11 is 237.178 kJ/mol, and is positive because the reaction is non-spontaneous. The Gibbs free energy represents the maximum possible useful work, or reversible work, under constant pressure and temperature conditions. This corresponding to a reversible voltage of 1.23 volts:

$$E_{rev} = \frac{237.178\ kJ\ mol^{-1}}{-2 \cdot 96{,}485\ C\ mol^{-1}} = 1.23\ volts \tag{13}$$

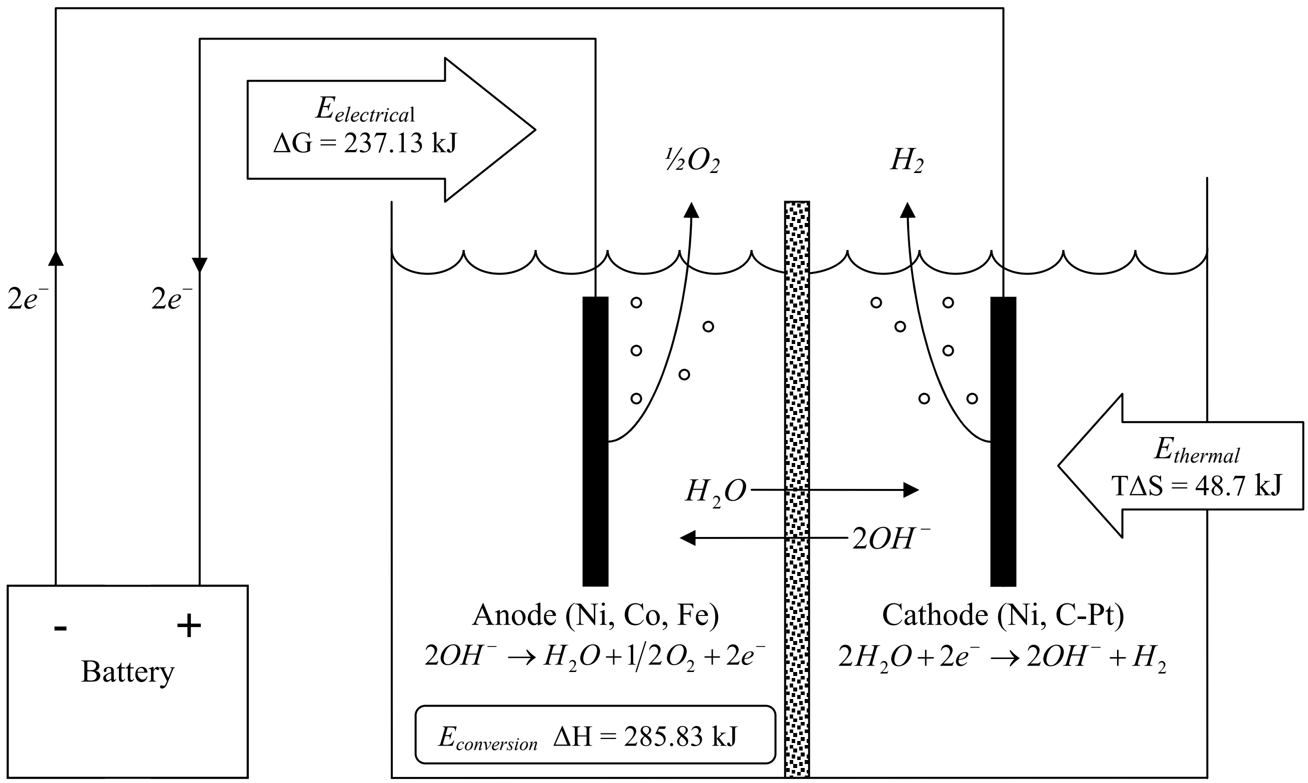


Figure 4-4 Schematic of the electrolysis process.

However, the total amount of energy needed for splitting water is equal to the heat of combustion of hydrogen, or change in enthalpy, *ΔH*. The total energy demand for electrolysis can be expressed by a *thermoneutral potential difference*, E_{tn}:

$$E_{tn} = \frac{\Delta H}{nF} \tag{14}$$

where the standard enthalpy of 285.83 kJ/mol corresponds to a voltage of 1.481 volts. In an ideal system under standard conditions, applying a voltage of 1.481 volts would produce hydrogen and oxygen isothermally, that is, without producing waste heat. This system would have a thermal efficiency of 100 percent. However, applying a voltage as low as 1.23 volts (the reversible potential difference) could still generate hydrogen and oxygen by absorbing heat from the surrounding environment. This is seen in the relationship between the Gibbs free energy and the enthalpy:

