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ORGANIZATIONAL, INTERFACE AND FINANCIAL BARRIERS TO THE COMMERCIAL DEVELOPMENT OF COMMUNITY ENERGY SYSTEMS

Robert Schladale and Ronald Ritschard

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INTRODUCTION

Study Design

At the present time the United States is engaged in a vigorous search for new energy supplies. Community energy systems are small scale technologies capable of providing new sources of supply. Most of these technologies are fully developed, but none has been commercialized to the point of meeting more than a fraction of a percent of U.S. energy demand. The objective of this study is to isolate some of the non-technological barriers that have impeded their commercialization, and to suggest incentives that state and federal governments could provide for overcoming them.

Scope

A community energy system is a general term for a process that produces either steam, electricity, or gas from small-scale technology using locally available stocks and flows. The scope of this analysis is limited to systems producing electricity, and the electrical output of a community energy system will typically fall in the range of 10 kilowatts to 50 megawatts.

The category of community energy systems includes all of the following energy producing systems:

Solar heating and cooling
Solar industrial process heat
Photovoltaic electricity
Municipal solid waste electricity or gas
Small wind power
Low-head hydroelectric power
Biomass conversion of agricultural wastes
Industrial cogeneration

Because it would be unfeasible to review all of these technologies in the present analysis, only four will be investigated: 1) combustion of municipal solid waste (MSW); 2) small wind power; 3) industrial cogeneration; and 4) photovoltaic electricity. The rationale for choosing these four are several. First, they are representative of all community energy systems; the barriers and incentives faced by any of these technologies cover virtually all the major barriers and incentives faced by any of the systems. Second, each is substantially different

from the others, providing breadth while minimizing redundancy. Third, each makes use of a resource that is relatively abundant in the states of Federal Region 9, to which this study is confined.

The scope of the barriers to be addressed has also been restricted to three general areas: 1) Organizational barriers, 2) Interface barriers, and 3) Financial and Investment barriers. Organizational barriers stem from deficiencies in organizations that attempt to develop a community energy resource, and may involve things such as a lack of awareness of opportunities, lack of familiarity with energy technology, or an inability to finance a feasibility study.

Interface barriers cover a broad range of problems that arise when an organization seeking to develop a community energy system must interact with other organizations whose institutional policies and procedures were developed to meet an earlier set of conditions, i.e., before the advent of community energy systems. Consequently, smooth interaction may be difficult, and current policies and procedures may have to be revised to facilitate the growth of the new systems. The major barriers in this class involve relations between public utility commissions and electric utilities.

Finally, financial and investment barriers stem from the fact that new energy systems, although technologically proven in laboratories and demonstration projects, possess no real world track record. Consequently, they are deemed risky, and investors will either avoid making commitments to them, or will do so only after attaching a high risk premuim to their interest rate.

Organization

This report includes three central sections, one each dealing with organizational, interface, and financial barriers. The first and third are broken down by type of community energy system: that is, the financial and organizational barriers to each of the four systems under study are dealt with separately. The other section reviews the generic problem of interfacing small scale producers of electricity with electric utilities, a barrier that is common to all four community energy systems.

For purposes of simplicity it is assumed that each of the four technologies will be developed by one particular organization and financed by one particular financial mechanism. The organizational and financial mechanism for each technology are listed in Table 1.

TABLE 1

DEVELOPING AND FINANCING AGENCIES

Technology	Organization	Financing Mechanism
Municipal Solid Waste	Municipality	Municipal Bonds
Small Wind Power	Entrepreneur	Venture Capital
Industrial Cogeneration	Private Firm	Retained Earnings
Residential Photovoltaics	Private Homeowner	Commercial Banks

There is a comparative advantage to associate a particular developing agency with a particular technology. A municipal government is most likely to develop an MSW-electricity plant because it must collect and dispose of solid waste as a routine public service. Thus it has access to the energy resource, and a need to do something with it. A private industry is most likely to develop cogeneration because to do so requires a steam boiler system, which is precisely what most manufacturing and processing industries use to power their machinery. A residential homeowner possesses a rooftop, which is often unshaded and therefore an ideal location for a photovoltaic electricity system; the advantage here stems from the elimination of costly support structures that would otherwise be required to hold the photovoltaic arrays. With respect to small wind systems a private entrepreneur possesses only one advantage: the ability to move into an expanding market. Because the present energy situation offers a huge market for reliable new technologies, and because small wind technologies are already well-developed and subject to significant returns to scale from mass production, the industry may be subject to very high growth in the coming decades -- precisely the environment in which entrepreneurs have thrived in the past. None of the other technologies under study present quite the same opportunity; nor are the other developers as likely to take the risks that an entrepreneur will.

Each of these four technologies could be developed by other organizations and each of the four organizations could develop other technologies. To cover all combinations of energy technology and developing organization would be time-consuming, tedious, and repetitious. Most organizational barriers will

manifest themselves in the same way no matter which technology is developed. Therefore, only the most likely association of technology and organization will be reviewed.

The choice of a financial mechanism for each energy system is more restricted than the choice of developing organization. Municipal governments routinely utilize bonds to finance large capital projects because tax revenues will prove insufficient to cover construction costs. Moreover, because interest on these bonds is tax-free, the municipality can issue them at rates roughly one-half the standard bond interest rate, greatly reducing financing costs. Retained earnings are the most common method by which an industrial firm finances capital projects and most desirable because the firm has the money in hand and can control its use. Alternatively, the firm could borrow from a bank, but because its line of credit will be limited it will go that route only for an investment that is necessary, offers a very high return, or is especially attractive for some other reason. By comparison, residential homeowners will usually look for a bank-issued home improvement loan for capital projects because their savings are either insufficient, or because they wish to keep some savings in reserve as a hedge against the proverbial "rainy day". Finally, because small wind systems are relatively risky investments at present, and because small wind firms will be too small to issue stock or to have adequate lines of credit at commercial banks, the most probable form of financing for them will be through venture capital firms that specialize in small, high-risk firms with large growth potential.

In addition to the specific financing mechanism attached to each technology in Table 1, some attention will be paid to alternatives. For example, a municipal solid waste plant might be built by a private firm using corporate bonds and/or its own capital; or a residential homeowner might have a photovoltaic system financed by the local electric utility rather than a bank.

ORGANIZATIONAL BARRIERS TO COMMUNITY ENERGY SYSTEMS

An "organizational barrier" may be generally understood to be a deficiency within an organization that is attempting to do something -- here, to develop a community energy system. The particular barrier may involve a lack of manpower skilled in economic or technological assessment techniques, a lack of awareness regarding opportunities, a lack of ability to manage a development

effort, a lack of knowledge regarding regulations to which such an effort is subject, or other similar difficulties originating in the organization.

Objectives and Organization

This chapter will discuss barriers that are likely to exist in four organizations, each of which is developing a different community energy system. The organizations and associated technologies are:

Municipal Governments	--	MSW Electricity Plant
Private Entrepreneurs	--	Wind Power
Industrial Firms	--	Cogeneration
Residential Homeowners	--	Photovoltaics

Some barriers will be shared by several organizations, while others will be specific to one or two developers. The major barriers to each organization are listed in Table 2.

TABLE 2

SUMMARY OF MAJOR ORGANIZATION BARRIERS

Barrier	Muni. Gov't.	Priv. Entr.	Indus. Firm	Res. Home
Technical/economic evaluation	X		X	X
Funding for feasibility studies	X			X
Obtaining fuel	X	X	X	
Legal skills		X	X	X
Project Management	X			X
Construction & Maintenance				X
Political support	X	X		
Facility resale				X

In the analysis that follows all barriers existing within a given organization will be discussed as a group, in order to suggest the relative magnitude of the difficulty each faces. Immediately thereafter will come the identification and evaluation of public policies that could be useful in eliminating the barriers.

Policy Evaluation Criteria

Policies for overcoming the barriers that will be identified should ideally be as simple and inexpensive as possible while still being effective. The creation of new bureaucracies is considered less preferable than reliance upon ones that already exist. The expenditure of large sums of money will not be recommended because of the distorting impact it might have upon energy system development and energy consumption. For example, if public subsidies make inefficient projects appear to be economically viable, and if energy prices are so low as to encourage excess consumption, then both macroeconomic efficiency and conservation objectives will suffer.

Preference will also be given to those policies that call for action at a local level and for the negotiation of differences among parties as opposed to solution via federal or state statute. Since community energy systems must be adapted to the resources of local areas which will have characteristics peculiar to the areas involved, and the cooperation of multiple local agencies and organizations will be essential for their success, the imposition of state and federal law, however well meaning, may result in prohibitons or requirements that frustrate rather than stimulate development. This will not always be the case, however, and in some circumstances state laws may help eliminate unnecessary restrictions imposed by local interest groups.

Organizational Barriers to Municipal Solid Waste Energy

A municipal government faces first the barrier of a lack of awareness regarding local potential for turning municipal solid waste into useful energy. Neither the members of a city council, nor a mayor, nor a city manager, are likely to be familiar with the technologies involved, or the quantities of solid waste available. The responsibility for providing such information to the municipal government may be delegated to the city engineer, or the director of a department of public works. But this does not really solve the awareness problem. It is likely that a request for information to the appropriate agency will come only after the government has become aware that some potential may exist.[1]

Once an awareness has developed, the community is unlikely to have the technical or economic skills necessary to determine whether a project is feasible. A consultant may then be hired to perform a feasibility study that identifies available technologies, expected capital and operating costs, expected revenues, likely environmental impacts and regulations which will have to be met, and the sequence of permits, which must be obtained. However, since consultant fees may range up to $400,000, a financial barrier may arise unless the community can obtain state or federal supporting grants.[2]

A third potential barrier lies in the requirement that the municipality ensure the availability of sufficient solid waste fuel of consistent composition for the life of the proposed plant. Since an economically sound project requires a large capacity plant, consuming 800-1200 tons of refuse per day, all but the largest municipalities must supplement internally collected refuse with that from neighboring communities.[3] This requires the negotiation of contracts either with the neighboring communities, or the private refuse collection firms that serve them. Complications may arise if a neighboring community served by a private firm has retained, in its contract with that firm, the right to resource recovery -- i.e., the right to extract ferrous metals, aluminum, and glass for resale if it so desires. In some cases the sale of these recyclables may make a marginal MSW project economical; in all cases the existence of this right means that negotiations must be carried on not only with the private collection firm but the neighboring community.[4]

A different barrier to supplementing internal trash sources arises when neighboring municipalities simply refuse to provide waste for the project, either because they want to develop their own project, they oppose having an MSW plant located nearby, or they find landfilling a cheaper alternative. Still another related complication centers on the need to guarantee consistency in refuse composition for the lifetime of the project (to ensure that the fuel value remains sufficiently high). This may require projections of the growth in residential, commercial, and industrial populations in the refuse source area over the next twenty or thirty years.

The question of where to locate an MSW plant may pose another barrier. The most likely candidates for MSW projects are large urban areas where available land is in high demand. Even when the municipality owns land that could be devoted to an MSW plant, competition may arise from other groups desiring to see that land used for parks, parking lots, schools, or some other public project.

Should all the aforementioned barriers prove surmountable, the municipality may face a simple but crucial barrier in terms of its own ability to coordinate the development effort. In addition to obtaining grants for a feasibility study, contracting for a reliable refuse supply, and dealing with land use controversies, the municipality must work closely with an engineering consultant to develop a detailed facility plant, prepare environmental impact statements and reports, obtain building permits from local or county planning agencies, obtain operating permits from local air pollution control boards and water control boards, negotiate a site for ash disposal, obtain various permits from the Army Corps of Engineers (for coastal impacts) and Federal Aviation Administration (for cooling towers and smokestacks), and prepare a bond issue to finance the project. A municipal employee must have the time and skill to keep the project on schedule.

Finally, a municipality faces a potential barrier in terms of public support. Because an MSW project will be expensive (about $70 million for a 1000 ton-per-day plant) the most likely form of financing is via sale of municipal bonds, whose issuance requires approval by a majority of voters in a bond referendum. Obtaining majority approval may pose problems because of the project's high cost, the unfamiliarity of the public with the new technology, and the controversies regarding land use and likely impacts on health, safety, and the local environment.

Overcoming Municipal Barriers

Lack of awareness of solid waste resources and waste-to-energy technologies is not a problem in municipalities that are encountering difficulties in landfilling their waste at a reasonable cost. The high cost of landfilling has spurred interest in MSW projects in a number of California cities.[5] In areas where landfill costs have not stimulated public awareness, county or regional solid waste management boards could collect resource and technology availability data and provide it to municipalities, perhaps with recommendations for MSW developments in appropriate central locations. Some state funding for this coordination effort would be appropriate. Alternatively, this information could be collected and disseminated by a state agency.

The technical work involved in development of an MSW project is best handled by a consultant, as noted above. State and federal grants such as those made available for six California projects would be appropriate when local governments cannot afford the expenditure.[6]

Difficulties in ensuring a reliable supply of refuse of consistent composition for the life of an MSW plant stem from two causes: first, the possibility that the local refuse supply may change, and second, the need to augment local supplies with those of neighboring jurisdictions. The former problem must be dealt with by two actions. First, projections of local residential, industrial, and commercial growth over the life of the project must be performed. Assuming that the quantity and composition of input into the refuse stream can be estimated on a per-capita basis (for the residential sector) and on a per-employee basis (for the industrial and commercial sectors), the growth projections can be used to estimate the availability of local refuse resources at particular future times. These estimates would probably best be performed by a state office of planning or economic development, or possibly by a state office responsible for solid waste management. However, there remains the possibility that changes in society's packaging practices might also impact future refuse availability and composition, and predicting these effects with any reliability will be impossible. Therefore, the net impact of all potential changes will be somewhat uncertain, but obviously risky projects should be identified, and their development cancelled or delayed.

The need to augment local refuse with that of neighboring cities or towns poses an equally complicated barrier. A neighboring municipality may oppose an MSW development for several reasons noted above, or it may demand compensation for the value of recyclable materials included in its refuse, particularly if a right to resource recovery has been included in its contract with a private collection firm. State law could be employed to eliminate these potential barriers but a negotiated solution would be preferable. The best state policy would be to encourage such negotiation, perhaps under the auspices of county or state offices dealing with solid waste management.

The problem of insufficient personnel-time to manage and coordinate the development effort is best overcome by allowing municipalities to utilize state or federal grant money to hire an individual for this purpose. Indeed, a municipality engaged in a development effort is likely to incur expenses other than salary expenses that it might need to have offset by a grant. Hiring an employee to manage the development is reasonable since the project may take several years to bring to completion; on the other hand, hiring full-time personnel to perform the technical analyses that otherwise would be contracted to a consultant is not reasonable since that work should require no more than a few months.

Ensuring public support for an MSW project requires that the members of the municipal government obtain adequate publicity in the local media of the benefits that the project will provide. It would be helpful if the benefits were translated into terms that the public can appreciate. For example, a reduction in landfill costs could be translated into lower taxes or the deferral of a planned tax hike. The energy derived from burning the refuse could be translated into so many barrels of oil saved, or so many more gallons of gasoline available for motor vehicles. A fair presentation of the costs involved should also be made, and members of the city council or mayor's office should be prepared to debate opponents of the project. The effort to develop public support should not be slighted, and should be started early in the project, especially if it will be subject to approval by referendum.[7]

Organizational Barriers to Wind Energy

Private firms intending to develop community wind power systems will be familiar with the technologies involved and the economic opportunities they face. Because such firms are likely to be staffed by entrepreneurs with a technical background, however, they may be incompletely aware of the process of doing business in a highly regulated environment, and the procedures for dealing with large and bureaucratic electric utilities and regulatory agencies. Moreover, although they are certain to become aware of the relevant procedures quickly, their small size may make it difficult for them to devote sufficient manpower to utility and regulatory relations.

There is also the possibility that small firms will lack the capability to adequately assess the precise wind resource in a given community. Where they do possess the capability, performing the assessment may take at least a year, since wind strength must be measured over all seasons. This will both slow development and impose high initial costs on a firm that may not be able to absorb them.

A third organizational problem for a community wind firm may be a lack of political support both at the local and state level. Where zoning variances are required for the placement of wind turbines, or transmission lines are required for connection with a utility grid, obtaining the necessary permits may be somewhat more difficult for a firm that has little or no political influence. And again, even if the lack of political influence proves unimportant, any long delays in a permit process could put a small firm out of business. Large firms with substantial resources and adequate cash flow are much more able to survive long delays.

Overcoming Wind Barriers

Private wind entrepreneurs would benefit significantly if the rules and regulations by which they must sell electrical energy to utilities were standardized, and made available in a form understandable by individuals not trained in regulatory law. At present this entire area is in a state of flux. Stimulated by the passage of the Public Utilities Regulatory Policies Act of 1978, the Federal Energy Regulatory Commission (F.E.R.C.) and state public utility commissions are now revising the rules under which energy sales from small power producers to electric utilities take place. The new rules are intended to stimulate such sales, and consequently in the future the regulations that a private entrepreneur must meet should impose a far lighter burden than at present. Detailed discussion of this issue follows in the next section (Interface Barriers).

Assessing local wind resources will remain a problem for community wind developers unless someone else analyses the resource and makes available information on average wind speed and variability. The federal government has financed similar resource studies of solar insolation, while in California the state legislature has recently appropriated an additional $800,000 to complete an inventory of the state's wind resources initiated earlier.[8] No other state in Federal Region 9 has yet begun a similar wind survey, but it would appear that the only obstacle to their doing so is financial. How this barrier may be overcome in different states will depend upon the influence and power of the various interested parties.

Lack of political support is not an organizational deficiency susceptible to correction by government intervention, since the ability to mobilize friendly intervention is precisely what the deficiency involves.[9] Rather, the solution is for wind developers to create a formal trade association, similar to and perhaps affiliated with the Solar Energy Industries Association.

Organizational Barriers to Industrial Cogeneration

Industries with a desire to cogenerate are already involved in producing steam for their industrial processes. Consequently they are more likely than not to possess an engineering staff capable of attaching a turbine-generator to their existing steam system. A possible barrier may arise if the engineering staff is small and lacks the time required to devote to an installation effort.

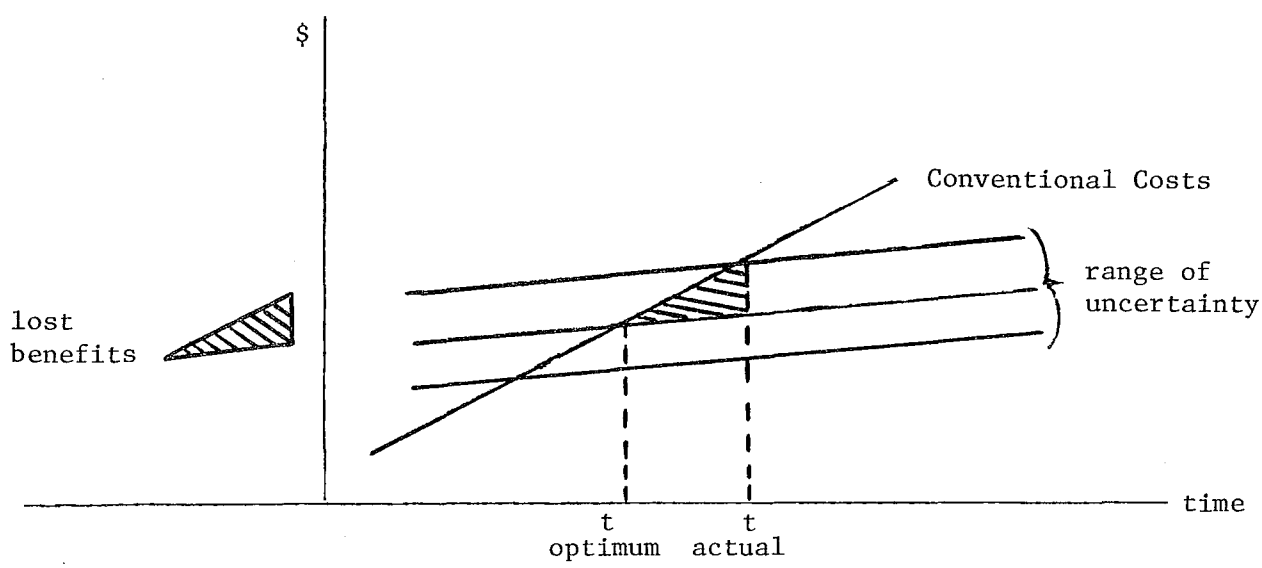
Plant management's unfamiliarity with cogeneration and the uncertainty regarding its reliability could pose another barrier. In some industrial processes the cost of a power outage, in terms not only of lost production but damaged product, is perceived to be much larger than the potential energy savings.[10] Even if the process produces output not subject to damage, management may be slow to accept cogeneration because it is an added responsibility and because electricity production is not something they are trained to engage in.

A third barrier to industrial cogeneration is the difficulty a given plant's managers may have performing an economic analysis of a proposed cogeneration investment.[11] This results from unfamiliarity not only with cogeneration technology, but with the pollution control devices and environmental regulations required for its operation.[12] This uncertainty will tend to cause risk-averse managers to postpone commitments to cogeneration until well past the optimum time, as shown in Figure 1. In the meantime, both private and social benefits are lost.

The requirements of interacting with electric utilities and state regulatory agencies pose a fourth organizational barrier to cogeneration.

FIGURE 1

UNCERTAIN COSTS LEADS TO LOST BENEFITS



Like private wind developers, firm management will initially lack knowledge of regulatory procedures and the details of interacting with electric utilities. Technical managers may wish to avoid becoming responsible for these relations because of their legal nature, and may lack the administrative staff to study them. Similar arguments can explain management's possible reluctance to face the complexities of environmental and fuel allocation regulations, tasks for which they are similarly unprepared.

Overcoming Cogeneration Barriers

No incentive is recommended for overcoming the barrier of insufficient engineering staff. An industry seeking to install cogeneration facilities could hire an engineering firm to perform the work, if necessary. The provision of such services by government has no precedent; cost subsidies for the entire project can be provided via tax code changes. This will be discussed later (Financial Barriers).

The problem of unfamiliarity with cogeneration technology requires that industrial management be educated. Information is already available in publications from the Department of Energy (DOE) and by technology manufacturers.[13] Education is best performed by professional associations rather than the government since executives are more likely to be influenced by their peers than by government.

The performance of confident cost-benefit analyses is complicated by uncertainties regarding the future price of energy, the price that cogenerated electricity may be sold for, and the nature and cost of environmental regulations that must be met.[14] While information that can clear up much of these uncertainties exists, it is not routinely collected by potential cogenerators, and the cost of obtaining it may be sufficient to eliminate interest. One solution would be to have regional offices of the Department of Energy provide relevant data, taking care to keep it up to date. Another alternative, recently adopted by the California Public Utilities Commission, requires the Pacific Gas and Electric Company to develop a financial analysis program for use by potential cogenerators, and to provide appropriate information regarding environmental regulations that have to be met including the cost of meeting them.[15] Alternatively, other agencies of state government could be assigned these tasks, depending upon the particular interests, responsibilities and powers of the legislature and regulatory agencies of a given state.

As discussed with regard to wind power development, the regulations that

small power producers must adhere to are now being revised to make small power sales simpler and less costly to the producers involved.

Organizational Barriers to Residential Photovoltaics

The DOE-sponsored National Photovoltaic Conversion Project has determined that the most cost effective method to implement photovoltaic power systems will be to mount the arrays on residential rooftops.[16] Provided that the rooftops face south, it is not necessary to purchase land and build supporting structures upon which to lay the solar cells. The cost of land and support structures may come to dominate the cost of photovoltaic systems if largescale reductions in the cost of cells are realized.

The typical homeowner is subject to a number of barriers that may slow the spread of photovoltaic rooftops. First, the homeowner is unlikely to understand the technical activities required to install a photovoltaic system. Even with a good understanding, carrying out the activities is likely to require the skills and tools of an electrician. Armed with these capabilities, the homeowner must still have a clear understanding of the legal barriers he or she faces, primarily local zoning regulations, before installing a system. In some cases the homeowner may have to seek clarification of those regulations or a variance from them. Finally, once a system is installed, maintenance will be required. A homeowner not adept at such tasks may judge them a sufficient disincentive even if all other barriers are removed.[17]

Because of these installation problems, and because of the requirement that the rooftop be south facing and capable of supporting a photovoltaic array, it is likely that new housing will provide most of the sites for photovoltaic systems. In this case, the barriers to residential photovoltaics will actually exist within new home building organizations. It is the homebuilding industry that will be called upon to seek clarification of or variances to local zoning regulations and that will install the photovoltaic systems.

