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UTILITY SOLAR FINANCE: ECONOMIC AND INSTITUTIONAL ANALYSIS

Edward Kahn, Leonard Ross, Peter Benenson, and James Cherry

October 1979

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LBL-9959

Utility Solar Finance: Economic and Institutional Analysis

Edward Kahn*
Leonard Ross†, 1
Peter Benenson*
James Cherry†, 2

October 1979

*Energy and Environment Division
Lawrence Berkeley Laboratory
University of California, Berkeley

†Earl Warren Legal Institute
University of California, Berkeley

1. Boalt School of Law
University of California,
Berkeley

2. California Public Utilities
Commission
San Francisco, California

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ACKNOWLEDGEMENTS

This research was supported by Dr. Roger Bezdek, Chief of the Market Analysis and Evaluation Branch, Office of Solar Applications, U.S. Department of Energy. Edward Kahn was the principal author of Sections 1-4 and 6. Section 5 was primarily the work of Leonard Ross and James Cherry. Material in Section 6 was presented to the California Public Utilities Commission hearings on utility solar finance (OII-42) under the sponsorhsip of the Natural Resources Defense Council. The analysis benefitted from the contributions and criticism of Terry Lash, Laura King and Jim Frankel. Section 7 is based on the work of Edward Kahn and Peter Benenson. Considerable assistance was provided by Ray Czahar, Finance Division, California Public Utilities Commission and Prof. R.A. Meyer, University of California Graduate School of Business Administration, Berkeley. In addition, helpful discussion was provided by Larry DiSimone and Ralph Purves, San Diego Gas and Electric Company; Mike Merrill, Pacific Gas and Electric Company; John Shue, Pacific Power and Light Company; Stephen Feldman, University of Pennsylvania and Michael Edesess, Solar Energy Research Institute. Figure 1 is reprinted with permission of Moody's Investors Service. Figure 2 is due to Duane Chapman.

1.0 Introduction

Among the several generic incentive programs proposed to accelerate the widespread use of on-site solar energy is a class of financing alternatives administered by regulated public utilities. It is the purpose of this report to analyze various forms of utility solar finance. This analysis will delineate the complexity of the regulatory issues involved with any scheme which uses public utilities as financial intermediaries for on-site solar.

The study begins with concrete examination of various types of utility solar financing arrangements. The focus is on the costs of each arrangement to the utility. The discussion then broadens to consider the generic economic impacts of utility solar finance on both the customer and the corporation. With this background, the broader social issues associated with utility involvement in the solar market are surveyed. The legal and regulatory concerns which would shape practical utility solar finance programs are delineated. From this abstract set of issues we return to the concrete and examine the particular cost factors that determine economic viability of utility solar finance in a detailed case study. Finally, the complex interactions of federal taxation and state regulatory practices are described. These indicate the wide variation in potential costs across regulatory jurisdictions.

Utility solar finance is an intrinsical complex issue. This stems from the central position already occupied by public utilities in the existing energy distribution and marketing system. Whether utilities finance solar energy or not, they are impacted intermediaries in <u>any</u> plan to accelerate the commercialization of on-site systems. If utilities are external to the solar incentive process, then they may well emerge in a role as a constraint on the solar engineering/economic optimization. This constraint appears in the form of utility pricing policies for back-up energy. Feldman and Anderson have

shown the effect that utility prices have on solar design choices [1,2]. In turn, the utility pricing of back-up energy is determined by the changes in load shape and cost of service imposed on the utility by widespread adoption of solar technology. Bright and Davitian have shown that under ideal conditions the solar impact upon utilities can be minimal [3]. It is not at all clear, however, that the real world will react as flexibly as predicted by an optimization model in which all inputs are known with certainty.

Utility participation in solar energy finance is likely to create a different set of adjustments to the energy supply planning process than if there were no such participation. These differences would be due to both the potential scale of a solar program as a whole, and to the optimal design of individual systems. Current incentives for solar energy in the form of tax credits have had a highly limited effect. In California, for example, the state income tax credit has produced a response which is highly skewed towards upper income groups. Table 1 shows recent data on this trend. It is clear from this table that 75 percent of all applicants had adjusted gross income of over $20,000 per year and 30 percent were over $40,000 per year. In certain markets, such as the multi-family rental market, there is no incentive, even with potential tax credits, to invest in solar energy applications. Bezdek, Hirshberg and Babcock attribute the lack of incentive in the apartment sector to the investment goals of owners and the structure of the tax code [5]. A solar finance program administred by regulated utilities would, in principle, be addressed to larger markets than the tax credit approach currently attracts.

A more subtle but equally important effect of utility solar finance is the potential for more optimal system design. A private or corporate decision to invest in solar energy will be based on current energy prices. Insofar as these prices are public utility rates, the investment decision and the optimum

Table 1

California Solar Energy Tax Credit
Applications by Income Level

ADJUSTED GROSS INCOME	APPROXIMATE NUMBER OF SOLAR CREDIT CREDIT APPLICATIONS	
Less than 9,999	885	
10,000 - 14,999	1,155	4,150
15,000 - 19,999	2,110	
20,000 - 24,999	2,855	
25,000 - 29,999	2,902	16,382
30,000 - 39,999	4,504	
40,000 - and over	6,061	

California Franchise Tax Board Date
cited in (4)

economic design of a solar system will be biased away from solar systems which displace large amounts of energy. The reason is simply that current public utility rates are based on average historical costs. These are lower than the marginal cost of new supply. Economic efficiency is achieved by trading off options at marginal cost. Under current market arrangements, there is no actor who can insure that the appropriate value of displaced energy will be reflected in the private decision process. Utilities, however, are in a position to compare marginal costs. Other things being equal, this would result in more efficient and presumably larger scale investment in solar systems.

Although utility solar finance might well accelerate the adoption of on-site solar systems, there are risks and costs associated with such arrangements. The main risk identified with utility solar finance is the potential for monopolization associated with the scale of such activity. This risk has been characterized in a variety of ways.[6,7] Apart from a generalized antipathy toward monopoly, there are real and potential costs of using the utilities as a principal financial intermediary for solar commercialization. In principle, banks and other conventional financial institutions have a lower cost of money than regulated utilities. This is readily apparent by a comparison of capital structures. Banks are capitalized at roughly 95 percent debt (i.e., deposits) and only 5 percent equity. Utilities typically have about 35 percent equity capital which is costlier than debt or preferred stock. The cost difference between debt and equity is at least several percentage points. Thus by encouraging utility solar finance, society would be choosing an intrinsically more expensive source of finance than might be available through conventional means. This extra social cost must be weighed against the potentially greater market available to on-site solar through utility finance.

Other less readily quantifiable risks of utility solar finance include the potential for economic distortions induced by a tendency toward excess capitalization or by possible motives to cross-subsidize solar activity from other investments. This first effect, excess capitalization, is generally thought to be due to a bias toward capital induced by rate of return regulation. This bias, first described by Averch and Johnson [8] may not necessarily obtain in a climate of economic uncertainty[9] where risk-aversion would induce a bias away from capital. Regulatory action to limit excess capitalization (sometime called "gold plating") for on-site solar systems may well be easier than for large scale supply projects where the ability to predict true capital intensity is limited[10].

The risk of subsidization of solar is just the opposite case, where the utility underprices rather than overprices. Assessing the importance of this risk requires an analysis of the vendor market for on-site solar. If such analysis indicates that utility finance might involve unfair subsidies, regulatory alternatives exist to limit this danger.

In the analysis which follows various generic arrangements for utility solar finance will be surveyed. Each alternative will be characterized by its main advantages and disadvantages with regard to impact on customers, the utility and more general social concerns. After the generic alternatives have been discussed, individual issues will be addressed. These include:

(1) Analysis of economic impact on utilities of involvement in solar energy finance.

(2) Economic impact on non-participating utility customers of solar energy finance programs.

(3) Social cost analysis of utility involvement in the solar market.

(4) Case study of the Pacific Power and Light Co. approach to solar and conservation finance.

(5) Interaction of state regulatory practices and federal tax in the evaluation of solar finance costs.

2.0 Specification of Generic Utility Solar Financing Alternatives

Traditionally, finance has offered opportunitied for innovative arrangements that are limited only by uncertainties associated with the legal status of the proposed instrument. Thus, many variations of basic alternatives are possible for any financing mechanism. The current investigation by the California Public Utilities Commission into utility solar finance has produced a catalogue of fourteen variations.[4] It is doubtful if this exhausts the range of permutations and combinations of specific program features. Rather than enumerate all possibilities, it will be convenient to catalogue the major classes of alternatives and their main features. In any particular situation, conditions will favor some combination of the main features.

The discussion will begin by contrasting the role of solar capitalization by the utility with the role of financing. This will be followed by an analysis of the Pacific Power and Light Company's Residential Energy Efficiency Rider. This plan is the most far-reaching utility sponsored end-use efficiency program in the nation and has enjoyed widespread acceptance by customers. It has been proposed as a model for other utilities, and therefore deserves special attention. The survey will conclude by examining the role of leasing arrangement, the case for creating special utility solar subsidiaries, and the role of special bonding authorities.

2.1 Capitalization vs. Financing

The standard accounting treatment of any utility capital investment is that all appropriate costs for materials and labor are added to the undepreciated rate base to earn the allowed rate of return on capital. In the special

case of utility investment in on-site solar, such treatment may or may not involve cross-subsidization of solar investments by non-solar users. By "rolling-in" all solar costs into a rate base common to all customers, the non-solar user pays an incremental cost for conventional service over and above what he would have paid without the utility solar investment. If this increment is greater than the marginal cost of new conventional supply suitably allocated, then solar users may be said to be subsidized. The regulatory remedy for this situation is straightforward. Solar investments can be capitalized in a separate account charged only to solar users. While this would avoid cross-subsidization, it has the consequence of charging marginal costs for solar energy, but only average costs for conventional supply. Although public utility rates should not involve cross-subsidies in theory,[11] in practice it goes on to a considerable extent. The main practical concern in this regard is the magnitude of such subsidies. For typical conditions in the gas industry, it has been shown that "rolling-in" will have a small impact on non-solar rates.[12] The relatively small fraction of utility capital that would be devoted to solar is the reason for this result. Under widespread implementation, this effect could be considerable. A more stringent criterion concerning cross-subsidization is discussed in connection with the Pacific Power and Light Company plan.

A potential complication of any capitalization approach is the risk of gold plating. It is possible that utility ownership of solar would be biased toward expensive, over-designed systems that were excessively capital intensive. This is really just an instance of the Averch-Johnson[8] thesis that rate of return regulation induces a bias toward capital.

In terms of the engineering/economics of active solar space heating, for example, gold plating might take the form of under-investment in glazing, insulation, weather-stripping, etc. Such conservation investments reduce the

thermal load that must be supplied by collectors and are considerably less expensive.[13] Unfortunately, the utility might have difficulty qualifying for federal tax benefits such as rapid amortization and investment credit from residential conservation investment. The IRS only grants such benefits to investment that is made on the owner's property and dedicated to his use.[14] A utility's residential meter passes these tests, but conservation and solar investments would have more difficulty. Without equal tax treatment for all energy options, the utility could not be expected to make efficient choices.

The generic alternative to capitalization is a strictly financial role for the utility. In this role, the utility would act as a bank which makes loans for a predetermined time period at a fixed rate of interest. The costs of such a program depend critically on the choice of loan period and interest rate. The appropriate loan period should be the economic lifetime of the solar system. Unfortunately, there is considerable uncertainty about this period. Choice of a relatively long lifetime, say 20 years, would almost certainly mean that individual components would require earlier replacement. In Table 2, estimated component lifetimes for solar hot water heating systems are listed based on California Public Utilities Commission recommendations.[15] Some provision for the cost of replacing components must be made if the finance is based on a 20 year lifetime.

Economic lifetime is also an important parameter under capitalization. In that case, it represents the length of time the capital investment is in the utility rate base. Lifetime also determines the depreciation schedule using any method of depreciation. Depreciation will reduce the rate base under capitalization, but is irrelevant to the utility under financing.

Table 2

Solar Hot Water Heating System Component Lifetimes

ITEM	ESTIMATED LIFETIME
Solar Collectors - copper type	20
Pumps	10-15
Valves	5
Solar Hot Water Storage Tank	20
Back-up Hot Water Heating System	10
Controller	10
Associated Copper Plumbing	20

Fixing an appropriate interest rate under financing can be approached in a number of ways. The standard procedure in the conventional economic analysis of utility investment projects is to calculate a fixed charge rate to be charged annually against capital cost to yield the pre-tax weighted average cost of capital.[16] Thus, a capital structure is assumed, the cost of each kind of capital is estimated and tax effects are added in (see Table 3). Fixed charge rates will vary across regulatory jurisdictions depending on the treatment of federal tax preference. Utility commissions which require "flow-through" of investment tax credit and accelerated depreciation to customers will tend to see lower fixed charge rates than commissions where tax preference is captured by the utility. This subject will be discussed in some detail in Section 7. For now it is sufficient to observe that for solar energy finance, assuming that no tax credits would be available to the utility, the pre-tax cost of capital is currently in the range of 17 to 22 percent. The conventional interest rate so determined would be the same under capitalization or financing.

Because the pre-tax cost of capital is so high compared to bank rates, utility solar financing would not be particularly attractive. However, it is not at all clear that the standard procedure used to determine fixed charge rates, as sketched above, is the appropriate tool for utility economic analysis. Public utilities may be thought of as a portfolio of investments, the sum total of which provides a service to customers. These investments differ widely in their financial and economic risks. Large, long lead time supply projects have more uncertain returns than relatively safe investment in transmission and distribution. Among electric generation projects, there can be substantial differences in risk.[17,18] The conventional analysis fails to capture these differences. This failure is the subject of concern within the utility plan-

ning community. It was discussed recently in a committee paper sponsored by the Power Engineering Society of the Institute of Electrical and Electronic Engineers (IEEE).[19]

Roughly speaking, projects with greater risk ought to return a greater proportion of their investment annually. One framework in which to assess this trade-off between risk and return is the Capital Asset Pricing Model (CAPM).[20,21] In the case of electric utility investment, the risks associated with end-use substitution investments such as solar hot water heating or ceiling insulation appear considerably lower than those associated with large scale generation projects.[22] If correct, this means that the return required from such investments ought to be lower than the weighted average cost of capital. This will mean a lower effective interest rate for solar finance by the utility. The discussion of relative risk is explored further in Section 3.2.

Assuming that the risk of solar investment by utilities is sufficiently low to justify an interest rate which is lower than the pre-tax cost of capital, it remains to discuss the regulatory devices available to capture this effect. As a practical matter, it would be possible to "roll-in" solar investments under capitalization and charge them at a cost of capital which is less than the pre-tax rate. This amounts to changing the capital structure on the margin, weighting it more heavily toward lower cost instruments and less toward common equity. Under a financing arrangement the treatment would be essentially the same, although it would be more transparent that this class of investment is being handled differently than conventional investment. A financing subsidiary, for example, might be capitalized at 10 percent or 20 percent common equity and the rest would be debt. The effect of capital structure on pre-tax cost of capital is shown in Table 3.