$$\Delta G = \Delta H - T\Delta S \tag{15}$$

where the Gibbs free energy takes into account a change in entropy, ΔS, and T is the temperature of the surrounding environment. For a reversible process, $T\Delta S$ is the heat demand of the system, and would be equal to 48.7 kJ/mol when applying a voltage equal to the reversible potential difference. In this case, the electrical energy required to drive the reaction would be less than the combustion energy of hydrogen ($\Delta G < \Delta H$), resulting in an electricity-to-hydrogen efficiency of 120 percent. In this ideal system, the electrolysis reactor would be operating as a refrigerator, extracting heat from its surroundings. In actual systems, operating voltages are significantly higher than the thermoneutral potential difference of 1.481 volts ($\Delta G > \Delta H$), and the system operates at an efficiency less than 100 percent while releasing waste heat into the environment.

The electricity-to-hydrogen or thermal efficiency of an electrolytic cell can therefore be defined as the ratio of the thermoneutral potential difference to the operating voltage of the cell:

$$\eta_{elec} = \frac{E_{tn}}{E_{op}} \tag{16}$$

where, under ideal and standard conditions, the operating voltage E_{op} would be equal to the reversible voltage, E_{rev}, resulting in an efficiency of 120 percent (1.481 V/1.23 V). Typical conversion efficiencies for alkaline electrolysis systems range from 70-85 percent, though advanced and fuel cell systems can approach 90 percent.

Conventional alkaline electrolysis

Commercial alkaline systems typically involve temperatures between 70 and 90˚C and an electrolyte concentration of 30 percent KOH, providing approximately the maximum conductivity (Scott 1995, 273). Alkaline electrolyzers are typically manufactured with bipolar designs but some have unipolar designs. Both designs are compared in Figure 4-5. The unipolar configuration involves a single diaphragm and two electrodes. The biopolar configuration involves two diaphragms on either side of a common bipolar electrode that serves as both an anode and cathode to two additional electrodes. The insulator shown at the bottom of the common electrode prevents ion transfer between the two sides of the reactor.

Diaphragms for alkaline systems are typically made of asbestos, cathodes are commonly made of steel, and anodes are usually nickel coated steel. Electrodes are manufactured with rough catalytic surfaces to provide ample activation sites for the half reactions discussed above. The reactor itself must be constructed from a corrosion resistant material such as carbon steel. Water cooling is typically used to remove heat from the reactor, and water must be added to the KOH solution as a feedstock at the same rate that hydrogen and oxygen are removed as gases. Other components of an electrolysis system typically include a AC/DC rectifier, a deionization reactor for the incoming water supply, and dehumidifiers for the resulting oxygen and hydrogen gas streams.

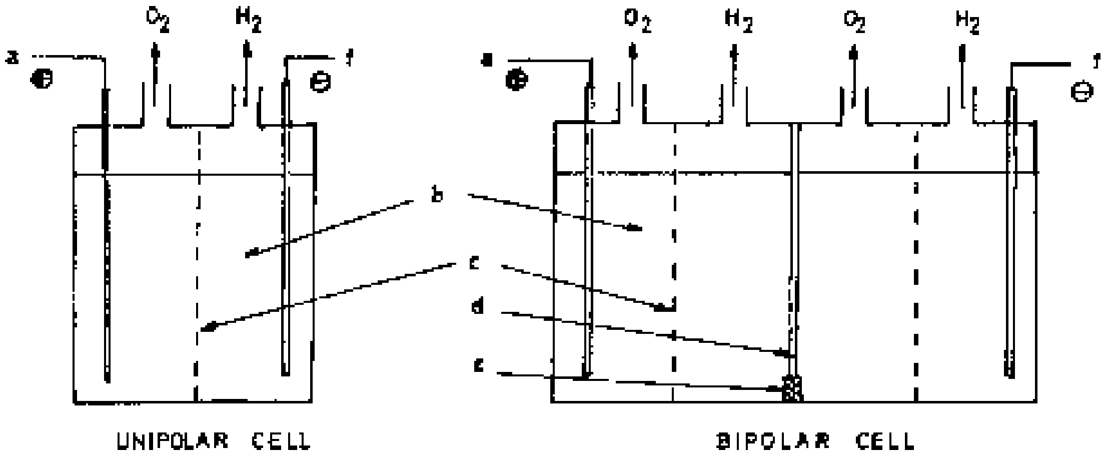


Figure 4-5 Comparison of unipolar and bipolar cell components: a) anode, b) electrolyte, c) diaphragm, d) bipolar electrode, e) insulator, and f) cathode (Yildiz and Pekmez, 1995).

