Title

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Publication Date

1982-04-01

Lawrence Berkeley Laboratory

UNIVERSITY OF CALIFORNIA

APPLIED SCIENCE DIVISION

ANALYSIS OF THE PERFORMANCE AND COST EFFECTIVENESS OF NINE SMALL WIND ENERGY CONVERSION SYSTEMS FUNDED BY THE DOE SMALL GRANTS PROGRAM

J. Kay
(M.S. Thesis)

April 1982

APPLIED SCIENCE DIVISION

Prepared for the U.S. Department of Energy under Contract DE-AC03-76SF00098

DISCLAIMER

LBL-15998

TITLE: ANALYSIS OF THE PERFORMANCE AND COST EFFECTIVENESS OF NINE SMALL WIND ENERGY CONVERSION SYSTEMS FUNDED BY THE DOE SMALL GRANTS PROGRAM

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This work was suported by the Assistant Secretary for Conservation and Renewable Energy, Office of the State and Local Programs, Small Scale Technology Branch of the U.S. Department of Energy under Contract No. DE-AC03-76SF00098.

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Acknowledgements

Many people have given both concrete help and moral support throughout this project. A few merit special recognition. Dr. F. Bart Lucarelli, recently at the University of Petroleum and Minerals in Dhrahran, Saudi Arabia, helped to formulate an outline for this project and gave direction to the initial stages of the research. His incisive criticisms and persistent encouragement have been indispensable in my efforts to complete this project.

Prof. Marshal F. Merriam of the Department of Materials Sciences and Mineral Engineering at the University of California, Berkeley, provided guidance in the development of a method to calculate wind output for different types of machines. He also provided contacts for interviews with wind machine manufacturers and dealers in the San Francisco Bay Area and elsewhere in the U.S. His careful review of technical details helped to eliminate many inaccuracies contained in earlier drafts.

Drs. Mark Levine and Donald Grether of the Applied Science Division of the Lawrence Berkeley Laboratory provided very thorough reviews of earlier drafts. Their criticisms pointed to economic and institutional problems that the paper needed to address.

Others who provided useful technical help included Profs. Mark Christensen and Anthony Fisher of the Energy & Resources Group at UC Berkeley; Mr. Neil Holbrook of Power Tower Intenational, Pleasant Hill, CA; Mr. Ted Finch of the Bronx Frontier Project; Mr. Joseph P. Seele of the New Alchemy Institute, E. Falmouth, MA.

Finally, a few special expressions of gratitude are in order. Ms. Hannah R. Clark, formerly a technical editor of the Lawrence Berkeley Laboratory, single-handedly edited several drafts, made numerous corrections, and in many cases, helped to clarify ambiguous technical descriptions. Her organizational skills and willingness to work unreasonable hours ensured reasonably timely completion of the initial drafts. Ms. Charlotte Standish of the Solar Group in the Applied Science Division at LBL has willingly and cheerfully ploughed forward with the final drafts of this report amidst other considerable pressures on her time and resources. Ms. Cynthia Ashley and Dr. Michael Wahlig, administrator and leader of the Solar Group, respectively, coordinated the administrative completion of the report.

My wife, Judith Webb Kay, and son Jeremy have endured with loving patience long hours of absence and preoccupation on the part of husband and father. Without their support through the darkest hours, the report could not have been completed.

While all these people deserve thanks, responsibility for any misrepresentation remains my own.

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Chapter 1.

Analytic Framework For Evaluating Small Wind Energy Systems

Introduction

This report presents an analysis of the technical performance and cost effectiveness of nine small wind energy conversion systems (SWECS) funded during FY 1979 by the U.S. Department of Energy. Chapter 1 gives an analytic framework with which to evaluate the systems. Chapter 2 consists of a review of each of the nine projects, including project technical overviews, estimates of energy savings, and results of economic analysis. Chapter 3 summarizes technical, economic, and institutional barriers that are likely to inhibit widespread dissemination of SWECS technology.

*This work was supported by the Assistant Secretary for Conservation and Renewable Energy, Office of the State and Local Programs, Small Scale Technology Branch of the U.S. Department of Energy under Contract No. DE-AC03-76SF00098.

Selection of Projects

The nine systems use wind energy for a variety of applications. Each system has an output (in good winds) of between one and forty kW. System costs range from about $10,000 to nearly $50,000. Six systems generate electricity, two pump water, and one generates heat by hydraulic friction. Regional DOE offices responsible for implementing the Small Grants Program gave funding preference to grantees who were enthusiastic about developing new systems or who seemed likely to demonstrate interesting commercial applications of existing solar technologies.

Measurement of Energy Savings

The energy saved by each system is the amount of fossil based energy whose consumption is avoided because of wind generated energy. This avoided consumption is the sum of the energy associated with performing the task at the end-use, plus losses in generation, transmission, and distribution. The method used to derive primery fuel savings is outlined below. At the time of completion of research (April, 1982) the nine projects under study had been operating for less than a year, and thus energy savings were estimated either from design specifications or from the brief operating experience of the system. In this paper, reported energy savings reflect potential savings. They represent the savings that could be achieved if the project worked according to the grantee's specifications. The specific estimation procedures are discussed under each heading.

1. Wind Electric Systems. In the case of three systems (Raymond Miller's Cincinnati Project, the Evanston Environmental Center Project, and the U.S. Virgin Islands Project), manufacturers supplied operating data that related average wind velocity to energy output. Manufacturers assume that wind speeds are distributed according to a Rayleigh distribution*. They measure the power produced by the windmill at different wind speeds. For measurements purposes, winds of different speeds are typically induced from wind tunnel or highway tests. The power curve resulting from the tests and the Rayleigh assumption enables the manufacturers to predict monthly energy outputs given mean monthly wind speeds. This method typically overestimates wind output because ideal testing situations like wind tunnel measurement ignores such problems as hysteresis and yaw alignment lag.[1] The project managers of the other three electric systems (The Bronx Frontier project, the Attitash Ski Resort project, and the Minnesota Farm project.) have provided

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* The Rayleigh distribution, also known as the Chi-Square, can be expressed in cumulative form as follows:

$$RC = 1 - \exp[-\ \pi/4 \times (v/\bar{v})^2]$$

where:

RC = Rayleigh cumulative
WC = Weibull cumulative
v = actual wind speed
$\bar{v}$ = mean wind speed

Rayleigh is a special case of the Weibull distribution, the cumulative form of which is given by

$$WC = 1 - \exp[-\ (V/C)^k].$$

Thus the Weibull is equivalent to the Rayleigh if k=2, V=v, and $C = \frac{2\bar{v}}{}$ Studies by Corotis et al.[2] and Cliff[3] indicate that k = 2 is typical for the continental U.S. and that the Rayleigh distribution yields good estimates for net power from SWECS when compared with detailed wind frequency distribution data.

estimates of energy savings from their own experiments. In the case of all six electric systems, energy savings have been checked according to the procedure outlined below. My calculations appear in Appendix A. (I have adopted a conservative approach; in the case where the grantee's own estimate is either below my estimate or above it by no more than 15%, I use his figure. Otherwise my own is substituted.)

(1) I obtained a mean wind speed for each project site and assumed that the winds have a Rayleigh distribution about that mean. The accuracy of these speeds varied. See Table 1 for source of mean wind speed.

(2) I compiled the manufacturers' specifications on (a) cut-in and cut-out speeds (the wind speeds between which a wind machine produces power) and (b) rated wind speed (the wind speed necessary for maximum power generation).

(3) Considering the cubic relationship between potential wind speed and theoretical power available in the wind I computed:

$$P/A = 1/2\ \rho v^3$$

P/A = power per unit area in W/m^2

ρ = density of air at sea level = 1.2 kg/m^3

v = instantaneous wind speed in m/s

(4) I combined the above formula with the differential Rayleigh distribution to obtain a power distribution. Integrating this curve yields an estimate of energy available in the wind.

(5) I obtained an estimate an average rotor coefficient of performance (COP) or the ratio of power in the shaft to total power in the wind.* The COP depends on the type of rotor, the number and orientation of the blades, and other factors. Typically, the COP ranges between .10 and .40 and varies with the ratio of the speed of the blade tip to the wind speed, which is called the tip speed ratio (TSR). For this analysis, I have assumed that all electric projects have an average COP of 0.35, an optimistic but not unreasonable figure.

(6) I applied this COP to the estimated power distribution at the site to obtain an estimate of kWh generated by the machine. I reduced this estimate by 20 percent to adjust for maintenance and repair shutdowns and for line and efficiency losses of auxiliary equipment (batteries, alternators, etc.). Unfortunately, adequate data do not exist to allow me to estimate for hysteresis and yaw alignment lag. To the extent that these problems exist, my estimates are biased upward.

2. Wind Pumping Systems. The two water pumping windmills were both completed and operating before the analysis period for this report terminated. Thus, actual operating data on the amount of water pumped were available. Using these data I followed the steps below:

*Even under ideal conditions, the rotor COP cannot be more than 0.593 for horizontal axis machines.

(1) I divided the mass of water lifted from the well to the collection point by the time period over which pumping took place to get the average rate of water flow.

(2) I then estimated the head through which the water was lifted. (Head losses caused by friction and bends in the pipes, were so small they were ignored.)

(3) I multiplied the head and the head losses by rate of flow to obtain the power needed to lift the water.

(4) I divided this number by an estimated electric pump efficiency (assumed at 0.7) to obtain displaced power going into the pump.

(5) I combined the last estimate with the time period of the observation to obtain the approximate electric energy savings per unit of time. This savings estimate was then checked against the available wind energy. An implicit assumption is that all pumped water can be used. Maintenance down time is assumed negligible.

3. Wind Heat Generators. The analysis below includes only one heat conversion project, and the computation of the energy savings is discussed in the project description. All available shaft power is assumed to be converted into heat. The system is considered to be perfectly insulated so that all the heat enters the transfer fluid. I assume that all the heat is usable. To the extent that there are times when heat availability and heat requirements do not coincide, this assumption overstates the value of heat produced.

Estimating Economic Feasibility

1. The Basic Task

The calculations of economic feasibility are hypothetical on two grounds. First, not all projects had been completed at the time of close of research (April, 1982). Much performance is still subject to confirmation. Second, and more fundamental, all of these projects have been paid for by the government. In assessing feasibility, I took actual cost and performance data and assumed that private investment produced the SWECS. The object is to determine whether any given project could stand on its own economically if government support had not been forthcoming.

The difficulty with taking only a private prospective on the SWECS projects, however, is that society may experience indirect benefit by having renewable resource projects replace nonrenewable systems. In the absence of corrective public policy, the total benefit to society (the sum of the value of market priced energy savings and intangeables) is likely to be greater than the direct benefit to the individual making the SWECS investment.* Some likely sources of divergence between private and social value merit dicussion.

2. Divergence between Private and Social Costs

In perfect competition, private and social costs would be identi-

*The Public Utilities Regulatory Policy Act of 1978 (PURPA) has made some attempt to resolve the differences between public and private benefits. These attempts have been frought with difficulties and uncertainties. See discussion in Chapter 3 below.

cal. Energy markets, however, are highly imperfect, distorted by government subsidies, monopoly and cartel market conditions, environmental costs, and until recently, extensive price controls.

For example, to develop oil and coal resources, the U.S. Government has given the industries tax subsidies such as oil depletion allowances, accelerated depreciations and investment tax credits.[4] Also, in order to safeguard national access to foreign oil, the federal government has developed a massive military machine. From the 1946 passage of the Atomic Energy Act to the on-again-off-again Clinch River Breeder Reactor project, federal subsidy of Nuclear fission R&D has amounted to at least several billion dollars.[5]

In addition to subsidies that are not reflected in market prices, society sometimes must bear environmental or other external costs associated with commercial energy use. In the case of nuclear fission power, the external cost is mostly in the form of risk. The well known Rasmussen Report[6], criticized on the basis of overly conservative assumptions and some outright errors[7], estimates that death from cancer and prompt deaths could number from less than 1,000 to nearly 200,000 from a worst-case hypothetical LWR Accident; illnesses and genetic defects could affect roughly between 100,000 to well over a million people; and that corresponding property damage could range from $2.8 to $28 billion (1975 dollars). These estimates do not include the effects of either natural disaster (earthquake, tornado, tsunami) or malicious human activity (war, sabotage, terrorism). While the costs imposed by nuclear power are mostly in the form of incurred risk of future problems, the social costs imposed by coal-fired power generation are somewhat more quantifiable in terms of historical problems. Between 1970 and 1977, over 420,000 federal compensation awards were made to miners and former miners with black lung disease[8], costing the government over $5.5 billion[9]. (After 1977, as a result of legislation passed that year, industries paid a greater share of these accruals, thus internalizing the externalities in the price of coal.) A recent study by Gleick[10] indicates that in 1975, fatalities involving coal transport (both public and occupational) were nearly 4600. Total injuries came to over 150,000 in the same year. SO_2 emmissions from coal-fired plants may cause respirtory problems and losses in agricultural productivity from acid rain. Climatologists worry about the long term effects on earth's temperature and weather patterns from increasing CO_2 buildup from coal combustion.

The external costs of oil use differ from these associated with coal and nuclear in that there is a significant foreign political component in them. Over 6 million barrels of crude oil and refined petroleum products per day that were consumed in the U.S. in 1979 originated in OPEC countries.[11] This fact has subjected the U.S. economy to two risk-related costs. First, a sudden disruption of oil supplies on account of cartel collusion or serious Mid-East war could result in millions of dollars worth of lost economic activity. This risk has been the basis for calls by policy makers for strategic stockpiling of oil reserves. Second, because the U.S. is such a large consumer of OPEC oil, both relatively and absolutely (the U.S. and OECD countries consumed about 21 and 60 percent of the 24 mbd OPEC production, respectively)[12], any marginal change in the level of oil imports in the U.S. will affect world oil prices significantly.

Such price changes would lead to additional macroeconomic changes. Stobaugh[13] cites an example in which an increase in imports of 5 mbd could cause an increase in outflow of funds from the U.S. of $58 billion. The direct $58 billion drop in demand for U.S. goods and services could cause additional indirect drops in income and aggregate demand (Stobaugh estimates between $10 billion and $100 billion) through a multiplier effect, the actual amount depending on how much of the original $58 billion found its way back into the U.S. economy through direct purchases of goods and services or reinvestment by OPEC dollar holders.

Although Stobaugh's example is hypothetical, the dynamic of lost income, employment, and discretionary capital available for American-owned investment is accurately illustrated. On the basis of these two risks (sudden disruption and price-change induced macroeconomic disruption), Plummer[14] has developed a set of premiums that should be attributable to the social costs of imported oil. That is, each barrel of oil purchased (or not purchased by dint of conservation effort or solar application) carries with it a value to society in addition to its current market price, depending upon its use. A barrel added to the U.S. stockpile has a cushioning value in addition to the value it woild have if it were put to use immediately in the economy. Similarly, a barrel of oil no longer purchased from OPEC is worth more to U.S. society than current market value; it makes a contribution to diminishing the economic possibility of future OPEC price hikes and attendant macroeconomic dislocations.*

*These arguments are applicable at the level of marginal changes in the U.S. economy, which is very large. Thus, in my discussion here, "on the margin" really means the last million barrels, not the last single barrel.

Our discussion of differences between private and social costs of oil have focused almost exclusively on foreign oil. Environmental aspects of offshore oil drilling and oil shale retortion will very likely be important sources of divergence between private and social cost of domestic oil use in the future. It is unlikely that environmental legislation will be strict enough to force oil producers to internalize all these costs even if that were technically possible.

A final source of divergence I shall mention relates to the risk of breakdown in large, centralized energy systems. Lovins attributes electric utility systems in particular with this risk.[15] He has discussed with optimism the potential that wind, photovoltaic, and combined renewable resource systems hold for the enhancement of system stability. One of Lovins' principal criticisms of highly centralized systems is their overdependence on the timely functioning of many interactive parts, any one of which is suseptible to sabotage by some combination of human error, hardware error, or active malice. The 1965 and 1977 blackouts in the U.S. Northeast disrupted the energy supply of 10 to 20 million people due to transmission system breakdowns.[16] The cost to society of such brittleness includes loss of goods and services, increased vandalism, and vulnerability to threats against national security.

The extent to which this brittleness is important depends on how much it has been a factor in influencing electric utility reliability historically. A major recent study of utility reliability gives cautious support to Lovins' argument. Between 1971 and 1979 the load involved in bulk power interruptions (interruptions involving outages of 100 MW or more, lasting 15 minutes or longer, and caused by outages of facilities rated at 69 KV or above) increased at a rate of about 14.5 percent per year from less than 8000 MW/interruption to over 14,000 MW/interruption.[17] The number of interruptions per year also increased at a rate of 44 percent per year from less than 30 to over 85.[18] Even when these figures are divided by annual sales of KWh, the normalized figures still show increases: between 1971 and 1979, the ratio of the number of interruptions to electric sales per year increased at somewhat less than 20 percent per year while the ratio of interrupted load to electric sales has increased by 7 percent annually.[19] Among generic causes for these outages, electric system component and operation failure accounted for 59 percent, while weather accounted for most of the remainder.[20] While these points tend to support Lovins and indicate growing system vulnerability, overall utility performance has still been excellent. Throughout the 1970's, the energy not delivered to customers as a result of bulk outages was much less than 0.01 percent of the energy that was delivered.[21] Nonetheless, this type of vulnerability might not be present in less interactive, more diversified systems.

