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FEASIBILITY ANALYSES FOR
SMALL WIND ENERGY CONVERSION SYSTEMS

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# FEASIBILITY ANALYSES FOR SMALL WIND ENERGY CONVERSION SYSTEMS

By

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# ABSTRACT

FEASIBILITY ANALYSES FOR
SMALL WIND ENERGY CONVERSION SYSTEMS

By

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A feasibility study for Small Wind Energy Conversion Systems contains at least three essential elements: 1) an on-site wind data assessment program, 2) the calculation of the SWECS annual energy output, and 3) an economic analysis. Methods contained in the literature for performing these three tasks were reviewed and new methods were introduced for calculating SWECS annual energy output and economic merit. Programs written for the TI-59 programmable calculator are included in the Appendix.

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I would like to extend a warm thankyou to my two co-major professors, Dr. Bill A. Stout and Dr. Jes Asmussen,Jr. This thesis would not have been produced but for them.

Dr. Stout allowed me to work on a wide variety of alternative energy topics, and in a sence, turned me loose to follow my own interests. I'll always appreciate Dr. Stout's enthusiasm, easy going manner, and the opportunity he provided me to become involved in the field of wind energy.

Dr. Asmussen taught me most everything I know about wind energy and was always willing to explain new things. He spent hours with me going over particular details and refining new ideas, and was often a source of great inspiration. Dr. Asmussen has become a good friend and I've truly enjoyed working with him.

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## NOMENCLATURE

| | |
|---|---|
| A | area |
| AEO | annual energy output |
| c | Weibull scale factor |
| $COE_o$ | current cost of energy |
| $\overline{COE}$ | levelized cost of energy |
| DOE | Department of Energy |
| ft | feet |
| IC | total installed cost |
| IC/AEO | ratio of total installed cost to annual energy output |
| k | Weibull shape factor |
| kW | kilowatt |
| kWh | kilowatt-hour |
| m | meters |
| m/s | meters per second |
| mph | miles per hour |
| MW | Megawatt |
| MWh | Megawatt-hour |
| n | power low exponent |
| $\overline{P}$ | average power |
| $P_r$ | rated power |
| P(v) | power output as a function of wind speed |
| $\rho$ | density |
| $\rho(v)$ | wind speed probability (frequency) density |

| | |
|---|---|
| SWECS | small wind energy conversion system |
| v | wind speed |
| $\overline{V}$ | average wind speed |
| $V_i$ | cut-in wind speed |
| $V_r$ | rated wind speed |
| $V_o$ | cut-out wind speed |
| WECS | wind energy conversion system |
| WTG | wind turbine generator |

# CHAPTER ONE

# INTRODUCTION

As the price of electricity continues to rise, homeowners, farmers, and small businessmen are becoming increasingly interested in Small Wind Energy Conversion Systems (SWECS) as an alternative to the exclusive use of utility-supplied electricity. Though motivations differ, potential SWECS owners want to know if a SWECS installation at their site makes sense economically. The purpose of this thesis is to review the methods used to ascertain the economic feasibility of a SWECS installation at a particular site and where necessary, develop new methods which can account for the unique circumstances of a particular installation.

A SWECS feasibility analysis generally contains three different elements: 1) an on-site wind data assessment program, 2) the calculation of the SWECS Annual Energy Output (AEO) at the site, and 3) an economic analysis. The SWECS economic analysis is based, in part, on the SWECS Annual Energy Output. Methods for calculating SWECS AEO use wind data from the wind data assessment program and the choice of calculation methods may dictate the kinds of wind data that must be gathered. Conversely, the wind data obtainable from different kinds of wind instruments may dictate which AEO calculation methods may be used.

This thesis reviews the procedures contained in the literature for performing on-site wind assessment programs, calculating SWECS AEO values and performing SWECS economic analyses. New methods are presented for calculating both the SWECS AEO and economic merit. The interrelationships between the wind assessment program, SWECS AEO calculations, and economic calculations are also considered.

Chapter 2 describes different types of wind systems and briefly considers utility rules for utility-interconnected SWECS. Chapter 3 discusses various wind characteristics that are relevant for SWECS feasibility analyses and considers the following questions:

1. What are some examples of average wind behavior in Michigan, including yearly, monthly, and diurnal average wind speed variability?

2. What statistical models for describing wind behavior are used in SWECS AEO calculations?

3. What wind data are necessary to utilize these statistical models?

4. How do parameters which specify the statistical models vary with time of year and height above ground?

5. What instruments are commonly used to measure wind data?

6. How does the data obtainable from different wind measuring instruments influence the choice of statistical models?

7. How long a period should a wind assessment program last? What factors influence the necessary assessment period?

Chapter 4 reviews a variety of methods that have been used to calculate SWECS energy output and presents a new method suitable for use on the TI-59 programmable calculator. Several methods were used to calculate the AEO of a particular Wind Turbine Generator (WTG) and the results were compared. Chapter 4 considers the following questions:

8. Which methods for calculating WTG AEO are most suitable for a variety of WTG designs?

9. How are calculated AEO values affected by variations in the parameters of statistical models used to describe wind behavior? How do these effects influence the choice of statistical models used for AEO calculations and the wind instruments used in wind data assessment programs?

10. What size WTG best matches the electrical demand patterns of a particular site?

11. How do errors in the estimated long term average wind speed affect predicted AEO values?

Chapter 5 reviews methods for calculating the economic merit of a particular SWECS application and introduces a new method based on the life-cycle cost approach. The formulas for this new method are listed and several examples analyses are discussed. Chapter 5 considers the following questions:

12. What are the limitations of previously used economic calculation methods?

13. How can the economic merit of a particular SWECS application best be described?

Chapter 6 summarizes the previous chapters and systematically answers the questions just posed. Chapter 7 points to areas that need further research.

Two programs designed for use on the TI-59 programmable calculator have been developed. The first calculates the SWECS AEO; the second calculates a variety of figures of economics for a particular SWECS application. The Appendices contain the program lists and operating instructions.

## CHAPTER TWO

## WIND ENERGY CONVERSION SYSTEMS

A Wind Energy Conversion System (WECS) is any system which converts wind energy to either mechanical, thermal, or electrical energy. This thesis focuses on WECS that convert wind energy into electricity and of a size suitable for homes, farms, or small businesses. These systems are usually called Small Wind Energy Conversion Systems or SWECS, and have Wind Turbine Generators (WTG) with rated powers of 100 kW or less. The WTG is a subsystem of the entire SWECS and refers to the rotor or air foil, the drive train, and the electrical generator. The term SWECS usually denotes the entire system, including the WTG, tower, batteries or inverters, and even the utility in some instances.

### WTG Applications

WTGs are usually designed for use in either isolated systems (Fig.1) or utility-interconnected systems (Fig. 2), usually referred to as isolated SWECS or utility-interconnected SWECS, respectively. An isolated SWECS stands alone as a completely independent energy source. Electricity is usually stored in a battery bank and is either used as DC or inverted to AC with an inverter. A utility-interconnected SWECS uses the utility as a "storage system." The utility supplies any electricity the wind system cannot; excess wind generated electricity is sent back through the utility lines. In most states, excess energy may be purchased or "bouought back" by the utility for around 1/4 to 1/2 the normal retail rate.

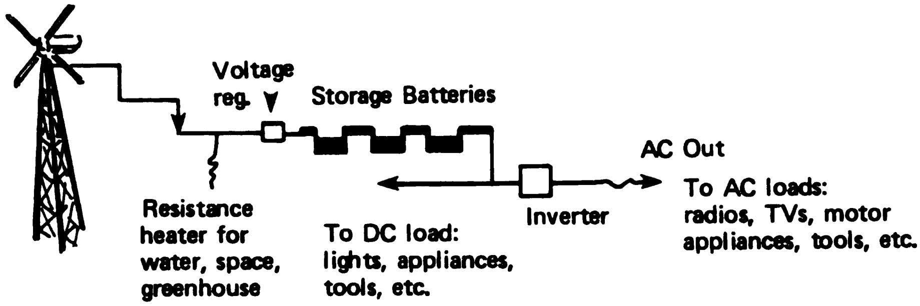



Figure 1. A block diagram of an Isolated SWECS (20).

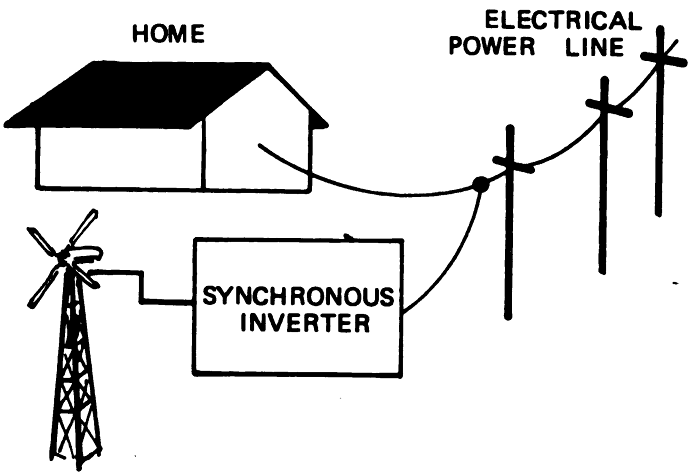



Figure 2. One type of a Utility-Interconnected SWECS (20).

This thesis focuses almost exclusively on utility interconnected SWECS since they are by far the most popular type of SWECS sold today.

## Utility-Interconnected SWECS

Systems A through C (Fig. 3) represent utility-interconnected SWECS and provide electricity identical in frequency and voltage to that of utility electricity, i.e., these systems are "synchronized"

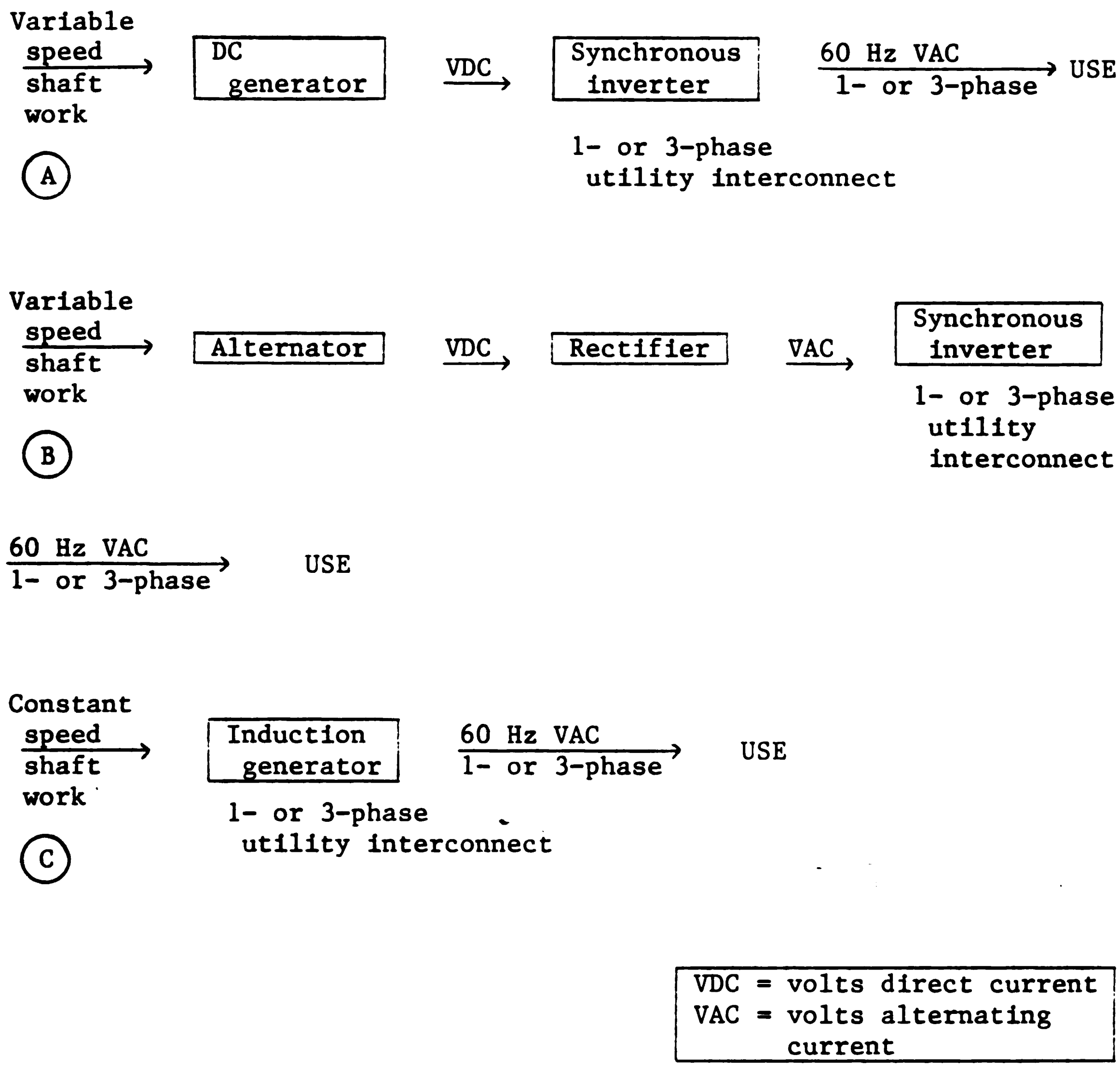



Figure 3. Three utility-interconnected wind energy conversion systems.

with the utility lines. Single or three-phase equipment is used depending on the utility service available.

Two kinds of utility-interconnected SWECS are available: 1) systems having a synchronous inverter (A and B in Figure 3); and 2) systems having an induction generator (C in Figure 3). SWECS with synchronous inverters are sometimes called Variable-Speed Constant-Frequency systems (VSCF). The WTG rotor speed changes with wind speed producing an AC electrical output of constant frequency identical to utility current. SWECS whose WTG contain induction generators are sometimes called Constant-Speed Constant-Frequency systems (CSCF). Due to the nature of the induction generator, the rotor speed can change at most 5 to 10 percent, regardless of wind speed. Unfortunately, rotors with constant or near constant rotational speeds cannot maintain optimum blade tip-to-wind speed ratios and suffer losses in aerodynamic efficiency in varying wind speeds. Therefore, the CSCF system or WTG with induction generators have larger rotor diameters compared to VSCF systems of similar power ratings. However, the CSCF system (C in Figure 3), may cost less because it has the simplest utility interconnect and requires fewer components.

The solid-state synchronous inverter in Systems A and B converts variable voltage direct current electricity into alternating current electricity at the same frequency as the utility line. These inverters, a modification of an electronic device used with industrial motor controls, require the utility's 60 Hz voltage for operation. When the normal utility AC is "down," the synchronous inverter will not operate. The solid-state electronics chop-up the DC electricity into the proper 60 Hz AC, and under certain conditions, could produce harmonic frequencies higher than 60 Hz which may require additional filtering.

## Utility Rules and Rate Structure for Utility-Interconnected SWECS

Permission from the utility company is required for hookup. The utility requires, among other things, a detented meter (a meter that cannot run backwards), a second meter if the company will buy back excess wind-generated electricity, and a manual disconnect switch to prevent possible backfeed when utility lines are down. Though utility-interconnected SWECS are designed to work only when utility power is available (automatic disconnect), the manual disconnect switch is an added safety feature.

The utility pays for the spinning reserve, distribution networks and overhead required to provide the SWECS owner with electricity during periods of low wind speeds. Only part of the utility's costs are due to fuel and SWECS may be only a fuel saver. These facts must be accounted for when specifying both the normal cost of electricity supplied to the SWECS owner and the buy-back price. The Michigan Public Service Commission (PSC) currently requires large utilities to buy back solar/wind-generated electricity at 2.5¢kWh, less than 1/2 of the cost of electricity purchased from the utility.

The SWECS owner pays for the initial installation (about $40) which includes an extra meter to measure the energy bought back by the utility. Utilities may also charge the SWECS owner $3.85/mo ($46/yr) for metering. At 2.5¢/kWh, a SWECS owner must sell back in excess of 300 kWh/mo to pay for this charge. Many small WTGs in Michigan generate only 400-800 kWh/mo--scarcely enough energy to justify a sell-back meter.

## WTG Machine Characteristics

A simplified description of the WTG power output as a function of wind speed (denoted P(v)), is illustrated in Fig. 4. This description of the P(v) curve is known as the straight line or ramp approximation (3).

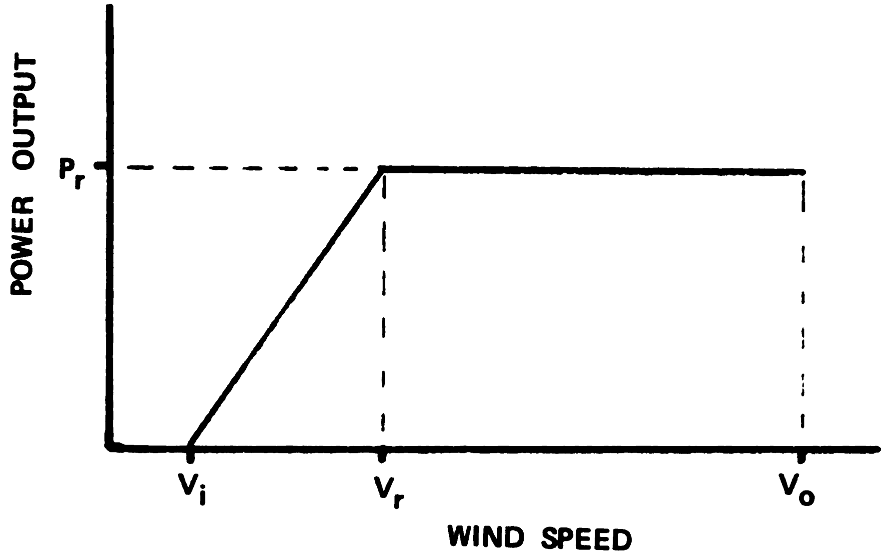



Figure 4. Ramp approximation of WTG P(v) curve (3).

The nomenclature in Fig. 3 has the following meaning:

$V_i$ = cut-in wind speed. This is the wind speed at which the WTG begins producing power.

$V_r$ = rated wind speed. The WTG achieves its rated power at this wind speed.

$V_o$ = cut-out wind speed. The WTG "cuts-out" or shuts down at this wind speed. The exact mechanism which causes this to happen varies for different WTG.

$P_r$ = rated power. Usually a WTG has a specified rated power, achieved at the rated wind speed.

$V_i$, $V_r$, $V_o$, and $P_r$ are collectively known as the WTG machine characteristics and are usually specified for each WTG by the manufacturer. Problems encountered when AEO calculations are based on $V_r$ and $P_r$ values are discussed in Chapter 4.

# CHAPTER THREE

# CHARACTERISTICS OF THE WIND

## Introduction

Wind is a form of energy derived primarily from the sun. Thus SWECS are classified as a solar technology by the DOE. As a simplified explanation for wind phenomena, variations in incident solar radiation with respect to location and time cause temperature differences in the atmosphere. These temperature differences lead to variations in atmospheric pressure, resulting in air movement from high pressure to low pressure regions. Air movements which dominate large areas and are relatively constant in direction are called prevailing or planetary winds. The prevailing winds in North America usually run from west to east. Regional terrain or topographical features such as a lake or bluff can also create local temperature variations which cause air movements known as local winds. The best sites for SWECS installation will take advantage of both the prevailing and local winds.

Chapter 3 describes some of the most important wind characteristics pertaining to SWECS applications, including: power in the wind, yearly, monthly and annual wind speed variability, wind direction, the use of various statistical models to describe wind behavior, height influences, and wind data assessment.

## Wind Power

Moving air molecules have mass and speed and therefore kinetic energy. This energy can be extracted by the blades or propeller of a WTG. The rate the wind passes by some reference point can be related to available wind power by equation 1.

$$P = \frac{1}{2} k\rho AV^3 \qquad (1)$$

where

$P$ = instantaneous power (kW)

$k$ = 9.8 x 03 (N-$s^2$/kg-m)

$\rho$ = air density (kg/$m^3$)

$V$ = wind speed (m/s)

$A$ = cross sectional area ($m^2$)

The available wind power depends on the cube of the wind speed. Thus, small differences in wind speed can make a significant impact on the available wind power. For example, though a 5.4 m/s wind is only 20 percent faster than a 4.5 m/s wind, the available power in a 5.4 m/s wind is nearly 73 percent higher than that in a 4.5 m/s wind.

Variations in the density, $\rho$, due to altitude and temperature differences also have an impact on wind power availability. For example, assuming an otherwise identical wind regime, a wind system located at the Rocky Flats test center (elevation of 183m (6,000 ft)) would produce almost 20 percent less power than the same wind system located in Muskegon, Michigan (elevation 192m (630 ft)) (18). Considering temperature effects, the long term mean temperatures in Muskegon for January and July are -3.3° C (26° F) and 21.7° C (71° F), respectively, corresponding to an almost 10 percent difference in air density (18). Thus, for the same wind speed, Michigan winter winds contain almost 10 percent more power than Michigan summer winds. Though altitude and temperature effects are usually accounted for in WTG performance tests (5), they are sometimes neglected when WTG energy output calculations are made in feasibility analyses.

## Average Winds in Michigan

### Yearly Average

The single most important wind characteristic pertaining to wind power applications is the yearly average wind speed. In fact, estimates for WTG Annual Energy Output are sometimes based on the yearly average wind speed alone. Figure 5 illustrates yearly average wind speeds at selected Michigan locations.

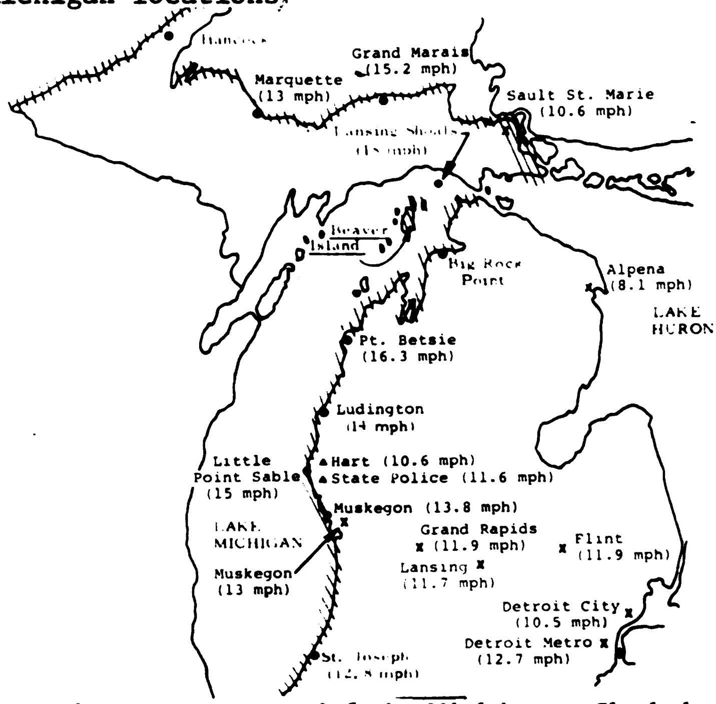



Figure 5. Wind energy potential in Michigan. Shaded areas indicate regions which have the best potential for wind energy systems. Wind speeds indicated are yearly averages, correct to 21.3 m (70 ft) using a height correction exponent of .16 (1, 13).

( 1.0 mph = .447 m/s )

The areas along the eastern shore of Lake Michigan and the southern shore of Lake Superior have very high yearly average wind speeds--some of the highest in the Midwest. Unfortunately, the average wind speeds for the vast majority of Michigan remains largely unknown. The extent of wind speed attenuation as one travels inland from the coastal regions is also largely uncategorized but must be determined if an accurate potential of SWECS is to be established in Michigan.

Figure 5 depicts long term yearly average wind speeds but the yearly average wind speed may change considerably from year to year. Figure 6 illustrates the variability of yearly average wind speeds for 1966-1980 for the Muskegon County Airport. Both the absolute values of the wind speeds and the percent difference from the 15 year average of 6.0 m/s can be read from the Figure.

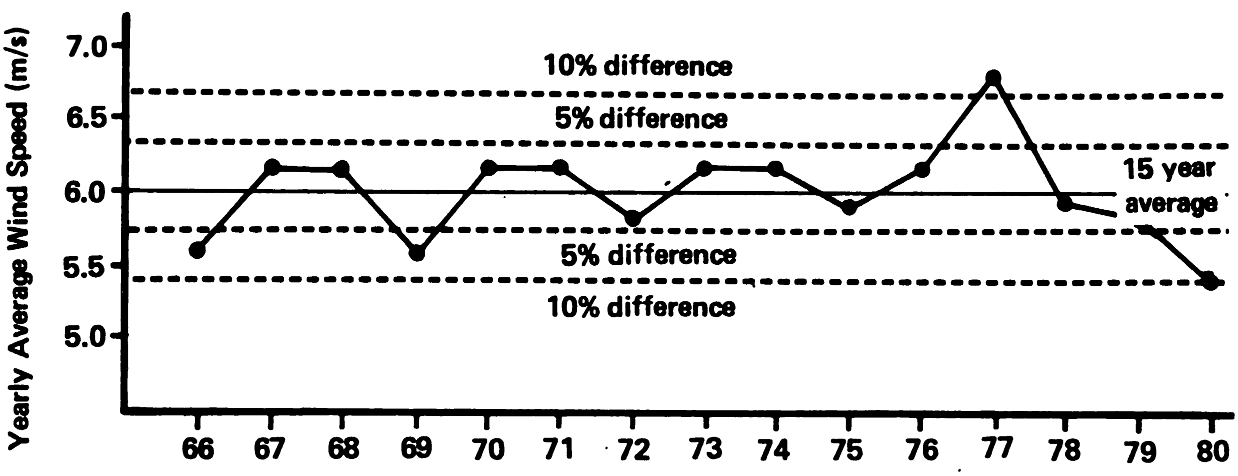



Figure 6. Yearly average wind speeds for Muskegon County Airport, 1966-1980 (corrected to 21.3 m using a height correction exponent of .16). Source: (15).

For almost one year out of every three, the yearly average wind speed differs from the long term average by 5 percent or more. Two years had average wind speeds that differed from the long term average by nearly 10 percent. Wind records for other Michigan locations indicate even more dramatic variations, some as high as 20 percent (22). Though relatively unimportant for the long term SWECS performance, this seemingly small year to year variability can have a significant impact on the length of data aquisition time necessary to accurately estimate the long term average wind speed. As shall be shown, even small errors in the estimation of the long term average wind speed can balloon into large errors in the calculation of WTG Annual Energy Output.

## Monthly Averages

Wind speeds vary significantly between the seasons. In Michigan, the highest wind speeds occur during the winter months; the lowest wind speeds occur during the summer. Figure 7 illustrates long term (1965-75) monthly average wind speeds and the percentage difference from the long term yearly average for the Muskegon Coast Guard Station.

The summer months have average wind speeds almost 20 percent lower than the yearly average whereas the winter months have wind speeds almost 20 percent higher. Depending on the design of the SWECS, these variations will produce even more dramatic differences in the monthly SWECS energy output. The long term yearly average wind speed at the Muskegon Coast Guard Station is 0.2 m/s higher than for the Muskegon County Airport (Fig. 7 compared to Fig. 6).