Table 3

Capital Structure and Average Cost of Capital

RATIO		INCREMENTAL COST	AFTER-TAX WEIGHTED COST	TAX MULTIPLIER[a]	PRE-TAX COST OF CAPITAL
A. Standard Case					
Debt	50%	9.5%	4.75%	1.00	4.75
Preferred Stock	10%	9.5%	0.95%	2.04	1.94
Common Equity	40%	14.0%	5.6 %	2.04	11.42
			11.30%		18.11%
B. Leveraged Subsidiary					
Debt	80%	9.5%	7.60%	1.00	7.60
Equity	40%	14.0%	2.80%	2.04	5.71
			10.40%		13.31%

(a) Calculation of Tax Multiplier:

1. Reduce Income by State Income Tax Rate = 9%

   100 - 9 = 91%

2. Calculate Federal Tax at 46%

   91% x 46% = 41.86%

3. Add State Income Tax - 41.86% + 9% = 50.86%

4. Tax Multiplier is the Reciprocal of 1 minus the marginal tax rate

$$= \frac{1}{1-.5086}$$

$$= 2.04$$

A substantial administrative problem associated with financing plans is the design of the re-payment schedule. This is especially important when considering the effect of social mobility on the term of loans. Under-capitalization return on the investment is achieved as part of the ordinary rate-making process. Since the utility "owns" the equipment, it doesn't matter if the nominal occupant of a building with this equipment changes. The current occupant of the residence will still make "payments" through the rate structure. Where an explicit loan is made, some provision must be made for solar borrowers who move from their solar residence. Is the loan liquidated at this time, or transferred to the new owner? What if the new onwer doesn't want to assume the loan? This problem is significant because the average turnover time for houses is less than the 20 year amortization often required to make solar loans cost-effective. It is estimated that the average house changes owners at a point between the fifth tenth year from purhcase.[4] Few solar projects are cost-effective if amortized at 10 years or less. Thus, not only is there uncertainty over the economic life of solar systems, but demographic mobility tends to reduce and complicate one of the main advantages of public utility finance, the ability to raise long term capital. The most outstanding practical solution to this dilemma is the energy conservation finance plan designed and implemented currently by the Pacific Power and Light Company. It is to this subject that we now turn.

2.2 The Pacific Power and Light Company (PPL) Residential Energy Efficiency Rider

PPL is an investor-owned electric utility operating principally in Oregon, but in six other states as well. Its Residential Energy Efficiency Rider is a unique combination of capitalization and finance elements used to encourage investment in residential weatherization. Although not addressed to solar applications, the approach is generalizable under certain conditions.

The main features of the PPL program are as follows:

(1) PPL performs a home energy audit and recommends specific weatherization investments whose life-cycle cost is less than the marginal cost of new supply.

(2) Upon approval of the homeowner, PPL arranges for contractor installation of the weatherization materials.

(3) PPL pays for all materials and labor.

(4) The homeowner agrees to repay these original costs with no interest on or before the point of sale.

(5) PPL accounts for these investments by adding them to rate base using no amortization.

(6) All customers pay the carrying charges on the capital for as long as the loan is in the utility rate base.

(7) Upon transfer of the home and repayment of loan, the rate base is reduced by the amount of the loan.

This program is attractive to all parties involved in the transaction. Customer response has been good; there has already developed a substantial backlog of requests for participation. The current completion rate is about 5,000 homes per year.[23] The scale of the program is sufficiently large to support the assertion that public utility finance can make major differences in the adoption rate of weatherization investments. Benefits of this program to the utility will be discussed in some detail in Section 3.2.

The main structural innovation of the PPL plan is the use of the time of property transfer as the point at which the loan must be liquidated. This feature, combined with the capitalization of the loans in rate base, has the effect of evening out the allocation of program cost between participants and non-participants. Under simple capitalization, in plans such as the FEA's

Rosenberg proposal,[24] residential conservation investments were to be capitalized in rate base for their estimated economic lives. The FEA proposal used 15 years for this lifetime. This means that non-participants carry the cost of the program over the entire period. Under the PPL plan, the non-participants' burden will end long before the benefits of the investment cease. Since the PPL plan is still an actual loan, where all customers bear the interest cost, repayment on resale eliminates a basic inequity of simple capitalization. Non-participants do not continually pay for the benefits received by others. While there are still subtle questions of customer equity involved in the PPL plan, its combination of features tends to eliminate some of the most troublesome features of simple financing or capitalization.

Apart from its structural innovations, the PPL plan has a particular definition of cost-effectiveness used to evaluate end-use conservation investments that is a major constraint on program scope. Conventional utility economic analysis of investments for central station supply is based on the minimum marginal cost criterion. That alternative is best which has the lowest marginal cost. To account for the differing incidence of costs and benefits to participants and non-participants, PPL has proposed a more stringent criterion on its program. An end-use conservation investment program must save energy at an average cost whichis less than the difference between the utility's marginal cost of new supply and the current average retail cost. If a program meets this test, then non-participants will have no higher a cost of energy under the program than without it. The derivation of this criterion is given in Section 4.1. Its application is discussed in the California case study in Section 6.

2.3 Leasing Arrangements

Leasing capital equipment rather than purchasing it is a financial device introduced to transfer tax benefits among parties to a transaction, so that all actors are better off.[15] It has recently become a factor in public utility finance. San Diego Gas and Electric Co., for example, sold its Encina 5 power plant to the Bank of America and leases it back from them. The arrangement resulted in a net cost of capital to the utility of about 6 percent. While this is an attractive rate of interest in today's market, the long term effect on the utility's credit is not positive. The reason is that utility bond rating agencies view the lease as a long term debt obligation which leverages the utility further and provides no equity protection.[26]

The San Diego Gas and Electric lease is based on a situation in which the utility has federal tax credit it cannot absorb because of insufficient revenue. These are passed through to the bank which shares the benefit in the form of a lower interest rate. Other tax situations are possible. The natural gas utilities are not generally in the same tax position as electric utilities or combination companies. Electric power generation is so captial intensive that electric utility investments generate substantial tax preferences. Natural gas utilities, on the other hand, have relatively smaller capitalization. Their construction projects are either smaller than those of electric utilities or so large in nature (LNG for example) as to require wholly unconventional financing. For relatively modest scale incremental investments, gas utility solar finance using leasing techniques would enable the utility to capture tax benefits not otherwise available to them and pass some of these along to customers. In a study of gas utility finance alternatives for residential solar applications, MITRE found the leasing alternative most attractive.[12] This conclusion followed from assumptions of more highly leveraged utility subsidiary finance than under simple capitalization and the capture of tax benefits. It

is as yet an unresolved issue whether utilities which own or lease solar equipment would actually qualify for conventional investment tax credit. Under utility leasing there would be no capture of state or federal tax credits aimed at consumers.

2.4 Utility Solar Subsidiaries

Public utility companies sometimes engage in businesses that are not part of their monopoly franchise, but which may be tangentially related to their main activities. To separate these non-utility operations from the regulated activities, it is conventional to create subsidiary corporations for non-utility businesses. For particular activities it may not be entirely clear whether it does or does not come under the scope of the monopoly franchise. In these cases, subsidiaries are also useful devices to create a financial separation from the parent company. Such a separation may be used to allow more latitude to the subsidiary than the parent, or conversely to allow a close regulatory scrutiny of the particular activity.

One of the major concerns involved in organizing a utility subsidiary is the determination of an appropriate capital structure and accounting correctly for the cost of a subsidiary's capital.[27-29] Table 3 indicated that capital structure has a major impact on average cost of money. What is less clear is the justification of different capital structures and the imputation of costs to each instrument. The cost imputation is complicated in turn by the variety of corporate devices which can be used to control the subsidiary.

The most logical grounds upon which to impute subsidiary capital structure and costs is on the basis of project risk.[30] The practical problem is that usually the risks of a new project are not readily quantifiable beforehand. Some general guidelines with regard to the effects of diversification are available. In a substantial empirical study across many industries, Rumelt found that a limited amount of diversification could reduce the risk of parent corporations.[31] However, unless it were constrained to some functional relation to the main line of business, diversification may show no particular benefit. In the public utility sector, Fitzpatrick and Groebner found confirmation for these general conclusions.[32] In particular, natural gas utilities which have diversified widely into unrelated businesses appear to have increased their risk by such activity. This increases the cost of capital to the parent's utility customers. On the other hand, electric utilities have relatively little non-utility activity and could, by some limited diversification, reduce their risk. The specific risks of utility solar investment are discussed in Section 3.2.

The results of Fitzpatrick and Groebner suggest the third major issue associated with utility subsidiaries, whether these businesses should be regulated or not. This is a decision that will often be made on the pragmatic ground of whether a would-be regulator has sufficient staff time and resources available to regulate subsidiaries. If such time and resources are not available and the risks to utility customers appear substantial, then the regulators only option is to forbid the activity. More ambiguous situations arise when the risks are not well-understood. For the issue of solar investment by utilities, there is likely to develop a leader-follower situation among state regulators. In California, substantial regulatory analysis of the issue is currently being pursued. This process is likely to generate information and

perhaps precedents for other commissions to rely upon. States with limited resources for regulatory scrutiny may be expected to develop guidelines based on California experience.

2.5 Special Bonding Authorities

The last major feature of a utility solar finance program to be examined here is the use of special bonding authorities as a means of raising relatively low cost capital. When municipalities and other specially constituted local agencies raise capital, they sell bonds whose interest is tax-free to the purchaser. The interest paid on the bonds of private corporations including investor-owned utilities is taxable. Therefore, the latter will have a cost of debt capital which is greater than the tax-exempt debt sector. This fact has created interest in the possibility of financing residential solar systems through tax-exempt mechanisms.

One approach to the tax-exempt capital market is through existing publicly owned utilities. A widely cited example is the city of Santa Clara, California. The city currently leases solar swimming pool heaters to residents through its water department. There are plans to lease solar hot water heaters.(33) The use of municipal utilities as a vehicle for widespread implementation of solar systems may be attractive where these utilities have established service territories and are in sound financial condition. If such institutions must be established as a pre-condition for utility solar finance, then major advantages of utility finance, its security and convenience, will be missing.

Special bonding authorities may also be used for access to the tax exempt capital market. In California, the state govenerment administers a Pollution Control Financing Authority which issues tax-exempt bonds to finance investments in pollution control. In the past, investor-owned utiltiies have used such funds to finance power plant scrubbers.(34) It has been suggested that such an arrangement might be used for utility solar finance.(4) It is not

clear that such an arrangement would qualify under the legislation. Furthermore, in this particular case, there are limits on the amount of capital obtainable through this mechanism. The Authority is legally capable of floating $50 million per quarter. In the five years since its inception, total funding has been about $270 million.[34] If the roughly 400,000 electric water heaters in California were replaced at a cost of $2,500 each, the total capital requirement would be about one billion dollars. This is almost four times the amount of bonds issued. At the maximum rate, it could be financed over five years, but this would crowd out any other investment in pollution control.

3.0 Economic Impacts of Solar Investment on Utilities

In this section a survey will be made of the various economic effects utility investment in on-site solar will have on the utility company involved. The discussion will address both the planning process for new conventional utility supply and the current financial position of the utility industry. Special consideration will be given to the role of federal tax preferences. Relatively little attention will be paid to the specific program features identified in Section 2 in hopes of concentrating upon the fundamental choices involved in determining whether the utilities ought to play a role in solar energy finance.

3.1 Internalization vs. Externalization

If regulated utilities are not allowed a role in on-site solar finance, they still will be impacted intermediaries as the residential solar market develops. In a scenario where utilities are external to the solar market, the main policy questions of interest center on the ability of the utility to respond to that market development. The appropriate responses would involve re-optimization of the utility supply plans to reflect the changed nature of demand facing the utility.

Literature analyzing the solar/utility interface is usually based on an implicit view of this adjustment process. Bright and Davitian, for example, assume in their study of solar back-up energy costs that all changes in utility demand caused by solar penetration in the residential market are known with certainty.[3] Therefore, costs can be calculated by comparing various runs of a utility optimization model. At the other extreme, Willey analyzes several scenarios involving large scale solar market development where the utility either capitalizes or ignores on-site solar.[35] This study finds that utility capitalization of solar results in lower utility costs than the case where the solar market develops and the utility makes no adjustment whatsoever.

It is likely that reality lies somewhere between the assumptions of perfect information and no adjustment process at all. Another way of putting this is that from the utility perspective uncertainty is inherent in the planning process. If the utility is external to the solar market development process, then that process will compound the already substantial demand uncertainties facing both electric and gas utilties. While utility planners are beginning to recognize the need to treat forecasted demand growth probabilistically,[19] the current state-of-the-art shows major unexplained structural differences among the existing demand forecasting models.[36]

Utility solar finance would help to make the solar market development process internal to utility planning rather than external. In this case, discriminatory solar rates would be less likely to be proposed by utilities and adopted by regulators. In theory, an integrated utility planning process would would choose among solar, conservation and conventional technologies on an unbiased economic basis. Thus, the utility would no longer have an incentive to defend its economic stake in large supply projects whose demand would be less expensively served by solar investment. Since internalization carries with it the risk of monopoly action in the solar market, and the concurrent danger

that technology would be retarded, some steps short of utility ownership deserve consideration. These alternatives are discussed in Section 5.

3.2 Electric Utility Financial Risk Profile

Any proposal for utility solar finance must examine the impact of such schemes on the risk structure of the utility. For this assessment to be realistic, it is important to understand the current financial position of the utility industry. By general consensus, the outlook for electric utilities is not particularly good.[37] The major factors contributing to the industry's problems have been alluded to above. The cost, scale and construction time required for major new supply projects have been growing. This has been coupled with uncertain demand growth that has lagged behind past expectations. The interaction of cost escalation, long project lead times, and softening demand have combined to put a serious strain on electric utility cash flow.[18]

From the perspective of the utility's financial stability and viablility, investment in on-site solar involves a trade-off between technical risk and the flexibility of small scale incremental supply. In a fundamental way, on-site solar resembles nuclear and hydro generation in that all these technologies are substitutions of capital for conventional fuels. In a regulated industry, such substitutions are advantageous because they immunize the utility's earnings from the effects of regulatory lag. The current climate of rising marginal costs and persistent inflation tends to cause earnings attrition, because utility rates are typically set on the basis of cost estimates that will turn out to be less than acutal costs. Fixed costs are by nature not subject to inflation or escalation once the initial capital has been sunk. In a regulated industry, the adjustment of variable costs to inflation and escalation will always lag due to the administrative delays attendant on the rate making process. The principal advantage of solar investment as a substitute of capital for fuel is the small scale of each unit.

