

AN ECONOMIC ANALYSIS OF GRID-CONNECTED RESIDENTIAL  
SOLAR PHOTOVOLTAIC POWER SYSTEMS

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THE ECONOMIC AND POLICY IMPLICATIONS  
OF GRID-CONNECTED RESIDENTIAL SOLAR  
PHOTOVOLTAIC POWER SYSTEMS

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ABSTRACT  
(Revised)

The question of the utility grid-connected residential market for photovoltaics is examined from a user-ownership perspective. The price is calculated at which the user would be economically indifferent between having a photovoltaic system and not having a system. To accomplish this, a uniform methodology is defined to determine the value to the user-owner of weather-dependent electric generation technologies. Two models are implemented for three regions of the United States, the first of which is a previously developed simulation of a photovoltaic residence. The second is an economic valuation model which is required to translate the outputs from the simulation into breakeven array prices. Special care is taken to specify the input assumptions used in the models. The accompanying analysis includes a method for analyzing the year-to-year variation in hourly solar radiation data and a discussion of the appropriate discount rate to apply to homeowner investments in photovoltaic systems.

The results of this study indicate that for the regions characterized by Boston, Omaha, and Phoenix, under the assumptions noted, photovoltaic module breakeven costs for the residential application are in the range of \$.68, \$.43 and \$1.27 per peak system watt respectively (.42, .24, .89 per peak module watt).

FOREWORD TO REVISED VERSION  
December 1978

Appendix A to this volume presents revised values for breakeven capital costs for photovoltaic modules in residential applications. In the main body of the report, specifically in Section V, the measure for BECC, dollars/watt (peak), as reported in this paper is in delivered, system or effective peak watts (module). The use of dollars/watt (peak) is somewhat ambiguous in the literature; it is necessary to point out that this measure is not dollars/watt (peak) of module output. The methodology used in this study consistently focuses upon delivered energy. The system NPV figure is the value of the energy delivered by the particular system under consideration - the valuation procedure per se is not sensitive to the efficiency of the system which delivers the energy.

Conversion from a dollars/watt (peak) system is a straightforward algebraic process. The dollars/m<sup>2</sup> figure is the same in both situations; the question relates to the number of watts of delivered energy at either the system or the module; and this question is merely which  $\eta$ (efficiency), system or module, to use in the conversion:

$$\text{Dollars/watt (peak) system} = \frac{\text{Dollars/m}^2}{\eta_{\text{system}} \times 1000\text{w/m}^2}$$

$$\text{Dollars/watt (peak) module} = \frac{\text{Dollars/m}^2}{\eta_{\text{module}} \times 1000\text{w/m}^2}$$

Since  $\eta$ (system) is used multiplication of the values listed in this report by  $\eta$ (system)/ $\eta$ (module) will yield a dollar value for module peak watts.

The results presented in Appendix A incorporate the results of research in cell efficiency, increased information on balance of systems costs and results of discussion and comment concerning the May 1978 version of this paper. For this reason these values should be used to represent current best estimates of breakeven capital costs for photovoltaic modules in residential applications.

## TABLE OF CONTENTS

	<u>Page</u>
Abstract	2
Foreword to Revised Version	3
Table of Contents	4
Table of Tables	7
Table of Figures	9
Acknowledgment	10
I. Solar Photovoltaics as an Electric Power Source	11
1.1 Introduction	11
1.2 History of the Federal Photovoltaics Program	13
1.3 Photovoltaic Market Segments and Their Relationship to the Federal Plan	17
1.4 Scope of This Study	22
1.5 Footnotes	24
II. A Uniform Economic Valuation Methodology	27
2.1 Introduction	27
2.2 Economic Valuation of Photovoltaics	29
2.3 Unique Features of Photovoltaics Which Affect Economic Valuation	30
2.4 Previous Approaches to Economic Valuation	32
2.5 Suggested User-Owned Economic Valuation Methodology	38
2.6 Footnotes	41

## TABLE OF CONTENTS (continued)

	<u>Page</u>
III. Simulation Model Description and Input Assumptions	43
3.1 Regional Definition	43
3.2 Valuation Model	45
3.3 Model Inputs	50
3.3.1 System Configuration	50
3.3.2 Insolation Data	52
3.3.3 Appliance Loads and Behavioral Assumptions	54
3.3.4 Rate Schedules	59
3.4 Footnotes	69
IV. Economic Model Inputs and Sensitivity Analysis Assumptions	73
4.1 Fuel Price Escalation and Cell Degradation Rate	73
4.2 Discount Rate	75
4.3 Subsystem Costs	86
4.4 Footnotes	90
V. Results and Interpretation	94
5.1 Basic Results by Array Size	94
5.2 Sensitivity Analysis	107
5.2.1 Choice of Year	107
5.2.2 Discount Rate	110
5.2.3 Degradation Rate	110
5.2.4 Cell Efficiency	111