3. Outline of Methodology of Social and Private Valuation of SWECS.

In general, a SWECS will be considered economically feasible if the discounted value of the energy produced over the economic life of the system exceeds the capital and discounted annual system costs. The method of calculation is known as life cycle costing (LCC). Two different calculations will be made. The first will value the energy at the average cost the private investor would expect to incur in the absence of the SWECS (e.g., his utility bill). The second valuation will approximate the marginal value to society of the displaced commercial energy.

As a proxy for this marginal social value, I have chosen the energy value of a KWh of electricity generated from OPEC oil when this oil is measured according to its total value to society. The assumpton that energy displaced by wind is energy that would have been provided by oil is, of course, false in general. Justification for using it here has two principal bases.

First, foreign oil does find its way into thermal generation plants and home central heating, particularly in the Northeast and Southwest. It represents an expensive, critical, and risky source of commercial energy. Clearly, usage of coal or nuclear fuel carries different sources of risk. Difficulty in quantifying these risks in dollar terms (e.g., value of lives lost in coal mining accidents or value of nuclear fuel theft) caused me to choose oil instead of coal or nuclear as the basis for value of fuel displaced.

The second basis for my choice is methodological. Over the next two to three decades, coal or nuclear electric power, aided by conservation, load management, and perhaps solar power sources, should largely displace oil-fired power plants. Thus in the long run, in many parts of the country, wind power or other newable sources can be said to be replacing oil. To the extent that some parts of the country rely very little on oil-based electricity or heat, an oil-based cost of electricity probably overstates the value of wind energy. In either case, an oil-based value approximates an upper bound on the value of wind turbines; I argue that if wind energy is not cost effective based on replacing oil, there is little likelihood that cost effectiveness can be achieved at all for a grid-connected user. An oil-based avoided cost thus provides a "first-hurdle" test at cost effectiveness, although by no means a final one.

The figure for a social value of electricity displaced I compute as follows:[22]

- I computed the weighted average of the traded costs of OPEC oil in 1980 to be $33.48/bbl.

- To this I added a $5.00/bbl import reduction premium.[23]

- Next, I divided the total Kwh of electricity produced from petroleum-fired plants in 1980 by the total petroleum energy (in Kwh) consumed to produce the electricity. The numerator of this quotient is 246 billion Kwh.[22(a)] The denominator is 718 billion Kwh.[22(b)] The quotient is thus 0.34. This represents the U.S. average efficiency of petroleum conversion to electricity in generation. Since transmission and distribution losses are estimated to average about 10 percent,[22(c)] my overall conversion efficiency factor is (0.34) x (0.90) = 0.31.

- The social value of $38.48/bbl can be expressed in gross energy equivalent as 2.26¢/kWh. Dividing this figure by the efficiency factor of 0.31 yields 7.29¢/kWh (base year 1980 dollars) net electricity delivered, which I use as the estimate of the long run opportunity costs of oil imports.*

4. The Valuation Procedure

Life Cycle Costing (LCC) is the method for evaluating all relevant costs and revenues for an energy system over its economic life. The LCC method is applied in four steps.

(1) Estimation of Capital Costs: First costs are the costs of purchasing and installing an energy system less any capital savings from not using a fossil fuel system. The first cost of a system, whenever possible, is the actual cost or expected market cost of the system. I have obtained estimates of equipment, installation, and annual operation and maintenance (O&M) costs on the basis of extensive phone interviews, correspondence, and site visits to manufacturers, dealers, DOE regional technical monitors, and the individual project managers. In a case where the grantee is developing a prototype system, first cost is taken either from his estimate of what the system will cost when commercially available or from comparisons to systems already marketed. The actual costs of the system do not correspond to the grant award for two reasons. First, actual outlays necessary for project completion often exceed

*The social cost estimate is incomplete. First, electric utilities do not burn crude oil, rather they burn either residual or distillate. The cost of this can range between 0 to 20 percent above typical crude prices. Conceivably, in extraordinary supply situations it might even be slightly less. Second, no premiums have been calculated to reflect social costs of ar pollution, oil spills, military costs to "protect" the Persian Gulf, etc. The reason for these omissions is an obvious lack of reliable data. It should be noted that the omissions are probably quite significant.

the grantee's original expectations and some infusion of the grantee's personal funds has often been necessary. Second, the grant awards usually include allocations for monitoring and demonstration, activities that do not produce energy.

(2) Estimation of Annual Net Revenues: Net revenue is the constant dollar value of energy or other output produced or saved over the life of a system less operating, maintenance, and replacement costs.

(3) Conversion of Costs and Revenues to Present Values: Most of the costs of wind systems are incurred in the first year or two. Most of the benefits accrue afterwards, annually for twenty years or more. To convert dollar values into time-equivalent amounts, a discount rate is used, raised to a power corresponding to the year beyond the present year in which it occurs.

In estimating LCC for each project, the following assumptions were made.

- All future costs and revenues are expressed in 1980 dollars.

- Nonenergy costs and revenues are assumed to remain constant in real terms.

- I have selected 7 percent as the real annual discount rate at which to discount future costs and benefits. Some discussion of how I arrived at this rate is necessary. The Solar Energy Research Group has used real discount rates of close to 3 percent for the evaluation of wind systems[24] Their rationale is that this rate approximates the real rate of return on long term home mortgages. I believe the 3 percent rate is inappropriate because it reflects a very low level of perceived risk on the part of the investor. (If investments A and B yield the same expected return, but if the variance between B's outcome is greater than A's, then B is riskier than A, and a risk-averse investor would pay more for A. Thus, comparable expected returns on riskier investments are worth less in present value terms: they are discounted at a higher rate[25]). A figure between 2 and 3 percent is obtained by subtracting the rate of inflation from the nominal money market interest rate during peiods of stable inflation. Thus these rates appear to reflect an essentially risk-free rate of return.[26]

The question of how much of a increase in the discount rate is needed to reflect the risk associated with windmills is a tricky one. Ibbotsen and Sinquefield have found that the long term real rate of return on a broad sampling of stocks (evaluated between 1926 and 1976) was just under 7 percent.[27] I consider that windmill investments are at least as risky as investments in an average stock. There is considerable evidence suggesting that perceived risk is far greater. Studies of implicit discount rates observe consumer purchases of energy saving equipment. Based on the amount of purchase and the estimated savings attributable to them, the analyst can deduce what that consumer or group's discount rate <u>would</u> <u>have</u> <u>been</u> to make that particular bundle of expenditure the optimal bundle. In one such recent study, Housman found that consumers evidenced implicit, real discount rates of 5 to 85 percent to evaluate the life cycle costs of room air conditioners, with a U.S. median of about 20 percent.[28] Discount rates as high as this imply in part a "consumer myopia," an overperception of risk due perhaps to imperfect consumer information, high borrowing costs, resale market imperfections, and the like.[29] Thus, my valuation using 7 percent assumes that consumers are no more myopic than are average stock market investors. Tests of cost-effectiveness using this rate represent a "first hurdle"; if wind systems are not cost effective at 7 percent, they certainly will not be at 20 percent.

The National Security Act of 1980 (P.L. 96-294, Sec. 405, 94 Stat. 611) specifies that a 7 percent discount rate should be used by the federal government to discount energy conservation and renewable resource projects.[30] Thus 7 percent is used in both the private and social calculations.

- A base year energy price is either the actual price per unit paid by the grantee or the marginal social value of 8.08¢/kWh.

- Energy prices are escalated at two real annual rates of 2 and 6 percent.

(4) Determination of Cost-Effectiveness: A system is deemed cost-effective if the net present value of before-tax revenues during the life cycle equals or exceeds the corresponding costs. The ratio of the net present value of before-tax revenues to costs is called the savings to investment ratio (SIR). By definition, energy systems with a SIR equal to or greater than 1.0 are cost-effective.

The social SIR gives an indication of whether the wind project is a rational allocation of society's resources The before-tax SIR indicates roughly whether a specific energy system that relies on renewable energy resources can compete against the fossil fuel alternative without government subsidies. To determine the extent to which individual investors are subsidized requires a detailed analysis of the economic sectors in which the system can be used and of the applicable investment criteria and tax laws. While such analysis is beyond the scope of this report, the principal factors that determine the tax impact can be summarized and a conservative estimate of that impact given.

The tax impact of any investment in an energy system based on renewables depends principally on two factors. The first factor is an allowed energy-tax credit that depends on technology type and sector of application. The second is an interest-cost deduction that depends upon the method by which the system is financed, the level of income (for a residential application) or gross sales (for a commercial application), and the method of depreciation (for a commercial application).

The interest cost deduction is highly variable and difficult to compute because it depends so heavily on the individual situation of the investor. For this reason I have not tried to quantify it. The federal tax credit is much more straightforward: 40 percent of the first $10,000[31] of initial system cost for residential wind applications and 25 percent[32] of the total cost (no ceiling) for commercial applications.[17] The commercial rate is actually the sum of a 15 percent energy tax credit and a 10 percent investment tax credit, the latter of which can be applied to any fixed investment in a new business.

No state tax impacts have been evaluated, primarily because of variations in state tax laws. Including state differences makes estimates of cost-effectiveness less comparable across regions. Moreover, because many state estimates depend on the amount of federal tax credit claimed, the actual effect of the omission is reduced somewhat. The after-tax SIR indicates whether the wind system would be purchased by a rational consumer given current economic conditions and tax consequences.

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22. U.S. DOE. Annual Report to Congress. Op. Cit.

22.(a) DOE/EIA 1980 Annual Report to Congress, Vol.2, p.155, Table 65. (DOE/EIA-0173(80)/2) Data represent gross electricity output at the generator terminals, minus power plant use. They thus represent net electricity generated.

22.(b) Ibid, p.162, Table 69 and Appendix, p. 227. Total Kwh energy equivalent of petroleum burned in power plants is derived as follows: (421.3×10^6 bbl oil)(5.8×10^6 btu (bbl oil)/ + (0.2×10^6 short tons of petroleum coke) (665 bbl/short ton) (6.024×10^6 btu/bbl of coke)/ (3413 btu/Kwh) $\cong$ 718 billion Kwh.

22.(c)U.S. Congress, Office of Technology Assessment, Application of Solar Technology to Today's Energy Needs, (OTA-E-66) June 1978, pp.141-2.

23. Chao, Hung-Po, and Peck, Stephen (October 1980), Energy Policies and The Oil Import Premium (preliminary draft), Energy Policy Research Inst. (EPRI), Palo Alto, Ca. Peck indicates that the lower end of Plummer's scale (around $5) is appropriate.

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30. I am indebted to Ms. Rosalee Ruegg of The National Bureau of Standards, Gaithersburg, MD for her discussions with me on social and private discount rates.

31. Anderson, Jan (July/August 1980), "Federal Energy Tax Credit Increased," Solar Law Reporter, Vol. 2, No. 2, pp. 235-237.

32. Dawkins, Lisa, and Troutman, George (May/June 1979), "Solar Energy Legislation in the 95th Congress," Solar Law Reporter, Vol. 1, No. 1, pp. 140-143 They discuss the original version of the Energy Tax Act of 1978. According to my conversation with an IRS representative in Oakland, Ca., March 1981, the energy tax credit for commercial businesses has increased from 10 to 15 percent in addition to the regular 10 percent investment tax credit.

CHAPTER 2

THE PROJECTS

Introduction

Each of the projects discussed below is described in a technical overview. Following each overview is an estimation of the energy that could be produced by the wind system. Finally, a brief economic analysis, which includes an accounting of project costs and a valuation of energy benefits, summarizes that project's potential feasibility.

The word "potential" is important here. Most of the projects were not actually operating at the close of the analysis period (April, 1982) and those that were, had only been in operation a few months. The reliability of two of the manufacturers (Humingbird and Mehrkam) has been open to serious question (some details of this are given with each relevant project discussion). In the case of one unfinished wind system (The U.S. Virgin Island project) it is possible that the project manager had no intention of completing the project he was paid to do. Finally, only in the case of five out of the nine projects (see Table 1) were the wind resource estimates based on on-site measurements.

In four cases where no anemometry was done at the site, mean windspeed was provided by project manager. In most cases, the project manager simply took data from a nearby weather station and modified it according to how he felt his site was different. (General experience shows that this rough technique usually overestimates the wind resource). Once the estimate of mean wind speed is obtained, energy output and the value of the output are computed according to the methods outlined in Chapter One. Wherever possible, data on equipment costs supplied by the grantee were corroborated by interviews with manufacturers and dealers.

It is clear that much the data is subject to substantial error. The technical, economic, and institutional difficulties discussed in Chapter 3 are such that the data on which the analysis is based are more likely to be optimistic than pessimistic (e.g., actual project costs are likely to be higher, actual wind output and actual value per unit output lower, than is reported here). A summary of each project's status and economic reliability is presented in Table 1 at the end of the chapter.

I: Demonstration of a Wind Turbine Generator for Use in an Urban Environment

Grantee:
Evanston Environmental Center
2024 McCormick Blvd.
Evanston, IL 60201
(312) 328-2100

Grant Award: $27,000
DOE Project: IL79-849
Manager:
Mr. Harold Benjamin, BSEE

PROJECT OVERVIEW[1]

The goal of the grantee is to determine whether wind energy can make a significant contribution to meeting the electricity needs of urban residences. In particular he will examine whether a small wind electric generator that is tied into the utility grid is technically sound and economically feasible. The project contains a strong demonstration component. The grantee has provided free training sessions for volunteers to help install the tower and foundation. Further demonstration will consist of operating and monitoring the wind machine over a period of one year and seeking public reactions and publicizing the experience in local media.

The wind turbine and generator have undergone numerous modifications since the beginning of the project. Several plans to install vertical axis machines, originally thought to be well suited to the gusty winds in the area, have been abandoned both because of incompatibility between the generator and the corresponding vertical axis tower and because of the first manufacturer's inability to produce a workable turbine.

The turbine that the grantee finally chose is manufactured by Hummingbird Windpower Corp.,[1.(a)] Unfortunately, the Hummingbird Machine also has been plagued with problems. Carlos and Mario Gottfried, owners of PGI, originally intended to use a three phase synchronous permanent magnet AC generator that could, through carefully controlled circuits, make direct contact with a utility line. The machine was to have been able to connect either with a single phase or 3-phase utility line. Direct connection would have imposed a constant 257 rpm on the rotor and the delivered power would have been in phase with and at the same frequency and voltage as line power. Unfortunately, high, gusty winds prevented maintenance of in-step operations. The control circuits

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[1.(a)] Hummingbird Windpower, Holanda 3, Mexico 21 D.F., Tel. 905-582-3111.

became complex expensive, and still did not work. Ultimately, the concept of direct contact was abandoned.

Hummingbird has promised to deliver, for no extra cost, a new system that utilizes the same generator whose ouput will be rectified to DC with diodes and an 8 kw synchronous inverter manufactured by Gemini and distributed locally by Windworks, Inc.[1.(b)] The result is that the new circuitry is one-third the original cost of the original circuitry, although this is about offset by the inverter cost. The machine can now cut-in at 8 mph instead of 10 mph and because of the variable rotor speed, can maintain nearly constant tip-speed ratio.

The rotor is a 3-blade, 14 ft diameter upwind type, rated to deliver about 4 kw at about 23-24 mph. As windspeeds increase from rated windspeeds, a fan tail gradually turns the machine out of the wind until funding is complete at about 60 mph. The rotor and generator will set atop a 70 ft tower already installed at the site, manufactured by Unarco-Rohn. Necessary wiring between the generator site and the Environmental Center monitoring building is complete. As of my last contact with the grantee in April 1982, the machine had been installed and had run for a few hours during its first week.

ENERGY SAVINGS

According to preliminary anemometry testing done by researchers at the center during April and May 1980, the mean monthly wind speeds are

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[1.(b)] Windworks Inc., Mukwonago, WI 53149.

about 1 mph below those at Midway Airport in Chicago. The readings at the site were taken at 58 feet above ground, whereas the tower and, consequently, the hub height will be at 70 feet. By basing wind regime assumptions on the lower heights, I may have biased the energy estimates downward by a small amount. However, the entire correlation procedure is so uncertain that the height difference is unimportant.

The manufacturer has provided figures that relate mean monthly wind speed to estimated net electric energy produced. According to his calculations, the annual busbar generation of electricity is about 5300 kwh. My own calculations indicate that, based on all his assumptions, this figure is much too high and in fact exceeds the Betz limit. Therefore, I have chosen to use my own estimate of savings, which is 2622 kwh. See Appendix A for details.

PROJECT ECONOMICS

The grantee has reported the following project costs:

Tower	$2640
Foundation (including drilling, reenforcing bars, concrete, structural analysis, & soil testing)	$1912
Turbine (with swivel tail & 3-phase synchronous generator)	$4397
8 kW Windworks Invertor	$2000
Miscellaneous (copper wire, electrician's time, digging trench to bury wire)	$3759
Total equipment & installation:	$14708

Annual Operation & Maintenance (O&M)
(manager's estimate - annual) $150/yr

In addition, utility sources give the average cost of electricity in northern Illinois as 7.5¢/kWh, as of 1981[2] which I shall use as a private cost with which to evaluate energy savings. Because this wind system is intended for residential use, I assume that 40 percent of the first $10,000 of installed costs is recovered by the potential investor as a residential tax credit. Using the 7.29¢/kWh figure derived in Chapter 1 to estimate social costs, the following results of economic analysis are obtained for this project at real energy value escalation rates of 2 and 6 percent. See Appendix B for details.