Nuclear generation exhibits diseconomies of scale that are reflected in the standard financial ratios used to evaluate a utility's corporate credit. The ratio of earnings to interest payments, measured in various ways, indicates the extent to which a bond holder has assurance that he will be paid. Bertschi has shown a systematic relationship among these ratios which distinguishes companies building nuclear plants from those which have no nuclear construction.[38] The capital requirements for a nculear plant are of such a magnitude and occur over such a long period of time, that a sever strain is placed upon the credit of their sponsors. Once construction is complete, this strain disappears and the financial stability of the utility improves.

Solar investments, while capital intensive, would be made in increments that are more easily adjusted to the financial capability of the utility. This benefit is magnified by the short lead time involved in most solar residential applications. It is the long construction and licensing period for large scale projects which imposes the financial strain. Under the most common regulatory procedures, the utility will not earn a return on capital allocated to construction until the plant goes into service. Although there are regulatory remedies to the financial lag induced by long construction periods, these are not politically popular in many constituencies.[39]

It should be emphasized that the financial strains and risks of large scale projects get reflected in the capital market. One measure of the capital market risk evaluation is the differential bond yield on public utility debt issues. Figure 1 shows a time series of the bond yields and the yields spread among utilities that are rated differently by Moody's Investor Services.[40] This figure provides a capsule financial history of the utility sector. It shows that during periods of macro-economic stress, the market risk premium as measured

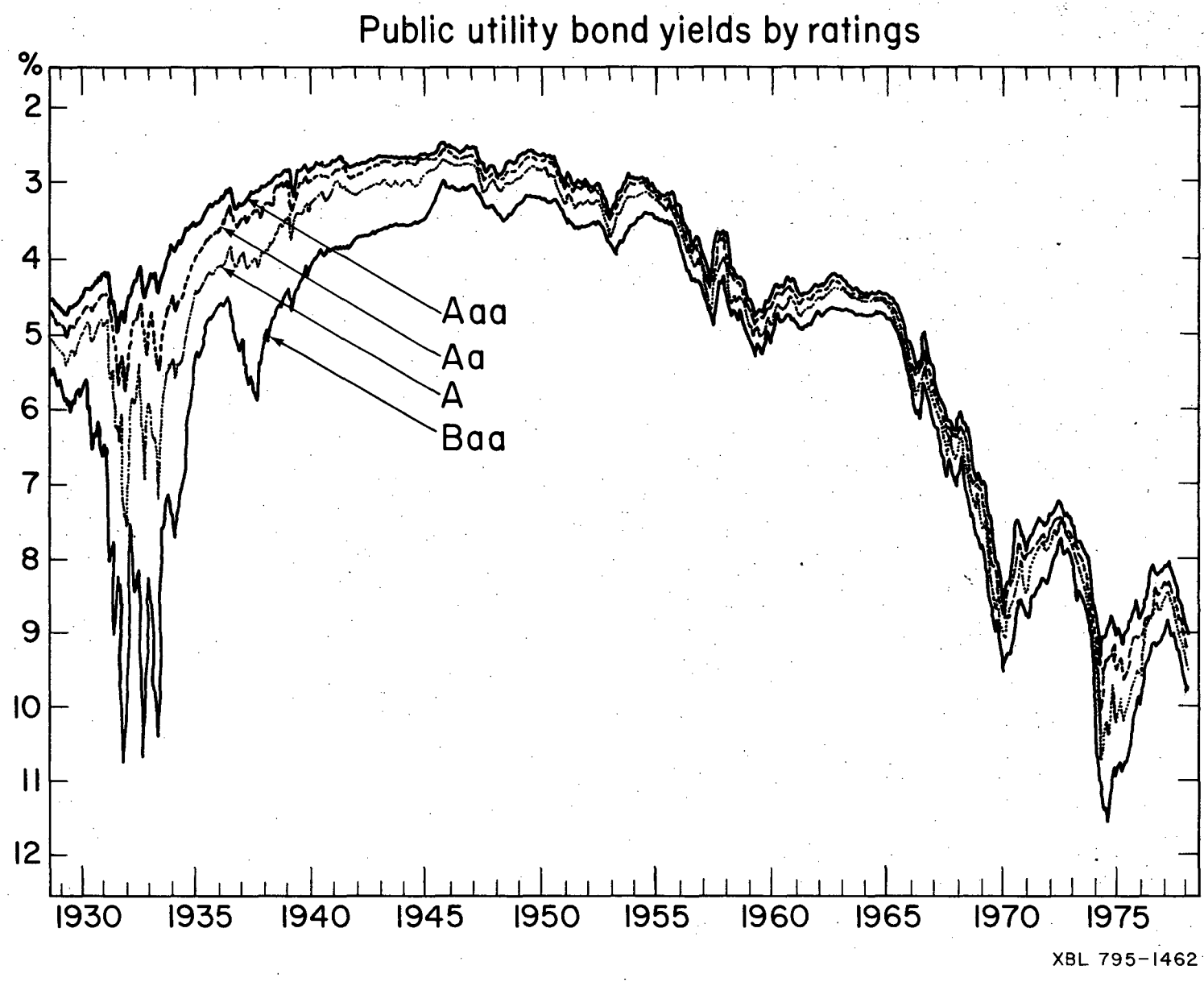

Fig. 1

Reproduced from 1978 Moody's Public Utility Manual

by the spread between high and lower rated bonds, is larger than in economic growth periods. For the last few years, studies have also shown a risk premium in the common equity market that is linked to the magnitude of construction activity.[41-43]

In principle, solar investment could be expected to mitigate the risk of utility investment in large scale projects, at least to some degree. Preliminary conceptual analysis suggests that this would be the case.[22] But without substantially more experience with widespread use of residential solar technology, it is not possible to dismiss the technical risk and uncertainty associated with any relatively unconventional technology. Therefore, as a practical matter, any utility solar finance program ought to start at a relatively small scale and grow larger as more experience on performance is developed. Although, in principle, utilities ought to be able to provide maintenance services for solar investments, it might be more desirable that these costs be borne by participants in utility finance programs. Such a treatment of maintenance expenses would tend to minimize the technical risk of the program to the utility. Again, more actual experience will indicate the dimensions of this potential problem.

3.3 Federal Tax Effects - Excess ITC

The role of federal corporate income taxes in determining a utility's cost of capital was indicated in Table 3. The nominal income tax rate of 46 percent, however, is usually offset by tax preferences associated with capital investment. The two major tax incentives for utility investment are accelerated depreciation and investment tax credit. Given the size of current electric utility capital programs, the effective tax rate for utilties ranges from 0 to 20 percent.[44] This effective rate would be even lower on average if it were not for a limitation on use of ITC. In both the tax revision laws of 1975 and 1978, explicit limitations were placed on the use of ITC to offset tax obliga-

tion. These limits vary from year to year, going from 70 percent in 1979 to 80 percent in 1981, and 90 percent in 1982.[45] The importance of this limitation is that many utilities are currently in the anomalous position of having substantial ITC carry-forward balances that cannot be used.[46] The constraint which creates this is the inability of the utility to generate sufficient income to absorb the credits. The importance of this effect is that it can create a de facto tax credit for utility solar finance. Such a program, or indeed any program which generates revenue will capture some of the excess ITC. This will lower the incremental tax rate on such programs in a significant way.

It is instructive to examine a little data on excess ITC. In one recent survey of 45 investor-owned utilities, 22 percent were found to have ITC carry-forward balances which average $18 million.[47] It is not surprising that Pacific Power and Light Company has an ITC carry-forward of considerable proportion. According to its 1978 Annual Report to the California PUC, PPL had about $12 million excess ITC. It is unlikely that this balance will decline. This is due to the magnitude of PP&L's construction program. Over the next seven years (1979-1985), PP&L's capital budget for generation and transmission projects alone is estimated at $1.7 billion.[48] This will generate approximately $170 million in ITC. The average ITC over this period would be $24.4 million per year. In 1978, PP&L used a little over $21 million ITC to offset income taxes.[49] Considering that additional ITC is likely to be generated by investment in distribution plant, PP&L can reasonably look forward to a positive ITC carry-forward balance into the mid-1980's.

The effect of utilizing excess ITC on the incremental cost of capital can be seen by re-calculating the tax multipliers used in Table 3. For illustrative purposes, let us assume that the average ITC utilization limitation is 80 percent. Table 4 retraces Table 3 calculation of marginal tax rate and pre-tax cost of capital.

Table 4

Effect of Unutilized ITC on
Marginal Cost of Capital

A. Tax Multiplier

1. Reduce Income by State Income Tax Rate = 9%

$$100 - 9 = 91\%$$

2. Calculate Federal Tax at 46%

$$91\% \times 46\% = 41.86\%$$

3. Net Out ITC up to 80%

$$(1 - .80) \times 41.86\% = 8.37\%$$

4. Add Back State Income Tax = 8.37% = 9%

$$= 17.37\%$$

marginal tax rate

5. Tax Multiplier $= \frac{1}{1 - .1737}$

$$= 1.21$$

B. Pre-Tax Cost of Capital: Standard Case

	Ratio	Incremental Cost	Weighted Cost	Tax Multiplier	Pre-Tax Cost of Capital
Debt	50%	9.5%	4.75%	1.0	4.75%
Preferred Stock	10%	9.5%	0.95%	1.21	1.15%
Common Equity	40%	14.0%	5.6 %	1.21	6.78%
			11.30%		12.68%

C. Pre-Tax Cost of Capital: Leveraged Subsidiary

Debt	80%	9.5%	7.60	1.0	7.60
Equity	20%	14.0%	2.80	1.21	3.39
			10.40		10.99

The calculations in Table 4 show that the impact of excess ITC on the cost of capital is large. In the case of a standard capital structure, the effective cost goes from 18.11 percent to 12.68 percent. For a leveraged subsidiary, the cost goes from 13.31 percent to 10.99 percent.

Thus, while the phenomenon of excess ITC has significant implications for utility solar finance, it is not particularly clear why some utilities have significant ITC carry-forward balances and others do not. The most likely explanation of the variation among utilities in this regard is the different state regulatroy treatment of construction expenditures and tax preferences. In Section 7 a more systematic investigation of the relation between regulatory practices and ITC carry-forward is conducted.

4.0 Economic Impacts of Utility Solar Finance on Customers

Utility solar finance raises a variety of issues regarding the equal treatment of participants in such programs as opposed to non-participants. To make programs attractive to customers, utilities will make inducements whose costs may or may not be justified. There are realtively straightforward tests which may be applied to assess the equity among utility customer classes of solar incentives. The issue becomes more complicated when the incentives of a utility solar finance program interact with other incentives such as tax credits. Here the remedy for inequity is less transparent. Finally, there is a range of economic equity questions arising from the recognition that utility solar finance may not be society's least cost alternative. The social cost perspective is explored in detail in Section 5.

4.1 Non-Participant Break-Even Requirement

Utility investment in end-use efficiency differs fundamentally from investment in centralized supply because the benefits of the former have more unequal incidence than those of the latter. In principle, no single class of customers

would benefit more from a new power plant than any other class. In practice there may be rate-making devices which distort the benefits of new investment to favor one class,[50] but there is nothing inherently unequal about the distribution of benefits. Where end-use efficiency is concerned, however, the benefits to participants are immediate and substantial in the form of reduced consumption and lower utility bills. The non-participant receives the indirect benefit of decreased requirement for new high cost supply projects. Not only is this less tangible than a reduced utility bill, but it is possible that non-participants could bear an increasing share of utility revenue requirements. This would mean that their average cost of energy was higher because the total revenue collected from participants had diminished.

To avoid this potential inequity, a bound can be derived on the incentive to participants which will avoid increasing the average cost of energy to non-participants. Essentially the appropriate incentive should be the difference between marginal and average unit energy costs times the amount of energy displaced by conservation or solar investment. This incentive can be implemented through rate structures in the case of no utility solar finance.[51] Alternatively, the criterion can be used to set cost goals for a utility capitalization program for end-use substitution investments. This is exactly the approach of Pacific Power and Light Company.

A formal deriviation of the break-even cost for non-participants is given below. The presentation follows a simple model used by PP&L.[52]

Let G = initial consumption of non-participants

C = initial <u>total</u> consumption

I = marginal cost of supply/kwh

g = annual growth rate

x = cost of conservation (or solar)/kwh

r = average cost of supply/kwh initially

Assumption: All growth in load is from non-participants in conservation program (under conservation total consumption is constant before and after conservation measures).

1. gC = new load, supplied by plant at marginal cost

non-participant revenue requirements = proportional share of total dollar requirements

$$\text{proportion} = \frac{\text{Initial non-participants consumption} + \text{New load of non-participants}}{\text{new total load}}$$

$$= \frac{G + gC}{C + gC}$$

$$\text{total dollar requirements} = rC + I\ (gC)$$

$$\text{non-participants' share of revenue} = \left[\frac{G + gC}{C + gC}\right] \left[rC + IgC\right]$$

2. gC = new load, "supplied" by conservation

In this case, the proportion of total supply used by non-participants increases

$$\text{proportion} = \frac{G + gC}{C}$$ -- only "C" because there is no new supply for the system overall

$$\text{total dollar requirements} = \underset{\text{(initial)}}{\downarrow rC} + \underset{\text{(rate)}}{x}\underset{\text{(amount)}}{(gC)\downarrow}$$

$$\text{non-participants' share of revenue} = \left[\frac{G + gC}{C}\right] \left[rC + xgC\right]$$

3. If revenue from non-participants is to be the same under the conservation approach as under new supply (at marginal cost) approach, then:

$$1. = 2$$

$$\left[\frac{G = gC}{C + gC}\right] \left[rC + Igc\right] + \left[\frac{G + gC}{C}\right] \left[rC + xgC\right]$$

$$\text{then } xg\mathcal{C} = \frac{\left[\frac{\mathcal{C} + g\mathcal{C}}{\mathcal{C} + g\mathcal{C}}\right] \left[r\mathcal{C} + Ig\mathcal{C}\right]}{\left[\frac{G + gC}{C}\right]} - r\mathcal{C}$$

$$xg = \left[\frac{1}{1+g}\right] \left[r + Ig\right] - r$$

$$xg = \frac{r + Ig - r(1+g)}{1+g}$$

$$= \frac{(I - r)g}{1+g}$$

$$x = \frac{I - r}{1+g}$$

if $g \ll 1$

$I - r$ = difference between marginal cost and average cost (initial)

4.2 Interaction of Utility Solar Finance with Other Solar Incentives

A number of incentives for development of the residential solar market currently exist or are proposed. Where these simply compete with utility solar finance, there is no particular policy problem. Society may wish to favor one kind of financing over another, but there is nothing extraneous which complicates the choice. Other incentives will interact economically with utility solar finance and this creates policy complications. The main difficulty occurs with Federal Income Tax Credits for individuals. Before exploring this case, it is convenient to take up a less difficult case, the interaction of utility rate reform with utility solar finance.