Year to year monthly averages vary even more dramatically than year to year yearly averages. For any given year and month, the difference

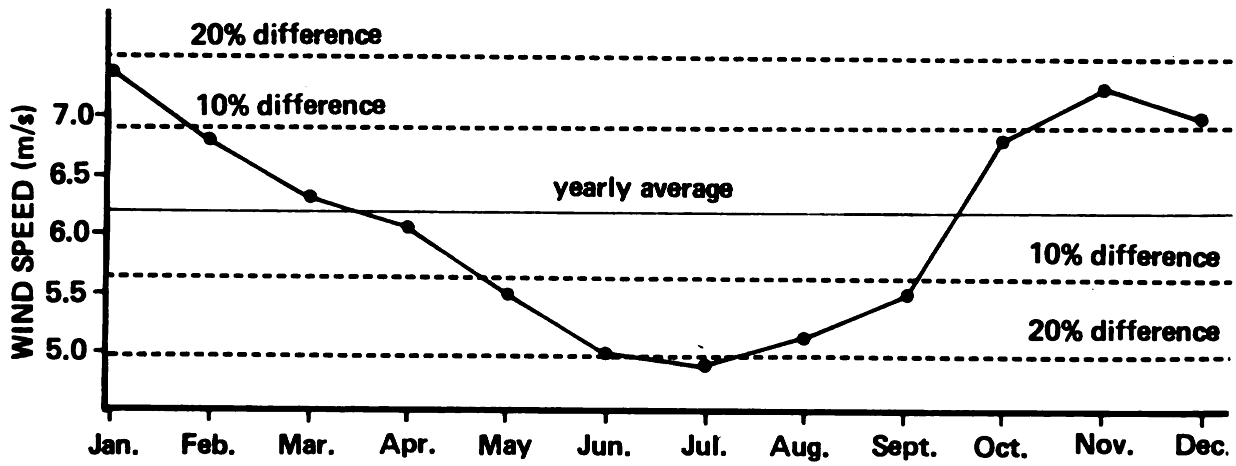



Figure 7. Long term monthly average wind speeds for Muskegon Coast Guard Station, 1965-75 (corrected to 21.3 m using a height correction exponent of .16).

between the monthly average wind speed can be higher than 30 percent but is generally around 9 percent (22).

## Diurnal Variations

Wind not only displays reoccurring seasonal speed variations but reoccurring daily or diurnal speed variations as well. Figure 8 illustrates diurnal wind behavior for the Muskegon Coast Guard Station in 1972.

Generally, wind speeds are lowest in the early morning and highest in the mid-afternoon. However, diurnal wind behavior can be even more variable than year to year monthly average wind speeds and may be very unlike Fig. 8 for any particular day.

## Wind Direction

Depending on the site, wind direction has a significant impact on the WTG energy performance. If the terrain is relatively flat and there

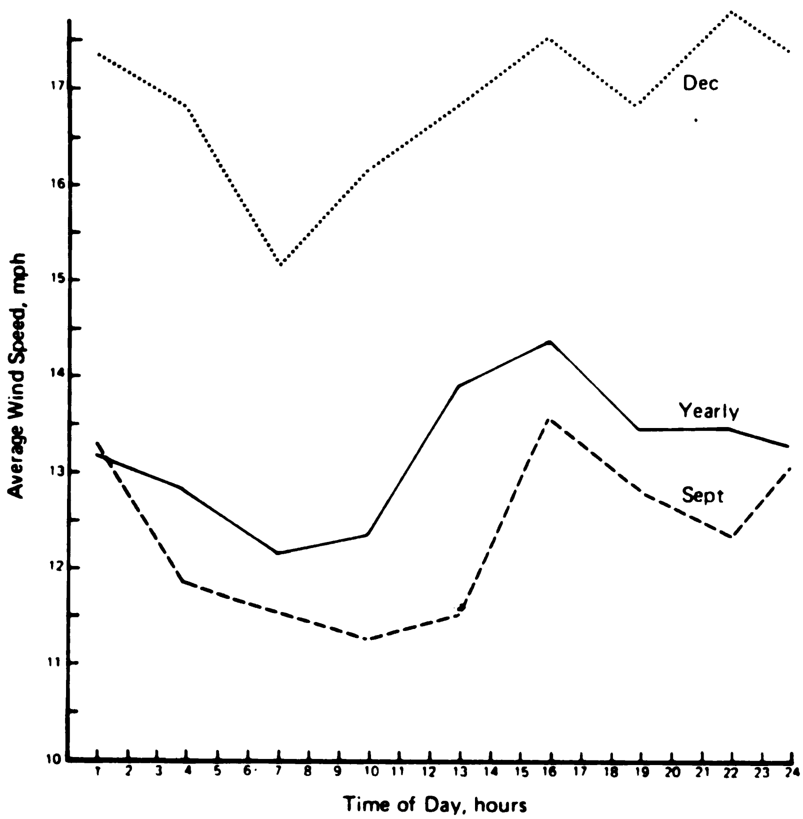



Figure 8. Daily wind patterns for Muskegon, 1972 (corrected to 21.3 meters using a height correction exponent of .16) (1).

are no nearby obstructions, variations in wind direction may be relatively unimportant for well designed WTGs. Obviously, nearby obstructions in particular direction can reduce WTG power output, particularly if winds from that direction contain a significant portion of the yearly available wind power.

Wind direction is usually illustrated by a wind rose (Fig. 9). Wind roses show the direction the wind is coming from, the fraction of the total time the wind blows from that direction, and the average wind speed from that direction.

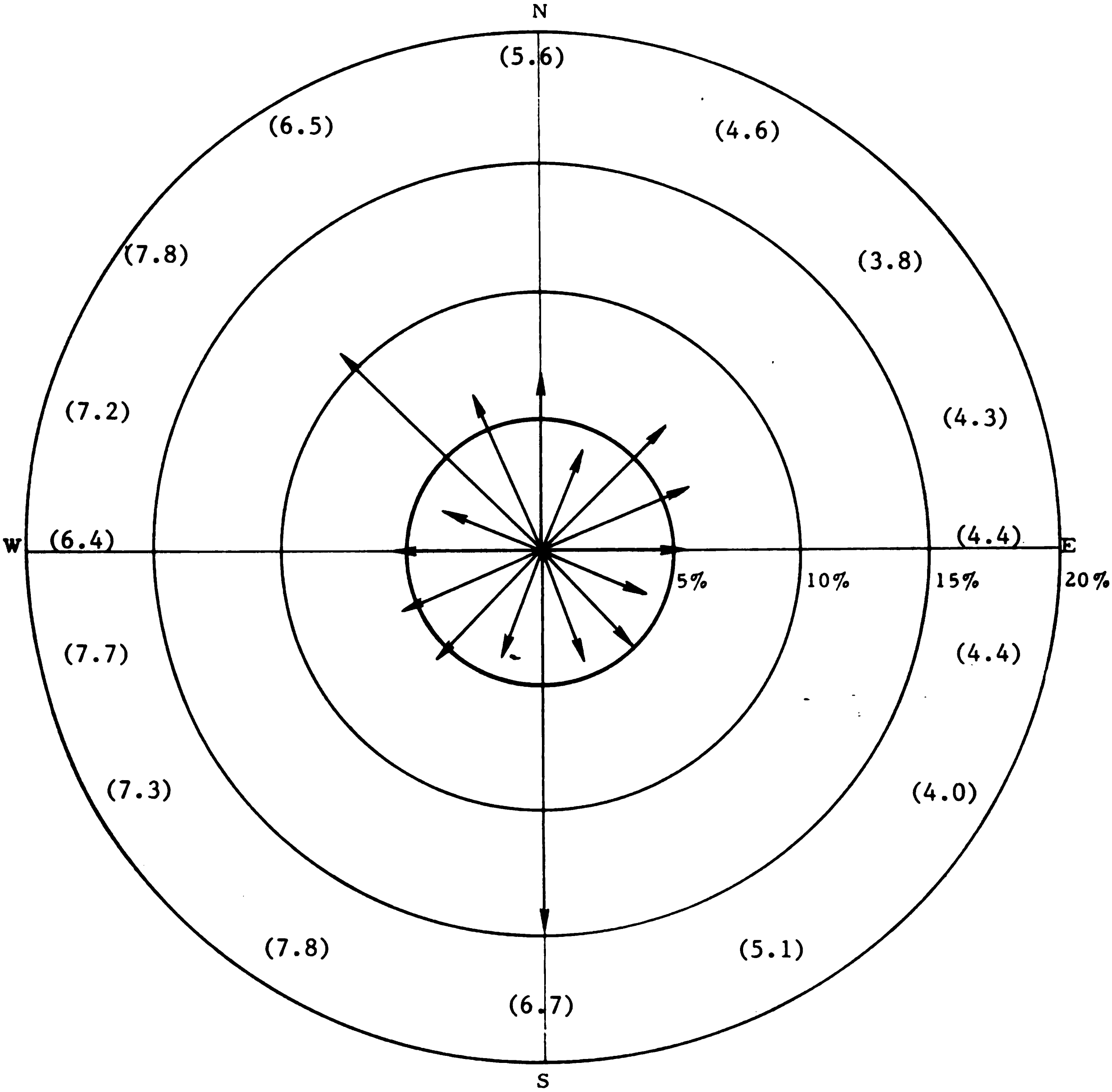



Figure 9. Muskegon Coast Guard 1972 Annual wind rose. ( ) = average velocity in m/s corrected to 21.2 m (70 ft) using a height correction exponent of .16 (1).

For the Muskegon Coast Guard Station, the prevailing winds are from the northwest. The significance of the Coast Guard Muskegon wind behavior is best illustrated by an energy rose (Fig. 10).

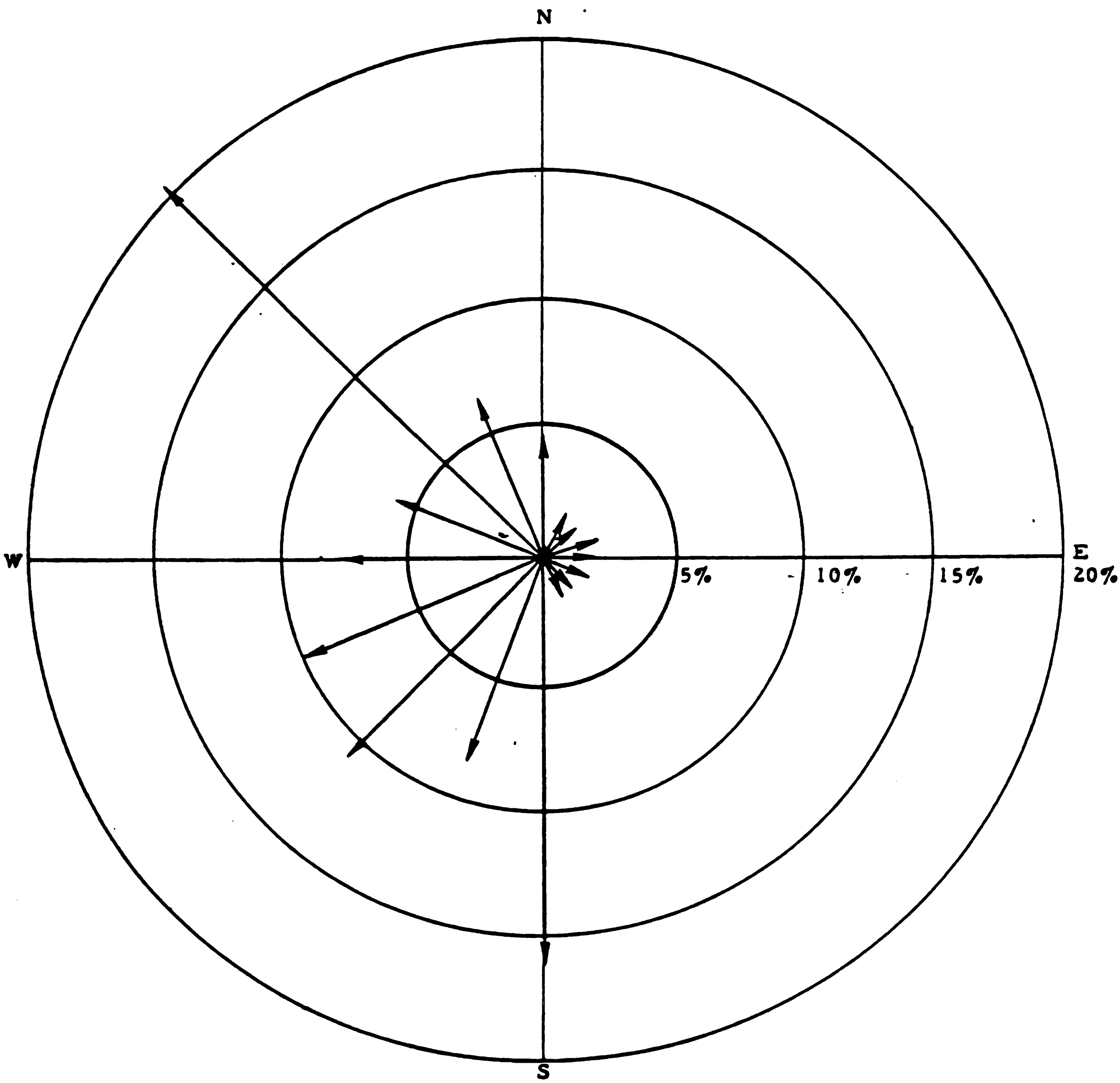



Figure 10. Muskegon Coast Guard 1972 Annual energy rose (1).

Figure 10 suggests that easterly winds at this site are relatively unimportant for SWECS energy production.

Figures 9 and 10 illustrate annual directional wind behavior. The wind direction for a particular month may be unlike annual behavior. In particular, a recent study suggests that areas near the Lake Michigan coastal region exhibit significant daily wind direction variability during the summer, due to lake breeze effects (29). The lake breeze effect induced variability may be relatively unimportant for wind power applications, however, since the summer winds contain only a small fraction of the annual available wind power.

## Models for Describing Wind Behavior

For the purposes of calculating the expected SWECS energy output, wind behavior is often described by statistical models. Though usually introduced as cummulative probability distribution functions, the models take their probability density forms when used for WTG energy output computations.

A variety of probability density functions are used for SWECS energy output calculations. The most notable of these are the Weibull, the Rayleigh, the gamma, and the Gaussian or normal probability densities. Though the gamma and normal probability densities are thought to adequately describe many actual wind regimes (1, 11), and in fact the gamma probability density was found to produce the best description of wind behavior in one study (1), most researchers have used the Weibull probability density as the proferred statistical model for calculating SWECS energy output. As a result, only the Weibull probability density, and the Rayleigh probability density, a special case of the Weibull probability density, will be considered further.

## Weibull Probability Density Function

The formula for the Weibull probability density is:

$$\rho(v)dv = (k/c)(v/c)^{k-1}\exp\left(-(v/c)^{k}\right)dv \qquad (2)$$

where

$\rho(v)dv$ = probability of finding a wind speed between v and v + dv

k = shape factor (dimensionless)

c = scale factor (m/s or mph)

The Weibull shape factor, k, and the Weibull scale factor, c, are related to the mean wind speed, $\overline{V}$, and the standard deviation, $\sigma$, by

$$k = (\sigma/\overline{V})^{-1.086} \text{ and} \qquad (3)$$

$$c = \overline{V}/\Gamma(1 + 1/k) \qquad (4)$$

where $\Gamma$ is the usual gamma function (10). Equations 3 and 4 show that a large shape factor implies a low standard deviation (or variance) and that a single value for $c/\overline{V}$ is associated with each k value.

Figure 11 illustrates the influence of the shape factor, k, on the shape of the Weibull probability density curve.

The relationship between $c/\overline{V}$ and k is illustrated in Fig. 12. The $\Gamma$ function introduces computational complications when the Weibull c and k factors are determined from site average wind speed and variance data so an equation for the curve in Fig. 12 was emperically derived and determined to be

$$c/\overline{V} = 0.014k - 0.065\exp\left(-(3.1(k-1.3))\right) + 1.164 \qquad (5)$$

Equation 5 is used in the computer programs for calculating SWECS annual energy output.

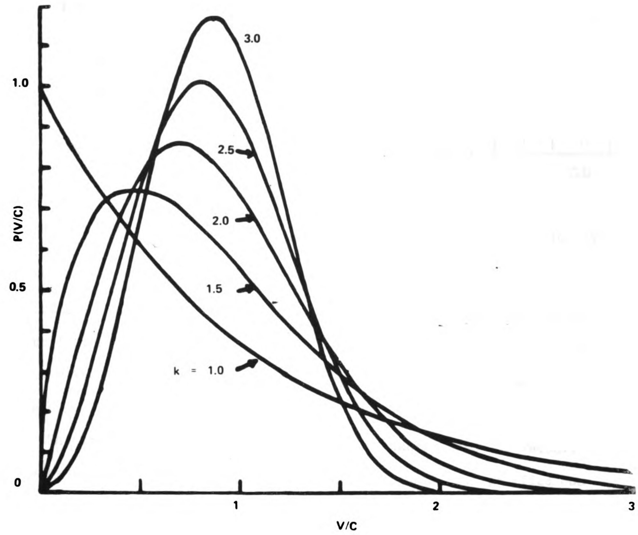



Figure 11. Weibull probability density function for various k values (9).

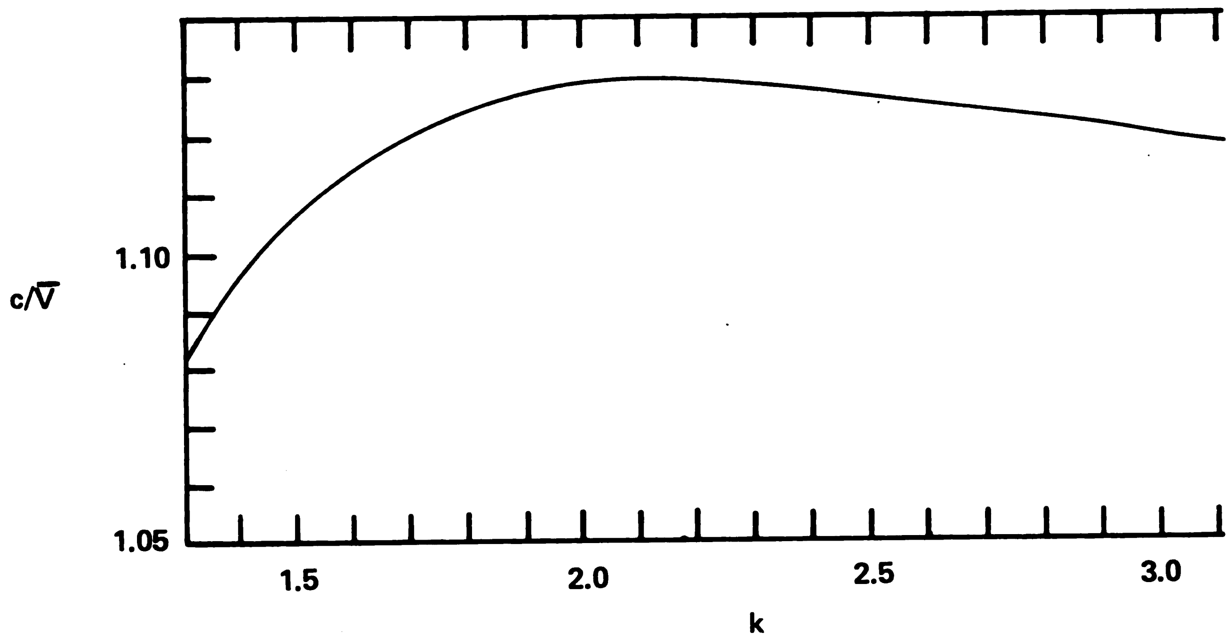



Figure 12. Ratio of Weibull c to mean wind speed vs. Weibull k value (9).

## Rayleigh Probability Density Function

The Rayleigh probability density function is a special case of the Weibull probability density, obtained when k = 2.0 (see Fig. 11). Since the k value is specified, the ratio $c/\overline{V}$ is also specified, equal to 1.128 (see Fig. 12).

The Rayleigh density function may be more useful than the Weibull density function since it is a single parameter function, specified completely by the mean or average wind speed. As a result, only the average wind speed need be determined for the site implying a potentially less complex and expensive wind data assessment program. The Weibull density function is more general than the Rayleigh density function, however, and can be manipulated to fit a wider variety of actual wind regimes.

There are two questions: 1) Does the Rayleigh density function adequately describe the wind regime in question, and 2) What errors may be introduced if the Rayleigh density function is used for AEO calculations when the site wind behavior is best described by some other Weibull distribution? The answer to the second question influences the answer to the first and will be investigated in detail in the next chapter. As a partial answer to the first question, many wind regimes with yearly average wind speeds above 4.0 m/s (8.9 mph) are thought to be Rayleigh distributed (9). The Rayleigh density function is popular for energy output computations since sites must have yearly average wind speeds greater than 4.5 m/s (10.1 mph) to currently have economic interest for SWECS applications (3). Also, many sites exhibit more year to year variability in the actual wind speed distribution than there is between any particular year and the Rayleigh description (7). However, as shall be shown, the compiled height corrected Weibull k factors for several Michigan locations suggest that the site wind behavior is best described by the more general Weibull density function.

## Variations in Weibull k and c Factors

Weibull k and c factors vary with the season and with height above ground (6, 9, 10).

### Seasonal Variations

The Weibull k factor varies with the season; higher k values (lower variance) occur in the winter and lower k values (higher variance) occur in the summer (see Table 1).

Table 2 helps illustrate the data from Table 1 by listing the seasonal Weibull k factors as a percentage of the annual Weibull k factor.

Table 2 shows a general pattern of lower variance in the winter winds and higher variance in the summer winds (higher and lower k values).

Table 1. Seasonal Weibull k Values for five Michigan locations.

| Location | Winter | Spring | Summer | Fall | Annual |
|---|---|---|---|---|---|
| Detroit | 2.20 | 2.08 | 1.78 | 1.93 | 2.03 |
| Flint | 2.18 | 2.11 | 1.92 | 2.07 | 2.01 |
| Grand Rapids | 2.19 | 2.11 | 1.92 | 1.90 | 2.00 |
| Lansing | 2.54 | 2.27 | 1.93 | 2.28 | 2.13 |
| Muskegon | 2.20 | 2.21 | 2.18 | 2.13 | 2.08 |

Source: (9)

Table 2. Seasonal Weibull k factors as a percentage of the annual Weibull k factor.

| Location | Winter | Spring | Summer | Fall |
|---|---|---|---|---|
| Detroit | + 8% | + 2% | -12% | - 5% |
| Flint | + 8% | + 5% | - 5% | + 3% |
| Grand Rapids | +10% | + 6% | - 4% | - 5% |
| Lansing | +19% | + 7% | - 9% | + 7% |
| Muskegon | + 6% | + 6% | + 5% | + 2% |

Thus, winds blow "steadier" in the winter and are more variable in the summer. The average of the seasonal k values is higher than the annual k value due to the nonlinear form of the Weibull density function.

## Height Variations

Both the Weibull c and k factors vary with height above ground (9, 10). Height variations in Weibull k factors are sometimes overlooked in SWECS energy analyses.

Weibull c Factors

The Weibull c factor varies with height according to the formula

$$c_2 = c_1 \; (Z_2/Z_1)^{\eta}$$

where

$c_2$ = average c value at height $Z_2$ (m/s)

$c_1$ = average c value at height $Z_1$ (m/s)

$Z_1$ = anemometer height (m)

$Z_2$ = new height at which the value for $c_2$ is estimated (m)

$\eta$ = power law exponent (or height correction exponent)

$$= [0.37 - 0.088 \ln(c_1)]/[1 - 0.088 \ln(Z_1/10)] \tag{6}$$

Source: (9)

The power law exponent as described in equation 7 is a function of the original anemometer height and the c factor determined at that height, and is useful for flat terrain only (9). Using equation 7, the power law exponents for all the five Michigan locations and for all seasons are calculated to be 0.23 ± 10 percent.

Since $c/\overline{V}$ varies from 1.115 to 1.129 for most sites ((9) and Fig. 11), one can closely approximate the variations in average wind speed, $\overline{V}$, with respect to height changes by equation 8 or

$$\overline{V}_2 = \overline{V}_1 \; (Z_2/Z_1^{\eta}) \tag{7}$$

Rather than use equation 7, the power law or height correction exponents for use in equation 8 are usually determined from a chart similar to Table 3, which illustrates the terrain dependence of the power law exponent.

Table 3. Height correction exponent for different terrain.

| Roughness characteristics | Height correction exponent |
|---|---|
| Smooth surface, ocean, sand | .14 |
| Low grass or fallow ground | .16 |
| High grass or low row crops | .18 |
| Tall row crops or low woods | .21 |
| High woods with many trees | .28 |
| Suburbs | .40 |

Source: (17)

Figure 13 illustrates the effect of the height correction (power law) exponent on the predicted wind speed profile for three different terrains.

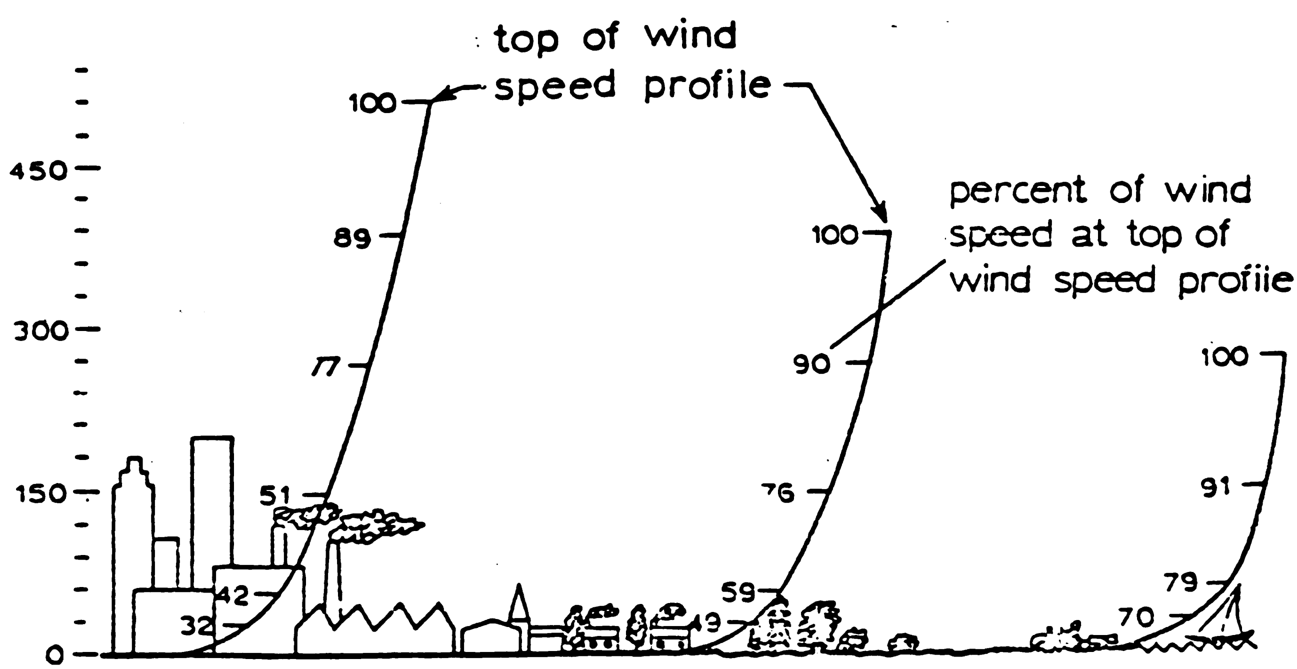



Figure 13. Wind speed profiles for three different height correction exponents (11). $\eta$ = .40, .25, .14.

The use of height correction exponents of 0.16 (used in Figs. 6, 7, and 8) or 0.14 (the 1/7 power law) are the most popular because, in part, they are the most conservative (produce the smallest wind speed increase) for upward height corrections of wind speed. The exponent value of 0.4 produce the most conservative adjustments (produce the largest wind speed decrease) for downward height corrections but one seldom has use for such corrections. Wind speeds are corrected to 21.3 m (70 ft) which is a common hub height for WTG located in Michigan.

Since 0.16 is a conservative height correction exponent for upward corrections, the speed corrections are relatively minor. The possible errors of a wrong prediction are relatively small even for height corrections of 15 m (50 ft). The common anemometer height of 10 m should be sufficient for smooth terrain. For much rougher terrain, the anemometer should be placed as high as possible to reduce possible height correction errors.