	2%	6%
Social SIR	0.06	0.13
Private before-tax SIR	0.06	0.14
Private after-tax SIR	0.08	0.19

II: Wind Powered Pumping and Water Storage on a Michigan Farm

Grantee:
Mr. Thomas Klaus
Rt. 1, Box 68
Cooks, MI 49817
(906) 644-2761

Grant Award: $6710
DOE Project: MI79-113

PROJECT OVERVIEW[3]

The grantee has installed a multibladed windmill to pump water from an existing well into a pond. The pond water is used for irrigation of 15 acres of strawberries during moderate to dry spring, summer, and early fall seasons. Water is also sprayed over the strawberry plant blossoms and young fruit to protect them from being killed by the rapid thawing that often occurs after a frost. Since the summer of 1980 the wind-powered pump has effectively replaced a 5.5-hp submersible pump, which is kept functional in case a backup is needed.

The windmill has a 10-ft. diameter and is mounted on a 50-ft. tower. The tower rests on a concrete base, which sits directly on top of an 8-in. diameter well that is 180 ft. deep. Water is available at 75 ft. and is pumped from this depth to the wellhead, whence it flows downhill 300 ft. to a pond with a 1.2 million gallon capacity.

ENERGY SAVINGS

The grantee has claimed that about 6000 Kwh will be saved by the windmill annually. Very little concrete information exists about the mean annual windspeed at the site, but some preliminary anemometry results from tests at a nearby branch of Michigan State University indicate that they may be about 15 mph, a rather high average. Even when one assumes this speed is right, 6000 kWh is much too high. A more reasonable savings figure is about one quarter of that, or 1565 kWh. See Appendix A for details.

PROJECT ECONOMICS

Project costs can be summarized as follows:

Windmill	$1100
Tower	$1300
Pump	$ 210
Rods, pipe fittings, etc.	$ 700
Total capital costs	$3310
Installation	$2100
Total capital & installation	$5410
Annual O&M	$ 150
Pump replacement (every 5 yrs)	$ 210

The economic benefits of the project can be summarized as follows. Recent bills from Wisconsin Electric Power Co. (serving both Wisconsin and part of Michigan) indicate that the average kWh cost of electricity for this firm is about 4¢/kWh as opposed to the social value of 7.29¢/kWh. Thus, private and social energy savings values for the base year are $63 and $113, respectively. Based on the capital and O&M costs summarized above, the following SIR calculations are obtained for escalation rates of real energy values of 2 and 6 percent.

	2%	6%
Social SIR	0	0.19
Private before-tax SIR	0	0
Private after-tax SIR	0	0

III: A Wind to Heat Converter

Grantee:
Mr. Evan D. Fisher, BSME
Rt. 2, Box 215
Bellaire, MI 49615
(616) 377-7139

Grant Award: $22,250
DOE Project: MI79-122
Manager:
Mr. Fisher

PROJECT OVERVIEW[4]

The grantee is attempting to demonstrate the technical and economic feasibility of a wind-driven machine that converts wind energy into heat. Connected by suitable shafting and gearing, the windmill impeller drives a rotory hydraulic brake. The brake consists of a veined disc attached to a shaft. The disc rotates through a viscous oil, creating friction and heat. The oil is then pumped either to a test building that is heated directly by the oil or to an insulated storage tank.

The prototype is being constructed in the grantee's shop and installed on a hilltop site adjacent to the building. The building was recently subdivided into three insulated rooms and a larger noninsulated room. The insulated rooms will be used to evaluate the performance of the wind machines.

The prototype consists of a steel tower nearly 50 ft. high, a 2-blade rotor approximately 40 ft. in diameter, a horizontal shaft at the apex of the tower, and a right angle gearbox. The horizontal shaft is rotated by the blades and is free to swing in the wind. The gear box connects the horizontal shaft with a vertical shaft. The latter rotates the veined disc of the converter, which is mounted at the base of the tower. A second gear box will be located at the base in order to optimize the velocity of the disc.

The prototype is being constructed from existing materials and components modified for this specific use. Sections of a used oil derrick will be the tower; the impeller was made out of helicopter blades; the horizontal shaft and right-angle gearbox were the rear axle of a dump truck; and the converter was a torque converter of an automatic transmission.

When power generation is coincident with the heating load, the oil will be pumped in a single closed loop directly into the baseboard convectors in the test building. When there is no coincidence, such as during periods of strong winds and mild weather, oil will be diverted to a loop that enters a heat exchanger, which is submerged in a 4000-gallon, insulated water tank. When heat is needed on windless days, oil will be drawn through the tank into the baseboards. The grantee will manually adjust a set of valves to divert the flow. Eventually he hopes to replace these valves with thermostatically controlled solenoid valves.

All pipelines are 3/4-in. copper encased in 4-in. plastic drainage pipe and foam insulated. The pipelines are buried about 30 in. below ground level. Normally, winter snow will provide 18 to 30 in. of additional insulation.

The variable winds encountered may preclude the use of helicopter blades. The inertia of the cross shaft with these blades attached is large, and the response of swinging downwind may take longer than the shifting of the wind, producing high stress in the blades. If the blades are allowed to operate at all air speeds, the drag on them during high winds may be too much strain on the tower. Considerable damage was inflicted during Winter 1980-81. Construction was still ongoing during Summer 1981.

DIRECT ENERGY SAVINGS

The grantee reports that he expects the average wind speed to be 12 mph at the tower hub. His blades will be pitched at a 45 degree angle, enough to achieve high starting torque at low wind speeds. His brake is a fail-safe solenoid that should activate in winds of 40 mph.

We assume that the wind is Rayleigh distributed, approximately, about a mean of 12 mph. If we assume very low (essentially zero mph) cut-in speeds and high cut-out speeds, the average energy is about 0.18 Kwh/m^2. Such cut-in and cut-out assumptions are optimistic and give the project full benefit of the doubt. Given a rotor diameter of 12.2 m, the energy available in the wind is about 180 MWh annually.

The analysis must account for several energy losses. The first and most important loss is incurred in the conversion of power in the wind to rotary shaft power. Because the blades are old helicopter blades originally intended for rotation in a horizontal plane, the grantee expects a COP of no more than 0.15. Shaft and gearing losses will account for another 10 percent of power dissipated. If the heat exchanger is thoroughly immersed in the water tank and if the tank is as well insulated as the grantee says, the heat exchanger losses will not be significant. Finally, I assume that the system delivers useful heat for only eight months of the year. These factors reduce direct energy gain to about 15,000 kWh of heat annually.

PROJECT COSTS AND ECONOMICS

The grantee has provided a breakdown of costs into three categories: costs he actually incurred on the project, probable costs of repeating the project (incorporating knowledge he has gained into a hypothetical second unit), and costs that reflect economies of scale attendant on full scale production. The grantee claims that Operation and Maintenance Costs should to be negligible.

Item	Actual	2nd unit	Production
Labor			
Eng.	$ 9285	$ 5000	$ 1000
Tech.	800	5000	2500
Tower	2000	2000	1500
Converter	575	500	200
Pitch Control	450	750	500
Gear box & shaft	395	400	200
Tank	1981	2000	500
Blades	0	2000	500
Consultants	100	0	0
Subcontracts	932	400	0
Misc. costs	3045	2500	1500
Obligations	2705	0	0
Subtotal	$22,250	$20,550	$9,000
Overhead (30%)		6165	2700
Cost total		$26,715	$11,700
Profit (10%)		2672	1170
Gross total		$28,387	$12,870

Assembly and erection costs of the tower and foundation are included here, but in another application, total costs will vary according to the costs of local labor and materials such as concrete. The transportation charges here included for the 4000-gallon steel storage tank (over a 15 mile distance) will also vary. Actual costs include insulation for the thermal storage tank and the adjacent structure that will be heated, but do not include the installation of connections with an existing heating system.

The project differs from the others in the study in that heat rather than fuel-based electricity is being conserved. The 15 MWh of energy savings is the energy equivalent of the heat replaced by this system. The private and social costs of energy, 1.97¢/kWh (heat) and 2.3¢/kWh (heat), respectively, are derived from the costs of oil with and without the import premium. The private and social energy savings for the base year are $295 and $345, respectively. Considering these savings and the cost estimates given above for full scale production, the following SIR ratios were obtained:

	2%	6%
Social SIR	0.42	0.70
Private before-tax SIR	0.36	0.60
Private after-tax SIR	0.52	0.87

IV: Wind Generated Electricity on a Minnesota Farm

Grantee:
Natural Resources, Inc.
412 Endicott-on-Fourth
St. Paul, MN

Grant Award: $19,600
DOE Project: MN79-382
Manager:
Mr. Merle Tate
Rural Rt. No.1
Cannon Falls, MN 55009
(507) 263-2448

PROJECT OVERVIEW[5]

The grantee has installed a 10 kW wind turbine on his farm in central Minnesota. His aim is to generate electricity for on-farm use and to sell excess electricity to his local cooperative, the Goodhue County Cooperative Power Assn. The Association has agreed to purchase the excess power and has provided a transformer that is adequate for handling both the normal customer load and the full expected generator output. In addition, they have installed a standard kWh meter that records the energy supplied by the cooperative to the farm load and a second kWh meter to record the net energy supplied by the windmill into the grid. The cooperative has agreed to monitor the monthly output, the hours of windmill operation, the load requirements, and the wind velocity.

The wind machine is an 8-10 KVA recently designed, built, and marketed by Jacobs Wind Electric in cooperation with Control Data Corp. It is a 3-blade, 23-ft. diameter, upwind rotor. Shaft power is fed through a set of gears into a 10 kW, 3-phase alternator. Rectifying diodes will take the variable AC output of the alternator and change it to pulsating

DC. The DC current will be converted to 60-cycle, 110 AC by a synchronous inverter that has been specially designed by Jacobs for use with the alternator.

The project has been complete and running since March 1981. The turbine cuts in at 7 mph and furling is accomplished by centrifugal governors, activating at 225 rpm, which corresponds to a wind speed of 30 mph. The governors feather the blades and simultaneously cause a fantail to pull the machine out of the wind. The low cut-in speed, corresponding to a rotational speed of 40 rpm, is made possible both by a high gear ratio (6 to 1) and by the low speed characteristics of the alternator. The turbine sits atop a 60-ft. tower on a horizontal shaft. The gearing connects this shaft at right angles to a vertical shaft that drives the generator, which is inside the tower.

DIRECT ENERGY SAVINGS

For years the grantee has owned and operated an 8kW Jacobs Machine. Output from this machine indicates an average site windspeed of 11 mph. Assuming a Rayleigh distributed wind regime, and a rotor radius of 11.5 ft., the energy available in the wind during a 30 day month is 3786 kWh. Tate reports that between March 27 and March 31, 1981 he recorded 129 kWh of generation. These data imply a daily average of 32 kWh and a monthly average of somewhat less than 1000 kWh at wind speeds prevailing then. COP of the machine is thus 0.26. This estimate appears to be well within reasonable limits. See Appendix A.

PROJECT COSTS AND ECONOMICS

Capital costs break down as follows:

Tower	\$2000
Jacobs 10 KVA	\$13,500
Inverter & Controls	\$2890

Other costs are

Crane rental	\$ 200
Cement	\$ 185
Meters & wiring (REA)	\$1200

Total capital and other: \$19,975

Allow 1 percent of wind machine costs for O&M: \$160/year

The average farm in Goodhue County (I assume that Merle Tate's farm is average) consumes about 1500 kWh a month, with a low of 1300 in July and a high of 1800 in winter because of heating needs. The cooperative has promised to pay Tate 2.5¢/kWh for energy fed back into the grid. At the same time, energy he avoids taking from the grid is worth 5.6¢/kWh. Assuming that half the electricity generated by the wind machine is fed back and the other half consumed by on-site load, the actual perceived value to Tate of the energy savings is 4¢/kWh, which is low compared to the social value I have assumed of 8.08¢/kWh. For the base year, private and social value of energy savings are thus \$486 and \$970, respectively.

Based on these figures and the capital and O&M cost estimates listed above, the following SIRs are obtained for the project.

	2%	6%
Social SIR	0.46	0.71
Private before-tax SIR	0.22	0.36
Private after-tax SIR	0.29	0.48

V: Wind Electricity Generation at a Ski Resort

Grantee:
Attitash Lift Corp.
Route 302
Bartlett, NH 03812
(603) 374-2369

Grant Award: $41,000
DOE Project: NH79-856
Manager:
Mr. Jeff Lathrop

PROJECT OVERVIEW[6]

The grantees will install and test a SWECS on a site immediately above their highest ski lift. The Attitash Corp. runs four lifts during winter and one during summer and is very power intensive. In January of 1979, the resort consumed 64,000 kWh, mostly on lift operation. Given the persistent, year-round winds recorded on nearby Mt. Washington (averages atop Mt. Washington is over 30 mph), the grantees considered Attitash an ideal testing site for a SWECS. After monitoring the results of the wind machine, the owners will consider installing a much larger (500 kWh to 1 MW) machine that could substantially reduce their net power consumption from the grid.

The site for the test machine is located on a ridge at 2225 ft., just off corporation property on land owned by the U.S. Forest Service. Environmental and archeological impact reviews (required by the Dept. of Agriculture) delayed installation of the foundation and tower. Moreover, the manufacturer, Mehrkam Energy Development Corp. of Hamburg Pa., has been bought out by Butler Manufacturing Co., of Kansas City, which has caused further delays by introducing some redesign of the wind system components. As of August 1981, the tower foundation and base plate had been installed, and the turbine rotor, blades, generator and associated controls were waiting at the mountain base for the arrival of the tower itself, expected by the end of August. All wiring is done.

The generator built by GE is rated at 40 kW, corresponding to a wind speed of 30 mph. The cut-in speed is 11 mph. The turbine has 4 blades with a rotor diameter of 36 ft. and will operate coupled to an induction motor. Both the turbine and the motor/generator will sit atop the 40 ft. tower. At their own expense ($40,000), the grantees have installed a 3-phase power line that extends 5500 ft. from the test site down the mountain to hook up with the New Hampshire Public Service Co. Transmission capacity of the grantees' line is 2.5 MW, large enough to handle the largest wind turbine that would ever be installed at the site. The line will be cost-effective only if sometime in the next 2 to 3 years the grantees install a much larger wind turbine and are able to sell the power generated at favorable rates. The grantees' current plans are to sell all the power they generate to the Public Service Co. of New Hampshire.

ENERGY SAVINGS

The grantee conducted anemonetry testing at the site for a full year, between September 1980 and September 1981. Analysis of the results indicates an annual average windspeed of about 14 mph. The grantee estimates that after accounting for conversion losses in the generator, transport losses in the power line, and machine down time. The machine should deliver about 50,000 Kwh/yr. Assuming the generator can perform as rated, this estimate appears reasonable. See Appendix A.

ECONOMIC FEASIBILITY

Total project costs (including installation) will be $45,000 for everything but the power line. Including the power line, costs will be $85,000. Assuming that the $40,000 additional expense for the line will be apportioned proportional to capacity usage between a 1 MW machine to be built at some future date (using the same line) and the present machine, 96 percent of the cost will be attributed to the larger machine and only 4 percent to the current machine. Thus, the current capital costs are $46,600. O&M costs are assumed to be $700 a year, which is 1.5 percent of total capital costs.

Commercial purchasers of electricity of the New Hampshire Public Service Co. pay an average of 5.5¢/kWh. New Hampshire statute maintains, however, that qualifying cogenerators can receive 7.7¢/kWh and 8.1¢/kWh for unreliable and reliable power, respectively. A small hydro generation site would qualify as reliable whereas wind qualifies as unreliable. The state values cogenerated energy at about the same rate as the running costs of the most expensive new capacity, such as the nuclear power plant at Seabrook or a new oil fired plant.

Using the 7.7¢/kWh figure as the private energy costs and the 7.29¢/kWh as the social gives private and social energy savings values in the base year of $3850 amd $3636, respectively. Based on these values and the project costs cited above, the following SIRs are obtained:

	2%	6%
Social SIR	0.82	1.26
Private before-tax SIR	0.88	1.34
Private after-tax SIR	1.17	1.79

VI: Wind Electricity at the Bronx Frontier

Grantee:
Bronx Frontier Development Corp.
1080 Leggett Avenue
Bronx, N.Y. 10470
(212) 542-4640

Grant Award: $48,730
DOE Project: NY79-539
Manager:
Mr. Ted Finch

PROJECT OVERVIEW[7]

The grantees have used the awarded funds to test and develop a wind energy conversion system in the South Bronx in New York City. The SWECS is located on a 3.2-acre lot at Hunt's Point overlooking the East River and will produce electricity to power the aeration blowers that the grantee uses in a 50-ton/day composting operation.

The wind turbine is manufactured by the Mehrkam Wind Energy Corp. of Hamburg, Pa. and is a 4-blade, 35-ft. diameter downwind rotor. The machine should cut in at 11 mph and reach the rated power output of 25 kW at 26 mph. The rotor and generator sit atop an unguyed steel tower, which is 64 ft. tall and 42 in. diameter and encased in a reinforced concrete base.

This project has undergone numerous design modifications. Originally, the project manager tested the SWECS using batteries for energy storage and voltage regulation and again using capacitors for voltage regulation alone. In the battery mode, the variable AC output of the wind turbine was rectified to DC, using diodes. The DC output was fed into a battery pack (consisting of fourteen 12-V, 550-amp batteries with a total storage capacity of 92.4 kWh) or into a 20-kW synchronous inverter. Power from the inverter was then to have been used to power the on-site aeration blower or to have been sold back to Con Edison. The capacitor mode worked similarly, except that all power generated was to have been used either on site or sold immediately.