The Public Utility Regulatory Policies Act (PURPA) mandated the explicit analysis of electric utility rate reform by state regulatory commissions. Such reforms might have an explicit or implicit incentive effect upon the residential solar market. For example, time-of-day rates based on existing or projected

daily cost variations could favor residential solar applications for hot water heating in a summer peaking utility. A cost study of this problem which considered the solar alternative explicitly would, in all likelihood, come up with a solar incentive that would be more attractive than the implicit incentive which would result from no solar analysis at all. For example, a recent study of this problem concluded that discounts to solar users were appropriate if limited to the difference between marginal and average costs.[51] Since this is the same criterion underlying the PP&L zero-interest loan program, it would be unfair to allow both the discount and the favorable financing. This would be the same as giving the justifiable subsidy twice. In principle, such difficulties are avoidable, since the utility is internalizing all costs and can be expected to avoid excessive incentives. In practice, the possibility of utility solar finance may well complicate the process of rate reform under PURPA. The appropriate assumptions for cost studies of rate reform depend on the policy toward utility solar finance. If this is changeable or unknown, then the accuracy of rate reform cost analysis becomes questionable. Resolution of such problems amounts to the formulation of consistent state regulatory policy. In principle, this is feasible.

The interaction of utility solar finance with the tax credit incentives is more complex. The equity problem is simple to describe; it is excessive incentives. The resolution is more difficult because there is no institutional framework for rationalizing and coordinating justifiable subsidies from the perspective of utility costs with those justified by social costs. In practical cases, it may turn out that the tax credit mechanism is literally being used twice under utility solar finance. The excess ITC situation described in Section 3.3 turns out to be a significant determinant of costs in the case analyzed in Section 6. Thus, a participant in such a solar finance program would

be eligible for both a zero interest loan and substantial state and federal tax credits. To avoid this double incentive, it has been proposed that the state credit be signed over to the utility.[4] This solution would have administrative complexities and doesn't really solve the problem when excess utility ITC is involved. An alternative would be to terminate tax credits for participants in utility solar finance programs.

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5.0 Social Cost Analysis

Evaluating the role of utilities in solar energy presents a curious policy dilemma. The utilities themselves are wary of the solar market: it is novel, politically and perhaps economically risky, and alien to the experience of utility managers. Public interest groups and antitrust experts have identified numerous ways in which utility involvement could stunt the solar market, unfairly enrich utilities or waste customer resources. The National Energy Conservation Policy Act interposes legal obstacles to utility financing or ownership of solar devices. Yet government officials continue to look to utilities to promote solar applications. The reason is simple: no one else is doing it successfully. Despite the increasingly favorable economic case for solar water heating and passive solar space heating, market acceptance may lag years or decades behind economic rationality. The temptation is strong to turn to the utilities for capital, operating subsidies, or expertise and credibility in the energy marketplace. This section will outline some of the difficulties with utility solar involvement and outline some possible solutions.

Why Care?

Development of the solar industry is not an end in itself, but a means to objectives which are in a broad sense economic. Reduction of dependence on fossil fuels, as mentioned below, has national security advantages which are plausibly enormous, but impossible to quantify. But despite the existence of this potentially overwhelming value for all forms of non-fossil energy, it is worthwhile briefly to pursue a conventional economic analysis of the reasons for either government or utility subsidies to solar energy. Starting from the

economic assumption that any subsidy requires justification, we can identify the varying kinds of market imperfections which affect the solar industry and examine the remedies they imply.

At the outset, it is worth distinguishing between the concepts of social cost or benefit and private cost or benefit. The "social benefit" of a utility solar program is measured by the total savings to society from the introduction of the solar program, compared to the cost of the likely alternative. The private benefit to the utility can be measured in terms of increased utility profits, likely increases in the price of the utility common stock, or some other measure thought to represent the goal of utility managers. The private benefit to the homeowner (or other user of solar equipment) is measured by the difference between the cost of the solar equipment and the expected decrease in utility bills. Since the decrease in bills will take place over time, these homeowner benefits must be measured in terms of the "present value" of the future savings.

An analysis of the cost of utility finance can serve as an illustration of the difference between these perspectives. Utilities, as indicated earlier have a less leveraged capital structure than banks — that is, their proportion of equity to debt is higher, and the resulting cost of capital to the utility may also be higher.* But the ability of banks to rely on back-up from the federal government suggests that the social cost of bank capital is distorted by these explicit and implicit government guarantees.

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* In theory, the cost of capital to a firm should be independent of its debt-equity ratio if there were no distortions due to tax treatment of dividends and interest, and if there were no transactions in costs in the event of bankruptcy (the Modigliana-Miller theorem). In practice, tax distortions (the fact that interest is deductible, whereas dividends are not) probably lead to an optimal capital structure strongly weighted toward debt.

5.1 Market Imperfections

5.1.1 Externalities

(a) National Economic Interest in Diversified Energy Supply and Reduced Oil Dependence

Even if solar energy prices were expected to remain above the cost of an equivalent amount of imported oil, the social value of solar energy might substantially exceed its worth to the individual customers. The true social cost of oil imports exceeds even expected sharp increases in prices, since society must pay for uncertainty about the timing and extent of those increases and for their effect on inflation, GNP and unemployment. Thus, for example, Data Resources Incorporated estimated in 1979 that a $5.00/barrel increase on the price of OPEC oil would raise inflation by 2.5 percent and lower GNP by an equivalent percentage. Hence, the approximately $18 billion direct effect would be translated into a $50 billion loss in GNP. A similar calculation in a New York Times editorial led to an estimate of $100/barrel as the true social cost of a barrel of imported oil. This cost is not borne by the utility or businesses choosing between oil (or oil-generated electricity) and non-fossil energy.

Apart from the short-run risks to the economy of abrupt oil price hikes, there are risks of depression, inflation, social disruption, and war associated with anxiety over the shortage of fossil fuels in general and liquid fuels in particular. While synthetic coal processes could eventually meet U.S. energy needs, the problems of cost, lead-time and environmental hazard are so substantial that the development of substitues may have a value vastly exceeding even the projected cost of oil imports.

(b) Pollution

Another externality in solar energy use is its replacement of high-polluting fossil fuels. Properly, these costs should be measured against an estimate of the averted pollution damages, but damage estimates are exceedingly imprecise:

a Resources for the Future study of the 1977 National Energy Plan, for example, surveyed damage estimates for the amount of generation of electricity by coal called for in the Plan. Estimates of air-pollution related deaths ranged from near zero to 6,000; the range for non-fatal diseases was between 10,000 and one million.*

In the abscnce of reliable damage estimates, we can substitute as a measurement of air pollution costs the amount of money that society is prepared to pay to reduce pollution. The U.S. Environmental Protection Agency estimates that the electric utilities industry spent $6 billion for air pollution abatement in 1978, of which $4.5 billion was spent in response to federal legislation. These amounts are likely to rise substantially as the requirements of the Clean Air Act become more stringent (e.g., the requirement for scrubber installation on coal-fired power plants and the increasing shift to desulphurized fuel oil). In addition to these direct expenses, society bears the economic cost of the law's restrictions of growth of major industrial polluters in both clean and dirty areas of the nation.

The production of some kinds of solar equipment, for example, copper tubing or plastic collectors, itself involves substantial pollution. A full economic analysis of solar (which, to our knowledge, has not been undertaken) would estimate both environmental costs and benefits.

5.1.2 Price Distortions

(a) Average Cost Pricing

The rates utilities charge to their customers are based on historical average costs, which reflect the actual cost of investment and of raising debt

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*William Ramsay, Unpaid Costs of Electrical Energy (Resources for the Future, 1979).

capital and preferred equity. Efficient resource use would require pricing to be based on incremental costs, the cost of new supplies and currently raised capital. In a period of rapid inflation, incremental utility costs are likely to exceed average costs by a wide margin. For example, Pacific Gas and Electric Company estimates its incremental costs at about 7.5 cents per kilowatt hour and its average costs at 3.8 cents. Since customers will base their investment decisions on average cost rates, they are likely to under-invest in solar or other conservation devices.

(b) Lack of Time-of-Day Pricing

The costs of providing electric utility service vary radically according to the season and time of day. A T.V.A. study, for example, estimated a ratio of 2.6 to 1 between system costs of electricity in peak versus offpeak summer hours. The study found a high coincidence of water heater load with the system peak. Two conclusions follow: solar installations can save money for the entire system by reducing peak load; other peak-shifting devices (such as timing equipment costing $250-$300) combined with time-of=day rates might be comparably or even more cost-effective than solar. Indeed, T.V.A. found that the system savings due to solar were almost entirely accounted for by the capacity rather energy reduction.

Other systems with different load characteristics and generating-plant would have different cost comparisons, some of which might make solar even more attractive compared to conventional generation and superior to load-shifting devices. For example, we can use the VEPCO estimates of typically daily load patterns for uncontrolled water heating to illustrate the difference between the T.V.A. and the Long Island Lighting (LILCO) systems. Under TVA's hypothetical peak-off-peak pricing system, approximately 78 percent of water heating is coincident with peak periods. The LILCO tarifff distinguishes between peak,

intermediate, and off-peak. Eleven percent of water heating would be charged peak rates, while 64 percent would fall in the intermediate range. But the LILCO's system shows greater time-of-day differences in energy charges than does TVA's. An average kilowatt hour eliminated through solar usage would save 5.3 cents, versus 1.52 cents for a load shifting device which did not reduce energy consumption.*

5.1.3 Poor Information and Uncertainties about the Reliability of Solar Systems

These market shortcomings are symptomatic both of a real social cost (of providing information or insuring against unreliability) and of the immature development of institutions which could reduce that cost (such as joint warranty funds or government testing services).

5.1.4 Customer Aversion to Making Choices Based on Lifecycle Costs

Studies of the solar industry invariably identify the industry's major marketing problem as the reluctance of consumers to make a large front-end investment in energy-saving devices. In economist's terms, this reluctance may be due to: a) poor information or uncertainty about the performance of the solar device (see below); b) aversion to taking the risk involved in a long-term investment; c) inability or inaccuracy in prediction of future energy or solar costs; d) irrationality. This last is a difficult category to identify: is the family who does not want to be the first on their block to buy a "solar gizmo" being irrational or prudent?

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*VEPCO study cited in Tennessee Valley Authority, Update of July 17, 1978, Study to Evaluate Power Credit for Solar Water Heating" (xeroxed; Solar Applications Branch, 426 United Bank Building, Chattanooga, Tenn. 37401). The LILCO tariff is cited in Ernest Habicht, "Electric Utilities and Solar Energy: Competition, Ownership, Subsidies & Prices," in The Solar Market, Proceedings of the Symposium on Competition in the Solar Energy Industry, Bureau of Competition, Federal Trade Commission, 1978 (p. 236).

The customer's risk aversion or uncertainties of prediction may represent both genuine social costs and, in part, avoidable market failures. Economists have extensively debated whether governmental investment decisions should be based on a less cautious evaluation of the costs of risk-bearing, and a greater willingness to invest now for future returns, than the investments of the private economy. There is some consensus that society should be willing to accept higher risk and a lower payoff, because it can diversify risks across a variety of projects and (more controversially) because it should reflect a collective commitment to future generations which individual investment decisions do not. This argument would justify an across-the-board subsidy for all investments. As applied to a specific investment, such as solar energy, the decisive questions concern: a) the likely risk and social rate of return (taking into account externalities and the other market imperfections identified here); b) and the ability of the government (directly through public expenditures or indirectly through personal tax credits or incentives for utilities) to make more prudent investment choices than the private market; c) an overall budget constraint on the government, forcing choices among investment projects, all of which have higher returns than the "appropriate" level as described above.

At present, it might seem that the budget constraint would be the overriding consideration in view of the "tax revolt." But energy is a special case, and it is probably best to view solar investment by the federal government as a competitor with other major energy supply projects rather than with the budget as a whole. Similarly, a government program of incentives to encourage utility solar investment should be analyzed in comparison with other possible utility investments (including conservation options).

5.1.5 Traditional "Infant Industry Conditions in the Solar Market

Although solar water heating was used in the United States during the 1930's, the disappearance of the industry for three decades and its reemergence in a context of new technology and high uncertainty may qualify solar as a twice-born "infant industry." Certainly, passive solar housing has credentials for the crib. However, the argument for aiding "infant industries," properly stated, involves proving more than their immaturity. The usual rate-of-return investment criterion applies: will the increased productivity in later years justify the extra investment now? For solar water heating, the argument could be based on (rather uncertain) economies of scale in manufacturing, induced technological change from a greater assured market, or more rapid development of a contracting and manufacturing industry whose warranties will command consumer confidence. For passive solar housing, the same arguments apply with additional force because of greater promise for major technological change, the traditional sluggishness of the housing industry in financing or accepting technological change and barriers due to lending institutions and building codes. A question remains whether subsidies are theoretically the most efficient way of overcoming these barriers; or, even if they are not, whether they are necessary to build the industry up to sufficient scale so that it can overcome the remaining institutional difficulties itself.

5.1.6 Distortions in Utility and Regulatory Incentives

We have proceeded thus far on the premise that the appropriate investor in solar equipment would be the dwelling owner, absent some market imperfection calling for utility or government involvement. But one ought to begin with a netrual assumption concerning utility investment. Utilities have a franchise to supply energy; most states have at least some combined gas and electric utilities, so there is no general principle confining utilities to one form of energy. In the past, utility regulators have approved utility promotion pro-

grams involving rebates on gas and electric appliances. Thus, there is no obvious incongruity in utilities undertaking to supply solar energy. There are, to be sure, important antitrust and incentive arguments against some kinds of utility involvement: utilities are regulated as natural monopolies; the provision of solar energy is not a natural monopoly; complications result from joining the two activities under a single corporate and regulatory scheme. Nonetheless, it is worthwhile to ask whether utility involvement is blocked by the equivalent of market imperfections as well as by legal or public policy considerations (see discussion below). The most obvious candidate for such an imperfection is the attitude of many utilities toward solar and conservation activity. For reasons which combine an engineering outlook, profit incentives, long-term concern over decentralized systems, anticipation of public policy, and simple inertia, most utilities did not, on their own initiative, pursue cost-effective conservation investments. As pressure from regulatory commissions and tight capital markets has increased, utility attitudes toward conservation have begun to change. A similar, slower transition may be underway with respect to solar energy. In the meantime, utility disinterest in solar may be viewed as a peculiarity in market behavior of not an outright imperfection.

5.1.7 Taxes, Subsidies and Regulated Gas and Oil Prices

Conventional energy sources have benefitted from major subsidies and tax incentives.* For oil and gas, the depletion and intangible drilling allowances available in 1974 amounted to a subsidy of 13 percent of the market price (compared with one percent for coal and nothing for hydroelectric and nuclear power).

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*See An Analysis of Federal Incentives Used to Stimulate Energy Production, (Pacific Northwest Laboratories, PNL-2410) prepared for U.S. Department of Energy, Assistant Secretary for Conservation and Solar Applications, Division of Solar Applications.