## Weibull k Factors

The height correction formula for the Weibull k factor is

$$k_2 = k_1[1 - 0.088 \ln(Z_1/10)]/[1 - 0.088 \ln(Z_2/10)] \qquad (10)$$

where

$k_2$ = Weibull k factor corrected to height $Z_2$

$k_1$ = Weibull k factor at height $Z_1$

$Z_1$ = anemometer height (m)

$Z_2$ = new height (m)

Source: (9)

According to equation 9, the Weibull k factor is less affected by height variations compared to the Weibull c factor. Table 4 shows the dividend of the bracketed portions of equation 9 for a variety of upward

Table 4. Multiplying factors for Weibull k factors corrected from 10.0 m to a variety of new heights.

| New height (m) | New height (ft) | Multiplying factor |
|---|---|---|
| 10.0 | 32.7 | 1.00 |
| 12.5 | 40.8 | 1.02 |
| 15.0 | 49.1 | 1.04 |
| 17.5 | 57.2 | 1.05 |
| 20.0 | 65.4 | 1.06 |
| 22.5 | 73.6 | 1.08 |
| 25.0 | 81.8 | 1.09 |

height corrections from 10.0 m (32.7 ft). For example, if the annual (or seasonal) Weibull k factor is 2.00 (Rayleigh assumption) at 10.0 m, the Weibull k factor at 22.5 m is estimated to be 2.16 (2.0 x 1.08 = 2.16; see Table 4). The relationships depicted in Table 4 could be generated by the equation for Weibull c factor height variation (equation 6) if the height correction exponent was around 0.09, an exponent value even less than the "most conservative" suggested value of 0.14 used for c factor corrections.

Table 5 presents the Weibull k factors for the five Michigan locations, corrected to 21.3 m (70 ft).

Table 5 indicates that the Rayleigh assumption (k = 2.0) may not be as suitable as suggested in Table 1.

Table 5. Seasonal Weibull k values for five Michigan locations, corrected to 21.3 m.

| Location | Winter | Spring | Summer | Fall | Annual |
|---|---|---|---|---|---|
| Detroit | 2.17 | 2.05 | 1.76 | 1.90 | 2.00 |
| Flint | 2.42 | 2.35 | 2.14 | 2.30 | 2.24 |
| Grand Rapids | 2.21 | 2.13 | 1.94 | 1.92 | 2.02 |
| Lansing | 2.61 | 2.33 | 1.98 | 2.34 | 2.19 |
| Muskegon | 2.46 | 2.47 | 2.44 | 2.38 | 2.32 |

## Wind Data Gathering

The reliability of any SWECS feasibility analysis is greatly enhanced by some form of on-site wind data assessment. Though average wind speeds are often estimated over relatively broad regions, wind behavior displays considerable variability due to local terrain effects. On-site wind data assessment is particularly important for SWECS located in Michigan since the Michigan areas with the highest yearly average wind speeds have highly complex terrain.

### Instrumentation for Wind Data Assessment

There are basically two choices of instruments for a reasonably priced wind measurement program for potential SWECS applications: 1) some type of recording anemometer or a digital data logger which places wind speeds into bins of specified wind speed increments, and 2) a wind run meter which measures wind run. Wind run is the length of the wind stream that passes by the meter (in a given period) and can be used to calculate the average wind speed. For example, if 120 km of wind passes by the instrument in a 24 hr period, the average wind speed is 5 km/hr.

The advantage of the recording anemometers is that hourly wind data can be retrieved and as a result the Weibull k and c values as well as the diurnal wind speed variations can be determined for the site. Only the average wind speed can be determined from a wind run meter, and therefore the use of the Rayleigh probability density for energy output calculations is implied. The advantage of the wind run meter is that it is relatively inexpensive, costing only about $150. Anemometers capable of recording hourly wind data cost $700 or more. Due to the cost differential, many potential SWECS owners may choose a wind run meter for wind data assessment.

The anticipated widespread use of wind run meters, along with the height corrected annual k factor data from Table 5, provides a motivation to investigate the errors in calculated AEO that could be produced by assuming the wind is Rayleigh distributed when the site wind behavior is actually best described by some other Weibull density. As shall be shown, WTG design strongly influences the affect that variations in the Weibull k factor have on the predicted SWECS energy output. The designs of some large WTG produce a relative insensitivity to k. An insensitivity to k implies that wind data assessment programs for sites where these large wind systems are candidates could potentially yield more useful information if several wind run meters were placed in a variety of locations and heights rather than just one or two recording anemometers placed in a single location.

## Required Duration of Wind Assessment Programs

As a sometimes used rule of thumb, the wind assessment program should be carried out for at least a full year. The objective is to predict long term wind behavior based on a much shorter period of analysis. Unfortunately, Fig. 6 showed that there can be significant year-to year variability in yearly average wind speed at a particular site. For example, the yearly average wind speed in 1977 at the Muskegon Airport was 12 percent higher than the long term average wind speed (see Fig. 6). Two other first order weather stations, the Grand Rapids Airport and the Detroit Metro Airport, displayed even more year-to-year variability. The yearly average wind speeds for the Detroit Metro and Grand Rapids Airports were averaged for three consecutive years, starting with each successive year (see Fig. 14). The three year averages were then compared to the long term average. For example, the data point at 1966 compares the three year average wind speed for 1966, 1967, and 1968 to the long term average.

As shown in Fig. 14, even consecutive three year averages can differ significantly from the 15 year average wind speed. For example, if the wind speeds were measured and averaged for 1974, 1975, and 1976, the value obtained would be 18 percent higher than the 15 year average at the Detroit Metro Airport and 6 percent lower than the long term average at the Grand Rapids Airport. If the candidate sites were in these locations and there were no weather stations, even a three year wind data assessment program would be inadequate.

An important question is the extent to which the data at a candidate site can be correlated to a nearby weather station. A strong correlation implies that a much shorter period of data assessment need be performed, perhaps even less than a year. Unfortunately, there are conflicting reports on the degree of correlation between candidate sites and a nearby weather station. In a study performed by Corotis et al. (1977) on six

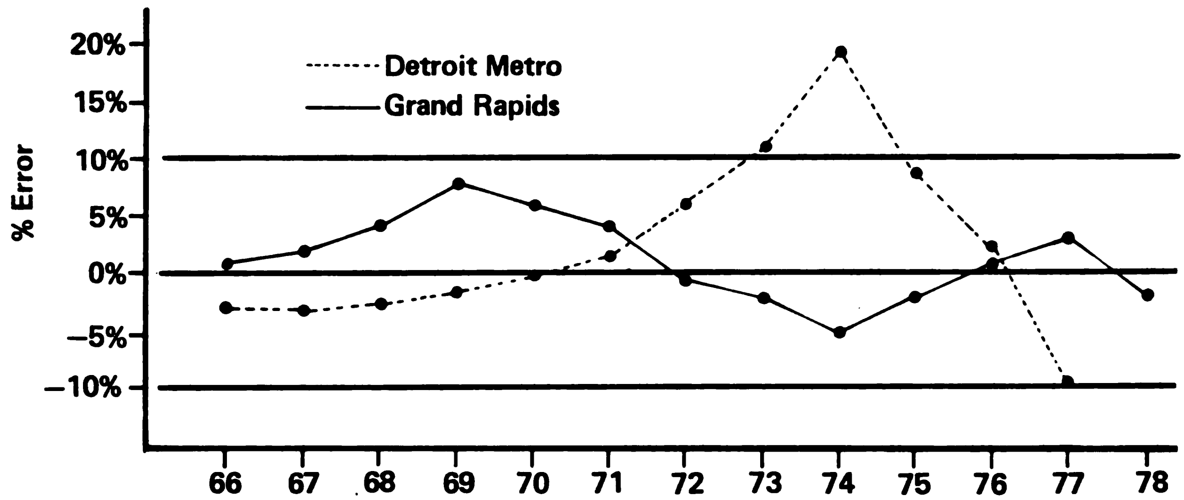



Figure 14. Three year average wind speeds as a percent error from the 15 year average (15).

different sites in Illinois, strong correlation was found between weather stations as far as 100 km apart (6). Similarly, a study by Asmussen et al. concluded that the correlation between the wind data from various Lake Michigan Coast Guard Stations was very high (1).

However, a study performed by Justus et al. (1979) on twenty different pairs of weather stations concluded that "the use of nearby, climatological site, long term data to adjust short term candidate site data yields only minimal improvement in [the candidate site data]" (11). Weber (1978) obtained the same results for a series of weather stations in southwest lower Michigan (29). In particular, he noted the poor correlation between data from nearby weather stations near the shoreline environment. Unlike the Asmussen et al. study, Weber compared the wind data from a station located right on the Lake Michigan shore to stations located several miles inland. The Asmussen et al. study compared the wind data from stations all located on the shore.

The poor correlation between stations located right on the Lake Michigan shore and several miles inland is partly illustrated by Fig. 15, a comparison of yearly average wind speeds in 1966-75 for the Muskegon County Airport and the Muskegon Coast Guard Station. Though only a short distance apart, these weather stations displayed very dissimilar wind behavior from 1966 to 1971 and very similar behavior in 1971 to 1975. Figure 15 suggests that the degree of correlation between nearby weather stations can be quite good for some periods and rather poor for others, thus providing a partial explanation for the different conclusions of the various wind correlation studies.

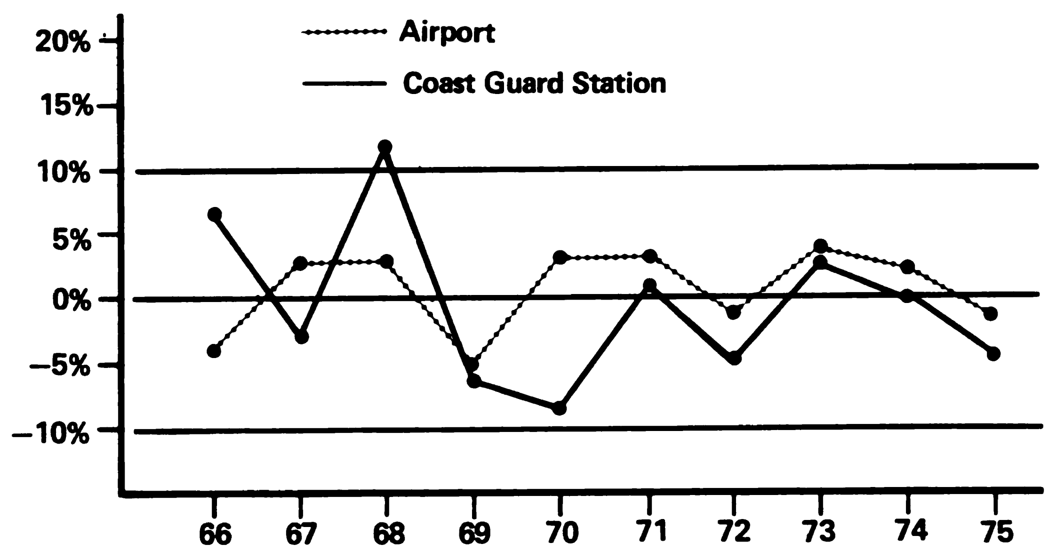



Figure 15. Yearly average wind speeds as a percent error from the 10 year mean for 1966-1975 for the Muskegon County Airport and the Muskegon Coast Guard Station (1, 15).

In the absence of a demonstrated correlation between wind data at a candidate site and a nearby weather station, data assessment at the candidate site should be carried out for more than a year, perhaps even more than three years. Since most potential SWECS owners lack the expertise to perform correlation analysis, extended periods of candidate site data assessment are recommended.

# CHAPTER FOUR

## CALCULATION OF WTG ENERGY OUTPUT

The single most important performance criteria for Wind Turbine Generators is their expected Annual Energy Output in various wind regimes. The calculation of AEO is not an easy task, however, since the performance characteristics of different WTG are widely dissimilar, as are the wind characteristics among different sites. Chapter 4 reviews methods for calculating AEO that have been used in the past and presents a new computer based method which uses a curve fitting technique to describe WTG machine characteristics. Use of the Rayleigh vs. Weibull density functions are also considered.

To determine the expected energy output of a particular WTG located at a particular site, two functions must be known:

$P(v)$ = WTG power output as a function of wind speed, and

$\rho(v)$ = wind speed probability density

The average power, $\overline{P}$, can be calculated by integrating the product of $P(v)$ and $\rho(v)$ over the WTG cut-in wind speed, $V_i$, and cut-out wind speed, $V_o$, or

$$\overline{P} = \int_{V_i}^{V_o} P(v)\,\rho(v)dv$$

The Annual Energy Output, AEO, can be calculated by multiplying the average WTG power output, $\overline{P}$, by the number of hours in a year, or

$$AEO = \overline{P} \cdot 8760 \text{ hr/yr}$$

Monthly energy outputs can be calculated in a similar fashion. Hourly energy outputs are usually calculated without the use of probability densities by directly plugging the hourly average wind speed into the P(v) function.

The wind speed probability densities, $\rho(v)$, used in AEO calculations have already been discussed in detail in Chapter 3. A simplified description of the WTG power output, P(v), as a function of wind speed was illustrated in Chapter 2.

The various methods for calculating AEO that have been used in the past differ primarily in the way the actual WTG P(v) curve is approximated. Four of the most widely used methods for approximating the actual P(v) curve have been the straight line or ramp (3), cubic, Justus (8, 9), and Powell (19) approximations. Table 6 summarizes the equations used to approximate the WTG power output curve when $V_i \leq v \leq V_r$.

Table 6. Expressions for WTG power output when $V_i \leq v \leq V_r$.

| | |
|---|---|
| Straight line | $P(v) = A + Bv$ |
| Cubic | $P(v) = Av^3$ |
| Justis | $P(v) = A + Bv + Cv^2$ |
| Powell | $P(v) = A + Bv^k$ |

The coefficients A, B, and C are simply generalized coefficients and are functions of $V_i$, $V_r$, and $P_r$. That is, when the values of only $V_i$, $V_r$, and $P_r$ are specified, the approximating P(v) curve is completely specified when $V_i \leq v \leq V_r$.

When $V_r \leq v \leq V_o$, the straight line, cubic, Justus, and Powell approximations all assume that the WTG power output remains constant and equal to the WTG rated power. The assumption that $P = P_r$ when $V_r \leq v \leq V_o$ may not be true for a particular WTG and the errors introduced by this possibly wrong assumption are considered in a later section of this chapter.

A study was performed to compare the four methods listed in Table 6 to two other more general approaches--the piecewise linear approximation and the hand calculated discrete approximation described in the Performance Rating Document (5) prepared by the American Wind Energy Association (1980). The discrete approximation will be denoted the SWECS Standard approach since the Performance Rating Document is an attempt to establish SWECS performance standards. All six AEO calculation methods were evaluated by applying each to a single generic WTG P(v) curve and comparing the resulting calculated AEO values.

The piecewise linear approximation and SWECS Standard approach can be used only when the shape of the entire actual WTG P(v) curve is known. The piecewise linear approach is just one of several curve fitting techniques that might be used. For example, the use of Nth order polynomials was briefly investigated but rejected since the order of the "best fitting" polynomial varies from one WTG to another and the computations necessary to determine the order and coefficients of the best approximating polynomial, using a least squares approach, are too cumbersome to perform on a small programmable calculator.

All of the methods for calculating AEO were programmed on the TI-59 programmable calculator and the complete equations used are available in Appendix B. Since the TI-59 performs operations much more slowly than the larger computers, the various integrals were solved by integrating by parts and a small remaining term was approximated by a short series (see Appendix B)

## Six Methods of Approximating P(v)

The actual WTG power output curve that was approximated by the various methods is illustrated in Fig. 16. Figure 16 was obtained from the Performance Rating Document and describes a generic WTG P(v) curve (5).

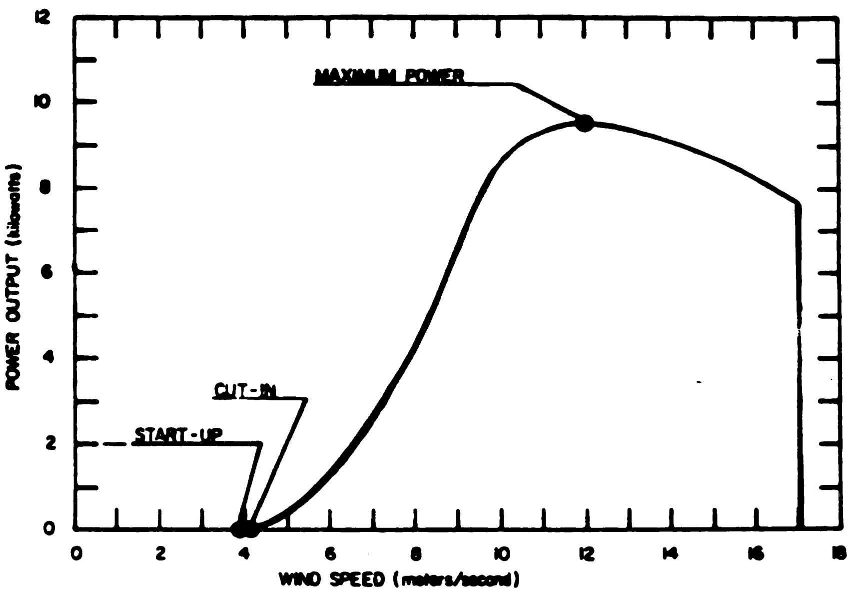



Figure 16. Generic WTG Power Curve

The term rated power was replaced by the term maximum power, as suggested in the Performance Rating Document. The rated power and the maximum power may or may not be the same for a particular WTG. When the straight line, cubic, Justus, or Powell methods were used, the maximum power in Figure 16 was taken to be the rated power.

Every WTG has a characteristic P(v) curve which may or may not be the same as that provided by the manufacturer. When using any AEO calculation method, an actual WTG P(v) curve based on extensive field testing (such as the tests proposed in the Performance Rating Document) should be used. The AEO calculation methods also assume that the WTG satisfactorily adjusts to changes in wind direction (no yaw problems) and that the site wind regime is reasonably well behaved and not too turbulent.

Straight Line Approximation

The formula for P(v), using the straight line approximation, is P(v) = A + Bv (see Appendix B). Figure 17 illustrates the straight line approximation.

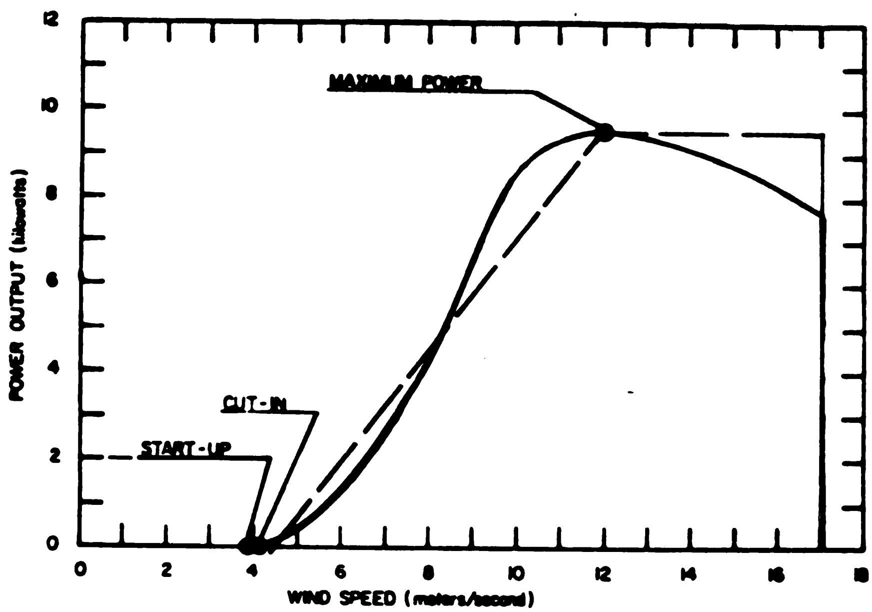



Figure 17. Straight line approximation of actual P(v) curve.

The power output is assumed to be constant above the rated wind speed. The straight line should be drawn for the best visual fit between $V_i$ and $V_r$. One may have to define a new "effective" cut-in wind speed (2). In Fig. 17, the effective cut-in wind speed has been adjusted slightly upwards from the actual cut-in wind speed.

Cubic Approximation

The formula for P(v), using the cubic approximation, is $P(v) = Av^3$. The coefficient A, determined from the WTG efficiency at rated (maximum) power, is derived to be $A = P_r/V_r^3$ (see Appendix B). Figure 18 illustrates the cubic approximation.

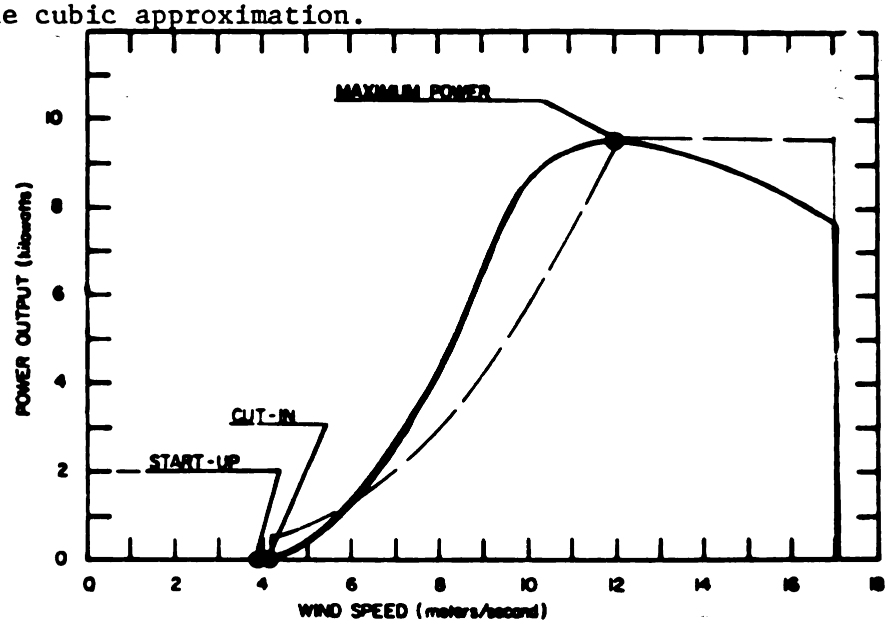



Figure 18. Cubic approximation of actual P(v) curve.

The stepwise jump in P(v) at $V_i$ in Fig. 18 is inherent for any simple cubic relationship which assumes a constant efficiency.

Justus Approximation

The Justus method approximates the P(v) curve with a second order polynomial, i.e., $P(v) = A + Bv + Cv^2$. The coefficients A, B, and C are determined by assuming that WTG has the same efficiency when the wind speed is at a midpoint between $V_i$ and $V_r$ as it does when the wind speed is equal to $V_r$ (see Appendix B).

The Powell method was developed in response to several problems with the Justus method (19). Therefore, only the Powell method will be directly compared with the other techniques.

## Powell Approximation

The formula for P(v), using the Powell approximation, is $P(v) = A + Bv^k$, where k is the shape factor of the Weibull probability density. The coefficients A and B are determined using the same efficiency assumptions as the Justus method. The Powell approximation is seen as an improvement over the Justus approximation since it will not predict a negative power output for part of the partial power range, when $V_i$ is less than 26 percent of $V_r$, and it can be analytically integrated (19). Figure 19 illustrates the Powell approximation.

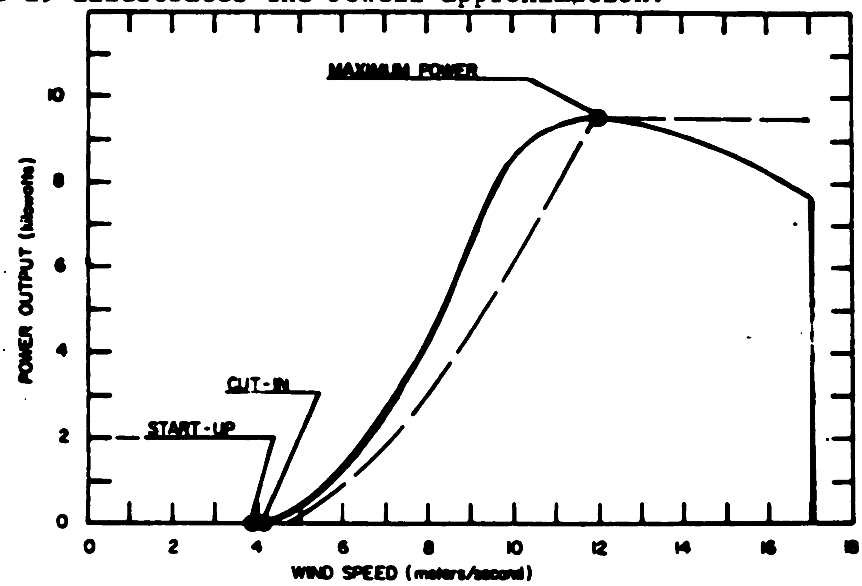



Figure 19. Powell approximation of actual P(v) curve.

## Piecewise Linear Approximation

The piecewise linear approximation uses a series of piecewise continuous line segments to approximate the actual P(v) curve (see Appendix B). Figure 20 illustrates the piecewise linear approximation.

Nine line segments were used in Fig. 20; more could be used to produce an even better approximation. Two different piecewise linear approximations were used. The first follows the actual P(v) curve from

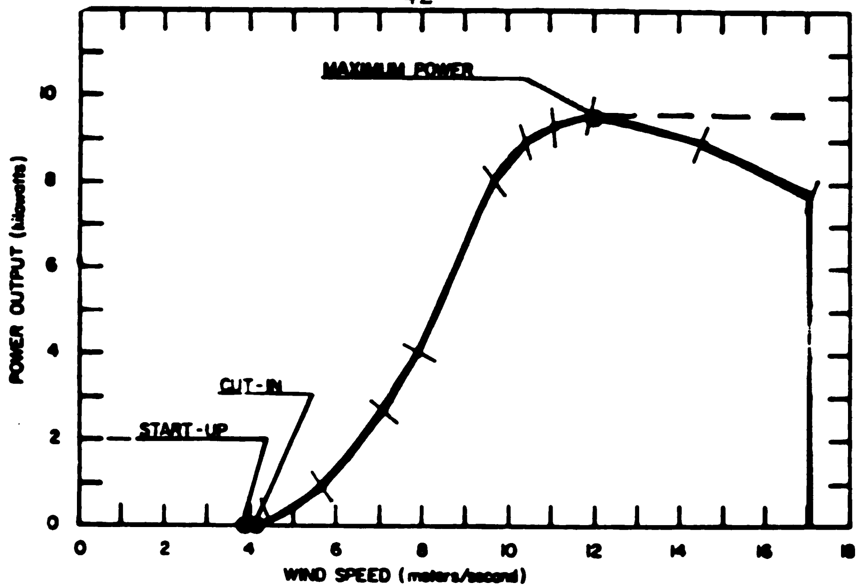



Figure 20. Piecewise linear approximation of actual P(v) curve.

$V_i$ to $V_o$ as indicated by the heavy solid line. The second, indicated by the dashed line, sets $P(v) = P_r$ when $V_r \leq v < V_o$.

SWECS Standard Approximation

The SWECS Standard approach is the discrete approximation, computed by hand, of the original integral in equation 10. AEO is determined by multiplying the WTG power output at each unit wind speed by the probability of occurrence of that wind speed, and summing the products for each unit wind speed from $V_i$ to $V_o$ (5).

## Calculated AEO for the Six Methods

The AEO values calculated by each of six methods are tabulated in Table 7. The Rayleigh probability density was used for three different yearly average wind speeds. Table 7 depicts the AEO values obtained from each method as a percentage of the result obtained by using the piecewise linear approximation.

Table 7. A comparison of calculated AEO.

| | $\overline{V} = 4.5m/s$ | $\overline{V} = 5.5m/s$ | $\overline{V} = 6.5m/s$ |
|---|---|---|---|
| Piecewise linear | 100% | 100% | 100% |
| Piecewise linear ($P(v) = P_r$, $V_r \leq v < V_o$) | 100% | 101% | 101% |
| SWECS Standard (discrete approximation) | 93% | 97% | 98% |
| Straight line | 108% | 94% | 99% |
| Cubic | 81% | 78% | 81% |
| Powell | 82% | 76% | 85% |

## Discussion

For purposes of comparison, the AEO obtained from the piecewise linear approximation is used as the "true value" since, in general, the error introduced by using this technique can be made arbitrarally small if a large number of line segments are used. The nine line segments used in the example yielded almost identical results compared to the calculated AEO based on 18 line segments. The minimum number of line segments which should be used for a given curve was not investigated.