The capacitor mode was much more cost-effective than the battery mode. The battery charge-discharge efficiency proved to be much lower than anticipated. Moreover, the batteries did not regulate output voltage very efficiently, lowering the overall COP of the system considerably. Had the grantee done no further work on the system, he would have chosen to eliminate the batteries and operate the system exclusively with capacitors.

Ultimately, the grantee chose a third option: elimination of on-site load servicing and use of a 3-phase, 3-wire induction generator rated at 25 kW and built by Toshiba International. Operating with an induction generator imposes a constant rotational speed on the rotor. Above a certain wind speed, enough power is available to increase rotor torque sufficiently to overcome internal losses in the generator so that power can be fed back to the utility grid at line frequencies and voltages. This third mode has proved to be both more efficient and less costly than either of the previous two.

ENERGY SAVINGS

Anemometry and actual operation during spring and summer of 1981 confirm an annual average wind of from 11 to 13 mph at the Hunt's Point site. During winter and early spring, the wind speeds can be very high because the north winds funnel along both the Hudson and the East rivers.* In the late spring and early fall the wind speeds are usually considerably lower, sometimes below 10 mph as a monthly average. Considering actual operating experience during 1981, the grantee expects that the following annual outputs can be expected on a conservative basis:

* When I visited the project in April 1981, intantaneous wind speeds were being recorded at about 22 mph.

Mode	Expected annual kWh
Batteries	20,000
Capacitors	25,000
Induction generator	30,000

Because of his decision to use the induction generator, 30,000 kWh will be taken as the energy savings potential of this machine. (See Appendix 1).

SYSTEM COSTS

The project manager has provided a detailed list of costs involved in the battery mode of operation. The costs of the induction mode are similar, except that the costs of the batteries and associated expenses are eliminated and the O&M costs decrease because the insurance is expected to be less.

Item	Battery Mode Cost	Hours required
Background research: wind data, negotiations, zoning, structural eng., FAA & FCC preliminaries	$0 direct	40
3-mo. wind site analysis (2 accumulators & 1 guyed telescoping pole) & survey of available SWECS products	$ 600	60
Eng. plans & filing fees: electrical, structural, utility, & fire dept.	$ 1300	50
Tower foundation costs: backhoe, soil tests, & concrete	$ 3500	5
Electrical conduit trench & materials	$ 1000	10

Trucking of turbine parts from Pa.	$ 525	4
355-ft. dia. rotor, turbine, 64-ft. tower, tower base sleeve, control panel, wiring from turbine to controls (about 175 ft.), rectifier, lighting arrester & servo motor for yaw drive	$24,475	10
Crane rental for tower & turbine installation	$ 300	8
Tower-climbing safety equipment	$ 500	8
3 lightning rods & wires	$ 100	8
14 lead acid batteries, 12 V, 550 amps at $275 ea.	$ 3850	10
Explosion-proof area for batteries (concrete wall & fire door), explosion proof thermostat & heater & light, ventilation materials, & battery shelves	$ 2500	15
20-kW, 3-phase synchronous inverter & air core reactor, box & shipping	$ 8500	10
Electrical wire trough & parts mounting	$ 500	5
Backfeed meter pan for utility detent meter	$ 300	2
Undervoltage relay trip	$ 350	3
Automatic yaw controls & additional control wiring	$ 3200	10
Total battery mode capital costs	$51,500	255

Adjustments for induction mode

Subtractions:	
battery bank	- $ 3850
explosion-proof area	- 2500
synchronous inverter	- 8500
Addition:	
3-phase induction generator	+ $ 3000
Total adjustments	- $11,850

Total adjusted capital costs	$39,650	
1st year property & liability ins.	$ 1145	10
Lightning-strike repair (mostly to repair brakes)	$ 1300	15
Battery maintenance	$ 300	
Inverter shipping for warranty repair	$ 200	5
Replacement of yaw motor and associated expenses	$ 600	15
Phone calls, travel, & misc.	$ 1000	100
1st year battery mode O&M summary	$ 4545	145
less savings because of using induction mode	- $ 530	
Revised 1st year O&M costs	$ 4015	
less trial & error repairs (includes $500 misc. expenses)	- $ 2600	
Subsequent year O&M induction mode costs	$ 1415	

ECONOMIC ANALYSIS

According to recent action by the New York State Legislature, the proposed value of energy back fed to the utility system is 6.0¢/kWh. Using this figure and the 7.29¢/kWh social value figure, private and social energy savings values for the base year are $1800 and $2182, respectively. Based on the cost figures compiled above, the following SIRs are obtained:

	2%	6%
Social SIR	0.31	0.62
Private before-tax SIR	0.19	0.45
Private after-tax SIR	0.26	0.59

VII: Wind Powered Electricity in an Urban Residence

Grantee:
Prof. Raymond Miller
Dept. of Physics
Zavier University
Dana & Victory Pkwy
Cincinnati, OH 45239
(513) 745-3651

Grant Award: $9910
DOE Project: OH79-673
Manager:
Prof. Miller

PROJECT OVERVIEW[8]

A separate project overview is unnecessary in this case because the grantee has also contracted with PGI of Mexico City to install a Hummingbird 4kW machine identical to the one purchased by the Evanston Environmental Center. The only differences are (1) the wiring costs are less because the distance between the grantee's house and the site is less than that between the Evanston building and its site; and (2) the wind regime appears slightly better. The tower foundations and the house itself have been installed. Delivery cannot be expected before spring of 1982.

ENERGY SAVINGS

On the grantee's recommendation, I shall use the anemometry data taken at the Cincinnati Airport as a substitute for the mean monthly wind speeds that prevail at the grantee's site. The annual average is about 10.5 mph, with little monthly variation. When these data are used with the data provided by Hummingbird on the performance of the machine, they provide a forecasted energy output of 5950 kWh yearly. As was the case in the analysis of the previous Hummingbird Machine (Evanston, Ill.) this figure is much too high. I derive instead a figure of 3705 kWh. See Appendix 1.

ECONOMIC COSTS

Project costs are listed by the grantee as follows:

Turbine, generator, & controller	\$ 6400
Concrete, tower, wiring, & installation	\$ 6000
Total	\$12,400

According to utility tariff records for the Cincinnati area,[9] average household cost of electricity should be 4.8¢/kWh. Using this value and the 7.29¢/kWh marginal social value, private and social energy savings for the base year are \$178 and \$269. Using these base-year figures in combination with the cost data provided above, I computed the following SIRs:

	2%	6%
Social SIR	0.19	0.31
Private before-tax SIR	0.10	0.18
Private after-tax SIR	0.14	0.26

VIII: Wind-powered Irrigation System for Small Pecan Orchards

Grantee:
Darrell R. Goulden
1107 Foreman Rd., NE
Yukon, OK 73099
(405) 354-3619

Grant Award: $3408
DOE Project: OK79-152
Manager:
Mr. Goulden

PROJECT OVERVIEW[10]

The grantee, a biologist and part-time farmer, has built a wind-powered irrigation system for his pecan orchard. Extensive bibliographic research has revealed that although ranchers have used wind power extensively to pump water for range stock, very few people have put wind power to use for crop irrigation.

The system consists of a windmill, pump, storage tank, trunk lines, and feeder lines. The windmill is a Dempster model 12A. It has a horizontal shaft turbine with a 15-blade, 6-ft. diameter rotor. The blades are made of metal with a curved, nonairfoil shape that causes them to rely primarily on wind drag as the motive force. The turbine, mounted on a 28-ft. galvanized steel tower, has a fantail to keep the plane of the rotor oriented perpendicular to the direction of the wind.

The windmill shaft is connected to a set of heavy gears with a cam that moves a connecting rod up and down as the fan blades turn. The connecting rod is attached to a metal rod called a "sucker" rod, which is centered in a 2-1/2 in. galvanized pipe. The sucker rod operates a reciprocating pump, which raises water in a pulsating fashion.

Water is collected in a 1000-gal stock tank located near the windmill and elevated 3 ft. above the highest point in the orchard. This position ensures that gravity will be adequate to cause a smooth flow of water through the trunk and feeder lines. The trunk lines are 3/4-in. plastic pipes buried 1 ft. below the surface. Branching from these are 3/4-in. feeder lines that terminate at the base of each tree. The feeder lines are capped with adjustable valves for flow control.

ENERGY SAVINGS

The grantee reports an average windspeed of about 11 mph. The well depth is 40 feet and the pump is located 33 feet below the surface. The stock tank abuts the tower base and is located about 1.5 feet above ground. Based on this data, the water head should be 34.5 feet = 10.5 meters. Head losses over this distance are negligible.

According to the grantee, the windmill pump operates about half time during April and May and then continuously from June through September inclusive. This corresponds to the pecan growing season and is the equivalent of about five months continuous operation. All these assumptions together yield about 180 kWh of energy avoided. See Appendix A for details.

ECONOMIC COSTS

The direct costs of the unit are as follows:

Windmill (includes engine with mast pipe, complete wheel, vane & stem group)	$1150
28-ft. tower	$ 850
Model 81 pump cylinder, plunger & check valve	$ 120
Windmill force pump	$ 200
Galvanized pipe, fittings, & sucker rod	$ 150
Plastic piping feeder lines	$ 400
1000-gal galvanized steel stock tank	$ 220
Misc. hardware	$ 100
Total equipment costs	$3145
Installation costs, including well drilling and the digging of irrigation conduits	$ 600
Total gross costs	$3745

From gross costs I must net out those costs associated with using an electric pump system, such as the shallow-well ejector pump and the pressurized holding tank that would probably have been used here but are avoided as a result of using a windmill. Also, I must exclude any costs associated with the windmill that would also be incurred using an electric system, such as the cost of the plastic distribution pipes and the fraction of total installation costs associated with them.

Cost of 6-1/2 hp ejector pump	$ 240
Cost of 80 gal. pressurized tank	185
Cost of plastic pipe	400
Cost of drilling & installing pipe	250
Total costs to be netted out	$1075

Thus, the net marginal investment costs of the wind system are $3745 - $1075 = $2670. Operation and maintenance is negligible. I cannot legitimately net out the costs of extending an electric line to the property because the farmer would still want to have electric service for residential use.

Utility tariff data for Oklahoma indicate that residential electricity costs average about 5¢/kWh.[11] Using this and 7.29¢/kWh marginal social benefit, private and social energy savings values for the base year are $9 and $14, respectively. The following SIRs result:

	2%	6%
Social SIR	0.08	0.13
Private before-tax SIR	0.05	0.09
Private after-tax SIR	0.07	0.12

IX: Wind Electricity in the Virgin Islands

Grantee:
Frenchman's View Condominium Assn
13-14 Frenchman's Bay Estates
P.O. Box 2358
St. Thomas, V.I. 00801
(809) 774-4061

Grant Award: $9635
DOE Project: VI79-07
Project Manager:
Mr. David Graham

PROJECT SUMMARY[12]

A complete analysis of this project is not possible. The project manager, Mr. David Graham, an officer in the Pan Tech. Management Corp. of Babylon, N.Y. and formerly President of Caribbean Power Ltd. of St. Thomas, has not responded to any inquiries since the fall of 1980. He has not submitted any final report on the project, and Morell Thompson, program manager for DOE Region II, has impounded further spending on the project.

According to the grant proposal, the condominium association was to have used the grant to purchase and install an Enertech 1500 wind machine at the condominium site, located on Flag Hill, at an elevation of 800 ft., where there are persistent trade winds. Preliminary odometer measurements by Caribbean Power Co. indicate that 13 mph is probably a reasonable annual average wind speed.

Some arrangements had been made for the V.I. Water & Power Authority (WAPA) to accept power generated by the machine into the local power grid on an experimental basis and to provide two-way metering for the condominium association. Whatever tentative agreement there was seems to have fallen apart. WAPA is notoriously unreliable, usually experiencing several five-minute (and longer) power outages a month. Average costs for residential customers is $0.25 kWh, a figure I shall use as a measure of electricity costs that would have been avoided had this project been completed.

According to my last conversations with the project manager, total project costs were to have amounted to about $7000, including the machine, wiring, shipping, and installation. The manufacturer of the wind machine estimated that O&M would be about $100 annually.

The Enertech 1500 that would have been used consists of a horizontal axis, 3-blade rotor driving an induction generator. Rotor diameter is 13 ft. Cut-in, rated, and furling wind speeds are 10 mph, 22 mph, and 40 mph, respectively. Rated power output is about 2.1 kW. Based on these assumptions, Mr. Graham had estimated about 5200 kWh annual output. My own calculations confirm that this is reasonable. See Appendix A for details.

ECONOMIC SUMMARY

Energy savings for this project for the base year would have amounted to about $1300 at V.I. prices.

At fuel escalation rates of 2 and 6 percent, the private SIRs would be as follows:

	2%	6%
before tax	2.18	3.22
after tax	3.64	5.37

Because of the peculiar situation regarding fuel costs in the U.S. Virgin Islands, a meaningful social SIR cannot be calculated by the method I have developed in Chpater 1. Fuel costs are particularly high becasue the islands are not part of the massive distribution sytem that delivers petroleum and refined products to the U.S. Mainland. Local fuel costs reflect high transportation overhead. Similar situations exist in other island communities, making wind energy attractive there.

Table 1. Summary of Project Status and Economics

Name	No.	Status of Operation as of 4/82	Source of Wind Estimates	Social SIR		Before Tax SIR		After Tax SIR*	
				2% esc	6% esc	2% esc	6% esc	2% esc	6% esc
Evanston Center	IL79849	Tower up; rotor 2 generator delivered working on experimental basis	2-month on-site anemometry and extrapolation	0.06	0.13	0.06	0.14	0.08	0.19
Michigan Farm Wind Water Pumping	MI79113	Fully Operational	Extrapolation from nearby site anemometers	0	0.19	0	0	0	0
Michigan Wind to Heat Convertor	MI79122	Construction ongoing during summer and fall 1981	Extrapolation from NWS data on nearby site	0.42	0.70	0.36	0.60	0.52	0.87
Wind Powered Electricity for a Minnesota Farm	MN79382	Fully Operational	Performance of previous windmill corrobrated by nearby anemometers	0.46	0.71	0.22	0.36	0.29	0.48
Wind Electricity Generation at a Ski Resort	NH79856	Tower foundation and wiring complete. Generator and turbine delivered but not installed. Tower not yet delivered	One year anemometry, from September 1980 to September 1981 on site	0.82	1.26	0.88	1.34	1.17	1.79
Bronx Frontier Development Corp	NY79539	Fully operational in induction mode	6 month anemometry on site	0.31	0.62	0.19	0.45	0.26	0.59
Wind Powered Electricity in an Urban Residence	OH79673	Tower foundations and tower installed. Waiting on all other parts. Wiring done.	Cincinnati Airport data used.	0.19	0.31	0.10	0.18	0.14	0.26
Wind Powered Irrigation for Small Pecan Orchard	OK79152	Fully operational	Nearby anemometry	0.08	0.13	0.05	0.09	0.07	0.12
Wind Electricity in the U.S. Virgin Islands	V19907	Abandoned	One month anemometry on site	--	--	2.18	3.22	3.64	5.37

*accounts for tax credits only, no depreciation or expense deductions included.

REFERENCES

1. All information concerning project costs comes from telephone interviews with Harold Benjamin on 17 and 18 October 1980, from a site visit on 7 January 1981, and from correspondence. Information on differences between old and new Hummingbird designs provided by Mr. Chuck Silverson, returning engineer for PGI, in Mancato, Minnesota, by phone on October 30, 1981.

2. Roach, Fred, Yeamans, Marilyn, and Aragon, Patricia (May 1981), Residential Conventional Fuel Prices and Future Projections: An Update Reflecting October-December 1980 Conditions, Los Alamos Scientific Laboratory, Los Alamos, N.M., LA-8838-ms, p. 20. An average electricity bill in Chicago is 6.8¢/kWh in October-December 1980. I inflated this by 10 percent to reflect prices at the end of 1981.

3. Phone interviews and correspondence with Mr. Klaus during August and September 1980.

4. Telephone conversations and correspondence with Evan Fisher, December 1980.

5. Telephone conversations and correspondence with Merle Tate, project manager; with Thomas Griffin, Natural Resources, Inc., St. Paul, Minn.; and with officials at DOE Region V offices, Chicago, Ill., December 1980 to October 1981.

6. Progress of this project has been followed over an extended period by one on-site visit and by correspondence and telephone contact from March 1980 to August 1981.

7. See Reference 6.

8. Correspondence and telephone conversations between October and December 1980.

9. Roach, Yeamans, and Aragon, op. cit., p. 24.

10. Information here is from correspondence and telephone conversations from July 1980 to February 1981.

11. Roach, Yeamans, and Aragon, op. cit., p. 24.

12. Information comes from correspondence and telephone conversations with David Graham and Morrell Thompson, also from a site visit to DOE Region II offices in New York in April 1981.

CHAPTER 3

ANALYSIS AND CONCLUSIONS

Introduction

The nine projects offer useful insights into the workings and failings of SWECS in the United States. The projects, which apply SWECS in different sectors and for different end uses, illustrate several complexities and problems in using small, decentralized energy systems. In this chapter, I discuss the results of the economic analysis and relate the findings to the two research questions raised in Chapter 1: (1) is there a public policy rationale for government subsidies of SWECS, and (2) if justified, what role(s) should government agencies play in encouraging the development and distribution of SWECS in the U.S.? The chapter has three sections: (1) a review and critique of the economic findings, (2) a discussion of the technical and institutional problems the projects experienced, and that are likely to persist and (3) a list of policy recommendations that government agencies might implement to encourage the best use of SWECS in the U.S.