Direct government development expenditures for nuclear power and the benefits of exemption from full liability insurance have amounted to billions of dollars; tax exemption of public utilities (through the investment tax credit and accelerated depreciation) have further reduced the cost of utility provided energy. While some of these tax benefits have been modified, their influence may still be effective through utility investment in plant and equipment chosen in response to subsidized prices.

Recently, Congress has enacted a 20 percent tax credit for customer purchased solar devices. President Carter has proposed a multi-billion dollar public investment in a Solar Bank. As of now, there are not studies available comparing the total benefits from this credit with the subsidies for other forms of energy.

5.2 The Utility Role

Some of these possible market imperfections are already, or might best be, addressed by government rather than by utilities. Governments are now providing tax subsidies to consumers, testing laboratories, and information and R&D programs; the proposed Solar Bank would vastly increase available funds for solar development. Nonetheless, utility involvement may appear attractive for any of several reasons:

(1) Government subsidy programs may involve centralized decision-making on technology. Encouraging utilities to be purchasers of solar technology, or conduits for individual purchase, could be designed to decentralize decision-making.

(2) If the utility owned solar systems and if it were motivated to minimize costs, it would choose between solar and conventional technologies on the basis of marginal costs.

(3) The utility can serve as a taxing mechanism to subsidize solar technology, thus correcting the distortions introduced by average cost pricing.

For example, the utility could measure the difference between incremental and average cost, and provide that amount as a direct grant or a loan subsidy to solar consumers.

(4) As established, conservative organizations, utilities have the ability and reputation for making decisions in favor of reliable technology. Thus, the utility may have a role to play in testing or certifying solar equipment, supervising contractors, or experimenting with various forms of finance, marketing and warranties.

(5) While utility customers who do not use solar should not subsidize the full social value of a national transition from fossil fuels, they might fairly be asked to pay for the gains to the tuility itself in reduced dependence on vulenerable energy sources.

(6) Utilities may enjoy economies of scale in risk-taking in solar investment.

(7) There may be economies in using utility employees to promote, market or service solar installations.

(8) Utility investment or financing of solar technology may diversify the utility's risk and thus reduce the total cost of capital to the utility.

In what follows, we shall first give a general outline of the kinds of roles available to utilities in solar development, and the types of public policy problems these present. Subsequent sections will discuss two key utility solar strategies and conclude with suggestions for public policy.

5.2.1 Possible Kinds of Utility Involvement

The utility role in solar technology may include any of a number of activities:

(1) Utility ownership of distributed solar installations (we are not concerned here with large central installations which might be considered part of

the utility's "natural" monopoly).

(2) Utility financing of solar purchases by customers.

(3) Utility subsidies through cash rebates.

(4) Mixed ownership, financing and subsidy schemes.

(5) Main extension allowances.

In addition, the utility may be involved in research and development expenditures, demonstration projects, and marketing and promotion activities. These forms of utility activity do not pose major regulatory difficulties and will not be discussed further in this paper.

5.2.2 Dangers of Utility Involvement

(1) Gold-plating. One theory of utility incentives holds that, if the allowed rate of return on capital exceeds the return required by the market, the utility will tend to make excessively captial-intensive investments. While this theoretical incentive may be inapplicable in a period of capital tightness and below-book prices for utility shares, utility bureaucracies may nonetheless have a built-in bias for capital-intensive equipment.

(2) Inexpert, biased or inflexible decision-making: utilites are, and will continue for some time to be, dominated by persons trained in conventional energy technology and unused to direct market discipline in technology choice. Decisions on the kind and amount of solar investment may be poorly made by an organization with such an orientation. In particular, one might expect utilities to be biased against passive solar technology (which would involve no separable, ownable piece of equipment). The danger might involve not merely a short-term waste of resources, but a lasting misdirection of the solar industry.

(3) Cross-subsidization - so long as utility rates are set below the profit-maximizing rate for a monopolist, the utility might raise rates on its monopoly services in order to subsidize its solar activities. The result would be unfairly damaging to solar competitors.

Even if the utility did not raise its general rates, it might subsidize or unfairly advantage its own solar activities by diverting resources from its other markets (such as management or marketing personnel), discriminating in its repair services, or requesting rate structures which give an advantage to its own solar activities.

4) Over-regulation. In theory, vigilant regulation could protect against all these abuses; in practice, regulatory agencies may be inattentive, overworked, co-opted, or inadequately informed to prevent unfair utility conduct. More serious, perhaps, is the danger of over-regulation. A regulatory agency which begins by policing utility solar conduct may, over time, exercise supervisory powers over an increasing segment of the solar market.

5) Monopolization. Concern that utilities might "monopolize" the solar industry summarizes many of the problems discussed above — cross-subsidization (giving the utility an unfair advantage over competitors), discouragement of innovation, regulatory protection. In addition, it evokes a familiar (if controversial) theme of antitrust discussion: that small suppliers or contractors might be precluded from competition even by ostensibly fair pricing and conduct by utilities.

These possible dangers are reflected not merely in public policy discussions on utility solar involvement, but in antitrust questions which might restrict utility involvement. As the following section makes clear, the issues overlap substantially.

5.3 Antitrust Issues Concerning Utility Involvement

Since utilities are monopolies, their involvement in other markets raises serious antitrust questions. Two issues are central to analyzing possible utility roles in solar energy: (1) the effect of regulatory approval on the legality of utility conduct under the antitrust laws; (2) the antitrust policy issues which should be considered in making the regulatory decision. In our view, these issues are essentially identical.

Before 1975, a federal antitrust challenge to the activities of a regulated utility had first to surmount a defense based on Parker v. Brown.* This 1943 case established a "state action" exemption shielding private conduct from antitrust prosecution when the conduct was undertaken pursuant to a state regulatory scheme. The scope of regulatory immunity was never unlimited; and in a 1973 case involving a federally regulated utility, the Court upheld an antitrust action against an electric power company's refusal to sell power to a municipal distribution company.** In 1975, the Supreme Court began an intense process of challenge to the Parker doctrine of state immunity;*** the 1976 case of Cantor v. Detroit Edison held that a utility practice of replacing light bulbs free of charge could be challenged under the antitrust laws, even though the practice had been followed since 1890 and was part of the original tariff filed (and approved) by the state regulatory commission in 1916.**** The Court noted that the practice was never specifically approved by the agency, and that such passive, non-contemporary approval did not justify a "state action" exemption. Perhaps liberated by the decision in Canror, courts began finding utility pricing practices vulnerable to antitrust attack when they matched conduct which in an unregulated context would be termed "predatory."*****

In recent years, the Supreme Court has pulled back from the possible implications of Cantor. So long as the action of a state agency is within the

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*317 U.S. 341 (1943).

**Otter Tail Power v. United States, 410 U.S. 366 (1973). See discussion in Klebber, Draft Paper on Utility Solar Activities and Antitrust Law for California Public Utilities Commission.

***Goldfarb v. Virginia State Bar, 421 U.S. 773 (1975).

****Cantor v. Detroit Edison, 428 U.S. 579 (1976).

*****FPC v. Conway, 426 U.S. 271 (1976) and City of Mishawaka v. Indiana & Michigan Elec. Co., 560 F. 2d 1314 (7th Cir. 1977, cert. denied 436 U.S. 922 (1978). See Klebber, pp. 11-12.

scope of its legislatively-granted authority and forms part of a scheme of regulation, the cases say that antitrust immunity applies. Indeed, rather than decide challenges to state economic regulation under the antitrust laws, the Court has chosen to invent First Amendment doctrine and perform its economic analysis under that rubric.*

For the purposes of evaluating a proposed utility solar program, it is not necessary to attempt a precise formulation of the current state of the Parker v. Brown rule. Instead, a conservative approach would assume that the regulatory program itself should serve the economic goal of antitrust--competitive efficiency--in all areas where the regulated firm's monopoly is not inevitable. In some jurisdictions, regulatory agencies are required by law to take antitrust considerations into account in relevant utility proceedings. California, for example, has adopted such a rule in general by court decision, and by statute specifically orders the Public Utilities Commission in its regulation of utility solar programs to "ensure that the solar industry is competitive and free from the potential dominance of regulated electrical and gas corporations." Federal decisions have long held that regulatory agencies must attend to the antitrust consequences of their decisions. The required accommodation to antitrust considerations is not, in general, dictated by the formal doctrines of antitrust cases but by the general goals of the law and the kinds of economic reasoning developed in the cases.

Applying this principle to utility involvement in solar enterprise, we can identify two basic policy questions concerning utility involvement in solar energy: (1) How should the utility and the customer share in the ownership of the installation? (2) What degree of subsidy should be provided by the utility to the user?

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*Friedman v. Rogers, U.S. (1979).

5.4 Policy Questions

5.4.1 Utility and Customer Ownership Options

1. Utility Ownership under Regulatory Supervision

The economic case for utility ownership is significantly based on lowering risk to the utility by purchasing "modular" solar equipment rather than large-scale conventional technologies. The "modularity" of solar installations can reduce risk in two different ways. First, the chance of failure of an entire installation can be borne easily because the cost per installation is small. Second, the developing nature of solar technology may provide the utility with an opportunity to diversify its risks across different types of devices, either simultaneously or over time. To be sure, this diversification is likely to have a cost. The purchasing utility may have to accept higher bids, lower performance standards, or less adequate proof of reliability in order to achieve diversification.

In a profit-maximizing firm, we could theoretically rely upon internal incentives to assure a proper tradeoff between the costs and benefits of diversification. But the profit incentives for a regulated firm offer no such guarantee. As discussed above, some economic theories would lead to a prediction that utilities would "gold-plate" their equipment purchases. But apart from this supposed incentive toward capital overinvestment, utilities may be unduly conservative and inflexible in their choice of solar technology. The business is new to them; the political, if not economic, costs of failure are high; incentives are strong to choose the system which appears to be the best understood, even if its cost is high or its technology is becoming obsolete.

If this conjecture is correct, a regulatory commission has five options. It may decline to second-guess utility management; it may reserve the right to approve the utility's choice of equipment; it may establish its own criteria for utility purchases; it may require the utility to operate through a separate

subsidiary; or it may confine the utility to a role (such as financing, subsidizing, or exclusion) which vests the right of technology choice in the customer rather than the utility. The middle choices--involving utility decision-making under criteria set by the regulatory commission--may be successful in curbing the extent of utility bias; but they might also aggravate the delay and caution inherent in utility ownership of equipment. The last two choices have properly been the focus of attention.

2. Utility Ownership through Separate Subsidiaries

To avoid the difficulties and perverse incentives of utility ownership, many have advocated that utility solar activities take place through a separate subsidiary. In regulatory practice, such subsidiaries are not directly subject to rate, entry, and price control. Instead, the regulator's concern is confined to transactions between the regulated entity and its unregulated subsidiary or affiliate. Thus, for example, the price charged by a subsidiary to its parent may be reduced if it is above fair market value. In situations where fair market value connot be established, the regulator may (as the California Public Utilities Commission has done with respect to major telephone companies) impute a maximum rate of return to the manufacturing company and disallow amounts paid by the parent which would result in higher rate of return for the subsidiary. Apart from prices, the regulator will be concerned with the financial status of the subsidiary and its implications for the parent company; with the method of accounting for goods and services which are used jointly by the two companies; and with any payments for good will, patent or know-how licensing, or general management.

In the case of a solar subsidiary of a uitlity, the accounting difficulties may not be severe. The utility might undercharge the subsidiary for general management services; but otherwise there would be little overlap in the activities of the two organizations. The substantial question is whether there is

any significant social gain, or anti-competitive difficulty, resulting from a truly arms-length relationship between the utility and the subsidiary. At one extreme, it is possible to imagine a solar subsidiary which did not in any way trade on the reputation, service force, or financial power of the parent utility. This kind of subsidiary would represent merely an investment by the utility. The public would gain the entry of a new competitior in the solar market, and would risk only the possibility that the parent utility's facility planning and rate proposals would be designed to maximize profits for the subsidiary. This result, at worst, would amount to a modest, concealed subsidy for solar facilities, and would provide an opportunity for discrimination against competitors. While these risks are plausible, their importance may not be great. Accountants for the regulatory commission, and potential plantiffs' antitrust lawyers, could detect major unreported diversions of management personnel to the solar subsidiary.

While there is little *a priori* reason to expect substantial social gain from the establishment of arms-length utility solar subsidiaries, there is similarly no strong reason to preclude an experiment. In a few cases, utility management has been highly motivated to invest in and promote solar installations. A five-year authorization from the regulatory commission, especially if accompanied by a non-discriminatory subsidy program, would allow opportunity for evaluation and competition.

Anti-competitive dangers. If the utility role is limited to subsidizing and financing solar installations, the anti-competitive dangers seem minimal. The only "distortions" which might be introduced by the subsidy would affect alternate fuels. As we have argued earlier, the price of those fuels has been and continue to be affected by major regulatory and tax subsidies. Even if solar subsidies were raised to a level exceeding those for competing fuels, there

would be no basis for antitrust complaint. Subsidies are so engrained in the system of regulation, and in the tax treatment of energy, that any legal intervention on antitrust or efficiency grounds would be unmanageable.

If the utility financed solar installations, it might reduce competitive opportunities for banks, savings and loans and other finance institutions. Two theories might support an argument that the utility had an unfair advantage: its finance terms might include a subsidy, or it might be thought to have preferred access to customers through billing, convenience, or reputation. These latter considerations involve some genuine economies, and should be defensible by a regulatory commission. In strict fairness, however, the utility might be expected to offer subsidies through any financial institution, not simply through its own auspices. A regulatory commission should investigate the administrative cost and likely degree of participation by financial institutions before rejecting this alternative.

5.4.2 The Degree of Utility Subsidy

Several criteria are possible for setting the rate at which the utility should subsidize solar installations:

(1) The difference between the social marginal cost of solar and that of alternatives. As discussed above, this difference could be quite large, especially if a generous allowance were made for the social cost of imported oil. It seems unreasonable, and quite possibly illegal, to expect utility ratepayers to bear these kinds of costs.

(2) The difference between the utility's marginal costs for solar and conventional power. This criterion measures the gain to all utility customers from solar development.

A number of complications arise in calculating this difference; a typical complexity involves prediction of future costs of alternate sources.

Solar installations will save future fuel expenditures. These savings require estimating the future cost of fuel and discounting it to present value. If fuel costs escalated only at the general rate of inflation, this calculation would pose no problem--the discount rate would be set equal to the fuel escalation rate plus some premium for the pure time value of money. This premium is typically equal to 2 to 3 percent, so the margin of doubt would be small. But, at the moment, it seems more likely that oil prices will rise significantly faster than the inflation rate than that they will fall in real terms. The production cost of coal (quite apart from owners' royalties) is likely to rise rapidly if current plans for expanded production are carried out. Uranium costs are a relatively small percentage of the cost of nuclear power, and may be reasonably stable in real terms. But the long lead time for nuclear plants had made nuclear power cost estimates as unreliable as those of oil fired plants.

