ASYNCHRONOUS LOADS

Wake up, North Wind. South Wind, blow on my garden. Song of Songs 4.16

We saw in the previous chapter that there are at least six distinctly different electrical generators that will allow a wind turbine to operate in a variable speed mode. The electrical output of these generators varies from rather poor quality, in the sense of widely varying frequency and voltage, to utility quality electricity. We saw that it is possible to have a variable speed turbine and still operate in parallel with the utility network. This design option needs to be considered in the design of each new wind system to determine if more energy can be captured from the wind or if overall equipment costs can be reduced.

If the wind energy system actually operates independently of the utility grid, the character of the load becomes very important to proper system operation. The load needs to be able to accept the highly variable power delivered by the turbine if the system is to work satisfactorily. We saw several instances in the previous chapter where battery or resistive loads could accept such variable power readily. There are many other possible loads which may be proposed for wind turbines and some knowledge of their characteristics will be helpful in any system design. Many of these loads can be operated either with or without electricity as an intermediate step. That is, the mechanical output of a wind turbine can be connected directly to a piston pump for pumping water, or the mechanical output can be converted to electrical form, and then back to mechanical by use of an electrical motor. In either case, we need the characteristics of a piston pump to determine the loading effect on the wind turbine. In this chapter we shall consider a number of loads which might be proposed for use on a wind turbine operating independent of the utility network. These loads therefore can be called asynchronous loads, whether they actually require electrical power or if they only use power in a mechanical form.

The vast majority of wind turbines built in the past have been used for non-electrical applications. Water pumping and grain grinding are classical applications of wind power. Wind turbines have been used for many centuries by a number of cultures for watering livestock, land drainage, irrigation, salt production, and supplying household needs.

We might divide these turbines into two basic types: the indigenous and the American multiblade. The indigenous windmills typically use locally available materials such as wood, sail cloth, and bamboo mats. The American multiblade was developed in the late 1800's and has been used widely in North America and Australia. It has a highly evolved design, uses mass produced steel components, and is available on the international export market. The indigenous turbine will only be regionally available. The indigenous turbine is characterized by locally made components, relatively low capital costs, short life, and high maintenance, which may be a good solution in a country which is short on foreign exchange and long on cheap labor.

These machines compete rather well with all the alternatives except an electric utility network with inexpensive coal or nuclear generated electricity. The energy they produce will cost perhaps twice the amount per equivalent kWh as centrally generated electricity but perhaps half the amount of a gasoline or diesel engine to accomplish the same task. Therefore, they look very attractive wherever there is no electrical network, whether it is a developing nation or the interior of Australia. Their use is expected to continue and perhaps even accelerate as design improvements are made and oil becomes less available.

Other mechanical applications are beginning to appear which may use these water pumper designs or may require entirely new machines. There is a need in many places for the pumping of substantial amounts of water, but where the flow can basically follow the availability of the wind. City water supplies and large irrigated farms could use large wind machines with mechanical rather than electrical output. Oil wells can be pumped when the wind is available, since in many cases the electrical pumps only operate a few hours a day on the small oil wells. Wind machines can be used to stir water, either to remove ice for stock watering or to add oxygen for pollution control. They can be used to heat water by mechanically stirring it, and thereby compete with oil for space heating, especially in northern latitudes. They can be used to dry grain by operating fans to move either ambient or slightly heated air through a grain bin.

In addition to these basically mechanical loads, home appliances, heat pumps, electrolysis cells, and fertilizer cells may be considered as possible loads for a wind electric generator. We shall now proceed to briefly examine some of these loads.

1 PISTON WATER PUMPS

The water pump may be man's earliest invention for the substitution of natural energy for muscular effort in the fulfillment of man's needs. The earliest pumps, known as Persian wheels or water wheels, were undershot water wheels containing buckets which filled with water when they were submerged in a stream and which automatically emptied into a collecting trough as they were carried to their highest point by the rotating wheel. The motion of the water in the stream provided the energy for the wheel.

Pumps have evolved into many different types over the centuries. They can be broadly divided into two major categories, the *dynamic* and the *displacement*. Energy is continuously added to a dynamic pump and periodically added to a displacement pump.

The dominant dynamic pump is the centrifugal pump, which includes radial flow and axial flow. Displacement pumps may be either reciprocating or rotary, with a number of subdivisions within each type. The vast majority of pumps in operation today are centrifugal, although reciprocating pumps are still normally used with the American multiblade turbine. We shall discuss the two pump types, the reciprocating and the centrifugal, that appear to have the most application to wind turbine systems, starting with the reciprocating type.

A sketch of a basic water pumping wind turbine is shown in Fig. 1. This sketch was prepared by Aermotor, now a Division of Valley Industries. At one time, the Aermotor turbines accounted for 80-90 percent of all water pumper sales in the United States, hence are likely to appear in old photographs. They are now manufactured in Argentina. Their 1980 sales in the United states were on the order of 3500 units, which was more than the combined production of all electric generating wind turbines in that year.

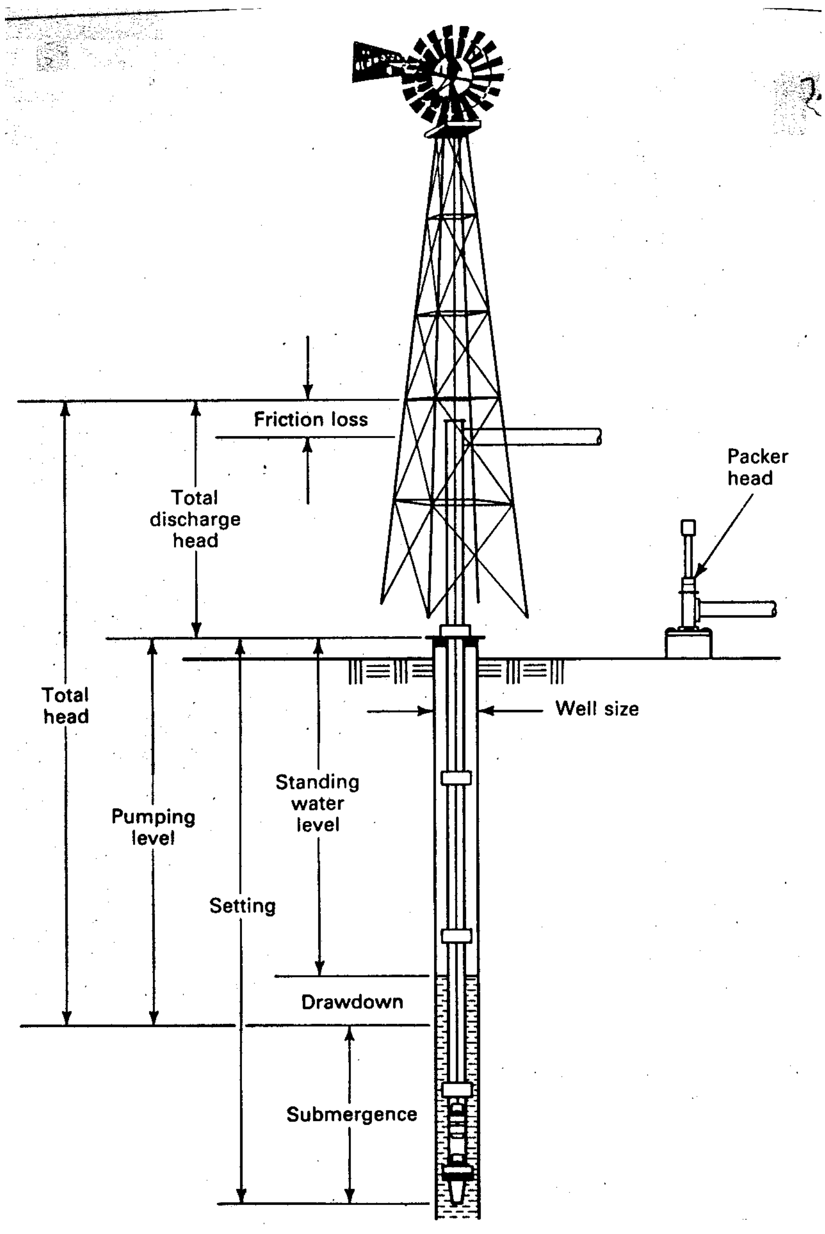

Figure 1: Aermotor illustration of key water pumping terms.

This sketch shows the normal installation with the wind turbine located directly above the well. The turbine is connected to a gear box and crankshaft which converts rotary motion into reciprocating motion on the pump rod. The pump rod enters the well pipe through a packer head which allows the motion of the rod but blocks the water from leaking out. The pump rod then connects to the piston in the pump at the bottom of the well pipe.

The height of the equivalent column of water which is raised by the piston is referred to as the total *head*. It includes the distance from the water level in the well to ground level, from ground level to the height of discharge, and a quantity for friction losses of water flowing in the pipe.

The pumping level is seen to be greater than the standing water level by the amount of *drawdown*. This refers to the decrease in water level during pumping and may vary from an insignificant amount to several meters. Water has to flow back into the well from the subsurface water bearing strata of sand and gravel, called *aquifers*, so the drawdown will be generally proportional to the rate of pumping. The pump is normally located below the maximum draw down level by an amount adequate to ensure proper pump-suction operating conditions. This varies with the piston size, operating speed, flow rate, and pressure, but can be as much as 2 or 3 m.

A picture of a piston pump is shown in Fig. 2. Both the piston and the bottom of the pump have *check valves* which only allow water to flow in the upward direction. When the piston is lifted by the piston rod, the piston valve closes and the piston lifts the entire column of water above it, until water overflows out of the discharge pipe at the top. At the same time, a slight suction is formed under the piston, causing the suction valve to open and water to flow in under the piston. During the next half of the cycle, the piston moves down, causing the suction valve to close and the piston valve to open, so water flows through the piston into position to be lifted during the next half-cycle. The flow of water will be inherently pulsating due to this reciprocal action. This poses little or no problem in filling a tank, but may not be suitable in those applications requiring more uniform pressures and flows.

The piston packing must fit tightly to the cylinder liner to prevent leakage around the piston during the up stroke. The packing will often wear rapidly if the piston moves at a linear speed well above rated, so pump speeds must be limited to reasonable values. Other problems associated with overspeed operation are improper valve action and low suction pressure. If the suction pressure drops too low, the water will vaporize under the piston. This limits the flow and also causes vibration in the pump rod.

The pump size is normally described in terms of the piston diameter, which is the same as the diameter of the inside of the cylinder. The terms piston diameter, cylinder diameter, and pump size are all used interchangeably.

The actual flow to the discharge system is termed the pump *capacity*. The theoretical flow under ideal conditions is called the pump *displacement*. The displacement of the simple pump in Fig. 2 is given by

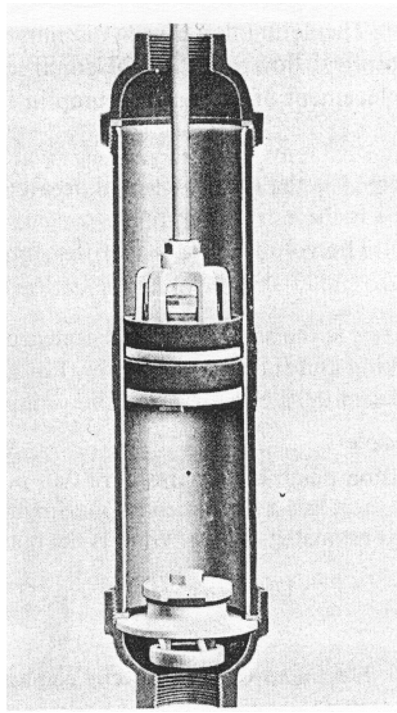

Figure 2: Diagram of piston pump. (Courtesy of Dempster Industries, Beatrice, Nebraska.)

$$D = AL_pf \qquad \mathrm{m}^3/\mathrm{s} \tag{1}$$

where A is the cross sectional area of the piston, L_p is the length of the stroke, and f is the number of pump cycles per second.

The volume capacity of the pump is given by

$$Q_v = D(1 - s) \qquad \mathrm{m}^3/\mathrm{s} \tag{2}$$

where s is the *slip*. The slip is a measure of the losses due to leakage around the packing and through the valves. For a well built pump, slip is probably between 0.03 and 0.05, increasing as the pump wears.

Example

A piston pump has an area A of 0.01 m^2 and a stroke of 0.2 m. The manufacturers data sheet lists a recommended maximum operating speed of 50 cycles per minute. The slip is estimated as 0.05. What is the pump volume capacity?

$$Q_v = D(1-s) = AL_pf(1-s) = (0.01)(0.2)\frac{50}{60}(1-0.05) = 1.58 \times 10^{-3} \ \ \mathrm{m}^3/\mathrm{s}$$

The pump volume capacity can also be expressed as 1.58 L/s, or 5.70 m^3/h, or 25.1 gal/min.

We see that the SI expression for volume capacity is well under unity, while the number of liters per second, cubic meters per hour, and gallons per minute are above unity. This makes the non-SI units slightly easier to remember. However, we shall primarily use the SI units, but will lapse into other units occasionally to help the reader understand those units which have been so widely used. The conversion factors for capacity units are that 1 m^3/s is equal to 35.315 cubic feet per second, usually abbreviated cfs, and is also equal to 15,850.32 U. S. gallons per minute, abbreviated gal/min or gpm. One cubic meter contains 264.17 U. S. liquid gallons and one cubic foot contains 7.4805 U. S. liquid gallons. River flows in the United States have historically been expressed in cfs while pump capacities are more often given in gal/min.

In power calculations we will need to express capacity in terms of mass flow rather than volume flow. If ambient temperature water is being pumped, it is usually sufficiently accurate to assume that one liter of water has a mass of one kilogram, or 1 m^3 has a mass of 1000 kg. We can define a *mass capacity* Q_m kg/s as the mass flow, where $Q_m = 1000Q_v$ if Q_v is expressed in the SI units of m^3/s.

The power input to a pump is given by

$$P_m = \frac{gQ_m h}{\eta_p} \qquad \text{W} \tag{3}$$

where $g = 9.81$ N/kg is the gravitational constant, Q_m is the mass capacity of the pump expressed in kg/s, h is the head in m, and η_p is the pump mechanical efficiency. The quantity $gQ_m h$ can be thought of as an output power

$$P_o = gQ_m h \qquad \text{W} \tag{4}$$

or the energy required to raise a given mass of water a height h, divided by the time required to do it. The mechanical efficiency includes losses in the mechanical friction between the piston packing and the pump cylinder and also the pump rod and the water it moves through. These losses are in addition to those included in the slip. The mechanical efficiency is usually between 0.9 and 0.95 but can be as low as 0.5.

Example

Find the power input to the pump of the previous example if the head is 20 m and the mechanical efficiency is 0.92.

The capacity Q_m is assumed to be 1.58 kg/s. The power input is then

$$P_m = \frac{9.81(1.58)(20)}{0.92} = 337 \ \text{W}$$

If the volume capacity is given in the English units gal/min, which we shall call Q_g, and the head is given in feet, Eq. 3 becomes

$$P_m = \frac{0.1886 Q_g h}{\eta_p} \quad \text{W}$$

$$= \frac{2.529 \times 10^{-4} Q_g h}{\eta_p} \quad \text{hp} \tag{5}$$

The second expression yields power in horsepower rather than watts. Both expressions are strictly valid only for water with a density of 1 kg/L and may need a correction if warm water or other liquids are to be pumped.

Proper operation of the water pumping system requires that the pump size and turbine size be matched to the total head. The multiblade turbines are typically sold in diameters of 6, 8, 10, 12, 14, and 16 ft. Pump diameters are available in quarter inch increments from 1.75 to 5 inches and in one inch increments above 5 inches. If we put a large diameter pump on a small turbine over a deep well, the turbine will not be able to develop sufficient torque to raise the water column to the discharge level. The pump acts like a brake up to some very high wind speed where torque becomes adequate for pumping to occur. On the other hand, if we put a small diameter pump on a large turbine we may get only a small fraction of the possible capacity.