The results in Table 7 were obtained by analyzing a single generic WTG and therefore, the results are specific to the P(v) curve in Fig. 16.

Line 2 from Table 7 indicates that the assumption that $P(v) = P_r$ when $V_r \leq v < V_o$, an assumption held by the straight line, cubic, Justus, and Powell approximation, does not cause significant differences in AEO compared to the full piecewise linear approximation.

Line 3 indicates that the discrete approach used in the Performance Rating Document is quite accurate, producing better results as the average wind speed increases. Though the Performance Rating Document suggests the calculations be based on units of m/s, their example is based on miles per hour. If m/s were used, the errors would be reduced, though the calculations become somewhat more tediuos.

The results of the straight line approximation, line 4, indicate that though this technique can produce a useful first-round approximation, the results are not as accurate as the piecewise linear approach. The accuracy of this method is dependent on a judicious "eye ball fitting" of a straight line to the actual WTG P(v) curve between $V_i$ and $V_r$ (assuming the shape of the curve is known).

The cubic and Powell approximations, lines 5 and 6, can seriously underestimate the AEO from this WTG. Returning to Figs. 18 and 19, the graphs of these approximating curves, these results are not unexpected. The results highlight the problem of a method where AEO is a function of the rated power. Such methods assume that there exists some well defined point where the WTG power output suddenly levels off to a constant value ($P_r$). Such a point does not exist for the WTG depicted in Fig. 16. Observation of many commercial WTG indicates that this is usually the case.

The question becomes, what value should be used as the rated power for the WTG? In the analyses just presented, the maximum power was taken to be the rated power, yet this assumption produced AEO values which were too low. More accurate results could probably be obtained if the rated power was shifted leftwards on this curve, yet there seems to be no systematic way to determine the extent of such a shift. One might say that the rated power should be defined such that the cubic or Powell approximating curves produced a "best fit" to the actual P(v) curve. However, if the shape of the actual P(v) curve was known, a more accurate curve-fitting approach such as the piecewise linear approximation could be used.

As a final note, the calculated AEO from all six methods is the energy obtained from the WTG and not necessarily from the entire SWECS. Synchronous inverters, necessary for Variable Speed-Constant Frequency (VSCF) systems, are not 100 percent efficient and reduce the net available energy from the SWECS compared to the energy produced by the WTG. Since the economic analysis is based on the net available energy, the calculated WTG AEO should be adjusted for VSCF systems.

## The Effect of Weibull k Factors on the Calculated WTG Energy Output

The Rayleigh probability density function might be used for energy output calculations, particularly if only the average wind speed is known, even though the actual wind regime may be better described by some other Weibull probability density. To determine the errors introduced by a possibly wrong Rayleigh assumption, a sensitivity analysis was performed to determine the effect of variations in the Weibull k factor on the calculated energy output. Four different hypothetical WTG designs were used in the sensitivity analysis (see Table 8). Designs A and B correspond to WTG with high rated wind speeds and low and high cut-in wind speeds, respectively. Designs C and D correspond to WTG with low rated wind speeds and low and high cut-in wind speeds, respectively.

For the sensitivity analysis, energy output was calculated using the straight line or ramp approximation. Though not a completely

Table 8. Machine characteristics for four different WTG designs used in the sensitivity analysis.

| Design | Cut-in wind speed | Rated wind speed | Cut-out wind speed |
|---|---|---|---|
| Design A | 2.7m/s ( 6.0 mph) | 15.6m/s (35.0 mph) | 26.8m/s (60 mph) |
| Design B | 4.5m/s (10.0 mph) | 15.6m/s (35.0 mph) | 26.8m/s (60 mph) |
| Design C | 2.7m/s ( 6.0 mph) | 5.4m/s (12.0 mph) | 26.8m/s (60 mph) |
| Design D | 4.5m/s (10.0 mph) | 5.4m/s (12.0 mph) | 26.8m/s (60 mph) |

satisfactory method for calculating WTG energy output if the actual P(v) curve is known, the ramp approximation and the use of a rated power is suitable for sensitivity analyses if a variety of WTG designs are used. Table 9 shows the calculated energy output values for various k values, as a percent of the value obtained when the Rayleigh assumption is used (k = 2). The calculations were performed for three different average wind speeds: 4.5m/s (10.1 mph), 5.5m/s (12.3 mph), and 6.5m/s (14.5 mph).

A value of 90 percent in Table 9 indicates that the energy output expected from the specified WTG located in that wind regime is only 90 percent of the value obtained when the wind is Rayleigh distributed. A value of 110 percent means that the energy output expected from the specified WTG located in that wind regime is 110 percent of the value obtained when the wind is Rayleigh distributed. Thus, values less than 100 percent in Table 9 indicates that the Rayleigh assumption overestimates the energy obtainable from the wind. Values over 100 percent indicate that the Rayleigh assumption underestimates the energy obtainable from the wind.

Table 9. Calculated WTG energy output for various Weibull k factors as a percent of the value obtained when k = 2.

| Weibull k factor | V = 4.5m/s (10.1 mph) | V = 5.5m/s (12.3 mph) | V = 6.5m/s (14.5 mph) |
|---|---|---|---|
| <u>Design A - low cut-in, high rated wind speeds</u> | | | |
| 1.3 | 111% | 104% | 98% |
| 1.4 | 110 | 104 | 99 |
| 1.5 | 108 | 103 | 100 |
| 1.6 | 106 | 103 | 100 |
| 1.7 | 104 | 102 | 100 |
| 1.8 | 103 | 101 | 100 |
| 1.9 | 101 | 101 | 100 |
| 2.0 (Rayleigh) | 100 | 100 | 100 |
| 2.1 | 99 | 100 | 100 |
| 2.2 | 97 | 99 | 100 |
| 2.3 | 96 | 98 | 99 |
| 2.4 | 95 | 98 | 99 |
| 2.5 | 94 | 98 | 99 |
| 2.6 | 93 | 97 | 99 |
| 2.7 | 92 | 97 | 99 |
| 2.8 | 91 | 97 | 99 |
| <u>Design B - high cut-in, high rated wind speeds</u> | | | |
| 1.3 | 139 | 119 | 106 |
| 1.4 | 133 | 116 | 106 |
| 1.5 | 127 | 114 | 106 |
| 1.6 | 121 | 111 | 105 |

Table 9 (cont'd).

| Weibull k factor | $\overline{V}$ = 4.5m/s (10.1 mph) | $\overline{V}$ = 5.5m/s (12.3 mph) | $\overline{V}$ = 6.5m/s (14.5 mph) |
|---|---|---|---|
| Design B (cont'd) | | | |
| 1.7 | 115% | 108% | 104% |
| 1.8 | 110 | 105 | 103 |
| 1.9 | 105 | 103 | 101 |
| 2.0 (Rayleigh) | 100 | 100 | 100 |
| 2.1 | 96 | 98 | 99 |
| 2.2 | 92 | 95 | 98 |
| 2.3 | 88 | 93 | 96 |
| 2.4 | 85 | 91 | 95 |
| 2.5 | 81 | 90 | 94 |
| 2.6 | 79 | 88 | 94 |
| 2.7 | 76 | 87 | 93 |
| 2.8 | 73 | 85 | 92 |
| Design C - low cut-in, low rated wind speeds | | | |
| 1.3 | 86 | 84 | 83 |
| 1.4 | 89 | 87 | 87 |
| 1.5 | 91 | 90 | 89 |
| 1.6 | 93 | 92 | 92 |
| 1.7 | 95 | 94 | 94 |
| 1.8 | 97 | 96 | 96 |
| 1.9 | 99 | 98 | 98 |
| 2.0 (Rayleigh) | 100 | 100 | 100 |
| 2.1 | 101 | 102 | 102 |

Table 9 (cont'd).

| Weibull k factor | $\overline{V}$ = 4.5m/s (10.1 mph) | $\overline{V}$ = 5.5m/s (12.3 mph) | $\overline{V}$ = 6.5m/s (14.5 mph) |
|---|---|---|---|
| Design C (cont'd) | | | |
| 2.2 | 103 | 103 | 103 |
| 2.3 | 104 | 105 | 105 |
| 2.4 | 105 | 106 | 106 |
| 2.5 | 106 | 108 | 107 |
| 2.6 | 107 | 109 | 109 |
| 2.7 | 108 | 110 | 110 |
| 2.8 | 109 | 111 | 110 |
| Design D - high cut-in, low rated wind speeds | | | |
| 1.3 | 93 | 86 | 83 |
| 1.4 | 94 | 88 | 86 |
| 1.5 | 96 | 91 | 89 |
| 1.6 | 97 | 93 | 92 |
| 1.7 | 98 | 95 | 94 |
| 1.8 | 99 | 97 | 96 |
| 1.9 | 99 | 98 | 98 |
| 2.0 (Rayleigh) | 100 | 100 | 100 |
| 2.1 | 100 | 102 | 102 |
| 2.2 | 101 | 103 | 104 |
| 2.3 | 101 | 104 | 105 |
| 2.4 | 101 | 106 | 107 |
| 2.5 | 101 | 107 | 108 |
| 2.6 | 101 | 108 | 110 |
| 2.7 | 101 | 109 | 111 |
| 2.8 | 101 | 110 | 113 |

The results of the sensitivity analysis in Table 9 support the following statements:

1. The effect that the Weibull k factor has on expected energy output is strongly influenced by the design of the WTG. For example, the possible errors of a wrong Rayleigh assumption are not very large for WTG design A (low cut-in, high cut-out wind speeds). They are higher for the other three designs.

2. The effect of variations in the Weibull k factor is substantially reduced as the average wind speed increases for WTG designs A and B (high rated wind speeds). The effect of variations in the Weibull k factor is increased as the average wind speed increases for WTG designs C and D (low rated wind speeds).

3. The direction of the effect of the k factor values is reversed for designs A and B compared to designs C and D. For designs A and B (high rated wind speed), the Rayleigh assumption underestimates the calculated energy output for low k values and overestimates the calculated energy output for high k values. For designs A and B (low rated wind speed), the Rayleigh assumption overestimates the calculated energy output for low k values and underestimates the calculated energy output for high k values.

4. Annual Weibull k values for most sites range from 1.7 to 2.3 (9). A yearly average wind speed of 4.5 m/s (10.1 mph) is generally considered too low for economical SWECS applications (1, 23). If we confine our attention to yearly average wind speeds of 5.5 m/s and 6.5 m/s, and to Weibull k factors of 1.7 to 2.3, we can place the following error bounds on the use of the Rayleigh assumption (see Table 10). Thus, for design A, the use of the Rayleigh assumption for energy output

Table 10. Errors in calculated AEO if wind is assumed Rayleigh distributed when wind behavior is best described by Weibull distribution with $1.7 \leq k \leq 2.3$.

| WTG design | Percent error ($\overline{V}$ = 5.5m/s) | Percent error ($\overline{V}$ = 6.5m/s) |
|---|---|---|
| Design A - low cut-in, high rated wind speed | ±2 | ±1 |
| Design B - high cut-in, high rated wind speed | ±8 | ±4 |
| Design C - low cut-in, low rated wind speed | ±6 | ±6 |
| Design D - high cut-in, low rated wind speed | ±6 | ±6 |

calculations produces at most a 2 percent error even if the wind is actually best described by some other Weibull distribution with $1.7 \leq k \leq 2.3$.

The analyst should be aware of the impact of WTG design on energy calculations if they assume that the wind is Rayleigh distributed. There are indications that design A (low cut-in, high rated) may become the most popular WTG design. If so, then the Rayleigh density function can be used with confidence for energy output calculations, even if the wind is best described by some other Weibull distribution with $1.7 \leq k \leq 2.3$.

5. Though annual Weibull k values generally range from 1.7 to 2.3, Tables 1 and 5 in Chapter 3 indicated that seasonal k values fall outside this range. The analyst desiring to calculate seasonal energy outputs may or may not find the Rayleigh assumption suitable, depending

on the WTG design and the suspected range in k values. (If the seasonal k values are known, then of course, the correct Weibull density function can be used).

## Matching the WTG Size with the Site Electrical Demand

For a utility-interconnected SWECS, any part of the wind-generated electrical output that cannot be used at the site will be sent back to the utility. The fraction of the WTG output that can be used directly at the site is called the Direct Use Factor. The value for the Direct Use Factor has an important impact on the wind system economics, since any wind-generated output used directly at the site can be given a value equal to the full retail price of utility-supplied electricity. Any electricity sent back to the utility is only worth the "buy-back" price, usually less than half the full commercial price. Thus, the economics favor any system and load combination in which a high Direct Use Factor value can be achieved. In general, a high Direct Use Factor value is obtained when the WTG is sized such that its power output is small compared to the electrical demand.

The Direct Use Factor is often difficult to determine for a particular combination of SWECS output and electricity demand, due to the high variability in both SWECS power output and the site electrical demand. At any given moment, there may be a high or low power output and a high or low power demand. Direct Use Factors for WECS intended for large applications are easier to estimate since larger loads are generally less variable than might be expected from a single residence or farm. The electrical demand for an individual home can shift drastically in a matter of seconds as high power consuming appliances such as stoves or clothes dryers are turned on and off.

## Methods for Estimating Direct Use Factor Values

To estimate the Direct Use Factor for a particular SWECS application, one must determine both the expected hourly WTG power output and the expected hourly site power demand. Some sites have power demands which are very similar from day to day or week to week. Figure 21 shows a power demand profile for the city of Hart, Michigan during the week of January 6-12, 1974 (1). A WECS designed for this application could have a power rating as high as 1.0 MW and still result in a Direct Use Factor close to 100 percent.

For much smaller site demands, such as that which might be expected from a single residence, a reliable value for the Direct Use Factor is hard to determine. One technique is to match four different seasonal daily power output projections with four different daily demand patterns representing a "typical" day in the season (28). The accuracy of this technique is uncertain.

One of the big question marks for SWECS applications for individual residences or farms is the extent to which the load can be managed such that power demand is shifted to meet wind power availability. Sites which use electricity for hot water or space heating may have loads which can be considered manageable, particularly if oversize heat storage systems are used.

In 1966-67 Consumers Power Company and the Shiawassee County Cooperative Extension office conducted a detailed study on the electrical usage of a household and dairy farm near Owosso, Michigan. A breakdown

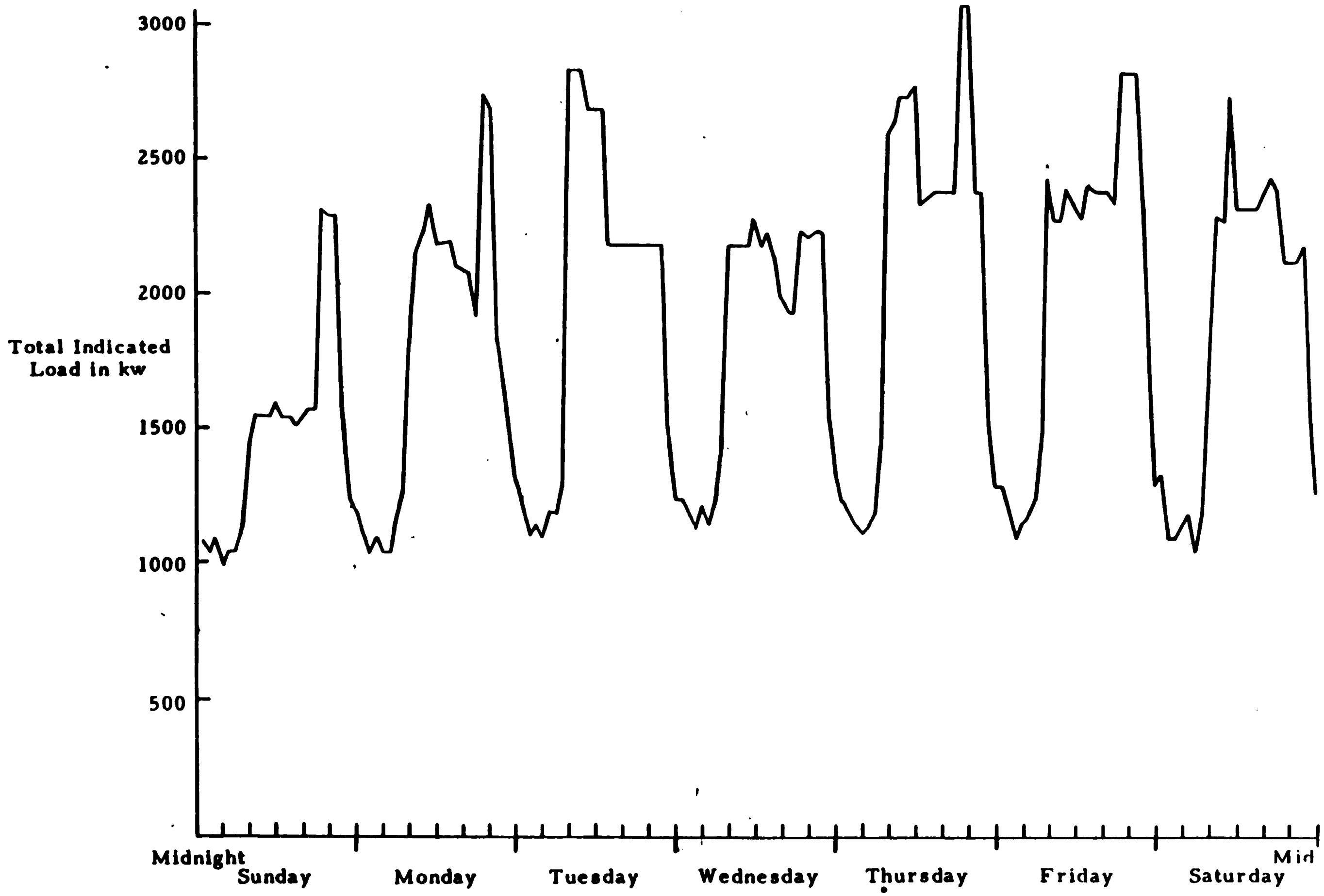



Figure 21. Typical Hart load profile (week of January 6-12, 1974) (1).

of their electrical use is given in Table 11. The 1800 square foot house with nine roome and two baths was essentially an all electric house including electric baseboard heating, an electric water heater, dishwasher and automatic laundry. Disregarding the electric heat, the household used about 1,100 kWh per month. The largest consumer was the hot water heater which used approximately 500 kWh/mo, followed by the refrigerator, which used about 175 kWh each month.

The 327 acre farm had a dairy herd of 70 milk cows plus 80 heifers and calves. The farm also had about 3,000 laying hens. The electrical energy used in the barn, silo area and for the poultry operation is also shown in Table 11.

Figure 22 depicts the total electrical use for the 12 months and all electrical use except space heating.

Figure 22 shows that the home electrical demand, exclusive of space heating, remains relatively constant while the total electrical use increases dramatically (as we might expect) for the winter months. This is an interesting fact for SWECS applications since the wind speeds are generally the highest during the winter months. In fact, Fig. 22 matches up almost identically with a monthly wind speed graph for Muskegon described in Chapter 3 (see Fig. 7 on page15 ). Since the wind power availability may be closely matched with the demands of an electrically heated house, such a house becomes a prime target for a SWECS installation. However, monthly load demands such as that shown in Fig. 22 are only suggestive. Some type of hourly analysis would still be required.

| EQUIPMENT | 1966 June | July | Aug. | Sept. | Oct. | Nov. | Dec. | 1967 Jan. | Feb. | March | April | May | Annual Totals Usage kwh |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| HOUSE | | | | | | | | | | | | | |
| Electric Heat--12.4 kw | 3 | -- | 19 | 754 | 1,657 | 2,481 | 3,299 | 3,490 | 2,840 | 1,744 | 1,246 | 207 | 17,740 |
| Water Pump--½ hp | 15 | 16 | 15 | 12 | 13 | 10 | 14 | 13 | 12 | 14 | 13 | 17 | 164 |
| Dishwasher | 14 | 15 | 14 | 13 | 14 | 14 | 13 | 14 | 12 | 12 | 13 | 14 | 162 |
| Water Heater--80 gal. | 537 | 553 | 460 | 408 | 466 | 455 | 525 | 522 | 472 | 546 | 506 | 635 | 6,085 |
| Clothes Dryer | 25 | 36 | 82 | 42 | 42 | 59 | 80 | 85 | 78 | 107 | 85 | 50 | 771 |
| Electric Range | 73 | 82 | 111 | 106 | 114 | 96 | 93 | 99 | 85 | 90 | 93 | 81 | 1,123 |
| Freezer | 79 | 90 | 93 | 77 | 66 | 59 | 53 | 52 | 44 | 60 | 59 | 75 | 807 |
| Automatic Washer | 9 | 7 | 6 | 3 | 15 | 4 | 4 | 5 | 4 | 6 | 6 | 9 | 78 |
| Refrigerator--Auto. Defrost | 178 | 189 | 182 | 175 | 163 | 159 | 167 | 160 | 147 | 176 | 161 | 176 | 2,033 |
| Lighting & Miscellaneous | 123 | 121 | 117 | 162 | 177 | 192 | 203 | 192 | 157 | 173 | 164 | 143 | 1,924 |
| Total House | 1,056 | 1,109 | 1,099 | 1,752 | 2,727 | 3,529 | 4,451 | 4,632 | 3,851 | 2,928 | 2,346 | 1,407 | 30,887 |
| BARN | | | | | | | | | | | | | |
| Water Heater--40 gal. | 505 | 592 | 616 | 672 | 666 | 705 | 710 | 726 | 703 | 700 | 596 | 489 | 7,680 |
| Hay Dryer--7½ hp | 916 | 324 | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | 1,240 |
| Stock Waterer | -- | -- | -- | -- | 27 | 72 | 67 | 64 | 53 | 50 | 35 | 10 | 378 |
| Milking Machine--1½ hp | 161 | 192 | 177 | 178 | 186 | 176 | 168 | 179 | 157 | 175 | 156 | 164 | 2,069 |
| Milk Pump--½ hp | 23 | 29 | 26 | 27 | 27 | 26 | 25 | 26 | 23 | 26 | 22 | 24 | 304 |
| Space Heater--1,200 watt | -- | -- | -- | -- | -- | -- | -- | 10 | 1 | -- | -- | -- | 11 |
| Milk Cooler--2 hp | 412 | 470 | 487 | 443 | 440 | 492 | 575 | 552 | 477 | 447 | 518 | 521 | 5,834 |
| Truck Milk Pump | 3 | 3 | 4 | 3 | 4 | 3 | 5 | 2 | 3 | 4 | 3 | 3 | 40 |
| Gutter Cleaner--3 hp | 13 | 4 | 6 | 5 | 5 | 16 | 30 | 22 | 19 | 16 | 19 | 6 | 161 |
| Dairy Vent Fans--½ & 1/6 hp | 63 | 76 | 57 | 19 | 2 | 99 | 153 | 171 | 147 | 213 | 117 | 56 | 1,173 |
| Miscellaneous | 142 | 166 | 151 | 159 | 158 | 176 | 158 | 179 | 152 | 168 | 153 | 137 | 1,899 |
| Total Barn | 2,238 | 1,856 | 1,524 | 1,506 | 1,515 | 1,765 | 1,891 | 1,931 | 1,735 | 1,799 | 1,619 | 1,410 | 20,789 |
| SILO AREA | | | | | | | | | | | | | |
| Silo Unloader #1--7½ hp | 51 | 33 | -- | 5 | 44 | 30 | 19 | 20 | 22 | 45 | 42 | 27 | 338 |
| Feeder #1--3 hp | 26 | 16 | -- | 2 | 13 | 8 | 5 | 4 | 6 | 15 | 14 | 25 | 134 |
| Stock Waterers 3--300 watt ea | -- | -- | -- | -- | 32 | 126 | 203 | 225 | 202 | 144 | 83 | 19 | 1,034 |
| Silo Unloader #2--3 hp | 19 | -- | -- | -- | -- | 10 | 16 | 19 | 16 | 19 | 17 | 18 | 134 |
| Feeder #2-- 3 hp | 7 | -- | -- | -- | -- | 7 | 8 | 10 | 9 | 8 | 8 | 8 | 65 |
| Dusk-Dawn Light--175 watt | 47 | 57 | 65 | 73 | 79 | 83 | 86 | 81 | 66 | 68 | 55 | 52 | 812 |
| Water Pump--1½ hp | 137 | 162 | 140 | 107 | 103 | 88 | 79 | 74 | 78 | 97 | 84 | 115 | 1,264 |
| Total Silo Area | 287 | 268 | 205 | 187 | 271 | 352 | 416 | 433 | 399 | 396 | 303 | 264 | 3,781 |
| POULTRY OPERATION | | | | | | | | | | | | | |
| Ventilation--4 hp | 346 | 386 | 376 | 339 | 269 | 207 | 159 | 192 | 156 | 335 | 348 | 363 | 3,476 |
| Lighting 24-40 watt | 130 | 155 | 272 | 302 | 295 | 337 | 297 | 294 | 348 | 362 | 333 | 248 | 3,373 |
| Feeders | 50 | 50 | 47 | 47 | 48 | 49 | 56 | 52 | 48 | 50 | 45 | 44 | 586 |
| Pit Cleaners 2--3/4 hp | -- | -- | -- | -- | -- | 18 | 33 | -- | -- | -- | -- | -- | 51 |
| Egg Washer | 54 | 56 | 54 | 64 | 73 | 68 | 62 | 83 | 90 | 85 | 67 | 48 | 804 |
| Egg Cooler | 448 | 438 | 370 | 194 | 87 | 73 | 60 | 62 | 58 | 123 | 119 | 355 | 2,387 |
| Total Poultry Operation | 1,028 | 1,085 | 1,119 | 946 | 772 | 752 | 667 | 783 | 700 | 955 | 912 | 1,058 | 10,677 |
| MISCELLANOUS | 151 | 162 | 133 | 89 | 75 | 82 | 95 | 121 | 115 | 82 | 140 | 141 | 1,386 |
| Total kwhr | 4,760 | 4,480 | 4,080 | 4,480 | 5,360 | 6,480 | 7,520 | 7,800 | 6,800 | 6,160 | 5,320 | 4,280 | 67,520 |

Table 11. Monthly Electricity Usage in kWh for Consumers Power Test Farm

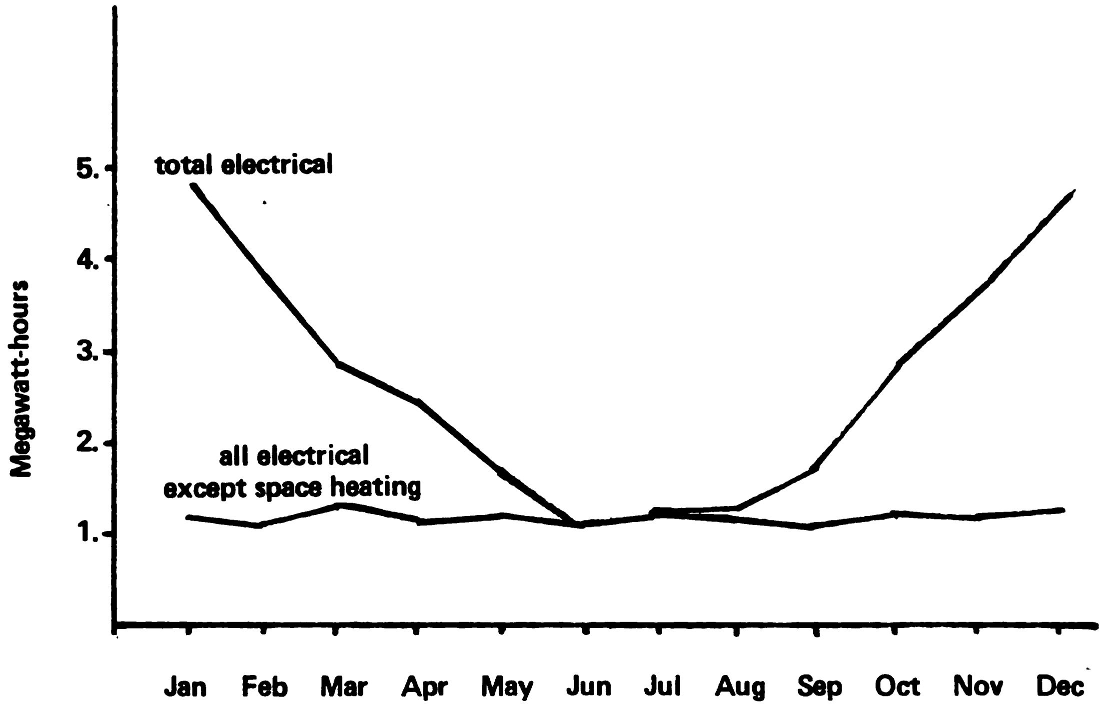



Figure 22. Electrical Use for Michigan farm including and excluding electrical space heating.