Typical alkaline electrolysis system conversion efficiencies range from 70 to 80 percent, and advanced PEM systems are expected to achieve up to 90 percent or higher. Stoll and von Linde (2000) report typical conversion efficiencies for commercial alkaline electrolysis systems of 4.2 to 5 kWh of electricity per Nm^3 of hydrogen, depending on the size, type and condition of the production plant. The authors state that a typical conversion rate is 4.6 kWh/Nm^3, corresponding to an efficiency of 77 percent on a HHV basis (65 percent for LHV). In their assessment of long-term (2015), wind-electrolysis production systems, the H2A study group assumed an average conversion efficiency of 71 percent (LHV), and a capital cost of $300 per input kW (Mann, 2004).

High pressure, high temperature electrolysis

The voltage required for the dissociation of water can be reduced by increasing the reactor temperature. High temperature systems such as the German HOT ELLY system have achieved 92 percent conversion efficiency, a significant improvement over the highest low temperature system efficiencies of around 85 percent (Donitz et al. 1990). Electrolysis at elevated temperatures is referred to as steam electrolysis, as the water substrate is not maintained in a liquid phase. In addition to increased conversion efficiency, high pressure systems have the advantage of delivering pressurized hydrogen, which can result in reduced system capital costs in cases where compressed hydrogen is the intended product.

A novel high temperature steam electrolysis system is under development at Lawrence Berkeley National Laboratory in which natural gas is instead of air is used within the reactor. The presence of natural gas and water rather than air at the cathode reduces the voltage required to split water molecules, thereby increasing the conversion efficiency. The natural gas reacts with oxygen produced in electrolysis, resulting in hydrogen and carbon dioxide gas products. In essence, this process reduces electricity consumption (by approx. 90 percent) by substituting natural gas for electricity, a tradeoff that reduced fuel costs. In addition, the units can be modular and can produce a pressurized hydrogen product (Pham, 1999; Pham et al., 2002).

4.3.3 Storing hydrogen in wind turbine towers

Storage of wind power as hydrogen could offer many of the same benefits as CAES systems. For long-term applications, underground storage of hydrogen in caverns has been proposed (Vanhanen and Lund 1995). However, the economics of underground hydrogen storage would probably not be as favorable as

CAES if the goal is to provide reliable baseload power. A smaller scale and possibly near-term storage option is to store hydrogen produced from wind power inside the towers of wind turbines. This concept has been explored in a number of recent DOE studies (Fingersh 2003, Kottenstette and Cotrell 2003). The concept involves co-locating an electrolysis system with the wind turbine to generate hydrogen using excess wind power, storing the hydrogen within the turbine tower, and converting the hydrogen back into electricity on demand via a fuel cell or combustion engine/generator. The main advantages of this concept are that costs are reduced because several components provide multiple functions (tower, generator, power electronics and controller), and the tower or group of towers becomes a dispatchable power source capable of supplying peak power. Figure 4-6 shows a potential configuration for hydrogen storage in a wind turbine tower.

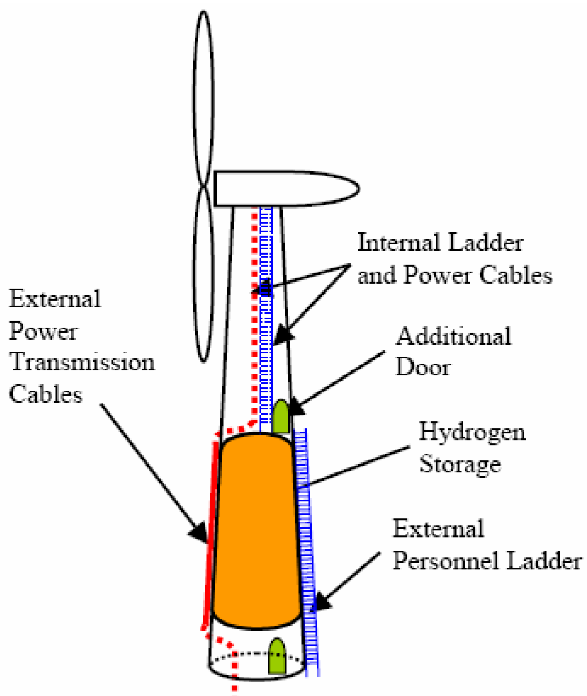


Figure 4-6 Potential configuration for hydrogen storage in a wind turbine tower (Kottenstette and Cotrell 2003).