There is an adjustment on the torque arm of many water pumpers which can help optimize a given system to a particular pumping level. By shortening the torque arm, the length of stroke is shortened and less water is lifted per revolution of the turbine. At the same time the force available to the piston rod increases so that a greater head can be pumped. A system designed for a given head at maximum stroke can be adjusted to satisfactorily pump smaller amounts of water if the water table should become lower. This cannot be done dynamically on these simple machines, but once per season should be adequate to compensate for changes in the water table and in the seasonal wind speeds.

We see in Eq. 3 that the required pump power is directly proportional to the capacity. The capacity is directly proportional to the number of pump cycles per unit time and, therefore, to the turbine rotational speed in r/min. The turbine output then varies as the turbine rotational speed while the turbine input, the power in the wind P_w, varies as the cube of the wind speed. We learned in Chapter 4 that the best match of turbine to load occurs when the load input power varies as the cube of the rotational speed. This allows the turbine to stay at the peak of its coefficient of performance curve over a wide range of wind speeds. The piston pump is not an optimum load for a wind turbine since it presents a relatively heavy load at light wind speeds and a light load at strong wind speeds. The inherent speed regulation is poor in that the pump speed theoretically changes by a factor of eight while the wind speed changes by a factor of two. The speed regulation will not actually be that bad because the slip, mechanical efficiency, and turbine coefficient of performance all deteriorate with increasing turbine speed, but there will still be substantial changes in the turbine speed.

Speed is regulated by turning the turbine sideways to the wind in strong winds. The dual task of turning the turbine into the wind in light winds and out of the wind in strong winds is accomplished by some rather ingenious mechanisms which we shall not discuss in detail. These have been perfected over many years of experimentation and work very reliably. A picture of the vane mechanism for the Dempster, another well-known water pumper, is shown in Fig. 3.

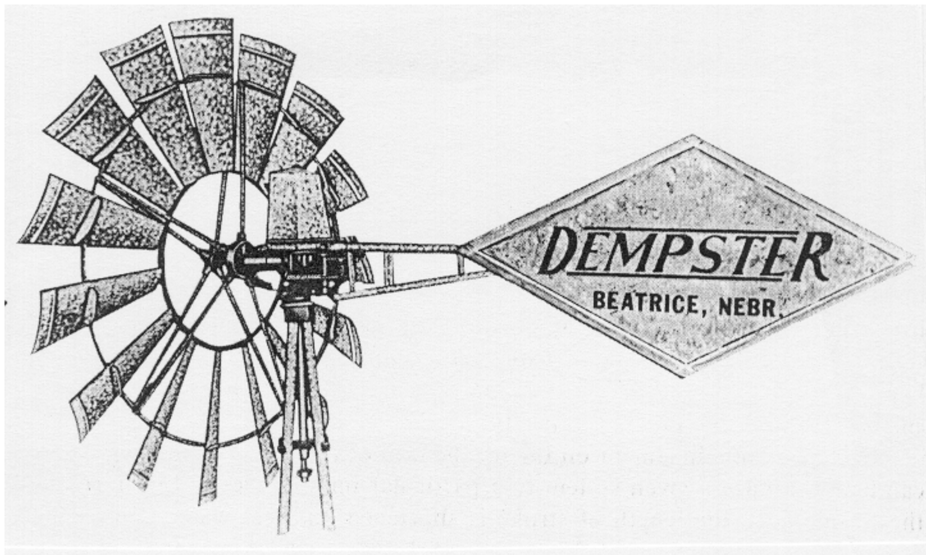

Figure 3: Dempster water pumper. (Courtesy of Dempster Industries, Beatrice, Nebraska.)

We now return to the matter of selecting turbine size and pump size for a given application. Manufacturers data sheets are essential at this point. A typical data sheet for the Dempster water pumper is shown in Table 7.1. This table presents data for five turbine diameters and five cylinder sizes. The original table gave head in feet and capacity in gallons per hour, but these have been converted to meters and liters per second in this table.

We note in the table that the product of head and capacity is almost constant for any given diameter turbine, as would be expected from Eq. 3. The rated wind speed of the Dempster is 15 mi/h (6.7 m/s) so the capacities shown will not be exceeded greatly in stronger winds, due to the speed control mechanism on the turbine.

TABLE 7.1. Dempster Pumping Capacities in a 15 mi/h wind

	Turbine Diameter									
	6 ft; 5-in. stroke		8 ft; 7.5-in. stroke		10 ft; 7.5-in. stroke		12 ft; 12-in. stroke		14 ft; 12-in. stroke	
Cylinder Diameter (in.)	Head (m)	L/s	Head (m)	L/s	Head (m)	L/s	Head (m)	L/s	Head (m)	L/s
2	29	0.137	41	0.205	64	0.167	93	0.217	139	0.185
2.5	19	0.217	27	0.320	42	0.261	61	0.339	91	0.290
3	14	0.309	20	0.463	31	0.375	45	0.487	67	0.416
3.5	10	0.421	15	0.631	23	0.512	33	0.662	49	0.568
4	8	0.549	11	0.820	17	0.668	25	0.864	38	0.742

If we put a larger pump cylinder size on a given turbine, the capacity increases but the maximum head decreases. That is, a 10-ft diameter turbine can pump 0.167 L/s at a head of 64 m or 0.375 L/s at a head of 31 m.

We see also that several different combinations of turbine size and cylinder diameter are possible for a given head. A head of about 20 m, for example, can be pumped by a 6-ft turbine and a 2.5-in. cylinder, a 8-ft turbine with a 3-in. cylinder, a 10-ft turbine with a 3.5-in. cylinder, and a 12-ft turbine with a 4-in. cylinder. The main difference among these combinations is the capacity and, of course, the cost. We have to select the combination which will meet all the load requirements at minimum cost. This will usually require a discussion with the wind turbine distributor and visits with other wind turbine owners in the area who have similar applications.

In these stand alone applications, not only the average wind speed is important, but also the number of consecutive hours or days without wind. The storage tanks must be sized so that storage is adequate for the longest calm period that would be expected. The turbine and pump must then be able to refill the storage perhaps during one day while water is still being withdrawn. The alternative is to go to the well and pump the necessary water by hand, a rather undesirable task. We illustrate some of these ideas in the following example.

Example

You have just inherited 640 acres of grass land in the Kansas Flint Hills. This was part of a large ranch and cattle which grazed this section of land had to go elsewhere to drink. You want to fence it so you have to supply water. The soil is not suitable for building ponds so you have to pump water from a well. The nearest utility line is three km from the well and the cost of installing the line would be $8000 per km if you wanted to use electricity for pumping. You can buy a new water pumper turbine, tower, pump, and stock tanks for less than $6000. The initial capital investment of the wind system is less than 25 percent of the utility system, and maintenance on these proven systems is less than the yearly utility bill would be so you decide to buy a water pumper wind turbine. You estimate your pasture will support 100 yearling steers which drink about 45 liters of water each per day. The pumping head is 22 m. You decide on enough stock tank capacity to last through three calm days, with the turbine and pump sized to fill all the storage in one day of rated wind speeds while the cattle continue to drink. Which size of Dempster turbine and pump listed in Table 7.1 should you choose?

The steers drink a total of 45(100) = 4500 liters of water per day. A three day storage capacity would, therefore, consist of 13,500 liters of stock tank capacity. The turbine needs to pump this 13,500 liters plus the 4500 liters consumed the fourth day for the tanks to be full the end of the fourth day. To pump 18,000 liters in 24 hours requires an average capacity of 0.208 L/s. Table 7.1 indicates that the 6-ft diameter turbine will not pump at this rate for this total head. The 8-ft turbine with a 2.5-in. cylinder will pump over 0.320 L/s at this head, which meets the basic requirements. A larger size would probably waste money and also waste water when the tanks overflow. In fact, a 2.25-in. cylinder might be preferable to the 2.5-in. cylinder since this limits the flow to a smaller amount and also allows pumping to start in lighter winds.

We should not let this example imply that using a water pumper is always the most economical solution to water pumping needs. If the electric utility lines are already in place close to the well, an electric motor will be cheaper to install and operate. The total energy input to the electric motor pumping 4500 liters per day through a head of 22 m for a six month grazing season will be approximately 100 kWh. The cost increment of the installed 8-ft Dempster turbine over an electric pump is perhaps $2000 in 1981 dollars. We shall discuss economics in the next chapter, but even without the fine details, we can see that the unit cost of energy is rather expensive. If the $2000 could draw 15 percent interest, this would be $300 per year. We would be spending about $3 per equivalent kWh for the water pumping system. The utility will charge a minimum amount each year for being connected to the power lines, but this charge plus the charge for the actual energy used should be well under $300 per year. The utility will usually be the best economic choice any time that long stretches of distribution line do not have to be built.

This also points out that energy can have very high prices in small quantities and still be acceptable. It requires perhaps one kWh to pump enough water from a 25 m depth for one cow for one year. If this is at a farm where there are other loads, so the minimum charge for utility connection does not bias the results, the cost of this energy is only a few cents. This amount of energy is small enough and essential enough that a price of several dollars is acceptable if there is no alternative. Studies performed on these small water pumping wind turbines indicate an equivalent energy cost of 20 to 30 cents per equivalent kWh in good wind regimes where all the water can be used1. This was in 1978 when the average cost of electricity in the United States was under 5 cents per kWh. They still make economic sense, however, if relatively small amounts of water need to be pumped from a well one km or more from existing distribution lines.

2 CENTRIFUGAL PUMPS

The piston pumps which we considered in the previous section are generally used only in relatively small sizes. Larger capacity pumps are usually centrifugal. There are many more centrifugal pumps manufactured today than piston pumps, so we need to examine some of their characteristics.

The centrifugal pump can be thought of as a turbine operating in reverse, so the power input will be proportional to the cube of the speed of the fluid passing through the pump, which is proportional to the pump rotational speed. The centrifugal pump, therefore, makes a good load for a wind turbine, at least near the optimum operating point for the pump.

The important operating characteristics of a centrifugal pump are the capacity Q, the head h, the input power P_m, the efficiency η_p, the rotational speed n, and the diameter d of the rotating wheel or *impeller* which actually moves the liquid being pumped. Relationships among these variables are usually expressed graphically. The number of possible graphs is reduced by defining a dimensionless parameter called the *specific speed* n_s which will be the same for all geometrically similar pumps[12, 17]. It is given by

$$n_s = nQ^{0.5}h^{-0.75} \tag{6}$$

The specific speed can be expressed in any consistent set of units. Historically, the units have usually been r/min for n, gal/min for Q, and feet for h. This choice yields specific speeds between perhaps 500 and 10,000 for most pump designs. Farm irrigation pumps would usually have n_s between 1500 and 5000. If the capacity is expressed in m^3/s and the head in m, we get a different specific speed n_s', where $n_s' = n_s/51.64$. We shall use the non-SI version to hopefully help the reader understand existing manufacturers data sheets.

Specific speed allows comparison among pumps in much the same way that the Reynolds number allows comparison among pipe flows and airfoils. It is not intended to be a precise value, so is always rounded off to no more than two significant digits. It is calculated at the best or peak efficiency point of pump operation. That is, when it is desired to calculate the specific speed from performance curves, the capacity and head values for the peak efficiency point are used. If a pump has several stages, the specific speed is calculated on the basis of the head per stage. For a given head and capacity, a higher specific speed pump will operate at a higher speed and will be of smaller physical dimensions.

The peak efficiency of a pump varies with many parameters, but generally varies with specific speed and capacity as shown in Fig. 4. We see that the very largest pumps have a peak efficiency of about 90 percent at a specific speed of between 2000 and 3000. The efficiency will decrease as operating conditions change from the optimum conditions for which the pump was designed. Lower capacity pumps of the same quality of design will also have lower peak efficiencies. A pump of one hundredth of the capacity of the largest unit may have a peak efficiency of 65 percent at a specific speed of 2000. The equivalent quality of design for a pump of the same capacity but built for a specific speed of 500 may have a peak efficiency of only 48 percent. We, therefore, want to choose a pump for any wind driven application that has a specific speed large enough to have a good efficiency.

The efficiencies in this figure are representative of what was considered good practice in the days of cheap energy. We can expect pump efficiencies to improve as more efficient pumps become cost effective with increasing energy costs. Candidate pump efficiencies should be carefully investigated for those applications where total energy costs are significant when

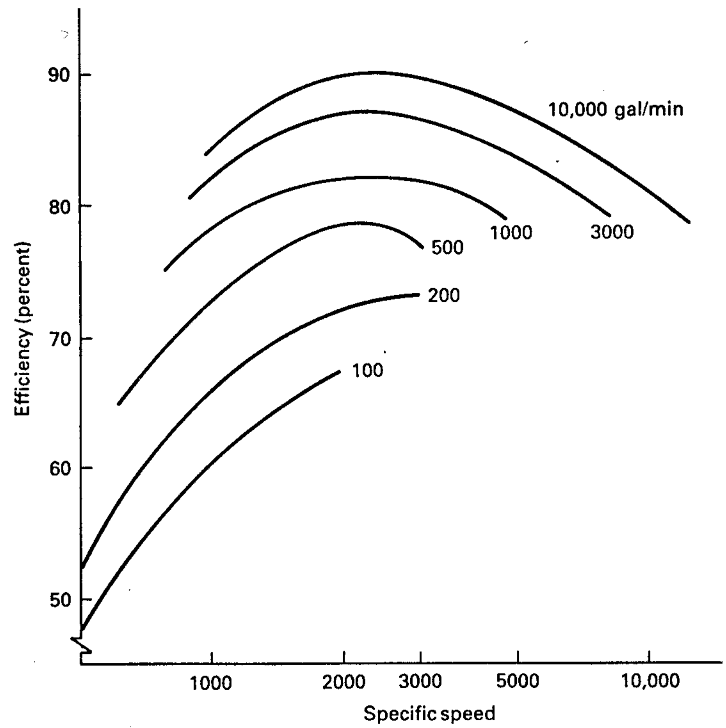

Figure 4: Pump efficiency versus specific speed and size. (From Ref. 2)

compared with initial pump costs.

Pump characteristics at constant speed are usually given as curves of head, efficiency, and input power plotted against capacity, as shown in Fig. 5. We notice in this figure that we have a maximum value of head for zero capacity or flow rate. The head then decreases with increasing capacity until it reaches zero at the maximum capacity. We can think of the head as the height of the column of water which must be lifted by the pump action for water to actually flow. As this height gets greater, the amount of water which the pump action can actually lift against this head will get smaller, finally reaching zero at the maximum head. At this head, the pump impeller is beating against the water in the pump, but no water is actually flowing out of the pump. Instead, the water is flowing around the impeller where it does not fit tightly in the pump housing. The output power, and hence the efficiency, are zero at this point since the capacity is zero. All the power input to the pump is being converted into heat since no useful work is being done. This can be a useful source of heat if we only need to convert mechanical energy directly to heat, but normally would not be a proper way to operate the pump. The heat could boil the water and ruin the pump.

As the head seen by the pump is decreased, more and more water will flow until finally a maximum capacity is reached at zero head. The efficiency, which is proportional to the product of head and capacity, goes through a maximum and decreases to zero at the zero

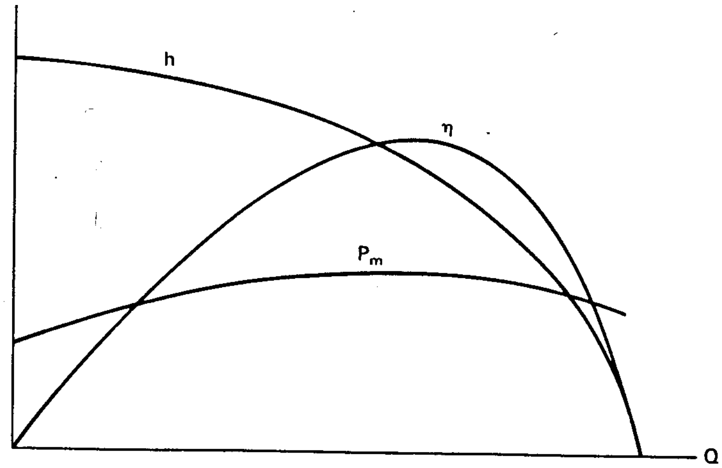

Figure 5: Pump characteristics of head, efficiency, and input power as a function of capacity at constant speed.

head point. The power input is now being used to overcome pumping losses and ultimately appears as a temperature increase in the water flowing out of the pump.