## Errors in the Estimated Long Term Average Wind Speed and their Effect on the Calculated Annual Energy Output

The difficulties of predicting the long term average wind speed based on a one year or even three year wind data assessment program has been discussed in Chapter 3. The effect of errors in the predicted long term average wind speed on the calculated AEO was investigated for two different WTG designs in three different yearly average wind speeds (Fig. 23). The wind was assumed Rayleigh distributed and the straight line or ramp approximation was used. The WTGs were spedified to have cut-in wind speeds of 3.6 m/s (8.0 mph), rated wind speeds of 5.3 m/s (12 mph) and 15.6 m/s (35.0 mph), and cut-out wind speeds of 26.8 m/s (60 mph).

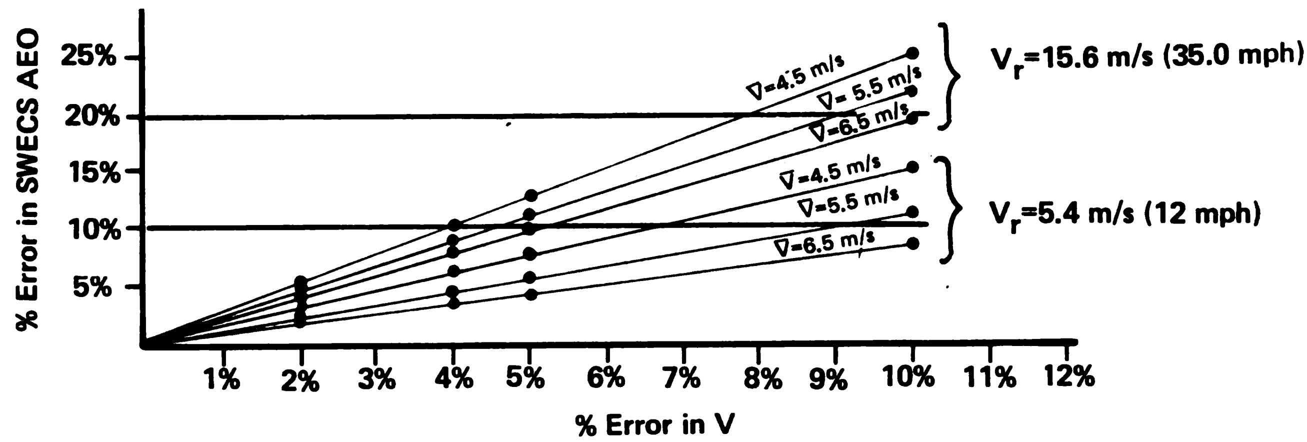



Figure 23. Percent error in AEO vs. percent error in predicted long term average wind speed.

Figure 23 shows that errors in the calculated AEO due to errors in the predicted long term average wind speed are greater for the WTG with the higher rated wind speed and lower for higher yearly average wind speeds. If WTG with higher rated wind speeds are proposed for a site with a long term yearly average wind speed of 4.5 m/s, a 5 percent error in the predicted wind speed can balloon to a 13 percent error in calculated annual energy output. For these WTG, errors in $\overline{V}$ have a much greater impact on AEO than do errors in the Weibull k factor. Figure 23 gives further impetus to long periods of site wind data assessment.

# CHAPTER FIVE

## ECONOMICS

The projected SWECS economic performance is clearly of primary importance to any SWECS feasibility study. Can SWECS be economical? The answer to this question depends on the 1) SWECS cost and performance, 2) yearly average wind speed, and 3) cost of utility-supplied electricity. The second two points highlight the site-dependent nature of wind system economics. The yearly average wind speed can change dramatically over relatively short distances and the cost of electricity is different for different users depending on which utility provides service, the rate structure, the amount of energy used, and even the income tax rate for businesses.

Wind system economics are also dependent on the loan interest rate or the cost of money, the length of the loan, the price escalation rate of utility-supplied electricity, the discount rate or time value of money, the general inflation rate, the state and federal marginal income tax rates, and, if the SWECS will be used in a commercial application, the depreciation lifetime. Values used for many of these parameters will be different for different purchasers.

Since wind system economics are affected by so many factors that may be unique for each potential SWECS application, it is difficult to make general rules concerning SWECS economic viability. Realistic economic projections require site-specific analyses.

To perform a SWECS economic analysis, two performance criteria must be determined: the SWECS Annual Energy Output in kWh, and the total system installed cost (IC). Methods for calculating AEO have already been discussed. Alternatively, one can rely on manufacturers estimates though these are not always reliable (2).

The total installed cost of the SWECS includes costs other than the wind turbine generator and tower. In fact, these "extra costs" vary from one manufacturer to another and usually contribute significantly to the final economics of the SWECS installation. The total installed cost of a SWECS includes the following:

1. Wind turbine generator.
2. Tower costs.
3. Installation cost--including labor, foundation costs and site preparation.
4. Transmission, distribution and power conditioning equipment. This includes inverters, circuit breakers, batteries, power factor correction equipment, harmonic filtering and any initial installation costs for additional utility metering.
5. Shipping and transportation costs to the site.
6. Tax credits (see Appendix A for a list of Michigan and federal tax credits).

The total installed cost, IC, is the sum of items 1-5 <u>minus</u> available tax credits. Many states and the federal government offer substantial tax credits for the promotion of alternative energy systems. These credits are subtracted in full from the amount of tax paid. The analyst must determine each of the costs (and tax savings) and sum them to establish IC, the <u>total</u> system installed cost.

## SWECS Economic Analyses

SWECS economic analyses usually compare two alternatives--the costs of purchasing and installing a wind-electric system and the costs of not doing so. For utility-interconnected SWECS, the total cost of the wind system and resulting lower utility bills are compared with the utility bills expected from a continued exclusive use of utility-supplied electricity. Rather than calculate the total costs for each alternative, the same results can be obtained by simply comparing the total wind system costs with the expected utility bill savings.

### IC/AEO Ratios

The key question when evaluating different commercially available SWECS is how much useful energy can be extracted from a given wind and at what cost. The ratio of the total installed cost (IC) to the annual energy output (AEO), i.e., the IC/AEO ratio, expresses this concept as a number. SWECS with low IC/AEO ratios have the best economic potential (1, 17, 24). The IC/AEO ratio can be estimated for various commercially available SWECS without lengthy economic calculations and can be used to find the best buy or several best buys among the SWECS with an appropriate size for a given application.

Conventional power systems are often rated in terms of installed cost per power rating, i.e., IC/kW. It is misleading to rate SWECS in this fashion, however, since the WTG rated power is often a poor indicator of its expected AEO. Other factors such as $V_i$ and $V_r$ strongly affect WTG performance. The economic merit of a wind system is ultimately related to its energy output, since electricity is generally sold in units of energy, now power. The ratio of installed cost to annual energy output, IC/AEO, also directly ties the SWECS economic merit to a particular site since AEO depends on the site yearly average wind speed.

Other Figures of Economic Merit

The IC/AEO ratios of commercially available SWECS can be compared to determine the relative economic merit among various wind systems. To determine if any system should be installed, i.e., what are the costs of installing a wind system compared to the costs of an exclusive use of utility-supplied electricity, a full fledged economic analysis should be performed.

The results of such analyses are commonly expressed by a variety of figures of economic merit, including the lifetime net savings on the SWECS, the payback period, the breakeven IC/AEO ratio, and the lifetime cost of wind-generated electricity in ¢/kWh. Each of these figures of economic merit contain somewhat similar information.

The lifetime net savings is the total utility bill savings minus the total wind system costs, calculated over the entire system lifetime and usually discounted into today's dollars. The payback period is the length of time the system must last to produce enough utility bill savings to pay for all the associated costs.

The breakeven IC/AEO ratio is a value that can be compared to the IC/AEO ratios of commercially available wind systems. If the two ratios are equal, the purchaser of the wind system would breakeven with the investment. To breakeven means that the lifetime costs equal the lifetime savings. The IC/AEO ratio of a commercially available wind system must be lower than the breakeven IC/AEO ratio for the purchaser to save money.

The last figure of economic merit is the lifetime cost of wind-generated electricity in ¢/kWh, also known as the cost of energy. Two different cost of energy values are commonly used: the levelized or average cost of energy, denoted $\overline{\text{COE}}$, and the current cost of energy, denoted $\text{COE}_0$. The $\overline{\text{COE}}$ is that value which, if held constant over the life of the system, would recoup all the system costs. The $\text{COE}_0$ is that value which, if inflated each year over the life of the system at a rate equal to the estimated utility price escalation rate, would recoup all the system costs. $\overline{\text{COE}}$ must be compared to the calculated levelized cost of utility-supplied electricity, determined over the projected SWECS lifetime. $\text{COE}_0$ is simply compared to today's utility prices. Both $\overline{\text{COE}}$ and $\text{COE}_0$ can be thought of as breakeven prices. That is, if the calculated $\text{COE}_0$ is the same as today's utility rates levelized the purchaser would breakeven with the SWECS installation.

Though both $\overline{\text{COE}}$ and $\text{COE}_0$ ultimately yield the same information, $\text{COE}_0$ is a preferred figure of economic merit for the following reasons:

1. $\text{COE}_0$ is simpler to use and may be easier to understand for many nontechnical persons. $\text{COE}_0$ can be compared directly with today's utility rates and no additional calculations are necessary. To effectively use $\overline{\text{COE}}$, the levelized cost of utility-supplied electricity must be calculated for each new economic scenario.

2. Formulas used to calculate $\text{COE}_0$ are not sensitive, compared with the $\overline{\text{COE}}$ formulas, to the absolute values of four of the economic parameters: 1) the general inflation rate, 2) the utility price escalation rate, 3) the discount rate, and 4) the loan interest rate. (Each of these parameters are described in detail following the next section on economic formulas.) The $\text{COE}_0$ formulas are sensitive only to the differences between the values of these economic parameters. For example, if

the general inflation rate, utility price escalation rate, discount rate, and loan interest rate were specified to be 12 percent, 16 percent, 15 percent, and 17 percent respectively for one economic scenario and 8 percent, 11 percent, 10 percent, and 12 percent respectively for another, identical $COE_0$ values would be calculated for eqch scenario. Though the absolute values of the parameters in the first scenario are 5 percent points higher than the second scenario parameter values, the difference between the economic parameters is identical in each case.

Since $\overline{COE}$ depends on the absolute values of the four economic parameters, a different $\overline{COE}$ would be calculated for each scenario. Further, a different levelized cost of utility-supplied electricity would be calculated for each scenario.

The use of $COE_0$ makes the analyst's job easier since the differences between the four economic parameters are easier to specify than their absolute values. For example, an analyst may not know whether the projected general inflation rate will level out 8 percent or 13 percent but may know that inflation is generally around 2 percentage points lower than the utility price escalation rate.

It may be intuitively clear that the true economic merit of a SWECS is based on the differences between rather than the absolute values of the economic parameters. In times of high inflation, loan interest and discount rates rise, and because of the utility overhead, fuel costs, etc., rise, the price of utility-supplied electricity rises. The important question for SWECS economics is not just how fast the cost of electricity goes up but how fast it goes up in comparison with the inflation rate, interest rate, etc.

Though the first economic scenario might be considered a high inflation case and the second economic scenario a low inflation case, the ultimate economic gain or loss from a potential SWECS purchase would be the same in either economic climate. To specify a high inflation economic scenario, the projected inflation rate must be high in relation to the other parameters.

The use of $COE_0$ implies a standard, the difference between the economic parameters, making it much easier to compare the results of diverse economic analyses.

## Methods for Calculating Figures of Economic Merit

Two different methods for calculating SWECS economic merit are considered: the fixed charge rate method and the life-cycle cost method.

### Fixed Charge Rate Method

The fixed charge rate method, commonly used by utilities to evaluate alternative power generating sources, is also popular for non-utility SWECS economic analyses. The fixed charge rate method yields a single figure of economic merit--the levelized lifetime cost of energy--$\overline{COE}$ (17). A simplified formula for $\overline{COE}$, using the fixed charge rate method, is

$$\overline{COE} = \frac{FCR \cdot IC + LF \cdot AOM}{AEO}$$

where

$\overline{COE}$ = levelized cost of energy

FCR = fixed charge rate

IC = installed cost

LF = levelizing factor

AOM = annual operation and maintenance costs

AEO = SWECS annual energy output

Source: (17)

The fixed charge rate is expressed by the formula:

$$FCR = \frac{1}{1-\tau}\left(CRF - \frac{\tau}{N}\right) + \beta_1 + \beta_2$$

where

$\tau$ = effective income tax rate

N = system lifetime

$\beta_1$ = property tax factor

$\beta_2$ = insurance costs factor

CRF = capital recovery factor

$$= \frac{k}{1 - (1 + k)^{-N}}$$

and

k = effective (after tax) interest rate on capital.

Source: (17)

The levelizing factor is expressed by the formula

$$LF = CRF \cdot G_1$$

where

$$G_1 = \left(\frac{1 + g_{omf}}{k - g_{omf}}\right) \left[1 - \left(\frac{1 + g_{omf}}{1 + k}\right)^N\right]$$

when

$g_{omf} \neq k$

$g_{omf}$ = k and

$g_{omf}$ = escalation factor for operations, maintenance, and fuel

Source: (17)

The fixed charge rate method, though adequate for utility economic analyses, may not be satisfactory for non-utility owned SWECS economic analyses. The fixed charge rate method as just written does not take into account the following:

1. The fixed charged rate method assumes that a loan with a length equal to the system lifetime is used to pay for the wind system. This will probably not be true for the non-utility SWECS owner.

2. The time value of money, k in the previous formula, may not be based on the effective loan interest for non-utility SWECS owners, for reasons just described. In general, the time value of money is different for different people.

3. No allowance is made for depreciation.

4. The effects of income tax are not considered.

5. It is often unclear which value should be used for the fixed charge rate.

6. The method yields only a single figure of economic merit, $\overline{\text{COE}}$, which cannot be directly compared with today's utility rates.

Though the fixed charge rate formula could be adjusted to account for these deficiencies, an entirely new set of economic equations were developed for non-utility SWECS owners, based in part on the life cycle cost methods found in the f-chart analysis for solar hot water heating systems (4).

## Life Cycle Cost Method

The life cycle cost method is seen to be more useful than the fixed charge rate method since a wider variety of economic figures of merit are calculated and all the unique features of a particular SWECS application can be accounted for.

The equations used in the life cycle cost analysis have been adapted from Beckman et al. (1977). Table 12 lists the various economic parameters and their symbols. A detailed description of each variable is presented after the equations.

Table 12. Economic parameters used in life cycle cost analysis.

| Economic parameter | Symbol | Units |
|---|---|---|
| Annual loan interest rate | $r$ | % |
| Term of loan | $N_r$ | yr |
| Market discount rate per year | $d$ | % |
| General inflation rate per year | $i$ | % |
| Utility price escalation rate per year | $e$ | % |
| Estimated lifetime of system | $N_s$ | yr |
| Down payment (as fraction of investment) | %DP | % |
| Federal income tax bracket | Fed. tax | % |
| Insurance and maintenance costs | I & M | % |
| Depreciation lifetime | $N_d$ | yr |
| Salvage value (fraction of investment) | S | % |

Let

$G_1$ = general inflation present worth factor

$G_2$ = utility price escalation present worth factor

$G_3$ = loan interest present worth factor

$$G_1 = F(N_s, i, d) = \frac{1+i}{d-i}\left(1 - \left(\frac{1+i}{1+d}\right)^{N_s}\right) = \sum_{j=1}^{N_s} \left(\frac{1+i}{1+d}\right)^{j}$$

$$G_2 = F(N_s, e, d) = \frac{1+e}{d-e}\left(1 - \left(\frac{1+e}{1+d}\right)^{N_s}\right)$$

$$G_3 = F(N_r, r, d) = \frac{(1+r)}{(d-r)}\left(1 - \left(\frac{1+r}{1+d}\right)^{N_r}\right)$$

$$\frac{1}{CRF_1} = F(N_r, 0, r) = \frac{1}{r}\left(1 - \left(\frac{1}{1+r}\right)^{N_r}\right)$$

$$\frac{1}{CRF_2} = F(N_r, 0, d) = \frac{1}{d}\left(1 - \left(\frac{1}{1+d}\right)^{N_r}\right)$$

$$\frac{1}{CRF_3} = F(N_d, 0, d) = \frac{1}{d}\left(1 - \left(\frac{1}{1+d}\right)^{N_d}\right)$$

$$\frac{1}{CRF_4} = F(N_s, 0, d) = \frac{1}{d}\left(1 - \left(\frac{1}{1+d}\right)^{N_s}\right)$$

Loan payment factor,

$$= \frac{CRF_1}{CRF_2}$$

Loan interest factor,

$$= \frac{CRF_1}{CRF_2} + (G)[r - CRF_1]$$

<u>Capital Cost</u>

Capital cost

= %DP + (1 - %DP) [(loan payment factor) - [(loan interest factor) x (Federal tax)]

$$= \%DP + (1 - \%DP)\left(\frac{CRF_1}{CRF_2} - \left((\text{Fed. tax}) \times \left(\frac{CRF_1}{CRF_2} + G_3\,(r.-CRF_1)\right)\right)\right)$$

Insurance and Maintenance

$$= (I \,\&\, M)\,(G_1)$$

Salvage Value

$$(S.)\left(\frac{1+i}{1+d}\right)^{N_s}$$

Depreciation (straight line)

$$\frac{(\text{Fed. tax})(1-(S.))}{(CRF_3)(N_d)}$$

(A.) = Residential life cycle cost factor

= (Capital cost) + (I & M cost) - (Salvage value)

(b.) = Business life cycle cost factor

= (Capital cost) + (I & M costs)(1 - tax rate) - (Salvage value)

- (Depreciation)

Businesses can deduct I & M costs and can depreciate capital, thereby lowering their costs. Savings, however, must be treated as taxable income.

Additional Parameters Used for Utility-Interconnected SWECS

Let

YC = yearly metering charge

IC = total installed cost

UF = direct use factor

PR = price ratio of buyback price to normal utility charge

EUF = economic utilization factor

MCF = metering charge factor

Then

$$EUF = [(UF + (1 - UF)(PR)], \text{ and}$$

$$MCF = \frac{YC}{IC}\ (G_1)$$

## Breakeven IC/AEO Ratio

residence:

$$\text{Breakeven IC/AEO} = \frac{G_2 \times (\text{cost of utility-supplied electricity}) \times (EUF)}{((A.) + (MCF)}$$

business:

$$\text{Breakeven IC/AEO} = \frac{G_2 \times (\text{cost of utility-supplied electricity}) \times (EUF) \times (1 - \text{tax rate})}{((B.) + MCF)}$$

If breakeven $\frac{IC}{AEO}$ > commercially available $\frac{IC}{AEO}$, money is saved with SWECS purchase.

If breakeven $\frac{IC}{AEO}$ = commercially availably $\frac{IC}{AEO}$, SWECS purchase breaks even.

If breakeven $\frac{IC}{AEO}$ < commercially available $\frac{IC}{AEO}$, money is lost with SWECS purchase.

## Lifetime Net Savings, Payback Period

Residence:

$$\text{Utility Bill Savings} = AkWh \times G_2 \times (\text{cost of utility-supplied electricity}) \times (EUF)$$

$$\text{Total wind System Costs} = IC \times ((A.) + MCF)$$

Business:

$$\text{Utility Bill Savings} = AkWh \times G_2 \times (\text{cost of utility-supplied electricity}) \times (EUF) \times (1 - \text{tax rate})$$

Total wind

$$\text{System Costs} = IC \times ((B.) + MCF)$$

Lifetime

$$\text{Net Savings} = \text{Utility Bill Savings} - \text{Total Wind Systems Costs}$$

$$\text{Payback Period} = \frac{\text{Total Wind System Costs} \times N_s}{\text{Utility Bill Savings}}$$

Cost of Energy

Residence:

$$COE_o = \frac{IC \times ((A.) + MCF)}{AkWh \times G_2 \times EUF}$$

Business:

$$COE_o = \frac{IC \times ((B.) + MCF)}{AkWh \times G_2 \times EUF \times (1 - \text{tax rate})}$$

Levelized cost:

$$\overline{COE} = G_2 \times CRF_4 \times COE_o$$

## Description of Economic Parameters Used in the Life Cycle Cost Analysis

There are 11 different economic parameters associated with the life cycle cost analysis (see Table 12). They are as follows:

1. Loan interest rate - The loan interest rate is the full interest rate charged for any loan used to pay for the SWECS.

2. Term of loan - The term of the loan is the length of the loan in years.

3. Discount rate - The discount rate reflects the time value of money. A discount rate of 10 percent means that money is considered to be

worth 10 percent less each year. Alternatively, $110 in next year's money would be equal to $100 in today's money (5).

A variety of values can be used for the discount rate depending on the relative values for the "effective" loan interest rate and length of the loan, the after-tax rate of return on the best alternative investment, and the projected general inflation rate. In general, the highest value is used as the discount rate.

If the after-tax rate of return on the best (realistic) alternative investment is larger than either the "effective" loan interest or the general inflation rate, the after tax rate of return should be used as the discount rate. In this way, the time value of money is linked with opportunity costs.

If the predicted general inflation rate is the largest value, it should be used as the discount rate. In this way, the time value of money is tied to inflation.

If the length of the loan is relatively long, such as would be expected if the wind-system purchase was tied to a new home mortgage, the "effective" loan interest rate might be used as the discount rate. The "effective" loan interest is equal to the loan interest multiplied by (1 - the "effective" tax rate). (See parameter #8 for a discussion of the effective tax rate.) For example, if the loan interest is 15 percent and the "effective" tax rate is 30 percent, the effective loan interest rate is (1 - .3)(.15) = .105 or 10.5 percent. If the length of the loan is relatively short, five years or less, then the effective loan interest rate should be discarded as a possible candidate for the discount rate.

Some analysts have tried to let the discount rate reflect the risk of the new investment. Higher risk investments are assigned a higher discount rate. However, unless the analyst has some firmly established method for assigning risk to various alternative investments, it is best to avoid linking the discount rate to investment risk.

The discount rate is a highly influential economic parameter in the life cycle cost analysis and should be determined with care. In SWECS economic analyses, a high discount rate tends to reduce the potential savings.

4., 5. General inflation rate, utility price escalation rate - Two different "inflation" values are used. The general inflation rate is simply the reported annual inflation rate and reflects changes in the consumer price index for a wide variety of goods and services. The utility price escalation rate reflects price changes for a single "good" --utility-supplied electricity. The values for these two parameters are the predicted future average values over the entire wind system lifetime.

Though no one knows for sure what will happen in the future, past information can be helpful. Table 13 illustrates the annual price increases from 1973-1980 for all consumer price index items (general inflation), electricity, and gasoline.

Table 13 indicates that for the years 1973-1980:

a) The price of electricity has not increased nearly as fast as the price of many other energy forms. One reason is that a substantial portion of the price of electricity is due to generator costs, maintenance of the distribution system, etc., and the prices of these items have not increased as fast as the primary forms of energy such as coal and oil.

b) The price of electricity has increased faster than general inflation. For the entire United States, the difference is 0.6 percent. The

Table 13. A comparison of various annual price increases (1973-1980).

| | General inflation | | Electricity | | | Gasoline |
|---|---|---|---|---|---|---|
| Year | U.S. | Detroit | U.S. | Consumers Power, MI | Detroit Edison | U.S. |
| 1973 | 6.2% | 6.6% | 5.0% | 8.6% | 3.1% | 9.8% |
| 1974 | 11.0% | 10.8% | 18.1% | 20.6% | 17.9% | 35.4% |
| 1975 | 9.1% | 7.4% | 13.2% | 21.7% | 18.4% | 6.8% |
| 1976 | 5.8% | 5.4% | 6.3% | 7.6% | 10.4% | 4.2% |
| 1977 | 6.5% | 6.9% | 6.6% | 1.0% | 10.6% | 5.8% |
| 1978 | 7.6% | 7.6% | 7.4% | 11.7% | 6.9% | 4.3% |
| 1979 | 11.5% | 12.7% | 5.7% | 1.6% | 6.7% | 35.3% |
| 1980 | 13.4% | 15.6% | 14.2% | 19.1% | 10.0% | 33.2% |
| Avg. | 8.9% | 9.1% | 9.6% | 11.5% | 10.5% | 16.9% |

Source: (13, 14, 26)

difference is larger for Detroit and the two major Michigan electrical utilities.

c) The price of electricity and gasoline varies more dramatically from year to year than general inflation. Notice the big price increases in 1974 and 1975--the years following the oil embargo.

6. Estimated lifetime of system - A well-engineered machine should last 20 yr or more. Most SWECS on the market are new and relatively little is known about system lifetimes. As with any product, certain machines are of higher quality and would be expected to last longer than others. These SWECS may be more expensive initially but less expensive when the costs are projected over the system lifetime. Certain components, such as batteries, may not last as long as the WTG; whereas, a

good tower may last considerably longer. Since system lifetimes are unknown, a range of values should be used in a sensitivity analysis. A value of less than the expected lifetime can be used if the salvage value is properly adjusted.

7. Down payment - The down payment is used as its fraction of the total installed cost. For example, a \$600 down payment for a \$6,000 system would be a down payment of 10 percent. If cash is paid, the down payment would be 100%.

8. Effective tax rate - The federal and state income tax rates can be lumped together into a single "effective" tax rate. All state income taxes are deductable from federal income taxes. In states where federal income taxes are not deductible from state income taxes, the formula for the effective tax rate is:

$$\%E = [F + S - (F \times S)] \times 100\%$$

where

$\%E$ = effective tax rate (as a %)

$F$ = federal marginal income tax rate (as a decimal fraction)

$S$ = state income tax rate (as a decimal fraction)

For example, if the federal marginal income tax rate is 30% and the state income tax is 2.6%, then

$$\%E = [.30 + .026 - (.30 \times .026)] \times 100\%$$
$$= 31.8\%$$

This is the appropriate formula to use in Michigan.

In states where federal income taxes are deductible from state income taxes, the formula for the effective tax rate is:

$$\%E = \frac{F + S - (2 \times F \times S)}{1 - (F \times S)} \times 100\%$$

$$= 31.3\%$$

For residences, the federal marginal income tax rate is a satisfactory approximation for the effective tax rate. For businesses the effective tax rate should be calculated according to the formulas.

9. Insurance and maintenance costs - The variable used in the life cycle cost analysis is the predicted annual insurance and maintenance costs as a fraction of the total cost. Though values of 1% to 3% per year of the total installed cost are commonly used in economic predictions for a variety of equipment, 4% may be more realistic for SWECS since 1) the technology is new and maintenance costs are expected to be higher in the early years of SWECS development, and 2) the total installed price is less than the actual commercial price when tax credits are included. The lower values (1% to 3%) were designed for use on the entire commercial price of the new equipment.

A rigorous method for calculating the "adjusted" insurance and maintenance costs is

$$\text{Adjusted I \& M costs} = \text{normal expected I \& M costs} \times \frac{\text{Total purchase price}}{\text{Total installed cost}}$$

For example, if the yearly I & M costs are expected to be 2% of a total purchase price of \$10,000 and the total installed cost is \$4,800 (\$10,000 - \$5,200 tax credits), then the adjusted I & M cost is

$$\text{Adjusted I \& M cost} = 2\% \times \frac{\$10{,}000}{\$\ 4{,}800}$$

$$= 4.2\%$$

10. Depreciation lifetime - Only businesses and farmers can depreciate equipment. SWECS for residential purposes cannot be depreciated.

Straight line depreciation is used. The economics of any equipment purchase improves when it can be quickly depreciated.