Fingersh (2003) estimates that an 85 meter tall 1.5 MW turbine has an internal volume of about 660 to 870 m^3. Assuming that about one-third of this volume could be used for hydrogen storage, between 400 and 520 kg of hydrogen could be contained in a single tower at a pressure of 10 atm. Assuming an electrolyzer conversion efficiency of 80 percent (49.25 kWh per 1 kg of hydrogen), this storage capacity represents between 13 and 17 hours of turbine operation at its rated power output. Given the temporal power supply fluctuations anticipated for a single turbine, or across an entire wind farm, this is a significant amount of reserve capacity, and would result in improved market value for the wind power system. Kottenstette and Cotrell (2003) determine that utilizing the existing tower structure as part of the hydrogen storage system can reduce storage costs by approximately 30 percent. They report that storage capacity for 940 kg of hydrogen would add $83,000 to the cost of a 1.5 MW turbine, a 44 percent increase to the tower capital cost. The economic efficiency of adding hydrogen storage and conversion capability to a wind turbine or wind farm would depend upon the added market value of the dispatchable power capacity, and would need to be determined on a site and grid-specific basis.

5 Wind Energy Economics

In their recent book on wind energy, Manwell, McGowan and Rogers (2002) suggest the following five major cost components for wind power:

- Availability
- Turbine lifetime
- Operation and maintenance costs
- Capital costs
- Financing costs

The availability of wind energy has improved over time due to an increased ability to extract energy from a range of wind speeds, as well as reductions in downtime due to maintenance needs. Manwell et al. (2002, 428) state that data collected in the United States during the 1990's suggested wind farms were operating at 95 percent availability. More recent data suggests 98-99 percent availability (McGowan and Connors 2000, 173).

In the economic analysis of turbine systems, it has been common practice in Europe to assume a turbine lifetime of 20 years to determine electricity costs. However, U.S. analysis, and the 1997 DOE/EPRI study in particular, has assumed 30 years with the understanding that maintenance regimes would be closely followed. This would involve, for example, approximately 10 overhauls and potential replacement of key components over the life of the turbine.

Improvements in wind technology have resulted in reductions in operation and maintenance (O&M) requirements. The Danish Wind Turbine Manufacturers Association suggests O&M costs of 1.5 to 3 percent of total capital costs (Manwell et al. 2002). As might be expected, studies have suggested that O&M costs tend to increase over the lifetime of the turbine. Lemming et al. (1999) report that O&M cost increases vary with the size and age of the turbine, with annual costs for smaller turbines (150 kW) increasing from 1.2 to 7.0 percent of total wind farm installed costs over their 20 year lifetime, and costs for larger turbines (600 kW) increasing from 1.0 to 4.5 percent of total installed costs over their 20 year lifetime. This gradual increase in O&M costs should be taken into account in any detailed economic analysis of wind energy costs.

In general, capital costs for the turbines in a wind farm compose some 65-75 percent of total project capital costs in developed nations. In a recent presentations, Lyons report capital costs at being 69 percent of the total cost of energy for a typical onshore 50 MW wind farm (2004). The percentage of total project capital attributed to turbines is approximately 30 to 50 percent in less developed countries, due to increased requirements for supporting infrastructure (WEC 1993). However, capital costs are expected to reduce with time due to learning-by-doing and mass production. The DOE/EPRI study assumed a 36 percent reduction in the per kW capital cost of wind turbines between 2000 and 2030 (1997). However, more recent DOE estimates of future capital cost reductions appear to be more conservative (Short et al. 2003, 8). For additional information on learning effects for wind turbines, see Neij (1999), Ibenholt (2002) and Junginer et al. (2005).

Because wind turbines have no fuel costs, unlike conventional power sources, the cost of energy from a wind turbine system is very dependent upon how capital costs are financed. Parsons (1998) reports that the production cost of wind energy could range from 0.027 to 0.049 $/kWh, assuming Class 4 winds and year 2000 wind turbine technology, due to varying project financing assumptions associated with public power companies, investor-owned utilities, and independent power producers. Also see Wiser and Kahn (1996), and Johns (1999).

5.1 Estimating the cost of wind power

There are several approaches to determining costs associated with wind energy. In the following section, the cost of energy (COE) for wind power is determined by taking into account various capital and O&M costs associated with wind power technology and transmission. A production cost approach is employed to project future wind costs, relying on the results of a DOE/EPRI study that projected future costs based upon probable cost reductions in various turbine components (1997). An alternative to this production cost approach is to evaluate avoided costs (i.e., costs that would have been incurred had a wind energy system not been installed). This approach can be very site specific, and is perhaps a better indicator of the market value of wind power if applied to a particular grid. This approach is also consistent with the inclusion of external environmental costs, such as avoided sulfur oxide or carbon emissions, which should be taken into consideration in any comprehensive evaluation of the private and social costs of wind power. By comparison, the production cost approach provides a generic estimate of wind power costs.