There is no reason to believe that small homebuilders will be any more understanding of photovoltaic technology than homeowners. While the installation of solar systems could be subcontracted to electrical contractors, the builders are not likely to be interested in doing so for a number of reasons.[18] Foremost among these will be a desire to avoid the risk that photovoltaic-equipped housing will not sell, or will sell more slowly than conventional housing.[19] Second will be a desire to avoid increasing the per-unit cost of construction. Given the limited borrowing credit of most small homebuilders, the greater the

per-unit cost,the fewer the units that can be built. And while fewer units may not necessarily mean lower overall profit, there is some evidence that is does. Builders will prefer not to take the chance, since their small size means that even a minor drop in profit may put them out of business.

A third objection of some homebuilders will stem from the need for an additional inspection of each new home. Whether the inspection is performed by a public utility company technician, or the local building inspector, the builder will view it as another obstacle to the sale of the property.

The need to orient all rooftops in a south facing direction will be opposed by builders who could otherwise put up more units on a given tract of land. A related objection is that the single orientation will impose a monotonous pattern upon a development, making it less attractive to potential buyers. Alternatively, additional landscaping or other architectural features could be used to disguise the monotony, but these might increase the cost of the homes.

Overcoming Residential/Builder Barriers

The organizational barriers to the development of residential photovoltaic systems will be significantly reduced by the development of modular and standardized systems. These systems are likely to become available as demand for photovoltaic systems grows, and their spread will be comparable to that of central heating and air-conditioning systems in the 1960's. Much of the work may be performed by contractors with skills similar to those involved in the former innovations. To ensure that installation is performed accurately, and to build homeowner confidence, state certification dependent in part upon the contractor's willingness to warrantee the work for an appropriate period of time might be utilized (although care should be taken to prevent certification from becoming a barrier to entry of new contractors, as has occurred in the past with other occupations).[20] Alternatively, electric utilities could be allowed to install and maintain the systems, and provided with a fair return on their investment through rate-basing.[21]

Zoning codes defining any limitations on the deployment of photovoltaic systems will develop as the systems come into use. If these codes appear to be unnecessarily restrictive, state legislation could set limits on how restrictive the codes might be. Such legislation would be similar to the various solar rights acts that have been passed in California and Arizona.[22]

The requirement that rooftops be south-facing will be likely to meet declining resistance from builders as the demand for all types of solar systems

increases, and as experience is gained in communities like Davis, California, where such local ordinances already exist. If it appears that local real estate and building interests can prevent the widespread adoption of such ordinances, some state legislation might be required. Alternatively, state or local laws could be passed requiring that all new homes possess photovoltaic rooftops -- similar to the regulations now in effect in cities like San Jose and San Diego that require solar water heating in all new homes.

The resistance of builders to constructing homes with photovoltaic rooftops could be overcome by a variety of state or local laws, but a softer form of persuasion would be better. In this respect standardized technology would again prove valuable. This implies that the development of such technology should be underwritten by a state or federal research and development effort.[23] At the same time, government-sponsored workshops explaining the installation of rooftops would be useful. Homebuilder fears that photovoltaic-equipped homes will not sell as rapidly as conventional homes could be offset by the provision of "solar mortgages" -- mortgages in addition to those conventionally offered by lending institutions -- to cover the additional cost of solar equipment. Finally, homebuilder objections to the need for an additional inspection could be met by appropriate revisions to local building codes requiring that inspection be completed within a certain time frame.

Summary of Organizational Barriers

The significant barriers to development of each of the four technologies reviewed in this section, and the policy options available to government to overcome them, are listed in Table 3. Of these, five deserve special attention.

Municipalities are almost certain to require financial assistance from state or federal government to cover the costs involved in a feasibility study for a municipal solid waste plant. Even large municipalities are subject to serious budget restrictions at present (in some cases more so than smaller communities). In addition to consultant fees for a feasibility study, local governments will face additional development costs that may total several million dollars before the time when they are able to issue bonds. (Once bonds have been issued, of course, further funding problems are eliminated.)

Ensuring an adequate fuel supply may require state assistance if neighboring jurisdictions, whose solid waste is required, will not cooperate with a municipality engaged in an MSW development. A state agency could be given responsibility for establishing solid waste "resource districts" and perhaps the power

to offer an MSW franchise to any municipality in the district. Interested municipalities could then bid for the franchise by indicating the amount of state financial assistance they would require to pursue the project. The community offering the lowest bid would get the franchise.

All four community energy systems under study would interface with electric utilities. Consequently the barriers affecting utility and regulatory relations are especially important. While the F.E.R.C. and some state public utility commissions (notably California, but not the other states in Federal Region 9) are moving to eliminate the barriers, more work in the future will be required. Additionally, because of the possible recalcitrance of electric utilities, enforcement of fair sales contracts should be performed via routine reviews of utility/small power producer relations in each state.

Industrial management must become more cognizant of cogeneration opportunities. For the immediate future, cogeneration offers the single largest source of supplemental energy supplies available to the U.S. Consequently an effective program of information and education is required.

Residential homeowners appear least likely to possess all the skills required to install a residential photovoltaic system. Special assistance in the form of a state or utility-run installation program should be investigated. Standardized system development would help lower costs and simplify installation, but mass production of such systems may not be economical unless a definite installation program exists that can guarantee a market. Some creative program design is required to ensure competitive installation which will, in turn, stimulate product quality at minimum cost.

Footnotes

1. In many communities an Energy Committee of the Town Council has been set up. This may help overcome at least the awareness barrier.

2. The $100,000 - 400,000 covers only consultant fees for a feasibility study. Should that show the project worthwhile, additional consulting work would be required, as would the hiring of an engineering firm to design a facility. These costs could add several million dollars to the total amount that would have to be spent before a bond could be issued. A municipality might obtain a short-term loan for these costs, repayable through funds obtained in the bond issue. But this is relatively risky financing: if the project fell through, there would be no bond issue and the community would be left with a large debt to repay in a short time.

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4. For example, the City of Alameda, one of six California municipalities engaged in MSW developments, must negotiate with Oakland scavenger, a private collection agency serving Oakland, and with the City of Oakland, which has a right to resource recovery. Although the alternative to providing refuse to Alameda for Oakland scavenger will shortly become a 76 mile round-trip haul to Altmont, and although the City of Oakland is not now making use of its right to resource recovery, neither are apparently being overly cooperative. --Personal communication from Bob Boshoven, Bureau of Electricity, City of Alameda, December 1979.

5. This is particularly true in San Francisco, Berkeley, and Alameda. Central Contra Costa Sanitiation District has a different reason for investigating an MSW-to-gas facility: the state Public Utilities Commission has indicated that it must develop alternative fuel sources for its wastewater treatment plant (in other words its gas allotment may be cancelled in the early 1980's).

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to offer an MSW franchise to any municipality in the district. Interested municipalities could then bid for the franchise by indicating the amount of state financial assistance they would require to pursue the project. The community offering the lowest bid would get the franchise.

All four community energy systems under study would interface with electric utilities. Consequently the barriers affecting utility and regulatory relations are especially important. While the F.E.R.C. and some state public utility commissions (notably California, but not the other states in Federal Region 9) are moving to eliminate the barriers, more work in the future will be required. Additionally, because of the possible recalcitrance of electric utilities, enforcement of fair sales contracts should be performed via routine reviews of utility/small power producer relations in each state.

Industrial management must become more cognizant of cogeneration opportunities. For the immediate future, cogeneration offers the single largest source of supplemental energy supplies available to the U.S. Consequently an effective program of information and education is required.

Residential homeowners appear least likely to possess all the skills required to install a residential photovoltaic system. Special assistance in the form of a state or utility-run installation program should be investigated. Standardized system development would help lower costs and simplify installation, but mass production of such systems may not be economical unless a definite installation program exists that can guarantee a market. Some creative program design is required to ensure competitive installation which will, in turn, stimulate product quality at minimum cost.

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8. The analysis of wind and solar resources is a subsidy to firms engaged in activities related to those fields, and therefore the information has a value and could have a price. However, the federal government has traditionally provided a great deal of information on resource availability to resource developers -- most notably in the Landsat resource mapping programs. The information produced is usually made available at a nominal cost. There seems no reason to change the rules of the game now.

9. In California the Office of Planning and Research is responsible for assisting developers of various sorts meet the regulatory requirements of the California Environmental Quality Act. Under A.B. 884 (effective 1/1/78) O.P.R. is authorized to help coordinate the regulatory review process. Various time limits were set by which reviewing agencies would have to inform a developer whether or not the relevant regulatory requirements had been met in the development proposal, and if not, what changes are required. This will mitigate the problem of little political influence, at least in California.

10. "Industry Wary: No Rush to Cogeneration," Industry Week, 4/4/77.

11. Different industries tend to calculate the benefits of cogeneration differently, although there is no clear reason for doing so. See: "Energy Paybacks Draw More Attention," B.J. Feder, Energy User News, 11/27/78. Also: "Capital Investment to Save Energy," G.N. Hatsopoulos et al, Harvard Business Review, March-April 1978.

12. See: Decision 91109, California Public Utilities Commission, 12/19/79, page 29. This document may be obtained from the Process Office, California Public Utilities Commission, 350 McAllister Street, San Francisco, California.

13. For example: "Gas Turbines and Cogeneration," The Garrett Corporation, 9851 Sepulveda Blvd., Los Angeles, California, 90009. "Cogeneration: Technical Concepts, Trends, Prospects," U.S. Department of Energy, Division of Fossil Fuel Utilization, 400 First Street N.W., Washington, D.C. 20545. Publication No. DOE-FFM-1703 (free).

14. An additional factor which may complicate the analysis is concern that the federal government may impose rationing at some future date under a system whereby the industry receives a certain percentage of its historic level of use. This provides an incentive to industry to consume more, thus keeping up its historic level of use. See: Energy Future, Robert Stobaugh and Daniel Yergin, editors, New York, 1970, page 157.

15. Decision 91109, California Public Utilities Commission, 12/19/79, page 44.

16. Personal communication from Gary Jones, Sandia Photovoltaic Project, August 1979.

17. An additional consideration is the mobility the typical homeowner If the payback period on a photovoltaic system is twenty years, but the typical homeowner moves every six years, a large portion of those homeowners may not want to invest in a costly rooftop system. See Energy Future, op. cit., page 172-3.

18. See: "Community Impediments to Implementation of Solar Energy," Marilyn Duffey-Armstrong and Joe E. Armstrong, SRI, 1979.

19. Solar equipped housing may sell more slowly than conventional housing for two reasons. First, buyers purchasing homes with federally insured morgages that have loan ceilings will want to purchase as much real housing as possible; to the extent that a loan ceiling means they will have to give up some amenities to pay for an energy system, their desire to do so will naturally be reduced. Second, private mortgage lenders using standardized guidelines to assess a borrower's ability to repay a loan do not recognize energy as one of the costs to be considered. Although a solar system will reduce a homeowner's monthly fuel bills, and thus increase his or her ability to meet mortgage payments, this increased ability is ignored; while the increased cost of the solar system, if included in the cost of the mortgage, is included. See: Solar Law Reporter, Volume 1, No. 3, Page 777.

20. A state law requiring warrantees for solar installations could solve the problem of reliability, and as of June 1979 such warrantees were required in Maine, California, and New York. Whether this alone is sufficient to build consumer confidence is questionable given the less-than-sterling track record of poorly trained solar installers to date. In California, the California Solar Energy industries Association has established a bonding program which makes available an Installation Warranty Maintenance Bond. This bond may be purchased by customers at a cost equal to 1% of the final contract price, as long as the work is performed by a CALSEIA member. See Solar Law Reporter, Volume 1, No. 1, page 15.

21. According to the National Energy Conservation Policy Act, Section 216, utilities are forbidden from making loans for conservation or solar installations. However, utilities may obtain exemptions, and it is possible that this provision may be repealed (a number of reputable voices have been raised against it).

22. The state of California is currently reviewing all statewide building codes to identify sections that might hinder the use of solar energy. Solar Law Reporter, Volume 1, No. 3, page 775.

23. A representative of ARCO Solar indicated to the California Public Utilities Commission in August of 1979 that ARCO Solar had signed a contract with Johns-Manville to produce roofing with embedded solar cells. This is one step towards standardized systems. More are likely to follow.

INTERFACE BARRIERS

Introduction

Electricity produced by a community energy system, such as municipal solid waste, wind power, cogeneration, or photovoltaics cannot easily be stored in quantity. While substantial research into energy storage is currently being funded by the Department of Energy and other groups like the Electric Power Research Institute an ultimate solution is not yet in sight. It may even be the case that the problem is never overcome to the extent desired because of unalterable physical laws (at least insofar as chemical storage is concerned). But even if new chemical storage techniques are developed, the likely resource constraints for the materials needed may well limit the applicability and usefulness of the techniques. Other forms of energy storage face other constraints; the one most commonly utilized, pumped hydro, is constrained by a lack of appropriate storage sites. Moreover, matching a wind turbine or rooftop photovoltaic system to a pumped hydro facility involves an obvious mismatch in scale. In light of these it may be useful to redefine the United States' energy situation as both a supply and storage problem. In the past, conventional fuels provided both the supply and storage of energy although the latter generally went unremarked.

The best solution to the problem of storing electricity from distributed sources is to feed it into the electric grid of the local utility. Problems are bound to arise when a small energy system is coupled with a utility grid, the most important being the price the utility will pay to the small producer. An evaluation of this and other interface issues is the subject of the present section.

Credit should be given at the outset to the California Public Utilities Commission (hereafter C.P.U.C.) and to Pacific Gas and Electric (PG&E). Both have provided extensive information in the form of written reports and personal communications. On September 6, 1978, the C.P.U.C. formally initiated Order Instituting Investigation 26 (OII 26), an "investigation into the electric resource plan and alternatives of Pacific Gas and Electric Company." Throughout 1978 and 1979 both the C.P.U.C. and PG&E developed information on the issue of small power producers interfacing with the utility's grid. The result was substantial mutual understanding of the interface barriers, and potential means for overcoming them.[1]

To some extent, then, this paper is a case study -- and of a significant case: not only is PG&E, the largest consolidated utility in the nation, but the C.P.U.C. is one of the most vigorous state commissions in terms of pursuing new

conservation and alternative energy programs. Furthermore, although the C.P.U.C.'s investigation focused on only one utility, in the past its decisions have, when appropriate, been routinely extended to the other major electric utilities in the state.[2] It is not unlikely that in the future other state commissions and electric utilities will model their responses to the problems reviewed here in a similar way.

This discussion goes beyond the California case study in looking at some additional barriers created by the peculiar attributes of the four technologies under study. These will be addressed in a later section.

The Purchase Price

The purchase price is the amount that an electric utility will pay to a small power producer who delivers energy and, in some cases, capacity to the utility system. Energy, as the term is used here, is simply electricity measured in kilowatt-hours. Capacity is a measure of reliable output; an industry that agrees to feed 5,000 kilowatts of electricity continuously into the grid is providing firm, reliable power that is worth more than an unpredictable number of kilowatt-hours dumped into the grid at an unpredictable time.[3]

The purchase price that an electric utility is willing to pay a small producer has been recognized for some time to be the critical determinant of the economic viability of small energy systems. A brief review of the history of this issue will make the current situation more understandable.

Purchase Pricing the Recent Past

Until the present, the purchase prices offered by electric utilities were so low that they offered no incentive to a potential small energy developer to go into business.[4]

Foremost among the reasons for low purchase prices was the desire of the utilities to avoid encouraging competition in the power generation field. This was a predictable position motivated by several considerations. First, if an external firm produced power, the utility would have less reason to expand its rate base. The rate base is the yardstick by which a private utility's profit is determined.[5]

Second, utility management is often conservative, preferring to rely upon technologies they are familiar with, and that have worked well in the past. Considering the support most large utilities have given to nuclear power, however, this conception may be only partically correct, since nuclear is itself a new and not always reliable technology.[6] Perhaps another motive for utility management's

conservative bias stems from the fact that the field of electricity generation has always been organized as a regulated monopoly. To promote competition is directly counter to the rules of the game as they have always been played.

Another way of viewing utility management is to see it as a group with a strong sense of mission; electricity generation is their right and responsibility, and a job that, until the mid-70's had been performed with ever-increasing efficiency. This was reflected both in falling electricity rates and in the high prices at which utility stocks sold.[7] It is likely that many utility executives felt pride in the accomplishments of their firm and the electric utility industry. Hence the generally negative reaction to individuals who were at once severe critics of the industry and at the same time advocates of small power production may partially be explained as the product of wounded pride.

A third motivation for keeping purchase power prices low stems from the difficulty of managing multiple generation sources. Load management is a complicated business even when small numbers of large generating units are considered. With large numbers of small units the management problem is bound to be more complicated, especially if those units are not all easily dispatchable.[8] From an administrative point of view, the requirements for maintaining contracts and communications with many independent power producers will impose new overhead costs upon the utility, which in turn will be forced to seek reimbursement through higher rates. Ultimately neither load management nor administrative problems are insurmountable, but do require a utility to change its standard operating procedures after decades of relying upon -- and in some cases being shaped by -- the old original ones.

State public utility commissions also did little to encourage the development of small power production in the past. Their purpose is first and foremost to ensure that ratepayers obtain high quality service at the lowest possible price.[9] For a very long time no small power producers could deliver energy more cheaply than a regulated utility. Consequently, even if a utility had made a substantial effort to promote small power production the state commission might have disallowed associated expenses, considering them the product of poor management, and detrimental to the interests of the ratepayers.[10]

Another reason for the inactivity of state commissions on this issue stems from the fact that in many states the regulatory agencies were "captured" by the utilities they were designed to regulate.[11] This need not be taken as an indication of corruption in the regulatory process, since it is often the case that individuals dealing with specific policy issues come to accept common goals, no matter which side -- utility or regulatory agency -- they represent.[12] But

an unfortunate consequence of this situation is the dulling of analytical sensitivity, and a tendency to fall back upon old solutions to new problems -- even when the old solutions are no longer appropriate. This problem tends to be most severe when the old approaches worked well for a very long time, as was the case with electric utility regulation.

Lastly, the purchase prices offered by the local utility must be judged in comparison with the standby rates the utility charges. Until the present small producers have been exclusively industrial cogenerators, who have generated power for internal use, selling any excess to the utility. At times when its own facilities were not operating, the cogenerator would have to purchase power from the utility. In order to do this, the cogenerator would have to pay relatively high standby rates, whose economic function was to compensate the utility for providing backup service.[13] However, guidelines for standby rates were either poor or non-existent, and there was nothing to prevent utilities from making these rates higher than actual cost justified. The resulting net benefits to a cogenerator were even smaller than the low purchase prices suggested.

In summary, a combination of factors including utility management practices and regulatory disinterest, but dominated by increased efficiency in conventional power generation, led to a drop in the share of U.S. electricity produced by small power producers (primarily cogenerators) from 15% in 1950 to about 5% in 1975.[14] This drop was a direct response to low purchase power rates and high standby rates.

Current Issues of Purchase Pricing

In 1978 Congress passed the Public Utilities Regulatory Policies Act (P.U.R.P.A.) that recommended that state public utility commissions review a variety of electricity pricing issues, including the prices at which electric utilities sell and buy electricity.[15] Sections 201 and 210 directed the Federal Energy Regulatory Administration (F.E.R.C.) to develop federal regulation necessary to promote the development of small power production. While the language of the Act was considerably weaker than that originally proposed, the regulatory agencies in some states and at the federal level have pursued Congress' recommendations so vigorously that many critics of the weak language may now be more satisfied than they ever expected to be.

In developing rules to implement Section 210 of P.U.R.P.A., F.E.R.C. adopted the notion of "avoided cost" that is, electric utilities should be willing to pay small power producers an amount up to what it would cost them to obtain energy and capacity from their next least expensive source.[16] Thus the

avoided cost to the utility can be either the cost of generating additional electricity from new facilities, or the cost of purchasing it from another supplier such as the Bonneville Power Authority.

The concept of avoided cost is very similar to the concept of marginal cost, i.e., the cost of producing the next unit of a given commodity. The staff of the California Public Utilities Commission argued in OII 26 that PG&E should pay small power producers a purchase price equivalent to its marginal cost.[17] The economic rationale for establishing purchase prices equal to marginal or avoided cost is that only by doing so are society's resources efficiently allocated.[18] As a simple example, if it costs a utility 10 cents to generate one more kilowatt-hour of electricity, and a cogenerator can produce it for 5 cents, society as a whole is better off if the cogenerator produces the electricity, since twice as much can be obtained for a given amount of money. The resulting savings in money or resources may then be put to another productive use.

During the latter part of 1979 the idea of matching purchase prices to marginal cost continued to gain ground. In August, while OII 26 was still in progress, PG&E made a new offering to small power producers under which it agreed to pay according to its marginal cost. A few months later the staff of the C.P.U.C. issued a draft procedure for calculating marginal costs.[19] On February 19, 1980, the F.E.R.C. issued its final rule implementing Section 210 of P.U.R.P.A., effective March 20, 1980.[20] This rule requires that each state regulatory authority adopt a set of standards for purchase prices by March 20, 1980.

The heightened interest in small power production on the part of both regulatory commissions and utilities derives naturally from the recent rapid cost increases for conventional fuel, as well as from the difficulty utilities have been having of late in raising capital for new construction.[22] For the public, increased use of alternative energy systems means reduced dependence upon foreign oil, greater economic security, a reduced balance of payments deficit, the development of new energy industries providing new jobs, and in some cases a reduction in fossil fuel pollution. As protectors of the ratepayers' interests, state public utility commissions find alternative energy systems that are cost competitive to be attractive means for keeping electricity rates lower than otherwise. Moreover, as the public has become increasingly dissatisfied by a seemingly endless series of utility rate hikes, regulatory commissions have become more assertive in demanding that the utilities look at potential low-cost alternatives. For utilities, the benefits stem from having other groups invest

capital in electricity generating technologies, thus spreading the burden that utility management and stockholders are finding increasingly difficult to bear. Indeed, current interest rates make raising capital nearly impossible for any electric utility because their allowed rates of return are lower than investors can earn elsewhere, and because falling demand makes long-term borrowing at high interest rates a very unattractive gamble.

The central reason why small power production has now become cost competitive is high fuel prices. Conventional power plants running on fossil fuels have no alternative but to pay the increased prices. But energy systems such as wind and photovoltaics, which do not utilize fossil fuel, have incurred no similar cost increases. Thus the cost per kilowatt-hour for conventional power has now become as expensive as the cost per kilowatt-hour for alternative systems. Cogeneration, while relying upon fossil fuel, is exceptionally energy efficient. Consequently the cost of its output has not risen as much as that of conventional power plant, leaving it once again cost competitive.[23] In short, the great success of conventional electricity generation in the 1950's and 60's, which resulted from substantial returns to increases in scale, has been undermined by the huge fuel price rises of the 70's. Now returns come to fuel efficiency, precisely the area in which cogenerators and other small power producers excel.

Electric utilities do not have to find the process of developing greater reliance upon small producers an unattractive proposition. The C.P.U.C. has the legal right to vary a utility's rate of return by one-half to one percent, as a means of rewarding or penalizing it for actions in or opposed to the public interest.[24] Several years ago PG&E received an increase in its rate of return because of its cooperation in promoting energy conservation. During OII 26, the staff of the C.P.U.C. recommended that the utility be penalized a similar amount for insufficient effort to promote cogeneration -- which the Commission had earlier ordered it to do. It is possible that if the new contract offering by PG&E attracts a significant amount of small energy development, the utility might again receive a positive increment to its rate of return. Since the use of such rate-of-return inducements is available to most state public utility commissions, similar actions in states other than California is a distinct possibility.

PG&E's New Offer for Energy and Capacity

Pacific Gas and Electric's new contract is designed for use with industrial cogenerators and municipal solid waste plants producing electricity. Its principles can easily be extended to wind and photovoltaic power producers, and

the contract as a whole might serve as a good model for other electric utilities.