11. Salvage value - If the full expected lifetime is used variable #6, it is prudent to assume that the salvage value is zero. If less than the expected lifetime is used, a salvage value can be calculated as follows:

a) Estimate the salvage value (in today's dollars) of the system after some desired period of analysis.

b) Divide this value by the total installed cost (total purchase price--tax credits).

The following four variables must also be specified when utility-interconnected SWECS are analyzed.

12. Yearly metering charge - A yearly extra charge may be assessed for the dual metering system required for utility buyback. Some utilities add \$3.85/mo to their bill (\$46.20/yr) to account for the special handling a dual metering system requires.

13. Cost of utility-supplied electricity in \$/kWh - To calculate the lifetime net savings and/or the payback period the current cost of electricity, per kilowatt-hour, must be known. The best way to determine this cost is to look at the utility bill and divide the total monthly charge by the number of kWh used. In this way, any normal monthly fixed charges are included in the \$/kWh price.

14. Utility buy-back price - The utility buy-back price is the price paid by the utilities, in \$/kWh, for excess wind-generated electricity. In Michigan, Detroit Edison and Consumers Power both pay \$.025/kWh (2.5¢/kWh).

15. Direct Use Factor - The Direct Use Factor is the fraction of the total SWECS energy output that can be used directly at the site. In general, it is difficult to determine this value for a particular SWECS application. See Chapter 4 for a more detailed discussion.

## Sample Analyses

Two sample analyses were performed using the life cycle cost method. The first is for a residence, the second for a business. The values used for the various economic parameters are not necessarily recommended values, but rather examples of what might be used.

### Example #1

The wind system used in the first example is the Astral Wilcon 10kW, a utility-interconnected SWECS.

IC The total installed cost is estimated to be:

| | | |
|---|---|---|
| Wind turbine generator | | $ 8,100 |
| Tower | | 2,500 |
| Installation | | 2,000 |
| Synchronous inverter | | 2,400 |
| Shipping | | 1,000 |
| | Total purchase price | $16,000 |
| | Tax credits[1] | 4,816 |
| | TOTAL INSTALLED COST | $11,184 |

AEO Assuming that the yearly average wind speed at the proposed site is 5.5m/s (12.3 mph), the manufacturer estimates that the system should produce 22,000 kWh each year. In both this and the next example, values used for AEO are based solely on manufacturer's estimates.

---

[1]See Appendix A for tax credits.

| | |
|---|---|
| Current Cost of Utility-Supplied Electricity | In example #1, the current cost of utility supplied electricity is taken to be 5.5¢/kWh. |
| Utility Buy-back Price | The buy-back price is assumed to be 2.5¢/kWh. |
| Yearly Metering Charge | The extra charge for a dual metering system is assumed to be $46.20/yr. |
| Direct Use Factor | A variety of values are used for the Direct Use Factor, the fraction of the WTG output that is used directly at the site. The values range from .2 to .8. |
| Economic Parameters | The following values were used in example #1. |
| 1. Loan interest rate | 12% |
| 2. Term of loan | 5 yr |
| 3. Discount rate | 12% |
| 4. General inflation | 10% |
| 5. Utility price escalation rate | 12% |
| 6. System lifetime | 20 yr |
| 7. Down payment | 10% |
| 8. Effective income tax | 32% |
| 9. Insurance and maintenance | 4% |
| 10. Depreciation lifetime | --- |
| 11. Salvage value | $0 |

Results for Example #1

Table 14 presents the calculated values for the four figures of economic merit based on four different Direct Use Factor values.

Astral Wilcon 10 kW

IC = \$11,180

AEO = 22,000 kWh/yr

Commercially available IC/AEO = .508

Current cost of utility-supplied electricity = 5.5¢/kWh

Table 14. Results of example #1 for four Direct Use Factor values.

| Direct Use Factor | Breakeven IC/AEO | Lifetime net savings | Payback period | Current cost of energy ($COE_o$) |
|---|---|---|---|---|
| .2 | .371 | -\$5065 | 27 yr | 7.5¢/kWh |
| .4 | .442 | - 2425 | 23 yr | 6.3¢/kWh |
| .6 | .514 | + 215 | 20 yr | 5.4¢/kWh |
| .8 | .586 | + 2855 | 17 yr | 4.8¢/kWh |

Each of the figures of economic merit contain similar information. For example, when the Direct Use Factor is .2, the breakeven IC/AEO is less than the commercially available IC/AEO ratio (.371 < .508), indicating that the SWECS investment under these assumptions is a money losing proposition. The poor economics are confirmed in the next column; compared to a continued exclusive use of utility supplied electricity, \$5065 dollars are lost over the system lifetime with the SWECS installation. The payback period is projected to be 27 years, 7 years longer than the system lifetime. Finally, the calculated current cost of wind-generated electricity is 2¢/kWh higher than the current cost of utility supplied electricity (7.5¢/kWh compared to 5.5¢/kWh).

As another example, consider the economic results when the Direct Use Factor is .6 (60% of the SWECS output is used at the site). The breakeven IC/AEO ratio is just slightly higher than the commercially available IC/AEO ratio (.514 > .508) suggesting that the SWECS installation could be a slight money saver. The next column indicates this (lifetime net savings = $215). The payback period is equal to the system lifetime of 20 years (these figures are rounded to the nearest year), and the current cost of wind generated electricity is 5.4¢/kWh, compared to the 5.5¢/kWh cost of utility supplied electricity.

Example #1 shows that the Direct Use Factor can be a very influential variable. Depending on Direct Use Factor, the SWECS was shown to be either a money saving or a money losing investment.

Example #2

Example #2 depicts a hypothetical cherry farm (a business) located near Traverse City, Michigan. The wind system used in example #2 is the Jay Carter, 25kW, a utility-interconnected SWECS.

IC The total installed cost is estimated to be:

| | |
|---|---|
| Wind turbine generator (including tower) | $21,000 |
| Shipping | 7,000 |
| Installation and foundation costs | 3,500 |
| Total purchase price | $31,500 |
| Tax credits[1] | - 7,875 |
| TOTAL INSTALLED COST | $23,625 |

[1]See Appendix A for tax credits.

AEO Assuming that the yearly average wind speed at the site is 6.2 m/s (14 mph), the manufacturer estimates that the system should produce 50,000 kWh per year.

| | |
|---|---|
| <u>Current Cost of Utility-Supplied Electricity</u> | In this example, the current cost of utility-supplied electricity is taken to be 6.6¢/kWh. |
| <u>Utility Buy-back Price</u> | The buy-back price is assumed to be 3.0¢/kWh. |
| <u>Yearly Metering Charge</u> | The extra charge for a dual metering system is assumed to be \$46.20 per year. |
| <u>Direct Use Factor</u> | Direct Use Factor values ranging from .2 to .8 are used in the analysis. |
| <u>Economic Parameters</u> | The following example values were used in this analysis. |

| | | |
|---|---|---|
| 1. | Loan interest rate | 14% |
| 2. | Term of loan | 20 yr |
| 3. | Discount rate | 11% |
| 4. | General inflation | 10% |
| 5. | Utility price escalation rate | 12% |
| 6. | System lifetime | 20 yr |
| 7. | Down payment | 10% |
| 8. | Effective income tax | 25% |
| 9. | Insurance and maintenance | 4% |
| 10. | Depreciation lifetime | 20 yr |
| 11. | Salvage value | \$0 |

Results for Example #2

Table 15 presents the calculated values for the four economic figures of merit based on four different Direct Use Factor values.

Jay Carter 25 kW

IC = \$23,625

AEO = 50,000 kWh per year

Commercially available IC/AEO ratio = .473

Current cost of utility-supplied electricity = 6.6¢/kWh

Table 15. Results of example #2 for four Direct Use Factor values.

| Direct Use Factor | Breakeven IC/AEO | Lifetime net savings | Payback period | Current cost of wind-generated electricity |
|---|---|---|---|---|
| .2 | .420 | -\$3,801 | 22 yr | 7.4¢/kWh |
| .4 | .502 | + 2,140 | 19 yr | 6.2¢/kWh |
| .6 | .583 | 8,081 | 16 yr | 5.3¢/kWh |
| .8 | .665 | 14,023 | 14 yr | 4.7¢/kWh |
| 1.0 | .746 | 14,964 | 13 yr | 4.2¢/kWh |

Table 15 indicates that at least 40% of the AEO must be used at the site if this particular SWECS application is to be economical. If all the produced AEO was used at the site the system would pay for itself in 13 years.

## The Use of Graphs to Illustrate Economic Results

Graphs depicting breakeven IC/AEO ratios vs. calculated $COE_o$ values provide a useful way to illustrate the economic results. Though specific for a certain site, these graphs can be applied to a variety of commercially available SWECS.

Due to the mathematical relations between the various formulas found in the life cycle cost analysis, a linear relationship will always exist between the breakeven IC/AEO ratio and the calculated $COE_o$. Figure 24 illustrates such a graph, constructed from the economic assumptions in example #1 and a Direct Use Factor of 100%.

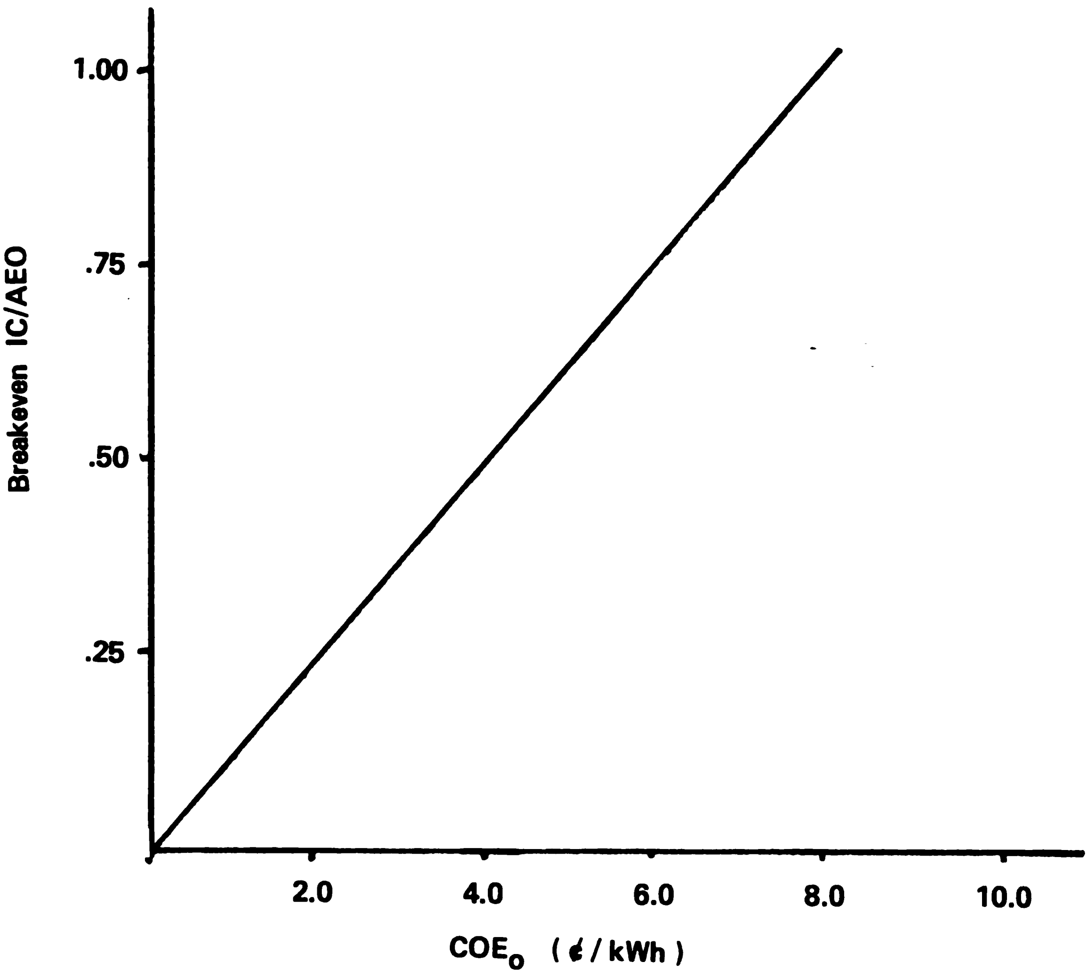



Figure 24. Breakeven IC/AEO vs $COE_o$ for example #1 (assuming a Direct Use Factor of 1.0).

Assuming that 100 percent of the SWECS annual energy output can be used directly at the site, Fig. 24 shows the IC/AEO ratio that corresponds to a particular calculated $COE_o$. Since the calculated $COE_o$ can be compared with today's utility prices, a graph such as Fig. 24 can be used to determine the maximum IC/AEO ratio of a commercially available SWECS for a particular current utility price. For example, if the cost of utility supplied electricity at the site is 6.0¢/kWh, the IC/AEO ratio of some commercially available SWECS must be less than .75 for the system to be economical. If the cost of utility supplied electricity was 4.0¢/kWh, the SWECS IC/AEO ratio must be less than .50 for the system to be economical.

Remember that Fig. 24 assumes that 100 percent of the output can be used at the site. A series of straight lines can be constructed based on a variety of Direct Use Factor values. Figure 25 depicts such a graph, based on the economic assumptions in example #1.

Figure 25 graphically describes not only the results of example #1 contained in Table 12, but also the expected $COE_o$ value for any SWECS, based on its IC/AEO ratio and the estimated Direct Use Factor value. Sensitivity analysis for the various economic parameters are also easily depicted by these graphs and "uncertainty" brackets can be placed along each axis to give estimated upper and lower values for the calculated $COE_o$ values.

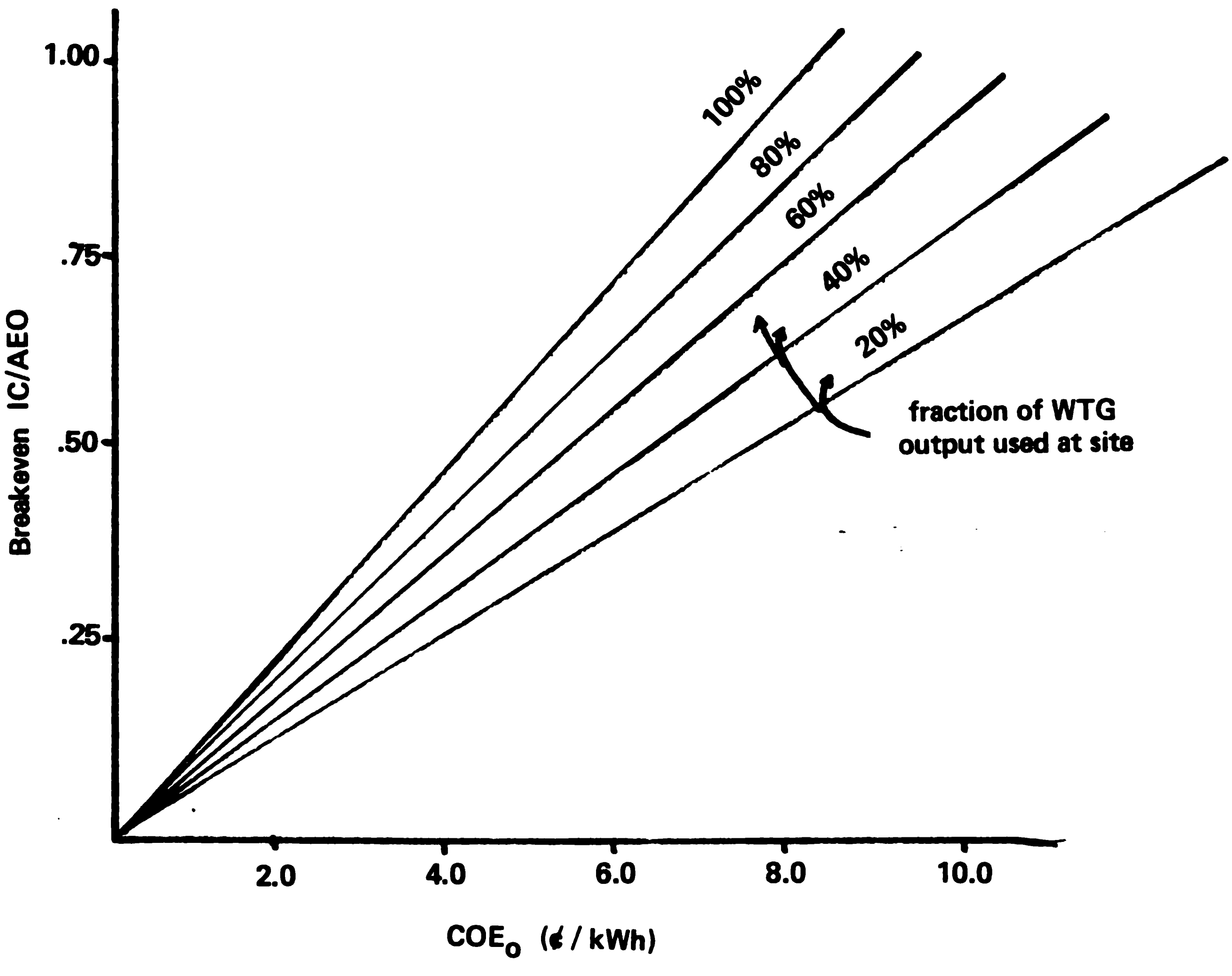



Figure 25. Breakeven IC/AEO ratios vs. COE$_o$ for example #1 (using a variety of Direct Use Factor values).

# CHAPTER SIX

# CONCLUSIONS AND SUMMARY

To assess the feasibility of a proposed SWECS installation, wind data should be gathered at the site, the expected SWECS AEO must be calculated based on the gathered data, and an economic analysis must be performed based on the calculated SWECS performance. Methods for performing these three tasks were reviewed and new methods were developed for calculating SWECS AEO and SWECS economic merit. The interrelationships between wind data assessment programs, the energy output calculations and the economic calculations were also discussed.

Answers to the specific questions posed in the introduction are listed in order of their appearance.

## Answers to Questions and Objectives

1. Several tables and graphs depicting average wind behavior were displayed in Chapter 3. Yearly, monthly and daily variations in wind behavior were discussed.

2. A variety of statistical functions for modeling wind behavior used for SWECS AEO calculations were considered, including the gamma, Gausian, Rayleigh and Weibull density functions. The Weibull density function and the Rayleigh density function, a special case of the Weibull density function, were considered to be the most useful.

Though wind regimes at most sites with yearly average wind speeds greater than 4.0 m/s are considered to be Rayleigh distributed, tabulated

Weibull statistics from five different Michigan locations indicate that the more general Weibull density function may provide a better description.

3. The Weibull density function is specified by the yearly average wind speed and the wind speed variance. The Rayleigh density function is a single parameter function, specified completely by the yearly average wind speed.

4. Height and seasonal variabions in the Weibull c and k factors were considered. Tabulated data for seasonal variations in Weibull k factors indicate that wind speeds are more variable in the summer and less so in the winter. Formulas for correcting Weibull c and k factors due to height variations were discussed.

5. The most common types of instruments used for wind data assessment are the wind run meters and the recording anemometers. Wind run meters yield average wind speed only but are less expensive than recording anemometers. Both the average wind speed and the wind speed variance can be determined from recording anemometer data.

6. Since wind run meters provide average wind speed behavior only, the use of the Rayleigh density function for AEO calculations is implied. The recording anemometers yield wind speed variance data in addition to average wind speeds so the more general Weibull density function can be used. The cost differential between these instruments provides motivation to investigate the errors introduced if the Rayleigh density function is used for AEO calculations when the site wind behavior is best described by some other Weibull density function.

7. The factors affecting the length of time a wind data assessment program should be carried out include historic variation in yearly

average wind speed, the possible correlation between wind behavior at the candidate site and a nearby weather station, and the effect of errors in the estimate long term average wind speed on calculated AEO values.

Fifteen year wind records for the Muskegon Airport, Detroit Metro Airport and the Grand Rapids Airport indicate that the yearly average wind speed for any given year may be 20 percent away from the long term average wind speed. Several consecutive three year averages for the Detroit Metro Airport were as high as 18 percent away from the long term yearly average wind speed.

Results from several studies attempting to correlate wind behavior between candidate sites and nearby weather stations differed as to whether sufficient correlations existed between the studied sites to warrant a reduced assessment period at the candidate site. In the absence of a demonstrated correlation between wind behavior at the candidate site and a nearby weather station, candidate site wind behavior should be assessed for more than one year, perhaps more than three. The effect of errors in the estimated long term average wind speed on calculated AEO values are considered in the answer to question 11.

8. A variety of methods for calculating WTG AEO were reviewed, including the Justus, cubic, ramp, Powell, and SWECS Standard approaches. These methods were compared to a newly developed technique which uses a piecewise linear curve fitting technique to approximate the actual WTG P(v) curve.

The Powell and cubic approximations underestimated the AEO obtainable from a particular generic WTG. The ramp approximation was also inaccurate but was seen to be the most useful technique if the shape of the actual P(v) curve is unknown. If the shape of the WTG power output curve is known, some generalized curve fitting technique should be used. Different WTG have different P(v) curves and there is no simple analytical expression that can be used to approximate all actual WTG. The piecewise linear approximation is a general approach and is easily performed on a programmable calculator (see Appendix). The SWECS Standard approach (discrete approximation) is also a general approach but is tedious to perform, especially if the effects of changes in $\overline{V}$, k, c, etc., must be quickly determined.

9. A sensitivity analysis compared calculated AEO values using Weibull density function (with a variety of Weibull k factors) to the calculated AEO values using the Rayleigh density function (k = 2.0). AEO values were calculated using the ramp approximation for four different WTG designs (Design A - low cut-in wind speed ($V_i$), high rated wind speed ($V_r$); Design B - high $V_i$, high $V_r$; Design C - low $V_i$, low $V_r$; Design D - high $V_i$, low $V_r$) and three different yearly average wind speeds ($\overline{V}$ = 4.5 m/s, $\overline{V}$ = 5.5 m/s, $\overline{V}$ = 6.5 m/s). Assuming that most sites can be described by Weibull density functions with $1.7 \leq k \leq 2.3$ and that sites with $\overline{V}$ = 4.5 m/s will not support economic SWECS applications, the sensitivity analysis indicated that the use of the Rayleigh density function for AEO calculations introduces little error when wind behavior is actually best described by some other Weibull distribution with $1.7 \leq k \leq 2.31$ The errors due to a possibly wrong Rayleigh assumption were at most ± 2 percent for Design A and around ± 6 percent for Designs B, C and D (see Table 10 for specific details).

Since the Rayleigh density function yields AEO values that are similar to those obtained from the Weibull density function with

$1.7 \leq k \leq 2.3$, wind run meters should be suitable instruments for most wind data assessment programs

10. Methods for matching the WTG power rating with the site electrical demand were considered. If the utility buy-back price is less than the retail price of utility-supplied electricity, economics generally favor WTG with low power outputs compared to the site power demand.

Seasonal wind speed profiles closely match seasonal electrical resistance heating demands, indicating that wind-generated electricity may be put to good use in houses which have electrical resistance heating.

11. Errors in the estimated long term average wind speed may balloon into large errors in calculated AEO for some WTG designs and yearly average wind speeds. The error magnification is most noticeable for WTG with high rated wind speeds and sites with low yearly average wind speeds.

12. The method for calculating SWECS economics known as the fixed charge rate method was found to be inadequate to account for all the unique features of a particular SWECS application. A new approach was introduced which is capable of performing site-specific SWECS economic analyses. The parameters used in the new approach were described in detail and several example analyses were presented.

13. The relative economic merit among SWECS of a similar size is best described by the ratio of the total installed cost (IC) to the AEO, or the IC/AEO ratio. SWECS with low IC/AEO ratios are the best economic buys.

To compare a SWECS purchase with the continued exclusive use of utility-supplied electricity, four different figures of economic merit can be calculated:

a) Breakeven IC/AEO Ratio

b) Lifetime Net Savings

c) Payback Period

d) Current Cost of Energy ($COE_o$)

The calculated IC/AEO ratio of the proposed SWECS must be less than the Breakeven IC/AEO ratio if the system is to be economical. The Breakeven IC/AEO Ratio provides a handy reference figure for quickly estimating the economic potential of various commercially available SWECS. The current cost of energy, $COE_o$, was taken to be a more useful figure of economic merit than the commonly used levelized cost of energy, $\overline{COE}$, since $COE_o$ can be compared with today's electricity prices ($\overline{COE}$ cannot be) and may be easier for the general public to understand.

Graphs depicting the calculated Breakeven IC/AEO ratio vs. the calculated $COE_o$ were introduced and were seen to be an excellent way to provide a graphical illustration of the results of an economic analysis.

## CHAPTER SEVEN

## RECOMMENDATIONS FOR FURTHER RESEARCH

The topic of wind energy utilization is very broad and there are a host of areas that are currently being researched and need further research. Rather than list them all, the following are areas that I feel are particularly important:

1. More field data describing actual SWECS performance in the field is needed. Both the actual WTG energy output performance and the amount of energy buy-back for various WTG size and electrical load pattern combinations need to be investigated.

2. Load management for SWECS applications remains relatively uninvestigated. Microprocessors can direct the wind-generated electricity to a hierarchy of needs, at the bottom of which would probably water heating. The potential for such management at certain sites should be high.

3. Sensitivity analyses for AEO calculations should be performed on statistical models other than the Weibull. Perhaps the use of alternate probability densities such as the gamma produce similar results. In such a case, the analyst could be more confident in the use of Weibull statistics.

# APPENDIX A

# APPENDIX A

## TAX CREDITS FOR SWECS INVESTMENTS IN MICHIGAN

| Year | Credit | Maximum Allowable[3] |
|---|---|---|
| MICHIGAN[2] | RESIDENTIAL | |
| 1981 | 20% of 1st $2,000; 10% of next $8,000 | $1,200 |
| 1982 | 15% of 1st $2,000; 5% of next $8,000 | 700 |
| 1983 | 10% of 1st $2,000; 5% of next $8,000 | 600 |
| | COMMERCIAL | |
| The state of Michigan has not yet created tax credits for commercial establishments but may do so in the near future. | | |
| FEDERAL | RESIDENTIAL[4] | |
| Until 1/1/86 | 40% of 1st $10,000 | $4,000 |
| | COMMERCIAL | |
| | 15% investment credit in addition to the regular 10% investment credit | Unlimited |

[1]The total tax credits are not the simple sum of the state and federal credits because the state credits are treated as taxable income for federal income taxes, and the federal credits may be treated as taxable income for state income taxes.

Let $S_c$ = State income tax credits
$F_c$ = Federal income tax credits
$T_s$ = State income tax rate
$T_f$ = Federal income tax rate

In states where federal taxes are not deductable from state income tax, the formula for the "adjusted" tax credit is:

$$S_c + F_c - (T_f \times S_c)$$

In states where federal taxes are deductable from state income tax, the formula for the "adjusted" tax credit is:

$$\frac{S_c + F_c - (T_f \times S_c) - (T_s \times F_c)}{1 - (T_f \times T_s)\ 1 - (T_f \times T_c)}$$

Note that for businesses (in Michigan), $S_c = 0$.

[2]The Michigan Energy Administration must certify your eligibility.

[3]Tax credits for multi-family units is to "of next $13,000" and the maximum allowable credits go up accordingly.

[4]This credit must be claimed with IRS form #5693.

APPENDIX B

APPENDIX B

## PROGRAM FOR CALCULATING WTG ENERGY OUTPUT

### Equations Used in Analysis

#### Straight Line Approximation

$P(v) = 0 \qquad ; \quad v \leq V_i \text{ and } v \geq V_o$

$P(v) = A + B_r; \; V_i \leq v \leq V_r$

$P(v) + P_r \qquad ; \; V_r \leq v < V_o$

$$A = \frac{-V_i P_r}{V_r - V_i} \qquad ; \; B = \frac{P_r}{V_r - V_i}$$

$$AEO = 8760 \cdot \int_{V_i}^{V_r} (A+B_v)\rho(v)dv + P_r \int_{V_r}^{V_o} \rho(v)dv$$

If $\rho(v)$ = Rayleigh probability density, then. . .

$$^{1}AEO = 8760 \cdot P_r \cdot \frac{a\sqrt{2\pi}}{V_r - V_i} \quad \text{erf}\,\frac{V_r}{a} - \text{erf}\,\frac{V_i}{a} - \exp \; - \frac{1}{2}(\frac{V_o^2}{a})$$

where erf(x) = error function

$$= \frac{1}{\sqrt{2\pi}} \int_{o}^{x} \exp\,[-(y^2/2)]\; dy \text{ and}$$

$$a = \sqrt{2/\pi}\;\overline{V}$$

If $\rho(v)$ = Weibull probability density, then

$$^{2}AEO = 8760 \cdot \quad -(A + Bv)\exp[-(v/c)^k] \;\Big|_{V_i}^{{}^{3}V_r}$$

$$- P_r\exp[-(v/c)^i] \;\Big|_{V_r}^{V_o} + BK_e$$

---

[1]Obtained from (3).