The actual curve of the input power P_m versus the capacity will vary with the specific speed of the pump. At low specific speeds, P_m will increase with capacity. It may peak at around the maximum efficiency point, as shown in Fig. 5, or it may continue to increase until the maximum capacity point is reached. At a specific speed of approximately 4000, the pump power input becomes nearly constant, independent of capacity. At still larger specific speeds, the pump shaft power may actually decrease with increasing capacity.

Suppose now that our pump is operated at some other speed n_2. A new head versus capacity curve will be obtained as shown in Fig. 6. It can be shown that equivalent points on the two curves are found from the relationships

$$\frac{Q_2}{Q_1} = \frac{n_2}{n_1} \tag{7}$$

$$\frac{h_2}{h_1} = \frac{n_2^2}{n_1^2} \tag{8}$$

If the efficiency remains the same at equivalent points, the input shaft power variation is given by

$$\frac{P_{m2}}{P_{m1}} = \frac{n_2^3}{n_1^3} \tag{9}$$

We immediately note that this is of the proper form to optimally load a wind turbine in variable speed operation.

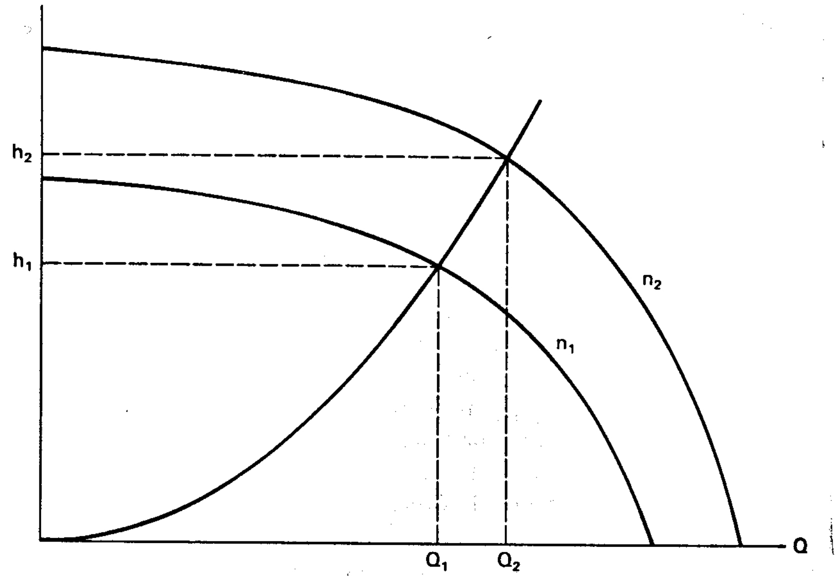

Figure 6: Head versus capacity curves for two different speeds.

Characteristic curves for an actual pump are shown in Fig. 7. The top portion shows the head capacity curves as the impeller size is varied. A given pump housing will accept a maximum size of impeller, but smaller impellers can also be used. A smaller impeller will result in a lower head capacity curve but also requires less input shaft power, as seen by the dashed lines. This can be useful in practical applications where a wind turbine does not have enough power to drive a pump that has been purchased for it[6]. Only the impeller needs to be changed, saving the cost of another entire pump.

Figure 7.7a also shows the pump efficiency for a given impeller. The 8.875-in. diameter impeller will have an efficiency of 65 percent at a head of 74 ft and a capacity or flow rate of 370 gal/min. The efficiency rises to 86 percent at a head of 65 ft and a flow rate of 800 gal/min. It then starts to decrease, reaching 70 percent at a head of 42 ft and a flow rate of 1140 gal/min. Efficiency is above 80 percent for flow rates between 580 and 1080 gal/min. This is a rather efficient pump over a significant range of flow rates.

Also shown on the same figure are a set of dashed lines indicating the input shaft power in *brake horsepower* (bhp). The brake horsepower is the mechanical power $T_m\omega_m$ carried by the rotating shaft and expressed in English units as horsepower. The input shaft power necessary for a given head and capacity can be determined by interpolating between the dashed lines. For example, the 8.875-in. diameter impeller requires 10 bhp at 280 gal/min, 15 bhp at 780 gal/min, and about 17.5 bhp at 1100 gal/min.

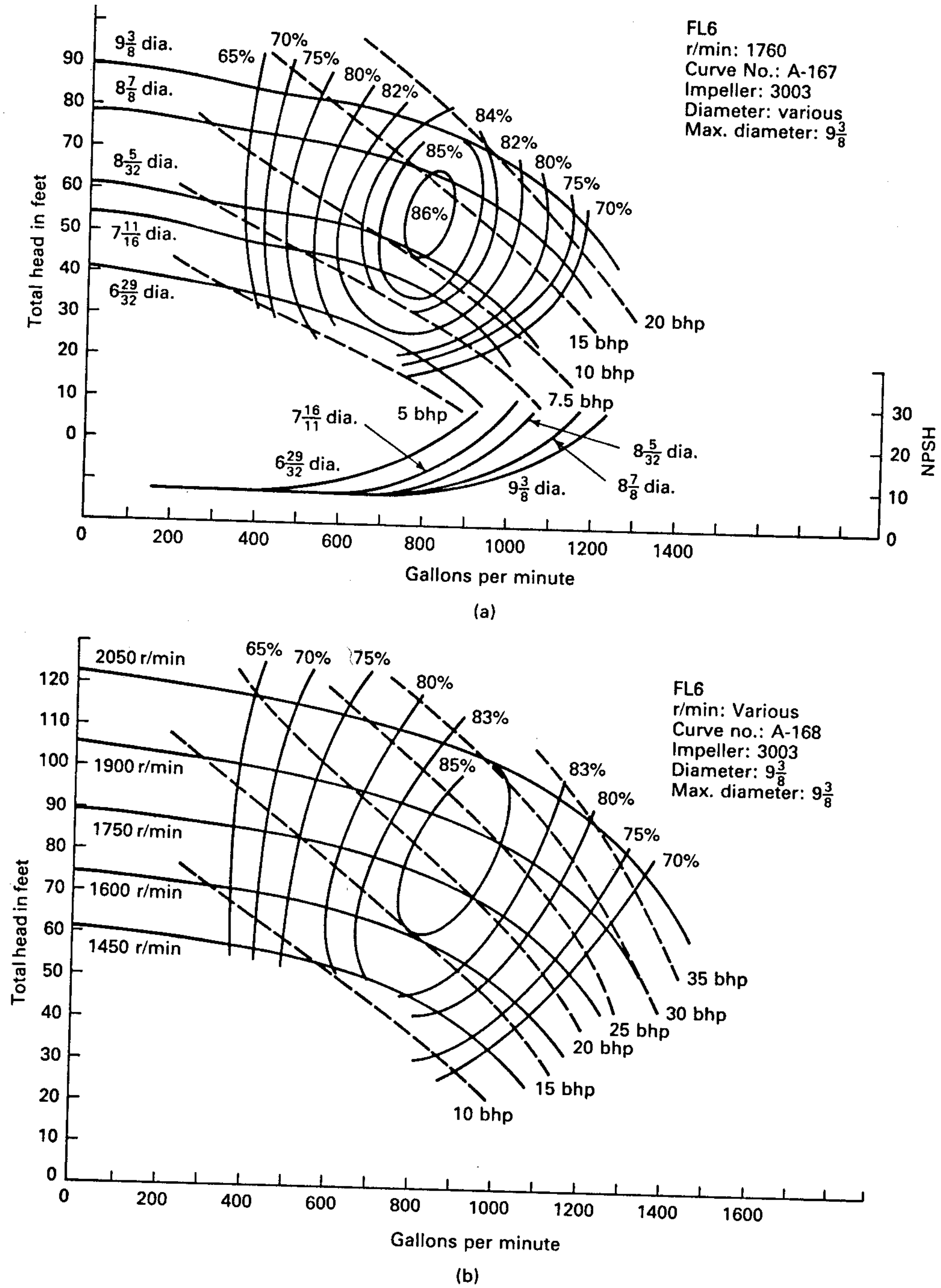

Figure 7: Pump performance curves for Jacuzzi Model FL6 centrifugal pump: (a) head-capacity curves as the impeller size is varied; (b) head-capacity curves for a $9\frac{3}{8}$-in.-diameter impeller at variable speed. (Courtesy of Jacuzzi Bros. Inc., Little Rock, Arkansas.)

The normal operation of a wind pumping system would be variable speed operation of a given impeller with a fixed head, rather than fixed speed operation of several different impellers at different heads. When we operate the largest possible impeller of Fig. 7a at variable speed, the resulting head capacity curves are shown in Fig. 7b. Suppose we have a fixed head of 80 ft. There will be no flow at all for the pump of Fig. 7b until the pump speed exceeds 1650 r/min. As speed increases further, the operating point moves to the right along the 80-ft head line. The flow rate is 680 gal/min at 1750 r/min, with an efficiency of about 82 percent. At 1900 r/min, the flow rate is 1080 gal/min with an efficiency of 83 percent. The efficiency begins to decrease rapidly at greater speeds, dropping to 70 percent at a flow rate of 1380 gal/min. The input shaft power increases from less than 10 bhp to about 40 bhp along this constant head line.

We can begin to see the importance of careful design of the wind driven pump system. We would not want to use this particular pump if the head were 120 ft or more because of the high rotational speeds required and also because of the losses which would be experienced at wind speeds below cut-in. We would probably not want to use this pump on heads below 60 ft since we are moving into a lower efficiency region with such low heads. The turbine mechanical output power would need to be rated at no more than about 35 bhp, assuming the water source can supply the corresponding flow rates. If we are pumping from a well that can deliver only 500 gal/min, with a head of 80 ft, a turbine rated at more than about 13 bhp will pump the well dry momentarily, probably ruining the pump.

A good design, therefore, requires site specific information about the head and flow rate capability of the source, detailed characteristic curves of a family of pumps, and power versus speed curves of the wind turbine. Satisfactory results will be obtained only when all the system components are carefully matched.

There is another set of curves on Fig. 7a which we have not discussed thus far, but which should be discussed because they indicate another limitation of pump operation. The axis at the right is labeled NPSH, which stands for *Net Positive Suction Head*. To explain this term, we draw on our background in physics and recall that a vacuum in the top of a pipe inserted into a tank of 0^oC water exposed to a sea level atmosphere will pull the water up in the pipe to a level of 33.90 ft or 10.33 m above the level in the tank. Pump operation can create a partial vacuum in the input or suction line so it is possible for a pump to be located above the level of water which is to be pumped. A practical limit is about 20 ft because of pump tolerances. The pump and input line will probably need to be filled with water from some source, or *primed*, before pumping can occur, when it is located above the water level.

As pump sizes or rotational speeds increase, however, a dynamic effect becomes apparent which requires the pump to be lowered with respect to the water level. This effect is called *cavitation*, which refers to the formation and subsequent collapse of vapor-filled cavities in the water or other liquid being pumped. When the local pressure at some point on the suction side of an impeller blade drops below the vapor pressure, a bubble of vapor is formed. As the bubble flows through the pump, it will encounter a region where the local pressure is greater than the vapor pressure, at which time it will collapse. This causes noise, vibration, and mechanical damage to the pump interior if allowed to continue. One way of eliminating this effect is to lower the pump with respect to the water level, thereby increasing the pressure on the suction side of the pump. It may be necessary for a given pump to be mounted below the water level to prevent cavitation. Oftentimes the term Net Positive Suction Head will apply to this situation while the term *Net Positive Suction Lift* will apply to the case where the pump can be located above the water level. We see in Fig. 7a that this particular pump must be located at least 8 ft below the water level under any circumstances. It may need to be as much as 30 ft below the water level at higher flow rates. This does not affect the allowable head between the two reservoirs involved, but does affect the pump location. That is, if water needs to be pumped 80 ft from a lower reservoir to an upper one, the 80-ft head line applies even if the pump is 30 ft below the top of the lower reservoir and 110 ft below the top of the upper reservoir.

The size and orientation of the input and output piping can also affect pump operation and perhaps cause cavitation in what would appear to be a well designed system. The assistance of an experienced pump installer is important to a successful system. The information presented here should allow us to make a tentative design, however, which can then be refined by those more knowledgeable about pumps.

One possible design procedure is the following. We first select a wind speed u_m at which both the wind turbine and the pump can operate at their maximum efficiencies. This wind speed would be somewhere between the cut-in and rated wind speeds of the turbine so the pump can operate around its maximum efficiency point for a good range of wind speeds. A logical wind speed is the speed u_{me} which contributes the maximum energy during the period of interest. If $f(u)$ is the probability density function of the wind speeds, then $u^3 f(u)$ is a maximum for $u = u_{me}$. When $f(u)$ is given by the Weibull function described in Chapter 2,

$$u_{me} = c\left(\frac{2+k}{k}\right)^{1/k} \qquad \text{m/s} \tag{10}$$

where k is the shape parameter and c is the scale parameter. During the summer months in the Great Plains u_{me} is typically 8 or 9 m/s.

We then determine the wind turbine power at the wind speed u_{me}. From a knowledge of the pumping head at a given site, we find the necessary mass capacity Q_m which will use this much turbine power. We use Eq. 3 with an assumed pump efficiency appropriate to this power level. This step may need to be repeated if the efficiency of a proposed pump differs significantly from this assumed value.

We can now choose either the actual speed or the specific speed of the pump and solve for the other one from Eq. 6. We want the specific speed high enough to get good pump efficiency, as determined from Fig. 4, but we also want the actual speed to be as low as possible to eliminate the need for extra stages of speed increase in the gearbox. We then go to the manufacturers data sheets to see if there is a standard pump available which meets the requirements for specific speed, head, and capacity at a good efficiency. We would probably want to examine adjacent units in a family of pumps to see if we are at a good design point.

In general, high pump rotational speeds permit a given capacity with a smaller and less expensive pump than would be required for a pump with the same capacity at lower speeds. Cost tradeoffs between a higher gear ratio, more expensive gear box and a higher speed, less expensive pump should be considered in the design.

The turbine tip speed ratio at the design point would be

$$\lambda = \frac{r_m \omega_m}{u_{me}} \tag{11}$$

where r_m is the turbine radius in meters and ω_m is the angular velocity in rad/s.

The turbine rotational speed in r/min is then

$$n_{\text{tur}} = \frac{30}{\pi}\omega_m \tag{12}$$

The ratio of the pump rotational speed n_p over the turbine rotational speed is the step-up ratio of the gear box, n_p/n_{tur}.

We recall from Chapter 4 that the mechanical power output of the turbine for a standard atmosphere is

$$P_m = 0.647 C_p A u^3 \qquad \text{W} \tag{13}$$

where C_p is the coefficient of performance, A is the turbine swept area in m^2, and u is the wind speed in m/s. We shall assume an ideal gear box and use the same P_m as the mechanical power input to the pump. This is not a bad approximation, but can be easily corrected if necessary. If we need power in horsepower, we simply divide the value obtained from Eq. 13 by 746.

We have selected a design wind speed by using Eq. 10, but we need cut-in and rated wind speeds to find the capacity factor that was discussed in Chapter 4. The cut-in wind speed may be determined by extrapolating the constant pump input power curves, shown as dashed lines in Fig. 7, back to the zero capacity axis, and estimating the pump input power for the specified head. This power is then used in Eq. 13 to find u_c.