(3) The difference between the utiltiy's average cost for power and the marginal cost of new conventional supply. This criterion, used in the Pacific Power and Light programs, measures the gain which customers who do not benefit directly from solar installations would receive from cost-reduction for the system as a whole. It is a very stringent criterion, and not one applied to other forms of utility investment. The process of regulation normally results in the setting of rates according to broad categories--e.g., all residential users, or all such users in a given geographical area. No further attempt is made to distinguish among users who benefit from new equipment or innovations and those who do not. Finally, when direct subsidization of a certain end-use is deemed desirable (for example, promotion of gas or electric appliances during the 1950's and 1960's), the cost has been borne by ratepayers as a whole without an attempt to protect existing ratepayers from any rate increase. A similar rule has applied to "main line extensions"--extensions of the utility plant to cover new or remote settlement. A certain footage of extension has been allowed free of charge; the rationale has been the utiltiy's duty to serve all of its customers.

Legally, public utilities are bound not to discriminate against any customer. Here, as elsewhere in the law, the term "discrimination" refers to an unreasonable classification, or one whose basis involves prohibited categories (such as race). If a utility chose the second cost-allocation criterion rather than the third, it could defend against any charge of discrimination on the following bases: (1) that the solar installation represented a demonstration project, whose product had to be sold below cost in the same way that would be true for an experiemental nuclear breeder or coal gasification plant; (2) that even if the scale of solar investment exceeds that customary for demonstration plants, the investment could still be regarded as a demonstration of the economic feasibility of solar, and would benefit all ratepayers by promoting better information and market development if solar; (3) that any new investment is likely to produce some relative shift in rates in favor of one or more classes of customers (e.g., by geographical area).

5.5 Conclusion

There is both legal and economic justification for a program of utility subsidization of solar installations by customers. A subsidy equal to the difference between the marginal cost of the next best supply alternative and either current average costs or the marginal cost of the solar equivalent would be efficient and permissible. Direct utility involvement, beyond subsidization, requires some degree of empirical inquiry. The least problematic utility activity--financing purchases--would require some investigation of financing alternatives through conventional sources. Utility ownership of installations should be undertaken through a separate subsidiary. In general, the anti-competitive risks of a utility solar subsidiary seem modest. They are likely to be outweighed by efficiency gains where the utility's reputation, sales force, or incentive structure is particularly useful. For example, retrofitting multi-family dwellings is an activity which may not be

undertaken by the apartment owner when the units have individual meters; utility involvement might be especially appropriate here. In each case, the question should be approached through a regulatory evaluation of accounting procedures, incentives, and competitive market structure.

6.0 A Case Study of Utility Solar Finance: Adapting the PP&L Plan to the Pacific Gas and Electric Company

The Pacific Power and Light Company plan for capitalizing end-use conservation loand depends for its success upon several unique circumstances. The two principal local conditions which may not be generalizable are the widespread use of electric heating in under-insulated buildings and the presence of substantial hydro resources. The first condition offers a large and attractive market for conservation investment. The second condition means that the difference between marginal cost and average cost is large. This is true because the capital cost of the hydro is largely amortized and the running cost is negligible. With a large difference between marginal and average cost, more end-use conservation/substitution is cost-effective.

In this case study the main features of the PP&L plan will be examined for conditions representing the Pacific Gas & Electric Company (PG&E), a large investor-owned utility operating in Northern California. This utility has proportionally less hydro than PP&L and a milder climate. Although PP&L limits its program to space heating efficiency investments, the method will be extended here to include solar hot water heating as well.

The case study proceeds in three major steps. First, estimates of the long run marginal cost (LRMC) for residential space and water heating are developed. Second, the cost of conservation for electric space heating and solar hot water heating are estimated. After comparing these costs to the maximum allowable cost under the marginal minus average cost criterion, it becomes clear that space

heating efficiency investments clearly qualify under the test. Solar hot water heating, although less expensive than the alternative LRMC, only qualifies in certain cases. Because there is considerable uncertainty concerning some of the key economic variables which determine solar performance, it is not clear that utility capitalization under the PP&L plan is justified. A utility end-use investment program incorporating both space heating efficiency investments and solar hot water heating will pass the cost-effectiveness test. The specification of such a combined program is the third and final element of the study.

6.1 Methodology for End-Use LRMC Analysis

The purpose of this section is to develop estimates of the marginal cost of electricity for particular end-uses. The analysis begins by focusing on the coal-fired power plant proposed by PG&E known as Fossil 1. This 800 MW unit is considered a generic representation of marginal supply costs for a utility which is substituting out of oil-fired generation. The capital costs for the plant are estimated, including best available control technology (BACT) for emissions, and expressed in 1978 dollars. The capital cost is annualized using an appropriate fixed charge rate (FCR). Fuel costs are also expressed in 1978 dollars with an allowance made for potential escalation in rail freight charges.

Capital and fuel costs are not the same as demand and energy costs. Technologies such as coal, nuclear and hydro are essentially substitutions of capital for fuel. Therefore, some fraction of the capital should be allocated to energy and some to demand. This distinction is recognized in standard references such as the NARUC Electric Utility Cost Allocation Manual, but no standard method is recognized by the industry for making the allocation for individual plants. It is perfectly natural, however, to approach the issue by looking at demand-related capital from the persepective of system reliability.

The basic notion from which to start is the effective capacity of a generating unit. This has been defined in the planning literature as the amount of additional peak load a power system can carry at the fixed reliability level when a new unit is added. Due to forced outages, this will be less than the rated capacity. For large units such as Fossil 1, effective capacity will be lower than for small units, since more back-up is needed when large units fail. If the effective capacity of a unit is x, where x is expressed as a fraction of rated capacity, then the incremental reserve requirement will be $y = 1-x$, where y is also a fraction of the rated capacity of the unit in question.

To evaluate the costs of meeting demand, one uses as reference the cost per kW of peaking capacity or other units with very high effective capacity. Call this LCC for load carrying capacity. Then demand related capital can be calculated by Demand Related Capital = ($/kW of LCC) (1/x). This is then annualized with a fixed charge rate.

Energy costs per kwh are the sum fuel cost per kwh and annualized energy related capital, adjusted for transmission losses. Energy related capital is just nominal $/kw of the marginal unit less $/kw of LCC. This is annualized using a fixed charge rate and converted to a cost per kwh using an estimated capacity factor or hours per year of production.

Individual end uses will all incur the same energy costs. They will differ with respect to demand costs. To calculate the demand cost, one needs to estimate the system diversified load factor for the end use in question. This can be done by dividing the diversified demand into the annual kwh consumption for the given end-use. The result is an equivalent number of hours per year per kW of diversified demand. This number divided by 8760 gives a load factor. The demand cost of a particular end-use kWh is the annualized demand related capital divided by the equivalent number of hours per year.

The cost of displaced end-use energy us just the energy cost plus the appropriately computed demand cost for that end use.

6.2 Long Run Marginal Cost of Displaced Electricity - Pacific Gas & Electric Co.

6.2.1 Marginal Cost of New Supply: Analysis of Fossil 1

A. Capital Costs = $\$1.157 \times 10^9$

$$BACT = \frac{.483}{\$1.640 \times 10^9}$$

$$\div 800 \text{ MW} \cong \$2050/\text{kW (1986\$)}$$

Using a 6 percent escalation gives a 1978 cost of $1286/kW (see Ref. 1).

B. Annualized Capital Charges (see Ref. 2)

Using FCR = .154

= $198/kW-yr

C. Fuel Cost

35 mills/kWh (1985 $) (see Ref. 2)

Using a 6 percent deflater gives a 1978 cost of 23 mills/kWh

Fuel cost uncertainty due to potential rail freight rate increases estimated by doubling the transportation component of the 23 mills/kWh. PG&E estimates 8 mills/kWh for coal transportation which, when doubled, yields a potential fuel cost of 31 mills/kh (1978 $). (See Ref. 3).

6.2.2 Allocation of Fossil 1 Costs to Demand and Energy

A. Demand Related Capital

1. Effective Capacity Estimate of Fossil 1 (see Ref. 4)

Use Garver equation for C=800, r=.12, m=350,

Effective capacity=547 MW

= .68 Rated Capacity

This implies that demand related capital will be 1.47 x $/kW of load carrying capacity (1.47 = 1/.68).

2. Cost of Load Carry Capacity (LCC) (See Ref. 2)

Gas Turbines	$193/kW
Geothermal	$358/kW
Combined Cycle	$289/kW
Helms Pumped Storage	$311/kW

Since resource plan has no gas turbine capacity, use a generic $300/kW. (See Ref. 1).

3. Demand Related Capital = ($/kW) LCC x Effective Capacity Adjustment

= $441/kW

At FCR = .154 = $67.90/kW-yr

B. Energy Costs

1. Energy Related Capital - Fossil 1 ($/kW) - LCC ($/kW)

= $1,286 - 300

a) at FCR = .154 = $151.80/kW-yr

b) Using 65 percent capacity factor = 5700 hrs/yr

= 26.6 mills/kWh

2. Add fuel cost at 23 mills/kWh, get 49.6 mills/kWh

3. Adjust for losses = 8 percent, get 53.6

Energy cost = 53.6 mills/kWh

With rail cost uncertainty - 61.6 mills/kWh

6.2.3 Allocation of Demand Costs to End-Use Applications

A. Space Heat

1. Electric Space Heat Unit Energy

Consumption = 6827 kWh (See Ref. 5)

(UEC)

2. Estimate of system Diversified Load Factor

a) Diversified Demand = 3.04 kW

= (10kW/3.29) (See Ref. 6)

c) End Use Load Factor = 26 percent

= (2245/8760)

B. Water Heating

1. Electric Water Heating UEC = 4452 kWh (See Ref. 5)

2. Estimate of System Diversified Load Factor

a) Diversified Demand = .75 kW (See Ref. 7)

b) Equivalent Hours/Year = 5396

= (4452/175)

c) End-Use Load Factor = 68 percent

= (5936/8760)

6.2.4 Cost of Displaced Energy

A. Space Heat

1. Demand = 30 mills/kW

= ($67.90/2245)

2. Energy = 53.6 mills/kWh

3. Total - 83.6 mills/kWh

B. Water Heating

1. Demand = 11.4 mills/kWh

($67.90/5936)

2. Energy = 53.6 mills/kWh

3. Total = 65.0 mills/kWh

References (Section 6.2.1 - 6.2.4)

1. Testimony of R. Czahar, ERCDC Docket No. 77-NOI-4, February 28, 1979.

2. Pacific Gas and Electric Co., Fossil 1 and 2 NOI, December 1977.

3. See "Railroad Deregulation Finds Little Sympathy on Capital Hill," Energy Daily, Vol. 7, No. 106, June 5, 1979, and "Rail Rates Slow a Shift to Coal," Business Week, July 23, 1979, pp. 171-4.

4. For method, see L.L. Garver, "Effective Load Carrying Capability of Generating Units," IEEE PAS-85, August 1966, pp. 910-19. For estimates of the parameter m, see E. Kahn, "The Reliability of Distributed Wind Generators," Electric Power Systems Research, Vol. 2, 1979, p. 1014.

5. Personal communication with M. Jaske, Assessment Division, CEC, August 7, 1979.

6. Diversity factor from N.R. Schultz and H.E. Campbell, "Power Distribution," Standard Handbook for Electrical Engineers, Ed. D.G. Fink and H.W. Beatly (New York: McGraw-Hill, 1978).

7. Feldman, S.L., R.M. Wirtshafter, M. Abrash, and B. Anderson, The Impact of Federal Tax Policy and Electric Utility Rate Schedules Upon the Solar Buildings/Electric Utility Interface, October 1, 1978.

6.3 Methodology for Cost and Value Estimattion of Decentralized Substitution Technologies

Capital costs for conservation and solar water heating investments are estimated on a per-unit basis. These are based primarily on PP&L estimates and checked against LBL surveys.

Energy savings for space heating were estimated from computer runs used to analyze building energy perfromance standards. The Fresno climate is treated as representative of the Pacific Gas and Electric Co. service area.

Performance of solar hot water heaters was estimated using F-chart, a standard computer design tool. The output of this program is the solar fraction of total load. This is converted to energy, by multiplying these fractions by estimated electric energy use for water heating.

To calculate the cost of utility finance with repayment on sale of residence, assumptions are made about utility capital structure, effective tax rate and expected duration of the investment in utility rate base. The assumed tax rate is based upon the projection that PG&E will be in a position of continuously carrying forward surplus investment tax credits generated by electricity supply investments. Given these assumptions, the future value of a $1 loan and carrying costs is calculated for the period of utility finance. This is then discounted

back to the present at the after tax weighted average cost of capital. The number calculated in this manner is a multiplier of the loan capital which reflects the present value of the carrying charges.

The cost of energy displaced by end-use investment is then the capital cost of the substitution technology times the present value multiplier divided by the lifetime energy savings. This latter quantity is just annual savings times the economic lifetime of the investment. Since there is some uncertainty about the lifetimes involved, sensitivity estimates are made by varying this parameter.

6.4 Cost and Value of Decentralized Substitution Technologies

6.4.1 Capital Cost of Substitution Technologies

A. Space Heating Efficiency

1. Ceiling Insulation

   a) 22¢/ft^2 retail for R-19 (See Ref. 1)

   b) R-5 to R-41 at 42¢/ft^2 (See Ref. 2)

      R-11 to R-41 at 35¢/ft^2

      R-19 to R-41 at 27¢/ft^2

2. Floor Insulation

   a) 45¢/ft^2 for R-11 (See Ref. 3)

   b) 40¢/ft^2 for $-19 (See Ref. 2)

3. Storm Windows

   a) $2.75/ft^2 retail materials cost (See Ref. 3)

   b) $4.00/ft^2 (Portland) (See Ref. 3)

      $4.00/ft^2 (Montana) (See Ref. 2)

B. Solar Water Heating (See Ref. 4)

Fixed Cost = $400

Variable Cost = $22/ft^2

6.4.2 Performance Estimates

A. Space Heating Efficiency: Fresno Climate (See Ref. 5)

Comparison of building with $-19 ceiling, R-11 walls and single glazing (A) with R-30 ceiling, R-11 walls and double glazing (C4) and R-38 ceiling, R-19 walls and double glazing (E4).