[2]This equation and all subsequent equations (except the Powell approximation) were solved by continued integration by parts.

[3]Evaluate between the limits.

$$\text{where } K_e = \int_{V_i}^{V_r} \exp\,[-(v/c)^k]dv$$

Using Simpson approximation,

$$K_e = \frac{h}{3}\,(f_o + 4f_1 + 2f_2 + 4f_3 + f_4)$$

$$\text{where } h = \frac{V_r - V_i}{n}$$

and $n = 4$

$$f = \exp[-(v/c)^k] = f(x)$$

$$f_o = f(V_i)$$

$$f_1 = f(V_i + h)$$

$$f_2 = f(V_i + 2h)$$

$$f_3 = f(V_i + 3h)$$

$$f_4 = f(Vr)$$

Cubic Approximation

This formula is based on the fact that the power available in the wind is proportional to the cube of the wind speed, or

$$P = \frac{1}{2}\,K\eta\rho A v^3$$

where

P = adjustable constant depending on units

| P | A | $\rho$ | v | k |
|---|---|---|---|---|
| kW | sq ft | .000237 slugs/cu ft | mph | $4.28 \cdot 10^{-3}$ |
| kW | sq m | 1.22 kg/cu m | m/s | $9.81 \cdot 10^{-4}$ |

$\rho$ = air density

A = WTG blade sweep area

v = wind speed

$\eta$ = overall efficiency

Sometimes $\eta$ is simply assumed to be around 30 percent. Assuming that the WTG has an efficiency determined at $V_r$, then

$$\eta = \frac{P_r}{1/2k\rho AV_r^3}$$

Substituting into the first formula, we obtain:

$$P(v) = \frac{P_r}{V_r^3} v^3$$

and the coefficient

$$A = \frac{P_r}{V_r^3}$$

For the cubic approximation,

$$P(v) = 0 \quad ; \quad v < V_i \text{ and } v \leq V_o$$

$$P(v) = Av \ ; \ V_i \leq v \leq V_r$$

$$P(v) = P_r \ ; \ V_r \leq v < V_o$$

$$\text{and AEO} = 8760 \cdot \int_{V_i}^{V_r} Av^3\rho(v)dv + P_r \int_{V_r}^{V_o} \rho(v)dv$$

If $\rho(v)$ = Weibull probability density, then

$$\text{AEO} = 8760 \cdot \quad -3AV^3\exp]-(v/c)^k] + 3Av^2K_e$$

$$-6Av(V_r-V_i)K_e \Big|_{V_i}^{V_r} -P_r\exp[-(v/c^k)] \Big|_{V_r}^{V_o}$$

$$+6A(V_r-V_i)^2K_e$$

[4]The series approximation of this function converges very quickly and only 4 intervals are needed.

Justus Approximation (see 9)

$$P(v) = 0 \qquad v \le V_i \text{ and } v \ge V_o$$

$$P(v) = A + Bv + Cv \; ; \; V_i \le v \le V_r$$

$$P(v) = P_r \qquad ; \; V_r \le v < V_o$$

$$A = P_r V_i [V_a - 2V_r (V_a/V_r)^3]/2(V_r - V_a)^2$$

$$B = P_r [V_r - 3V_a + 4V_a (V_a/V_r)^3]/2(V_r - V_a)^2$$

$$C = P_r [1 - 2(V_a/V_r)^3]/2(V_r - V_a)^2$$

where

$$V_a = (V_i + V_r)/2$$

$$AEO = 8760 \cdot \int_{V_i}^{V_r} (A+Bv+Cv^2)\rho(v)dv + P_r \int_{V_r}^{V_o} \rho(v)dv$$

If $\rho(v)$ = Weibull probability density, then

$$AEO = 8760 \cdot \quad -(A+Bv+Cv\ )\exp[-(v/c)^k]$$

$$+2CvK_e \Big|_{V_i}^{V_r} \; -P_r \exp[-(v/c)^k] \Big|_{V_r}^{V_o} \; + (B-2C(V_r-V_i))K_e$$

Powell Approximation (see (19)

$$P(v) = 0 \qquad ; \; v \le V_i \text{ and } v \ge V_o$$

$$P(v) = A + Bv^k ; \; V_i \le v \le V_r$$

where

$$k = \text{Weibull shape factor}$$

$$P(v) = P_r ; \; V_r \le v < V_o$$

$$A = P_r V_i^k/(V_i^k - V_r^k)$$

$$B = P_r/(V_r^k - V_i^k)$$

$$\mathrm{AEO} = 8760 \cdot \int_{V_i}^{V_r} (A+Bv^k)\rho(v)dv + P_r \int_{V_r}^{V_o} \rho(v)dv.$$

If $\rho(v)$ = Weibull probability density, then

$$\mathrm{AEO} = 8760 \cdot \quad P_r - A + B^k((V_r/c)^k+1) \quad \exp[-(V_r/c)^k]$$

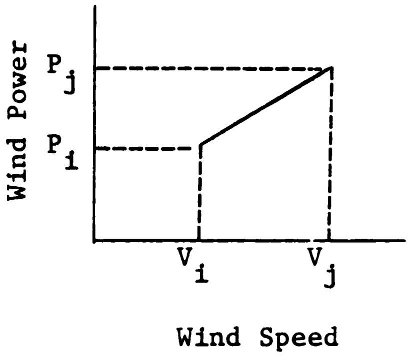
$$+ \quad A+Bc^k((V_i/c)^k+1) \quad \exp[-(V_i/c)^k]$$

$$- \; P_r \exp[-(\overline{V}/c)^k]$$

<u>Piecewise Linear Approximation</u>

$$[1]P(v) = \frac{(v - V_i)(P_j - P_i)}{(V_j - V_i)} + P_i$$

where for any line segment,




If (v) = Weibull probability density, then

$$\mathrm{AEO} = 8760 \cdot \sum_{\substack{i=1 \\ j=i+1}}^{N} \quad - \quad \frac{(v-V_i)(P_j-P_i)}{(V_j-V_i)} + P_i$$

$$\exp[-(v/c)^k] \quad \Big|_{V_i}^{V_j} + \frac{(P_j-P_i)}{(V_j-V_i)} K_e$$

---

[1]Notice that $V_i$ does not stand for the cut-in wind speed but rather the left value of any line segment.

where

$$K_e = \int_{V_i}^{V_j} -\exp[-(v/c)^k]dv$$

and is evaluated for each line segment using Simpson's approximation and

N = the number of line segments

See (25) for further details.

## Computer Operation Instructions

Up to 10 different line segments can be used.

| Wind Speed | | Power Output | |
|---|---|---|---|
| $V_1$ | STO 11 | $P_1$ | STO 21 |
| $V_2$ | STO 12 | $P_2$ | STO 22 |
| $V_3$ | STO 13 | $P_3$ | STO 23 |
| $V_4$ | STO 14 | $P_4$ | STO 24 |
| $V_5$ | STO 15 | $P_5$ | STO 25 |
| $V_6$ | STO 16 | $P_6$ | STO 26 |
| $V_7$ | STO 17 | $P_7$ | STO 27 |
| $V_8$ | STO 18 | $P_8$ | STO 28 |
| $V_9$ | STO 19 | $P_9$ | STO 29 |
| $V_{10}$ | STO 21 | $P_{10}$ | STO 30 |

Rayleigh - Section "A"

| Item | | Press | Prints | Display |
|---|---|---|---|---|
| 1 | Go to Section "A", Use of Rayleigh Probability Density | A | ______ | 0 |
| 2 | Enter average (mean) wind speed | ....,R/S | ....VM | |
| | | | 2K RAYLEIGH | 2 |
| 3 | Go to Section "E" | | | |

Weibull - Section "B"

| Item | | Press | Prints | Display |
|---|---|---|---|---|
| 1 | Go to Section "B" Use of Weibull Probability Density | B | ______ | 0 |
| 2 | Enter average (mean) wind speed | ....,R/S | ....VM | .... |
| 3 | Enter Weibull[1] k factor | ....,R/S | ....k WEIBULL | .... |
| 4 | Go to Section "E" | | | |

[1]The correct value for $C/\overline{V}$ is calculated.

Execution - Section "E"

| Item | | Press | Prints | Display |
|---|---|---|---|---|
| 1 | Go to Section "E", Execution | E | ______ | 0 |
| 2 | Enter number of line segments used, and begin execution | ....,R/S | ....N | |
| | | Calculates average power | ....P-AV | |
| | | Calculates annual energy output | ....AEO | .... |

## Program List

| | | |
|---|---|---|
| 000 | 76 | LBL |
| 001 | 16 | A' |
| 002 | 55 | ÷ |
| 003 | 43 | RCL |
| 004 | 32 | 32 |
| 005 | 54 | ) |
| 006 | 45 | Y$^X$ |
| 007 | 43 | RCL |
| 008 | 31 | 31 |
| 009 | 54 | ) |
| 010 | 94 | +/- |
| 011 | 22 | INV |
| 012 | 23 | LNX |
| 013 | 92 | RTN |
| 014 | 76 | LBL |
| 015 | 34 | √X |
| 016 | 97 | DSZ |
| 017 | 00 | 00 |
| 018 | 35 | 1/X |
| 019 | 61 | GTO |
| 020 | 23 | LNX |
| 021 | 76 | LBL |
| 022 | 35 | 1/X |
| 023 | 92 | RTN |
| 024 | 76 | LBL |
| 025 | 33 | X² |
| 026 | 43 | RCL |
| 027 | 09 | 09 |
| 028 | 75 | - |
| 029 | 43 | RCL |
| 030 | 08 | 08 |
| 031 | 54 | ) |
| 032 | 55 | ÷ |
| 033 | 53 | ( |
| 034 | 43 | RCL |
| 035 | 07 | 07 |
| 036 | 75 | - |
| 037 | 43 | RCL |
| 038 | 06 | 06 |
| 039 | 54 | ) |
| 040 | 54 | ) |
| 041 | 42 | STO |
| 042 | 37 | 37 |
| 043 | 36 | PGM |
| 044 | 09 | 09 |
| 045 | 43 | RCL |
| 046 | 06 | 06 |
| 047 | 36 | PGM |
| 048 | 09 | 09 |
| 049 | 11 | A |
| 050 | 43 | RCL |
| 051 | 07 | 07 |
| 052 | 36 | PGM |
| 053 | 09 | 09 |
| 054 | 12 | B |
| 055 | 04 | 4 |
| 056 | 36 | PGM |
| 057 | 09 | 09 |
| 058 | 13 | C |
| 059 | 36 | PGM |
| 060 | 09 | 09 |
| 061 | 14 | D |
| 062 | 42 | STO |
| 063 | 38 | 38 |
| 064 | 43 | RCL |
| 065 | 06 | 06 |
| 066 | 55 | ÷ |
| 067 | 43 | RCL |
| 068 | 32 | 32 |
| 069 | 54 | ) |
| 070 | 45 | Y$^X$ |
| 071 | 43 | RCL |
| 072 | 31 | 31 |
| 073 | 54 | ) |
| 074 | 94 | +/- |
| 075 | 22 | INV |
| 076 | 23 | LNX |
| 077 | 42 | STO |
| 078 | 33 | 33 |
| 079 | 43 | RCL |
| 080 | 07 | 07 |
| 081 | 55 | ÷ |
| 082 | 43 | RCL |
| 083 | 32 | 32 |
| 084 | 54 | ) |
| 085 | 45 | Y$^X$ |
| 086 | 43 | RCL |
| 087 | 31 | 31 |
| 088 | 54 | ) |
| 089 | 94 | +/- |
| 090 | 22 | INV |
| 091 | 23 | LNX |
| 092 | 42 | STO |
| 093 | 34 | 34 |
| 094 | 65 | × |
| 095 | 43 | RCL |
| 096 | 07 | 07 |
| 097 | 54 | ) |
| 098 | 94 | +/- |
| 099 | 85 | + |
| 100 | 53 | ( |
| 101 | 43 | RCL |
| 102 | 06 | 06 |
| 103 | 65 | × |
| 104 | 43 | RCL |
| 105 | 33 | 33 |
| 106 | 54 | ) |
| 107 | 85 | + |
| 108 | 43 | RCL |
| 109 | 38 | 38 |
| 110 | 54 | ) |
| 111 | 54 | ) |
| 112 | 65 | × |
| 113 | 43 | RCL |
| 114 | 37 | 37 |
| 115 | 54 | ) |
| 116 | 44 | SUM |
| 117 | 35 | 35 |
| 118 | 43 | RCL |
| 119 | 37 | 37 |
| 120 | 65 | × |
| 121 | 43 | RCL |
| 122 | 06 | 06 |
| 123 | 54 | ) |
| 124 | 94 | +/- |
| 125 | 85 | + |
| 126 | 43 | RCL |
| 127 | 08 | 08 |
| 128 | 54 | ) |
| 129 | 65 | × |
| 130 | 53 | ( |
| 131 | 43 | RCL |
| 132 | 33 | 33 |
| 133 | 75 | - |
| 134 | 43 | RCL |
| 135 | 34 | 34 |
| 136 | 54 | ) |
| 137 | 54 | ) |
| 138 | 44 | SUM |
| 139 | 35 | 35 |
| 140 | 43 | RCL |
| 141 | 35 | 35 |
| 142 | 44 | SUM |
| 143 | 36 | 36 |
| 144 | 92 | RTN |
| 145 | 76 | LBL |
| 146 | 44 | SUM |
| 147 | 43 | RCL |
| 148 | 11 | 11 |
| 149 | 42 | STO |
| 150 | 06 | 06 |
| 151 | 43 | RCL |
| 152 | 12 | 12 |
| 153 | 42 | STO |
| 154 | 07 | 07 |
| 155 | 43 | RCL |
| 156 | 21 | 21 |
| 157 | 42 | STO |
| 158 | 08 | 08 |
| 159 | 43 | RCL |
| 160 | 22 | 22 |
| 161 | 42 | STO |
| 162 | 09 | 09 |
| 163 | 25 | CLR |
| 164 | 42 | STO |
| 165 | 35 | 35 |
| 166 | 71 | SBR |
| 167 | 33 | X² |
| 168 | 71 | SBR |
| 169 | 34 | √X |
| 170 | 43 | RCL |
| 171 | 12 | 12 |
| 172 | 42 | STO |
| 173 | 06 | 06 |
| 174 | 43 | RCL |
| 175 | 13 | 13 |
| 176 | 42 | STO |
| 177 | 07 | 07 |
| 178 | 43 | RCL |
| 179 | 22 | 22 |
| 180 | 42 | STO |

```
181  08  08
182  43  RCL
183  23  23
184  42  STO
185  09  09
186  25  CLR
187  42  STO
188  35  35
189  71  SBR
190  33  X^2
191  71  SBR
192  34  √X
193  43  RCL
194  13  13
195  42  STO
196  06  06
197  43  RCL
198  14  14
199  42  STO
200  07  07
201  43  RCL
202  23  23
203  42  STO
204  08  08
205  43  RCL
206  24  24
207  42  STO
208  09  09
209  25  CLR
210  42  STO
211  35  35
212  71  SBR
213  33  X^2
214  71  SBR
215  34  √X
216  43  RCL
217  14  14
218  42  STO
219  06  06
220  43  RCL
221  15  15
222  42  STO
223  07  07
224  43  RCL
225  24  24
226  42  STO
227  08  08
228  43  RCL
229  25  25
230  42  STO
231  09  09
232  25  CLR
233  42  STO
234  35  35
235  71  SBR
236  33  X^2
237  71  SBR
238  34  √X
239  43  RCL
240  15  15
241  42  STO
242  06  06
243  43  RCL
244  16  16
245  42  STO
246  07  07
247  43  RCL
248  25  25
249  42  STO
250  08  08
251  43  RCL
252  26  26
253  42  STO
254  09  09
255  25  CLR
256  42  STO
257  35  35
258  71  SBR
259  33  X^2
260  71  SBR
261  34  √X
262  43  RCL
263  16  16
264  42  STO
265  06  06
266  43  RCL
267  17  17
268  42  STO
269  07  07
270  43  RCL
271  26  26
272  42  STO
273  08  08
274  43  RCL
275  27  27
276  42  STO
277  09  09
278  25  CLR
279  42  STO
280  35  35
281  71  SBR
282  33  X^2
283  71  SBR
284  34  √X
285  43  RCL
286  17  17
287  42  STO
288  06  06
289  43  RCL
290  18  18
291  42  STO
292  07  07
293  43  RCL
294  27  27
295  42  STO
296  08  08
297  43  RCL
298  28  28
299  42  STO
300  09  09
301  25  CLR
302  42  STO
303  35  35
304  71  SBR
305  33  X^2
306  71  SBR
307  34  √X
308  43  RCL
309  18  18
310  42  STO
311  06  06
312  43  RCL
313  19  19
314  42  STO
315  07  07
316  43  RCL
317  28  28
318  42  STO
319  08  08
320  43  RCL
321  29  29
322  42  STO
323  09  09
324  25  CLR
325  42  STO
326  35  35
327  71  SBR
328  33  X^2
329  71  SBR
330  34  √X
331  43  RCL
332  19  19
333  42  STO
334  06  06
335  43  RCL
336  20  20
337  42  STO
338  07  07
339  43  RCL
340  29  29
341  42  STO
342  08  08
343  43  RCL
344  30  30
345  42  STO
346  09  09
347  25  CLR
348  42  STO
349  35  35
350  71  SBR
351  33  X^2
352  76  LBL
353  23  LNX
354  43  RCL
355  07  07
356  55  ÷
357  43  RCL
358  32  32
359  54  )
360  45  Y^X
```

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 361 | 43 | RCL | 406 | 07 | 7 | 451 | 43 | RCL | 496 | 02 | 2 |
| 362 | 31 | 31 | 407 | 06 | 6 | 452 | 00 | 00 | 497 | 06 | 6 |
| 363 | 54 | ) | 408 | 00 | 0 | 453 | 69 | OP | 498 | 69 | OP |
| 364 | 94 | +/- | 409 | 95 | = | 454 | 06 | 06 | 499 | 04 | 04 |
| 365 | 22 | INV | 410 | 58 | FIX | 455 | 98 | ADV | 500 | 02 | 2 |
| 366 | 23 | LNX | 411 | 00 | 00 | 456 | 25 | CLR | 501 | 98 | ADV |
| 367 | 94 | +/- | 412 | 52 | EE | 457 | 42 | STO | 502 | 69 | OP |
| 368 | 85 | + | 413 | 22 | INV | 458 | 36 | 36 | 503 | 06 | 06 |
| 369 | 43 | RCL | 414 | 52 | EE | 459 | 61 | GTO | 504 | 69 | OP |
| 370 | 34 | 34 | 415 | 22 | INV | 460 | 44 | SUM | 505 | 00 | 00 |
| 371 | 54 | ) | 416 | 58 | FIX | 461 | 76 | LBL | 506 | 03 | 3 |
| 372 | 65 | × | 417 | 32 | X:T | 462 | 11 | A | 507 | 05 | 5 |
| 373 | 43 | RCL | 418 | 69 | OP | 463 | 98 | ADV | 508 | 01 | 1 |
| 374 | 09 | 09 | 419 | 00 | 00 | 464 | 25 | CLR | 509 | 03 | 3 |
| 375 | 54 | ) | 420 | 01 | 1 | 465 | 91 | R/S | 510 | 04 | 4 |
| 376 | 44 | SUM | 421 | 03 | 3 | 466 | 42 | STO | 511 | 05 | 5 |
| 377 | 36 | 36 | 422 | 01 | 1 | 467 | 10 | 10 | 512 | 69 | OP |
| 378 | 69 | OP | 423 | 07 | 7 | 468 | 69 | OP | 513 | 02 | 02 |
| 379 | 00 | 00 | 424 | 03 | 3 | 469 | 00 | 00 | 514 | 02 | 2 |
| 380 | 03 | 3 | 425 | 02 | 2 | 470 | 02 | 2 | 515 | 07 | 7 |
| 381 | 03 | 3 | 426 | 69 | OP | 471 | 42 | STO | 516 | 01 | 1 |
| 382 | 02 | 2 | 427 | 04 | 04 | 472 | 31 | 31 | 517 | 07 | 7 |
| 383 | 00 | 0 | 428 | 32 | X:T | 473 | 01 | 1 | 518 | 02 | 2 |
| 384 | 01 | 1 | 429 | 69 | OP | 474 | 93 | . | 519 | 04 | 4 |
| 385 | 03 | 3 | 430 | 06 | 06 | 475 | 01 | 1 | 520 | 02 | 2 |
| 386 | 04 | 4 | 431 | 98 | ADV | 476 | 02 | 2 | 521 | 02 | 2 |
| 387 | 02 | 2 | 432 | 98 | ADV | 477 | 08 | 8 | 522 | 02 | 2 |
| 388 | 69 | OP | 433 | 98 | ADV | 478 | 65 | × | 523 | 03 | 3 |
| 389 | 04 | 04 | 434 | 91 | R/S | 479 | 43 | RCL | 524 | 69 | OP |
| 390 | 43 | RCL | 435 | 25 | CLR | 480 | 10 | 10 | 525 | 03 | 03 |
| 391 | 36 | 36 | 436 | 35 | 1/X | 481 | 95 | = | 526 | 69 | OP |
| 392 | 58 | FIX | 437 | 91 | R/S | 482 | 42 | STO | 527 | 05 | 05 |
| 393 | 03 | 03 | 438 | 76 | LBL | 483 | 32 | 32 | 528 | 02 | 2 |
| 394 | 52 | EE | 439 | 15 | E | 484 | 04 | 4 | 529 | 98 | ADV |
| 395 | 22 | INV | 440 | 25 | CLR | 485 | 02 | 2 | 530 | 98 | ADV |
| 396 | 52 | EE | 441 | 98 | ADV | 486 | 03 | 3 | 531 | 98 | ADV |
| 397 | 22 | INV | 442 | 91 | R/S | 487 | 00 | 0 | 532 | 91 | R/S |
| 398 | 58 | FIX | 443 | 42 | STO | 488 | 69 | OP | 533 | 76 | LBL |
| 399 | 69 | OP | 444 | 00 | 00 | 489 | 04 | 04 | 534 | 12 | B |
| 400 | 06 | 06 | 445 | 69 | OP | 490 | 43 | RCL | 535 | 98 | ADV |
| 401 | 98 | ADV | 446 | 00 | 00 | 491 | 10 | 10 | 536 | 25 | CLR |
| 402 | 43 | RCL | 447 | 03 | 3 | 492 | 69 | OP | 537 | 91 | R/S |
| 403 | 36 | 36 | 448 | 01 | 1 | 493 | 06 | 06 | 538 | 42 | STO |
| 404 | 65 | × | 449 | 69 | OP | 494 | 69 | OP | 539 | 10 | 10 |
| 405 | 08 | 8 | 450 | 04 | 04 | 495 | 00 | 00 | 540 | 69 | OP |

```
541   00   00
542   04   4
543   02   2
544   03   3
545   00   0
546   69   OP
547   04   04
548   43   RCL
549   10   10
550   69   OP
551   06   06
552   98   ADV
553   91   R/S
554   42   STO
555   31   31
556   65   ×
557   93   .
558   00   0
559   01   1
560   04   4
561   94   +/-
562   85   +
563   01   1
564   93   .
565   01   1
566   06   6
567   04   4
568   75   -
569   93   .
570   00   0
571   06   6
572   05   5
573   65   ×
574   53   (
575   53   (
576   03   3
577   93   .
578   01   1
579   65   ×
580   53   (
581   43   RCL
582   31   31
583   75   -
584   01   1
585   93   .
586   03   3
587   54   )
588   54   )
589   94   +/-
590   22   INV
591   23   LNX
592   95   =
593   65   ×
594   43   RCL
595   10   10
596   95   =
597   42   STO
598   32   32
599   69   OP
600   00   00
601   02   2
602   06   6
603   69   OP
604   04   04
605   43   RCL
606   31   31
607   69   OP
608   06   06
609   32   X:T
610   69   OP
611   00   00
612   04   4
613   03   3
614   01   1
615   07   7
616   69   OP
617   02   02
618   02   2
619   04   4
620   01   1
621   04   4
622   04   4
623   01   1
624   02   2
625   07   7
626   02   2
627   07   7
628   69   OP
629   03   03
630   69   OP
631   05   05
632   32   X:T
633   98   ADV
634   98   ADV
635   98   ADV
636   91   R/S
637   00   0
638   00   0
639   00   0
```

APPENDIX C

# APPENDIX C

# PROGRAM FOR CALCULATING SWECS ECONOMICS

## Equations Used in Analysis

The equations used in this program can be found in the text and in (24).

## Computer Instructions

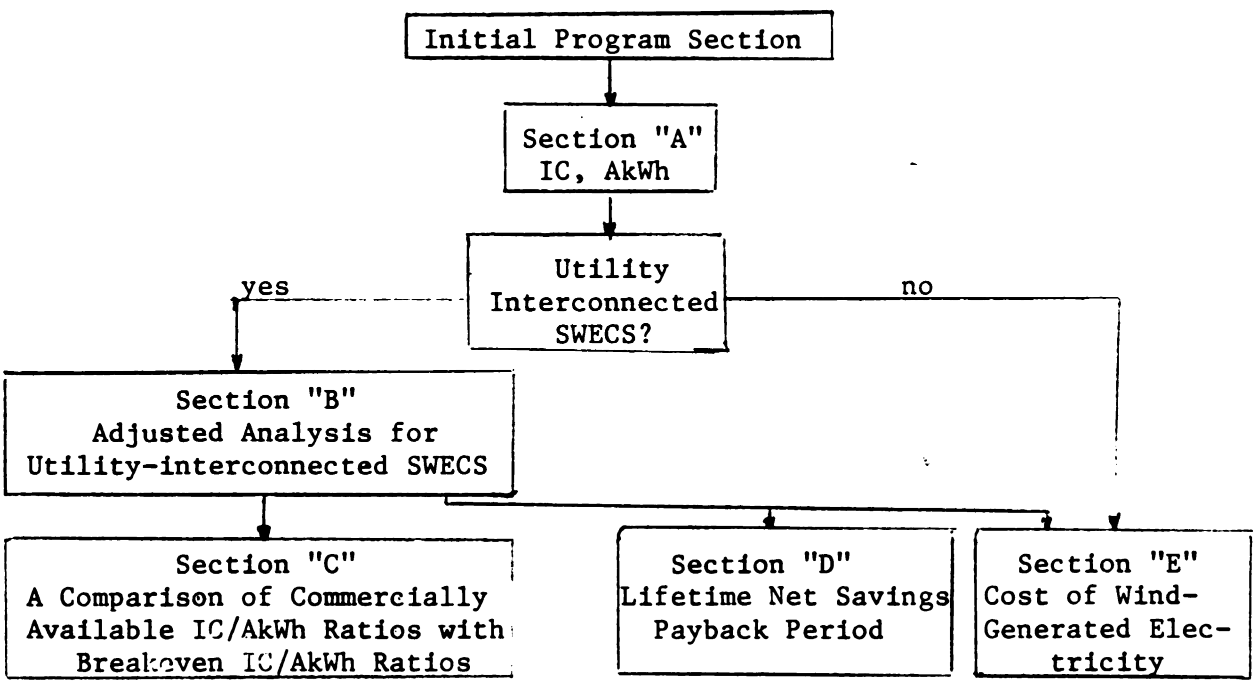



Figure 1. A flow chart for using the calculator.

The following pages illustrate the calculator instructions with the use of the data from example #1 in the text.