The rated wind speed is found in a similar manner. We move to the right in Fig. 7 along a constant head line until we reach the first system limit. This may be a flow rate limitation on the liquid source, a torque or speed limitation on the turbine, or a flow rate that causes the available Net Positive Suction Head to be exceeded. The turbine power at this point is used in Eq. 13 to find u_R.

We recall from Chapter 4 that the capacity factor is given by

$$\mathrm{CF} = \frac{\exp[-(u_c/c)^k] - \exp[-(u_R/c)^k]}{(u_R/c)^k - (u_c/c)^k} \tag{14}$$

We have omitted the furling speed term from this expression since it usually is a rather small fraction of the capacity factor. This implies that the turbine has some sort of pitch control or other speed control to limit the power output to its rated value at wind speeds well above the rated wind speed. If this is not the case (if the furling speed and the rated speed are very close together), the correction for furling speed can easily be made.

The average turbine output power or pump input power is then given by

$$P_{m,\mathrm{ave}} = (\mathrm{CF})P_{mR} \tag{15}$$

The average pump output power would then be

$$P_{o,\mathrm{ave}} = \eta_{p,\mathrm{ave}} P_{m,\mathrm{ave}} \tag{16}$$

where η_p,ave is the average pump efficiency for this combination of pump, head, and wind characteristics. It can be estimated by finding the fraction of time spent operating at each wind speed between cut-in and rated, finding the corresponding power, reading a set of curves like Fig. 7b to find the pump efficiency at each power, and taking the average. If this is too much trouble, we can always arbitrarily assume an average pump efficiency of perhaps 80 or 90 percent of the peak efficiency.

Example

A small town in western Kansas has to pump water from their water treatment plant to a storage tank against a total head of 70 ft. They currently use a Jacuzzi Model FL6 pump with an induction motor rated at 1750 r/min to pump water at 960 gal/min for three hours per day to meet the need. The motor and pump are turned off the remainder of the time. The pump impeller is the largest that will fit in the pump housing. The pump is located 25 ft below the water level of the lower reservoir. One of the city commissioners is interested in operating the pump from a wind turbine that is manufactured locally. It is a two-bladed horizontal-axis propeller type turbine that has a peak coefficient of performance of 0.35 at a tip speed ratio of 8. Propeller diameters are available in integer meter lengths. He asks you to tell him what size propeller and what ratio gearbox to use on this system.

As usual, you do not have all the data you would like for a good design, but you do the best you can with what you have. You estimate the Weibull parameters for this site as $k = 2.4$ and $c = 7$ m/s. From Eq. 10 the design wind speed is

$$u_{me} = 7\left(\frac{2+2.4}{2.4}\right)^{1/2.4} = 9.05 \text{ m/s}$$

You tentatively select the induction motor driven pump conditions as the design point for the wind driven pump. That is, you want a turbine that will deliver 20 bhp in this wind speed. You assume the air density to be 90 percent of the sea level value, and solve for the turbine area from Eq. 13.

$$A = \frac{(20 \ \text{hp})(746 \ \text{W/hp})}{(0.9)(0.647)(0.35)(9.05)^3} = 98.8 \ \text{m}^2$$

The rotor diameter for this area is 11.22 m. Since rotors are only available in integer meter lengths, you select the 11 m rotor. This reduces the area by about 4 percent, which in turn increases the wind speed necessary to get 20 hp by slightly over 1 percent or to 9.17 m/s, an amount which seems quite acceptable.

The mechanical angular velocity of the rotor in a wind speed of 9.17 m/s and a tip speed ratio of 8 would be, from Eq. 11,

$$\omega_m = \frac{u_{me}\lambda}{r_m} = \frac{9.17(8)}{5.5} = 13.34 \ \text{rad/s}$$

The turbine rotational speed in r/min is then

$$n = \frac{30}{\pi}(13.34) = 127.4 \ \text{r/min}$$

The pump rotational speed needs to be 1750 r/min at this operating point, so the gear box ratio should be 1750/127.4 = 13.74:1.

You note from Fig. 7a that the maximum flow rate is 1200 gal/min for a NPSH of 25 ft. This corresponds to a pump speed of 1900 r/min and an input shaft power of 28 hp according to Fig. 7b. The wind speed required for this shaft power is, from Eq. 13 and using a 0.9 air density correction,

$$u_R = \left[\frac{28(746)}{0.647(0.9)(0.35)(\pi/4)(11)^2}\right]^{1/3} = 10.25 \ \text{m/s}$$

From Fig. 7a, you estimate by extrapolation that water will start to flow at an input shaft power of about 7.5 hp, which corresponds to a cut-in wind speed of 6.61 m/s. The proposed system will, therefore, pump water at wind speeds between 6.61 and 10.25 m/s. Higher wind speeds can be used if a blade pitching mechanism can restrict the shaft speed to less than 1900 r/min so that shaft power does not increase above 28 hp.

The capacity factor can be determined from Eq. 14 as CF = 0.207. The rated power would be 28 hp, so the average power is (0.207)(28) = 5.79 hp. The average power required by the electric motor driven pump is 20 hp for three hours averaged over a 24 hour day or 20(3/24) = 2.5 hp. The wind turbine will have to be shut down over half the time because all the required water has been pumped.

You report to the city commissioner that the system should work satisfactorily if a good speed control system is used.

We should emphasize that pump characteristics vary significantly with pump design. The curves in Fig. 7 are only valid for that particular pump and should not be considered a good representation for all centrifugal pumps. Another pump design may yield a much better load match for a variable speed wind turbine than the one illustrated. It may be necessary to design the pump and wind turbine together in order to get the best match. There are a number of large scale irrigation projects under study around the world which could use such machines in very large quantities if the cost was acceptable.

3 PADDLE WHEEL WATER HEATERS

A significant amount of energy is used to heat water for the needs of homes, farms, and industry. Wind electric generators can be used to produce electricity for operating resistance heaters, as we have seen. If the only use of the wind generated electricity is to heat water, however, it may be more economical to heat the water directly by mechanical means.

A paddle wheel water heater which can be used for this purpose is shown in Fig. 8. It is basically a cylindrical insulated tank with baffles around the perimeter and paddles on a rotating impeller. This particular design is geometrically simple, has good strength characteristics, and is simple to build[5, 13].

The power input to such a water heater has been found experimentally to be[5]

$$P = 4.69 \rho L^{1.09} w^{0.62} b^{0.88} D^{-1.07} H^{0.64} d^{2.84} \omega_m^3 \qquad \mathrm{W} \tag{17}$$

where ρ is the density of water in kg/m^3, L is the length of the agitator blades, w is the width of the agitator blades, b is the width of the baffles, D is the tank diameter, H is the tank height, d is the diameter of the agitator disks, and ω_m is the angular velocity in rad/s. All dimensions are in meters. We notice immediately that the power input is proportional to ω_m^3 or n^3, the desired variation to properly match or load a wind turbine over a range of speeds. We also notice that when we add up the exponents of the length terms in Eq. 17, the resultant exponent is 5. That is, the power absorbing ability of this heater increases as the fifth power of any one linear dimension if all dimensions are scaled up equally. This compares very favorably with the power rating of an electrical generator, which increases as the volume or the cube of any one linear dimension.

Another advantage of this type of load is the lack of a well defined power limit. Electrical generators are limited by conductor and insulation properties at high temperatures, but the highest temperature of the water heater would be that of boiling water. A simple control valve could dump hot water when wind speeds were high, to maintain non boiling conditions. This means that a wider range of wind speeds between cut-in and rated may be possible with such a load. This could increase the average power output by a significant amount.

Example

A 100 liter paddle wheel water heater has dimensions $L = w = 0.11$ m, $b = 0.089$ m, $D = 0.61$ m, $H = 0.394$ m, and $d = 0.305$ m. What is the power input for a speed of 115 r/min? What is the rate of temperature rise in the tank in ^{o}C per hour, assuming no transfer of water into or out of the tank and no heat loss through the sides of the tank?

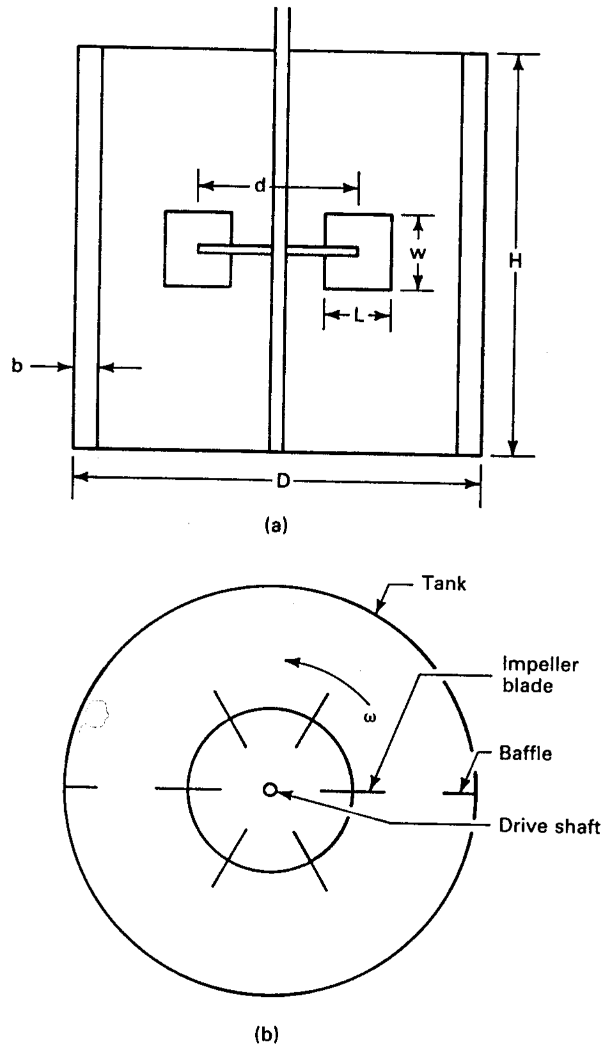

Figure 8: Paddle wheel water heater: (a) side view; (b) top view.

We first compute the angular velocity, $\omega_m = 2\pi n/60 = (2\pi)(115)/60 = 12.04$ rad/s. Then from Eq. 17, we find, for water with a density of 1000 kg/m^3,

$$P = 4.69(1000)(0.11)^{1.09}(0.11)^{0.62}(0.089)^{0.88}(0.61)^{-1.07}(0.394)^{0.64}(0.305)^{2.84}(12.04)^3$$
$$= 717 \text{ W}$$

For the temperature rise, we know that 1 kcal or 4184 J will raise the temperature of 1 kg of water 1 ^{o}C. The application of 717 W = 717 J/s yields a total input of 717(3600) = 2,581,200 J in one hour, or 2,581,200/4186 = 616.6 kcal. The tank contains 100 liters or 100 kg of water, so 616.6 kcal will raise the temperature 616.6/100 = 6.166 ^{o}C in one hour.

This heater may be operated in at least two modes, the high temperature or the preheater modes. In the high temperature mode we have an associated storage tank connected to the heater by a small pump. The pump is turned on when the heater temperature exceeds a preset upper limit and is turned off when incoming cold water drops the heater temperature to a preset lower limit. Only water at the desired final temperature is placed in the storage tank. This would be used in closed loop space heating systems or as a temperature booster for a solar heating system.

In the preheater mode, the heater is placed in the cold water line of a conventional water heater to reduce the energy consumption of that device. Water flow through the heater depends only on the demand of the particular application and not on the available wind power or the temperature of the heater. The application needs to be carefully sized so the average power from the wind does not exceed the original average power consumption of the conventional water heater. If the wind turbine produces too much hot water there could be a substantial waste, both in water and in the incremental cost of an oversized wind turbine.

4 BATTERIES

Most small asynchronous wind electric systems have used lead-acid batteries as a storage mechanism to level out the mismatch between the availability of the wind and the load requirements. They continue to be used in small systems that are isolated from the utility grid, or that need very reliable power. Compared with other components of a wind system, batteries used in these small systems tend to be expensive, short-lived, and not extremely efficient, hence their use has been limited to those applications which can justify the cost.

Batteries are also being used by electric utilities in relatively large scale systems to level out demand variations. In these large scale utility applications, batteries and the associated power conditioning equipment are generally located close to the load centers. They are charged during light demand periods and discharged at peak load times, when the incremental cost of generating electricity may be five times the cost of electricity from the most economical base load units. They have the advantage of increasing the average power flow down existing transmission and distribution lines so construction of new lines can often be deferred. They can be added quickly, because of modular construction. They can be located almost anywhere because of minimal environmental impact and no requirement for cooling water. They also have the advantage of providing reserve generating capacity in the form of "spinning" reserve for the utilities.

A battery bank and power conditioners can also be used effectively by small utilities without their own generation and by industries with high demand charges. The batteries can reduce the peak demand as seen by the generating utility, often with rather substantial savings.

Battery research is being performed for the electric utilities at the Battery Energy Storage Test (BEST) Facility in New Jersey, on the system of the Public Service Electric and Gas Company[8]. This facility allows the testing of batteries capable of storing several MWh of electrical energy. It provides the final proof to other utilities that a specific battery and power conditioning system is ready for installation on their system.

The first battery type to be tested at the BEST Facility was the conventional lead-acid battery. This battery has seen a number of improvements throughout the years and forms a basis for comparison with other battery types. Other batteries must demonstrate superiority over the lead-acid battery if they are to penetrate the market. The first three advanced batteries scheduled for tests were the zinc chloride, zinc bromide, and beta. Many other batteries are being developed by manufacturers so tests of at least a few other battery types would be anticipated. Results of these tests will be directly applicable to wind electric storage systems, especially in the larger sizes.

We shall now present a brief review of battery characteristics, which should be helpful to those trying to read the literature. We will then mention some of the goals and possible developments of these advanced batteries.

A battery consists of several voltaic cells connected together. The term voltaic comes from the Italian physicist Volta who, about 1800, constructed the first primary cell of record, at least in modern times. (There is some evidence that primary cells were used in electroplating gold in ancient Egypt). A *primary cell* basically uses an irreversible process to make electricity by the consumption of battery material. The familiar lead-acid battery contains *secondary cells* which are reversible. Secondary cells are, therefore, of most interest in wind electric systems, but we shall discuss both types for the sake of completeness.

A voltaic cell consists of two dissimilar materials, usually metals, in an electrolyte. A simple primary cell is shown in Fig. 9. It has one electrode of zinc in a zinc sulfate solution, and another electrode of copper in a copper sulfate solution. The two solutions are separated by a porous membrane which prevents mixing of the solutions but permits diffusion of ions either way. The zinc tends to dissolve in the zinc sulfate solution, forming Zn^{2+} ions. The electrons liberated in this process remain in the zinc strip, giving it a negative charge.

The copper acts just the opposite of the zinc, in that it wants to come out of the copper sulfate and plate onto the copper strip. The copper ions coming out of solution have a charge of +2, so the copper strip gives up two electrons upon the arrival of each copper ion, which makes the copper strip positive. If the circuit is completed through a resistor or other load, electrons will flow from the zinc to the copper in the external circuit, with conventional current flow being from copper to zinc. Current flow in the electrolyte is by sulfate ions, SO_4^{2-}, migrating from the copper strip through the membrane to the zinc strip. The process will continue until the zinc in the zinc strip is entirely dissolved, or until essentially all the copper in the copper sulfate solution has been plated out.

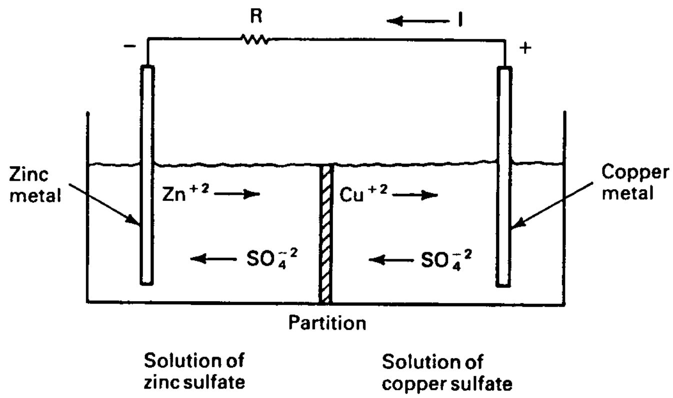

Figure 9: Zinc-copper voltaic cell.