Separate payments are offered for energy and capacity. Energy is simply the number of kilowatt-hours dumped into the utility's grid; a meter would be attached to the small power producer's facility to monitor its output. The value of the kilowatt-hours varies according to the time of day and season of year in which they are produced. For the second quarter of 1980 (May - July) the following energy purchase prices are in effect:

	May 1 to September 30	October 1 to April 30
On-Peak*	5.675¢/kwh	5.450¢/kwh
Partial-Peak	5.459	5.150
Off-Peak	4.700	4.599

*A definition of these time periods is given in Appendix A to this report.

The basis upon which these rates are established is the average cost of fuel for the preceding quarter; that is, February thru April 1980. The procedure of establishing purchase prices for energy based upon the cost of fuel in the preceding quarter will be repeated every three months, in order that purchase prices match as closely as possible the actual costs the utility avoids through its small power purchase. Thus it is probable that in the future these prices will either rise or fall, since the market prices for oil and natural gas do not appear to be perfectly stable.

Energy purchase prices, it should be emphasized, reflect only the fuel savings that the utility obtains by utilizing input from small power producers, and shutting down one or more of its own facilities. In contrast, capacity purchase prices reimburse the small producer for the costs that the utility avoids by not building a new facility to meet demand growth. The utility avoids these costs when a small producer agrees to provide firm power, and in so doing effectively meets all or part of new demand growth.

Since capacity payments are made to small producers who fully commit their facility's output to the utility's use, the value of that capacity depends upon how closely the facility in question can provide advantages similar to those of a utility-owned generating plant. Of importance are reliability, length of contract, dispatchability, and year of start-up.

To qualify for capacity payments a small power producer must be capable of

providing power to the utility during 80% of peak demand hours. In other words, forced outages at a rate of up to 20% will be tolerated. If a small power producer's unit is less reliable than this rate the unit may be placed on probation and capacity payments withheld until the unit proves itself again reliable. When it does, the withheld payments will be made up, and regular payment resumed.[25]

Length of contract is important because of the long lead time required to plan, site, build, and obtain operating permits for a conventional power plant. Utilities may often have a planning horizon of twenty years, and if small producers agree to contracts of at least five years then the small facilities can be effectively incorporated into the utility plan. The shorter the contract, the more uncertainty is injected into utility plans. For example, the utility may not know whether a small producer will renew its contract after a few years, and consequently may have to begin work on a utility-owned replacement facility just to be sure not to be caught short. This costs money, even if no new utility facility is ultimately built. Thus, there is an advantage to the utility of longer contracts, which justifies higher capacity payments for them.

PG&E can dispatch (start-up) its own units whenever the load on its system demands. In order for a small power facility to be most useful to the utility it should be equally dispatchable, although it need not be according to PG&E's contract. The seller has a choice of three methods for determining whether it meets its obligations, with full dispatchability required in only one. Capacity payments under either of the other two options are reduced if the standards they impose are not met. Details are presented in Appendix C of the contract.

The year of start-up is important only because it is assumed that capital costs for plants opening farther in the future will be higher due to inflation and regulatory constraints. Consequently PG&E will pay more per unit of capacity as the years go by. Its purpose in advertising higher future capacity payments may partly be to attract more potential sellers, although it must also do so to adhere to a marginal cost pricing formula.

The capacity prices offered by PG&E are stated in Table 4 on the basis of dollars per kilowatt per year. For example, a facility to open in 1981 and agreeing to a five-year contract, can expect to receive sixty dollars per year for each kilowatt of capacity provided. Thus an industry providing 5,000 kilowatts would receive $300,000 per year -- exclusive of energy payments for kilowatt-hours delivered. PG&E indicates that the capacity prices it offers will be modified as necessary should capacity-related marginal costs rise or fall. In addition, the capacity payment made to the small producer will be adjusted upward after a contract

TABLE 3

PG&E CAPACITY PURCHASE PRICES AS OF JUNE 1980

Operational Year	Length of Contract 1	2	3	4	5	6	7
1980	-	-	-	55	56	57	59
1981	-	-	57	58	60	61	62
1982	-	59	60	61	63	64	65
1983	60	62	63	65	66	67	69
1984	63	65	66	68	69	71	72
1985	66	68	70	71	73	74	76

Operational Year	Length of Contract 8	9	10	15	20	30
1980	60	61	62	68	73	81
1981	63	65	66	72	77	85
1982	67	68	69	75	81	89
1983	70	71	73	79	85	94
1984	74	75	76	83	89	98
1985	77	79	80	87	93	103

has been signed to the highest capacity price published before the facility begins operation.

Neither dispatchability nor reliability has explicitly entered into the capacity prices described in Table 4. However, reliability must be demonstrated by three consecutive months of acceptable operation before capacity payments will begin. Dispatchability is accounted for by the three capacity measurement options, as noted earlier. Depending upon the small facility's performance, the capacity payments under these options can be as large as if the facility were fully dispatchable.

Issues Related to Purchase Prices

The higher purchase prices now offered by PG&E must be reviewed in the

context of several related issures in order to determine whether or not they will provide adequate stimulus for small power development. The issues include standby rates, wheeling, simultaneous purchase and sale of energy, time-of-use pricing, curtailment, and the costs of interconnection and system protection facilities.

The issues of standby rates and wheeling have been effectively rendered moot by the adoption of a policy of simultaneous purchase and sale by both the federal and state regulatory agencies, and by PG&E.[26] Under this policy all the energy that a producer generates earns a return in accordance with the purchase prices noted above. At the same time, all the energy that the producer consumes is considered to have been purchased from the utility at the prevailing standard rate. Thus a producer retains his general service connection to the utility and has access to all the power required, with no need to pay standby charges. With regard to wheeling, the concept of simultaneous purchase and sale means that the producer sells all output at the point of generation, and buys all that is desired directly form the utility at the point where it is needed -- rather than wheeling it there. Thus any controversy as to a fair charge for wheeling is precluded.

There are some possible problems with the simultaneous purchase and sale of energy that may have to be cleared up in the future. PG&E's contract states that neither party will be bound by its terms when that party is hindered by a strike, walk-out, lockout or similar problem.[27] Whether any special conditions will attach to this provision will be determined only when the first small producer suffers a strike, walk-out, or lockout. A somewhat different problem could arise during a PG&E system emergency. On such an occasion a seller would be required to provide all output to the system, but PG&E would not be required to provide the seller with power. If the seller is a cogenerator that cannot run its manufacturing process without power, it would then have no use for the steam output of its cogenerating facility. Thus the steam would be wasted, and the cogenerator left in a dissatisfying position. Indeed, although such an eventuality is extremely unlikely to occur, its mere possibility may be enough to cause some industries to forego committing their capacity to the utility, and instead simply deliver non-firm energy. This is all the more likely given that even firms that do not provide capacity are allowed to obtain the benefits of simultaneous purchase and sale.[28]

Time-of-use pricing means that customers pay more for electricity during periods of peak demand, and less during periods of off-peak demand. Such a rate

structure provides incentives to users to move their usage whenever possible to off-peak hours, and in doing so reduce the ratio of peak to baseload demand. According to PG&E, time-of-use rates will encourage cogeneration because cogenerators naturally tend to operate during the day and consequently the benefits of meeting their own peak demand will be substantially greater than under a structure of average rates for all time periods. The exact extent of the difference in rates for different periods is revealed in the rate schedule for general service, reproduced on the following page (Figure 2).[29]

The issue of curtailment could reduce the rate of return on small energy production facilities, and thus make investment less attractive. The issue involves the utility's right to refuse delivery of energy whenever it has available alternative sources of lower cost power.[30] In California the only such source is hydroelectric power, which could lead to curtailment during the spring in years of abnormally high stream flow. Industrial cogeneration and municipal solid waste plants could schedule their maintenance periods during the spring (the contract allows for 35 days of maintenance outage each year, with the capacity payment still made during that period) and thus avoid the curtailment problem. Current PG&E practice is to limit curtailment to 600 hours per year, less than 35 days of full operation, so a carefully scheduled maintenance period could eliminate this potential loss. How curtailment might be handled with respect to the output of wind and photovoltaic systems is unclear, however, since PG&E's contract was not designed with those systems in mind. In all cases some effort should be made to wheel power from small producers to other utilities whenever PG&E cannot use it.

The issue of interconnection costs arises from the fact that in order for a small producer to send output into the utility grid certain metering equipment, lines, step-up transformers, and system protection facilities may have to be installed. Because full avoided costs are being offered to sellers under the PG&E contract, the seller will be required to pay the utility for construction, installation, and maintenance of these facilities. If the utility were to absorb these costs they would comprise an additional subsidy that would result in the utility paying more for purchased power than the maximum allowed under P.U.R.P.A., i.e., more than full avoided cost.[31] Therefore a potential small power producer needs to become aware of the magnitude of these costs through consultation with the utility, in case they should be large enough to make an otherwise attractive investment unacceptable.[32]

Figure 2

Schedule No. A-23

GENERAL SERVICE—TIME METERED

APPLICABILITY

This schedule is applicable to polyphase alternating current service for all customers of record served under former Schedule A-14 on September 20, 1975, to new customers thereafter whose maximum demand in any time period is 4,000 kilowatts or greater, and to existing customers served in accordance with any applicable General Service, Agricultural Power, Refinery, or Standby Service schedule, whose monthly maximum demand is 4,000 kilowatts or greater for 3 consecutive months. Any customer whose aggregate diversified monthly maximum demand at a single service location has fallen below 3,500 kilowatts for any 12 consecutive months may, at his option, thereafter elect to continue to receive service under this schedule or elect to be served under any other applicable schedule.

TERRITORY

The entire territory served.

RATES

	Per Meter Per Month	
	Period A	Period B
Customer Charge:	$715.00	$715.00
Demand Charge:		
On Peak, per kilowatt of Maximum Demand	$4.20	$2.80
Plus Partial Peak, per kilowatt of Maximum Demand	0.35	0.35
Plus Off-Peak, per kilowatt of Maximum Demand	No Charge	No Charge
Energy Charge:		
On Peak, per kilowatt hour	$ .01045	$ .01045
Plus Partial Peak, per kilowatt hour	.00845	.00845
Plus Off-Peak, per kilowatt hour	.00645	.00645

Adjustments:

The above base rates are subject to possible adjustment for voltage and/or power factor. In addition, bills for service will include adjustments, as specified in Parts B and C of the Preliminary Statement, as follows:

	per kwhr
Energy Cost Adjustment	$ .01954
Tax Change Adjustment	(.00071)
Total	$ .01883

SPECIAL CONDITIONS

1. **Time Periods:**

Period A is applicable to meter readings from May 1 to September 30, inclusive, for the following hours:

On Peak	12:30 p.m. to 6:30 p.m.	Monday through Friday, except holidays.
Partial Peak	8:30 a.m. to 12:30 p.m. 6:30 p.m. to 10:30 p.m.	Monday through Friday, except holidays.
	8:30 a.m. to 10:30 p.m.	Saturday, except holidays.
Off Peak	10:30 p.m. to 8:30 a.m. All day Sunday and holidays.	Monday through Saturday, except holidays.

Period B is applicable to meter readings from October 1 to April 30, inclusive, for the following hours:

On Peak	4:30 p.m. to 8:30 p.m.	Monday through Friday, except holidays.
Partial Peak	8:30 a.m. to 4:30 p.m. 8:30 p.m. to 10:30 p.m.	Monday through Friday, except holidays.
	8:30 a.m. to 10:30 p.m.	Saturday, except holidays.
Off Peak	10:30 p.m. to 8:30 a.m. All day Sunday and holidays.	Monday through Saturday, except holidays.

(continued)

Procedural Issues in Developing a Small Power Facility

The development of a small power facility may take several years of time. Some of the steps involve organizing the potential power producer (or some unit with the relevant institution) to pursue the idea of generating power, performing a feasibility study, obtaining engineering estimates and designs, obtaining the necessary building and environmental permits, and installing the facility.

It is not unreasonable that the electric utility, which is the potential consumer of a facility's output, will have some interest in the development effort. The utility's primary interest should be with those facilities that intend to provide it with firm capacity,since the utility may wish to include that capacity in its resource plan. Additionally, the utility will want to be certain that the technology to be employed will produce quality power, and that the electrical interconnections will have appropriate safety equipment. The utility will similarly have some interest in ensuring that the facility meets all appropriate environmental regulations, and has a reliable, long-term furel supply. Without the latter, the possibility remains that the small power source will be shut down unexpectedly. This could have a negative effect on a utility relying upon it.

PG&E has indicated that it takes the above interests seriously. One part of its contract (Appendix A, Section 3-2) stipulates that the utility must approve the plans for a new energy producing facility. Appendix A, Section 18 also requires that the facility obtain all required governmental authorizations and permits before a contract becomes effective.

If it seems that PG&E may be insisting on too much oversight of potential small power developments, it must also be noted that the utility has indicated a willingness to provide financing for potential cogeneration feasibility studies.[34] The utility has also shown an interest in working with potential cogenerators to identify the steps that must be taken to bring a new facility on-line. While there is some possibility that utility involvement could be obstructionist, particularly in light of the utility's past record, the potential for useful involvement seems significant. Additional experience with PG&E's new program will be necessary before a judgment on this issue can be made.

In addition to the development procedures a potential small producer must go through, a number of operational procedures new to the producer may have to be followed, depending upon the type of facility involved. Appendix A, Section 3-3 of PG&E's contract stipulates that the small producer must make daily telephone reports of hourly meter readings to PG&E's nearest switching center, while Appendix A, Section 4-1 requires the producer to "operate and maintain its

Facility and equipment according to Prudent Electrical Practices." None of these procedures should be considered an attempt by the utility to discourage potential small producers, since they appear to be reasonable and necessary for effective system and interface operation. However, a potential small power producer needs to be aware of all utility-interface operations which his facility will be responsible for, as well as the personnel required, and the cost.

Interface Issues Related to Particular Technologies

Cogeneration

Because industrial cogeneration units would be fueled by conventional fossil fuels, questions are likely to arise during contract negotiations regarding the availability of fuel supply and price, as well as the potential barrier imposed by air quality maintenance regulations. These are not strictly interface issues, to be resolved solely by the cogenerator and electric utility. However, as noted above, a utility is likely to take a strong interest in these matters because it wants its co-producers to be as reliable as possible.

The Power Plant and Industrial Fuel Use Act of 1978 (PIFUA) restricts the use of natural gas and oil in power plants and industrial boilers known as "major fuel burning installations." The intent of the Act is to promote the use of coal and other energy alternatives, and thus conserve the more scarce liquid hydrocarbons. There are two reasons why industrial cogenerators will desire to use oil or natural gas: (1) they are likely to be using one of the fuels in current operations, and may only want to use somewhat more than previously, rather than build a new coal-fired boiler; and (2) the liquid fuels, and especially natural gas, burn more cleanly than coal, and are therefore more likely to obtain the necessary permits from the local air quality maintenance district. Because most industry is located in non-attainment areas, additional deterioration of the air quality will not be permitted—rendering the use of coal virtually unacceptable for all potential cogenerators.

PIFUA and its implementing rules, as specified by the Economic Regulatory Administration (E.R.A.), allow a permanent exemption from the rules for cogeneration facilities. However, the exemption is discretionary with E.R.A., and the cogenerator must petition E.R.A. and sustain a high evidentiary burden to obtain it[35]. The statute requires the potential producers to show that the economic and other benefits of cogeneration cannot be obtained unless natural gas or oil can be used in the facility. Newly proposed regulations require the potential producer to demonstrate that the oil or gas to be consumed will be less than

would otherwise be consumed without the cogeneration unit, over and above the savings that PIFUA would achieve. The potential producer may include in these calculations displacement of oil or gas over a ten year period that otherwise would be burned by the electric utility purchasing the cogenerated power. All of this information must be provided in a complex document known as a "Fuels Decision Report" submitted as part of the exemption petition[36].

If the potential producer cannot meet the burden of proof with respect to the oil and gas savings, an exemption still may be granted under a public interest test, based on such factors as the use of technical innovation. Yet even if the cogenerator does meet the burden or proof, or qualifies under the public interest test, E.R.A. may still refuse to grant an exemption, or it may attach special terms and conditions that inject additional complexity or uncertainty into the venture. In all cases it would appear that, while cogeneration should clearly provide savings of oil or gas sufficient to meet E.R.A.'s "burden of proof" the regulatory procedures may prove so frustrating, or the attendant delays so disruptive, that a potential producer may end up dropping its cogeneration plans.

The California Public Utilities Commission has filed comments with E.R.A. criticizing the restrictive treatment of cogeneration exemptions and urging that changes be made in the rules to encourage cogeneration. However, the C.P.U.C. itself may play a role in delaying such development because it must approve gas service to new industrial customers with a minimum demand of 300 Mcf per day. Although approval is likely to be granted, the procedure imposes one more requirement upon firms that are relatively inexperienced in dealing with public utility regulations.

Recently the C.P.U.C. has taken action to make cogeneration more attractive by ordering P.G.&.E. to sell natural gas to cogenerators at the same price that it sells the gas to its Electric Branch (that is, P.G.&.E's Gas Branch sells gas to its Electric Branch, which then uses it to generate electricity). Previously P.G.&E. had sold gas to its Electric Branch at a lower rate than it sold it to industrial cogenerators, but the C.P.U.C. ruled that since both parties used the gas to generate electricity, price discrimination was unjustified.[37].

Natural gas priority is also a potential barrier that will concern cogenerators and the utility. Under present regulations administered by the F.E.R.C., industrial gas customers are granted priority 4—the lowest natural gas priority. This means that during any gas shortfall industry would be the first to lose its

supply. This poses a threat to an electric utility that relies upon substantial deliveries from industrial cogenerators to meet its load. At present the F.E.R.C. is considering whether to raise the priority of industries that cogenerate to priority 3—equal to that of electric utilities—to overcome this difficulty, as well as to promote cogeneration.

With regard to air quality barriers, current state and federal law requires that new point sources of pollution utilize the Best Available Control Technology (BACT) for each criteria pollutant for which there is a net increase of more than 150 pounds per day. In addition, the New Source Review Rules of the California Air Resources Board require that if there is a net increase of more than 250 pounds per day of a pollutant, which would cause or contribute to a violation of a state or federal air quality standard, then those emissions must be offset. Emissions offsets may be provided by reducing emissions at facilities owned by the potential cogenerator, or they may be obtained by assisting or in some other way causing another polluter to reduce emissions. Obviously this requirement could make some cogeneration ventures much more expensive than otherwise—perhaps even uneconomical.

To deal with the offsets problem, the California Legislature recently enacted A.B.524, effective January 1, 1980. The bill instructs local air pollution control districts to issue operating permits to cogenerators and MSW plants of up to 50 MWe, provided that such projects use BACT, and provided that project developers have either obtained or made "best efforts" to obtain offsets. In other words, the project need not necessarily obtain an offset to be granted an operating permot, but precisely what "best efforts" will mean in the judgment of various Air Quality Maintenance Districts remains to be seen[38].

Assembly Bill 524 also directs the State Air Resources Board, in conjunction with the local Air Quality Maintenance Districts and the C.P.U.C., to prepare an inventory by July 1, 1980, of potential cogeneration projects that could be constructed before 1987. This inventory must also include a complementary listing of the stationary sources that will have to be abated in order to maintain ambient air quality. Precisely who will pay to abate the current stationary source polluters is not specified in the law, but it is possible that some state subsidies may be made available, or that the state will simply order the current polluters to retrofit their installations with improved control technologies. However, since a large portion of the major stationary source polluters are electric utility facilities, their absorbing the clean-up costs could be considered a form of subsidy to cogenerators similar to the subsidy that would occur if they

absorbed the costs of interconnection. Whether this would be permissable according to F.E.R.C. regulations is not yet certain.

In summary, cogenerators face two major hurdles in getting a facility on-line: fuel availability and air quality maintenance. Both are complex issues that have been affected by recent legislation. Precisely how each of these issues will turn out is unclear at this time, although the potential and desirability of cogeneration suggests that efforts will be made to eliminate barriers that prove to be counterproductive.

Municipal Solid Waste (MSW)

Three issues are important to the utility/MSW interface: air quality maintenance, fuel supply, and ash disposal. The air quality issue for MSW plants is identical to that discussed above with respect to cogeneration. Fuel availability is a minor issue, not likely to occupy much utility attention because an MSW plant will be unable to obtain financing unless a reliable fuel supply has been contracted for.

Ash disposal remains an unresolved issue at this time. The problem is not technical, but economic. Therefore it should be of minor concern to the utility because so long as the MSW developing authority finds overall plant economics acceptable, and the plant is built, ash disposal will not impact operation. The utility will be interested only to see that the MSW operators have obtained an ash disposal permit from the state Department of Health.

The particulars of this issue center around whether ash must be disposed of in a Class I landfill (for hazardous wastes), or whether Class II-1 is sufficient. The cost per ton for the former method is about $55.00, while the cost per ton for the latter is about $16.00[39]. Assuming that an MSW plant generates ash in an amount equivalent to 10% of its throughput, and its throughput is 1000 tons per day, the difference in ash disposal costs will be about $1.4 million per year—enough to render some MSW projects uneconomical [40]. However, present uncertainties in the composition of the ash imply that the more expensive Class I disposal will be required. Once actual MSW operation begins the ash may be reclassified to Class II-1 if it meets the criteria for that class.

In summary, the issues of air quality, fuel availability, and ash disposal should all be of minor interest to a utility. Unless the costs of dealing with them are found acceptable by MSW project developers, the MSW/utility interface will not occur.

Wind Power

Four issues are relevant to the utility/wind power interface: power quality, safety, reliability, and variability.

Power quality depends upon the characteristics of the electricity generated by a wind turbine. This in turn depends upon the quality of the system's inverter, if it uses one, or its induction generator. At present no substantial utility experience with wind power exists, nor has any utility in Federal Region 9 signed a contract with a small wind power producer. Consequently it is difficult to project what technology requirements or power quality demands a utility may make, but it is likely that relatively high quality power will be demanded. This will impact project economics more than anything else.

Wind turbine safety will be a minor concern to the electric utility, which may include provisions in its contracts that exempt it from liability for any accidents caused by turbine blade failure, or other negative effects such as radio and television interference. More troublesome will be situations in which turbine continues to feed power into a line that the utility has shut down for maintenance work. Since wind turbines will be remotely coupled and decoupled from the grid by a pulse fed in from the grid, the wind developer may argue that the utility is liable for any safety-related accidents of this nature. The utility is unlikely to accept such responsibility, and furthermore can be expected to require use of the most effective safety equipment available to prevent any mishaps. This too will impact project economics.

The reliability of wind will be questioned by utilities because of the simple fact that the wind blows intermittantly. Although statistical analysis can be used to show that distributed wind turbines, allocated over the best sites, can be expected to provide reliable service equivalent to at least one-third of total capacity at all times, a utility is likely to accept this only after it has actually been demonstrated. Since the issue of reliability will be intimately related to the question of whether or not wind systems receive capacity payments, it will have a major impact on project economics.

The variability of wind power imposes limits upon the amount of wind energy that can be incorporated into a system. Average input from wind systems into a utility's grid cannot exceed 10-15% of the total system load; otherwise the fluctuations involved would require both additional reserve capacity and more complex load management techniques than currently available. However, sitting limitations in California, and probably in other states, are so restricted that building wind capacity sufficient to generate more than 10-15% of a utility's load is not feasible.[41]

In summary, the interfacing of wind power with a utility grid raises several issues not inherent in the interfacing of cogeneration or MSW systems. These are the issues of power quality and safety, which derive from the fact that wind turbines are substantially different from conventional steam turbine-generators, and reliability and variability, which derive from the intermittant nature of wind. All may strongly impact the economics of a wind project, the former by requiring expenditures on special inverters and safety equipment, and the latter by reducing or eliminating capacity payments.

Residential Photovoltaic Systems

Four issues peculiar to the interface between residential photovoltaic systems and electric utilities deserve comment. These include the issues of power quality, reliability, sizing of transmission lines, and safety.

Residential photovoltaic systems will require the use of an inverter to convert DC to AC. The utility will be concerned that the quality of the AC current is comparable to that produced by utility-owned facilities, and may impose certain technology standards. These could raise system costs, although this is not to say that they are unnecesary.

Photovoltaic units will produce power only when the sun shines, meaning that in Federal Region 9 they will generate output during about 75% of daylight hours. Predicting photovoltaic system availability should be easier than predicting wind system reliability if systems using real-time satellite imagery connected to a utility's computerized load management equipment become available. Presumably the satellite imagery would provide data capable of predicting the likely output of the photovoltaic units in a utility's grid for a given near-term time period.