5.1.1 Production costs

It is generally assumed that wind resources with Class 4 or stronger winds are capable of producing economically viable wind power. As shown in Figure 2-1, large expanses of Class 4 winds are located in North and South Dakota, Eastern Minnesota, Northern Nebraska and Northwestern Iowa. Another expanse covers Southwestern Kansas and the Oklahoma and Texas panhandles (Elliot et al. 1986).

The theoretical energy derived from these Class 4 winds can be calculated using Equation 7 (page 19), which is a simplified expression for the average power production of a wind turbine. Assuming a turbine with a blade diameter of 50 m, the swept area would be $\pi D^2/4$, or 1,963 m^2. This turbine would have a rated power of about 892 kW, assuming 2.2 m^2 of swept area per kW of rated power (Taylor, 1996, 302). Assuming a hub height of 50 m, the energy flux would be about 450 W/m^2 in Class 4 winds. Using Equation 7, we determine that the average power output of this turbine would be 230 kW. Assuming an availability of 97 percent, the annual yield would be about 2.0 GWh per year. Assuming eight of these turbines could be located on 1 km^2 of land with no reduction in annual yield, for example, spaced 10 diameters apart in the direction of the wind and 5 diameters apart in the traverse direction (Grubb and Meyer 1993, 171), the total annual production per land area would be 16 million kWh per km^2.

The year 2000 capital installation cost for this type of wind turbine has been estimated at $946 per rated kW (Cavallo et al. 1993, Table 6; Taylor 1996). However, capital costs are expected to drop, and performance is expected to improve. The 1997 DOE/EPRI study projected that capital costs will drop to as low as $635/kW by 2030, as shown in Table 5-1. The study also assumed that tower heights would increase, allowing greater wind speeds to be captured. However, the study did not increase rotor diameters. For the present analysis, wind speeds increase with height at the same rate as in the DOE/EPRI study, but rotor diameters are increased from 50 to 65 m. Turbine rated power is determined using DOE/EPRI power to swept area ratios, but annual energy yields are determined using Equation 7. These characteristics are projected for wind turbines between 2000 and 2030, as show in Table 5-1.

Given these assumptions, the cost of producing electricity from wind turbines can be calculated using the following cost of energy equation:

$$COE = \left(\frac{P_R (C_C \cdot CRF + C_{OR})}{E_{AY}} + C_{O\&M} \right) \cdot C_L \qquad (17)$$

Where P_R is turbine rated power (kW), C_C is the capital cost of the turbine ($/kW), CRF is the capital recovery factor (%/yr), C_{OR} is the levelized overhaul and replacement cost ($/kW-yr), E_{AY} is the annual energy yield (kWh/yr), $C_{O\&M}$ is operation and maintenance costs ($/kWh) and C_L is the annual land lease (percent of revenue/year). As shown at the bottom of Table 5-1, cost of energy estimates are determined for two capital recovery factors (10% and 15%), and two wind classes (Class 4 and Class 5). As indicated, the average wind power experienced by the turbine increases with hub height within each wind class.

The cost of energy estimates listed in Table 5-1 are shown graphically in Figure 5-1. Production costs drop by approximately $0.015/kWh between 2000 and 2010, but only small reductions are achieved between 2010 and 2030. Costs below $0.04/kWh are achieved by 2020 for three of the four wind turbines described, and the cheapest wind power produced is nearly $0.025 by 2030. As indicated, financing can have as much influence on production costs as wind speeds. The difference in the cost of energy for a capital recovery factor of 10 or 15 percent is greater than the difference between installing a turbine in Class 4 or Class 5 wind regions. It should be noted that the cost reductions indicated here are derived from a variety of technological changes, details of which are described in the 1997 DOE/EPRI report.

5.1.2 Transmission Costs

The largest expanses of inland wind resources in the United States are located far most large electricity demand centers, which tend to be clustered along the coasts. However, some existing transmission lines do pass through expanses of Class 4 wind resources. As discussed previously, researchers at NREL determined that 401 GW of wind capacity is within 20 miles of existing transmission lines (assuming Class 4 winds and a tower height of 30 m). However, the researchers did not conclude what portion of these lines would require additional transmission capacity investment (Parsons et al., 1995). One might assume that near-term smaller wind farms could be located relatively close to existing transmission lines, while larger wind farms, installed in the more distant future and relying upon more economical turbines, might be located at prime wind areas further from transmission lines. Ideally, some optimization would be attained by locating farms within prime wind resource areas (resulting in larger annual yields) and locating farms close to existing transmission lines or large urban centers (resulting in lower transmission costs). Moreover, some transmission lines could be upgraded to higher capacities, which would require lower capital costs than the construction of new lines.