Reversing the current flow will not reverse the chemical process. Once the zinc is dissolved, the only way the cell can be renewed is through a chemical process in which the materials are recycled. This limits the application of this and other primary cells in wind electric storage systems rather substantially. There is a possibility that very large battery storage systems could use wind generated electricity to operate the necessary chemical process, but this will take considerable developmental work. In the meantime, we shall turn our attention to reversible or secondary cells.

The secondary cell which has been used most widely is the lead-acid cell. In its simplest form it consists of a sheet of lead and a sheet of lead dioxide, PbO_2, placed in moderately dilute sulfuric acid. The lead dioxide may be supported by a sheet or grid of lead. The basic structure is shown in Fig. 10

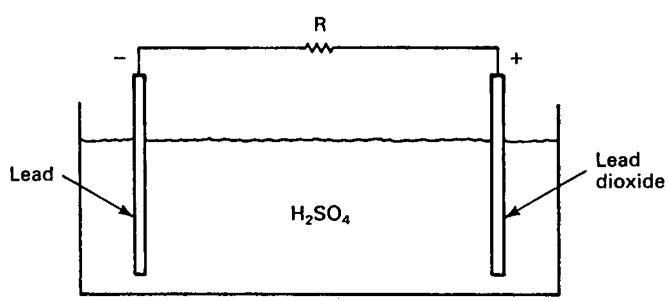

Figure 10: Lead-acid voltaic cell.

During discharge of the cell the lead electrode tends to form lead ions, with the electrons liberated in this process imparting a negative charge to the remaining lead. This forms the negative pole of the cell. In the presence of sulfuric acid the lead ions form insoluble lead sulfate, which deposits as a white substance on the metallic lead. The reaction for this is described in chemical terms by

$$Pb^{2+} + SO_4^{2-} \longrightarrow PbSO_4 \qquad (18)$$

The reaction at the lead dioxide electrode can be considered to proceed in two stages. First, the lead dioxide combines with hydrogen ions from the sulfuric acid and electrons from the external circuit to form lead ions and water, according to the equation

$$PbO_2 + 2e^- + 4H^+ \longrightarrow Pb^{2+} + 2H_2O \qquad (19)$$

Removing electrons from this electrode gives it a positive charge.

In the second part of the reaction, the lead ions just formed combine with sulfate ions from the sulfuric acid to form lead sulfate.

$$Pb^{2+} + SO_4^{2-} \longrightarrow PbSO_4 \qquad (20)$$

The overall reaction of the cell during discharge can be written as

$$Pb + PbO_2 + 2H_2SO_4 \longrightarrow 2PbSO_4 + 2H_2O \qquad (21)$$

We see that both the lead and lead dioxide electrodes become covered with lead sulfate during discharge. We also see that the concentration of sulfuric acid becomes lower during discharge, since the chemical reaction uses up the sulfuric acid and produces water. The reaction will slow down and eventually stop as the plates become covered with lead sulfate and as the sulfuric acid is depleted.

The reverse process occurs when an external source of electricity is connected to the terminals so that current flow is reversed. The lead sulfate is converted to lead and lead dioxide on the appropriate electrodes and the concentration of sulfuric acid is increased. In practice, the process is not completely reversible since some lead sulfate tends to flake off the electrodes and sink to the bottom of the cell where it can not participate in future cycles. Several hundred cycles are possible, however, in a properly built cell that is never allowed to be fully discharged.

The density of sulfuric acid is higher than the density of water, so hydrometer (density) measurements are commonly made to determine the state of charge of a cell. The quantity actually used is the specific gravity, which is the ratio of the density of the electrolyte to the density of water at 4^oC. The specific gravity of pure sulfuric acid is about 1.8, but this is substantially higher than what is actually needed in a cell. The proper specific gravity of a cell is a matter of engineering design. There must be enough sulfuric acid to meet the chemical requirements of cell operation and not so much that the acid would destroy the cell materials.

Cells designed for a low specific gravity electrolyte tend to have a longer life and lower standby loss, with less capacity, higher cost, and greater space requirements than cells designed for higher specific gravity electrolytes. Automobile type batteries typically have a fully charged specific gravity of about 1.29 at 25^{o}C. The electrolyte density varies with temperature so specific gravity needs to be measured at a particular temperature. A specific gravity of 1.08 at 25^{o}C would typically indicate a fully discharged battery.

The freezing point of the electrolyte decreases as the specific gravity increases. A specific gravity of 1.225 at 25^{o}C indicates a freezing point of -40^oC while a specific gravity of 1.08 at 25^{o}C indicates a freezing point of -7^oC. A discharged cell can easily be frozen and its container damaged, while a fully charged cell will not freeze at normal winter temperatures.

The open-circuit voltage varies with the state of charge and also with the manufacturing techniques used in making the cell. Fig. 11 shows the open circuit voltage for the Gates sealed lead-acid cell[7] and for a 12-V marine battery made by Goodyear. The Gates cell varies from 2.18 V at full charge to 1.98 V at full discharge. The Goodyear battery shows a cell voltage of about 2.1 V at full charge and about 1.9 V at full discharge. Other sources[10] indicate a range of voltages between 2.00 and 1.75 V per cell. These variations indicate the importance of using detailed battery information in a design of a wind generation- battery storage system.

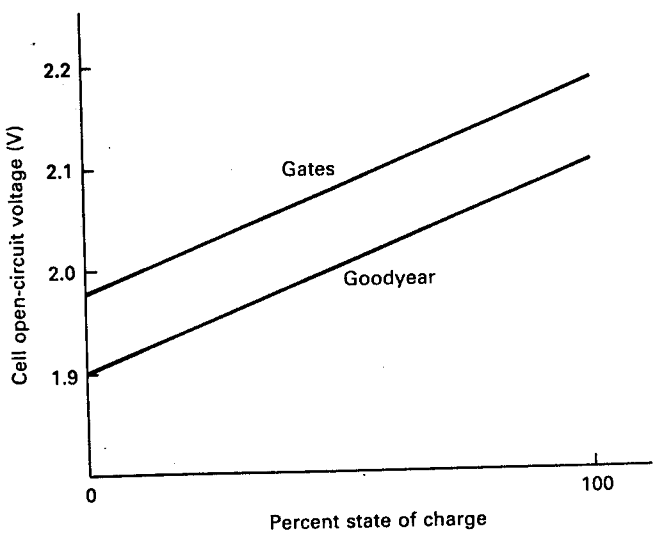

Figure 11: Relationship between the cell open-circuit voltage and the percent state of charge.

One important parameter of any battery is its energy density, expressed in J/kg or Wh/kg. A high energy density means that less mass of battery is necessary to store a given energy. This is not as critical in fixed locations except as it affects cost, but is very important if the battery is to be used in an electric vehicle. The theoretical energy density of a lead-acid battery is 365 kJ/kg (167 Wh/kg), while energy densities that have actually been achieved range from 79 to 190 kJ/kg (22-53 Wh/kg)[4].

The energy density of lead-acid batteries varies with the discharge rate over about a two to one range. This rate dependency is caused primarily by mass transport and ionic diffusion limitations. During discharge, crystals of lead sulfate deposit on the surface and in the pores of the electrodes, reducing the amount of surface area available for reaction, and causing a decrease in pore size that limits access of electrolyte. Simultaneously, the sulfuric acid within the pores becomes depleted and diluted. Higher discharge rates make these effects worse and reduce the total energy that can be recovered.

Another important parameter of any secondary battery is the cycle life. The cycle life of a lead-acid battery is inversely proportional to the depth of discharge, with 200 cycles being an excellent life at a 90 percent depth of discharge. As many as 2000 cycles may be possible if the lead-acid battery is only discharged 20 percent of its capacity. This means that batteries that are deeply discharged each day will last less than a year while batteries that are only lightly discharged may last five to ten years.

One advanced battery which may be a serious competitor with the lead-acid is the *zinc chloride* battery. Zinc and chlorine are low-cost, lightweight, and readily available. The positive plates of this battery are made of graphite while the negative plates are made of zinc. The electrolyte is a solution of zinc chloride, $ZnCl_2$, and water. The electrolyte has to be continuously circulated during operation. During the charge cycle, zinc is deposited from the electrolyte onto the zinc plates. At the same time, chlorine gas is liberated at the graphite electrodes. This gas is dissolved in a separate container of chilled water (below 9^oC) to form a ice-like solid, chlorine hydrate. The chlorine hydrate, $Cl_2 \cdot 6H_2O$, is stored until the battery is discharged.

During discharge the chlorine hydrate is melted and the evolving chlorine gas is dissolved in the circulating electrolyte. The gas is reduced at the graphite electrodes to become chloride ions. These chloride ions combine with zinc on the zinc electrodes to form more zinc chloride electrolyte. Discharge will stop when the chlorine hydrate is exhausted. The battery can be fully discharged each cycle without major difficulties, a big improvement over the lead-acid battery.

The projected energy density of this battery is 84 Wh/kg, as compared with about 20 Wh/kg for the lead-acid battery[2]. This greater energy density also makes this battery a good candidate for electric vehicles. The operating potential of this battery is about 1.9 V/cell, about the same as the lead-acid battery.

There are several difficulties with the zinc chloride battery which must be solved before it will see wide application. One is that inert gases tend to accumulate in the interior space of the battery because it operates below atmospheric pressure. These need to be detected and removed for proper battery operation. Also the graphite electrode tends to oxidize and deteriorate. This electrode is perhaps the limiting feature of the battery and considerable effort has been given to improving manufacturing techniques for it.

Another battery type of considerable interest is the *zinc bromide* battery. It is somewhat similar to the zinc chloride battery in that the electrolyte, aqueous zinc bromide, is pumped through the battery. One possible configuration for the battery is shown in Fig. 12. This sketch shows a battery with three cells, so with an open circuit voltage of 1.8 V/cell, the total voltage would be 5.4 V. The two interior plates are called *bipolar* electrodes. They are made of thin sheets of nonporous carbon. The same sheet acts as the positive electrode for one cell and the negative electrode for the adjacent cell. During charge, the surfaces marked with a + will oxidize bromide ions to bromine gas, which is dissolved in the electrolyte. At the same time zinc ions will be deposited as metallic zinc on the surfaces marked with a −. During discharge, the dissolved bromine gas and the metallic zinc go back into solution as zinc bromide.

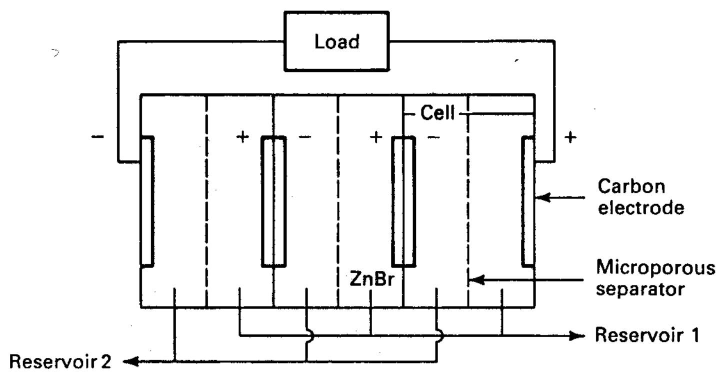

Figure 12: Diagram of a zinc bromide battery.

The bipolar electrodes have no need to be electrically connected to anything, so current flow can be completely uniform over the cross section of the battery. This simplifies the electrical connections of the battery and makes assembly very easy. It also makes the battery more compact for a given stored energy or a given power density.

There has to be a microporous separator in the middle of each cell to reduce the transport rate of dissolved bromine gas across the cell to the zinc on the negative electrode. Any gas that reacts with the zinc directly represents an efficiency loss to the system since the electron transfer necessary to produce the zinc and bromide ions does not produce current in the external circuit. For the same reason, the electrolytes for the two halves of each cell are kept in separate reservoirs. One reservoir will contain electrolyte with dissolved bromine while the other will not. The discharge cycle will continue until all the dissolved bromine is converted to bromide ions, so total discharge is possible without damage to the battery.

Most secondary batteries with zinc anodes have life problems due to the formation of zinc dendrites. This does not occur with this battery because the bromine will react with any dendrites as they form in the separator. Therefore, long cycle life should be possible.

Bromine gas is toxic, but the strong odor gives ample warning of a leak before the injury level is reached. The development difficulties include deterioration of the positive electrode, which limits cycle life. Another difficulty is the high self-discharge rate, where early versions would lose half their charge in two days while disconnected from the system. This can be improved by a better microporous separator. The energy efficiency is about 60 percent, as compared to about 70 percent for lead-acid batteries, because of this self-discharge problem. This efficiency would probably be acceptable to the utilities if the capital investment, expected life, and reliability were superior to those of the lead-acid battery.

Another battery type with exciting possibilities is the *beta* battery, named after the β-alumina used for the electrolyte. A major difference between the beta battery and the other batteries mentioned earlier is that the beta battery has liquid electrodes and a solid electrolyte. The negative electrode is liquid sodium while the positive electrode is liquid sulfur, with carbon added to improve the conductivity. β-alumina is a ceramic material with a composition range from $Na_2O \cdot 5Al_2O_3$ to $Na_2O \cdot 11Al_2O_3$. It is able to conduct sodium ions along cleavage planes in its structure, and therefore acts as both electrolyte and separator between the two liquid electrodes.

One possible construction technique is to use concentric tubes to contain the liquid electrodes, as shown in Fig. 13. In this version we have sodium inside the beta alumina and the sulfur outside, but it will also work with the sodium outside and the sulfur inside. The sulfur container is a mild steel coated with chrome. The two electrodes are electrically and mechanically separated from one another by a ring of alpha alumina at the top of the beta alumina tube. The steel cylinders containing the liquid electrodes are bonded to the alpha alumina ring by a thermal compression process. The alpha alumina ring can also be placed at the top of the cell so only a single steel tube is required as the outer container. Electrical connections are made at the top and bottom of the cell.

The cell open circuit voltage of the beta battery varies from 1.8 to 2.1 V, depending on the state of charge. Operating temperature has to be between 300 and 350^{o}C to maintain the liquid state of the electrodes and good conductivity of the electrolyte. Normal battery losses are adequate to maintain this temperature in a well insulated enclosure if the battery is being cycled every day. An electric heater may be necessary to maintain the minimum temperature over periods of several days without use. The temperature is high enough to be used as a heat source for a turbine generator, which may be a way of improving the overall efficiency in very large installations where significant cooling is required.

During discharge, a sodium atom gives up an electron at the upper steel cylinder. The sodium ion then migrates through the solid electrolyte to form sodium polysulfide, Na_2S_3, which is also liquid at these temperatures. If the discharge is continued too far, Na_2S_5 is formed. This is a solid which precipitates out and does not contribute to future battery cycles. Therefore, the beta battery cannot be fully discharged.

The energy density goal for the beta battery is 44 Wh/kg, about double that of the lead-acid battery[2]. The fraction of active material that is utilized during a cycle is about three times that of the lead-acid battery. The current density is 7 to 10 times as much as the lead-acid battery. And one of the major advantages is that the raw materials of sodium and sulfur are very abundant and inexpensive. The latter point is very important if these batteries are to be built in large quantities at acceptably low costs.

Major difficulties seem to be in developing the metal to ceramic seals and in developing the β-alumina electrolyte. Corrosion is a major problem. One problem with the electrolyte is the tendency to accumulate metallic sodium along its grain boundaries, which shorts out the cell. These problems seem to have been largely overcome, so the beta battery may be a major contributor to utility load leveling and to wind energy systems in coming years.