Economic Findings

The Individual Projects

The analysis shows that only one of the eight projects on the U.S. mainland, the Attitash project, could be cost effective from the point of view of society.

Analysis of the abandoned Virgin Islands project was frustrating. Because of extremely high avoided costs, the project seems the most likely wind application to be cost-effective. However, two caveats should be mentioned. First, the system might not be adequately serviced. People with the technical skill to operate and repair wind-electric systems have been difficult enough to find on the U.S. mainland, where there is a considerably wider market and a more extensive technical infrastructure. Second, utility intertie of this project depends upon the cooperation of an unreliable local utility. An island investor might be served more reliably by a stand-alone DC battery charger than by the utility. Enertech estimates that a similarly rated system that operates with batteries instead of AC utility intertie would cost close to $20,000, including installation and adequate battery capacity to serve a residence using energy at an average rate of 2 kW. This cost is more than double that of the intertie system and would eliminate the economic attractiveness of the project.[1]

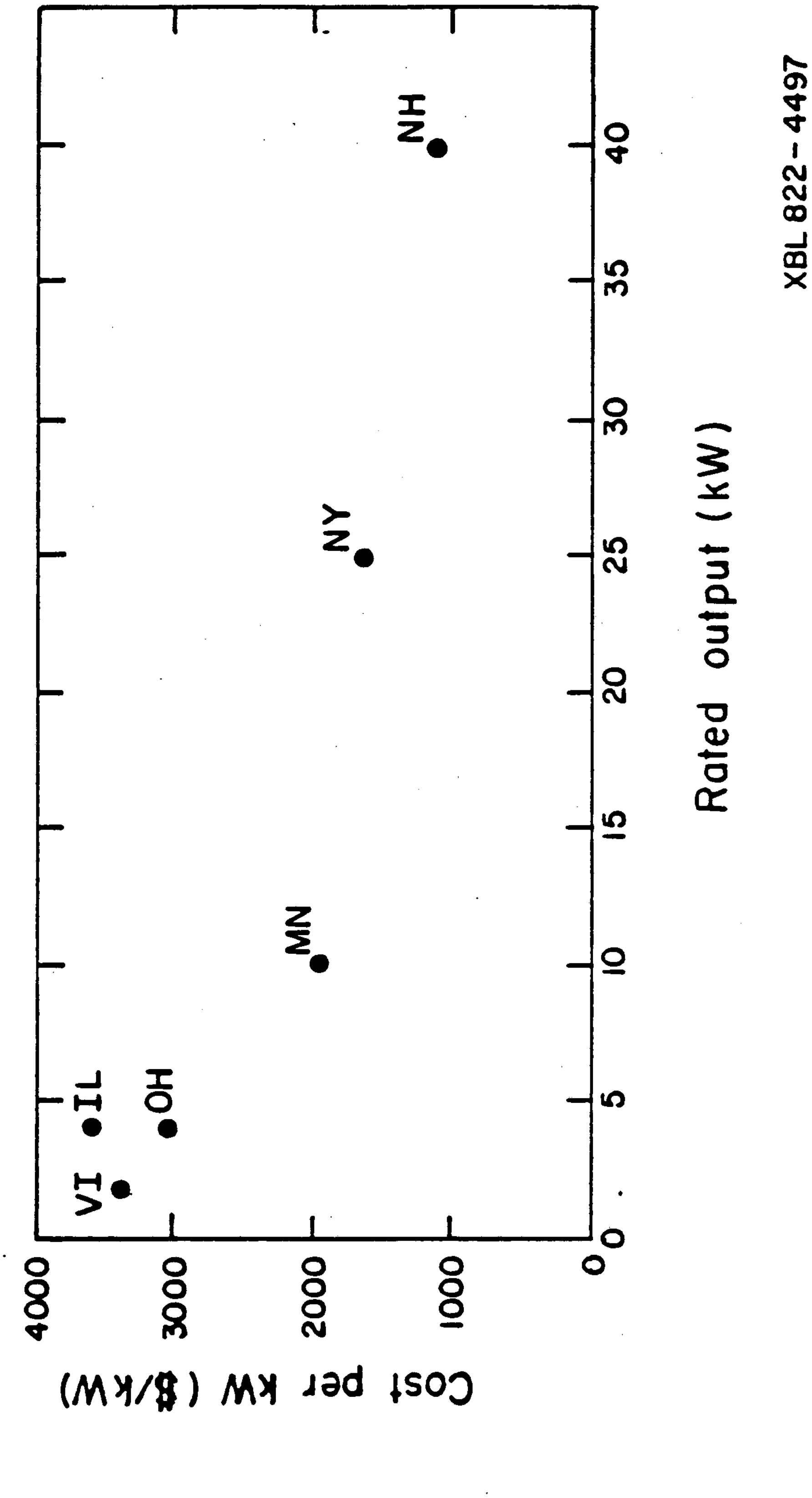
Although they are not the sole determinents of cost effectiveness, scale economies do influence the economic attractiveness of particular projects. If utility tie-in arrangements have been made so that the optimal scale of a machine is not limited by local load, larger machines seem to have more favorable economic outcomes than smaller ones, at least up to 40-kW, other things being equal. The costs of installation, wiring, and civil/electrical inspection do not vary proportionally. Once the investor has rented a crane to lift a generator onto a tower or hired an earth mover to dig a foundation, his costs do not increase very much when he increases the rating (and weight) of the generator or the size of the hole. Table 2 and Figure 1 illustrate these scale economies for the electric systems. The reader sould bear in mind that only the New York and Minnesota systems are actually installed and operating, and that the low cost of the New Hampshire system depends on apportioning 96 percent of the transmission line costs away from the current project. (See discussion in write-up.) Recent evidence suggests that (1) if anything, the actual costs of the systems will be higher than is represented here; and (2) the increases in cost for the different machine will not likely alter the pattern of decreasing costs per installed peak kW shown in Figure 1.

In particular, there is some indication that the total installed costs of the 4 kW Hummingbird machine is higher now (April 1982) than when the Ohio and Illinois grantees contracted with Gottfried in Spring of 1980. A Wisconsin farmer I interviewed ordered and paid for the latest (inventor version) Hummingbird model in January 1981, for a total installed cost (including tower) of about $12,000. His machine has been working fairly well since it was installed in late summer of 1981 (some problems with the fan tail furling need to be solved, but according to the farmer and Hummingbird's retained engineer, these appear minor). The dealer that delivered the machine went bankrupt over the summer. While the cause of his bankruptcy is unknown, perhaps $12,000 was too low for the sellers to realize any profit.[2]

Similarly, conversations with dealers in Cailfornia[3] and Minnesota[4] indicated that the total installed cost for the Jacobs 10 kW now range between $23,000-$29,000, depending on local soil conditions, licensing requirements, tower height and the like. Even with thse increases, it

Table 2. Relationship between KW Rating and Cost for Electric Applications, Summer 1980.

Project #	Project Cost	Rated Output	Cost/Rated KW
IL 79849	$14,708	4 KW	$3677/KW
MN 79382	$19,975	10 KW	$1998/KW
NH 79856	$46,600*	40 KW	$1165/KW
NY 79539	$39,650	25 KW	$1586/KW
OH 79673	$12,400	4 KW	$3100/KW
VI 7907	$7,000	2.1 KW	$3333/KW



Cost per kW ($/kW)
4000
3000
2000
1000
0
0
5
10
15
20
25
30
35
40
Rated output (kW)
VI
IL
OH
MN
NY
NH
XBL 822-4497

Fig. 1

appears that declining average costs over the 1-50 kW range are likely to persist.

None of the three nonelectic projects is cost effective under any assumption. The water pumping projects (M179113 and OK79152) displace very little electricity and thus have small payback. In the Michigan case, operation and maintenance costs negate the energy benfits entirely. Even under production cost assumptions, the heating project (M179122) could not break even, suggesting that heating applications will have to be very inexpensive to be viable.

A comparison between the Bronx Frontier and Attitash projects is instructive. The two are differentiated by four major factors that make Attitash potentially more successful. First, the wind regime is slightly better at Attitash (14 mph as opposed to 12 mph at Bronx Frontier). Because of the cubic relationship between power and wind speed, slightly higher wind speeds imply significant increases in available power. Second, the 40 kW generator at Attitash theoretically would allow the machine to take advantage of the higher wind speeds without pushing costs up proportionally.* Third, the price of electricity Attitash will receive for selling power back to New Hampshire Power Cooperative is 7.7¢/kWh more than the estimated proxy for social value per Kwh in this case. Next to California, whose PUC mandates 7.7¢/kWh for wind

*As mentioned above, there is some question as to whether the Mehrkam generator can deliver 40 kW. The grantee confronted Mehrkam with two instances he knew of (one machine in New York, the other in California) at which the Mehrkam machines were supposed to deliver 40 kW and did not. Responding to this, Mehrkam asserted that in both cases, other factors besides the generator prevented the attainment of 40 kW output. Mehrkam went on to assure the Attitash people that he had indeed delivered a 40 kW generator as stipulated in their contract.

power sold by a cogenerator, the New Hampshire rate is the highest in the country.[5] By contrast, the New York legislature has mandated 6.0 ¢/kWh for wind cogenerators.* Finally, O&M costs are very high in New York, primarily due to high insurance costs. (Insurance costs are really owning costs rather than O&M costs, but their effects on cost-benefit analysis are identical).

Energy Prices and Escalation Rates

The assumptions that the analyst makes about base year energy prices and escalations in these prices have major impacts on the outcome of the study. Unfortunately the precise type of fuel that wind systems will be replacing, the price of that fuel, and its rate of price escalation are all highly uncertain.

I have assumed that fuel costs will increase more rapidly than the overall rate of inflation and that O&M costs and equipment and installation costs will increase at the rate of inflation.

*A very important issue in the case of Bronx Frontier, and of many urban intertie applications, relates to the rate structure under which the investor pays for electricity. Most residential rate structures contain components of both capacity and energy costs in the charges per kWh. Most commercial rates in urban areas, on the other hand, break out capacity and energy charges separately. The interests of the utility are served by billing cogenerators for each separately unless the cogeneration is time reliable, as is the case with certain hydro or biomass cogeneration projects. Con Edison has an extensive and expensive transmission and distribution network. Capacity credit in tie-in rates must be justified. The 6.0¢/kWh that the New York State Legislature has recently mandated as the official rate that cogenerators must receive is undoubtedly lower than the total marginal costs (running costs plus capital costs) of Con Edison. In fact 6.0¢/kWh is less than marginal running costs alone during the on-peak and shoulder-peak periods.[6]

Several studies and simulation modeling efforts have been pursued in order to understand the relationship between energy prices and overall inflation. Studies by Mork and Hall,[7] Eckstein,[8] Perry,[9] and Pierce and Enzler[10]4 all ascribe significant weight to the energy price spurts of 1974-1975 and 1979-1980, and to continued energy price decontrols as explanatory factors to the inflation of the past decade. Energy price increase, particularly those of foreign oil that originate outside the U.S. economy, definitely lead U.S. domestic inflation. It would appear that an assumption that energy prices will continue to "pull" U.S. inflation is justified.

The specific assumptions of 2 and 6 percent annual real increases do not take into account qualitative trends in the generation of electric power. These trends are important because generation costs will determine the value of wind energy for producing electricity.

Wind and other renewable technologies producing electricity will find coal plants emerging as principal competitors. The other major contenders are nuclear power and energy conservation. Four major studies completed in the late 1970s all indicate that the capital costs of nuclear capacity will exceed that of coal by up to 25 percent[11] A study completed subsequent to the TMI accident of March 1979 predicts that nuclear capacity completed in the late 1980s may exceed the cost of corresponding coal capacity by more than 70 percent.* The Komanoff study

*Statistical analysis in this study, by Charles Komanoff,[12] indicates that in 1978, average new nuclear capacity costs had already exceeded corresponding coal costs by 52 percent ($887/kW for nuclear and $583/kW for coal). By 1988 he projects that costs of capacity coming on line that year will be $1374/kW for nuclear and $794/kW for coal.[13] He attributes the growing discrepancy (73% by 1988) to the need to resolve outstanding nuclear safety issues. Cost figures are in 1979 dollars.

predicts that because of this large difference in capital costs, the lifetime generation costs from nuclear is likely to be 20 to 25 percent higher than lifetime generation costs from coal.[14] The principal commercial competitors of wind-electricity are likely to be coal and oil, rather than nuclear and oil.

Total generating costs differ less than total capital costs because the coal itself is a much larger proportion of total coal generating costs than uranium is of nuclear generating costs. Komanoff's 20 to 25 percent discrepancy prediction is based, among other things, on a presumed real escalation rate of from 2 to 2.5 (he uses 2.3) percent for the mining and transportation of coal.* This rate duplicates the rate of increase in real costs in the period 1974-79, a period marked by large increases in coal production, considerable labor-management strife, and boosts in investment and operating costs based on new health, safety, and environmental requirements.

From the point of view of evaluating wind-electric benefits, a differentiation between trends in costs of coal-fired or oil-fired capacity versus trends in fuel costs is critical. Utility regulators will see little justification in giving small, dispersed cogenerators using wind any credit based on capacity savings because the energy available from

*Komanoff asserts that this increase will cover mainly the costs of reducing heath and safety risks and environmental damage associated with mining and transportation.[15]

them is too random.* Most of the benefit attributable to SWECS will be on the basis of energy alone.

The economic analysis accompanying each project (See Chapter 2.) has shown the effects of using oil costs as a measure of avoided costs. If coal costs become a reasonable measure because coal is used for base load generation, utility intertied SWECS of the nature studied in this report are unlikely to be commercially viable in the next several decades. Komanoff's 2.3 percent assumption does not reflect the experiences of 1979 and 1980, when the cost of coal delivered to utilities actually declined in real terms. Indeed, his "worst case" (most expensive) scenario for 1988 foresees an energy cost component of no more than 2.86¢/kWh in 1979 dollars for electricity from coal. This worst case assumes a 4 percent real fuel cost increase. His base case assumes a 2.3 percent fuel cost increase, which implies a 1988 fuel cost of only 1.96¢/kWh in 1979 dollars.[18] Recent technological trends and emerging management practices in coal mining and transportation indicate a distinct possibility that at least the rate of price increases will be lowered, if not actually reversed.[19] Given low electricity costs from coal and inexpensive ways to conserve electricity through increased appliance efficiency, SWECS may prove relatively uneconomic in all but extraordinary situations.

*This is not the case for large, multi-MW wind farms where dispersed geographic location implies both an even, more predictable availability of capacity as well as less threat of no capacity at all. Justus and Hargreaves[16] have modeled availability statistics for large arrays of windmills. Kahn[17] has discussed planning issues in connection with the integration of large-scale wind and solar systems with conventional power grids.

Technical & Institutional Issues for SWECS

Technical Issues

Design & Operation Research. Numerous researchers have emphasized the possibility for innovative methods of power extraction and augmentation as a means of enhancing the economics of SWECS. In the U.S., the Solar Energy Research Institute (SERI) has provided technical monitoring for several such projects funded by DOE.[20] In addition, Rockwell International has provided extensive testing of all manufactured and marketed SWECS at Rocky Flats, Colorado. All research of which I am aware has so far indicated that overcoming the power conversion limit established by Betz[21] (59.3 percent) is very unlikely. The actual efficiency attainment of nearly all machines is considerably below this limit.

More promising research has concentrated on improving mechanical performance of existing designs,[22] such as developing a reliable vertical axis (VAWT) SWECS. All of the SWECS in this study have been horizontal axis (HAWT). In theory, VAWTs offer several design advantages. They eliminate the need for a yaw mechanism. Electric generating equipment can be placed on or near the ground, easing structural requirements. The disadvantages include lower overall COP, lack of self-starting capacity, and expensive blades. VAWTs have been considered particularly suitable for areas in which gusty wind conditions prevail.

Most experimentation with VAWTs on a small scale has been disappointing. Attempts to bring blade costs down while maintaining reliability have met with failure so far.* Cases of unintentional self-starting and overspeeding have been cited for the larger Darrieus rotor.

Professional Standards. Numerous reliability problems, ranging from breaking failure to lightning susceptibility, to fraud, have been experienced by the grantees in the AT Program of DOE and by other small users of wind. Part of the difficulty in selecting a particular wind machine has been the absence of product standards acceptable to both wind manufacturers and to the public. One wind dealer has cited such labeling (analagous to labeling by the Underwriter's Laboratory of electrical equipment) an important factor in improving customer acceptance.[23]

Two cases in point deal with manufacturer output ratings and utility intertie requirements. Considerable variation has existed in methods of measuring expected power output from a wind machine. Some tests have been based on wind tunnel power testing; others have involved fixing a turbine to a platform mounted onto the rear of a truck and creating a relative wind by driving down a strip of highway![24] Different wind distributions and loss factors have been assumed. Members of the public, therefore, have no real idea about what to expect from any given machine.

When operation depends on utility interties, SWECS encounter special technical problems. Utilities require that power fed back into their grids be within acceptable ranges of specific voltages, frequencies, and phases and often require circuit breakers or other safety

* Managers of projects IL79-849 and OH79-673 considered VAWTs first and both abandoned the idea.

equipment in case of line failure. Potential investors, dealers, and manufacturers have complained that the cost of special breakers and transformers are often unnecessary and that their inclusion in a system can add up to 50 percent of the base cost.[25] If public utility commissions (perhaps under federal guidelines) could adopt specific safety standards for cogeneration systems and communicate these requirements to potential users through networks of dealers and manufacturers, considerable uncertainty regarding SWECS economics could be eliminated. AWEA standards should aid this process.