## TABLE OF CONTENTS (continued)

	<u>Page</u>
V. (continued)	
5.2.5 Fuel Price Escalation	111
5.2.6 Subsystem Costs	113
5.3 Comparison of Results to Utility Studies	114
5.4 Footnotes	117
VI. Policy Implications and Conclusions	119
6.1 New Information	119
6.2 Implications for the Long-Term Markets	119
6.3 Implications for Systems Tests and Applications (ST&A) Policy	122
6.4 Utility Response and Interactive Models: Further Research	123
6.5 Conclusion	125
6.6 Footnotes	129
VII. Appendices	131
VIII. Bibliography	157

## TABLE OF TABLES

<u>Table</u>	<u>Page</u>
1. Analysis Years Based on Statistical Analysis	53
2. Boston Time-of-Day Rate Structure	63
3. Omaha Time-of-Day Rate Structure	64
4. Phoenix Time-of-Day Rate Structure	65
5. Regression Results, Zero to Four Year Lag	82
6. Regression Results, Fuel Crisis Compensated	82
7. Discount Rates Reflecting Tax and Inflation Adjustments: Risk-Adjusted Base	87
8. Discount Rates Reflecting Tax and Inflation Adjustments: Mortgage Interest Base	88
9. Energy Transfers from Solar Array to Load and Grid by Time-of-Day Period and by Array Size: Boston	95
10. Energy Transfers from Solar Array to Load and Grid by Time-of-Day Period and by Array Size: Omaha	96
11. Energy Transfers from Solar Array to Load and Grid by Time-of-Day Period and by Array Size: Phoenix	97
12. Contribution of Solar Electricity to Residential Electricity Needs	98
13. Monthly Air-Conditioning Demand during "Typical" Solar Radiation Years	100
14. Array Size vs Breakeven Capital Cost: Effect of Varying Utility Buy-Back Rate	103
15. Sensitivity of Breakeven Capital Cost to Choice of Solar Radiation Year	108
16. Monthly Air-Conditioning Demand during "Best" and "Worst" Solar Radiation Years	109

## TABLE OF TABLES (continued)

<u>Table</u>		<u>Page</u>
17.	Effect of Varied Discount Rate on Breakeven Cost	110
18.	Sensitivity of Breakeven Cost to Altered Degradation Rates	111
19.	Sensitivity of Breakeven Cost to Increased Cell Efficiency	112
20.	Sensitivity of Breakeven Cost to Altered Fuel Price Escalation Rate	112
21.	Sensitivity of Breakeven Cost to Subsystem Cost Estimates	113

## TABLE OF FIGURES

<u>Figure</u>		<u>Page</u>
1.	Photovoltaic Applications and Breakeven Costs	20
2.	Regional Definition-Factor Analysis Process	44
3.	Composite Solar Energy Planning Regions	46
4.	Simulation Model Scheduling Heuristic	48
5.	System Configuration Baseline Assumptions	50
6.	Appliance Use and Behavioral Assumptions	55
7.	Sample Appliance Load Vectors	58
8.	Formula for Revenue-Return Equalization	67
9.	Rate Structure Adjustment Calculation for Boston	68
10.	Alternative Degradation Rate Scenario	74
11.	Contribution of Solar to Residential Load vs Array Size	99
12.	Air-Conditioning Demand during Selected "Typical" Insolation Years.	101
13.	Breakeven Capital Cost vs Array Size: Boston	104
14.	Breakeven Capital Cost vs Array Size: Omaha	105
15..	Breakeven Capital Cost vs Array Size: Phoenix	106
16.	Photovoltaic Applications and Breakeven Costs	120
17.	Proposed Model Interaction for Utility Response Analysis	125

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Paul Carpenter

Gerald Taylor

## I. SOLAR PHOTOVOLTAICS AS AN ELECTRIC POWER SOURCE

### 1.1 INTRODUCTION

Among the emerging technologies which may provide solutions to current energy problems, photovoltaic power is, perhaps, the most unique. Without moving parts or intermediate thermal conversion, the sun's radiation is converted directly into usable electric power. Because of the peculiar properties of the semiconductor materials which make up photovoltaic cells (often called "solar cells"), incident sunlight creates an electrical potential which can be used to generate a flow of electrons, or electric current. Individual cells, each creating a small amount of electricity, can be linked to produce energy in amounts suitable for myriad practical applications including central power (utility) stations.