Bldg.	Heating kWh	Cooling kWh
A	5297	2624
C4	3220	2309
E4	2397	2163

B. Solar Hot Water Heating (in percentage of solar load) (F-chart runs)

City	100 ft^2 collector	80 ft^2 collector
San Diego	92.4	83.1
Sacramento	85.9	79.9
San Jose	81.5	72.4

6.4.3 Valuation of Substituion Technologies under Utility Capitalization

A. Calculation of present value factor to reflect current value of loan and carrying charges.

1. Capital Structure (See Ref. 6)

   52% debt at 9.4%

   12% preferred at 9.6%

   34% common at 13.0%

2. Effective tax rate = 20% (See Ref. 7, 8)

3. Estimated life of investment in rate base = 7.5 years

4. Future Value of $1 Loan + Carrying Costs

$$= \left[1.00 + .52\ (.094) + \left[\frac{.12\ (.096) + .34\ (.13)}{1 - 0.20}\right]\right]$$

$$= 2.317$$

Discounted at 10.5% (=after tax weighted average cost of capital)

$$= 1.096$$

B. Current Value of Substitution = (PV factor x Capital Cost)/ Annual Displaced Energy x Economic Life

1. Space Heating Efficiency

Capital Cost Estimate = $1200*

Estimated Displaced Energy = 3200 kWh/yr

Economic Lifetime = 20 years

Cost of Displaced Energy = 20.6 mills/kWh

If economic lifetime were 25 years, than cost is 16.5 mills/kWh.

2. Solar Water Heating (using 80 ft^2 collector)

Capital Cost = $2160

Estimated Displaced Energy (UEC x Solar Fraction)

Sacramento	3557 kWh
San Jose	3223 kWh

Economic Lifetime is uncertain, so evaluation made for 10, 15 and 20 years.

Cost of Displaced Energy (mills/kWh)

	10 years	15 years	20 years
Sacramento	66.8	44.5	33.4
San Jose	73.7	49.1	36.9

References (Section 6.4.1 - 6.4.3)

1. Wright, J., A. Meier and M. Manlhardt, "Energy Conservation Measures Before You Insulate Your Walls," LBL Draft, August 1, 1979.

2. Pacific Power & Light Co., Workpapers on Potential Conservation Benefits and Costs for Montana Residential Customers.

3. Jan Wright, Personal communication.

4. Bezdek, R.H., A.S. Hirshborg and W.H. Babcock, "Economic Feasibility of Solar Hot Water and Space Heating," Science, Vol. 203, March 23, 1979, pp. 1214-1220.

*Capital Cost Estimate for Space Heating Efficiency

1500 ft^2 Ceiling Insulation at 27¢/ft^2 =	$405
150 ft^2 Storm Windows at $4.00/$ft^2$ =	$600
Miscellaneous =	$195
	$1200

5. Pacific Northwest Laboratory, Draft Report of Economic Analysis of Proposed Building Energy Performance Standards, PNL-3044, July 1979.

6. Testimony of R. Czahar, ERCDC Docket No. 77-NO1-4, February 28, 1979.

7. Czahar, R., A Study of Solar Financing, CPUC, San Francisco, California, April 24, 1979.

8. Mulligan, G., "Legislative History of the Investment Tax Credit," undated CPUC Memo.

6.5 Programmatic Implications

The results of the previous section must be compared against the marginal minus average cost criterion to determine cost-effectiveness. In 1978, the average system cost of electricity in the PG&E service area was 37.5 mills/kWh. This is simply electric revenues divided by kWh sales. In Section 6.2.4, the LRMC for electric space heating was estimated at 83.6 mills/kWh. For electric water heating, the corresponding LRMC is 65.0 mills/kWh. Allowing for potential escalation in coal hauling charges brings this to 91.6 and 73.0 mills/kWh respectively. The resulting marginal minus average cost band is 46 mills/kWh for space heating and 27.5 mills/kWh for water heating: with higher rail freight charges the values are 54 and 35.5 respectively.

Now we compare these allowable costs to the estimated cost of conservation and solar hot water heating. Conservation investment is clearly justified. The annualized cost of such investment is less than half the maximum allowable cost, and probably closer to a third as much. The economics of solar hot water heating are more ambiguous. Except in one or two cases, the annualized cost, while less than the alternative LRMC is greater than the marginal minus average test. Provided the lifetime is 20 years and the rail freight charges do escalate as projected, solar hot water heating will pass the stringent requirement; otherwise it will not.

At this point, a subtle feature of the marginal minus average cost criterion must be recalled. This is a test for an entire program, and not for one particular investment. The PP&L plan itself involves a package of investments, some of which are less expensive than others. The cost-effectiveness criterion speaks to the average prformance of the portfolio. Therefore, the results of the previous calculations imply that some appropriate mix of conservation investment and solar hot water heating will make a cost-effective substitution for new supply. The policy problem is to find an appropriate mix of these investments which will maximize the benefit to all parties.

There are two inter-related issues affecting the design of a utility program of end-use substitution and investments. These are the proportion of solar vs. conservation investment and the scale of the effort as a whole. Data on the current aggregate consumption pattern, substitution potential and capital requirements of a maximal program are given in Table 4.

These data show that the size of the electric space heating sector is slightly larger than the electric water heating sector. Together these form 5.8 percent of the total market. The substitution potential in water heating is larger than in space heating, however, since the displacable fraction is greater. A maximal program for single family units would have a capital requirement of $900 million.

To design a feasible program we need to know how to mix the solar investment with the conservation investments. Since the calculations in Section 6.4.3 assume a range of inputs, and consequently yield a range of estimates, we must first select an expected value. For the purposes of designing a program, the estimated expected value need not be extremely accurate. Let us choose values of 18 mills/kWh for conservation 40 mills/kWh for solar water heating. Using these estimates, the conservation is 28 mills under its maximum cost and the solar is

Table 4

PG&E Electric Substition Market

Residential Space and Water Heating

1. 1978 Space Heating Consumption (See Ref. 1)

   Housing Type:

   A. Single Family = 13.-5 x 10^9 kWh

   B. Multi-Family - 3.66 x 10^8

   Total = 17.21 x 10^8 kWh

2. 1978 Water Heating Consumption (See Ref. 2)

   Housing Type:

   A. Single Family = 12.61 x 10^8 kWh

   B. Multi-Family = 2.58 x 10^8

   Total = 15.19 x 10^8 kWh

3. 1978 Total Utility Sales to Customrs = 56.13 x 10^9 kWh (See Ref. 2)

   Total Market Share = $\frac{(1) + (2)}{(3)}$

   = 5.8%

4. Maximum Feasible Conservation: Single Family Housing Market

   A. Space Heating = (.5) x (14)

   = 6.78 x 10^8 kWh

   B. Water Heating = (.75) x (24)

   = 9.46 x 10^8 kWh

5. Capital Requirements for (4)

   A. Estimating $1,200 capital for annual savings of 3200 kWh = 38¢/kWh

   Total Capital = ($0.38/kWh) x 6.78 x 10^8 kWh

   B. Estimating $2,160 capital for annual savings of 3200 kWh = 68¢/kWh

   Total Capital = ($0.68/kWh) x 9.46 x 10^8 kWh = $640 million

References:

1. M. Jaske, CEC 1978 Pacific Gas & Electric Co., End-Use Analysis, Personal communication, August 7, 1979.

2. 1978 Pacific Gas & Electric Company Annual Report.

12.5 mills over its maximum. A combined program of 2 kWh of solar substitution for 1 kWh of conservation would yield a mix at just about the maximum allowable cost. A look at Table 4, however, shows that the maximal solar substitution market in single family homes is only about 1.4 times the electric space heating conservation market (9.46/6.78 = 1.40). Therefore, the maximum ratio of kilowatt hours displaced by solar to those displaced by conservation is 1.40 to 1.0.

It remains to decide if this maximum ratio ought to be adopted as a program goal. One way to decide this is to consider the effect of uncertainty in the solar cost estimate. If we choose 45 mills/kWh instead of 40, and a 1.4 to 1 ratio, we come quite close to the maximum allowable cost (i.e., 1.4 (45) + 18 = 81 compared to 1.4 (27.5) + 46 = 84.5). At 50 mills/kWh and a 1.4 to 1 ratio, we exceed maximum allowable cost. Since some uncertainty is inherent in the cost estimates, a conservative approach would be to limit the solar/conservation ratio to 1 to 1. Extra savings associated with this more limited goal would reduce overall utility revenue requirements, providing an additional benefit to non-participants.

Using a solar/conservation ratio of 1 to 1 allows the program to pass the cost effectiveness test comfortably. Due to the inherently low cost nature of substitution investments, it is logical to scale the program to the maximum feasible market for space heating efficiency. As Table 4 indicates, this is aoubt 6.8×10^8 kWh. By the previous argument, the solar hot water program ought to aim for the same size market. This is over 70 percent of the maximum feasible single family market. The capital requirements of such a program would be $720 million. If we assume that only 90 percent of the market is actually feasible, then the program will save 1.22 billion kilowatt hours or about 2.2 percent of 1978 use. The capital cost would then be roughly $650 million.

7.0 State Regulatory Policies and their Impact on ITC Utilization

The purpose of this section is to examine the interactions between state regulatory policies and the ability of utility companies to use the investment tax credits granted under Federal law. The importance of ITC carry-forward balances ("excess ITC) was identified in section 3.3. This phenomenon can lower the utility's cost of capital for a solar finance program, by reducing the tax obligation associated with new investment that may not itself generate ITC. The case study in section 6 incorporated this effect. The more general question of what determines whether a utility will have excess ITC is addressed here.

Because the determinants of ITC utilization are many and the interactions complex, attention is concentrated on two major areas of state regulatory policy: flow-through versus normalization of tax preferences and CWIP in rate base versus AFUDC. These state regulatory policy options will be defined in some detail below. For now it suffices to identify these policy choices as major determinants of the tax obligation of utilities. If a regulatory commission is interested in encouraging utilities to use their excess ITC for a solar finance program, the availability of such a mechanism will depend on these major regulatory policy choices.

7.1 Flow-Through vs. Normalization of Federal Tax Preferences

Two tax benefits or preferences are available to the utilities from the federal government - accelerated depreciation and investment tax credits. Accelerated depreciation schedules enable the utility to depreciate their capital equipment for tax purposes at a rate that exceeds straight line depreciation. This accounting method understates income in the early years of the life of the equipment, and overstates it in the later years. The understatement of income in turn results in a lower tax obligation in the early years, and a higher one in the later years relative to straight line

depreciation. In addition they can claim depreciable lifetimes that are shorter than the economic lifetime of capital equipment. (1) Investment tax credits enable the utility to deduct from their income tax obligation a stipulated fraction of their investment in new capital equipment for the year the equipment was put in service. Under current law tax credits are available for large projects during the construction period ("qualified progress payments" (2)).

Accelerated depreciation constitutes a tax deferral. It is created by a "timing difference which occurs when transactions affecting taxable income are realized in one period, but do not enter into the determination of pre-tax accounting income until subsequent periods" (3). Its value to the utility is the time value of money. Though total taxes remain unchanged, there is an additional benefit if there is inflation; the taxes paid at a later point in time are worth less in purchasing power than if they were paid immediately. The deferred taxes are tantamount to an interest free loan extended by the government to the utility. Capital costs are thereby reduced. The cost of the loan is borne by the rest of the taxpayers who forego (some temporarily, others permanently) the benefit they would have derived if the taxes were collected and spent to increase public welfare. The benefits of accelerated depreciation each year are determined by the calculation method and measured by the product of the tax rate and the difference between depreciation for tax and book purposed. Investment tax credits constitute an outright grant, not a loan. As such their value is measured by the absolute amount of the credit and the yield from investing it. The total deduction may be claimed in one period or amortized over the life of the asset (3), subject to certain constraints set forth by the Internal Revenue Service. In particular, 100% of a company's tax obligation cannot be offset by tax credits (4).

Both accelerated depreciation and investment tax credits are intended

to reduce the utility's tax obligation, thereby making more of its pretax income available for discretionary disbursement, assuming the utility can retain the benefits. In practice, this assumption does not always hold. Some regulatory jurisdictions permit the utility to retain the benefits by setting rates as though the tax benefits were not claimed. This is termed normalization. The difference between tax obligations with and without the tax benefit is set aside in a normalization reserve. The utility holds this reserve which in the early years of the asset provides funds for plant replacement and expansion. In other jurisdictions the regulating agencies require that the benefits be passed on to the ratepayers immediately, termed flowthrough. Only the actual taxes paid are considered allowable expenses for ratemaking purposes.

One rationale for flowing through the benefits to the current ratepayers is that they should not be charged for tax payments that will never have to be paid to the government (5). The only time such payments will be due is when a utility stops or significantly reduces new investments. Under normalization, there is a tradeoff between, on the one hand paying lower taxes during the early part of the asset's life and having the funds available for other expenses and, on the other hand, incurring a higher tax payment in later years when depreciation expense declines, taxable income rises, and income taxes rise. When the taxes become due, presumably they would be paid out of the normalization reserve. If these funds have been invested in plant replacement or expansion, then the normalizing company must utilize the capital market to raise cash (6). If the rate payers are charged the interest for so doing, they are paying for part of the same tax expense twice.

Under flowthrough, it is assumed that rates will increase as depreciation expense declines (1). No allowance for a reserve fund for deferred taxes is made in the revenue requirements. This entails a risk to the utility that it will not be able to collect enough revenues in later years to pay its

deferred taxes without reducing its rate of return. To collect these revenues, the regulatory commission must allow rate adjustments so that the allowed rate of return can be maintained during the later years of the asset life, and the elasticity of demand for electricity must be low enough so that the rate increases actually yield the required revenues in the later years of the asset life.

The items to which normalization and flowthrough are usually applied are investment tax credits, accelerated methods of depreciation, shorter asset lives permitted by Class Life and Asset Depreciation Range, interest on funds borrowed to finance construction, removal costs of retired property, and and deduction of captialized overhead costs (3).

7.2 Normalization Typically Increases ITC Utilization

In this section a simple model of the tax effects related to the flow-through/normalization choice will be used to examine ITC utilization. Following Linhart,(7) we can express the differences in the time pattern of tax obligation by the equations below, describing the case of a single plant vintage.

$$\Delta T_j = T_{FT_j} - T_{N_j} , \qquad (1)$$

$$= \frac{T_o}{1-T_o}\left[\rho_e (1-\delta) N_J + T_o (D_{B_j} - D_{T_j})\right] ,$$

where T_{FT_j} = taxes in the year j under flow-through

T_{N_j} = taxes in the year j under normalization

ρ_e = rate of return on equity

δ = fraction of total capital which is debt

D_{B_j} = book depreciation in year j

D_{T_j} = tax depreciation in year j

N_J = normalization reserve at the start of year j

$$= \sum_{k=1}^{j-1} T_o (D_{T_k} - D_{B_k})$$

T_o = federal tax rate.