Electricity Storage. The question of storage is particularly important for wind systems in view of the extreme changes in wind availability at any particular site. A load-generation gap exists when there is need for electricity but there is no wind or when there is no need for power but there is plenty of wind. For small, distributed systems, batteries offer the only realistic solution for filling the load-generation gap besides using the grid itself for this purpose.

Batteries store the mechanical energy of the wind turbine in a chemical form and have been used for storage at remote sites. Most batteries have low energy density, short lifetimes, and high charge-discharge conversion losses, but according to a recent feasibility study completed by Battelle Memorial Institute,[26] utility customers may find on-site battery storage economically feasible in the coming years. Two expected changes will effect this feasibility. The first should mitigate the technical problems just mentioned: new nickel-zinc and ferrous sulfide batteries being developed by companies such as Gulf & Western will increase battery lifetime and energy density.

The second change is the provision of incentives for wind users. If power can be stored, a wind machine owner has the option of either using the power when it is generated or of waiting. He can store the energy and use it later himself if he has no current load or sell it back to the utility at a time when it is valuable to the utility. Examples of incentives that would cause the wind owner to consider the timing of his use and marketing would be (1) high purchase rates offered by the utility, or (2) high, ratcheted demand charges. The former would encourage him to sell when the marginal running and capacity costs of the utilities are highest.* High demand charges would encourage wind machine owners to keep their own average kW use as low as possible. Battery storage would help regulate their own load requirements from the utility grid.

If reasonably priced, reliable storage became available, one could imagine a wind turbine owner contracting with a utility for the sale of a certain amount of reliable energy during specified daily or seasonal periods. He could then decide what commitment level to offer. The higher level he chose, the more he would be able to sell at the commitment rate. Unfortunately, the higher the level, the greater the risk that he would not be able to amass the committed power and the greater the risk of incurring a penalty for not meeting his firm service level. Capacity credits must be based on dependable generation. Storage opens

*This occurs during peak demand periods. High marginal capacity costs are incurred because infrequently used plants have to be used or expensive wheeling power must be bought by the utility. Peak-load plants are more expensive per kW than base loaders because of both economies of scale and because each kW of capacity needs to be amortized over fewer kWhs generated by and sold from that plant. High marginal running costs are incurred because peaking plants, built smaller and more cheaply than base loading plants, tend to use fuel less efficiently.

possibility of valuing the capacity of the windmill as well as the energy it saves.

Cheap electricity storage is not likely to be available for several years, perhaps decades. At present, batteries serve as storage devices for remote site windmills with DC generators. Such storage is only cost effective when a utility line could not be extended at a reasonable cost.

Institutional Issues

Markets. The single major impediment to small-scale wind energy commercialization is high capital costs per unit of usable capacity. Besides having a low level of technical maturity, small-scale and, in many cases, large custom built machines have been very expensive. A real problem is the correlation between production costs and market size. For example, in the early 1980's, costs are such that only people located on wind sites that have a rather high average wind speed can be induced to buy a windmill.* If enough of these people do invest, wind turbine manufacturers will be able to expand, increase the efficiency of their operations, and lower their costs. This in turn will make wind machines cost effective for investors on less windy sites, who will then purchase machines, bringing about further economies in production.

Several wind manufacturers and distributors[27] have expressed the belief that an adequate tax credit could have a similar effect. First, only the wealthiest investors able to take most advantage of the credit

*Moreover, these potential investors will have to be able to sell energy or possess sufficient on-site load to warrant the investment.

would invest; then the market would expand and costs could decrease, paving the way for less wealthy investors. Whether recent tax credits have produced this effect is difficult to assess, although it is certainly clear that those who have invested most heavily are the wealthiest.*

If these effects have started to be felt, though, they have not yet begun to snowball. As was portrayed in the second chapter, tremendous problems still exist with servicing and with reliability of parts. Ownership of small firms (including Power Tower International and Mehrkam) have turned over rapidly. Accountability for their deliverables has been difficult to enforce. These problems, the technical difficulties cited above, and additional issues discussed below could discourage the broadening of the market for small scale wind machines.**

Construction, Siting, & Permits. Siting and construction pose additional costs on the wind investor, particularly in urban areas. Zoning ordinances may restrict the maximum height of a structure in a particular area. According to a northern California dealer, there have been

*In California, the solar tax credit has elicited a response that is highly skewed toward upper income groups. In 1979, 75 percent of all applicants for the 55-percent solar tax credit had incomes of $20,000 or more. 30 percent had incomes over $40,000.[28]
**The above discussion has emphasized primarily the demand side of the wind market. Resource impediments on the supply side are few. One study conducted at Los Alamos Scientific Laboratory (LASL)[29] estimates that the maximum potential development of wind machines to be owned by utilities is 313,500 1.5-MW machines, by residential investors is 9.6 million 10-kW machines, by the paper industry is 900 1.5-MW machines, and by farmers is 780,000 35-kW machines. Rapid deployment of the large machines in the utility sector could increase the demand for resin and fiberglass by 265 percent of current (1978) U.S. production by the year 2000. Relative demands on other materials such as cement, aluminum, copper, and steel would be minimal.

cases in which public hearings to obtain tower height limitation abatements have taken a full year.[30]

Several other planning-code related steps must be taken before a SWECS can be installed and operated in an urban area. This same dealer has listed three planning steps that must be taken before operation of the windmill can be permitted. First, a preliminary environmental impact statement must be filed with the county planning commission. This step is necessary to clear possible problems of excessive tower height, noise, potential TV or radio interference, and aesthetics. Second, a building commissioner must check construction plans for structural integrity and then, assuming that he grants approval and that construction proceeds, he must make a final site visit to check completed construction. Finally, a certified electrical engineer must check construction for adequate grounding and wiring. Total fees for these steps can range between \$600 and \$650 for residential size wind generators.

Time delays are perhaps even more important. One dealer has cited cases of wind turbine projects where, for every day at the wind site doing installation work, he spent 21 days doing paper work, attending hearings, and securing licenses.

<u>PURPA.</u> On 9 November 1978, President Carter signed into law the Public Utility Regulatory Policies Act (PURPA) of 1978, P.L. 95-617. PURPA was one of five major acts that together comprised the omnibus National Energy Act.

The impact of PURPA has been both extensive and intensive. It has set the stage for the total transformation of the regulatory and ratemaking environment for private for public electric utilities that fall within its purview.* Much of the recent emphasis by utility planners and commission staff on issues of load management, energy conservation, and cost-related time of use rates has been underscored, if not initiated, by PURPA.**

Of principal concern to this analysis is Title II and, in particular, Sections 201 and 210. Section 201 allows the Federal Energy Regulatory Commission (FERC) to issue orders requiring the interconnection to the utility grid of those vacilities that the law calls "qualifying" cogenerators and small-power producers (so-called QFs). The final FERC rules based on Sec. 201 require interconnection in most cases. These rules also prescribe precise definitions of QFs and the requirements for qualification for interconnections. The qualifications are based on size, type of fuel burned or of other energy used, and various thermodynamic efficiency criteria.

Certainly, Sec. 201 possesses controversial elements. Electric utilities have for decades become accustomed to the relatively simple task of generating electricity from central stations and transmitting and distributing large quantities over a large grid. Since PURPA, utilities have had to face the prospect that the generating plant feeding

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*This includes all utilities for which total annual sales in any calendar year starting 1 January 1976 amounted to 500 million kWh or more - every major utility.

**Many utlities and PUCs took prior initiative for innovative programing in these areas. In California, for example, mandatory time-of-use tariffs were implemented following a PUC decision in March 1976, stipulating that utilities in the state were to begin a phased implementation of marginal cost-based time-of-use rates for all users with maximum monthly demands of 500 kW or more. Utilities were also required to experiment with and analyze time-of-use rates in connection with below-500-kW customers.[31]

the grid might also become widely distributed. This new development presages major new engineering, financial, and planning challenges for the utilities.[32]

Even more controversial is Sec. 210. This section stipulates that utilities must not only interconnect with QFs, but must pay them for energy they want to sell and must sell to them supplementary and maintenance power when requested. Such buying and selling must take place at rates that are "just and reasonable" to electricity consumers and the utility, but at the same time these rates cannot discriminate against the QFs. The law virtually ensures lengthy hearing battles between utilities and QFs over rates. Moreover, a FERC ruling based on Sec. 210 provides guidelines for how the rates should be determined. The guidelines require that QF rates be closely related to the marginal costs of production, transmission, and distribution at the time of purchase or sale, so-called avoided costs.*

In fact, the implementation of Sec. 210 has been uneven. Many states, including California, use the full avoided costs as was recommended in the FERC 1979 proposed rules. Some PUCs, on the other hand, have defined avoided costs so that rates based on them are very low and provide little incentive for cogeneration. (See MN79-382 in Chapter 2.) In some cases, state legislatures have pre-empted PURPA and the PUCs and designed tie-in rates by legislative fiat (New Hampshire, Maine, and New York are all examples). Certain cogenerators have been able to obtain

*The development of criteria to measure utility marginal energy and capacity costs that together constitute avoided costs is very complex and politically sensitive. The California Energy Commission, in cooperation with utility companies in California, has summarized and evaluated many different marginal cost methodologies.[33]

firm contracts for deliverable energy, entitling them to higher rates and more favorable financing than those who rely on a straight tariff. For reasons described above, most SWECS have had a difficult time obtaining firm contracts. Potential wind investors face considerable regulatory uncertainty when trying to assess the payback they will realize on their systems.*

Financing. SWECS requires a large initial capital investment. In most cases, except those of the wealthiest investors, financing will probably be necessary. Because of the complexity of the subject, only a basic outline of some of the key issues will be presented here. The most conventional source of financing is commercial banks. Small entrepreneurs with some collateral may be able to attract bank lenders, but a new

*Recent court action has reduced the uncertainty surrounding PURPA implementation on some fronts while increasing uncertainty in others. Early in 1981, the Mississippi Power and Light Company (MP&L) filed suit against the FERC and DOE, changing that Titles I, III, and Section 210 comprised an unjust intrusion into the regulator and ratemaking prerogatives of the states. Federal District judge Harold Cox, a well known states-rightist, agreed and struck down these provisions of the Act. As a result, Mississippi and several other states suspended PURPA related activities. Finally, on June 1, 1982, the U.S. Supreme Court issued a decision that upheld the constitutionality of titles I, II, and III, thus reversing Cox's ruling and clearing the way for continued state implementation. While the proceedures involving state consideration of and determination on eleven ratemaking and regulators standards (the heart of titles I and III) can now proceed, implementation of Sec. 210 Remains in doubt as a result of other action. Specifically, the U.S. Court of Appeals for the District of Columbia struck down on 22 January 1982 FERC rules requiring utilities to buy power from small power producers at "full avoided cost". It also set aside the FERC interconnection requirement. Judge Malcom Wilkey of the Appeals Court said that FERC's "full avoided cost" rule had been adopted by that agency without full consideration of the public interest or the interests of cogenerators and electricity consumers. Moreover, the January ruling will allow utilities to refuse interconnection until FERC qualified the particular power producer in evidentiary hearing, a step that will clearly entail delay.

wind-electric system with no utility contract to purchase power will likely have a very difficult time finding financing.[35]

Another possibility is utility financing. This option has the advantages of placing financing with energy developers, whose cooperation might produce more favorable tie-in rates for the small investor. The two principal disadvantages are that utility capital is more expensive than bank capital* and utility financing opens up regulatory questions concerning monopolization and the possibility for cross-subsidization of sales from other investments.[37]

Conclusions

The evidence presented above permits the following conclusions:

(1) Considerable economic, technical, and institutional barriers exist, and may always exist, that impede the widespread commercialization of SWECS. In particular, it is possible that even if all the institutional problems and problems of reliability and serviceability were resolved, the systems still would not in most cases be a cost effective way to obtain energy when conventional sources or less expensive energy conservation techniques are available.

(2) SWECS appear to be at or near commercial viability for some remote sites at the present time. For such sites a major problem is serviceability and manufacturer reliability.

*Banks are generally capitalized with 95 percent debt in the form of deposits and only 5 percent in equity. Utilities obtain 35 percent of their capital from equity, which is more costly than debt or preferred stock.[36]

(3) Technical problems, high first costs, and low costs of conventional alternatives are such that the difference between the social value and private value of SWECS may not be large enough to warrant <u>any</u> government subsidy on the ground of market imperfections alone. It is possible that rationales for these subsidies will have to be based on noneconomic reasoning, such as a desire to promote decentralized electricity production to enhance national security.

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Appendix A

Energy Savings Calculations

(I) Explanation of Calculations

I.1 Wind Electricity Calculations

The basic method I use to calculate electricity production from windmills is to estimate the energy available in the wind and then reduce this estimate by the appropriate loss factors. Figure A-1 represents a theoretical wind machine power output curve placed below a theoretical wind power curve.

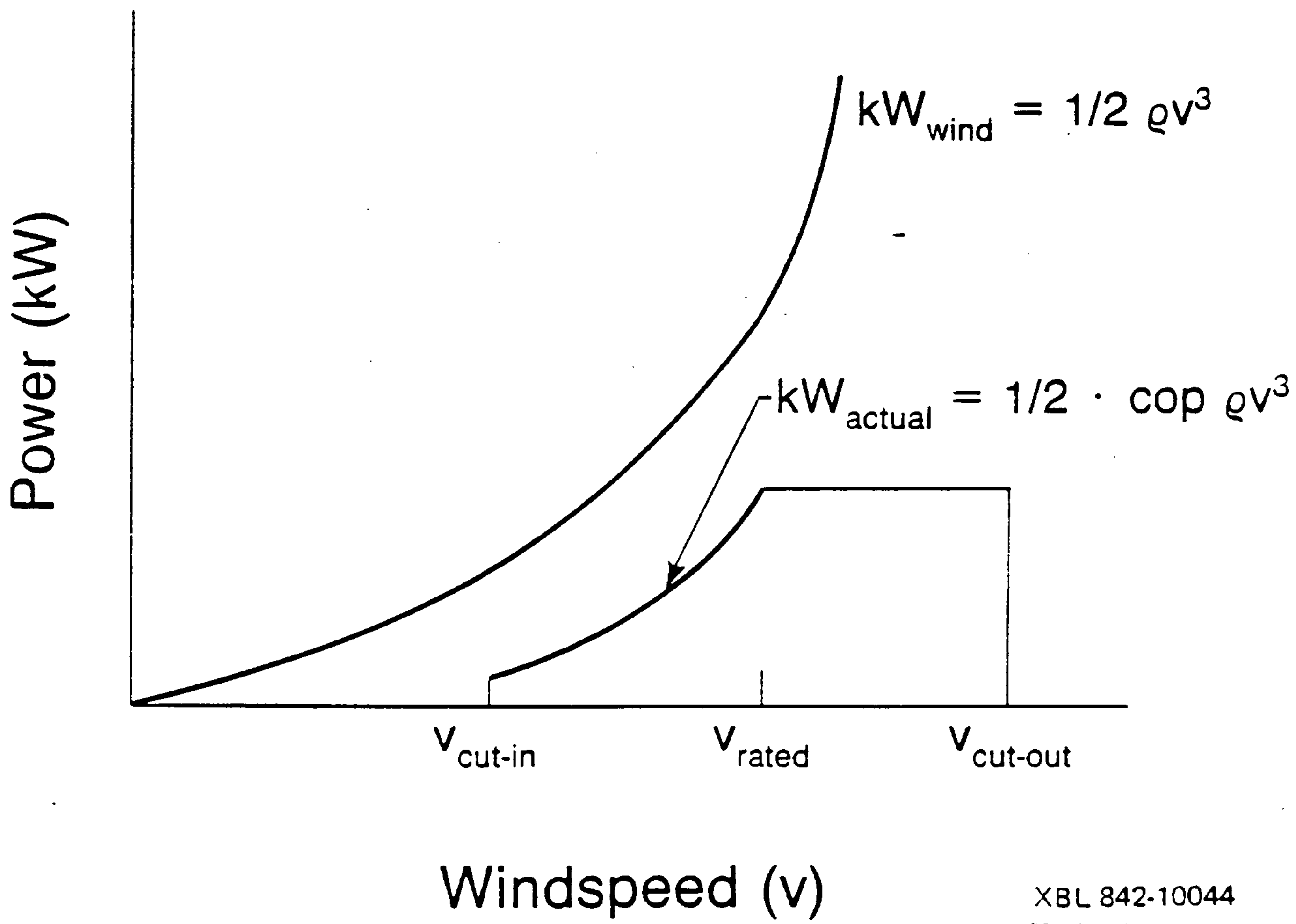

Figure A-1

In order to estimate power output, I modify the machine power output curve by a probability distribution corresponding to the wind regime. As stated in the text, The Rayleigh distribution is assumed. The cumulative form of this distribution can be expressed as

$$RC = 1 - \exp\{-\pi/4)(V/\overline{V})^2\}$$

= the probability that the wind at a random moment will be equal to or less than V, given a mean windspeed $\overline{V}$.