The number of possibilities for battery materials seems almost limitless[4]. The batteries discussed in this section seem to have the highest probability of wide use, but a technological breakthrough could easily move another battery type into the forefront. Whatever the ultimate winner is, these batteries will be used as system components, like transformers, by the utilities. If the utility has enough batteries on its system, it may not be necessary to physically place batteries at wind turbines for storage purposes. Of course, if it is desired to install large wind turbines on relatively low capacity distribution lines, batteries may be very helpful in matching the wind turbine to such a line.

The engineer designing the battery installation will be concerned with a number of parameters, including the voltage, current, storage capacity in kWh or MWh, the energy density per unit area of base (footprint), weight, height, reliability, control, heating and cooling requirements, safety, and maintenance. If the batteries are to be installed at a typical utility substation, the desired total capacity will probably be 100 or 200 MWh. The total battery voltage will probably be in the range of 2000-3000 V dc. These voltages would make maximum use of modern power semiconductors and would reduce current requirements as compared with a lower voltage installation.

A reasonable footprint is about 300 kWh/m^2 and a height of 6 m would probably be imposed by mechanical constraints. A height of 2 m may be better in terms of maintenance if the greater land area is available. The batteries should be capable of accepting a full charge in 4 to 7 hours and should be able to deliver all their stored energy in as little as 3 hours. They should be capable of more than 2000 charge-discharge cycles and should have an useful life of more than ten years. The energy efficiency, defined as the ratio of the ac energy delivered during discharge to the ac energy supplied during charge, should be at least 70 percent. This definition of efficiency includes both the efficiency of the individual cells and the efficiency of the power conditioning equipment.

Example

Your company is considering installing a 100 MWh beta battery installation at a substation. Individual cells are 0.8 m tall and occupy a rectangular space that is 5 cm on a side. Each cell can store 200 Wh of energy. The energy efficiency is 70 percent, and you assume all the losses occur during the charge cycle. That is, if you put in 200/0.7 Wh during charge, you get back 200 Wh per cell on discharge. The battery installation is to be charged during a five hour period and discharged during a three hour period. Half the losses are used to maintain battery temperature and the other half can be used to provide thermal input to a 25 percent efficient turbine generator. The cells are to be mounted two high, so the total height requirement is less than 2 m. The battery voltage is 2500 V dc.

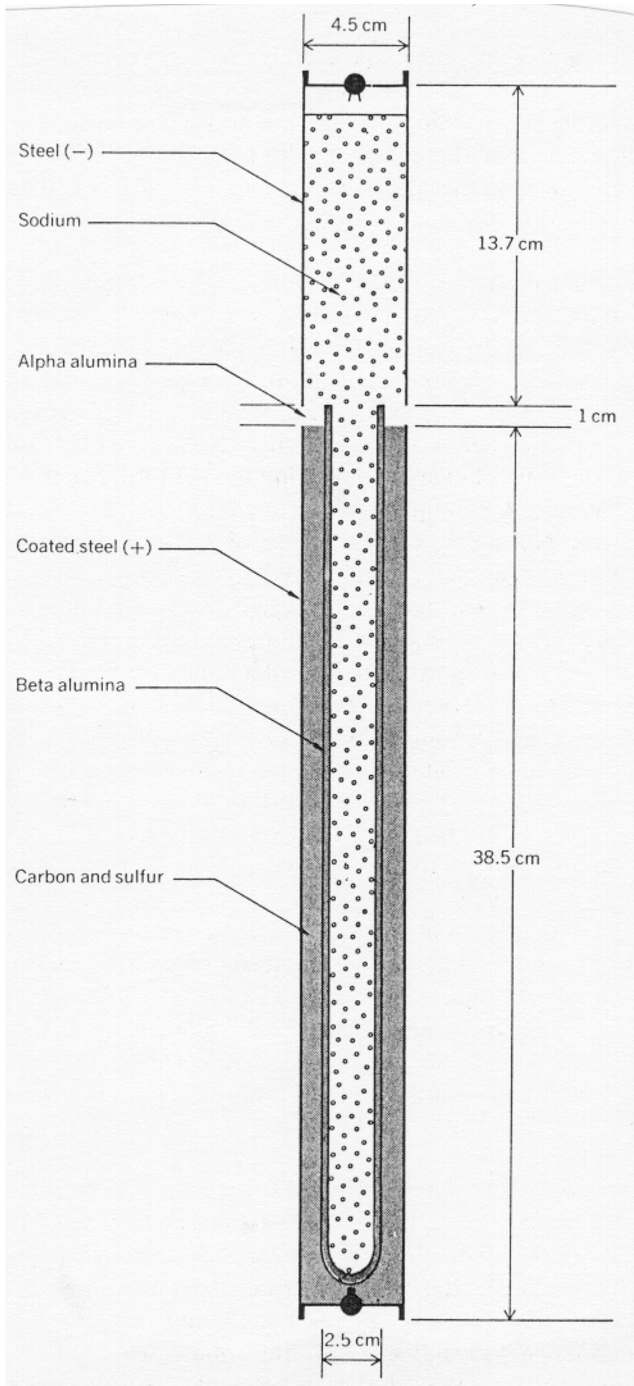

Figure 13: Beta battery cell. (©1979 IEEE)

1. How many cells are required?
2. What is the total land area required?
3. What is the battery current during charge and during discharge?
4. What should be the power rating of the turbine generator if it is to be operated at rated power for four hours during the day?

For part (a), if the total energy storage is 100 MWh = 100×10^6 Wh, and each cell contains 200 Wh, the number of cells is $100 \times 10^6/200$ = 500,000. This is obviously a significant manufacturing endeavor.

For part (b), if we stack the cells two high, we need only the area for 250,000 cells taking up space 5 cm on a side.

$$\text{Area} = 250,000(0.0025 \text{ m}^2) = 625 \text{ m}^2$$

This is an area 25 m on a side, which may be unacceptably large at some locations. The area can be reduced to one third of this value by stacking the cells six high rather than two high. This would probably have some benefits in terms of lowered losses to the atmosphere and easier recovery of heat for the turbine generator.

For part (c), the total energy required during charge is 100/0.7 = 143 MWh. The average power during charge is then 143/5 = 28.6 MW. Supplying this power at 2500 V dc requires a current of $28.6 \times 10^6/2500$ = 11,440 A. The average power during discharge is 100/3 = 33.3 MW. The current during discharge would be $33.3 \times 10^6/2500$ = 13,330 A. These currents are approaching a practical limit for conductors and protective devices, so it may be worthwhile to consider the economics of raising the voltage to 5000 V dc or more and lowering the current a proportional amount.

For part (d), the losses during a 24 hour period are 100/0.7 -100 = 43 MWh. Half of this amount or 21.5 MWh is available to our turbine generator in the form of 350^oC heat. The power output over a four hour period would be 21.5(0.25)/4 = 1.34 MW. If this can be used during the discharge cycle, the effective power rating during discharge would increase from 33.33 MW for the batteries to 34.67 MW for batteries plus waste heat. It would be desirable, therefore, to enter the peak load period of the day with the batteries as hot as possible and leave the peak load period with the batteries as cool as possible. If the batteries would tolerate a 40 or 50^oC temperature swing over a three hour period, both the stored heat and the losses could be used to power the waste heat generator.

5 HYDROGEN ECONOMY

The concept of the hydrogen economy has received considerable attention in recent years, especially since 1973[3, 1]. This concept basically describes an energy economy in which hydrogen is manufactured from water by adding electrical energy, is stored until it is needed, is transmitted to its point of use and there is burned as a fuel to produce heat, electricity, or mechanical power. This concept has some disadvantages, primarily economic in nature, but also has some major advantages. One advantage is that the basic raw material, water, is abundant and inexpensive. Another advantage is the minimal pollution obtained from burning hydrogen. The primary combustion product is water, with minor amounts of nitrogen compounds produced from burning hydrogen in air at high temperatures. Merely lowering the combustion temperature solves most of this pollution problem.

Hydrogen is a widely used gas. In 1973, the world production of hydrogen was about 250 billion cubic meters (9000 billion standard cubic feet). About a third of it was produced and used in the United States, requiring 3 percent of the U. S. energy consumption for hydrogen production. At that time 47 percent of the hydrogen was used for petroleum refining, 36 percent for ammonia synthesis, 10 percent for methanol synthesis, and the remainder for miscellaneous and special uses. These uses include the hydrogenation of edible oils and fats to make margarines and cooking oils, the manufacture of soap, the refining of certain metals, semiconductor manufacture, and as a coolant in large electrical generators. It is a feedstock in organic chemical synthesis leading to production of nylon and polyurethane. And, of course, liquid hydrogen is used as a rocket fuel.

Most of the hydrogen currently produced in the United States is obtained by the reaction of natural gas or light petroleum oils with steam at high temperatures. This reaction produces mostly carbon dioxide and hydrogen. The carbon dioxide can be removed by a scrubbing process in an amine solution or in cold methanol. The hydrogen produced by this reaction is not of high purity, but is satisfactory for large scale uses. In 1973, about 23 percent of the hydrogen produced in the United States was produced from oil, 76 percent from natural gas, and 1 percent by other methods, including electrolysis of water[11].

The use of hydrogen for all of these applications is expected to grow in the future. One possible major growth area would be the liquefaction and gasification of the large U. S. coal deposits. Coal has a high carbon to hydrogen ratio, so carbon has to be removed, or hydrogen added, to make a liquid or gaseous fuel. Most proposed reactions for synthetic fuels call for removing the carbon, but if hydrogen were available at a reasonable price it could stretch out these coal supplies significantly.

Hydrogen can be readily stored in the same types of underground facilities as are now used to store natural gas. This ability to store energy would allow large generating plants of various types, such as nuclear fission, nuclear fusion, wind, photovoltaic, and solar thermal, to operate under optimum conditions for the energy source. The nuclear plant can operate at full capacity day and night. Wind power can be captured when available. Wind energy captured by large wind farms in the High Plains region of the United States during the spring can be stored and transported to the population centers of the eastern United States during later peak demand periods. This can be done much more economically through hydrogen pipelines than in the form of electricity over extra high voltage transmission lines. Many of the existing natural gas pipelines can be readily converted to hydrogen.

The technology for the construction and operation of natural gas pipelines has been well developed. A typical trunk line, 1000 to 1500 km long, consists of a welded steel pipe up to 1.2 m (48 in.) in diameter that is buried underground. Gas is pumped along the line by gas-driven compressors spaced along the line typically at 160-km intervals, using some of the gas in the line as their fuel. Typical line pressures are 4 to 5 MPa. To convert this to the English unit of pounds(force) per square inch (psi), we note that 1 psi = 6894.76 Pa, and find equivalent line pressures of 600 to 750 psi.

A typical 0.91-m (36-in.) pipeline has a capacity of about 11,000 MW on an equivalent energy basis. That is, a pipeline of this size will transport about 10 times as much energy per hour as a three-phase 500-kV overhead transmission line. It requires less land area than the overhead lines and is more accepted by people because it is basically invisible. These factors combine to make the unit costs of energy transportation by pipeline much lower than for overhead transmission lines.

Hydrogen has about one-third of the heating value per unit volume as natural gas. This means that a hydrogen volume of about three times the volume of natural gas must be moved in order to deliver the same energy. The density and viscosity of hydrogen are so much lower, however, that a given pipe can handle a hydrogen flow rate of three times the flow rate of natural gas. Thus where existing pipelines are properly located, they could be converted to hydrogen with the same capacity to move energy. Different compressors are required, however, to pump the lower density hydrogen.

We have examined several asynchronous loads in this chapter, all of which involve some form of energy storage. Water is pumped and stored until needed. Heat is stored in the form of hot water. Wind generated electricity is stored in chemical form in batteries. Wind generated electricity can also be passed through electrolysis cells to produce hydrogen. Hydrogen can be stored for long periods of time and also transmitted over great distances. Technical and economic constraints indicate that only large facilities will be practical for hydrogen production, which is distinctly different from the cases of water pumping, space heating, and even battery charging. We shall examine some of the features of electrolysis cells as asynchronous loads for wind generators in the next section. First, however, we shall consider some of the properties of other fuels, to aid us in making the economic decisions which must be made.

Table 7.2 shows the energy content of several different fuels, some of which are not extensively used for generating electrical power but are included for general interest. Both English and SI units are given since the British Thermal Unit (Btu), pound, and gallon are so deeply entrenched in the energy area. Anyone who would read the literature must be conversant with these English units so we shall present a portion of our discussion using these units.

The energy content or heating values given are all the *higher heating values*. To explain this term, we recall that water vapor is one of the products of combustion for all fuels which contain hydrogen. The actual heat content of a fuel depends on whether this water vapor is allowed to remain in the vapor state or is condensed to liquid. The higher heating value is the heat content of the fuel with the heat of vaporization included. The lower heating value would then be the heat content when all products of combustion remain in the gaseous state. In the United States the practice is to use the higher heating value in utility reports and boiler combustion calculations. In Europe, the lower heating value is used. The lower heating value is smaller than the higher heating value by about 1040 Btu for each pound of water formed

Table 7.2 Heating Values of Various Fuels[a]

	Btu/lb	MJ/kg	Btu/gal (liquid)	MJ/L (liquid)
Hydrogen	63,375	147.3	37,442	10.42
Methane	23,875	55.49	83,945	23.37
Propane	21,666	50.35	104,870	29.20
Gasoline	20,460	47.55	120,000	33.4
Kerosene	19,750	45.90	136,000	37.9
Diesel Oil (1-D)	19,240	44.71	140,400	39.1
Diesel Oil (2-D)	19,110	44.41	146,600	40.8
Diesel Oil (4-D)	18,830	43.76	150,800	42.0
Ethyl Alcohol	12,780	29.70	83,730	23.31
Methyl Alcohol	9,612	22.34	63,090	17.56
Anthracite (Pa.)	12,880	29.9		
Low-volatile Bituminous (W. Va.)	14,400	33.5		
High-volatile A Bituminous (W. Va.)	14,040	32.6		
High-volatile C Bituminous (Ill.)	10,810	25.1		
Subbituminous A (Wyo.)	10,650	24.8		
Subbituminous C (Colo.)	8,560	19.9		
Lignite (N. Dak.)	7,000	16.3		

[a] *Source:* Data compiled from *CRC Handbook of Tables for Applied Engineering Science*, first edition, 1970. Reprinted with permission. Copyright CRC Press, Inc., Boca Raton, FL.

per pound of fuel. One pound of hydrogen produces about nine pounds of water, so the lower heating value of hydrogen, for example, would be about 63,375- 9(1040) = 54,000 Btu/lb.

We see from the table that hydrogen has a very high heating value on a Btu/lb or a MJ/kg basis, but because of the low density of liquid hydrogen, the heating value per liter is lower than the other liquid fuels. Hydrogen becomes a liquid only at temperatures close to absolute zero and the energy required to liquefy it may be on the order of one third of the energy content of the resulting liquid hydrogen. The capital equipment and energy required for liquefaction will probably prevent liquid hydrogen from being used as a fuel except in special applications. These include space flights and large aircraft where the high energy content per kg may help produce significant cost savings.

We also see that petroleum fuels have lower energy content per kg as their complexity increases, but that the energy content per liter increases because the density of the fuel is increasing. At the same price per liter or per gallon, diesel oil is a better buy than gasoline because the energy content is greater.

Ethyl alcohol and methyl alcohol have significantly lower energy contents per liter than gasoline or diesel oil, which means they need to be priced at a lower price per liter to be economically competitive. The alcohols are being used more and more for transportation purposes and may have a role in small cogeneration power plants.

Coal is much like crude oil in that its chemical properties vary widely from one field to another, and even within a field. Typical heating values are shown in the table for seven different coals found in the United States. Heating values are seen to vary by over a factor of two, from 14,400 Btu/lb for low-volatile bituminous from West Virginia to 7,000 Btu/lb for lignite from North Dakota. On the average, coals in the Western United States have lower heating values and lower sulfur content than Eastern coals. The lower heating values make the Western coals more expensive to ship, on the basis of delivered energy, while the lower sulfur content makes the Western coals more desirable for environmental purposes.