Lacking a comprehensive review of the most desirable wind sites, combined with a lack of information on the costs required to either upgrade existing lines or construct new transmission lines for each site, the present analysis proposes two generic but representative transmission cost estimates. The two cost estimates, outlined in Table 5-2, represent a likely range of potential future transmission costs for inland wind farms. The first estimate represents the installation of new AC transmission lines over a distance of 100 miles. This cost is representative of transmission costs for wind farms that could be installed in the near term and are close to either urban centers or existing transmission lines. These wind farms are likely to be installed when production costs per kWh are still high relative to future projected costs, and regional demand for wind energy is relatively small. The second estimate represents the installation of new HVDC transmission lines over a distance of 750 miles (for comparison, the *driving* distance between Bismark, ND, and Chicago, IL, is about 820 miles). Analyses have suggested that the breakeven point at which the costs of AC and DC transmission are equal is around 250 to 500 miles, depending upon the load (Hingorani, 1996, Hauth et al. 1997).

Table 5-2 shows transmission cost estimates based on three utilization rates: 30 percent, corresponding to the expected capacity factor for a wind farm, 61 percent, corresponding to the national average in 1992 (Barnes et al. 1995, xxi), and 80 percent, a capacity that could only be achieved by wind power with use of high-capacity electricity storage methods (see Section 4.3) or some other grid integration methods. Costs based on utilization rates higher than 30 percent would also apply for lines carrying multiple loads, for example, more than one wind farm or a wind farm coupled with other power sources. In the present analysis, costs for the two transmission scenarios are directly proportional to the rate of utilization.

Table 5-1 Projected characteristics and performance metrics for horizontal axis wind turbines.

Cost Factor	units	Year 2000	2005	2010	2020	2030
Turbine Capital Cost						
Installed Cost	\$/kW	\$1,000	\$750	\$720	\$675	\$635
Total Capital Cost	\$/turbine	\$561,438	\$719,511	\$802,584	\$915,389	\$885,539
Turbine Characteristics						
Hub Height	m	60	70	80	90	100
Rotor Diameter	m	46	55	60	65	65
Swept Area	m^2	1,661	2,375	2,826	3,317	3,317
Rated Power	kW	561	959	1,115	1,356	1,395
Rated Power/Swept Area	W/m^2	338	404	394	409	420
Cost of Energy (COE)						
O&M	\$/kWh	\$0.008	\$0.005	\$0.005	\$0.005	\$0.005
Overhaul	\$/kW-yr	\$4.3	\$3.6	\$3.1	\$2.2	\$2.1
Land Lease	%/yr	3.0%	2.5%	2.5%	2.5%	2.5%
Class 4 Winds						
Average Wind Power	W/m^2	400	434	448	465	474
Energy per swept area	kWh/m^2	884	959	989	1027	1047
Annual Yield	GWh/yr	1.5	2.3	2.8	3.4	3.5
COE (CRF = 15%)	*\$/kWh*	*\$0.069*	*\$0.055*	*\$0.051*	*\$0.047*	*\$0.045*
COE (CRF = 10%)	*\$/kWh*	*\$0.049*	*\$0.039*	*\$0.036*	*\$0.034*	*\$0.032*
Class 5 Winds						
Average Wind Power	W/m^2	500	543	560	581	592
Energy per swept area	kWh/m^2	1105	1199	1236	1283	1309
Annual Yield	GWh/yr	1.8	2.8	3.5	4.3	4.3
COE (CRF = 15%)	*\$/kWh*	*\$0.057*	*\$0.045*	*\$0.041*	*\$0.039*	*\$0.037*
COE (CRF = 10%)	*\$/kWh*	*\$0.041*	*\$0.032*	*\$0.030*	*\$0.028*	*\$0.027*

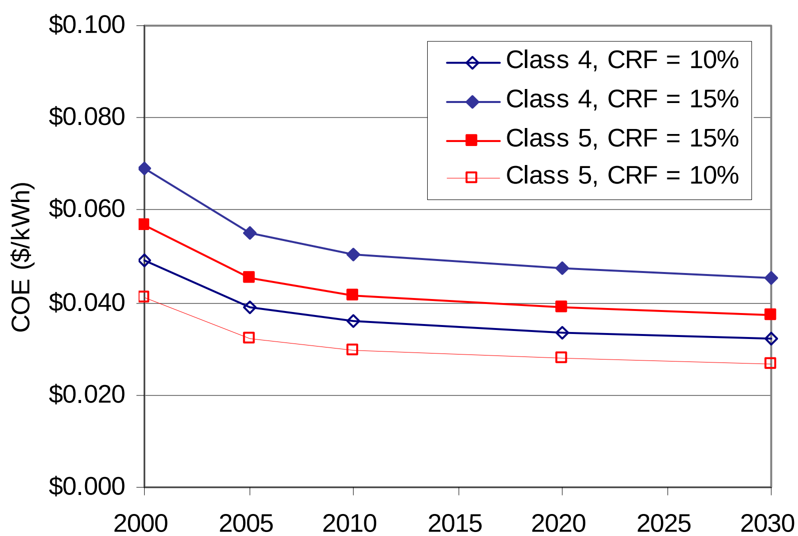


Figure 5-1 Estimated Cost of Energy (COE) for electricity produced from wind turbines.