Expressed in differential form, the Rayleigh distribution is thus

$$RD = \frac{d(RC)}{dv} = (\pi/2)(V/\overline{V}^2)\exp\{(-\pi/4)(V/\overline{V})^2\}.$$

The time-average power (TAP) available in the wind is given by the following expression:

$$TAP = \int_{V_{cut\text{-}in}}^{V_{rated}} (1/2\,\rho V^3)(RD(v))dv + (1/2\,\rho V^3_{rated})(\exp\{(-\pi/4)(\frac{V_{rated}}{\overline{V}})^2\}).$$

The first term in the above equation is the weighted average power between the cut-in windspeed and the rated windspeed. The second is the product of the fraction of the time that, given a mean windspeed of $\overline{V}$, the windspeed is above rated windspeed, times rated power output. TAP is in units of Power/area. The energy from a wind machine is thus given by the following formula:

Energy Output = (TAP) x (Area Swept by Windmill) x (8760 hours per year) * (COP) x (fraction representing other losses).

In fact, COP and other losses are indirectly functions of the windspeed (e.g., through the tip speed ratio, rpm of generator, etc.). In practice, however, assuming an average over all relevant windspeeds does not introduce too much inaccuracy. In most instances, I will assume a COP = 0.35 for horizontal wind electric machines, and other losses = 0.20.

I.2. Wind Pumping Calculations

When the grantee provides information about how much water is pumped over a period, this amount must be consistent with the amount of wind energy available to pump it. Thus I perform a dual analysis: (a) given rotor characteristics and site average windspeed, I calculate time-average power and available energy. (2) Using the equation

average power = (head) x (mass flow rate)

I solve for mass flow rate and calculate the mass of water pumped. The grantee's statements must be consistent with these calculations before they can be used in cost effectiveness calculations.

I.3 An Additional Note on the Rayleigh Distribution

It should be noted that the distribution is skewed. By definition, the median windspeed, V_{median}, is such that

$$\exp\{(-\pi/4)\left(\frac{V_{median}}{V_{mean}}\right)^2\} = 0.50 \quad .$$

After some calculations it is clear that $V_{median} = 0.94\ V_{mean}$. Because of this skewness and because of the cubic relationship between windspeed and windpower, the windpower achieved at the mean windspeed does not equal the time-average power in the wind, averaged over all windspeeds. In fact it turns out that

Average power over all windspeeds = E(PW)

can be expressed as

$$E(PW) = \frac{\rho\pi\overline{V}^2}{4} \int_0^\infty (V/\overline{V})^4 \exp\{(-\pi/4)(V/\overline{V})^2\}dv$$

$$= \frac{\rho\pi\ \overline{V}^3}{2} \cdot \frac{6}{\pi} = (\frac{6}{\pi})(\text{windpower at average windspeed}).$$

Thus, the average windpower is about 1.91 times the windpower at average windspeed. Because of the high starting torque of the wind pumping machines (low cut-in speed) and their inefficiency of operation at high windspeeds, I assume that the entire range of windspeeds is available from which to extract power. This assumption simplifies the calculations considerably.

(II) The Wind Power Calculations

The specific calculations follow.

Evanston Environment Center

Mean windspeed at site	= 9.2	mph	= 4.1	m/s
Cut-in windspeed	= 8	mph	= 3.6	m/s
Rated windspeed	= 24	mph	= 10.7	m/s
Cut-out windspeed	= 60	mph	= 26.8	m/s
Radius of rotor	= 2.13	m		

(1) = reference windspeed in m/s

(2) = fraction of time that instantaneous windspeed is within 0.5 m/s of reference windspeed, given mean.

(3) = power at reference windspeed in w/m^2

(4) = weighted power at reference windspeed in w/m^2 = (2) x (3)

(1)	(2)	(3)	(4)
4	0.18	38	7
5	0.14	75	11
6	0.10	129	13
7	0.07	206	14
8	0.04	307	12
9	0.02	437	8
10	0.01	600	5
11	0.004	799	3

(5) = fraction of time that $11 \leq V \leq 26.8 = 0.003$

(6) = power at 11 mls = 799 w/m^2

(7) = (5) x (6) = 2 w/m^2

(8) = weighted power = (4) + (7) = 75 w/m^2

(9) = weighted power in windswept area = 1070 w

(10) = available energy in wind = 9365 Kwh

(11) = expected energy from machine = (9365)(0.35)(0.8) = 2622 Kwh

Evanston Environmental Center (continued)

The grantee's estimates of available power output came from the statistics given below, where

(1) = monthly average windspeed at Midway Airport in mph

(2) = assumed site windspeeds = (1) - 1 mph

(3) = net electric output in Kwh

	(1)	(2)	(3)
J	11.3	10.3	593
F	11.8	10.8	610
M	11.5	10.5	600
A	11.4	10.4	597
M	10.6	9.6	549
J	8.9	7.9	243
J	8.0	7.0	164
A	7.9	6.9	157
S	8.9	7.9	243
O	9.6	8.6	400
N	11.5	10.5	600
D	10.6	9.6	549
		total:	5305 Kwh

clearly this figure is much too high.

Wind Electricity on a Minnesota Farm
(MN79382)

Mean windspeed at site	= 11	mph	=	4.9 m/s
Cut-in windspeed	= 7	mph	=	3.1 m/s
Rated windspeed	= 25	mph	=	11.2 m/s
Cut-out windspeed	= 30	mph	=	13.4 m/s
Radius of rotor	= 3.5 m			

(1) = reference windspeed in m/s

(2) = fraction of time that instantaneous windspeed is within 0.5 m/s of reference windspeed, given mean.

(3) = power at reference windspeed in w/m^2

(4) = weighted power at reference windspeed in w/m^2 = (2) x (3)

(1)	(2)	(3)	(4)
4	0.15	38	6
5	0.14	75	11
6	0.12	130	16
7	0.09	206	19
8	0.07	307	20
9	0.04	437	19
10	0.03	600	15
11	0.01	799	11

(5) = fraction of time that $11 \leq V \leq 13.5 = 0.01$

(6) = power at 11.2 m/s = 843 w/m^2

(7) = (5) x (6) = 8 w/m^2

(8) = weighted power = (4) + (7) = 125 w/m^2

(9) = weighted power in windswept area ≈ 4800 w

(10) = available energy in wind ≈ 42140 Kwh

(11) = expected energy from machine = (42140)(0.35)(0.8) ≈ 11,800 Kwh

Wind Electricity for a Ski Resort
(NH79856)

Mean windspeed at site	= 14 mph	=	6.3 m/s
Cut-in windspeed	= 11 mph	=	4.9 m/s
Rated windspeed	= 30 mph	=	13.4 m/s
Cut-out windspeed	= 40 mph	=	17.9 m/s
Radius of rotor	= 5.3 m		

(1) = reference windspeed in m/s

(2) = fraction of time that instantaneous windspeed is within 0.5 m/s of reference windspeed, given mean.

(3) = power at reference windspeed in w/m^2

(4) = weighted power at reference windspeed in w/m^2 = (2) x (3)

(1)	(2)	(3)	(4)
5.5	0.12	100	12
6.5	0.11	165	18
7.5	0.10	235	25
8.5	0.08	368	29
9.5	0.06	514	32
10.5	0.05	695	32
11.5	0.03	913	30
12.5	0.02	1172	26
13.5	0.01	1476	21

(5) = fraction of time that $13.5 \leq V \leq 17.9$ = 0.02

(6) = power at 13.5 m/s = 1476 w/m^2

(7) = (5) x (6) = 35 w/m^2

(8) = weighted power = (4) + (7) = 260 w/m^2

(9) = weighted power in windswept area = 25,000 w

(10) = available energy in wind = 216,500 Kwh

(11) = expected energy from machine = (216,500)(0.35)(0.8) = 60,600 Kwh

Bronx Frontier Development Corp
(NY79539)

Mean windspeed at site	= 12 mph	=	5.4 m/s
Cut-in windspeed	= 11.5 mph	=	5.1 m/s
Rated windspeed	= 26 mph	=	11.6 m/s
Cut-out windspeed	= 35 mph	=	15.6 m/s
Radius of rotor	= 5.3 m		

(1) = reference windspeed in m/s

(2) = fraction of time that instantaneous windspeed is within 0.5 m/s of reference windspeed, given mean.

(3) = power at reference windspeed in w/m^2

(4) = weighted power at reference windspeed in w/m^2 = (2) x (3)

(1)	(2)	(3)	(4)
5.5	0.13	100	13
6.5	0.11	165	18
7.5	0.09	253	22
8.5	0.06	364	24
9.5	0.04	514	23
10.5	0.03	695	20
11.5	0.02	913	16

(5) = fraction of time that $11.5 \leq V \leq 15.6 = 0.07$

(6) = power at 11.5 m/s = 913 w/m^2

(7) = (5) x (6) = 64 w/m^2

(8) = weighted power = (4) + (7) = 200 w/m^2

(9) = weighted power in windswept area = 17,800 w

(10) = available energy in wind = 155,930 Kwh

(11) = expected energy from machine = (155,930)(0.35)(0.8) = 43,660 Kwh

Wind Electricity for an Urban Residence
(OH76973)

Mean windspeed at site	= 10.5	mph =	4.7 m/s
Cut-in windspeed	= 8	mph =	3.6 m/s
Rated windspeed	= 23	mph =	10.3 m/s
Cut-out windspeed	= 60	mph =	26.8 m/s
Radius of rotor	= 2.1 m		

(1) = reference windspeed in m/s

(2) = fraction of time that instantaneous windspeed is within 0.5 m/s of reference windspeed, given mean.

(3) = power at reference windspeed in w/m^2

(4) = weighted power at reference windspeed in w/m^2 = (2) x (3)

(1)	(2)	(3)	(4)
4	0.16	38	6
5	0.15	75	11
6	0.12	130	15
7	0.09	206	18
8	0.06	307	18
9	0.04	437	16
10	0.02	600	12

(5) = fraction of time that $10.5 \leq V \leq 26.8$ = 0.02

(6) = power at 10.3 m/s = 652 w/m^2

(7) = (5) x (6) = 13 w/m^2

(8) = weighted power = (4) + (7) = 109 w/m^2

(9) = weighted power in windswept area = 1510 w

(10) = available energy in wind = 13,230 Kwh

(11) = expected energy from machine = (13,230)(0.35)(0.8) ≈ 3705 Kwh

The grantee's estimate is based on the following data, where (1) = mean monthly windspeed at Cincinnati Airport and (2) = estimated energy output.

	(1) (in mph)	(2) (in Kwh)
J	11.1	631
F	11.2	645
M	11.4	673
A	11.6	701
M	9.6	549
J	8.4	350
J	7.6	217
A	7.1	173
S	8.3	326
O	8.9	474
N	10.9	614
D	10.5	600
		total = 5950

This is obviously a bit high.

Windpower in the U.S. Virgin Islands
(V17907)

Mean windspeed at site	= 13	mph =	5.8	m/s
Cut-in windspeed	= 10	mph =	4.5	m/s
Rated windspeed	= 22	mph =	9.8	m/s
Cut-out windspeed	= 40	mph =	17.9	m/s
Radius of rotor	= 1.9 m			

(1) = reference windspeed in m/s

(2) = fraction of time that instantaneous windspeed is within 0.5 m/s of reference windspeed, given mean.

(3) = power at reference windspeed in w/m^2

(4) = weighted power at reference windspeed in w/m^2 = (2) x (3)

(1)	(2)	(3)	(4)
5	0.13	75	8
6	0.12	130	16
7	0.10	206	21
8	0.08	307	26
9	0.06	437	28
10	0.05	600	27

(5) = fraction of time that $10 \leq V \leq 17.8$ = 0.10

(6) = power at 9.8 m/s = 570 w/m^2

(7) = (5) x (6) = 57 w/m^2

(8) = weighted power = (4) + (7) = 183 w/m^2

(9) = weighted power in windswept area = 2256 w

(10) = available energy in wind = 19766 Kwh

(11) = expected energy from machine = (19766)(0.35)(0.8) = 5534 Kwh

MI79113

Wind Pumping on a Michigan Farm

1. Rotor radius = 5 ft = 1.52 m
2. Site average windspeed $\overline{V}$ = 15 mph = 6.7 m/s
3. Average power in wind assuming a cut-in speed of nearly zero and a very high cut-out speed

   $= \pi \times (1.52 \text{ m})^2 \times (6/\pi) \times (0.6) \times (6.7 \text{ m/s})^3)$

   = 2.5 kw, assuming Rayleigh distributed winds
4. COP of a multiblade pumping windmill is typically much lower than for a well designed, high-tip-speed-ratio electricity generator. Here I have assumed a COP of 0.2, an optimistic but not impossible figure.
5. (Average power in wind) x (COP) = (2.5 kw) x (0.2) = 500 w

   = work done by turbine
6. Pump efficiency on average = 0.50. This implies that work done by pump = 250 w.
7. How much water can be pumped given an average delivered power of 250 w over a six month period? To figure this out, we use the well depth of 75 ft = 22.86 m to figure out how much water can be delivered at 500 w, or 250 J/s. Ignoring head losses, which are very small, we have the equation

$$250 \text{ J} = (22.86 \text{ m}) \times (9.8 \text{ m/s}^2) \times (X \text{ kg}).$$

Solving this, X kg = 1.12 kg, lifted every second, 1.12 kg = 0.30 gal.

8. (0.30 gal/s) - 4.65 million gallons from April through September, the period in which strawberry farming should occur.
9. 250 w implies that the wind machine delivers about 1095 Kwh of energy during the six month farming period.
10. Assuming an electric pump were to deliver this same amount at an efficiency of 0.7, then 1565 Kwh would have to be consumed. This is a reasonable figure for energy savings in the analysis.

OK79152

Wind Powered Irrigation in a Pecan Orchard

1. Rotor radius = 3 ft = 0.91 m
2. Site average windspeed = 11 mph = 4.9 m/s
3. Average power in wind assuming a cut-in of nearly zero and a very high cut-out speed (reasonable with high starting torque machines with low lift-to-drag ratios)

   $= \pi \times (0.91\ m)^2 \times (6/\pi) \times (0.6) \times (4.9\ m/s)^3)$

   $= 350\ w$
4. Assume a COP = 0.2, as in MI79113.
5. Assume a pump efficiency of 50%
6. Work output of pump is thus

   $(350\ w) \times (0.20) \times (0.50) = 35\ w$
7. How much water can be lifted at a rate of 35 w on average? To find the water lifted in one second we use the following equation, ignoring head losses.

$$35\ J = (10.5\ m) \times (9.8\ m/s^2) \times (X\ kg)$$

   so

$$X\ kg = 0.34\ kg = 0.09\ \text{gallons}.$$

8. Given 5 months full time operation equivalent, we obtain the following:

(a) (0.09 gallons/second) x (5 months) x (30 days/month) x (24 hours/day) x (3600 s/hour) = 1.17 millions gallons of water

(b) (35 w) x (5 months) x (30 days/month) x (24 hours/day) = 126 Kwh

9. Given an electric pump efficiency of 70 percent, 126/0.7 = 180 Kwh/year is avoided.

Appendix B

SIR Calculations

(I) Introduction

Most of the contents of this appendix is self explanatory. The formula used to calculate uniform present work factors is

$$UPW = \frac{r - r^{n+1}}{1 - r}$$

where $r = 1/(1+d)$ and n = project liftime in years

and d = discount rate

The formula for the Discount-Escalation factor is exactly the same, except that $r = (1+e)/(1+d)$, where e = real rate of energy price escalation.