The sizing of transmission lines will become an important concern to the utility when a large number of photovoltaic units are added to a local distribution network. The lines are normally sized to handle less than 100% of the maximum load that a neighborhood could demand. The assumption is that every single consumer will not demand full power at the same time. However, at noon on a sunny day photovoltaic output would peak in all residential systems at the same time. As a result, the energy sent back into the grid from a completely photovoltaic-equipped neighborhood could exceed line capacity. This situation will be exacerbated if the peak output of a typical residential photovoltaic

system (about seven kilowatts) is greater than peak demand for the same residence. Under such circumstances a utility could either restrict the distribution of photovoltaic systems in a given neighborhood, or increase the size of its lines and the capacity of the local transformer—depending upon which was more economically justified.

Safety in the operation of a residential photovoltaic system requires that the system be subject to line commutated shutdown and startup. It might be possible that, in a neighborhood where many systems are operating, one system could fail to shutdown, and send out a signal that could cause other systems to restart. All systems might then feed power into a line that is down for repairs. This problem is likely to occur only in rare instances when several low-probability events occur simultaneously, and should be surmountable by approrpriate circuit design and safety equipment.

In summary, the interfacing of residential photovoltaic system with the local utility will raise several special issues similar to those caused by a wind/utility interface. As with the latter, utility demands for quality power and safe systems may add to system cost. The problem of load management with systems whose output is subject to interruption by clouds at uncertain intervals and for uncertain periods of time will certainly reduce substantially if not eliminate entirely any capacity payments. However, because the latter could severely impact the economics of photovoltaic systems, and because those systems do in fact offset the need for some utility peaking capacity, new contractual provisions different from those in PG.&E.'s current contract and tailored especially for photovoltaic and wind systems may be called for[42].

Conclusion

The rules and regulations covering the sale of electrical energy and capacity from small power producers to electric utilities have changed dramatically during the past year. Under earlier rules, the purchase prices offered by utilities were too low to encourage the development of small power production, but the higher prices now being offered will do much to reverse the situation.

The present section has sought to identify and discuss the issues that small power producers, utilities, and public utility commissions will face when establishing not only purchase prices but many of the other provisions of power sales contracts. At the present time, the California Public Utilites Commission is still in the process of adopting a uniform methodology for calculating the

marginal, or avoided, costs upon which purchase prices are based. Thus this issue, as well as many others related to power sales, will be subject to revision in the coming years. However, the revision is likely to involve primarily the fine tuning of the rules and regulations governing power sales contracts—rather that the development of an entirely new set of principals for such contracts, as was the focal point of the past year's activities.

The issues of small power/utility interfacing are summarized in Table 4 below. Again it should be noted that, while they were distilled from information developed primarily within California, the generic nature of the issues makes it highly likely that they will also be found pertinent in the other states of Federal Region 9—as well as the entire nation.

TABLE 4

SUMMARY OF ISSUES

Issue	Current Policy
Should marginal cost-based purchase prices be used?	Marginal cost-based prices are in use and likely to remain so. Strongly supported by economic theory, necessary for the proper allocation of society's resources.
Facility availability and reliability	P.G.&E. requires 80% availability during peak hours; S.D.G.&E. requires 85% during peak and shoulder. This may be too strict; experience will possibly lead to change.
Intermittant power capacity: what should capacity payments be?	Utilities differ on how to calculate payment for wind; no contracts yet for photovoltaics. Ultimately, capacity payments may be made in proportion to percentage of peak and shoulder availability.
Length of contract: impact on capacity payments.	Utilities pay more for longer contracts since this provides more security, less need to plan utility-owned replacements. This policy appears stable.
Dispatchability	Plants receiving full capacity payments must be fully dispatchable, or must be available during a high proportion of peak and shoulder hours. Precise features of this policy may be refined.

CONTINUED

SUMMARY OF ISSUES

Issue	Current Policy
Standby rates and wheeling	Rendered moot by the adoption of policy of simultaneous purchase and sale of energy.
Time-of-use pricing	Non-controversial. Provides more accurate and economically efficient prices. Makes cogeneration more attractive.
Curtailment	Federal regulations require utilities to refuse small power deliveries when they have cheaper alternatives. In the future this power could be wheeled to utilities lacking cheap alternatives. Requires new federal regulations if interstate wheeling is desired.
Interconnection costs	Non-controversial. Small producers are required to pay these costs by F.E.R.C. regulations. Otherwise purchase prices will exceed avoided cost.
Utility demands for approval of small producer's plant	P.U.C's could restrict utility demands if such demands appear unreasonable or obstructionist. At present the demands are in effect.
Fuel Availability	Primarily a cogeneration problem caused by PIFUA restrictions on new uses of oil and gas. Exemptions may be possible but hard to obtain. Exemption regulations may be modified.
Air quality mantenance	Most cogen and MSW facilities are located in areas where new point sources of pollution require B.A.C.T. and purchase of offsets. This policy not likely to be changed.
Natural gas price and priority	At present cogenerators pay more for gas and hold lower priorities for its delivery during shortfalls than do utilities. This bias is currently under regulatory review.
Ash disposal for MSW plants	Cal. Health Dept. currently requires Class I disposal. May allow cheaper Class II-1 disposal upon examination of actual ash output from MSW plants, if examination shows ash non-hazardous.

CONTINUED

SUMMARY OF ISSUES

Issues	Current Policy
Power quality and use of inverters	Wind may and photovoltaic power will require the use of inverters. Good inverters are expensive. This issue is receiving scant attention now since few wind and no photovoltaic interfaces are under development.
Safety equipment required	Utilities demand maximum system protection equipment. Little experience makes it hard to determine how much is actually necessary. Technology developments and regulatory rulings on this issue will come. Legal precedents will be established as to necessary equipment, and liability for accidents.
Sizing of transmission lines	No experience on this issue. Extensive or universal use of photovoltaic rooftop systems could require utilities to upgrade transmission lines and transformer capacity. This issue will not become important until photovoltaic system costs fall dramatically, i.e., for ten or twenty years.

APPENDIX A

Energy Prices

The purchase prices for energy are calculated in terms of cents per kilowatt-hour. The prices vary by time of day and season of year. Definitions of peak, partial-peak, and off-peak time periods are given below the prices.

	Period A May 1 to September 30	Period B October 1 to April 30
On-Peak	5.675¢/kwh	5.450¢/kwh
Partial-Peak	5.459	5.150
Off-Peak	4.700	4.599

Definition of Time Periods

	Mon. - Fri.	Saturday*	Sun.& Hol.
Period A May 1 - Sept. 30			
On-Peak	12:30 p.m. to 6:30 p.m.		
Partial-Peak	8:30 a.m. to 12:30 p.m.	8:30 a.m. to 10:30 p.m.	
	6:30 p.m. to 10:30 p.m.		
Off-peak	10:30 p.m. to 8:30 a.m.	10:30 p.m. to 8:30 a.m.	12:00 a.m. to 12:00 a.m.
Period B Oct. 1 - April 30			
On-Peak	4:30 p.m. to 8:30 p.m.		
Partial Peak	8:30 p.m. to 10:30 p.m.	8:30 a.m. to 10:30 p.m.	
	8:30 a.m. to 4:30 p.m.		
Off-Peak	10:30 p.m. to 8:30 a.m.	10:30 p.m. to 8:30 a.m.	12:00 a.m. to 12:00 a.m.

Footnotes

1. The full discussion of these issues is contained in Decision 91109, California Public Utilities Commission, December 19, 1979. Copies of this decision are available from the Process Office, C.P.U.C., 350 McAllister Street, San Francisco, Ca. Additional analytic work is presented in the staff report on OII 26, prepared by J.H. Quinley et al, C.P.U.C., May 18, 1979.

2. Since this chapter was written new power sales contracts have been developed by Southern California Edison and San Diego Gas and Electric. P.G.&E. has also developed a separate contract for small producers whose capacity is less than 100 kilowatts. These differ in detail from the original P.G.&E. contract, but the issues involved are similar, and the method of establishing separate prices for energy and capacity is similar.

3. For amplification see Decision 91109, C.P.U.C., op.cit., pp 18-20.

4. See "OII 26", report of May 18, 1979 by J.H. Quinley, op.cit p 5-4

5. A utility is allowed to charge rates that will recover all current year expenses plus a certain percentage return on its invested capital. The invested capital is the rate base, and to be included in the rate base a facility must be "used and useful." In recent years the allowed rate of return on invested capital has been in the range of 9-10% for California utilities.

6. There are other reasons why utilities preferred nuclear power. One appears to be that nuclear power represented high technology at a time when technology and progress were held in the highest esteem, and negative externalities not apparent. Second, there was a pervasive myth that nuclear power would provide electricity that was too cheap to meter.

7. See: Gandara, Arturo, Electric Utility Decision-making and the Nuclear Power Option, June 1977, R-2148-NFS, the Rand Corporation, Santa Monica, CA.

8. Dispatchability is obviously more difficult if the facility is not owned and operated by the utility. The cogenerator must have his system (at least the steam boiler) up and running whenever the industrial process requires. The solution is for the utility to back its own units in and out as the load varies, rather than attempting to control cogenerator facilities.

9. See: Shepherd & Wilcox, Public Policy Toward Business, Chapter 12.

10. Disallowing expenses would mean that the utility could not increase its rates to cover those expenses. Consequently, utility stockholds would pay the costs in lower dividends. Ratepayers pay the cost of all allowable expenses.

11. See for example: Davis, David H. Energy Politics, New York: 1978.

12. See for example: Stigler, George, "The Theory of Economic Regulation," Bell Journal of Economics, Vo. 2 (Spring 1971) p3.

13. For more details: Quinley, J.H., et al, "OII 26", May 18, 1979, pp 5-13.

14. Yergin, Daniel, and Stobaugh, Robert, Energy Future, New York: 1979.

15. This Act was one of five often referred to as the National Energy Act of 1978.

16. 18 CFR 292 (proposed). See F.E.R.C. Docket No. RM79-55, page 9. Federal Energy Regulatory Commission, October 18, 1979.

17. Recommended Commission Policies and Price Rules for Utility Purchases of Cogenerated, Auxiliary, and Small Production Facility Power, by Burton W. Mattson, C.P.U.C., July 20, 1979.

18. Kahn, Alfred, The Economics of Regulation, Vol. 1, John Wiley and Sons, Inc., New York: 1970. Chapters 3-5.

19. Mattson, Burton W., op.cit.

20. F.E.R.C. Order No. 69.

21. Ibid.

22. With present interest rates in double digits few large investors will buy utility stock when the rate of return on invested capital is only 9%. But even prior to the recent surge in interest rates, utilities were finding it increasingly difficult to raise capital. A good explanation of the cause of this difficulty may be found in Gandara, op. cit.

23. Furthermore, a manufacturing plant must burn fossil fuel to generate steam to run its processes. Since it must burn the fuel anyway, and can obtain a large return (from cogeneration) by burning only slightly more, a manufacturer may find that the benefits from cogeneration help offset the cost increases for the fuel it would have to burn for steam anyway.

24. In California this is permitted by Section 454(a) of the Public Utilities Code.

25. See P.G.&E. Power Sales Agreement, February 4, 1980. Appendix D, Section 5.

26. Ibid., Appendix E.

27. Ibid., Appendix A, Section 10.

28. In Decision 91109 a minority of C.P.U.C. commissioners dissented on this point. They argued that only those cogenerators agreeing to commit their capacity should obtain the benefits of simultaneous purchase and sale; otherwise, a larger proportion of industries would not commit capacity, thus reducing the ability of utilities to include that capacity in their resource plans.

29. As if clear from the general service schedule, the demand charge for on-peak service is very high relative to that for partial-peak and off-peak service. According to P.G.&E. cogenerators will not be subject to the general service demand charge if they provide reliable, available capacity. See: Meyer, Joseph G., Co-Generation: One Utility's Approach, Pacific Gas and Electric, December 5, 1979, page 11.

30. See: P.G.&E. Power Sales Contract, February 4, 1980, Appendix A, Section 9.
Also: Decision 91109, C.P.U.C., op.cit., page 24.

31. Note that the utility is also constrained by F.E.R.C. regulations from charging more for the interconnection than its net increased costs, when the interconnection costs to the small power producer are compared with any other necessary interconnection costs that would arise, if, instead of purchasing power from the small producer, the power were produced by the utility intself or purchased from another source. See Decision No. 91109, C.P.U.C., op.cit., page 28.

32. Interconnection costs should not make any small power venture uneconomical if the venture has been well-orchestrated. Ideally, these costs will be included in the project's initial cost estimates. In short, this issue is not especially controversial or complicated, it simply has never been addressed before.

33. The staff of the C.P.U.C. estimates 3-5 years to bring a new cogeneration facility on-line. See: Decision 91109, op.cit., page 14.

34. See: Meyer, Joseph G., op.cit., page 8-9.

35. For a fuller explanation see Decision 91109, op. cit., page 32, and P.I.F.U.A. sections 212(c), 312(c).

36. 10 CFR 503.37, 505.27.

37. This order has since been stayed. P.G.&E. has requested a re-hearing on this issue.

38. Recently the Environmental Protection Agency threatened to withhold Federal grants for highway and sewer construction because California has not made adequate progress in meeting the goals of the 1977 Amendments to the Clean Air Act. This suggests that the regional Air Pollution Control Districts will be forced to insist that offsets be obtained, as a means of complying with E.P.A.'s demands.

39. Personal communication from Bob Boshoven, Bureau of Electricity, City of Alameda, 12/11/79.

40. ($55.00 - $16.00) (.10) (1000 TPD) (365 days/yr) = $1.4 million.

41. Personal communication from John Nichols, Chief, Wind Office, California Energy Commission, 12/28/79.

42. This issue remains to be settled. Although photovoltaics will not provide firm capacity, it will provide important capacity during peak energy usage hours, and consequently may deserve a partial capacity payment.

FINANCIAL BARRIERS

Community energy systems face serious problems in attracting sufficient investment capital. There are several general reasons for this situation. First, although proven in laboratories and demonstration projects, community energy systems possess no substantial real-world experience. Consequently, investors deem them risky. Moreover, because they lack a significant share of the energy supply market at present, their future profitability is uncertain. Finally, potential investors such as industrial cogenerators or residential homeowners find the front-end capital costs difficult to bear, even when long-term benefits are attractive.

Both federal and state governments can play an important role in stimulating investment in new energy resources. Among the tools at their disposal are investment tax credits, grants, tax-exempt bonds, and low-interest loans. Naturally such programs are not without cost to the taxpayer. Thus an important set of questions for an energy policy analyst to ask are: What is the return on each tax dollar spent on incentives? What is the most efficient incentive? The most equitable? Which technologies merit the greatest share of limited incentive dollars?

These questions are at the core of the present section. They will be addressed within the framework established previously. That is, the financial barriers faced by each developer of the four energy systems under study—MSW, cogeneration, wind, and photovoltaics—will be dealt with separately. Barriers will be identified, and the cost of policies to overcome them will be estimated. A comparison of the costs of subsidies necessary to make each technology economically viable will be presented in the conclusion. This will provide some insight into the relative cost-effectiveness of public investments in each technology.

Economic Assumptions

Three rates will be used in the economic calculations included in this study: interest rates, a discount rate, and an electricity price escalation rate.

The interest rates that financial institutions charge for commercial bonds or demand on bond issues have changed substantially during the course of this study. For the present analysis an interest rate of 15% will be assumed on long-term, commercial financing. For tax-free municipal bonds the assumed rate will

be 8%. Although arguments for both higher and lower rates can be made, these rates have merit because they fall near the mean of recent experience, and because it is unlikely that much capital investment will take place at higher rates because private rates of return will not support it[1].

Future benefits will be discounted at the rate of 3%. This is approximately equal to the real interest rate prevailing in the general economy, i.e., the nominal bank interest rate minus inflation, and so renders the evaluation of an investment similar to that which would obtain in a private firm. Arguments could be posed favoring a higher discount rate on the grounds that future generations, which may have to bear part of the cost burden of long-term bond financing is used, will receive only part of the benefits. But future generations will also receive benefits deriving from the commercialization of new energy technologies, as well as from whatever savings in conventional energy that these developments permit us to pass on to them[2].

Electricity prices are expected to rise at a faster rate than the consumer price index because the fuels used by power plants are either becoming scarcer or more costly to extract. One estimate indicates the increase above inflation will be about 2.5%. This may seem conservative in light of the past year's experience, but other studies have shown that oil prices since 1974 have not moved inexorably upwards at a high rate, but have remained constant or even fallen in real terms except in periods of tight supply[3].

Inflation will be ignored in this analysis; all calculations will be performed in terms of constant dollars.

The Purchase Price of Electricity

The benefits of an investment in a community energy system depend upon the value of the electricity that is produced. This value can be calculated either as the cost that the producer would have to pay the local electric utility for an equivalent amount of electricity, or as the amount in dollars for which that production can be sold to the utility. In the analyses below, we will use the value that could be earned through sale of the electricity to the utility. The exact rates used will be those currently offered by Pacific Gas and Electric Company. A discussion of these rates, the issues involved in establishing them, and the regulatory proceedings and public laws that brought them about, has already been presented in a previous section.

Method of Evaluation

Once the barriers that each of the four technologies faces in obtaining financing have been identified a number of public policies suitable for ameliorating them will be evaluated. The primary criterion to be utilized in the evaluations is dollar benefits and costs. Additional criteria include political feasibility of a given policy, distributional or equity impacts, and the technical difficulty of implementing a policy.

Benefits are calculated using the current purchase prices of PG&E, as noted above. The costs of each technology will be based on current technology costs, including the cost of any necessary pollution control equipment and emissions offsets. An exception to this will occur with photovoltaics, where the Department of Energy's 1985 technology cost goal will be utilized. This exception is made because photovoltaics will not be economically viable unless and until that goal is met. It would make little sense to perform an analysis assuming non-viable costs[4].

More important to this analysis than technology costs are the costs of the financial incentives that either are presently in effect, or are likely policy tools for ameliorating financing barriers. In some cases the cost of these incentives can be calculated in a straightforward manner. For example, the cost of a 10% energy investment tax credit is equal to 10% of the investment's capital cost (assuming the investor has sufficient tax liabilities). The cost of using municipal bond financing, on the other hand, requires a more detailed analysis of the impacts of such financing on tax revenues, tax credits, and operating costs. In all cases these public costs will be compared to public benefits in terms of the dollar-cost-per-kilowatt of capacity subsidized, and/or the dollar-cost-per-kilowatt-hour subsidized. By evaluating all the incentives in terms of similar cost/benefit measures the relative economic attractiveness of each will be clearer.

Barriers and Incentives

Municipal Solid Waste (MSW)

The combustion of municipal solid waste to produce energy may be thought of simply as "burning garbage."[5] This is made possible by the fact that municiple refuse contains a large fraction of combustible material; its Btu content is roughly one-third that of coal.[6] Non-combustible materials may be removed from the waste stream before combustion through various recycling procedures,

or after combustion as part of the ash residue, depending on the economics of the particular situation. These non-combustibles are primarily ferrous metals, glass, and aluminum, and may provide an additional source of income for an MSW project.[7]

The heat produced by burning waste is used to produce steam in a boiler. The steam may then be used to power industrial processes, to spin a turbine-generator and produce electricity, or to do both via cogeneration. Since co-generation is discussed separately in this paper, only the production of electricity will be considered here.

The utility of an MSW plant stems not only from the fact that it produces energy from waste, but from the fact that it reduces the amount of landfill required for waste disposal. In a number of California communities the cost of landfilling has been the primary motivation for investigating MSW.[8]

A municipality seeking to build an MSW plant will find the task of arranging financing a formidable one, since capital costs for a 1,000 ton-per-day plant will be about $70 million. Municipalities will most likely meet such an expense by issuing municipal bonds, although it is possible that a private firm could be franchised to build and operate the plant for the municipality.

In the sections that follow three key issues are addressed. First: what barriers to the effective use of municipal bond financing does a municipality face? Second: given the interest rates, inflation rate, and tax policies currently in effect, are the net benefits to the public greater from an MSW project financed and owned by a municipality, or by a similar project privately owned and financed? Third, are the overall costs and benefits involved such that an MSW project is economically viable under either financing/ownership option?

1. Barriers to Financing via Municipal Bonds[9]

Municipal bonds possess two attributes that make them especially attractive to investors. First, their security is considered second only to United States bonds. Second, the interest they earn is exempt from federal income taxes, and from state income taxes in the state in which they are issued. In turn, this means that municipalities may issue them at rates of approximately one-half the private market rate.

Two types of bonds could be issued to finance an MSW project. General Obligation bonds are considered the best risk by investors because they are

backed by the taxing power of the government that issues them. However, before they can be issued, the issue must be approved by two-thirds of the voters in a bond referendum. Revenue bonds, by contrast, are not backed by any taxing power. Their repayment is funded solely through project revenues; consequently they are considered somewhat riskier. However, because they require voter approval by only a simple majority, revenue bonds are much more likely to be relied on.

While the use of municipal bonds may reduce the interest rate the municipality must pay by one half, the sheer magnitude of the sum to be financed means that a difference of as little as one-quarter of one percent can make a substantial difference in annual revenue requirements.[10] Municipalities will therefore seek to minimize even this reduced rate. However, the interest they must offer in order to sell the bonds will depend almost entirely upon the rating given their issue by a bond rating agency, such as Moody's Investor's Service, or Standard and Poor's Corporation. This rating depends in turn upon an evaluation of five specific factors. These factors in turn comprise the most serious barriers to effective use of municipal bonds.

The first factor will be a municipality's expected ability to meet the bond obligations.[11] This expectation will depend upon the type of bond to be issued; the amount and term of other outstanding municipal debt; past debt repayment behavior;[12] the project's estimated debt-coverate ratio;[13] and upon whether or not the project will retain control of the gate fee (the fee charged for each load of refuse dumped at the project).

The second factor rated will be the reliability of project technology. This will be estimated based on experience elsewhere with the same or similar technology, plus the extent of manufacturer's guarantee.

The likelihood of unexpected costs and construction delays will be the third factor rated. Either of these can be a serious threat to the project's ability to meet its obligations, particularly in its first years of operation. The risk here will be estimated from experience with other similar ventures, as well as from the nature and severity of the project's environmental impact. Organized opposition that could delay the project with litigation might also increase the perceived risk.

The fourth factor rated will be the availability of long-term contracts for the sale of the energy produced, while the availability of contracts for the required supply of refuse over the project's lifetime is the fifth. A municipality should have such contracts in hand when the bond issues is released.

2. Options for Overcoming the Barriers

Perhaps the most serious barrier to obtaining a favorable bond rating is the rater's perception of a municipality's likelihood to default. To mitigate the implied risk, and thus reduce the risk premium added to a bond issues's interest rate, a state or federal agency could take two actions. First, it could set up a special support fund that would back up the project's bond reserve fund. Alternatively, the state might provide MSW projects with outright grants, which would reduce the size of the bond issue required, and therefore the size of the annual debt obligation. Either action would reduce the risk of default as perceived by the bond rater.

The cost to the state of any grant would be equal to the size of the grant. The cost of a revenue support fund should be negligible if the fund is properly invested and earning high interest. Consequently it would appear that the latter is a better investment incentive.[14]

Whether either of these options is politically acceptable will depend upon state and federal budget constraints, on the support that proponents of MSW projects can muster, and on the perceived need for and social utility of MSW development as opposed to expenditures on other items. Although the state and federal governments do not routinely absorb the cost of risk in local government financial affairs, there is a history of government support for demonstration projects involving a variety of technologies. By sponsoring real-world operating experience with MSW technologies such support permits the identification and correction of technology bugs, thereby reducing the risk involved in subsequent MSW projects. Subsequent projects should then be deemed less risky, and not require similar subsidization. Moreover, since the knowledge obtained through demonstration projects is a public good it has a legitimate claim to government support, and thus is more likely to attract adequate legislative backing than are non-demonstration projects.

The bond rater's opinion of MSW technology would be relatively unimportant if the risk of default were reduced by the means indicated above. If not, the bond rater's opinion could be improved if the state required manufacturers to provide extensive guarantees. Since a large state such as California will offer a considerable market for a manufacturer, a state demand for guarantees will carry more weight than the demand of a single municipality. It is possible that the technology cost will increase if a guarantee is demanded, but this is a case of the manufacturer being forced to internalize a risk cost that would otherwise

be passed to the municipality. Either way the municipality ultimately pays for this cost, and at least when a guarantee is provided the risk impact on bond interest rates is reduced.