To work out specific cases the method of tax depreciation must be chosen. Although methods vary, one of the most common methods is double-declining balance (DDB). Under DDB, the depreciation expense in year j is given by

$$D_j = \frac{2K}{L} (1-2/L)^{j-1} , \qquad (2a)$$

where K = capital cost of the plant in question; L = lifetime of the plant, It is convenient to work with a continuous version of (2a) given by

$$D_j = \frac{2K}{L} e^{-2j/L} . \qquad (2b)$$

Substituting (2b) into (1), where book depreciation is straight-line, i.e., K/L in each year, and approximating the normalization reserve by an integral, we can rewrite (1) as follows

$$T_j = \frac{(K)}{L} \frac{T_o^2}{1-T_o} \left[\rho_e(1-\delta) \left(-Le^{-2(j-1)/L} + Le^{-2/L} - (j-1) + 1\right) + (1-2e)^{-j/L}) \right] \qquad (3)$$

By substituting appropriate parameter values into (3) we can determine at what point the tax burden associated with a given vintage of plant becomes greater under flow-through than under normalization. This will occur when the sign of (3) becomes positive. Inspecting (3) closely shows that the sign depends upon ρ_e, δ and L. It is conventional to treat the lifetime of investments in electrical generating equipment as 30 years long. For most electric utilities the debt fraction δ is around 50%, with most variation in the range from 45-55%. The return on equity, ρ_e, is a realized rate of return, rather than what is allowed by the regulators. Under inflationary conditions and with regulatory lag, the realized return is typically less than what is allowed. Realistic values of ρ_e range from a low of about 10% to a high of about 14%. Using these values, the sign of (3) typically becomes positive in year 8. Some sample calculations are given below.

$$\Delta T_7 = \frac{K}{30}\left(\frac{T_o^2}{1-T_o}\right)\left[\rho_e\ (1-\delta)(2.96) - 0.25\right],$$

for $\rho_e = .14$

$\delta = .45$,

$\Delta T_7 < 0$. This will be true for any larger δ or smaller ρ_e in the relevant range.

$$\Delta T_8 = \frac{K}{30}\left(\frac{T_o^2}{1-T_o}\right)\left[\rho_e\ (1-\delta)(3.26) - 0.17\right]$$

>0 for any (ρ_e, δ) pair with

$\rho_e(1-\delta) > 0.052$, such as

$\delta = .50$, $\rho_e = .13$.

Equation (3) must be re-written for the case in which the utility uses a shorter lifetime for tax purposes than for book purposes. The Asset Depreciation Range (ADR) guidelines for example, allow utilities to use a 16 year lifetime for nuclear plants and 22.5 years for conventional steam units (8). Using the symbols L_T and L_B for tax and book lifetime respectively, eg. (3) becomes

$$\Delta T_j = \frac{T_o^2\ K}{1-T_o}\left[\rho_e(1-\delta)(-e^{-2(j-1)/L_T} + e^{-2/L_T} - {}^{j-2}/_{L_B}) + \frac{1}{L_B} - \frac{2}{L_T}\ e^{-2j/L_T}\right] \qquad (4)$$

For parameter values in the range of interest, equation (4) is not substantially different in its implications than equation (3). A few calculations show this is the case. Consider the most extreme differences between L_B and L_T, the case where $L_B = 30$ and $L_T = 16$. Let us calculate ΔT_7:

$$T_7 = \frac{T_o^2\ K}{1-T_o}\left[\rho_e\ (1-\delta)(0.243) - 0.019\right]$$

for $\rho_e = .14$; $\delta = .50$; $\Delta T_7 < 0$. For $\rho_e = .16$, $\Delta T_7 = 0$, but this case is unlikely.

$$\Delta T_8 > 0 \text{ for } (\rho_e, \delta) \text{ pairs with } \rho_e(1-\delta) > 0.049.$$

This means that the cross over point at which taxes under flow-through become greater than taxes under normalization is usually year eight.

It remains to consider the more general situation of multiple plant vintages. The structure of eqs, (3) and (4) shows that ΔT_j is linear in K, the total capital cost of a given plant, for all years j. For all types of electric generating capacity the unit cost of capacity is increasing over time. There are, however, significant differences in the cost of a kilowatt of capacity across fuel types. Generally speaking the less expensive a fuel is, the more expensive is the capacity cost of using that fuel. Thus recent estimates show oil-fired capacity is less expensive than coal, which is less expensive than nuclear. Therefore given a fixed unit size, K will vary with fuel type.

Since utility investment in new plants can be expected to continue into the indefinite future, for replacement, if not for growth, there will be a tendency for normalization to increase taxes continually. As long as K grows for new plant vintages and new plant is added to rate base at least seven years after the last addition ΔT_j will be less than zero. Empirical evidence shows that the normalization reserve for utility companies is continually increasing (9). This is equivalent to $\Delta T_j < 0$ in the Linhart model with superposition of all plant vintages.

The tendency for normalization to increase taxes, hence ITC utilization depends on (a) continual growth in K and (b) plant additions at least every seven years. Condition (a) depends on fuel choice as indicated above and upon project scale. If a large project, say a 1000 MW unit, is followed by a moderate one, say 400 MW, then even with escalation in unit capacity costs, K will not necessarily grow. It would not be impossible, however,

even in this example for the smaller project to have a larger capital cost than the big project. If the capital cost per KW escalated at 15%/year in nominal dollars and there was a seven year lag between projects, then the capital cost of the smaller generator would exceed that of the larger.

An important limitation on the results of this discussion is due to the role of progress payments related to the generation of ITC. Our analysis of equations (3) and (4) only produced results on utility tax obligation. It was assumed that changes in tax obligation would be reflected in corresponding changes in ITC utilization. However recent changes in the timing of ITC generation may complicate the picture. Starting in 1978 utilities must take progress payments on ITC (2). Previously ITC was claimed only on completion of projects. Thus the time pattern of ITC generation has changed. This will affect the pattern of ITC utilization.

7.3 CWIP in Rate Base vs. AFUDC

The long construction lead times of current large scale electric generating plant have created cash flow imbalances for utilities. The amount of capital required for construction is large relative to income. In an unregulated industry product prices would be raised to cover the cost of construction. In traditional regulated utility practice the cost of funds associated with construction is only recoverable when the plant becomes "used and useful." Under the current conditions this delay imposes a serious burden on the company. Two regulatory devices have evolved to deal with this situation. These are known as CWIP (Construction Work in Progress) in rate base and AFUDC (Allowance for Funds Used During Construction).

CWIP is a standard utility account which includes the balances of all work orders for utility plant in the process of construction. The inclusion of this account in rate base will allow the utility to recover immediately

the costs incurred for financing new plant. Because rates must be raised to cover the cost of an investment which provides no immediate benefit, including CWIP in rate base is controversial. There is a substantial literature assessing the value of CWIP in rate base to ratepayer and utility stockholder (10,11,14,15). This literature is inconclusive and will not be discussed here. Instead it will be instructive to describe AFUDC, the alternative to CWIP in rate base. For an authoritative account see (12).

As an income statement item, AFUDC reflects both the cost imputed to equity and internal funds associated with construction, and the interest on debt and dividends so associated. None of the costs are realized immediately. As an income statement item AFUDC is a non-cash contribution to earnings. That is, revenue requirements are not increased to reflect AFUDC at the time it is reported as income. When a particular project is completed, all AFUDC costs associated with it are capitalized into rate base along with the direct construction expenditures. That is, both actual interest paid on debt and imputed interest on other funds are capitalized. Thus the utility will earn a return on the total AFUDC costs and depreciate them. The addition to rate base is larger under AFUDC than under CWIP in rate base, but the time pattern of additions to rate base is delayed.

The rationale underlying the use of AFUDC is that the opportunity cost of the equity and internal funds must be offset. The utility ties these funds up in construction and requires compensation for the time value of the capital which is not yet in rate base. As an income statement item AFUDC represents earnings. These are then treated as an asset upon capitalization of the plant and its entering into rate base. The ability to raise the capital for construction has a cost, it is the total AFUDC (i.e. actual plus imputed) associated with a given plant. This cost is recovered by captilization and subsequent depreciation.

Jurisdictions vary in the use of either CWIP in rate base or AFUDC. Some commissions use one or the other treatment consistently. In other cases a mixed treatment is adopted. Where AFUDC is used, the formula for computing its magnitude is not standard (12). One recent change of technique is to allow compounding of AFUDC costs. This will increase both the relative impact on earnings and capital costs of large scale construction. In 1978 a sample of the fifty largest investor owned electric utilities showed that 38% of income on the average consisted of AFUDC (13). Statistical studies have shown that AFUDC has a negative impact on the value of utility equity shares (14, 15). Given the magnitude of AFUDC, its impact on taxes can be expected to be large. It is to this subject that we now turn.

7.4 CWIP in Rate-Base Produces a Smooth Flow of Taxes

The motivation for CWIP in rate base is to smooth out the cash flow of utilities engaged in large construction projects. This smoothing effect corrects cash flow imbalances associated with AFUDC. This basic effect will carry over to the stream of tax obligations and tax payments under CWIP in rate base. The reason for this is simply that AFUDC as an item of income is not realized as cash, therefore is not taxable. When capitalization occurs, i.e. at the end of the construction period, AFUDC will produce greater revenues, taxable income and tax obligation than rate-basing CWIP. This is due to the extra increment to rate base associated with the capitalized AFUDC.

Once an asset is capitalized the time pattern of depreciation, income generation and tax generation will be parallel for AFUDC financing and CWIP in rate base. But since AFUDC financing means a larger rate base, then the time path of depreciation, income and taxes will be greater than AFUDC by a constant ratio. This ratio is the direct construction cost plus capitalized AFUDC to construction cost alone.

A graphic display of the time path of tax liability and after tax profit associated with AFUDC for a single plant vintage has been calculated by Chapman (16); It is reproduced in Figure 2. The negative tax liability during the construction period affects progress payments on ITC. After tax profit during this period is not cash. The time pattern of tax liability during the operational period is governed by the regulatory specification of flow-through accounting. As demonstrated in sec. 7.2, normalization would show greater tax liability in years one through year seven or eight and lower tax liability in years 8 through 16 compared to Figure 2. At year 16 in this case (nuclear plant) tax liability increases dramatically as the benefits of accelerated depreciation are exhausted.

Under CWIP in rate base the time pattern of profit and taxes would be compressed toward the horizontal axis of Figure 2. During construction, profit would be smaller since there would be no non-taxable AFUDC income. The profit in this case would be immediately realized as cash, and not a promissary note for future payment. During the operational period revenues associated with the plant will be smaller under CWIP than AFUDC. This is due to the smaller rate base. With smaller revenues, the tax liability will be correspondingly smaller. As argued above, the shape of the curves should be similar under flow-through and smoother under normalization.

7.5 Conclusion

Federal taxation introduces major complexities into state regulation of electric utilities. Conversely particular regulatory practices have major impact on utility tax payments. Any solar finance plan will interact with the overall utility tax payments. As argued in secs. 3.3 and 6.0, this interaction can have cost implications favorable to such programs. Yet this need not be the case in other circumstances. The California case study was

conducted for a utility which uses AFUDC and flow-through. Where substantial capital is tied up in construction, these regulatory practices can produce excess ITC. It is less likely to find excess ITC where CWIP and normalization are adopted. Both of these latter practices tend to produce a smoother flow of taxable income and tax liability than AFUDC and flow-through. Excess ITC seems to result from a timing lag between ITC generation and tax liability. To the extent that state regulatory taxes smooth out this lag, there will be less unutilized ITC.

ANNUAL TAX LIABILITY AND AFTER-TAX PROFIT, RATE BASE METHOD (MILLIONS OF DOLLARS)

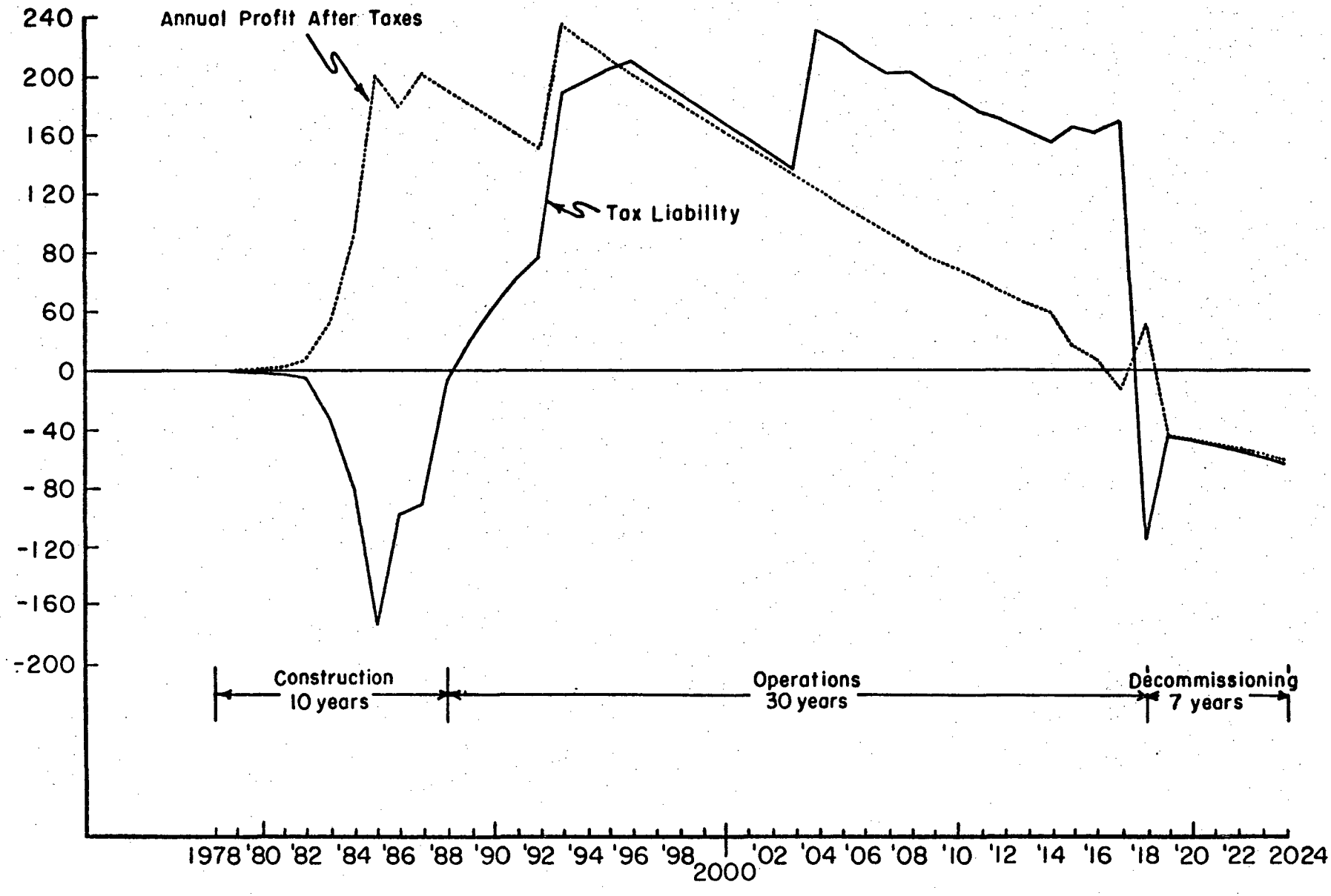

Fig. 2

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This report was done with support from the Department of Energy. Any conclusions or opinions expressed in this report represent solely those of the author(s) and not necessarily those of The Regents of the University of California, the Lawrence Berkeley Laboratory or the Department of Energy.

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