The gaseous fuels of Table 7.2 are usually sold on a volume basis rather than on a mass basis. We normally see the energy content of hydrogen expressed as 12.1 MJ/m^3 (325 Btu per standard cubic foot) rather than a given amount of energy per kg. The heating value of natural gas varies somewhat with the amount of propane, butane, hydrogen, helium, and other gases mixed with the methane, but is usually expressed as 37.3 MJ/m^3 (1000 Btu/ft^3).

To get an idea of the electrical equivalent of the U.S. consumption of hydrogen, we take the 1973 consumption of 80 billion cubic meters and find a total yearly energy of $(8 \times 10^{10})(12.1) = 97 \times 10^{10}$ MJ $= 26.9 \times 10^{10}$ kWh. The average power is the yearly energy divided by the number of hours in the year, 8760. The result is 30,700 MW. This power level would require 44 electrical generating plants of 1000 MW rating each with a capacity factor of 0.7. It is evident that a rather large investment of electrical generation and electrolysis equipment will be necessary for oil and gas to be eliminated as sources for hydrogen.

It should be evident that selling oil by the gallon, natural gas by the thousand cubic feet, and coal by the ton can lead to confusion by the consumer as to which fuel represents the best buy. An improvement on the system would be to sell fuels by energy content rather than volume or mass. There is a major trend in this direction among the electric utilities, and perhaps it will spread to other sectors of society in the future. Since the Btu is a small unit, this cost is usually expressed in dollars per million Btu, C_{MB}. Since there are 1054 Joules in one Btu, the cost per gigajoule (10^9 J) will be 0.949 times the cost per million Btu.

We may express this cost per million Btu as the cost per unit of fuel (gallons, pounds, etc.) times the number of units of fuel per million Btu.

$$C_{\mathrm{MB}} = \frac{\mathrm{cost}}{\mathrm{unit}} \left(\frac{\mathrm{units}}{10^6 \ \mathrm{Btu}} \right) \tag{22}$$

Example

In the spring of 1981, delivered costs of fuels to customers in the Kansas Power and Light Co. service area, excluding taxes, were \$2.00 per thousand cubic feet for natural gas with an energy content of 980 Btu per cubic foot, \$1.16 per gallon for No. 1 diesel oil, \$1.14 per gallon for gasoline, \$0.60 per gallon for propane, and \$12.00 per ton (2000 pounds) for Wyoming coal with 8500 Btu/lb energy content. Find the costs of the fuels per million Btu.

For natural gas, the cost C_{MB} is

$$C_{\rm MB} = (\$2.00/\text{unit})(1\ \text{ unit}/0.98 \times 10^6\ \text{ Btu}) = \$2.04/10^6\ \text{ Btu}$$

For diesel oil, the cost is

$$C_{\rm MB} = (\$1.16/\text{gal})(1\ \text{ gal}/0.1404 \times 10^6\ \text{ Btu}) = \$8.26/10^6\ \text{ Btu}$$

For gasoline, the cost is

$$C_{\rm MB} = (\$1.14/\text{gal})(1\ \text{ gal}/0.12 \times 10^6\ \text{ Btu}) = \$9.50/10^6\ \text{ Btu}$$

For propane, the cost is

$$C_{\rm MB} = (\$0.60/\text{gal})(1\ \text{ gal}/0.10487 \times 10^6\ \text{ Btu}) = \$5.72/10^6\ \text{ Btu}$$

For coal, the cost is

$$C_{\rm MB} = (\$12.00/\text{ton})(1\ \text{ ton}/2000\ \text{ lb})(1\ \text{ lb}/0.0085 \times 10^6\ \text{ Btu}) = \$0.71/10^6\ \text{ Btu}$$

We can see from these numbers that at this point in time coal is the best buy. We also see that natural gas is priced well under the price of other petroleum fuels. This is due to government regulation, and the differential can be expected to disappear in an unregulated market.

The cost per kWh generated by burning one of these fuels depends not only on the cost of the fuel and its energy content, but also on the efficiency with which it is burned. The reciprocal of efficiency, the *heat rate*, is the parameter that is commonly used in power plant calculations.

The heat rate is the number of units of fuel energy that must be used to produce one unit of electrical energy. In the English system this is given as Btu contained in the fuel per kWh of electrical output. In SI, this is given as joules in the fuel per joule of electrical energy output (or MJ/MJ or GJ/GJ depending on one's preference). In this form, it shows clearly the dimensionless nature of the plant efficiency. Average annual heat rates for new 1000 MW coal plants vary from 9700 to 10,200 Btu/kWh (2.84 to 3.00 MJ/MJ) depending on the type of coal used. Since there are 3410 Btu in one kWh, the efficiency of these coal plants varies from 3410/10,200 = 0.334 to 3410/9700 = 0.352. The heat rate for oil fired peaking units has tended to be poorer than that for coal fired base units, perhaps 11,000 to 12,000 Btu/kWh

(3.23 to 3.52 MJ/MJ). There are new types of fossil fueled generating plants being developed which use systems like magnetohydrodynamics and combined cycles to get the heat rate down to 8000 Btu/kWh (2.35 MJ/MJ) or less.

The cost of fuel per kWh can be defined as

$$C_{\text{fuel}} = C_{\text{MB}}(\text{heat rate}) \tag{23}$$

where CMB is in dollars per million Btu and the heat rate is in million Btu per kWh generated.

Example

The cost of coal delivered to a plant in Kansas is \$0.71/106 Btu in 1981 dollars. The heat rate is 9800 Btu/kWh. What is the fuel cost per kWh?

$$C_{\text{fuel}} = (\$0.71/10^6\ \text{Btu})(0.0098 \times 10^6\ \text{Btu/kWh}) = \$0.0070/\text{kWh}$$

Example

The cost of residual low sulfur fuel oil delivered to a municipal generating plant in 1981 is \$8.26/106 Btu. The heat rate is 11,000 Btu/kWh. What is the fuel cost?

$$C_{\text{fuel}} = (\$8.26/10^6\ \text{Btu})(0.011 \times 10^6\ \text{Btu/kWh}) = \$0.0909/\text{kWh}$$

Numbers such as shown in these examples are obsolete as soon as they are written, but they do illustrate the fact that oil fired electricity costs considerably more than coal fired electricity. This means that wind machines will probably be used to save oil before they can be justified to replace new coal generation.

We should mention that relatively large amounts of oil and natural gas are used as boiler fuels by the utilities. In 1977, $90.3 \times 10^9\ \text{m}^3$ of natural gas and 574.9 million barrels of oil were burned as boiler fuels[16]. Fossil fuels were used to generate $1,648.7 \times 10^9$ kWh, with coal contributing 60 percent of the total, gas 19 percent, and oil 21 percent. The average power from the oil and gas fired units was 75,000 MW.

It is national policy to replace this oil and gas fired electricity with electricity generated from coal and nuclear plants. However, political, environmental, and economic problems are delaying this transition. It appears that significant quantities of oil and gas will be used for boiler fuel for some time.

It seems logical that wind generated electricity would be used first as a fuel saver, so that less oil and gas would be burned when the wind is blowing. This eliminates the extra expenses for storage equipment and results in minimum cost to the electricity customer. The major technical limitation is the capacity of existing transmission lines. That is, a region of the country with 10,000 MW of oil and gas generation may only have 1000 MW of transmission line capacity which could be used to move wind generated electricity into the region. Additional transmission lines may be almost as politically and economically difficult to build as new coal generating plants within the region. This means that while at least 75,000 MW of wind generation could be utilized nationally in a fuel saver mode if transmission lines were adequate, perhaps only 10,000 to 20,000 MW could actually be utilized in this mode if electrical power had to be transmitted over existing transmission lines. This limitation would not be present if the wind generated electricity were used to make hydrogen, and the hydrogen shipped to the load centers by pipeline.

There will need to be a cooperative effort to use wind and solar electric systems, hydroelectric systems, load management, conservation, and perhaps load leveling batteries to maximize the use of wind and solar systems as fuel savers. Electrolysis of water can logically begin after the use of oil and gas as boiler fuels has been reduced to an absolute minimum. Existing oil and gas generating plants can be maintained as standby units for emergency use.

Of course, there may be special applications, such as off shore wind turbines, where electrolytic production of hydrogen could be justified more quickly than on shore. A great deal depends on the capital costs of wind turbines and electrolysis cells, as well as the cost and availability of fossil fuels. In any event, there will be interest in producing hydrogen from wind generated electricity, so a brief review of the technology is appropriate.

6 ELECTROLYSIS CELLS

It has been known for at least 150 years that water can be decomposed into the elements hydrogen and oxygen by passing an electric current through it. Electrolysis cells are widely used to produce hydrogen in laboratory quantities or where a high purity is required.

A simple electrolysis unit is shown in Fig. 14. There are two end plates and a bipolar plate in the middle, forming two cells. The electrolyte is distilled water with up to 25 percent of some alkaline added, such as sodium hydroxide (NaOH), potassium hydroxide (KOH), or lithium hydroxide (LiOH). An alkaline is used to produce a relatively low resistance in the electrolyte. Distilled water has a very high resistance, which causes unacceptably high losses if used by itself.

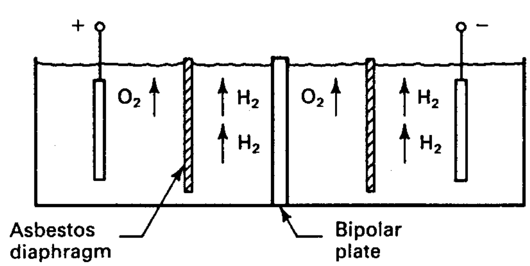

Figure 14: Two electrolysis cells in series.

The plates are mild steel, solid nickel, or nickel-plated steel. There is a diaphragm in the middle of each cell to prevent the mixing of the oxygen and hydrogen produced. The diaphragm is made of asbestos cloth in the older, low pressure systems.

When a direct current is applied, oxygen gas is evolved at the positive terminal of each cell and hydrogen gas at the negative terminal. Only the water is used up in this reaction so additional water must be continually added to maintain the same alkaline concentration.

A simplified version of the chemical process is shown in Fig. 15 for a single cell with a potassium hydroxide electrolyte. Initially, the two plates in the cell are surrounded by a solution of water, positive potassium ions, and negative hydroxal ions. When a voltage difference is applied to the electrodes, the negative ions migrate to the positive plate and the positive ions to the negative plate. If the applied voltage is large enough, four hydroxal ions at the positive electrode will give up one electron each and form one molecule of oxygen and two molecules of water. At the same time, four water molecules at the negative electrode accept one electron each, forming two molecules of hydrogen and four hydroxal ions. Current flow in the electrolyte is carried by the hydroxal ions migrating from the negative to the positive plate.

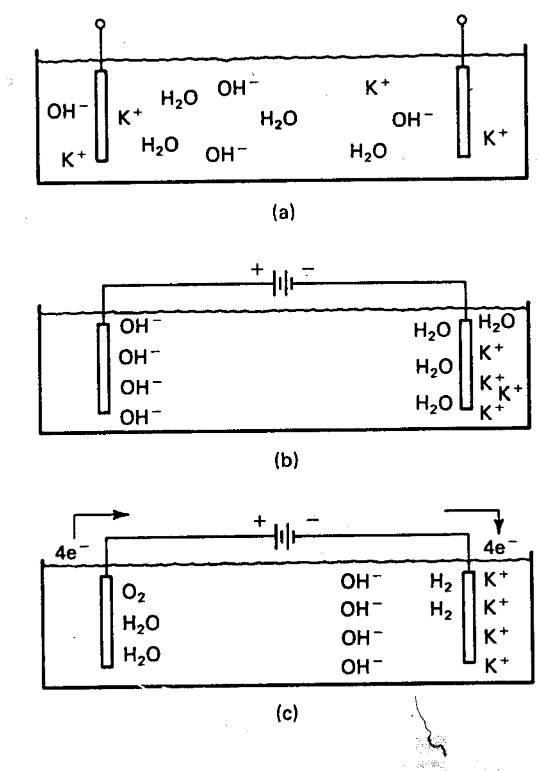

Figure 15: Chemical action in a simple electrolysis cell: (a) no voltage applied; (b) Limited voltage applied; (c) more voltage applied.

The gases which are produced must be captured by *headers* over the plates to prevent them from mixing or being lost to the atmosphere. A simple test tube filled with water and inverted over one of the plates is typically used in freshman chemistry to get a small quantity of hydrogen or oxygen for experimental purposes. Since the chemical formulation of water is H_2O, the volume of hydrogen given off will be twice the volume of the oxygen.

The voltage across each cell necessary to produce hydrogen is 1.23 V (the decomposition voltage of water at room temperature) plus a voltage at each electrode necessary to actually make the reaction occur, called the oxygen or hydrogen overvoltage, plus the voltage necessary to overcome the electrolyte resistance and the resistance of the conductors and plates. The power into each cell is the product of voltage and current. If all the current passes directly through the cells and produces hydrogen, the cell efficiency can be defined as the higher heating value of the hydrogen produced divided by the electrical power input.

$$\eta_t = \frac{(\text{moles of } \text{H}_2/\text{sec})(\text{energy/mole})}{VI} \tag{24}$$

The heat of formation or the higher heating value of one mole of hydrogen is 68.32 kcal or 286.0 kJ. As was mentioned in the previous section, the higher heating value includes the heat of condensation of the water vapor in the combustion products. The total value is available only if the combustion gases are cooled below the condensation point, which is not practical in the generation of electricity. The higher heating value is available, of course, when the hydrogen is burned to make steam and the steam is used in space heating applications where condensation occurs.

We recall from freshman chemistry that it requires two faradays of charge to produce one mole of H_2 gas. The current in Eq. 24 is in coulombs per second, so when we combine the current with the terms in the numerator and cancel the seconds, we have

$$\eta_t = \frac{(1 \text{ mole})(286.0 \text{ kJ/mole})}{V(2)(96,493 \text{ C})} = \frac{1.482 \text{ J/C}}{V} \tag{25}$$

This definition of thermal efficiency as heat energy out over electrical energy in is a common definition. It is of interest to note that the maximum theoretical limit of this efficiency is about 1.2 or 120 percent. This does not violate any laws of thermodynamics because we have not included the possibility of heat input to the cell as well as the electrical input. There are operating modes for high performance electrolysis cells where they actually operate in an endothermic mode, extracting heat from the surroundings and adding this energy to the electrical input to produce a given output heat energy. General Electric has reported[14] on a laboratory cell that operated at over 100 percent thermal efficiency up to rather large current densities. However, in most cases cost tradeoffs will result in the most economic operating point being somewhat under 100 percent efficiency.

Historically, electrolytic hydrogen has been made with large low pressure electrolysis cells typically operating at cell voltages between 1.9 and 2.1 V. This corresponds to a thermal efficiency range of 71 to 78 percent. The energy loss appears as low grade heat which must be removed from the system. The rated current on these large units may be as high as 15,000 A or even more. There will be hundreds of cells in series to yield a reasonable plant operating voltage.

These large electrolysis plants represent proven technology with readily available materials. The cost of the hydrogen produced is rather high, however, because of the inefficient, low pressure electrolysis process which is used. A substantial increase in the use of electrolytic hydrogen depends on an improvement of electrolysis efficiency and a decrease in capital costs.

The bubbles being evolved from the electrodes increase the resistance of the electrolyte. Therefore, one obvious way of improving the efficiency is to increase the operating pressure, since this compresses the bubbles. This has another advantage for some applications in that the gases can be produced at pipeline pressures and do not require compression after generation. The feedwater must be pumped at that same pressure but it requires less energy to pump the liquid than it does to pump the resultant gas.