The characteristics of any technology naturally have a great deal of impact upon its development and practical application. The nature of photovoltaic cells is such that there appears to be great potential advantage in their application. On the other hand, there are substantial practical problems which mitigate the technology's positive aspects and there appear to be some disadvantages as well that have not yet received much attention. While, for instance, the modularity of PV cells and the concomitant absence of significant economies of scale imply that energy can be produced in small quantities without high costs per unit output, the electricity produced is direct current which must be converted

to alternating current for most conventional uses by power-conditioning equipment (inverters). Inverters do exhibit scale economies and thus the advantages of modularity are offset by the need for power conditioning. Another advantage of the PV technology is its lack of moving parts which makes it ideal for remote or residential applications where generating equipment must operate for long periods while unattended. But such unattended applications require module designs which are both very safe and durable and the expense of achieving such designs is significant. Finally PV technology is frequently advocated as an ideal energy source because of the absence of such negative externalities as pollution. While it is true that PV devices produce energy without emitting pollutants there are other problems associated with widespread use. These problems include occupational and safety hazards during production and maintenance of photovoltaic cells, and extremely heavy energy consumption in the production of the semiconductor materials.<sup>1</sup>

The process of selecting development applications which economically achieve a favorable balance of these positive and negative characteristics is bound to be a difficult one requiring not only careful analysis but also a well-directed and documented testing program. Given a catalogue of the technology's characteristics a logical first step in such a selection process might be to identify applications for further study which exhibit positive aspects of photovoltaics while avoiding, insofar as possible, negative aspects. Since there is so

much uncertainty surrounding photovoltaic development (as with any new technology) both in terms of production and potential markets, another criterion in the selection process might be an application's potential for an orderly progression both in the acquisition of practical experience with the technology and market and production growth. A final factor to be considered, especially from a governmental policy perspective, is an application's commercial potential, i.e. capability to compete on its own in the marketplace. Other things being equal, the more rapidly an application achieves market competitiveness, the better for the taxpayer since governmental development or commercialization subsidies should no longer be necessary for a competitive product.

Before turning to a discussion of the relationship between specific photovoltaic applications or market segments and their economic/commercial potential (and how one goes about analyzing that potential), a short digression on the history of the Federal Photovoltaics Program is in order. This history is important because it has been perhaps the most aggressive of the technology development programs at the Department of Energy since nuclear power, and its nature has broad implications for the kinds of information required from the economic analysis of photovoltaic applications.

## 1.2. HISTORY OF THE FEDERAL PHOTOVOLTAICS PROGRAM

Since its inception in the early 1970s, the Photovoltaics Program within the Energy Research and Development Administration (now Department

of Energy) has focused its effort on driving the costs of photovoltaic devices down. This approach is manifested in several program objectives, actors, and concepts.

The specific objectives of the National Photovoltaic Conversion Program were first articulated at the NSF/RANN Cherry Hill, New Jersey Conference in the fall of 1973. Program goals were here for the first time described in terms of array costs. "It is anticipated that large-scale application of solar photovoltaic technology will become economically viable by approximately 1980. This will be made possible by the reduction of solar array cost to less than \$0.50/watt (peak)."<sup>2,3</sup> At the time this number was not supported with economic analysis of potential applications. It was later established by ERDA as its 1986 Photovoltaics Program goal.<sup>4</sup> Given the state of knowledge of photovoltaic technology and its applications at the time, the Cherry Hill statement of program objectives was not unreasonable.\* But much faith has been placed in that number as a target for economic value, independent of any particular applications environment or region.

Given the history of the photovoltaic conversion technology as a satellite power system, it is not surprising that many of the actors in the Photovoltaics Program were also actively involved in the space

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\*Since \$0.50/watt(p) represented a good estimate of 5¢/kWh translated to photovoltaic array terms.

program. The Jet Propulsion Laboratory through its Low Cost Silicon Solar Array Project is one such organization that now has primary responsibility for the development of a low-cost silicon technology.<sup>5</sup> "The primary goal of the LSSA Project is to develop by 1986 the technological and industrial capability to produce silicon solar photovoltaic arrays at a rate of more than 500 peak MW per year, having an efficiency of greater than 10 percent and a 20-year minimum lifetime, at a market price of less than \$500 per peak KW, (\$0.50/watt(peak))."<sup>6</sup> Thus, the JPL program is utilizing its experience in space program management to generate technical and production advances (supply-side phenomena) to meet the 1986 Cherry Hill/ERDA objective. The Aerospace Corporation, another space program actor, has performed a set of "Mission Analyses" of photovoltaic applications in residential, commercial and central station applications which brought together first-order technical performance and financial analyses.<sup>7</sup> In the majority of the research and development effort to date the program has placed primary effort on attainment of the goals, a legacy of the space program, and secondary emphasis on the costs of accomplishing this research and development.