Private Analysis

Project #: IL79849

Project Name: Evanston Environmental Center

(1) Assumed lifetime in years: 20

(2) 1980 base price of energy in units typically sold: $0.075 Kwh/year

(3) 1980 base year energy savings: 2622 Kwh

(4) 1980 base year value of energy savings = (2) x (3) = $197

(5) Discount-escalation factor for a 7% discount rate

(a) assuming 2% escalation: 12.57
(b) assuming 6% escalation: 18.15

(6) Present value of energy savings at (a) 2%: $2476
(b) 6%: $3576

(7) (a) Net annual O&M costs: $150
(b) UPW factor for 20 years: 10.59

(8) Present value of O&M costs assuming 0% real escalation: $1589

(9) Investment and installation costs before tax: $14,708
for residential project after tax: $10,708

(10) Discounted recurring replacement costs, if any: ---

(9) + (10) = (11) Total net investment costs before: $14,708
and after tax: $10,708

(12) Present value of net benefit: (6) - 8 @ 2% $ 887
@ 6% $1987

(13) SIR:

	@ 2%	6%
before tax:	0.06	0.14
after tax:	0.08	0.19

Private Analysis

Project #: M179113

Project Name: Wind Powered Water Pumping for Strawberry Irrigation

(1) Assumed lifetime in years: 30

(2) 1980 base price of energy in units typically sold: $0.04/Kwh

(3) 1980 base year energy savings: 1565 Kwh

(4) 1980 base year value of energy savings = (2) x (3) = $ 63

(5) Discount-escalation factor for a 7% discount rate

(a) assuming 2% escalation: 15.55
(b) assuming 6% escalation: 26.02

(6) Present value of energy savings at (a) 2%: $ 970
(b) 6%: $1639

(7) (a) Net annual O&M costs: $150
(b) UPW factor for 30 years: 12.41

(8) Present value of O&M costs assuming 0% real escalation: $1862

(9) Investment and installation costs before tax: $5410
for commercial project after tax: $4058

(10) Discounted recurring replacement costs, if any: $426

(9) + (10) = (11) Total net investment costs before: $5836
and after tax: $4377

(12) Present value of net benefit: (6) - 8 @ 2% $0
@ 6% $0

(13) SIR: @ 2% 6%

	2%	6%
before tax:	0.0	0.0
after tax:	0.0	0.0

Private Analysis

Project #: M179122

Project Name: A Wind to Heat Converter

(1) Assumed lifetime in years: 30

(2) 1980 base price of energy in units typically sold: $0.0197

(3) 1980 base year energy savings: 15,000 Kwh

(4) 1980 base year value of energy savings = (2) x (3) = $296

(5) Discount-escalation factor for a 7% discount rate

(a) assuming 2% escalation: 15.55
(b) assuming 6% escalation: 26.02

(6) Present value of energy savings at (a) 2%: $4603
(b) 6%: $7702

(7) (a) Net annual O&M costs: N/A
(b) UPW factor for 30 years: 12.41

(8) Present value of O&M costs assuming 0% real escalation: 0

(9) Investment and installation costs before tax: $12,870
for residential project after tax: $ 8,870

(10) Discounted recurring replacement costs, if any: ---

(9) + (10) = (11) Total net investment costs before: $12,870
and after tax: $ 8,870

(12) Present value of net benefit: (6) - 8 @ 2% $4603
@ 6% $7702

(13) SIR:

	@ 2%	6%
before tax:	0.36	0.60
after tax:	0.52	0.87

Private Analysis

Project #: MN79382

Project Name: Wind Generated Electricity on a Minnesota Farm

(1) Assumed lifetime in years: 20

(2) 1980 base price of energy in units typically sold: $0.0405/Kwh

(3) 1980 base year energy savings: 12,000 Kwh

(4) 1980 base year value of energy savings = (2) x (3) = $486

(5) Discount-escalation factor for a 7% discount rate

(a) assuming 2% escalation: 12.57
(b) assuming 6% escalation: 18.15

(6) Present value of energy savings at (a) 2%: $6109
(b) 6%: $8821

(7) (a) Net annual O&M costs: $160
(b) UPW factor for 20 years: 10.59

(8) Present value of O&M costs assuming 0% real escalation: $1694

(9) Investment and installation costs before tax: $19,975
for commercial project after tax: $14,981

(10) Discounted recurring replacement costs, if any: ---

(9) + (10) = (11) Total net investment costs before: $19,975
and after tax: $14,981

(12) Present value of net benefit: (6) - 8 @ 2% $4415
@ 6% $7127

(13) SIR:

	@ 2%	6%
before tax:	0.22	0.36
after tax:	0.29	0.48

Private Analysis

Project #: NH79856

Project Name: At Hitash Lift Corporation

(1) Assumed lifetime in years: 20

(2) 1980 base price of energy in units typically sold: $0.077/Kwh

(3) 1980 base year energy savings: 50,000 Kwh

(4) 1980 base year value of energy savings = (2) x (3) = $3850

(5) Discount-escalation factor for a 7% discount rate

(a) assuming 2% escalation: 12.57
(b) assuming 6% escalation: 18.15

(6) Present value of energy savings at (a) 2%: $48,395
(b) 6%: $69,878

(7) (a) Net annual O&M costs: $700
(b) UPW factor for 20 years: 10.59

(8) Present value of O&M costs assuming 0% real escalation: $7413

(9) Investment and installation costs before tax: $46,600
for commercial project after tax: $34,950

(10) Discounted recurring replacement costs, if any: N/A

(9) + (10) = (11) Total net investment costs before: $46,600
and after tax: $34,950

(12) Present value of net benefit: (6) - 8 @ 2% $40,982
@ 6% $62,465

(13) SIR:

	@ 2%	6%
before tax:	0.88	1.34
after tax:	1.17	1.79

Private Analysis

Project #: NY79539

Project Name: Bronx Frontier Development Corp.

(1) Assumed lifetime in years: 20

(2) 1980 base price of energy in units typically sold: $0.06/Kwh

(3) 1980 base year energy savings: 30,000 Kwh

(4) 1980 base year value of energy savings = (2) x (3) = $1800

(5) Discount-escalation factor for a 7% discount rate

(a) assuming 2% escalation: 12.57
(b) assuming 6% escalation: 18.15

(6) Present value of energy savings at (a) 2%: $22,626
(b) 6%: $32,670

(7) (a) Net annual O&M costs: $1415
(b) UPW factor for 20 years: 10.59

(8) Present value of O&M costs assuming 0% real escalation: $14,985

(9) Investment and installation costs before tax: $39,650
for commercial project after tax: $29,738

(10) Discounted recurring replacement costs, if any: ---

(9) + (10) = (11) Total net investment costs before: $39,650
and after tax: $29,738

(12) Present value of net benefit: (6) - 8 @ 2% $ 7,641
@ 6% $17,685

(13) SIR:

	@ 2%	6%
before tax:	0.19	0.45
after tax:	0.26	0.59

Private Analysis

Project #: OH79673

Project Name: Wind Powered Electricity in an Urban Residence

(1) Assumed lifetime in years: 20

(2) 1980 base price of energy in units typically sold: $0.048/Kwh

(3) 1980 base year energy savings: 3,705 Kwh

(4) 1980 base year value of energy savings = (2) x (3) = $178

(5) Discount-escalation factor for a 7% discount rate

(a) assuming 2% escalation: 12.57
(b) assuming 6% escalation: 18.15

(6) Present value of energy savings at (a) 2%: $2,237
(b) 6%: $3,231

(7) (a) Net annual O&M costs: $100
(b) UPW factor for 20 years: 10.59

(8) Present value of O&M costs assuming 0% real escalation: $1059

(9) Investment and installation costs before tax: $12,400
for residential project after tax: $ 8,400

(10) Discounted recurring replacement costs, if any: ---

(9) + (10) = (11) Total net investment costs before: $12,400
and after tax: $ 8,400

(12) Present value of net benefit: (6) - 8 @ 2% $1178
@ 6% $2172

(13) SIR:

	@ 2%	6%
before tax:	0.10	0.18
after tax:	0.14	0.26

Private Analysis

Project #: OK79152

Project Name: Wind Power Irrigation for a Pecan Farm

(1) Assumed lifetime in years: 30

(2) 1980 base price of energy in units typically sold: $0.05/Kwh

(3) 1980 base year energy savings: 180 Kwh

(4) 1980 base year value of energy savings = (2) x (3) = $9

(5) Discount-escalation factor for a 7% discount rate

(a) assuming 2% escalation: 15.55
(b) assuming 6% escalation: 26.02

(6) Present value of energy savings at (a) 2%: $140
(b) 6%: $234

(7) (a) Net annual O&M costs: 0
(b) UPW factor for 30 years: 12.41

(8) Present value of O&M costs assuming 0% real escalation: 0

(9) Investment and installation costs before tax: $2670
for commercial project after tax: $2003

(10) Discounted recurring replacement costs, if any: 0

(9) + (10) = (11) Total net investment costs before: $2670
and after tax: $2003

(12) Present value of net benefit: (6) - 8 @ 2% $140
@ 6% $234

(13) SIR: @ 2% 6%

	2%	6%
before tax:	0.05	0.09
after tax:	0.07	0.12

Private Analysis

Project #: VI7907

Project Name: Wind Electricity in the U.S. Virgin Islands

(1) Assumed lifetime in years: 20

(2) 1980 base price of energy in units typically sold: $0.25/Kwh

(3) 1980 base year energy savings: 5200 Kwh

(4) 1980 base year value of energy savings = (2) x (3) = $1300

(5) Discount-escalation factor for a 7% discount rate

(a) assuming 2% escalation: 12.57
(b) assuming 6% escalation: 18.15

(6) Present value of energy savings at (a) 2%: $16,341
(b) 6%: $23,595

(7) (a) Net annual O&M costs: 100
(b) UPW factor for 20 years: 10.59

(8) Present value of O&M costs assuming 0% real escalation: $1059

(9) Investment and installation costs before tax: $7000
for residential project after tax: $4200

(10) Discounted recurring replacement costs, if any: ---

(9) + (10) = (11) Total net investment costs before: $7000
and after tax: $4200

(12) Present value of net benefit: (6) - 8 @ 2% $15,282
@ 6% $22,536

(13) SIR:

	@ 2%	6%
before tax:	2.18	3.22
after tax:	3.64	5.37

Social Analysis

Project #: IL79849

Project Name: Evanston Environment Center

(1) Assumed lifetime in years: 20

(2) 1980 base year energy savings, in typical units: 2622 Kwh

(3) Proxy for marginal social value of energy: $0.0729

(4) (2) x (3) = Social value of base year energy savings: $191

(5) Discount-escalation factor:

(a) assuming 2% escalation and 7% discount: 12.57
(b) assuming 6% escalation and 7% discount: 18.15

(6) Present social value of energy savings

(a) assuming 2% escalation = 5(a) * 4 = $2399
(b) assuming 6% escalation = 5(b) * 4 = $3463

(7) (a) Net annual O&M costs: 150
(b) UPW factor for 20 years: 10.59

(8) Present value of O&M costs assuming % real escalation: $1589

(9) Investment and installation costs: $14,708

(10) Discounted recurring replacement costs, if any: ---

(11) Total net investment costs: (9) + (10) = $14,708

(12) Present value of net benefit:

(a) @ 2% = 6(a) - 8: $810
(a) @ 6% = 6(b) - 8: $1874

(13) SIR: @ 2% = 12(a)/11 = 0.06
@ 6% = 12(b)/11 = 0.13

Social Analysis

Project #: M179113

Project Name: Wind Powered Water Pumping for Strawberry Irrigation

(1) Assumed lifetime in years: 30

(2) 1980 base year energy savings, in typical units: 1565 Kwh

(3) Proxy for marginal social value of energy: $0.0729

(4) (2) x (3) = Social value of base year energy savings: $113

(5) Discount-escalation factor:

(a) assuming 2% escalation and 7% discount: 15.55
(b) assuming 6% escalation and 7% discount: 26.02

(6) Present social value of energy savings

(a) assuming 2% escalation = 5(a) * 4 = $1763
(b) assuming 6% escalation = 5(b) * 4 = $2951

(7) (a) Net annual O&M costs: $150
(b) UPW factor for 30 years: 12.41

(8) Present value of O&M costs assuming % real escalation: $1862

(9) Investment and installation costs: $5410

(10) Discounted recurring replacement costs, if any: $426

(11) Total net investment costs: (9) + (10) = $5836

(12) Present value of net benefit:

(a) @ 2% = 6(a) - 8: $ 0
(a) @ 6% = 6(b) - 8: $1089

(13) SIR: @ 2% = 12(a)/11 = 0
@ 6% = 12(b)/11 = 0.19

Social Analysis

Project #: M179122

Project Name: A Wind to Heat Converter

(1) Assumed lifetime in years: 30

(2) 1980 base year energy savings, in typical units: 15,000 Kwh

(3) Proxy for marginal social value of energy: $0.023

(4) (2) x (3) = Social value of base year energy savings: $345

(5) Discount-escalation factor:

(a) assuming 2% escalation and 7% discount: 15.55
(b) assuming 6% escalation and 7% discount: 26.02

(6) Present social value of energy savings

(a) assuming 2% escalation = 5(a) * 4 = $5365
(b) assuming 6% escalation = 5(b) * 4 = $8977

(7) (a) Net annual O&M costs: N/A
(b) UPW factor for 30 years: 12.41

(8) Present value of O&M costs assuming % real escalation: 0

(9) Investment and installation costs: $12,870

(10) Discounted recurring replacement costs, if any: ---

(11) Total net investment costs: (9) + (10) = $12,870

(12) Present value of net benefit:

(a) @ 2% = 6(a) - 8: $5365
(a) @ 6% = 6(b) - 8: $8977

(13) SIR: @ 2% = 12(a)/11 = 0.42
@ 6% = 12(b)/11 = 0.70

Social Analysis

Project #: MN79382

Project Name: Wind Generated Electricity on a Minnesota Farm

(1) Assumed lifetime in years: 20

(2) 1980 base year energy savings, in typical units: 12,000 Kwh

(3) Proxy for marginal social value of energy: $0.0729

(4) (2) x (3) = Social value of base year energy savings: $873

(5) Discount-escalation factor:

(a) assuming 2% escalation and 7% discount: 12.57
(b) assuming 6% escalation and 7% discount: 18.15

(6) Present social value of energy savings

(a) assuming 2% escalation = 5(a) * 4 = $10,969
(b) assuming 6% escalation = 5(b) * 4 = $15,845

(7) (a) Net annual O&M costs: $160
(b) UPW factor for 20 years: 10.59

(8) Present value of O&M costs assuming % real escalation: $1694

(9) Investment and installation costs: $15,745

(10) Discounted recurring replacement costs, if any: ---

(11) Total net investment costs: (9) + (10) = $19,975

(12) Present value of net benefit:

(a) @ 2% = 6(a) - 8: $9275
(a) @ 6% = 6(b) - 8: $14,151

(13) SIR: @ 2% = 12(a)/11 = 0.46
@ 6% = 12(b)/11 = 0.71

Social Analysis

Project #: NH79856

Project Name: A Hitash Lift Corporation

(1) Assumed lifetime in years: 20

(2) 1980 base year energy savings, in typical units: 50,000 Kwh

(3) Proxy for marginal social value of energy: $0.0729

(4) (2) x (3) = Social value of base year energy savings: $3636

(5) Discount-escalation factor:

(a) assuming 2% escalation and 7% discount: 12.57
(b) assuming 6% escalation and 7% discount: 18.15

(6) Present social value of energy savings

(a) assuming 2% escalation = 5(a) * 4 = $45,705
(b) assuming 6% escalation = 5(b) * 4 = $65,993

(7) (a) Net annual O&M costs: $700
(b) UPW factor for 20 years: 10.59

(8) Present value of O&M costs assuming % real escalation: $7413

(9) Investment and installation costs: $46,600

(10) Discounted recurring replacement costs, if any: ---

(11) Total net investment costs: (9) + (10) = $46,600

(12) Present value of net benefit:

(a) @ 2% = 6(a) - 8: $38,292
(a) @ 6% = 6(b) - 8: $58,580

(13) SIR: @ 2% = 12(a)/11 = 0.82
@ 6% = 12(b)/11 = 1.26

Social Analysis

Project #: NY79539

Project Name: Bronx Frontier Development Corporation

(1) Assumed lifetime in years: 20

(2) 1980 base year energy savings, in typical units: 30,000 Kwh

(3) Proxy for marginal social value of energy: $0.0729

(4) (2) x (3) = Social value of base year energy savings: $2182

(5) Discount-escalation factor:

(a) assuming 2% escalation and 7% discount: 12.57
(b) assuming 6% escalation and 7% discount: 18.15

(6) Present social value of energy savings

(a) assuming 2% escalation = 5(a) * 4 = $27,423
(b) assuming 6% escalation = 5(b) * 4 = $39,597

(7) (a) Net annual O&M costs: $1415
(b) UPW factor for 20 years: 10.59

(8) Present value of O&M costs assuming % real escalation: $14,985

(9) Investment and installation costs: $39,650

(10) Discounted recurring replacement costs, if any: ---

(11) Total net investment costs: (9) + (10) = $39,650

(12) Present value of net benefit:

(a) @ 2% = 6(a) - 8: $12,438
(a) @ 6% = 6(b) - 8: $24,612

(13) SIR: @ 2% = 12(a)/11 = 0.31
@ 6% = 12(b)/11 = 0.62

Social Analysis

Project #: OH79673

Project Name: Wind Powered Electricity in an Urban Residence

(1) Assumed lifetime in years: 20

(2) 1980 base year energy savings, in typical units: 3705 Kwh

(3) Proxy for marginal social value of energy: $0.0729

(4) (2) x (3) = Social value of base year energy savings: $269

(5) Discount-escalation factor:

(a) assuming 2% escalation and 7% discount: 12.57
(b) assuming 6% escalation and 7% discount: 18.15

(6) Present social value of energy savings

(a) assuming 2% escalation = 5(a) * 4 = $3382
(b) assuming 6% escalation = 5(b) * 4 = $4884

(7) (a) Net annual O&M costs: $100
(b) UPW factor for 20 years: 10.59

(8) Present value of O&M costs assuming % real escalation: $1059

(9) Investment and installation costs: $12,400

(10) Discounted recurring replacement costs, if any: ---

(11) Total net investment costs: (9) + (10) = $12,400

(12) Present value of net benefit:

(a) @ 2% = 6(a) - 8: $2323
(a) @ 6% = 6(b) - 8: $3825

(13) SIR: @ 2% = 12(a)/11 = 0.19
@ 6% = 12(b)/11 = 0.31

Social Analysis

Project #: OK79152

Project Name: Wind Powered Irrigation on a Pecan Farm

(1) Assumed lifetime in years: 30

(2) 1980 base year energy savings, in typical units: 180 Kwh

(3) Proxy for marginal social value of energy: $0.0729

(4) (2) x (3) = Social value of base year energy savings: $14

(5) Discount-escalation factor:

(a) assuming 2% escalation and 7% discount: 15.55
(b) assuming 6% escalation and 7% discount: 26.02

(6) Present social value of energy savings

(a) assuming 2% escalation = 5(a) * 4 = $210
(b) assuming 6% escalation = 5(b) * 4 = $351

(7) (a) Net annual O&M costs: 0
(b) UPW factor for 30 years: 12.41

(8) Present value of O&M costs assuming % real escalation: 0

(9) Investment and installation costs: $2670

(10) Discounted recurring replacement costs, if any: 0

(11) Total net investment costs: (9) + (10) = $2670

(12) Present value of net benefit:

(a) @ 2% = 6(a) - 8: $210
(a) @ 6% = 6(b) - 8: $351

(13) SIR: @ 2% = 12(a)/11 = 0.08
@ 6% = 12(b)/11 = 0.13

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