To ameliorate the risk imposed by the possibility of unexpected construction costs or delays the California State Sold Waste Management Board has recommended that the state legislature establish a $40 million supplementary fund for environmental protection equipment that might become required during the course of development of six pilot projects.[15] Assuming that these funds turn out to be needed, and that they are distributed evenly among the six projects, this would amount to a subsidy of about $167 per kilowatt of electrical capacity subsidized.[16] Whether this amount of subsidy is politically acceptable depends upon the same factors noted in reference to the use of grants and back-up bond reserve funds. To date, the California Legislature has not enacted the proposals of the State Solid Waste Management Board.

The availability of long-term contracts for the sale of energy to electric utilities should not be difficult to obtain. Utilities generally prefer long-term contracts because of their need to develop similarly long-term supply plans.

To ensure the long-term availability of a supply of refuse, state legislatures could direct regional authorities responsible for solid waste management to designate source areas—i.e., wastesheds—for each MSW project. Alternatively a state agency could perform this task. Thus each MSW project would be granted a right to utilize the waste generated within its specified wasteshed. Settlements could be negotiated with any impacted municipality that would otherwise perform its own resource recovery, to compensate it for any financial loss.

TABLE 5

BARRIERS AND OPTIONS FOR MSW

Barrier	Policy Option
1. Ability to meet bond obligation	1a. Bond reserve support fund
	1b. State/federal grants
2. Reliability of technology	2. Warrantee Requirement
3. Likelihood of unexpected costs and delays	3. State supplementary funds
4. Availability of contracts for sale of power	4. No action needed
5. Availability of contracts for refuse supply	5. State established waste-heads

Table 5 summarizes the barriers to the effective use of municipal bond financing. The most serious are barriers to obtaining the lowest possible bond interest rate, and appear to be surmountable by state or federal policies that in some cases require a significant commitment of funds. It is possible that nothing more than the provision by the state of a bond reserve fund would suffice to produce the lowest possible interest rate, in which case no long-term costs are incurred. Short-term costs involved in tying up a substantial amount of money—about $10 million per project—could, however, generate political opposition. As noted earlier, state willingness to provide financial subsidies will depend upon current budget constraints, on the support that proponents can muster, and on the competing demands and powers of other constituencies.

3. Cost of Municipal Bond Financing v. Private Financing.

Although it is commonly assumed that financing capital projects via municipal bonds is advantageous for governments, because of the lower interest rates that can be offered, there are some large hidden subsidies involved in municipal bond financing that should at least be identified to decision-makers and the public. The largest subsidy comes in the form of foreign tax revenues. For example, if a MSW project were financed by taxable bonds offering a 15% return, state and federal governments would collect millions of dollars each year in

taxes on the interest earned. Another subsidy is hidden in the fact of municipal ownership. Were the project owned by a private firm, that firm would pay income and property taxes that could also amount to millions of dollars each year.

On the other hand, a private project would qualify for both the conventional investment tax credit, and the special energy tax credit made available by the Energy Tax Act of 1978. On a $70 million investment, each of these 10% credits would provide $7 million in tax benefits. Furthermore, the higher capital costs of private ownership would certainly be passed on to the public, probably through higher refuse disposal rates.

Thus a central question for analysis is whether the public gains more than it loses through municipal bond financing. In order to reach some understanding of this issue a comparative analysis will be performed of two different financing approaches, municipal bonds versus private capital, as applied to the same model MSW project. The objective will be to determine the difference in revenue requirements between a public and a private project. The private project's requirements will certainly be higher because the firm must pay various taxes, but income to government will also be higher under private ownership for exactly the same reasons. Should the increase in tax revenues exceed the difference in revenue requirements, then private financing will be more cost-effective from the public point of view.

The parameters of the model MSW project and the formulas used in calculating revenue requirements are described in detail in Table 6 on the following page.

Table 1 in Appendix A derives the revenue requirement fro a private MSW project, while Table 2 makes it clear that over the twenty year life of the facility a private project will require nearly $250 million more in revenue requirement than would a municipal project. Local, state and federal taxes on income, interest and property for the same period would total $203 million, (Tables 3-5). Thus the net cost to the public of a private project is about $46 million.

Although the net benefits of municipal bond financing are clearly significant given the parameters of the model, they are sensitive to changes in the interest and tax rates, which could change over twenty years. Since the project analyzed here was a composite hypothetical facility it would be of slight value to perform additional analyses with alternative interest and tax

TABLE 6

MSW MODEL SYSTEM

MSW Model System

Capital Cost	=	$70,000,000
Operating Capacity	=	1,000 tons-per-day
Operating Costs	=	$11.60 per ton
Electrical Capacity	=	40,000 kilowatts
Electrical Output	=	250 million kilowatt-hours per year

Municipal Bond Costs

Annual interest @ 8%	=	$5,600,000	for 20 years
Annual sinking fund payments	=	$3,500,000	

Private Financing Costs

50% via internal funds requiring a 20% return on investment calculated as: .20($35,000,000 - accumulated depreciation)
50% via corporate bonds @ 15% = $5,250,000/year

Formula Logic*

Revenue Req. (annual) = (Sinking Fund + Operating Costs + Firm ROI + Bond Interest + Depreciation + Fed. Taxes + State Taxes + Property Taxes)

Fed. Tax = .46(Revenues - Interest - Accel. Dep. - State Tax)

State Tax = .096(Revenues - Interest - Accel. Depreciation)

Sinking Fund = Total Bond ÷ 20

Annual Interest = .15 (Total Bond Debt)

Tax Rates on Bond Interest: Federal = 46%, California = 11.6%

Depreciation is calculated via an accelerated method for tax purposes (Table 5, Appendix B), and via straight-line method for determining annual Firm ROI.

*Not all calculations can be performed using this logic, although it accurately represents the computational results, because of interdependencies among the variables. The actual computational procedures used are shown in Appendix A.

rates; rather, each proposed MSW project should be carefully reviewed by project sponsors along the lines of this analysis, and its particular cost/benefit situation determined. However, some general observations regarding sensitivity are possible. First, as the interest rate rises, private financing will grow less favorable from the public's point of view, since tax receipts will grow more slowly than public costs. Second, as tax rates rise, private financing will become more attractive, since the public will recoup a larger share of its costs. Third, the discount rate does not affect the analysis so long as the same rate is used to discount both the difference between private and public revenue requirements, and annual electricity revenues.

4. Evaluating the Incentives

Whether or not municipal bonds or private financing prove more attractive for the public in a given instance, the policy options described previously would be useful in obtaining the desired investment funds. But should they be utilized? Is MSW a cost-effective energy investment? Are the policy options equitable? Politically feasible?

The costs of MSW facilities have already been determined. The economic benefits are two: revenues from the sale of electricity, and a reduction in the cost of landfilling waste. Additional benefits may be obtained if recyclable materials in the waste are recovered either before or after combustion, while the value of developing new energy sources is certainly significant if unquantifiable.

Table 6 in Appendix A indicates what the electricity revenues will be for the model plant that was analyzed. They amount to $16.4 million in the first year of operation, about $3 million more than the revenue requirements for a municipally-owned plant. Thus a municipality with this plant would be entirely freed from the cost of disposing of its waste, and would receive a bonus of $3 million that it might utilize in whatever manner it saw fit.

A private project, on the other hand, would not be able to meet its revenue requirement from electricity revenues alone, and would have to charge a disposal fee for each ton of waste processed by theproject. During the first few years of project operation this fee would be about $50 per ton, which is ten times what the average municipality now pays for waste disposal. This fee eventually

falls to zero as electricity revenues rise and revenue requirements fall (due to capital depreciation). Over the life of the project the average disposal fee is $6.39 per ton (Appendix A, Table 5). This is only slightly more than the current average disposal cost, which can be expected to rise in the future as land for landfill becomes scarce. This suggests that a private project may not necessarily be detrimental to the public (especially if substantial risk is involved). It also reinforces the point made earlier that individual analyses should be made for each project considered.

In terms of equity impacts, a private project would result in a substantial redistribution of income away from the local community. Of the taxes collected, $149 million would go to the federal government, $40 million to the state government, and only $14 million to the local municipality in property taxes. At the same time, the community would pay $46 million in disposal fees over the twenty year life of a private project. With municipal bond financing, the municipality would benefit from surplus electricity revenues, i.e., revenues will exceed revenue requirements, as well as the elimination of waste disposal costs. The federal and state governments will lose tax monies, but since those taxes would have come out of the local community no real redistribution takes place.

Political feasibility has been discussed earlier with regard to policies for overcoming the barriers to effective use of municipal bonds. To those comments may be added the observation that MSW projects, whether public or private, appear to offer substantial benefits both for a municipality and for society as a whole. Even under private financing, disposal costs do not rise much above the average cost now being paid, while the development of a new source of energy has a definite "public goods" aspect to it that deserves some public subsidy—and should attract political support.

In sum, given the proviso that each project be analyzed carefully according to its own merits, the commercialization of MSW appears to be a step towards both developing new energy sources and utilizing what we have more efficiently, and therefore deserving of public policies that can support and assist it.

Small Wind Systems

Windmills have been used for centuries to provide mechanical and electrical energy for mankind. Prior to the development of rural electric cooperatives in the 1930's, millions of windmills provided electrical power on farms

in the United States.[18] The technology required in a wind turbine has changed little since then, and the potential energy available in the wind is substantial —perhaps 10-15% of California's total electrical demand, and a similar portion in the other southwestern states of Region 9.[19]

Wind power does possess some liabilities. The most serious liability is that the wind is intermittent. Even when distributed among the best locations in a state with reliable winds like California, the turbines are expected to operate no more than 33% of the time.[20] On the other hand, wind generation requires no liquid coolant, making it especially attractive in the water-poor southwest.

Wind turbines may also prove to be aesthetically objectionable to some communities, although public attitudes toward them seem to be more favorable than toward solar collectors.[22] They also pose some safety hazards: a turbine blade might break, or faulty controls might feed power into a line that is down for repairs. These should not prove to be insurmountable problems, and may well be more than offset by the two main advantages of wind power: the fact that it requires no conventional fuel to operate, and the fact that it produces no emissions.

Small wind turbines may range in size from one kilowatt to one hundred kilowatts. Larger wind turbines are being developed by NASA and several aerospace corporations, but these are too large to be considered as community energy systems. Small wind turbines could be spread out around the outskirts of a town, or integrated into it in vacant areas, or established on land or buildings owned by local industry. A large number could conceivably be operated by a local firm, which would provide a maintenance crew that would service the turbines according to a routine schedule. By contrast, large wind machines would not provide the opportunity for regular maintenance scheduling since fewer would be built, and their technology could require more sophisticated personnel. This is not to say that large machines do not also offer real benefits to society, but only to point out why they are not likely candidates for community energy systems.

Venture capitalists are the most likely form of financial backing for small wind developers because wind power at present represents the type of new, high risk enterprise that venture capitalists traditionally support.[23] Moreover, unlike MSW, in which the energy resource has historically been controlled by municipalities, the winds have most often been exploited by individuals, and

past developers of wind turbines have been private entrepreneurs.[24]

1. Barriers to Wind Financing via Venture Capital[25]

Venture capitalists, like investors in municipal bonds, are concerned with the risk of the enterprise they invest in. Unlike the latter, they do not weigh the level of risk solely against a pre-determined rate of return, but rather against both a variable rate (which may be zero) and the possibility of capital gains or losses.[26] Of these possible outcomes, the venture capitalist will be looking primarily for large capital gains. This is because he or she knows that initial earnings in new and risky ventures are likely to be small, and that virtually all will have to be plowed back into the firm to finance expansion. Indeed, this is what the venture capitalist desires: rapid firm expansion that will lead to rapid appreciation in the value of his or her stock.[27]

Historically, the first venture capitalists were wealthy American families like the Rockefellers and Whitneys. Since the late 1950's, the dominant source of venture capital has been small business investment corporations, licensed by the Small Business Administration and eligible for low-interest government loans, which they may then turn around and invest in new and risky businesses in the hopes of obtaining very high returns. During the 1960's, additional sources of venture capital developed, including investment banks, commercial banks, large corporations, informal investment syndicates, and publicly-held venture capital corporations. All differ from a typical small stockholder, who may be keeping a few hundred shares of blue chip stock as the basis for a secure retirement income, by being relatively unconcerned with consistency, reliability or security in dividend payments. Venture capitalists have other holdings that provide these attributes and consequently can afford to take risks. Most attractive to them is the fact that capital gains receive very favorable tax treatment. For example, a wealthy individual in the highest tax bracket would pay 70% in taxes on dividends, but only 28% on capital gains.[28]

The barriers to venture capital financing of wind energy producers are four. The first may arise if the entrepreneur is unable to raise sufficient capital to organize his firm, develop its product and potential market, and begin initial production. This much the entrepreneur will have to accomplish on his or her own; venture capitalists will usually provide funds only after the entrepreneur has proven that the project is feasible, and that he or she is

capable of making that project work. Venture capitalists, then, do not finance new ideas, but the expansion of ideas that have been shown to work.

The second barrier that may arise is the lack of a ready market in which the wind firm may sell its output. Two points are relevant here. First, state public utility regulations must permit such sales without requiring the wind energy firm to meet all the complex regulations that utilities must meet because no small firm could possibly afford the overhead involved in doing so. Second, because the wind firm's market is in most cases limited to the local electric utility, public utility regulations must control sales to prevent the utility from taking advantage of its monopolistic position and demanding an unreasonably low price. If these conditions are not provided a ready market for the firm will not exist, and venture capitalists will hesitate to become involved.

A third potential barrier centers around land acquisition and use. The construction of small wind turbines will require zoning variances in the local community, and may be subject to state laws requiring the assessment of likely environmental impacts. Here again a small firm may have some difficulty coping with extensive regulatory demands.

The fourth potential barrier stems from the fact that the first few community wind firms to go into business are likely to suffer substantially lower profits than what would be expected on average over the long term. This is because the first systems will require a certain amount of debugging and refinement, and because technology costs will remain relatively high until the demand for wind turbines develops to the point where mass production reduces it. Table 7 indicates how a firm's return-on-investment will vary as technology cost falls, and as the price which the output can be sold for rises.

2. Options for Overcoming the Barriers

The U.S. Congress has already taken action that should make it easier for wind firms to obtain needed first-stage financing. In 1978 it passed the Small Business Energy Loan Act that empowers the Small Business Administration to make low-interest loans either directly to small businesses in energy-related fields, or in cooperation with private lending institutions. Direct loans have a limit of $350,000 and bank guaranteed loans a limit of $500,000. Consequently only the capital necessary for getting a firm organized and off the ground is provided. But that should be sufficient to set the stage for venture capital involvement.

TABLE 7

VARIATION IN ROI WITH TECHNOLOGY COST AND ENERGY PRICE

Technology Cost	Average Energy Price	Return on Investment
$1500/kw	4.5¢/kwh	7.88%
	6.0	10.51
	7.5	13.14
$1000/kw	4.5¢/kwh	11.82%
	6.0	15.77
	7.5	19.71
$ 500/kw	4.5¢/kwh	23.65%
	6.0	31.54
	7.5	39.42

With regard to market uncertainties, state and federal rules regulating the sale of electricity from small power producers to electric utilities are currently being revised, prompted by Congressional enactment of the Public Utilities Regulatory Policies Act of 1978. Small producers are already being offered attractive prices for their output in some parts of the country. An additional form of asistance that might be offered would be state or federal contracts for the purchase of wind generated power. Recently the California Department of Water Resources has agreed to purchase up to 300 million kilowatt-hours per year from one wind firm, which now plans to build 7,000 fifty-kilowatt wind turbines for the purpose.[30]

Land use and zoning issues are not appropriately dealt with by state or federal agencies except where unreasonable barriers to wind energy are erected (and the first response to these would most likely be court action). In all other cases it is desirable for the wind firm to reach a mutual understanding with the community in which it will build its turbines. With regard to state requirements for environmental assessment, the California Legislature has attempted to minimize the regulatory burden imposed on developers of all sorts through passage of S.B. 884, effective January 1, 1978. This bill authorized the state Office of Planning and Research to assist developers by identifying the regulatory procedures that must be followed, and by

coordinating review of the developer's submittals among those agencies with a statutory interest. With regard to other states in Region 9, they do not require a similarly extensive environmental assessment procedure, nor with the exception of Hawaii are land values especially high, and competition among competing users keen.

The fourth barrier—low initial profitability—should be offset somewhat by the special tax credits for energy investments made available by the Energy Tax Act of 1978. Whether these alone will be sufficient depends upon (1) the actual cost which the firm must pay for wind turbines, and (2) the price at which it may sell its electrical output. Because technology cost is likely to fall in the future through mass production, and because the selling price is or is becoming attractive, additional tax credits are not recommended at this time. It is recommended, however, that federal and state policy makers keep well-informed as to the profitability of wind power. Now only may higher credits be required in the short-run, but over the long-run, as wind technology costs fall, it is possible that the tax credits should be phased out altogether.

A summary of the barriers to venture capital financing of small wind systems, and compensating policy options, is presented in Table 8.

3. Evaluating the Options

Federal and state government will face three direct costs in adopting the policies discussed above: the interest income lost when SBA loans are issued at rates lower than those that the government itself must borrow at, the cost of any direct purchases by government agencies of wind power, and the cost of the special tax credits for energy investment.

Assuming that the SBA provides loans at the relative low interest rate of 8% while the federal government must borrow at 15%, the subsidy cost of a $350,000 loan will amount to $73,956. (See Appendix B for calculations.) Because a firm receiving this subsidy may build any number of wind turbines, the subsidy cost-per-kilowatt of capacity will vary. For example, if 100 fifty-kilowatt machines are built and operated the subsidy will amount to $14.79 per kilowatt of capacity. If the system is limited to twenty machines, the cost rises to $73.95 per kilowatt, while if the system includes 500 fifty-kilowatt machines the subsidy is only $2.95 per kilowatt.

The cost of direct purchases of electricity from wind firms need not be

higher than the cost the government would pay if it purchased that electricity from a conventional power source. A government agency could choose to pay more for wind-generated power because it offers positive externalities—no fossil fuel consumption and no emissions—but in that case it would actually be paying for an additional public good. Thus no net costs are assumed here.

TABLE 8

BARRIERS AND OPTIONS FOR VENTURE CAPITAL FINANCING

1. Lack of first-stage financing	1. SBA loan program	1. Variable
2. Lack of a clear market	2a. Regulatory changes in process	2a. Admin. Cost only
	2b. Direct purchase of wind power	2b. No net costs
3. Land use regulations	3. Administrative assistance	3. Admin. cost only
4. Low initial profitability	4. Energy Investment Tax Credit	4. ~$100/kw

The cost of special tax credits for energy investments amount to 10% of the technology's cost. Although wind system costs currently range between $1,500 and $2,000 per kilowatt, these are the costs for prototype units.[31] Other estimates assuming large-scale mass production range as low as $50 per kilowatt.[32] Because no experience with mass production possibilities exists at present, none of these estimates can be taken as reliable. Costs will certainly fall below prototype costs, but as noted earlier if they fall very far the special tax credit should be eliminated. For this reason a technology cost of $1,000 per kilowatt, for a tax credit of $100/kilowatt was assumed.

Political feasibility is not likely to be a substantial problem for any of the policies suggested here because the SBA and tax credit progreams are already in operation, while the purchase of wind-generated electricity should arouse little opposition if the price paid does not exceed what would be paid to conventional sources. Furthermore, the purchase of electricity, rather than wind turbines as has sometimes been suggested, leaves all the risk in the wind firm: if the system does not work, the government receives no power, but also pays for none.

One potentially difficult political problem could arise if the funds provided by the SBA programs prove insufficient to assist a large enough contingent of wind firms so that competition promotes efficient firms, and firms that can survive. The current program has appropriated only $30 million for direct loans, and $45 million for bank guaranteed loans. This is enough to fund 85 direct and 90 bank-guaranteed loans for energy-related firms of all sorts, not merely wind firms. Whether additional funding will be made available if needed depends in part on the performance of the firms funded under current appropriations, on current budget constraints, and on the demands of competing constituencies.[33] While the disposition of Congress regarding these matters is not subject to prediction, it is at least interesting to note that the total funding for the SBA programs—$75 million—is equal to less than 1% of the Department of Energy's total 1980 budget of nearly $10 billion.

In summary, neither large government expenditures nor major government actions are recommended to make wind power more attractive to venture capitalists. This situation befits an industry that is susceptible to effective development by the private sector.

Industrial Cogeneration

Many industries burn fuel oil to create steam that then powers their machinery. Others burn oil or natural gas to create heat for drying processes. In either case a great deal of waste heat is exhausted to the atmosphere. Industrial cogeneration is the process of making use of that waste heat to produce electricity, and it is not a new process. In the 1930's industrial cogenerators produced 30% of all the electricity used in the U.S. By 1950, however, the figure had fallen to 15% and by 1975 to just 5%—primarily because ever-larger facilities at electric utilities brought returns to scale that reduced the price of electricity, in constant dollars, by about 1-2% per year.[34] Consequently, cogeneration became an unattractive investment. It now appears, however, that the limit on returns to scale has been reached. On the other hand, because of recent energy prices increases, the opportunity for returns to fuel efficiency is becoming increasingly significant. At the present, cogeneration is society's best option for obtaining these returns.

Because industrial firms are often situated within a surrounding community, industrial cogeneration is an appropriate community energy system. In some European countries the exhaust steam itself is used to heat buildings in the

vicinity of the industry. This is less likely in the U.S. because industrial zones are usually separated from residential and commercial zones, and the transport of steam over distances of more than about one mile involves large heat losses, making it unprofitable.[35] For this reason it was assumed in this analysis that the steam is utilized to produce eleectrical energy.

Since cogeneration is most likely to be developed by an established industry, that industry can be expected to use some of its retained earnings for financing. Alternatively the firm might turn to commercial bank loan financing, althouth it is likely to do so only if the investment offers very high returns since its line of credit will almost certainly be restricted.[36]

1. Barriers to Financing Cogeneration with Retained Earnings

When planning investments a standard business procedure is to rank all potential investments according to their expected rate of return. Investment funds are then allocated on a project-by-project basis, beginning with whichever offers the highest expected rate of return and continuing on down the ranking until either all funds have been committed, or until an external investment offers a more attractive return.

Because of the rising price of energy an investment in cogeneration now offers a rate of return that in some circumstances will approach 50%. However, three barriers continue to inhibit cogeneration investment. Foremost among these is the preference of firms for investments that will improve their competitive position in the markets which they serve. Even if cogeneration offers a higher rate of return than any production-related investment it will not serve to increase a firm's share in a given market or allow it to extend into new markets. Consequently its potential return will be discounted compared to that from mainstream business investments.[37]

A second barrier to cogeneration investment is the fact that cogeneration facilities will be added to a firm's property tax base, while the fuel or electricity, which would otherwise be purchased, is not so taxed.

A third barrier is the complex of public utility regulations that a firm may face if it wishes to sell excess power to the local utility. Since this barrier has already been discussed in relation to MSW and wind power, and is fully treated in the preceding Chapter, it will not be included here.

2. Options for Overcoming the Barriers

Several government actions could make cogeneration investments more attractive. The authors of Energy Future, the widely acclaimed study by the Harvard Business School, suggest that the best way to spur additional cogeneration investment is to increase the 10% tax credit for energy investments to 40%.[38] This, they argue, will enable cogeneration investment to yield a 30% return—the rate required by businessmen because of its non-production nature.

Alternatively state or federal government agencies might set up cogeneration loan programs, providing low-interest loans to industries, schools, hospitals and other large institutions that have the capacity to install cogeneration facilities.

A third alternative would be for state legislatures or Congress to order industries (and perhaps schools and hospitals) to install cogeneration equipment, perhaps providing additional tax credits or low-interest loans so as not to impose an economic burden upon the cogenerator. This would be politically difficult, but feasible if circumstances warranted, e.g., during an oil embargo, and if potential cogenerators appeared to be dragging their feet.

With regard to the problem of cogeneration facilities being subject to property taxes when purchases of energy are not, this disincentive could be removed by a state law exempting cogeneration investments from local property taxes.