Many other factors could significantly alter transmission costs. Hauth et al. (1997) report that total capital costs for transmission lines can vary from $250,000 per mile in sparsely populated areas to over $1,000,000 per mile in more developed areas. Cost estimates for the case studies in Barnes et al. (1995) suggest a similar range, from $482,000 to $1,573,000 per mile for 1 to 3 GW systems ranging from 300 to 680 miles in length. Altering the distances of the transmission lines shown in Table 5-2 would also affect transmission costs. For example, if the 408 kV DC bipole line were 500 rather than 750 miles in length, assuming the same average load of 600 MW, the resulting transmission cost would be $0.0133/kWh rather than $0.0179/kWh, a 26 percent reduction. The cost estimates shown in Table 5-2, though representative of likely wind transmission costs, could vary significantly depending upon the logistics and geography of a particular wind project. Note that the most expensive 750 mile transmission costs are roughly half the projecting production costs for wind power in Figure 5-1. However, if integration methods such as CAES storage are capable of increasing transmission line utilization to 85 percent, transmission costs would drop to roughly 20 to 25 percent of production costs projected for 2030.

Table 5-2 Transmission cost analysis for two representative transmission lines.

Cost Factor	**units**	**Transmission Type**					
		345 kV single circuit AC			**408 kV DC bipole**		
Distance	miles	100	100	100	750	750	750
Thermal load	MW	1,000	1,000	1,000	2,000	2,000	2,000
Average load	MW	300	610	850	600	1,220	1,700
Average Utilization	(Ave./Thr.)	30%	61%	85%	30%	61%	85%
Capital Costs [a]							
Line capital and land cost	$\$10^3$/mile	$750	$750	$750	$852	$852	$852
subtotal lines, etc.	*million $*	*$75*	*$75*	*$75*	*$639*	*$639*	*$639*
Substations (2)	$/kWth	$20	$20	$21	$120	$120	$121
subtotal substations	*million $*	*$20*	*$20*	*$21*	*$240*	*$240*	*$242*
Total capital cost	million $	$115	$115	$117	$999	$999	$1,002
Cost per GW-mile	$\$10^6$/GW-mi	$0.6	$0.6	$0.6	$0.7	$0.7	$0.7
Losses							
Line losses per mile	MW/mile	0.042	0.174	0.338	0.046	0.192	0.373
Total line losses	MW	4	17	34	35	144	280
Substation losses	% Ave. Load	1.0%	1.0%	1.0%	2.0%	2.0%	2.0%
Total average losses	% Ave. Load	2.4%	3.9%	5.0%	7.8%	13.8%	18.4%
Economic Assumptions							
Interest rate	%/year	9.0%	9.0%	9.0%	9.0%	9.0%	9.0%
Lifetime	years	30	30	30	30	30	30
Capital recovery factor (CRF)	%/year	9.7%	9.7%	9.7%	9.7%	9.7%	9.7%
Insurance & retirement	%/year	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%
Total Costs per kWh							
subtotal: line capital	*$/kWh*	*$0.0029*	*$0.0014*	*$0.0010*	*$0.0130*	*$0.0069*	*$0.0052*
subtotal: substation capital	*$/kWh*	*$0.0008*	*$0.0004*	*$0.0003*	*$0.0049*	*$0.0026*	*$0.0020*
Total Transmission Costs	**$/kWh**	**$0.0037**	**$0.0018**	**$0.0013**	**$0.0179**	**$0.0094**	**$0.0072**

[a] *Transmission line capital costs reported by Hirst and Kirby (2001) are $0.9 and $1.2 million per mile for, respectively, 345 and 500 kV lines. These quotes include costs for land, towers, poles and conductors, and the authors adjusted these values upwards by 20% to account for substations. The 20% increase for substation costs is removed, and substation cost estimates from Hingorani (1996) and Hauth etal. (1997) are used instead. These estimates are used assuming no cost distinction between AC and DC lines.*
[b] *Losses taken from Hauth et al., 1997, appendix D. Also see: Jacobson and Masters, 2001.*