The effect of pressure on cell voltage is shown in Fig. 16. The cell voltages of conventional alkaline electrolyzers (electrolysis cells) are shown as a band in the upper part of the figure. The horizontal axis is the *current density* of the cell, in A/m^2 or A/ft^2. The current density is the total cell current divided by the electrode area. As the current density increases, the cell voltage has to increase because of the resistances of the electrolyte and conductors. As the pressure increases, the electrolyte resistance drops, which lowers the cell voltage and thereby improves the efficiency. At 400 A/ft^2, the best conventional electrolyzer has an efficiency of about 69 percent, while at 1000 psi (6.895 MPa) the efficiency of a pressurized electrolyzer is 87 percent, and at 3000 psi (20.68 MPa) the efficiency is 91 percent. The high pressure cell is also capable of operating to at least twice the current density of the conventional electrolysis cells. This reduces the cross sectional area of the cell by a factor of two for a given input power, which helps to reduce capital costs. Of course, the high pressure container for the cell will be stronger and more expensive than the container for the low pressure cell. The much smaller volume of the evolved gases makes it possible for the overall capital cost per unit of hydrogen to be lower for the high pressure system.

Efficiency also increases with increasing temperature, as shown in Fig. 17. The cell voltage at 400 A/ft^2 is about 2.07 V at 80^oF and 1.63 V at 400^oF. The efficiency increases from 72 percent to 91 percent with this increase in temperature. The reason for this is that water becomes more chemically active at higher temperatures, so that it is easier to split into its constituent elements.

The information on Figs. 7.16 and 7.17 was taken from a high pressure KOH cell developed at Oklahoma State University[9]. The electrodes were made of solid nickel and were able to withstand the corrosive action of hot KOH without damage. These researchers discovered that many materials which would withstand KOH at high pressures or at high temperatures would not withstand the combination of high pressure and high temperature KOH. A great deal of research is being performed on various materials to help develop these high efficiency

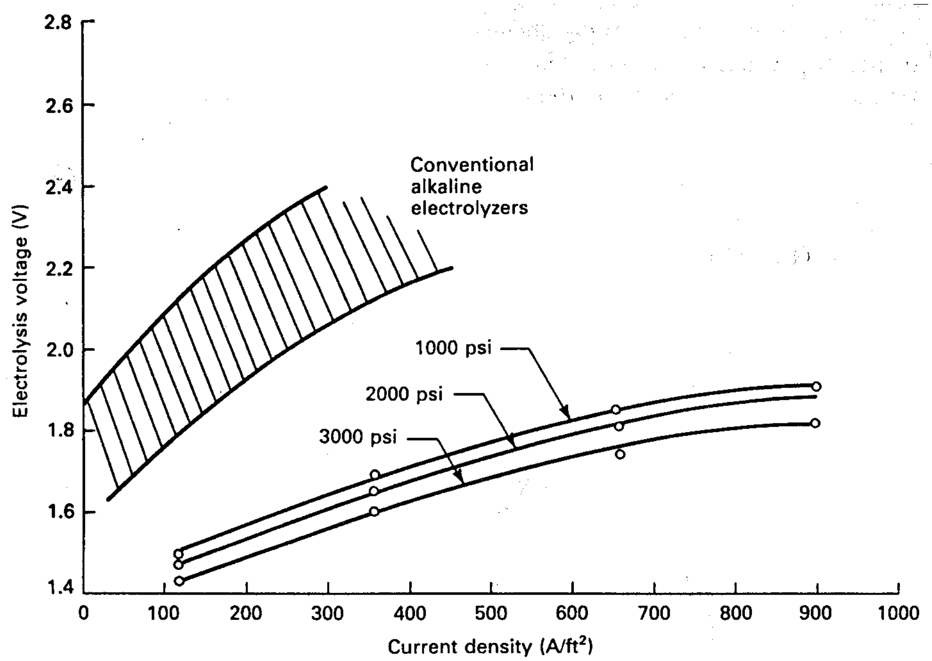

Figure 16: Plot showing the effect of pressure on electrolysis cell characteristics at 400^{o}F.

cells.

The Oklahoma State cell used asbestos sheets to separate the gases between the electrodes. Asbestos is also a standard separator for the low pressure cells. It is chemically an excellent choice since it is not attacked by the hot KOH. It is not such a good separator from a mechanical standpoint, however, since pressure differentials can blow holes in it. The electrolysis unit must then be torn down and rebuilt. The pressure controlling valves on the oxygen and hydrogen lines are difficult to build and operate in such a way as to maintain the very low differential pressures required by the asbestos cloth. These problems indicated the need for a high pressure cell which would not require the use of asbestos.

One recent design solution to this problem is the *solid polymer electrolyte* (SPE) cell. The basic construction of such a cell is shown in Fig. 18.

At the center of the cell is the SPE sheet. This sheet is perhaps 250 μm thick and is made of a perfluoronated linear polymer with sulfuric acid groups integrally linked to the polymeric structure to provide ionic conductivity[14]. This material is essentially a form of teflon which has excellent physical strength and forms a rugged barrier between the generated hydrogen and oxygen gases. When saturated with water the polymer is an excellent ionic conductor and it is the only electrolyte required. Ionic conductivity is provided by the mobility of the hydrated hydrogen ions ($H^+ \cdot xH_2O$). These ions move through the sheet of electrolyte by passing from one sulfonic acid group to another. The sulfonic acid groups are fixed,

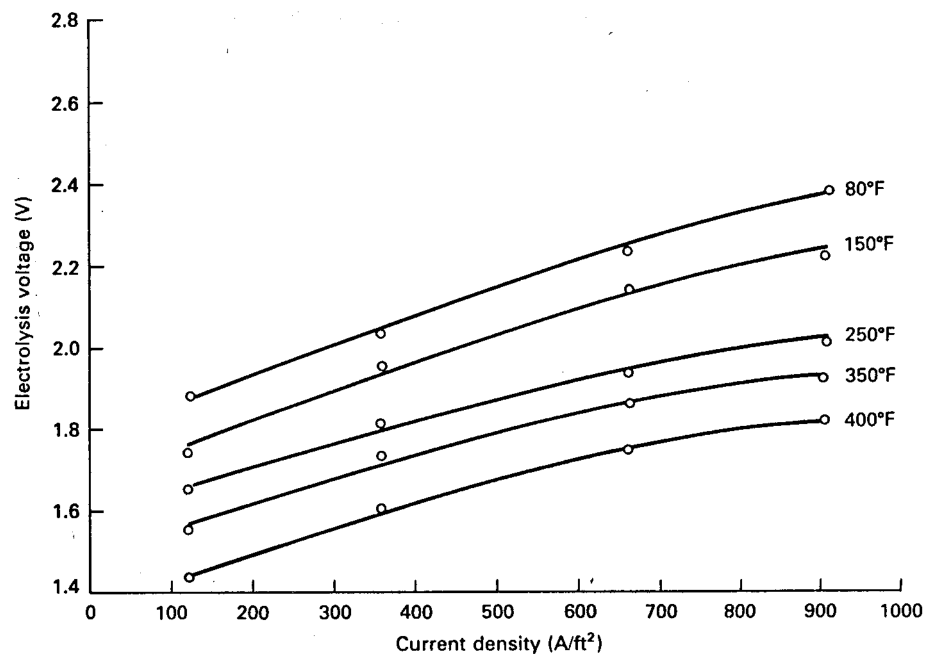

Figure 17: Plot showing the effect of temperature on electrolysis cell characteristics at 3000 psi.

keeping the acid concentration constant within the electrolyte. On the oxygen side, two water molecules are decomposed into one neutral oxygen gas molecule, four electrons which move off to the right within the metal screen, and four positive hydrogen ions which move through the solid electrolyte. These four ions receive four electrons coming from the left and become two molecules of hydrogen gas on the hydrogen side of the solid electrolyte.

The two faces of the SPE sheet are coated with a very thin film of catalyst to help the reaction occur. Platinum black works well but other catalysts are being developed for reasons of cost and availability.

The spaces for the water and gas next to the SPE sheet are formed by a multi-layer expanded metal screen package. The open spaces between the screen strands provide a low resistance flow path for the water and gases. The screen provides physical support for the SPE sheet to help it withstand high differential pressures and acts as an electrical current conductor. The fluid cavities are sealed around the edges by a silicon rubber gasket. This gasket also provides electrical insulation so current flows only where desired. Adjacent cells are separated by a metal sheet which provides mechanical separation of gases but does not contribute directly to gas production.

Early problems with the silicon rubber gasket have led to the testing of other separators. One version replaced the silicon rubber gasket and metal sheet with a sheet of molded carbon

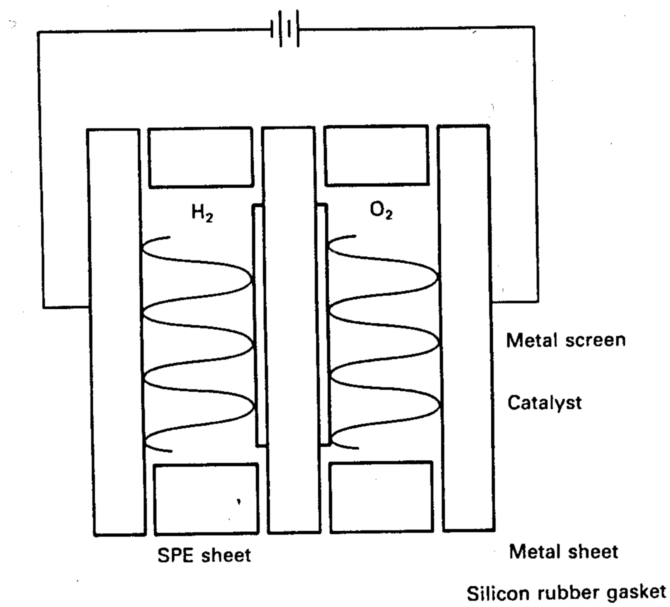

Figure 18: Solid polymer electrolyte electrolysis cell.

and titanium foil shield[15]. This separator is molded from a mixture of carbon and phenolic resin. The SPE sheet itself acts as the gasket. On the cathode (hydrogen) side, porous carbon fiber paper replaced the metal screen. On the anode (oxygen) side, the metal screen is formed of either perforated titanium foil, fabricated by acid etching, or porous titanium plate fabricated by a powder metallurgy process. Other developments in materials can be expected with the SPE cell as it continues toward wide commercialization.

Increasing the temperature increases the efficiency of the SPE cell just as it does with the alkaline cell. An increase in temperature from 180^{o}F to 300^{o}F reduced the cell voltage from 1.83 to 1.70 V at 1000 A/ft^2 for the GE cell[15]. This corresponds to a thermal efficiency improvement from 81 to 87 percent. Material problems become even more severe at temperatures above 300^{o}F (150^{o}C) so this may be a practical upper limit for temperature.

The efficiency of the SPE cell does not vary strongly with pressure since the current does not have to flow through a liquid electrolyte filled with gas bubbles. In fact, the GE efficiency goal for their SPE cell is 93 percent at 100 psi (0.69 MPa) and 88 percent at 600 psi (4.14 MPa)[15]. If pipeline pressure is not required, it may be more cost effective to operate the SPE cell at relatively low pressures.

It might be mentioned that water only needs to be supplied to the oxygen side of the SPE cell. The water on the hydrogen side is necessary to the reaction but is not used up, except for the water vapor that is carried off by the hydrogen gas. The cell only requires three fluid connections, one for water and two for the gases. This simplifies construction somewhat as compared with the high pressure alkaline cell.

7 PROBLEMS

1. You visit a farm where a wind turbine is driving a piston pump. You estimate the flow rate to be 0.8 L/s, the stroke to be 0.18 m in length, and the operating speed to be 35 cycles per minute. Estimate the pump diameter. You will need to assume a reasonable slip. Note: Systems installed in the United States prior to the mid 1980s were all sized in English units, so any calculated value should be rounded to the nearest 0.5 inch to express the size.

2. A rancher asks you for advice. His pumping head is 80 m and he needs 7000 liters of water per day, with enough stock tank capacity to last for two calm days. What size Dempster turbine and cylinder do you suggest?

3. Estimate the specific speed of the pump with characteristics shown in Fig. 7, assuming the rated speed is 1750 r/min and the maximum diameter impeller is used.

4. A Jacuzzi Model 25S6M10XP-T submersible turbine pump has a maximum efficiency of 70 percent at a capacity of 130 gal/min, a head of 550 ft, and a rotational speed of 3450 r/min.

   (a) What is the specific speed?

   (b) What is the required input power, both in horsepower and kW?

5. The pump in the previous problem is operated at 3000 r/min. Estimate the new head, new capacity, and new input shaft power if the efficiency remains the same. Express in English units.

6. You work for a company that is building a canal to carry water from the Missouri River to Western Kansas for irrigation purposes. The water must be lifted a total of 300 m in a series of stages of 10 to 20 m each. The total amount of water required per year is $4 \times 10^9 \mathrm{m}^3$. This can be pumped intermittently throughout the year as the canal supplies the necessary storage. You are asked to evaluate the concept of using wind turbines with a 90 m blade diameter to drive the necessary pumps. The wind regime can be characterized by the Weibull parameters $k = 2.2$ and $c = 7.5$ m/s. Cut-in, rated, and furling wind speeds are assumed to be $0.6u_m$, $1.1u_m$, and $1.6u_m$, respectively, where u_{me} is given by Eq. 10. The peak pump efficiency is assumed to be 0.9 and the average pump efficiency between cut-in and rated wind speeds is assumed to be 0.85.

   (a) What is the total average power input to all the pumps on the canal?

   (b) What is the total rated power input to all the pumps on the canal?

   (c) How many wind turbines are needed?

(d) Would you anticipate any problem in clustering the necessary number of turbines at a pumping station and making the mechanical connections between wind turbines and pumps and between pumps and necessary piping? Discuss.

7. A wind turbine manufacturer is offering for sale a 12 m diameter propeller mechanically connected to a Jacuzzi type FL6 centrifugal pump through a 12:1 gearbox. You have an application where large amounts of water need to be pumped against a head of 80 ft and this system could be used to reduce energy consumption by other pumps which are electrically driven. The wind characteristics are described by the Weibull characteristics $k = 2.2$ and $c = 7.5$ m/s. Water starts to flow with a pump power input of 8.5 bhp. Pump power input has to be limited to 35 bhp because of cavitation problems. The turbine efficiency is assumed to be a constant value of 0.32 over the operating range between cut-in and rated wind speeds. The pump efficiency averages about 0.8 under all operating conditions.

   (a) What is the cut-in wind speed?
   (b) What is the rated wind speed?
   (c) How much water will the system pump in a year? Express result in both gallons and m^3.

8. A paddle wheel water heater has dimensions $L = 0.07$, $w = 0.07$, $b = 0.038$, $D = 0.6$, $H = 0.4$, and $d = 0.2$ m, as defined in Fig. 8. The wheel is turning at a rotational speed of 4500 r/min. What is the power being converted into heat?

9. You install a 40-kW wind turbine on your farm. The rate structures are such that the utility will pay you a much better price for your excess generation if you can guarantee to supply them 10 kW during a 4 hour peak each day. You allow for two calm days in a row and decide on a 80-kWh battery bank with inverter. The 6-V lead-acid batteries have a base that is 0.18 m by 0.26 m. A total of 80 batteries are required, in two banks of 40 batteries each to get the necessary 240 V required by the inverter.

   (a) How big an area is required to store the batteries if they are to be in a single layer? Include space for access to the batteries and space between batteries for cooling. Justify your assumptions.
   (b) Battery efficiency is 0.85 during both charge and discharge. What is the rated current of each 6 V battery during discharge?
   (c) Is battery cooling a problem? Discuss.

10. You are designing a cogeneration power plant for an apartment building. Available fuels include No. 1 diesel at $1.70 per gallon, ethyl alcohol at $1.40 per gallon, and methyl alcohol at $1.30 per gallon. Each fuel is used at the same overall efficiency. Which fuel is the most economical choice, if efficiencies and capital costs are the same in all cases?

11. A large utility is paying $25/ton (2000 pounds) of coal with a heating value of 11,600 Btu/lb. The coal plant heat rate is 10,200 Btu/kWh. What is the fuel cost per kWh?

12. A municipal utility buys No. 2 diesel oil at $1.75/gal. The heat rate is 11,300 Btu/kWh. What is the fuel cost per kWh?

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