3. Evaluating the Options

The recent increases in energy prices have significantly altered the return on cogeneration. To analyze these changes, and the economics of the potential government incentives noted above, a hypothetical case as described in Table 8 will be utilized. (A fuller explanation of the rationale behind the parameters in this model appears at the outset of Appendix C).

TABLE 9

MODEL COGENERATION SYSTEM

Technology Description

An oil-fired system with a capacity of 5,000 kilowatts.
A load factor of 80%. (i.e., system operates 80% of the year)
Annual output = 35 million kilowatt hours.

System Costs

Cogeneration turbine-generator w/boiler:	$550/kw
Emissions control technology:	$125/kw
Purchase of emissions offsets:	$125/kw

Total system costs: $800/kw = $4,000,000/system

Annual Cost Factors	Annual Benefit Factors
Fuel	Electricity sales/savings
Depreciation	Tax credits
Maintenance	Accelerated depreciation
Standby charges	

Oil Fuel Costs: $14/barrel (1979) $28/barrel (1980)

Box 1 in Appendix C indicates that the model facility, if built and operating in Northern California during the first half of 1979 (prior to OPEC's June price increases), would have earned a return of 18.66%. Since this includes both the conventional and special energy tax credits and the return is still well below 30%, the need for additional credits seems evident.

Box 2 in Appendix C tells a different story. It reflects the fact that the current prices for electricity and oil are approximately double what they were in early 1979. The upshot is that now the return on cogeneration investment amounts to 38.6%. Moreover, even if all tax credits were removed the return would still exceed 34%—still in excess of what has been alleged as necessary to attract business investment.

Before discussing the merits of increasing the current energy investment tax credit let us compare its current cost—$400,000 on a $4,000,000 investment —with that of a $4,000,000 loan subsidized at the low rate of 8%. Assuming that the government itself must borrow at 15% (consistent with recent U.S. bond sales as well as with earlier analyses in this study), Box 3 in Appendix C shows that it will cost the government $841,844 to provide the loan at 8%.

This works out to a cost of $168.37 per kilowatt of capacity subsidized. The cost of the energy investment tax credit, by contrast, works out to $80 per kilowatt subsidized.

It seems obvious that no increase in investment tax credits should be granted for cogeneration if we are to avoid handing out substantial windfalls to industry. The source of the windfall would be the public since the public is paying both the higher electricity rates that have made cogeneration attractive and a portion of the taxes that are expended in credits. Given the current impact of inflation upon consumers it is inequitable to expect them to provide windfalls to businesses that more easily pass on their inflated costs in higher prices.

At the same time, an argument can be made against instituting a low-interest loan program since even without such a subsidy the investment would be highly rewarding. Moreover, if a loan program were introduced it should replace the tax credit program. But business would certainly lobby against losing the tax credit, and even if the change passed Congress some firms might delay planned cogeneration investment out of spite. In short, it might be best not to rock the boat.

Yet another issue complicates this question. At present, credit is tight. Tax credits, no matter how large, for an investment no matter how attractive, will be ineffective if an industrial firm cannot obtain the necessary investment capital. This is a problem that a loan program would address directly.

The solution may be to allow businesses the option of either a low-interest loan or the tax credits (both conventional and special energy) but not both. In addition to the equity argument raised above, we should remember that cogeneration, despite its substantial promise, still relies upon the combustion of fossil fuel, and will tend to negatively impact air and water quality in the predominantly urban areas where systems will be located. Most of these areas are already in violation of ambient air quality standards (thus the inclusion of offsets costs in the model). It would seem more sensible to offer preferential incentives to those energy investments that utilize renewable, non-polluting resources—if preference is to be given to any.

The third potential policy—ordering industries, schools, and hospitals to invest in cogeneration—may immediately strike one as politically unfeasible. However, a soft form of coercion may be developing already. A 1978 study relied upon heavily by the authors of Energy Future, reported that the required rate of return on gas-saving investments (including gas-fired cogeneration units) had dropped from about 30% to 20% at the time of their writing (March 1978), "probably because of fears of curtailment."[39] Memories of the natural gas shortages of the winter of 1977, plus a new awareness of the economic costs of having to shut down operations when gas supplies diminish, apparently have convinced many firms of the value of being able to make do with less. More to the point, the Federal Energy Regulatory Commission (F.E.R.C.) is currently considering whether to increase the natural gas priority of cogenerators from 4 to 3. Industrial gas users normally hold priority 4, the lowest for any class, meaning that in periods of restricted supply they would be the first to be curtailed. Under these circumstances, the value of obtaining a higher priority could be substantial. If the F.E.R.C. does adopt this policy it could achieve the same effect as legislation requiring cogeneration, but without political conflict and cost.

With regard to the second barrier—an increase in the firm's property tax liability—the cost of exempting a four million dollar investment from property taxes would amount to foregoing $54,000 in a community with a tax rate equal to the mean for Alameda County, California (1.3525% of full value). For a 5,000 kilowatt facility this amounts to an annual subsidy of $10.82 per kilowatt, or about .15¢ per kilowatt-hour, assuming a facility with the characteristics of the model in Table 9.

Whether stimulating cogeneration is worth this additional incentive should depend upon whether it will make any difference in an industry's decision to cogenerate or not. Given the fact that it will not provide additional capital to a credit-hungry business, and given that the rate of return is already high, the importance of this incremental return is negligible. Furthermore, were the four million dollars spent on another capital item, the firm would still face increased property taxes; thus a cogeneration investment does not impose an extra tax beyond that applied to any capital investment. On the other hand, the loss of $54,000 in tax revenues might have a significant impact upon a community, particularly given the currently financial difficulties of many urban governments. Moreover, it seems inequitable to ask a community

to forego tax revenues while at the same time accepting additional air pollution, all to produce electricity that may well be shipped to a community offering no subsidies to energy producers.

Table 10 summarizes the financial barriers and incentives to the use of retained earnings for financing cogeneration investments. The conclusion is that additional incentives are neither necessary nor merited, while eliminating the current energy investment tax credit (for cogeneration only) would cause more

TABLE 10

FINANCIAL BARRIERS AND INCENTIVES FOR COGENERATION

1. Return too low	1. Increase tax credit (not recommended)	1. $8/kw per % of ITC
2. Insufficient investment capital	2. Low-interest loans	2. $168/kw @ 8%
3. Property Tax	3. Exempt from tax (not recommended)	3. $11/kw/yr @ 1.3525%
4. Public Utility Regulations	4. Currently being addressed	4. Admin. only

trouble than it is worth. Moreover, cogeneration is potentially such an important contributor to the U.S.'s energy supply that we may not want to risk inhibiting its growth. For example, one facility with the characteristics of the model in Table 10 could save 38,440 barrels of oil per year (see Appendix C, Box 4). Estimates prepared for the Department of Energy indicate a cogeneration potential in the U.S. of from 15,000 to 54,000 megawatts of electrical capacity could be achieved by 1985.[40] Assuming that the mean between these high and low estimates is actually reached, 34,500 megawatts, and assuming that savings are proportional to those achieved in the model facility, the annual savings in oil (or its equivalent in natural gas) would amount to over 256 million barrels—or nearly 10% of our total oil imports. At a price of $28.00 per barrel, this would mean a reduction in our balance of trade deficit of almost $6.6 billion annually.

Residential Photovoltaics

Photovoltaic cells convert sunlight directly into electricity. The conversion occurs when a photon of light strikes a light-sensitive material and

displaces an electron. That electron, along with many others similaraly displaced, will subsequently flow across the cell in a direction governed by the magnetic fields on the cell surface and then into an electric circuit. The direct current thus induced may then be converted to alternating current via an inverter and utilized just as is the electric current available in a standard wall socket.[41]

Problems remain with commercializing photovoltaic systems. Most notably, they are expensive. Photovoltaic cells were initially developed to power satellites and manned space missions in which their cost—about $1,000 per peak watt[42]—was ignored. Production refinements during the 1970's reduced that cost to around $10 per peak watt, and the Department of Energy is funding research with a goal of 50¢ per peak watt by 1985. Assuming this barrier, and several less demanding system engineering problems are also overcome, photovoltaics could begin to appear on residential rooftops by 1990.[43]

1) Barriers to Financing Residential Photovoltaic Systems

Table 10 describes the costs, financing options, and benefits of the model photovoltaic system that will be used in the following policy analysis. Details of the calculations upon which the numbers are based appear in Box 1 of Appendix D.

As is evident for the table, the interest rates typically charged for home loans will require monthly payments in excess of the revenues from the sale of the electrical output. Only at the abnormally low loan rate of 6% will the homeowner break even. Part of the cause for this low return—apart from the system's limited output—stems from the fact that photovoltaic systems will not qualify for capacity payments from the utility, since they will not provide firm power. A second cause is the limited term of homeowner loans. Typically they are not extended for periods longer than ten years. By comparison, photovoltaic system life should be double that time period.

Should the economics of photovoltaics improve, however, an additional barrier may appear. Currently, mortgage lenders may refuse to provide mortgages that include the cost of solar hot water or heating systems because they feel that those systems will have a lower-than-cost resale value; thus they are not secure. This reflects the newness of solar technologies, and the fact that many solar systems installed to date have failed to perform as advertised. By 1990 solar water heaters may well have surmounted this obstacle, but

TABLE 11

MODEL PHOTOVOLTAIC SYSTEM: COSTS AND REVENUES

System Description

Roof-mounted, maximum output = 7 kilowatts
Average monthly output = 959 kilowatt-hours

System Costs

Total system cost = $6,000[44]
Financing: monthly payments on a 10 year bank loan vary with interest rate:

@ 6% =	$ 66.61
12% =	$ 86.08
15% =	$ 96.80
18% =	$108.11

Revenues

The value of each kilowatt-hour of electricity generated in 1990 is determined by escalating the average 1980 rate for peak and off-peak energy, as offered by Pacific Gas and Electric for the period May - July 1980, by 2.5% annually. This yields a rate of 6.99¢ per kilowatt hour.

Revenues = ($0.0699/kw-hr)(959 kw-hr) = $67.03

photovoltaic systems will still be new, and may receive similar treatment.[45]

A third barrier, originating also in mortgage lending practices, stems from the lenders' failure to recognize that solar technologies will reduce a homeowner's utility bills, and thus enable him or her to support larger monthly mortgage payments. Unless this ability is taken into account, the purchaser of a solar residence will be unable to obtain as much basic housing as the purchaser of a non-solar home because of the need to include solar system cost within the constraints of a fixed mortgage limit.[46]

2. Options for Overcoming the Barriers

One option for reducing the financing barrier to homeowner investment in photovoltaics is extension of currently available solar tax credits to photovoltaic devices. While the state credits offered by California and Arizona apply to all solar energy investments, the federal tax credits do not at present encompass photovoltaics. At least one bill now before Congress, S1760 (Packwood), would provide such extension.

A second option would be for state and federal governments to make low-interest and extended-term loans available. Several bills to establish a Solar Bank have been introduced in Congress, and it seems likely that some such institution will be authorized in the near future.[47] Depending upon the provision enacted, a homeowner might or might not be allowed to take advantage of tax credits as well as low-interest loans.

A third option would be to create quasi-public corporations dedicated to the development of residential photovoltaic systems. A given corporation would be assigned a franchise area within which to develop photovoltaic electricity. The return could be regulated just as in the case of an electric utility. The corporation would negotiate with homeowners for the use of their rooftops, offering a small rent in return. It would retain responsibility for installing and maintaining the systems, as well as for negotiating with the local utility regarding planning, implementation and sales.

A fourth option would be to allow electric utilities to develop residential photovoltaic systems. With regard to financing barriers caused by bank lending practices, these are most likely to disappear as experience with solar systems increases, and the systems become reliable. Section 244 of the National Energy Conservation Policy Act of 1978 (NECPA) aurthorized the Government National Mortgage Association to purchase up to $100 million of reduced-interest loans to homeowners for solar systems, and if extended and applied to photovoltaic systems this policy could serve to encourage private lenders to include the cost of photovoltaic systems in their mortgages—or even make it unnecessary.[48] NECPA also increased the loan ceilings on federally-insured mortgages for solar homes by $2,000, meaning that a homeowner purchasing a solar-equipped home need no longer end up with less housing than one purchasing a non-solar home.

3. Evaluating the Incentives

Whether or not a homeowner will find an investment in photovoltaics attractive or not will depend upon three factors: tax credits, loan interest rates, and the term of the loan. Some combination of subsidies for each of these factors will be necessary if photovoltaics are to become attractive as an investment.

How such subsidies might be combined is explored in Tables 12, 13, and 14. Table 12 analyses California, which offers total tax credits of $3,300, and indicates what the monthly payments would be on the required loan

Table 12

ANALYSIS OF CALIFORNIA PHOTOVOLTAIC INVESTMENT

i \ T	10 Yr	15 Yr	20 Yr
8%	$34.79	$27.57	$24.23
12%	42.60	36.01	33.62
15%	59.37	42.94	41.30

Table 12a Monthly Payments

Payments are averaged over the term of the loan. Total tax credits of $3,300 are used to reduce the principal 12 months after the loan is initiated. The figures above are approximations. For details, see Appendix E, Box 2.

i \ T	10 Yr	15 Yr	20 Yr
8%	$32.24	$39.46	$42.80
12%	24.43	31.02	33.41
15%	17.66	24.09	25.73

Table 12b Monthly Net Benefits

Net benefits is computed by subtracting monthly payments from $67.03.

Table 13

ANALYSIS OF ARIZONA PHOTOVOLTAIC INVESTMENT

i \ T	10 Yr	15 Yr	20 Yr
8%	$45.15	$35.68	$31.31
12%	54.45	45.86	42.55
15%	62.32	54.48	51.57

Table 13a Monthly Payments

Available tax credits include $1400 federal and $1000 state. Monthly payments calculated as for California. For details see Appendix D, Box 2.

i \ T	10 Yr	15 Yr	20 Yr
8%	$21.88	$31.35	$35.72
12%	12.58	21.17	24.48
15%	4.71	12.55	15.46

Table 13b Monthly Net Benefits

Monthly net benefits are computed by subracting monthly payments from $67.03.

ANALYSIS OF PHOTOVOLTAIC INVESTMENT FOR NEVADA & HAWAII

i \ T	10 Yr	15 Yr	20 Yr
8%	$56.68	$44.64	$39.18
12%	67.60	56.76	52.47
15%	76.73	66.79	63.03

Table 14a Monthly Payments

Available tax credits include $1400 federal credits. Calculations performed as for California. For details see Appendix D, Box. 2.

i \ T	10 Yr	15 Yr	20 Yr
8%	$10.35	$22.39	$27.85
12%	- .57	10.27	14.56
15%	-9.70	0.24	4.00

Table 14b Monthly Net Benefits

Monthly net benefits are computed by subtracting monthly payments from $67.03.

at varying interest rates and for terms of ten, fifteen, and twenty years. Table 12b identifies what the net monthly benefits would be for each case analyzed in Table 12a. Tables 13a , 13b , 14a , and 14b perform similar analyses for Arizona and for Nevada/Hawaii.[49]

It is clear from the tables that even for Nevada and Hawaii, which offer the lowest tax credits, some combination of interest rate and term will result in positive benefits to the homeowner. Indeed, it appears that some combinations, particularly in California, may yield greater benefits than policy-makers would normally think equitable, especially considering that public funds will be providing the investment capital.

To avoid the inequity that will result if all taxpayers provide subsidies so that a selected group of homeowners receive very high benefits, the agency disbursing loans will have to take into account carefully the different tax credits and other photovoltaic subsidies available in different states. Tables such as those developed above, but with greater detail, i.e., more interest rates, more terms, and taking into account the precise revenue from electricity sales offered in each utility area, should be available to Solar Bank loan officers. Loan personnel could then easily identify the interest rate and term that a particular applicant is entitled to, using as a criterion some target level of net benefits, say $20/month.

The cost of these policies to state and federal government will also vary according to the tax credits, interest rates, and terms offered. Some idea of what these costs will be is presented in Tables 15 through 17. The tables identify what the cost will be to a solar bank assuming a variety of low-interest rates and terms, and assuming that the Treasury must borrow at 15%.[50]

Whether large-scale programs providing a combination of financial incentives for photovoltaics will be politically feasible in 1990 is impossible to predict at this time. Congress is, as mentioned, likely to establish a Solar Bank; the extent to which it will be funded is another matter. Certainly political instability in the Middle East could spur investment in all sorts of energy alternatives, but a question still remains as to whether D.O.E.'s goal of 50¢ per peak watt for solar cells will be reached by 1985, and if not then, when?

Table 15

PUBLIC SUBSIDY COSTS FOR PHOTOVOLTAICS IN CALIFORNIA

i \ T	10 Yr	15 Yr	20 Yr
8%	$1,439	$2,390	$3,457
12%	643	1,076	1,553
15%	0	0	0

Table 15a Loan Subsidy Cost

i \ T	10 Yr	15 Yr	20 Yr
8%	2.1¢	2.5¢	2.9¢
12%	1.7	1.9	2.1
15%	1.4	1.4	1.4

Table 15b Subsidy per kw-hr

The loan principal is assumed to be $3,000 after all tax credits are subtracted and refinancing costs are added. The cost of this loan for each term and interest rate is then calculated, and subtracted from cost of a loan of similar term taken at 15%. For details see Appendix D, Box 3.

Total public subsidy includes loan subsidy from Table plus tax credits of $3,300. This is then divided among the total kilowatt-hours to be produced during the lifetime of the system (20 years). For

Table 16

PUBLIC SUBSIDY COSTS FOR PHOTOVOLTAICS IN ARIZONA*

i \ T	10 Yr	15 Yr	20 Yr
8%	$1,823	$3,028	$4,378
12%	815	1,363	1,967
15%	0	0	0

Table 16a Loan Subsidy Costs

i \ T	10 YR	15 Yr	20 Yr
8%	1.8¢	2.4¢	2.9¢
12%	1.4	1.6	1.9
15%	1.0	1.0	1.0

Table 16b Subsidy per kw-hr

See Appendix D, Box 3, for calculations

*See Footnote 51

TABLE 17

PUBLIC SUBSIDY COSTS FOR PHOTOVOLTAICS IN HAWAII/NEVADA

i \ T	10 Yr	15 Yr	20 Yr
8%	$2,254	$3,745	$5,415
12%	1,007	1,686	2,433
15%	0	0	0

Table 17a Loan Subsidy Costs

i \ T	10 Yr	15 YR	20 Yr
8%	1.6¢	2.2¢	3.0¢
12%	1.0	1.3	1.7
15%	0.6	0.6	0.6

Table 17b Subsidy per kw-hr

The creation of quasi-public corporations to develop residential photovoltaics implies additional "overhead" costs to a photovoltaics commercialization program—the costs of administration and corporation profit. But the availablity of a broker to assist homeowners in obtaining photovoltaic systems could provide society with substantial benefits. A broker could provide information, advertising, and other services that would help overcome the developmental barrier of waiting for millions of independent decision-makers to decide to invest in a new technology. The broker could absorb many of the transactions costs faced by homeowners, obtain the lowest possible financing via large bond and equity offerings, work with technology manufacturers to obtain standardized, mass-produced systems that minimize cost yet remain reliable, provide installation and maintenance, and coordinate photovoltaic development with the local electric utility. Assuming such a corporation is granted an exclusive right to serve a particular area it should be regulated by state or federal regulatory commissions. However, before such franchises are awarded, the possibility of establishing multiple firms competing in a given area should be investigated. This option might prove preferable to a regulated monopoly organization in terms of overall efficiency.

The cost to government of having brokers develop photovoltaics is likely to be less than those of a Solar Bank because the bulk of system financing would come from the private sector, not the Treasury. Tax credits similar to those assumed in Tables 12 thru 17 would probably remain necessary (with the broker obtaining the credits). Should the corporations have difficulty raising sufficient capital at reasonable prices the federal government could consider providing low-interest loans—assuming photovoltaic development is deemed a sufficiently desirable social good.

Assigning electric utilities the responsibility for photovoltaic commercialization would appear to be potentially the most efficient approach, since utilities could provide the same services as quasi-public corporations, without necessitating the organization of an entirely new institution. Utilities would also be in a position to effectively integrate photovoltaics into their long-term supply planning. Moreover, the administrative overhead involved in the selling and buying of photovoltaic electricity could be greatly simplified by having only the utility involved in record-keeping.

The costs to government for utility-sponsored commercialization are likely to be similar to those for the quasi-public corporation approach. Tax credits, assignable by the homeowner to the utility, are still likely to be necessary. However, at present electric utilities are prohibited from becoming involved in the financing, supplying, or installing of any residential energy conservation measure by Section 216(A) of the National Energy Conservation Policy Act. (Solar technologies are considered to be conservation measures for the purposes of the Act.) Whether this prohibition will disappear by 1990 is uncertain.[52]

Summary of Financial Barriers

The major financial barriers to each technology are listed in Table 18 along with potential compensating policies and their costs. The costs generally are of two types: direct dollar outlays (usually tax expenditures) or administrative costs involved in changing regulations. Note that the costs stated are only estimates, and that in some cases it was impossible to project a definite dollar value, e.g., what might the cost be of state-provided supplementary funding for MSW projects, should new air quality regulations require additional controls.

Given the foregoing qualifications, Table 19 offers a comparison of the direct public costs of subsidizing each of the four technologies. Note that only the subsidies involved in project financing are included, i.e., tax credits, low-interest loans, and tax exempt bonds. Other subsidy costs may arise during project development, and administrative costs will always exist, but these should not be substantial enough to change the comparative costs of different technologies by more than a factor or two.

TABLE 18

SUMMARY OF FINANCIAL BARRIERS

Barrier	Policy	Cost
MSW:		
Risk of failing to meet bond obligations	State bond reserve support fund.	No cost if fund is properly invested.
	State or federal grants.	Cost equal to size of grant.
Reliability of technology.	Statutorily required warrantees.	Administrative cost only.
Likelihood of unexpected costs.	State-supported capital reserve fund.	Possibly $100-200 per kilowatt.
Availability of refuse contracts	State-designated wastesheds	Political costs, administrative costs.
Wind:		
Lack of first-stage financing.	SBA loans	Vary with size of loan and interest rate; likely to be relatively small.
Lack of a clear market for wind electricity.	Regulations for power sales being revised.	Administrative only.
	Direct state purchase of wind power.	No net costs.
Restrictive land-use regulations.	State-provided assistance in dealing with regulations.	Administrative costs only.
Cogeneration:		
Rate of return insufficient	Increase tax credits (not recommended)	$8/kw per percent of tax credit.
Insufficient investment capital	Low-interest loans.	At 8% interest, a loan would cost $168/kw when federal bonds offer 15%.

CONTINUED

SUMMARY OF FINANCIAL BARRIERS

Barrier	Policy	Cost
Cogeneration:		
Property tax	Exempt cogeneration investments from tax. (not recommended.)	$11/kw/yr @ tax rate of 1.3525%
Public Utility Regulations	Currently being revised.	Administrative costs only.
Photovoltaics:		
Monthly loan payments exceed monthly revenues from sales	Low-interest and extended-term loans.	Variable from $0 to more than $5,000 for a $6,000 system.
	Tax credits	Currently cost $1,400 to $3,300 per $6,000 system
	Quasi-public corporations using private financing.	Tax credits would go to corporations. Electric customers might face higher rates.
	Electric utility to own and finance the systems.	Tax credits to utility. Possibly higher electricty rates.
Morgage lending bias against full financing of solar systems.	This bias mostly removed by N.E.C.P.A. Remaining bias likely to disappear as solar penetrates the market.	Administrative costs. Possibly some loan-guarantee costs.

TABLE 19

COMPARISON OF SUBSIDY COST IN c/KW-HR

Type of Subsidy	MSW	Wind	Cogen	PV
Tax Credits	----	.19¢	.06¢	1.8¢
Subsidized loans	----	----	.12¢	
Tax-Exempt Bonds	.19¢	----	----	----

For calculations, see Appendix E

From Table 19 it is obvious that cogeneration offers the greatest return per dollar of public subsidy. The cost per kilowatt-hour of electricity produced is one-third that for wind and MSW if only the presently available tax credits are provided. The use of low-interest loans to promote cogeneration would still be less costly than the subsidies for wind and MSW. The tax credit subsidy for cogeneration is only one-thirtieth the size of the subsidy necessary to enable photovoltaics to become competitive.