INITIAL DATA INPUT

| Item | Storage location | Example value | Press keys | Display | Your value | Press keys |
|---|---|---|---|---|---|---|
| 1. Loan interest rate | 01 | .12 | STO 01 | .12 | _____ | STO 01 |
| 2. Term of loan, years | 02 | 5 | STO 02 | 5 | _____ | STO 02 |
| 3. Discount rate | 03 | .12 | STO 03 | .12 | _____ | STO 03 |
| 4. General inflation | 04 | .10 | STO 04 | .10 | _____ | STO 04 |
| 5. Utility price escalation rate | 05 | .12 | STO 05 | .12 | _____ | STO 05 |
| 6. System lifetime | 06 | 20 | STO 06 | 20 | _____ | STO 06 |
| 7. Down payment (% of investment | 07 | .10 | STO 07 | .10 | _____ | STO 07 |
| 8. Effective income tax | 08 | .32 | STO 08 | .32 | _____ | STO 08 |
| 9. Insurance and maintenance | 09 | .04 | STO 09 | .04 | _____ | STO 09 |
| 10. Depreciation lifetime | 10 | 20 | STO 10 | 20 | _____ | STO 10 |
| 11. Salvage value | 11 | 0 | STO 11 | 0 | _____ | STO 11 |
| 12. 1=residence 2=business | 12 | 1 | STO 12 | 1 | _____ | STO 12 |

It is a good idea to check your memories to see if you have the proper values. To list memories push CLR INV 2ND LIST. These values are retained through the execution of any other program selection.

INITIAL DATA OUTPUT

| Item | Press | Prints | Display |
|---|---|---|---|
| 1. Execute initial program section | RST,R/S | OK | 0. |

There is no data output for sections "A" or "B".

Section "A"

DATA INPUT

| Item | Example value | Press | Prints | Display |
| --- | --- | --- | --- | --- |
| 1. Go to section "A" | | A | | 0. |
| 2. Enter total installed cost | 11,180 | R/S | 11,180 IC | 11,180 |
| 3. Enter annual energy output | 22,000 | R/S | 22,000 AEO | 22,000 |

Section "B"

DATA INPUT

| Item | Example | Press | Display |
| --- | --- | --- | --- |
| 1. Cost of utility-supplied electricity ($/kWh) | .055 | STO 29 | .055 |
| 2. Utility buy-back price ($/kWh) | .025 | STO 00 | .025 |
| 3. Yearly metering charge ($/yr) | 46.2 | STO 28 | 46.2 |

The preceding values are retained through any program section and may be entered at any ti-e. The only data that must be entered specifically in this section is the Direct Use Factor. If any of these three values are changed, however, section "B" must be re-run even if the same Direct Use Factor is used.

| Item | Example | Press | Prints | Display |
| --- | --- | --- | --- | --- |
| 1. Enter Direct Use Factor | .7 | B | .7 UF | .7 |

There is no data input for sections "C", "D", and "E".

Section "C"

DATA OUTPUT

| Item | Press | Prints | Display |
|---|---|---|---|
| 1. Execute program section "C" | C | | |
| | Total installed cost | 11,180 IC | |
| | Annual energy output | 22,000 AEO | |
| | Direct Use Factor | .7 UF | |
| | Commercially available IC/AEO | .508 CA | |
| | Breakeven IC/AEO | .550 BE | .550 |

Section "D"

DATA OUTPUT

| Item | Press | Prints | Display |
|---|---|---|---|
| 1. Execute program section "D" | D | | |
| | Total installed cost | 11,180 IC | |
| | Annual energy output | 22,000 AEO | |
| | Direct Use Factor | .7 UF | |
| | Utility bill savings (electricity bill savings) ($) | 20240 ES | |
| | Total wind costs ($) | 18705 WC | |
| | Lifetime net savings | 1535 NS | 1535 |
| 2. Payback period(yr) | R/S | 18 PB | 18 |

Section "E"

DATA OUTPUT

| Item | Press | Prints | Display |
|---|---|---|---|
| 1. Calculate current cost of wind-generated electricity | E | | |
| | Total installed cost | 10,800 IC | |
| | Annual energy output | 22,000 AEO | |
| | Direct Use Factor | .7 UF | |
| | Current cost of wind-generated electricity ($/kWh) | .051 COE | .051 |
| 2. Calculate level-ized cost of wind-generated elec-tricity ($/kWh | 2ND E' | .136 LCOE | .136 |
| 3. Calculate level-ized cost of utility-supplied electricity ($/kWh) | RCL 29, x:t,2ND E' | .147 LCOE | .147 |

## Program Cards

To use magnetic cards which have the program stored on them. . .

Entering program cards:

Step

1 Turn calculator off. Turn calculator on.

2 Repartition the calculator. Press 3 and OP 17. The calculator should display 719.29.

3 Press CLR, insert side 1, card 1. (The calculator should display 1. If there is a flashing display, press CLR and try again or press 1 INV write and try again.)

4 Press CLR, insert side 2, card 1.

5 Press CLR, insert side 3, card 2.

6 Press CLR, insert side 4, card 2.

To enter program steps into calculator:

Step

1 Turn calculator off, turn calculator on.

2 Repartition, press 3 and 2nd OP 17. (Calculator should display 719.29).

3 Press LRN.

4 Punch in program steps.

5 Enter proper values into memory locations.

6 Check calculator operation with sample values.

To store program onto magnetic cards:

Step

1 Press 1 2nd Write, insert side 1, card 1.

2 Press 2 2nd Write, insert side 2, card 1.

3 Press 3 2nd Write, insert side 3, card 2.

4 Press 4 2nd Write, insert side 4, card 2.

## Program List

| | | |
|---|---|---|
| 046 | 76 | LBL |
| 047 | 12 | B |
| 048 | 42 | STO |
| 049 | 03 | 03 |
| 050 | 91 | R/S |
| 051 | 76 | LBL |
| 052 | 13 | C |
| 053 | 42 | STO |
| 054 | 04 | 04 |
| 055 | 91 | R/S |
| 056 | 76 | LBL |
| 057 | 14 | D |
| 058 | 42 | STO |
| 059 | 05 | 05 |
| 060 | 91 | R/S |
| 061 | 76 | LBL |
| 062 | 15 | E |
| 063 | 42 | STO |
| 064 | 06 | 06 |
| 065 | 91 | R/S |
| 066 | 76 | LBL |
| 067 | 33 | X² |
| 068 | 53 | ( |
| 069 | 43 | RCL |
| 070 | 14 | 14 |
| 071 | 32 | X:T |
| 072 | 43 | RCL |
| 073 | 15 | 15 |
| 074 | 67 | EQ |
| 075 | 75 | - |
| 076 | 53 | ( |
| 077 | 01 | 1 |
| 078 | 85 | + |
| 079 | 43 | RCL |
| 080 | 14 | 14 |
| 081 | 54 | ) |
| 082 | 55 | ÷ |
| 083 | 53 | ( |
| 084 | 43 | RCL |
| 085 | 15 | 15 |
| 086 | 75 | - |
| 087 | 43 | RCL |
| 088 | 14 | 14 |
| 089 | 54 | ) |
| 090 | 54 | ) |

| | | |
|---|---|---|
| 000 | 61 | GTO |
| 001 | 53 | ( |
| 002 | 76 | LBL |
| 003 | 57 | ENG |
| 004 | 98 | ADV |
| 005 | 69 | OP |
| 006 | 06 | 06 |
| 007 | 98 | ADV |
| 008 | 92 | RTN |
| 009 | 76 | LBL |
| 010 | 90 | LST |
| 011 | 58 | FIX |
| 012 | 00 | 00 |
| 013 | 52 | EE |
| 014 | 22 | INV |
| 015 | 52 | EE |
| 016 | 22 | INV |
| 017 | 58 | FIX |
| 018 | 92 | RTN |
| 019 | 76 | LBL |
| 020 | 80 | GRD |
| 021 | 58 | FIX |
| 022 | 03 | 03 |
| 023 | 52 | EE |
| 024 | 22 | INV |
| 025 | 52 | EE |
| 026 | 22 | INV |
| 027 | 58 | FIX |
| 028 | 92 | RTN |
| 029 | 76 | LBL |
| 030 | 38 | SIN |
| 031 | 32 | X:T |
| 032 | 43 | RCL |
| 033 | 06 | 06 |
| 034 | 77 | GE |
| 035 | 39 | COS |
| 036 | 42 | STO |
| 037 | 13 | 13 |
| 038 | 76 | LBL |
| 039 | 39 | COS |
| 040 | 92 | RTN |
| 041 | 76 | LBL |
| 042 | 11 | A |
| 043 | 42 | STO |
| 044 | 01 | 01 |
| 045 | 91 | R/S |

| | | |
|---|---|---|
| 091 | 65 | × |
| 092 | 53 | ( |
| 093 | 01 | 1 |
| 094 | 75 | - |
| 095 | 53 | ( |
| 096 | 53 | ( |
| 097 | 01 | 1 |
| 098 | 85 | + |
| 099 | 43 | RCL |
| 100 | 14 | 14 |
| 101 | 54 | ) |
| 102 | 55 | ÷ |
| 103 | 53 | ( |
| 104 | 01 | 1 |
| 105 | 85 | + |
| 106 | 43 | RCL |
| 107 | 15 | 15 |
| 108 | 54 | ) |
| 109 | 54 | ) |
| 110 | 45 | $Y^X$ |
| 111 | 43 | RCL |
| 112 | 13 | 13 |
| 113 | 54 | ) |
| 114 | 54 | ) |
| 115 | 61 | GTO |
| 116 | 85 | + |
| 117 | 76 | LBL |
| 118 | 75 | - |
| 119 | 43 | RCL |
| 120 | 13 | 13 |
| 121 | 76 | LBL |
| 122 | 85 | + |
| 123 | 54 | ) |
| 124 | 92 | RTN |
| 125 | 76 | LBL |
| 126 | 65 | × |
| 127 | 01 | 1 |
| 128 | 04 | 4 |
| 129 | 01 | 1 |
| 130 | 07 | 7 |
| 131 | 69 | OP |
| 132 | 04 | 04 |
| 133 | 92 | RTN |
| 134 | 76 | LBL |
| 135 | 53 | ( |

| | | |
|---|---|---|
| 136 | 43 | RCL |
| 137 | 06 | 06 |
| 138 | 42 | STO |
| 139 | 13 | 13 |
| 140 | 43 | RCL |
| 141 | 04 | 04 |
| 142 | 42 | STO |
| 143 | 14 | 14 |
| 144 | 43 | RCL |
| 145 | 03 | 03 |
| 146 | 42 | STO |
| 147 | 15 | 15 |
| 148 | 71 | SBR |
| 149 | 33 | X² |
| 150 | 42 | STO |
| 151 | 16 | 16 |
| 152 | 43 | RCL |
| 153 | 05 | 05 |
| 154 | 42 | STO |
| 155 | 14 | 14 |
| 156 | 71 | SBR |
| 157 | 33 | X² |
| 158 | 42 | STO |
| 159 | 17 | 17 |
| 160 | 43 | RCL |
| 161 | 02 | 02 |
| 162 | 42 | STO |
| 163 | 13 | 13 |
| 164 | 71 | SBR |
| 165 | 38 | SIN |
| 166 | 43 | RCL |
| 167 | 01 | 01 |
| 168 | 42 | STO |
| 169 | 14 | 14 |
| 170 | 71 | SBR |
| 171 | 33 | X² |
| 172 | 42 | STO |
| 173 | 18 | 18 |
| 174 | 43 | RCL |
| 175 | 11 | 11 |
| 176 | 42 | STO |
| 177 | 13 | 13 |
| 178 | 71 | SBR |
| 179 | 38 | SIN |
| 180 | 25 | CLR |

| | | |
|---|---|---|
| 181 | 42 | STO |
| 182 | 14 | 14 |
| 183 | 71 | SBR |
| 184 | 33 | $X^2$ |
| 185 | 42 | STO |
| 186 | 19 | 19 |
| 187 | 43 | RCL |
| 188 | 02 | 02 |
| 189 | 42 | STO |
| 190 | 13 | 13 |
| 191 | 43 | RCL |
| 192 | 01 | 01 |
| 193 | 42 | STO |
| 194 | 15 | 15 |
| 195 | 71 | SBR |
| 196 | 33 | $X^2$ |
| 197 | 42 | STO |
| 198 | 20 | 20 |
| 199 | 43 | RCL |
| 200 | 02 | 02 |
| 201 | 42 | STO |
| 202 | 13 | 13 |
| 203 | 71 | SBR |
| 204 | 38 | SIN |
| 205 | 43 | RCL |
| 206 | 03 | 03 |
| 207 | 42 | STO |
| 208 | 15 | 15 |
| 209 | 71 | SBR |
| 210 | 33 | $X^2$ |
| 211 | 55 | ÷ |
| 212 | 43 | RCL |
| 213 | 20 | 20 |
| 214 | 95 | = |
| 215 | 42 | STO |
| 216 | 22 | 22 |
| 217 | 85 | + |
| 218 | 53 | ( |
| 219 | 43 | RCL |
| 220 | 18 | 18 |
| 221 | 65 | × |
| 222 | 53 | ( |
| 223 | 43 | RCL |
| 224 | 01 | 01 |
| 225 | 75 | - |
| 226 | 53 | ( |
| 227 | 43 | RCL |
| 228 | 20 | 20 |
| 229 | 35 | 1/X |
| 230 | 95 | = |
| 231 | 32 | X:T |
| 232 | 01 | 1 |
| 233 | 75 | - |
| 234 | 43 | RCL |
| 235 | 07 | 07 |
| 236 | 54 | ) |
| 237 | 65 | × |
| 238 | 53 | ( |
| 239 | 43 | RCL |
| 240 | 22 | 22 |
| 241 | 75 | - |
| 242 | 32 | X:T |
| 243 | 65 | × |
| 244 | 43 | RCL |
| 245 | 08 | 08 |
| 246 | 54 | ) |
| 247 | 54 | ) |
| 248 | 85 | + |
| 249 | 43 | RCL |
| 250 | 07 | 07 |
| 251 | 95 | = |
| 252 | 42 | STO |
| 253 | 24 | 24 |
| 254 | 43 | RCL |
| 255 | 10 | 10 |
| 256 | 65 | × |
| 257 | 43 | RCL |
| 258 | 16 | 16 |
| 259 | 95 | = |
| 260 | 42 | STO |
| 261 | 25 | 25 |
| 262 | 25 | CLR |
| 263 | 42 | STO |
| 264 | 15 | 15 |
| 265 | 01 | 1 |
| 266 | 42 | STO |
| 267 | 18 | 18 |
| 268 | 76 | LBL |
| 269 | 60 | DEG |
| 270 | 43 | RCL |
| 271 | 12 | 12 |
| 272 | 65 | × |
| 273 | 53 | ( |
| 274 | 53 | ( |
| 275 | 01 | 1 |
| 276 | 85 | + |
| 277 | 43 | RCL |
| 278 | 04 | 04 |
| 279 | 54 | ) |
| 280 | 55 | ÷ |
| 281 | 53 | ( |
| 282 | 01 | 1 |
| 283 | 85 | + |
| 284 | 43 | RCL |
| 285 | 03 | 03 |
| 286 | 54 | ) |
| 287 | 54 | ) |
| 288 | 45 | $Y^X$ |
| 289 | 43 | RCL |
| 290 | 06 | 06 |
| 291 | 95 | = |
| 292 | 42 | STO |
| 293 | 27 | 27 |
| 294 | 43 | RCL |
| 295 | 28 | 28 |
| 296 | 32 | X:T |
| 297 | 01 | 1 |
| 298 | 77 | GE |
| 299 | 52 | EE |
| 300 | 01 | 1 |
| 301 | 75 | - |
| 302 | 43 | RCL |
| 303 | 12 | 12 |
| 304 | 54 | ) |
| 305 | 65 | × |
| 306 | 43 | RCL |
| 307 | 08 | 08 |
| 308 | 65 | × |
| 309 | 43 | RCL |
| 310 | 19 | 19 |
| 311 | 55 | ÷ |
| 312 | 43 | RCL |
| 313 | 11 | 11 |
| 314 | 95 | = |
| 315 | 32 | X:T |
| 316 | 01 | 1 |
| 317 | 75 | - |
| 318 | 43 | RCL |
| 319 | 08 | 08 |
| 320 | 54 | ) |
| 321 | 65 | × |
| 322 | 43 | RCL |
| 323 | 25 | 25 |
| 324 | 85 | + |
| 325 | 43 | RCL |
| 326 | 24 | 24 |
| 327 | 75 | - |
| 328 | 43 | RCL |
| 329 | 27 | 27 |
| 330 | 75 | - |
| 331 | 32 | X:T |
| 332 | 95 | = |
| 333 | 42 | STO |
| 334 | 13 | 13 |
| 335 | 01 | 1 |
| 336 | 75 | - |
| 337 | 43 | RCL |
| 338 | 08 | 08 |
| 339 | 54 | ) |
| 340 | 65 | × |
| 341 | 61 | GTO |
| 342 | 36 | PGM |
| 343 | 76 | LBL |
| 344 | 52 | EE |
| 345 | 43 | RCL |
| 346 | 24 | 24 |
| 347 | 85 | + |
| 348 | 43 | RCL |
| 349 | 25 | 25 |
| 350 | 75 | - |
| 351 | 43 | RCL |
| 352 | 27 | 27 |
| 353 | 95 | = |
| 354 | 42 | STO |
| 355 | 13 | 13 |
| 356 | 76 | LBL |
| 357 | 36 | PGM |
| 358 | 43 | RCL |
| 359 | 17 | 17 |
| 360 | 55 | ÷ |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 361 | 53 | ( | 406 | 43 | RCL | 451 | 43 | RCL | 496 | 43 | RCL |
| 362 | 43 | RCL | 407 | 22 | 22 | 452 | 22 | 22 | 497 | 21 | 21 |
| 363 | 15 | 15 | 408 | 55 | ÷ | 453 | 67 | EQ | 498 | 65 | × |
| 364 | 44 | SUM | 409 | 43 | RCL | 454 | 22 | INV | 499 | 43 | RCL |
| 365 | 13 | 13 | 410 | 21 | 21 | 455 | 32 | X:T | 500 | 29 | 29 |
| 366 | 43 | RCL | 411 | 95 | = | 456 | 42 | STO | 501 | 65 | × |
| 367 | 13 | 13 | 412 | 71 | SBR | 457 | 21 | 21 | 502 | 43 | RCL |
| 368 | 54 | ) | 413 | 80 | GRD | 458 | 76 | LBL | 503 | 17 | 17 |
| 369 | 65 | × | 414 | 32 | X:T | 459 | 22 | INV | 504 | 65 | × |
| 370 | 43 | RCL | 415 | 01 | 1 | 460 | 01 | 1 | 505 | 43 | RCL |
| 371 | 29 | 29 | 416 | 05 | 5 | 461 | 03 | 3 | 506 | 18 | 18 |
| 372 | 95 | = | 417 | 03 | 3 | 462 | 02 | 2 | 507 | 95 | = |
| 373 | 42 | STO | 418 | 02 | 2 | 463 | 06 | 6 | 508 | 71 | SBR |
| 374 | 14 | 14 | 419 | 69 | OP | 464 | 04 | 4 | 509 | 90 | LST |
| 375 | 71 | SBR | 420 | 04 | 04 | 465 | 03 | 3 | 510 | 42 | STO |
| 376 | 65 | × | 421 | 32 | X:T | 466 | 02 | 2 | 511 | 26 | 26 |
| 377 | 43 | RCL | 422 | 71 | SBR | 467 | 03 | 3 | 512 | 01 | 1 |
| 378 | 14 | 14 | 423 | 57 | ENG | 468 | 69 | OP | 513 | 07 | 7 |
| 379 | 65 | × | 424 | 91 | R/S | 469 | 04 | 04 | 514 | 03 | 3 |
| 380 | 43 | RCL | 425 | 76 | LBL | 470 | 43 | RCL | 515 | 06 | 6 |
| 381 | 18 | 18 | 426 | 24 | CE | 471 | 21 | 21 | 516 | 69 | OP |
| 382 | 95 | = | 427 | 85 | + | 472 | 99 | PRT | 517 | 04 | 04 |
| 383 | 71 | SBR | 428 | 01 | 1 | 473 | 69 | OP | 518 | 43 | RCL |
| 384 | 80 | GRD | 429 | 52 | EE | 474 | 05 | 05 | 519 | 26 | 26 |
| 385 | 71 | SBR | 430 | 09 | 9 | 475 | 92 | RTN | 520 | 71 | SBR |
| 386 | 57 | ENG | 431 | 94 | +/- | 476 | 76 | LBL | 521 | 57 | ENG |
| 387 | 91 | R/S | 432 | 54 | ) | 477 | 17 | B' | 522 | 43 | RCL |
| 388 | 76 | LBL | 433 | 22 | INV | 478 | 20 | CLR | 523 | 22 | 22 |
| 389 | 16 | A' | 434 | 52 | EE | 479 | 91 | R/S | 524 | 65 | × |
| 390 | 25 | CLR | 435 | 42 | STO | 480 | 71 | SBR | 525 | 43 | RCL |
| 391 | 91 | R/S | 436 | 22 | 22 | 481 | 24 | CE | 526 | 13 | 13 |
| 392 | 71 | SBR | 437 | 69 | OP | 482 | 43 | RCL | 527 | 95 | = |
| 393 | 24 | CE | 438 | 00 | 00 | 483 | 28 | 28 | 528 | 71 | SBR |
| 394 | 71 | SBR | 439 | 02 | 2 | 484 | 32 | X:T | 529 | 90 | LST |
| 395 | 65 | × | 440 | 04 | 4 | 485 | 01 | 1 | 530 | 42 | STO |
| 396 | 43 | RCL | 441 | 01 | 1 | 486 | 67 | EQ | 531 | 22 | 22 |
| 397 | 14 | 14 | 442 | 05 | 5 | 487 | 44 | SUM | 532 | 04 | 4 |
| 398 | 65 | × | 443 | 69 | OP | 488 | 01 | 1 | 533 | 03 | 3 |
| 399 | 43 | RCL | 444 | 04 | 04 | 489 | 75 | - | 534 | 01 | 1 |
| 400 | 18 | 18 | 445 | 43 | RCL | 490 | 43 | RCL | 535 | 05 | 5 |
| 401 | 95 | = | 446 | 22 | 22 | 491 | 08 | 08 | 536 | 69 | OP |
| 402 | 71 | SBR | 447 | 71 | SBR | 492 | 54 | ) | 537 | 04 | 04 |
| 403 | 80 | GRD | 448 | 57 | ENG | 493 | 65 | × | 538 | 43 | RCL |
| 404 | 71 | SBR | 449 | 91 | R/S | 494 | 76 | LBL | 539 | 22 | 22 |
| 405 | 57 | ENG | 450 | 32 | X:T | 495 | 44 | SUM | 540 | 71 | SBR |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 541 | 57 | ENG | 586 | 25 | CLR | 631 | 71 | SBR | 676 | 00 | 00 |
| 542 | 94 | +/- | 587 | 91 | R/S | 632 | 57 | ENG | 677 | 55 | ÷ |
| 543 | 85 | + | 588 | 71 | SBR | 633 | 91 | R/S | 678 | 43 | RCL |
| 544 | 43 | RCL | 589 | 24 | CE | 634 | 76 | LBL | 679 | 29 | 29 |
| 545 | 26 | 26 | 590 | 43 | RCL | 635 | 19 | D' | 680 | 95 | = |
| 546 | 95 | = | 591 | 28 | 28 | 636 | 25 | CLR | 681 | 42 | STO |
| 547 | 71 | SBR | 592 | 32 | X:T | 637 | 91 | R/S | 682 | 18 | 18 |
| 548 | 90 | LST | 593 | 01 | 1 | 638 | 42 | STO | 683 | 06 | 6 |
| 549 | 42 | STO | 594 | 77 | GE | 639 | 15 | 15 | 684 | 01 | 1 |
| 550 | 27 | 27 | 595 | 94 | +/- | 640 | 04 | 4 | 685 | 04 | 4 |
| 551 | 03 | 3 | 596 | 01 | 1 | 641 | 05 | 5 | 686 | 01 | 1 |
| 552 | 07 | 7 | 597 | 75 | - | 642 | 01 | 1 | 687 | 69 | OP |
| 553 | 03 | 3 | 598 | 43 | RCL | 643 | 05 | 5 | 688 | 04 | 04 |
| 554 | 06 | 6 | 599 | 08 | 08 | 644 | 69 | OP | 689 | 32 | X:T |
| 555 | 69 | OP | 600 | 54 | ) | 645 | 04 | 04 | 690 | 71 | SBR |
| 556 | 04 | 04 | 601 | 65 | × | 646 | 43 | RCL | 691 | 57 | ENG |
| 557 | 43 | RCL | 602 | 76 | LBL | 647 | 15 | 15 | 692 | 65 | × |
| 558 | 27 | 27 | 603 | 94 | +/- | 648 | 71 | SBR | 693 | 53 | ( |
| 559 | 71 | SBR | 604 | 43 | RCL | 649 | 57 | ENG | 694 | 01 | 1 |
| 560 | 57 | ENG | 605 | 21 | 21 | 650 | 91 | R/S | 695 | 75 | - |
| 561 | 91 | R/S | 606 | 65 | × | 651 | 42 | STO | 696 | 43 | RCL |
| 562 | 43 | RCL | 607 | 43 | RCL | 652 | 18 | 18 | 697 | 18 | 18 |
| 563 | 06 | 06 | 608 | 17 | 17 | 653 | 35 | 1/X | 698 | 54 | ) |
| 564 | 65 | × | 609 | 65 | × | 654 | 65 | × | 699 | 85 | + |
| 565 | 43 | RCL | 610 | 43 | RCL | 655 | 43 | RCL | 700 | 43 | RCL |
| 566 | 22 | 22 | 611 | 18 | 18 | 656 | 15 | 15 | 701 | 18 | 18 |
| 567 | 55 | ÷ | 612 | 54 | ) | 657 | 65 | × | 702 | 95 | = |
| 568 | 43 | RCL | 613 | 35 | 1/X | 658 | 43 | RCL | 703 | 42 | STO |
| 569 | 26 | 26 | 614 | 65 | × | 659 | 16 | 16 | 704 | 18 | 18 |
| 570 | 95 | = | 615 | 43 | RCL | 660 | 95 | = | 705 | 61 | GTO |
| 571 | 71 | SBR | 616 | 22 | 22 | 661 | 42 | STO | 706 | 60 | DEG |
| 572 | 90 | LST | 617 | 65 | × | 662 | 15 | 15 | 707 | 00 | 0 |
| 573 | 32 | X:T | 618 | 43 | RCL | 663 | 02 | 2 | 708 | 00 | 0 |
| 574 | 03 | 3 | 619 | 13 | 13 | 664 | 04 | 4 | 709 | 00 | 0 |
| 575 | 03 | 3 | 620 | 95 | = | 665 | 01 | 1 | 710 | 00 | 0 |
| 576 | 01 | 1 | 621 | 71 | SBR | 666 | 05 | 5 | 711 | 00 | 0 |
| 577 | 04 | 4 | 622 | 80 | GRD | 667 | 69 | OP | 712 | 00 | 0 |
| 578 | 69 | OP | 623 | 32 | X:T | 668 | 04 | 04 | 713 | 00 | 0 |
| 579 | 04 | 04 | 624 | 01 | 1 | 669 | 43 | RCL | 714 | 00 | 0 |
| 580 | 32 | X:T | 625 | 07 | 7 | 670 | 18 | 18 | 715 | 00 | 0 |
| 581 | 71 | SBR | 626 | 01 | 1 | 671 | 71 | SBR | 716 | 00 | 0 |
| 582 | 57 | ENG | 627 | 05 | 5 | 672 | 57 | ENG | 717 | 00 | 0 |
| 583 | 91 | R/S | 628 | 69 | OP | 673 | 91 | R/S | 718 | 00 | 0 |
| 584 | 76 | LBL | 629 | 04 | 04 | 674 | 32 | X:T | 719 | 00 | 0 |
| 585 | 18 | C' | 630 | 32 | X:T | 675 | 43 | RCL | | | |

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