Disregarding the potential use of energy storage, and assuming transmission occurs with an average utilization rate of 30 percent, the present analysis suggests that wind power could be transmitted 100 miles for $0.0037/kWh, and 750 miles for $0.0179/kWh. Combining these costs with the wind production cost estimates indicated in Table 5-1 and Figure 5-1 results in the following likely scenarios for the year 2010: 1) wind power from Class 4 winds transmitted over a short distance (~100 miles) to either a load center or an existing transmission network for $0.039-$0.054/kWh, and 2) wind power from Class 5 winds transmitted over a long distance (~750 miles) to a load center for $0.048-$0.059/kWh. Table 5-3 shows other permutations of transmission distances and wind classes, with wind production cost estimates for 2010 and 2030. Table 5-4 indicates the same set of scenarios, but assuming that transmission utilization has been raised to 85 percent. This increase in transmission line utilization results in a cost reduction of $0.002/kWh for the 100 mile line, and $0.011/kWh for the 750 mile line (though the additional costs of storage capacity or other integration methods has not been estimated).

Table 5-3. Delivered cost of wind power with 30 percent transmission utilization ($/kWh).

Transmission	Turbine and Wind Resource			
	2010		2030	
	Class 4	Class 5	Class 4	Class 5
100 miles	$0.039 - $0.054	$0.033 - $0.045	$0.036 - $0.049	$0.030 - $0.041
750 miles	$0.054 - $0.068	$0.048 - $0.059	$0.050 - $0.063	$0.045 - $0.055

Table 5-4. Delivered cost of wind power with 85 percent transmission utilization ($/kWh).

Transmission	Turbine and Wind Resource			
	2010		2030	
	Class 4	Class 5	Class 4	Class 5
100 miles	$0.037 - $0.052	$0.031 - $0.043	$0.033 - $0.047	$0.028 - $0.039
750 miles	$0.043 - $0.058	$0.037 - $0.049	$0.039 - $0.052	$0.034 - $0.044

It is interesting to note that with high transmission utilization rates, wind power from Class 4 and 5 winds transmitted over 750 miles in 2030 is comparable to or cheaper than wind power from Class 4 regions transmitted 100 miles in 2010. In contrast, these long-term scenarios (Class 4 or 5 winds at 750 miles in 2030) are not competitive with near-term options (100 miles in 2010) when transmission lines are utilized at only 30 percent capacity. These results suggest that long-distance transmission of wind power, if combined with integration methods such as CAES or hydrogen storage to improve transmission capacity utilization, may be a viable approach to ensuring competitive wind costs as the capital costs of wind turbines decline over time. In addition, the dispatchability of wind systems coupled with storage capacity will increase the market value of delivered wind power. These production and transmission cost estimates are, of course, only one approach to estimating the future costs of wind power. For discussions of various methods of estimating the costs (and benefits) of wind power, see Petersik 1999, Short et al. 2003, Berry 2005, and Kennedy 2005.

6 Conclusion

Wind turbine technology has undergone major advances since the U.S. wind energy boom of the 1980s, resulting in significant cost reductions and rapid growth rates. Studies of wind resources in the United States suggest that ample land area exists where economically competitive wind power can be produced by modern wind turbines. However, additional costs imposed by factors such as transmission investemnts, conflicting land use, difficult terrain and extreme weather patterns will reduce the value of wind power in many of these regions.

Wind turbine designs vary, but most modern applications are horizontal axis turbines with three rotor blades rated from 0.5 to 1.5 MW, with recent prototypes exceeding 2 MW. Improvements in rotor blades and drivetrain components and designs have reduced capital and maintenance costs while improving the reliability and power output of wind turbines. These technological improvements have resulted in significant cost reductions. The delivered cost of wind power is approaching that of electricity produced by many existing power plants, though the potential costs (and benefits) of intermittency, storage and transmission complicate this comparison.

Based on the wind power production costs and electricity transmission costs described in this report, wind turbines located in Class 4 winds near load centers (i.e., ~100 miles) are capable of delivering electricity at a cost of $0.039 to $0.054 per kWh in the near term. For comparison, wind turbines located in Class 4 winds distant from load centers (i.e., ~750 miles) may be capable of delivering electricity at a cost of $0.039 to $0.052 per kWh by 2030, if fluctuations due to intermittency can be dampened economically, and $0.05-$0.063/kWh if fluctuations cannot be dampened.

Two promising storage methods that could be employed to dampen power fluctuations from wind farms include compressed air energy storage and hydrogen storage. In addition to reducing transmission costs by increasing transmission line utilization rates, these storage methods would increase the market value of wind power due to the resulting dispatchability of installed capacity (a benefit not included in the cost estimates above). In general, the cost of electricity from future wind power systems will be sensitive to regional wind resource profiles, further improvements in turbine technology, and transmission costs, as well as a variety of financial conditions and market dynamics.

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