Although it appears that the cost of MSW and wind subsidies are equal, the MSW calculation was made assuming that no value is obtained by recovering resources, such as aluminum and steel, from the waste stream. If this is done, the net public cost of MSW may fall to zero. On the other hand, MSW facilities will produce unpleasant emissions that will not be completely eliminated even with the best control technology. Wind systems will have no similar liability.

Photovoltaic systems are clearly less economical than the other technologies, but their relatively high cost should not inhibit further research and development on them. Cost reductions beyond those planned for 1985 by D.O.E. are a clear possibility; substantial research on photosensitive materials other that silicon has only begun. Moreover, when the subsidy cost of 1.8¢/kw-hr is compared to the projected 1990 price of electricity—about 7¢/kw-hr—it does not seem so unbearable.

As a final qualification it be noted that other factors—political demands, budget constraints, development of new or resurgence of old constituencies—are likely to have much influence upon the willingness of the federal

and state governments to provide energy investment subsidies in the coming years. Consequently the implications of the data in Table 17 should not be taken as the last word regarding what will—or even what should—be done to overcome financial barriers to the investment in community energy systems.

Footnotes

1. The average after-tax return for all industry during the period 1973-77 was 13.8%. It is unlikely that firms will pay a higher percentage that this to borrow money, since to do so would involve, on average, a loss. Source: The Economic Report of The President, Washington, January 1979.

2. Additional benefits from technology development which will accrue to future generations are: greater energy security, greater economic security, and lower prices for conventional fuels (since there will be reduced competition for them).

3. Pindyck, Robert S., Gains to producers from cartelization of exhaustible resources, Review of Economics and Statistics, May 1978

4. The D.O.E. goal for photovoltaic cell cost is $0.50 per peak watt by 1985. Current price is about $10.00 per peak watt.

5. For a detailed discussion of MSW conversion technologies see:

   Ritschard, R.L., Haven, K.F., Henriquez, M., Kay, J., and Walzer, W., Characterization of Solid Waste Conversion and Cogeneration Systems Lawrence Berkeley Laboratory, Berkeley, California, August 15, 1978. LBL-7883.

6. Ibid. p111

7. Note that as refuse classification technology improves, and as the value of recyclable materials rises, an increasing proportion of aluminum, ferrous metals and glass will be recovered prior to combustion, when their value is greatest.

8. In a number of California communities (e.g., San Francisco, Alameda) the cost of landfilling has been the primary motivation for investigating the MSW alternative. For example, by 1981 the City of Alameda's local landfill site will reach capacity, requiring the city to turn to a site in eastern Alameda county for disposal. Round trip distance to that site is seventy-six miles, and while the landfill operators charge only $2.50 per ton as their gate fee, the transportation cost for the city will be approximately ten times that. Currently Alameda pays only $2.80 per ton for local landfilling.

9. Material for this section is based upon:

California State Solid Waste Management Board, Refuse to Energy Conversion Projects, Sacramento, December 1977.
and:
Investment Bankers Association of America, Fundamentals of Municipal Bonds, Washington: 1969

10. At 7.75% interest on a $70,000,000 bond the annual interest will be $174,996 more than if the interest rate were 7.5%.

11. "Debt obligations" encompass both the interest that must be paid to bondholders each year and the annual payment into the sinking fund, which repurchases the debt at the end of twenty years.

12. Past debt behavior will be especially important if the municipality has ever defaulted on an obligation; if so, whether the municipality made a good-faith effort to re-finance the debt is more important than the actual default.

13. The estimated debt-coverage ratio is always vitally important, and an attractive issue will be one where this ratio approaches 1.5 (meaning that annual project revenues will be 1.5 times the amount required to meet both the annual interest payments and annual contribution to the sinking fund.

14. This assumes that there is no problem capitalizing the fund. There could be, since the fund would have to include $9.1 million for each project similar to the model identified in Table 3 (pg 20) which it covered. A grant might be $5 million, which could still improve the debt coverage ratio significantly while being easier to bear in the short run.

15. The uncertainty of such requirements stems from the fact that many local environmental regulations are still under development; few State Implementation Plans, as required by the 1977 Clean Air Act Amendments, have been finalized and approved by state legislatures and the Environmental Protection Agency.

16. This figure assumes all projects produce electricity, which they will not. However, they will produce gas or steam of similar energy content, so the cost estimate is justifiable. A typical 1,ooo tpd plant will have a capacity of 40,000 kilowatts; $6.67 million ÷ 40,000 kw = $167/kw. Note, however, that the $70 million project cost estimate does include funds for Best Available Control Technology for emissions controls; still, the additional funds might be required to purchase offsets, should they be required.

17. Note that this model is based in part on Refuse to Energy Conversion Projects, op.cit.

18. The actual number is about six million, with 150,000 still in operation. The Rural Electrification Administration was created by Executive Order 7037, May 11, 1935, and was subsequently incorporated into the Emergency Relief Act of 1935.

19. The potential for wind power in the Southwest is actually greater than 10-15% of demand, but must be limited to that range because wind output is variable and to provide backup for more than 10-15% would be uneconomical. For a discussion of California's wind potential see:
California Energy Commission, Looking Forward: Energy Choices for California, Sacramento, March 1979. Page 202-204.

20. Personal communication for John Nichols, Chief, California Energy Commission, Wind Office, December 1979.

21. Electric Power Research Institute, Research and Development Plan for 1979-1983. PS-831-SR, Palo Alto, July 1, 1978. EPRI's Plan indicates that electrical generating facilities now consumes 10% of the nation's freshwater runoff. At present the fresh water runoff in the Southwest is more than 100% allocated, making the satisfaction of future utility demands problematic at best.

22. Personal communication from John Obermeier, California State Office of Appropriate Technology, in reference to earlier studies of personal attitudes towards alternative energy technologies.

23. See, for example:
Sinclair, Leroy W., Venture Capital: the sourcebook of small business financing, Technimetrics, 1973.

24. The most famous manufacturer of wind turbines in the U.S. was Jacobs Electric, which built many of the "air motors" used on farms throughout the Midwest. The refinements added over the years by Jacobs are now being studied by researches at institutions such as the Solar Energy Research Institute.

25. Background for this section comes from:
Rubel, Stanley M., Guide to Venture Capital Sources, Chicago: 1974
Dominguez, John R., Venture Capital, Lexington, Massachusetts: 1974

26. Note that capital gains or losses are also possible with bonds, because the bonds may be bought or sold at other than par value; but the difference is usually small. See: "Investing in Tax Exempts," Business Week, July 25, 1977, p127.

27. In some cases venture capitalists are interested in dividends more than capital gains; however, this is not likely to be the case with wind power since substantial and continuous reinvestment will be necessary if the market is to be tapped on a large scale.

Given other characteristics of the market, it may have to be tapped on a large scale if it is to be tapped at all.

28. The Revenue Act of 1978 reduced capital gains subject to income taxation from 50% to 40%. Thus: (.50)(.70) = .35, while (.40)(.70) = .28.

29. Table 4 calculations of return on investment are obtained by assuming that each kilowatt of capacity produces electrical output during 30% of the year's hours, for a total of 2,628 kilowatt hours. This number is then multiplied by the various energy prices (4.5¢, 6.0¢ and 7.5¢) that are likely to be paid for wind energy in different parts of the Region over the next twenty years. This dollar amount is then divided by the technology cost ($500 - $1500/kw) to get the return.

30. Personal communication from Alvin Duskin, December 1979.

31. Personal communication from John Obermeier, December 1979.

32. Personal communication from Alvin Duskin, December 1979. Mr. Duskin argues that the technology of windmills is comparable to that of automobiles in terms of materials used, sophistication of the equipment, complexity of design, etc. He feels that through mass production the cost of automobiles has fallen to $2-3 per pound, and that the cost of windmills, if similarly mass produced, could fall into the same price range. That would leave U.S. Wind Power's 50 kilowatt windmill, weighing 2500 lbs., with a cost of $5,000 - $7,500, for a price per kilowatt of $50 - $75.

33. Political constituencies will certainly include, if not be dominated by, large energy and aerospace corporations. They may or may not oppose SBA funding of new, small competitors. They will oppose such funding if they feel the small firms will come to threaten their market power. On the other hand, recent experience indicates that successful small firms are inevitably gobbled up by large corporations; in that case, the corporations benefit from the SBA program that helped develop the lucrative acquisitions.

34. The actual decline in electricity prices averaged 1.7% per year between 1950 and 1970. See: Hatsopoulos, G.N., Gyftopoulos, E.P., Sant, R.W., and Widmer, T.F., "Capital Investment to Save Energy," Harvard Business Review, March-April 1978.

35. One exception to this rule is Manhatten, where waste steam from Consolidated Edison power plants provides heat for about 500 buildings. Of course, the population density is sufficient to permit such use. See: Energy Future, op.cit., page 154.

36. Another advantage of internal financing is that repayment deadlines need not be met. In times of economic instability such deadlines impose an extra risk on the firm.

37. Hatsopoulos et al, op.cit., page 111.

38. Yergin et al., op.cit., page 162.

39. Hatsopoulos et al., op.cit., page 113-114.

40. Thermo Electron, "A study of Inplant Electric Generation in the Chemical, Petroleum Refining and Paper and Pulp Industries." Report prepared for the Federal Energy Administration, Washington, D.C.

41. Kelly, Henry, "Photovoltaic power systems: a tour through the alternatives," Science 199: 634-643, Feb. 10, 1978.

42. A "peak" watt is the maximum amount of energy that a solar cell can produce, and is output when the sun's rays are perpendicular to the cell surface.

43. Other systems engineering problems facing photovoltaics include development either of energy storage or load management techniques that can offset its intermittant character, and the need for a low-cost, high-quality inverter to convert the direct-current output from the cells into standard alternative current. Against these liabilities must be weighed photovoltaics' benefits: no consumption of fossil fuels, no operating emissions, and the fact that maximum output occurs during midday, when electrical demand is also high.

44. The system cost used here has been estimated by the Sandia National Photovoltaics Project, and is used in their analyses. Personal communication from Gary Jones, Sandia, August 1979.

45. Miller, Alan S., "Legal Obstacles to Decentralized Solar Energy Technology - Part II," Solar Law Reporter, Vol. 1, page 727 and 777.

46. Ibid., Page 777.

47. Two of the leading contenders are: H.R. 605, the Solar Bank Act, introduced by Rep. Stephen Neal (D-Wash), and S-950, the Omnibus Solar Energy Commercialization Act, introduced by Senator John Durkin, (D-N.H.). The Neal bill has had Carter administration backing, although this may disappear with the advent of the recent budget-cutting effort.

48. Miller, op.cit., page 778.

49. Federal tax credits cover 30% of the first $2,000 spent, and 20% of the next $8,000. On a $6,000 investment they would total $1,400. California Solar credits cover 55% of system cost; on a $6,000 system this would mean $3,300 -- minus the federal tax credits.

50. The interest rate on Treasury bills at the time this analysis was performed (May 1980) was approximately 15%. Since that time interest rates have dropped substantially. This erratic behavior suggests instability in future interest rates as well as the likelihood that they may again rise to 15% or more. Consequently the calculations have not be redone.

51. Arizona offers a maximum of $1,000 in solar credits, or 35% of system cost, whichever is less. This is in addition to Federal credits. Hawaii and Nevada do not offer any state solar tax credits.

52. The rationale for Section 216(A) stems from the fact that utility executives have publickly stated that they have little faith in solar energy, conservation, or any alternatives other than coal and nuclear power. Such at least was true prior to the passage of N.E.C.P.A. in 1978. Utility attitudes have changed since then, as higher fuel and capital costs have forced them to re-evaluate their position. Some additional justification for Section 216(A) may come from Congressional opposition to promoting energy monopoly.

APPENDICES

TABLE 1

The Revenue Requirements for a Private Project

Year	Sinking Fund Plus Operating Costs	Firm Profits	1 + 2 / .54	3 / .904	Bond Interest	Accelerated Depreciation	Property Tax	Revenue Requirements
1	$ 5,984,000	$ 7,000,000	$ 24,044,000	$ 26,597,000	$ 5,250,000	$ 6,666,666	$ [illegible].947,000	$ 28,400,000
2	"	6,650,000	23,396,000	25,881,000	"	6,333,333	"	35,471,000
3	"	6,300,000	22,748,000	25,164,000	"	6,000,000	"	37,361,000
4	"	5,950,000	22,100,000	24,447,000	"	5,666,667	"	36,310,000
5	"	5,600,000	21,452,000	23,730,000	"	5,333,333	"	35,260,000
6	"	5,250,000	20,803,000	23,012,000	"	5,000,000	"	34,209,000
7	"	4,900,000	20,156,000	22,296,000	"	4,666,667	"	33,159,000
8	"	4,550,000	19,507,000	21,578,000	"	4,333,333	"	32,108,000
9	"	4,200,000	18,859,000	20,861,000	"	4,000,000	"	31,058,000
10	"	3,850,000	18,211,000	20,145,000	"	3,666,667	"	30,008,000
11	"	3,500,000	17,563,000	19,428,000	"	3,333,333	"	28,958,000
12	"	3,150,000	16,914,000	18,710,000	"	3,000,000	"	27,907,000
13	"	2,800,000	16,267,000	17,994,000	"	2,666,667	"	26,857,000
14	"	2,450,000	15,619,000	17,278,000	"	2,333,333	"	25,808,000
15	"	2,100,000	14,970,000	16,560,000	"	2,000,000	"	24,757,000
16	"	1,750,000	14,322,000	15,843,000	"	1,666,667	"	23,706,000
17	"	1,400,000	13,674,000	15,126,000	"	1,333,333	"	22,656,000
18	"	1,050,000	13,026,000	14,409,000	"	1,000,000	"	21,606,000
19	"	700,000	12,378,000	13,692,000	"	666,667	"	20,555,000
20	"	350,000	11,730,000	12,975,000	"	333,333	"	19,505,000

Notes

Sinking Fund + Operating Costs: $1,750,000 + $4,234,000 = $5,984,000

Annual firm profit = 20% of depreciated value of original asset. Original value is $35,000,000; depreciation is straightline at $1,750,000/year.

Columns 3 and 4 are sub-products necessary for calculating federal and and state income tax components of revenue requirements.

APPENDIX A

Calculations for Table 1

Col. 1: Sinking Fund + Operating Costs = $1,750,000
4,234,000

$5,984,000

Col. 2: Firm profits are 20% of depreciated value of firm investment. Original investment (internal funds only) = $35,000,000, and depreciation is straight-line for 20 years, @ $1,750,000/year.

Col. 3: This is a subproduct used to calculated federal corporate income taxes (Table 3) and revenue requirements.

Col. 4: This subproduct is used to calculate state (California) income taxes (Table 3) and revenue requirements.

Col. 5: Bond interest = 15% of total bond debt per year =

$$(.15)(\$35,000,000) = \$5,250,000$$

Col. 6: Accelerated depreciation is calculated via the sum-of-the-years digits method. The formula is:

$$\frac{2(N+1+M)}{N(N+1)} * (\$70,000,000) \quad \text{where:}$$

N = no. of years in depreciation period, here 20

M = year being depreciated (i.e., 1 thru 20)

Col. 7: Property Tax. An average of the range of industrial property tax rates currently in effect in Alameda County, California was used. The rates range from 1.175% of full capital value to 1.53%; the average is 1.3525%.

Computational Procedure

$$\text{Rev. Req.} = \frac{\dfrac{\text{Sink. Fund + Op. Cost + Firm ROI}}{.54}}{.904} + \left\{\begin{array}{l}\text{Bond Interest}\\ \text{Accelerated Depreciation}\\ \text{Property Tax}\end{array}\right.$$

APPENDIX A

Table 2

The Difference Between
Private and Municipal Revenue Requirements

Year	Municipal Revenue Requirement	Private Revenue Requirement	Discounted Difference
1	$13,334,000	$28,400,000	$15,066,000
2	"	35,471,000	21,492,000
3	"	37,361,000	22,646,000
4	"	36,310,000	21,021,000
5	"	35,260,000	19,481,000
6	"	34,209,000	18,011,000
7	"	33,159,000	16,604,000
8	"	32,108,000	15,263,000
9	"	31,058,000	13,988,000
10	"	30,008,000	12,777,000
11	"	28,958,000	11,625,000
12	"	27,907,000	10,530,000
13	"	26,857,000	9,483,000
14	"	25,808,000	8,497,000
15	"	24,757,000	7,555,000
16	"	23,706,000	6,657,000
17	"	22,656,000	5,826,000
18	"	21,606,000	5,004,000
19	"	20,555,000	4,248,000
20	"	19,505,000	3,520,000
		Total Difference:	249,294,000

Notes

Municipal requirements: Sinking Fund = 5% of $70,000,000 debt, plus
Operating costs of $4,234,000/year, plus
Interest payments = 8% of $70,000,000 debt
$3,500,000 + $4,234,000 + $5,600,000 = $13,334,000/year

Discount rate is 3%.

APPENDIX A

Table 3

Federal and State Corporate Taxes

Year	Federal Taxes	State Taxes
1	$ 0	$ 2,553,000
2	7,509,000	2,412,000
3	9,862,000	2,277,000
4	9,301,000	2,147,000
5	8,768,000	2,024,000
6	8,257,000	1,906,000
7	7,765,000	1,793,000
8	7,295,000	1,684,000
9	6,847,000	1,581,000
10	6,419,000	1,482,000
11	6,011,000	1,388,000
12	5,622,000	1,298,000
13	5,247,000	1,211,000
14	4,894,000	1,130,000
15	4,554,000	1,051,000
16	4,229,000	976,000
17	3,931,000	908,000
18	3,625,000	837,000
19	3,349,000	773,000
20	3,078,000	710,000
	$116,563,000	$30,141,000

Notes

Federal taxes are calculated by subtracting the values in columns 1 and 2 from column 3 in Table 1, and then discounting at 3%.

State taxes are calculated by subtracting column 3 from column 4 in Table 1, and then discounting at 3%

$14 million in tax credits are subtracting from federal taxes in years 1 and 2.

Table 4

Federal and State Interest Taxes
and Local Property Taxes

Year	Federal Taxes	State Taxes	Property Taxes
1	$ 2,135,000	$ 609,000	$ 947.000
2	2,073,000	591,000	919,000
3	2,012,000	574,000	892,000
4	1,954,000	557,000	866,000
5	1,896,000	541,000	841,000
6	1,842,000	525,000	817,000
7	1,788,000	510,000	793,000
8	1,736,000	495,000	770,000
9	1,685,000	481,000	747,000
10	1,636,000	467,000	726,000
11	1,589,000	453,000	704,000
12	1,542,000	440,000	684,000
13	1,497,000	427,000	664,000
14	1,454,000	415,000	645,000
15	1,411,000	403,000	626,000
16	1,370,000	391,000	608,000
17	1,330,000	380,000	590,000
18	1,292,000	368,000	573,000
19	1,254,000	358,000	556,000
20	1,217,000	347,000	540,000
	$ 32,714,000	$9,332,000	$14,508,000

Notes

State tax = 11.6% of interest on bond debt, discounted at 3%.
In year 1, this equals: (.0116)($5,250,000) = $609,000.

Federal tax = 46% of (interest - state tax). Discounted at 3%.

Property tax = 1.3525% of $70 million, discounted at 3%.

Table 5

A Comparison of
The Increased Revenue Requirements of a Private MSW Project
With the Increased Tax Revenues of the Same Project

Increase in Revenue Requirements for a private over a municipal firm	$ 249,294,000

Increase in taxes from a private firm:

Federal Corporate Tax	$ 116,563,000
State Corporate Tax	30,141,000
Federal Interest Tax	32,714,000
State Interest Tax	9,332,000
Local Property Tax	14,508,000
TOTAL	$ 203,258,000

Net cost to the public of a private project:

Costs:	$ 249,294,000
Benefits:	203,258,000
Net cost:	$ 45,936,000

Assuming these costs are passed on in higher refuse disposal costs, the net cost per ton:

$$\frac{\$45,936,000}{(1,000 \text{ tpd})(365 \text{ days/yr})(20 \text{ years})} = \$6.29/\text{ton}$$

Table 6

Annual Electricity Sales Revenues and the Refuse Disposal Fee for a Private Project

Year	Revenue Requirement	Electricity Revenue	Refuse Disposal Fee
1	$ 28,400,000	$16,400,000	$ 32.88
2	35,471,000	16,810,000	51.13
3	37,361,000	17,230,000	55.15
4	36,310,000	17,661,000	51.09
5	35,260,000	18,103,000	47.00
6	34,209,000	18,555,000	42.89
7	33,159,000	19,019,000	38.74
8	32,108,000	19,494,000	34.56
9	31,058,000	19,982,000	30.35
10	30,008,000	20,481,000	26.10
11	28,958,000	20,993,000	21.82
12	27,907,000	21,518,000	17.50
13	26,857,000	22,056,000	13.15
14	25,808,000	22,608,000	8.76
15	24,757,000	23,172,000	4.34
16	23,706,000	23,752,000	0
17	22,656,000	24,346,000	0
18	21,606,000	24,955,000	0
19	20,555,000	25,578,000	0
20	19,505,000	26,218,000	0

Notes

Electricity revenue is based on 250 million kw-hr/year, using rates described in Appendix A. Escalated at 2.5% per year.

Disposal fee is calculated by dividing the difference between revenue requirements and electricity revenues by 365,000 tons-per-year.

Appendix B

Box 1

A $350,000 loan granted at an interest rate of 8% for five years would yield the following total return:

$$\frac{(60)(\$350,000)(.00667)(1.00667)^{60}}{(1.00667)^{60} - 1} = \$425,632$$

To borrow $350,000 at 15% interest for five years the government would have to pay:

$$\frac{(60)(\$350,000)(.0125)(1.0125)^{60}}{(1.0125)^{60} - 1} = \$499,588$$

Total government cost of this subsidy:

	$499,588
	-425,632
	$ 73,956

The cost per kilowatt will vary with system size. For example:

$$\frac{\$73,956}{(100 \text{ turbines})(50 \text{ kw/turbine})} = \$14.79 \text{ /kw}$$

$$\frac{\$73,956}{(20 \text{ turbines})(50 \text{ kw/turbine})} = \$73.95 \text{ /kw}$$

$$\frac{\$73,956}{(500 \text{ turbines})(50 \text{ kw/turbine})} = \$\ 2.95 \text{ /kw}$$

Appendix C

Description of the Model System

For this analysis it will be assumed that a system is installed to provide 5,000 kilowatts of electrical capacity for an industry which routinely uses at least that amount. This is a moderately-sized cogeneration unit; systems may range from a few hundred to 50,000 kilowatts. Furthermore, it will be assumed that the firm has a demand for steam energy equal to its electrical demand; or, more explicitly, that the firm has a demand for steam sufficient to utilize all which is a byproduct of a 5,000 kilowatt cogeneration unit. (This assumption is necessary: unless the firm also had a demand for steam, cogeneration would be a pointless investment.) Finally, it will be assumed that the cogeneration unit operates with an 80% load factor, meaning that the firm must still purchase 20% of its electricity from the local electric utility.

The cost for cogeneration capacity will be assumed to be $800/kilowatt. The Garrett Corporation quotes a price of $425/kilowatt for its Model 990 cogeneration system, and a price of $490/kilowatt for its Model 831-800. Future costs for systems of similar design are estimated to cost $550/kilowatt in the early 1980's due to inflation. To this is added a cost of $25/kilowatt for an electrostatic precipitator (ESP), necessary to eliminate particulate pollution, and a cost of $100/kilowatt for a flue gas desulfurization (FGD) unit to eliminate sulfur dioxide emissions. Both of these are prices projected by the Office of Technology Assessment for Best Available Control Technology (BACT) which will be required on new emissions sources under state and federal regulations. Additionally, cogeneration facilities located in non-attainment areas (areas where federal ambient air quality standards are not currently being met) will be required to obtain "offsets" for their added emissions. The most straightforward way for a cogenerator to obtain

the necessary offsets is to provide financing to a current polluter who will then use those funds to purchase emissions control equipment capable of reducing his current emissions. Assuming ESP and FGD equipment similar in size to that utilized by the cogenerator is necessary for the offset, additional costs of $125/kilowatt will be incurred by the cogenerator. Thus total costs will be $550 + 2($25 + $100) = $800/kilowatt. For a 5,000 kilowatt facility, total costs will be $4,000,000.

BOX 1

Assume the total cost of $4,000,000 is financed out of retained earnings. This cost is depreciated via the sum-of-the-years-digits method for tax purposes, and via a straight-line method for internal accounting purposes. The lifetime is twenty years. The annual depreciation cost will therefore be $200,000, while net tax benefits amount to 46% of the annual accelerated depreciation deduction. The tax benefits are:

Year	Tax Deduction	Value at 46% Corporate Tax Rate
1	$ 380,952	$ 175,238
2	361,904	166,476
3	342,857	157,714
4	323,809	148,952
5	304,762	140,190
6	285,714	131,428
7	266,667	122,667
8	247,619	113,905
9	228,571	105,143
10	209,524	96,381
11	190,476	87,619
12	171,429	78,857
13	152,381	70,095
14	133,333	70,095

Formula

$$\frac{2(N+1+M)}{N(N+1)} \times \text{Cap.}$$

where:

N = no. of yrs to depreciate

M = age of investment

Cap. = total capital cost

CONTINUED

BOX 1 continued

Year	Tax Deduction	Value at 46% Corporate Tax Rate
15	$ 114,286	$ 52,572
16	95,238	43,809
17	76,191	35,048
18	57,143	26,286
19	38,095	17,524
20	19,048	8,762

This cash flow benefit is subtracted from annual cogeneration operating costs when return-on-investment is calculated.

Annual Operating Costs for 1979

Operating costs include fuel costs, amortization on the investment, maintenance, and standby charges. (Standby charges are additional charges which an electric utility will charge for providing backup service when a cogenerator's own facility is out of operation.)

The fuel costs amount to the difference between the amount of fuel the firm burns in cogenerating and the amount it previously burned to generate steam only. Garrett indicates that about 39.4% more oil or natural gas must be burned.

But how much was originally burned for steam production? Since by assumption equal amounts of steam and electrical energy are required, I assume that the amount of fuel originally burned was a quantity equal to that required to produce 5,000 kilowatts. Also, the following typical assumptions are required:

--the cogeneration unit operates with an 80% load factor
--10,500 Btu are required to produce one kilowatt-hour
--one barrel of fuel oil contains 5,800,000 Btu of energy

The amount of oil initially required =

$$\frac{(.8)(5{,}000\ \text{kw})(10{,}500\ \text{Btu/kw})(8760\ \text{hrs/yr})}{(5{,}800{,}000\ \text{Btu/bbl})} = 63{,}434\ \text{barrels/yr}$$

CONTINUED

BOX 1 continued

The amount of oil required for cogeneration =

(63,434)(1.394) = 88,428 or an increase of 24,994 barrels

The cost of 24,994 barrels of oil at the average price prevailing in 1979, $14.00 per barrel, is $349,916.

Amortization amounts to one-twentieth of the total capital cost per year, or $200,000.

Maintenance is estimated to amount to 2% of the original capital cost per year, or $80,000.

Standby charges will be based on the 1979 Standby schedule of Pacific Gas and Electric. They include a customer charge of $5.00 per month and a demand charge of $0.75 per kilowatt per month. These total $45,060 per year for a 5,000 kilowatt facility.

Total annual operating costs are:

Fuel	$ 349,916
Maintenance	80,000
Amortization	200,000
Standby	45,060
	$ 674,976

Benefits

Benefits include savings from producing rather than purchasing 35 million kilowatt-hours per year, plus a 20% tax credit (totalling $800,000) and the effective value of investment depreciation. To avoid making the investment seem unjustifiably attractive, it will be assumed that the available investment tax credit is spread out over five years, yielding an annual benefit of $160,000. The depreciation benefit was calculated above, and the electricity benefit is:

(.8)(8760 hrs/yr)(5,000 kw)($0.031/kw-hr) = $1,086,240

CONTINUED

BOX 1 continued

Total annual benefits are:	Electricity	$ 1,086,240	
	Tax credits	160,000	
	Depreciation	175,238	(year 1)
		$ 1,421,478	

Net annual benefits:	$1,421,478
	- 674,976
	$ 746,502

Return on investment (year 1): $\frac{\$746,502}{\$4,000,000}$ = 18.66%

NOTE: This is the return that would have been earned in 1979. Future returns beyond that year are not calculated because rising energy costs, while likely to be significant, would not have been known to a typical industrial firm. The firm would have based its decision primarily on the return as calculated here.

BOX 2

Here the investment analysed is identical to that analysed in BOX 1. The only difference is in the prices of fuel oil and electricity. Oil has doubled in price from $14.00 per barrel to $28.00, which the value of the electricity cogenerated is now determined by the higher rates available in the newest cogeneration contract offered by Pacific Gas and Electric. Furthermore, the cogenerator is no longer required to pay standby charges to the utility.

Annual operating costs are:	Fuel	$ 699,823
	Maintenance	80,000
	Amortization	200,000
		$ 979,823

CONTINUED

Box 1 continued

Annual benefits now differ from those available in 1979 because of the new contract terms that became available in early 1980. These are specified in Appendix A. Two electricity benefits will be earned:

A capacity payment. For a facility coming into operation in and agreeing to a twenty-year contract, the payment will be $73 per kilowatt. For a 5,000 kilowatt unit the total annual capacity payment will be:

($73/kilowatt)(5,000 kilowatts) = $365,000

An energy payment. The most recently published price for energy is approximately 5.2¢ per kilowatt-hour. The total annual energy earnings will be:

(.8)(8760 hrs/yr)(5,000 kw)($0.052/kw-hr) = $1,822,080

Total electricity benefits:	$1,822,080
	365,000
	$2,187,080

Total tax benefits will be identical to those in case 1: $160,000 in tax credits and $175,238 in tax deduction value.

Total benefits will be:	Electricity:	$2,187,080
	Tax credits:	160,000
	Tax Deduction:	175,238
		$2,522,318

Annual benefits less costs:	$2,522,318
	- 979,823
	$1,542,495

Annual return on investment: $\frac{\$1,542,495}{\$4,000,000}$ = 38.56%

CONTINUED

Box 2 continued

Annual return without tax credits: $\frac{(\$1,542,495 - \$160,000)}{\$4,000,000} = 34.56\%$

Cost per kilowatt of tax credits: $\frac{(.10)(\$4,000,000)}{5,000 \text{ kw}} = \$80/\text{kw}$

Box 3

Assuming a $4,000,000 loan is granted at 8% for five years, the monthly payments returned to the government would total:

$$\frac{(60)(\$4,000,000)(.00667)(1.00667)^{60}}{(1.00667)^{60} - 1} = \$4,867,739$$

Assuming the government must borrow at 15%, or could have earned a return at that rate by investing elsewhere, it must pay/could have earned:

$$\frac{(60)(\$4,000,000)(0.0125)(1.0125)^{60}}{(1.0125)^{60} - 1} = \$5,709,583$$

The government's losses:

	$5,709,583
	-4,867,739
	$ 841,844

The cost per kilowatt of capacity subsidized by this program:

$$\frac{\$\ 841,844}{5,000\text{kw}} = \$168.37/\text{kw}$$

Box 4

As calculated in Box 1, 24,994 extra barrels of oil are used by a 5,000 kilowatt cogeneration facility per year. In a standard power plant with a heat rate of 10,500 Btu/kw-hr and a load factor of 80% (identical to the characteristics of the model cogeneration unit) the same electrical output would require:

$$\frac{(.8)(5{,}000\ \text{kw})(10{,}500\ \text{Btu/kw-hr})(8760\ \text{hrs/yr})}{(5{,}800{,}000\ \text{Btu/bbl})} = 63{,}434\ \text{bbl/yr}$$

The savings per 5,000 kilowatt unit:

$$\begin{array}{r} 63{,}434\ \text{bbl/yr} \\ -24{,}994 \\ \hline 38{,}440\ \text{bbl/yr} \end{array}$$

For the U.S. as a whole, 34,500 megawatts would produce total savings of:

$$\frac{(30{,}000{,}000\ \text{kw})(38{,}440\ \text{bbl})}{5{,}000\ \text{kw}} = 265{,}236{,}000\ \text{bbl/yr}$$

At $28.00 per barrel, the balance of trade benefit could be:

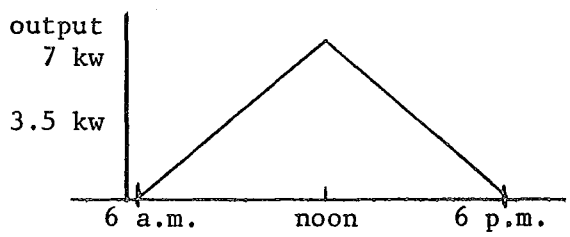
$$(\$28.00\ \text{bbl})(265{,}236{,}000\ \text{bbl/yr}) = \$6{,}587{,}000{,}000\ /\text{yr}$$

Appendix D

Box 1: The Model System

A typical residential rooftop photovoltaic system will be limited to seven kilowatts of peak output because of limited roof surface area. The cost of such a system, estimated by the Sandia Photovoltaic Systems Project is $6,000.

The output of a photovoltaic system depends upon the intensity of the sunlight hitting it. If the system's peak output is 7 kilowatts, then 7 kilowatts will be produced when the sun is at its apex. At other times of the day output is less. Averaging over the entire year the daily output of the system on a sunny day will follow roughly the curve shown below:



The total daily output implied by this curve equals the area under the curve: (.5)(7 kw)(12 hrs) = 42 kw-hr. Because the sun shines about 75% of the time in Region 9, the monthly output can be estimated:

$$\frac{(.75)(365.25 \text{ days/yr})(42 \text{ kw-hr/day})}{(12 \text{ months/yr})} = 959 \text{ kw-hr per month}$$

Monthly payments on a $6,000 loan can be calculated using the following formula:

$$\frac{(\$6{,}000)(i)(1+i)^n}{(1+i)^n - 1}$$

where: i = interest rate
n = no. of months in loan term

The revenue per kilowatt-hour is determined by averaging the current purchase price for On-Peak and Partial-Peak, Period A and Period B, and escalating at 2.5% for ten years (to 1990). This current average price is 5.2¢ and the formula for escalating this price is:

$$\text{1990 price} = (5.2¢/\text{kw-hr})e^{(.025)(10)} = 6.99¢/\text{kw-hr}$$

Box 2

It is a simple matter to compute monthly payments given a loan principal, interest rate, and term. The formula is:

$$\frac{(\text{Principal})(I)(1+I)^M}{(1+I)^M - 1}$$

where: I = monthly interest rate
M = number of months in the loan term

Calculating the monthly payments for a photovoltaics loan is complicated by the fact that tax credits are received after the loan is made. To present an accurate picture of the real costs of photovoltaics to a homeowner, the tax credits must be used to reduce the principal on the loan as soon as they are received. The result is that for a time the homeowner pays a high monthly payment, and once the credits are received pays a much lower payment. In Tables 4-9 thru 4-11 an average of these is presented for simplicity.

To compute the average it is assumed that tax credits are received twelve months after the loan is initially obtained, and are immediately applied to pay off a portion of the loan. The remaining balance is then refinanced at the same interest rate, and with a term equal to the remainder of the term on the original loan. Thus, if the original term were ten years, the refinanced term would be nine years.

The exact procedure for determining average monthly payments over the entire term of a loan is as follows:

1. Calculate monthly payments on a $6,000 loan at a given interest rate and term. Sum the monthly payments for the first year.

2. Calculate the reduction in principal from payments made during the first year. To do this, tables from Lake's Monthly Installment and Interest Tables (A.V. Lake: Denver) were used (Part III, pp 587-621). Subtract the principal paid off from $6,000 to determine the principal remaining after one year.

3. Subtract the tax credit amount from the principal remaining after one year. This is the amount that is refinanced. Calculate the monthly payments of this refinanced amount, at the same interest rate as that of the original loan, and for a term equal to 12 months shorter than that of the original loan.

Continued

Box 2, cont.

4. Multiple the refinanced monthly payments by the total number of months for which payment will be made, to determine the total amount of money to be paid out. Add to this the amount already paid out on the original loan during the first year (from Step 1 above).

5. Next, assume the tax credits were available from the start. Subtract the total credits from $6,000 to find the loan that would, under these circumstances, be required. Calculate the monthly payments for such a loan, given the same interest rate and term used before. Multiple the monthly payment by the total number of payments to obtain the total amount to be paid out.

6. Subtract the total paid out, as calculated in Step 5, from the total paid out, as calculated in Step 4. This represents the "penalty" a homeowner will pay when he or she refinances a photovoltaics loan. It results from the fact that the tax credits are not immediately available to reduce the necessary loan, but become available only 12 months later.

7. Next, subtract the available tax credits from $6,000, add the penalty as calculated in Step 6, and then compute the monthly payment for a loan of this amount. This yields the average monthly payment (or, more precisely, the best surrogate for it) which a homeowner will face over the life of the loan. This number is presented in Tables 4-9 thru 4-11.

8. Repeat this procedure for each combination of interest rate, term, and available subsidy.

Example: A loan is made to a Californian who is eligible for total tax credits of $3,300. The interest rate is 8% and the term is 10 years.

1. Monthly payments on a $6,000 loan are $72.80. Total payments during the first year are $873.60.

2. Reduction in principal during the first year amounts to $408. Thus after one year the remaining principal is $5,592.

Continued

Box 2, cont.

3. Subtracting the tax credits, the amount to be refinanced is $2,292. The term is now twelve months less than the original term, or 108 months.

4. Monthly payments on a loan of $2,292 at 8% for 108 months add up to $29.84. Multiplying by 108 months, the total to be paid out is $3,223. Adding in the amount paid out during the first year, the total amount to be paid out over ten years is $4,097.

5. Assuming tax credits are available from the start, the loan principal would be $2,700. Monthly payments for ten years at 8% for this loan would amount to $32.75. Multiplying by 120 payments yields a total payout of $3,930.

6. Subtracting the total payout from Step 5 from that of Step 4 yields a penalty of $167.

7. Beginning again with a $6,000 system, subtract tax credits of $3,300 and add the penalty of $167. Total loan principal then amounts to $2,867. The monthly payment on a loan with this principal, at 8% interest for ten years, is $34.79. This is the first entry in Table 4-9.

Box 3

Loan subsidy cost: This represents the difference between what it costs the government to borrow money at 15%, and what the government receives in return when lending at either 8%, 12% or 18%. When lending out at 15% the net cost is considered to be 0 because transactions costs are ignored throughout this analysis.

Example: What does it cost the government to make a $3,000 loan at 8% for ten years?

Cost to gov't: $$\frac{(120 \text{ months})(\$3{,}000)(0.0125)(1.0125)^{120}}{(1.0125)^{120} - 1} = \$5{,}808$$

Return to gov't: $$\frac{(120 \text{ months})(\$3{,}00)(0.00667)(1.00667)^{120}}{(1.00667)^{120} - 1}$$

$$= \$4{,}369$$

Difference:

$5,808
4,369

$1,439

Subsidy per kw-hr: This divides total subsidy costs among all the kilowatt-hours produced over the life of the system. The life of the system is designed to be 20 years, and total kilowatt-hours should be:

$$(20 \text{ years})(12 \text{ months/year})(959 \text{ kw-hr/month})$$

$$= 230{,}160 \text{ kw-hr}$$

The total subsidy costs include tax credits plus loan subsidy. For example, an 8% loan to a California also receiving $3,300 in tax credits would create a subsidy per kw-hr of:

$$\frac{(\$1{,}439) + (\$3{,}300)}{230{,}160 \text{ kw-hr}} = 2.1¢/\text{kw-hr} \quad \text{(See Table 4-12)}$$

Appendix E

Subsidy Cost per Kilowatt-hour

To compare the four technologies we must do so on the basis of subsidy per kilowatt-hour. To make comparisons on the basis of subsidy per kilowatt of capacity would be incorrect because wind and photovoltaic technologies do not provide firm capacity, while cogeneration and MSW do. However, is a kilowatt-hour is an equivalent unit of energy, not matter where it originates.

MSW

Here, the total subsidy cost is calculated in Table 5 of Appendix A. This equals $45,936,000. However, from this must be subtracted the benefits which come to the public from the elimination of waste disposal costs. The California State Solid Waste Board uses a cost estimate of $5.00 for these charges, which I judge reasonable and will use here. (Actually, because communities most interested in developing MSW will be those facing the highest disposal costs, a higher estimate could be defended.) The benefits are:

$$(1{,}000 \text{ tpd})(365 \text{ da/yr})(20 \text{ yr})(\$5.00/\text{ton}) = \$36{,}500{,}000$$

Subtracting this from $45,936,000 yields $9,436,000. I will consider this the net subsidy, although some MSW projects will recover recyclable materials (aluminum, glass, steel) which will provide further sbusidy cost reductions.

Total output of kilowatts for the model MSW facility analysed in this study is:

$$(20 \text{ years})(250 \text{ million kw-hr/yr}) = 5{,}000{,}000{,}000$$

Subsidy per kw-hr:

$$\frac{\$9{,}436{,}000}{5{,}000{,}000{,}000 \text{ kw-hr}} = \$0.0019$$

CONTINUED

Wind

For wind the only subsidy is a tax credit, which is estimated to cost $100 per kilowatt of capacity. Wind turbines will also have an expected lifetime of 20 years, and are assumed to have a load factor of .30 (they produce electricity 30% of the time). Total lifetime kilowatts:

$$(.30)(8760 \text{ hrs/yr})(20 \text{ years}) = 52{,}560 \text{ kw-hr}$$

The subsidy cost per kw-hr:

$$\frac{\$100}{52{,}560 \text{ kw-hr}} = \$0.0019$$

Cogeneration

Cogeneration units are assumed to operate 80% of the time, and to have a lifetime of 20 years. Thus the total output per kilowatt of capacity will be:

$$(.80)(8760 \text{ hr/yr})(20 \text{ years}) = 140{,}160$$

Subsidy cost per kw-hr:

Tax credits of $80/kw: $\frac{\$80}{140{,}160 \text{ kw-hr}} = \$0.0006$

Subsidized loan at $168/kw: $\frac{\$168}{140{,}160 \text{ kw-hr}} = \$0.0012$

Photovoltaics

Subsidy cost per kilowatt-hour is shown in Tables 4-8 thru 4-10. An average of the high and low costs in these tables (.6¢ - 3.0¢) is used in Table 4-16.

CONCLUSION

The purpose of this report has been to identify the barriers that groups and individuals will face when attempting to commercialize community energy systems. Three particular classes of barriers have been investigated: those within the organization attempting the commercialization, those that arise from attempts to link the community system with an electric utility, and those that impede the flow of investment capital into community energy systems.

General statements regarding the issues discussed here will be offered below, but the reviewer is advised that many more issues are noted in the text of each of the three main sections.

Organizational Barriers

With regard to organizational barriers, four are especially important:

1. Municipalities need financial assistance to cover pre-bonding costs in the development of an MSW facility.

   These costs may total several million dollars, an amount that few municipalities have at their immediate disposal.
2. Municipalities may also require state assistance to ensure an adequate fuel supply. The state should establish wastesheds for each MSW project.
3. Better information, education, and assistance should be made available to industrial management in order to accelerate the development of cogeneration.
4. Neither residential homeowners nor homebuilders are very likely to possess the knowledge or skills necessary to install a photovoltaic system. The development of standardized, mass-produced technologies might need to be subsidized by government. Direct involvement by electric utilities or some other brokering firm might be necessary.

These barriers are neither new nor particularly dramatic, but may merit more attention than they have heretofore received.

Interface Barriers

The issues involved in the interfacing of community energy systems with

electric utilities have received considerable attention since the passage of the Public Utilities Regulatory Policies Act of 1978. Much progress has been made in terms of developing regulations and purchase prices that make the sale of energy and capacity to utilities an attractive proposition. The Federal Energy Regulatory Commission and a number of state public utility commissions have been very effective in this regard.

Many interfacing issues and regulations remain in a state of flux, and further refinements to various policies are quite possible. Most of the recently developed policies were structured with the "firm" types of community energy systems—cogeneration and MSW—in mind. The applicability of these regulations for non-firm systems such as wind and photovoltaics is uncertain, although it is clear that different provisions will be required in some policies, such as those governing payment for capacity cost.

Among the issues to which attention will be paid in the immediate future are:

1. How reliable must a small power facility be to receive capacity payments? During what periods must it be available? Should capacity payments be made for non-firm power, at what rate, and under what regulations?
2. Must a small facility be dispatchable to obtain maximum capacity payments from the utility?
3. What control should the utility have over a private developer's plans for a new community energy system? Can the utility demand special system protection equipment or other special facilities? Who will decide whether demands for such equipment are reasonable or obstructionist?
4. How difficult will it be for cogenerators to obtain exemptions to the Power Plant and Industrial Fuel Use Act of 1978 in order to burn natural gas? Should cogenerators pay the same prices and hold the same priority for natural gas that electric utilities do?
5. Who will pay for necessary emissions offsets for new cogeneration and MSW facilities?

The authors feel that each of these issues will ultimately be decided in a manner conductive to further commercialization of community energy systems. The regulatory process may be slower than some would wish, but little experience exists

with interfacing technologies other than cogeneration. It would be unwise to impose regulatory changes whose effects could upset the smooth operation of the large utilities upon which society relies rather heavily. Moreover, rapid changes in the structure of the electricity industry might be unacceptable to politically power forces in state legislatures and Congress.

Financial Barriers

The central difficulties that developers of community energy systems face in obtaining sufficient investment capital are (1) the perceived risk of the new technologies, and (2) their relatively high cost compared to the historical cost of conventional power generating facilities. The recent cost increases for fossil fuels have made community energy systems much more competitive, although in most cases fossil fuel power plants still produce cheaper power. However, over the long-term it is clear that fossil fuel supplies will diminish, and rise in price. Thus commercialization of alternatives must be accelerated now, and for this reason various political bodies are willing to provide public subsidies to accomplish it.

The major financing barriers to the development of muncipal solid waste plants are the need to offer higher interest rates to bond holders because of project risk and the possibility of unexpected costs stemming from new emissions control regulations. Federal or state governments could provide guarantees to bondholders, and thus reduce the project risk; or they could provide grants that would directly reduce project cost. Either would make financing an MSW project more feasible, but neither option has yet been enacted anywhere.

The major financing barrier for wind developers is the lack of start-up capital. This problem may be overcome through loans from the Small Business Administration, but the analysis given previously suggests that the funds currently available may be inadequate for this purpose.

Cogeneration has received less than maximum investment in the past because its return on investment was considered too low. Because fuel prices have doubled during the past year this situation has changed. Cogeneration now offers very attractive returns, and no additional subsidies for it are proposed in this study. However, if tight credit should prevail in the future the provision of low-interest loans in place of currently available tax credits might be useful.

For photovoltaics, the central barrier is system cost. If rooftop photovoltaic systems are to become competitive they will require substantial subsidies in the form of low-interest, extended-term loans, as well as tax credits. The cost per kilowatt-hour of photovoltaic electricity subsidized may run as much as thirty times the cost per kilowatt-hour of cogeneration subsidized, even assuming that D.O.E.'s 1985 goal of 50¢ per watt for solar cells is achieved. Of course, an important reason for accepting high photovoltaic subsidies is the fact that cogeneration potential—as well as that of virtually every other source—is limited.

In summary, three general observations regarding community energy systems may be distilled from this study. First, although many barriers exist to the commercialization of the systems, few if any appear unresolvable. Perhaps most challenging will be the problem of expanding the use of cogeneration and municipal sold waste while at the same time maintaining or improving ambient qir quality. Second, the financial subsidies required to make community systems competitive are not extraordinary. Indeed, with the exception of photovoltaics they should not amount to more than about 10% of capital cost of the new systems, and mass production may eliminate the need for subsidies altoghether at some point in the future. Third, the administrative and regulatory procedures required to make community energy systems viable appear to be taking shape in a positive and timely fashion.

Finally, community energy systems appear likely to provide substantial benefits within Federal Region 9 in the future. The extent to which they can displace the United States dependence upon foreign oil, or nullify the need for synthetic fuel plants, has not been a subject of this study. At present, it appears that both of the latter will be required indefinitely. However, the technical availability of community energy systems, the fact that they can be integrated into current electricity supply structures, the relative modesty of the subsidies necessary to make them economically competitive, and their environmentally benign nature all suggest that accelerated efforts to commercialize them are justified, and would be a wise investment for the future welfare of the nation.

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