Given the program objectives and actors it is not hard to understand the concept behind the commercialization of photovoltaics in the program, a concept that has been characterized as a "market-pull" philosophy. The essence of this concept is that government purchases of photovoltaic cells, independent of their use in particular applications, is enough of a stimulus to drive the photovoltaic industry down the experience curve and thus meet the 1986 cost goals. This was articulated in the 1976 Photovoltaics Program plan:

a stimulus to drive the photovoltaic industry down the experience curve and thus meet the 1986 cost goals. This was articulated in the 1976

Photovoltaics Program plan:

It is expected that ERDA purchases of approximately 600 KWe through FY78, coupled with purchases by other federal agencies with ERDA's support, will result in a factor of 4 reduction in the present cost of silicon-based solar cells...A total government purchase of approximately 11 MW through FY 1983 is planned. Costs for silicon solar cell arrays are expected to drop to \$1000 per peak KW by 1984.<sup>8</sup>

"Market-pull" is a concept that is rational given the objectives and actors described above, especially in a situation where achieving cost goals is the primary objective. At present, however, there appears to be a greater realization that future strategies for the commercialization of photovoltaics require that attention be focused on the marketplace, particularly the marketplace in which electric utilities reside.

More recently, in the latest National Photovoltaic Program Plan,<sup>9</sup> an even more aggressive eight-cycle, eight-year photovoltaic procurement initiative has been proposed that would cost the government approximately \$380 million. The purpose of this new initiative is to accelerate by several years the diffusion of photovoltaic devices into the marketplace.<sup>10</sup> The "market-pull" concept has been institutionalized in terms of the so-called PRDA (Program Research and Development Announcement) which is the mechanism whereby the government solicits proposals from private sector interests to be recipients of these government-purchased modules for tests and applications purposes. This

new plan includes the same program goals as described above but they are now time-phased as follows.<sup>11</sup>

- . Near-term

- To achieve prices of \$2 per peak watt (1975 dollars) at an annual production rate of 20 peak megawatts in 1982.

- . Mid-term

- To achieve prices of \$0.50 per peak watt, and an annual production rate of 500 peak megawatts in 1986.

- . Far-term

- To achieve prices of \$0.10 to \$0.30 per peak watt in 1990, and an annual production rate of 10-20 peak gigawatts in 2000.

### 1.3. PHOTOVOLTAIC MARKET SEGMENTS AND THEIR RELATIONSHIP TO THE FEDERAL PLAN

Several attempts have been made to attach particular applications to the set of time/price horizons above. Before discussing the evidence which has accumulated to date, let us briefly consider the variety of potential photovoltaic markets and their characteristics.

While there are myriad potential uses for photovoltaics, most applications seem to fall into three major categories: remote applications, grid-competing (or load-center) applications, and grid-connected applications.

#### Remote Applications

This set of applications is composed of small-scale stand-alone systems that take advantage of the low maintenance and modularity

features of the technology. They include satellites, ocean buoys, cathodic protection, micro-scale agricultural pumping and other military-related applications. As can be seen, this set is made up of applications which heretofore had no (or very expensive) alternative energy sources. This fact means that these users are willing to pay a very high price for photovoltaic power and thus all current production is geared toward these uses. The remote market is not important with respect to the world's energy problems and in relative terms the market is very small.

#### Grid-Competing Applications

This set of applications includes those load centers which would otherwise need to be connected to the utility grid. A typical configuration would be a school or industrial plant with a large set of photovoltaic arrays supplemented by backup power from a diesel generator or other source. The category could also include a stand-alone house with some form of solar heating and cooling and electrical and thermal storage system for uninterrupted use. As one might guess, this set of applications may also be somewhat limited in market size due to the relatively low marginal cost of attaching oneself to the utility grid. To operate independent of the grid would imply the payment of a "premium" in the form of high capital costs in order to be totally independent.

#### Grid-Connected Applications

Since nearly all electricity generated in the United States is produced by large electric utilities, if the objective of the

commercialization of photovoltaic technology is to replace some of this conventional generation capacity, then the long-term market for photovoltaics is the grid-connected market. This set includes residences, schools, industrial and commercial establishments (in dispersed mode) as well as central station photovoltaic applications. There appear to be few technical problems associated with the interplay between on-site photovoltaic power as it is fed back into the grid and the use of electricity from the grid when the solar power is insufficient.<sup>12</sup>

It was mentioned above that several attempts have been made to attach various applications to the time/price framework of the National Plan. Figure 1 represents a plot of the various applications which have been studied and the "competitive" prices associated with those applications. As can be seen, there are significant gaps in the knowledge,<sup>13</sup> particularly with respect to breakeven prices of grid-connected applications, not to mention knowledge of the potential quantities demanded at these prices. As yet, no adequate measure of potential quantities demanded in the grid-connected market has been developed. As will be suggested later, one way to approach this question is to examine the effects of added penetration on utility system costs. While this method does not estimate a future demand curve, it does offer a means of defining demand potential. The best information available to date on the effect of photovoltaics on the utility system has been

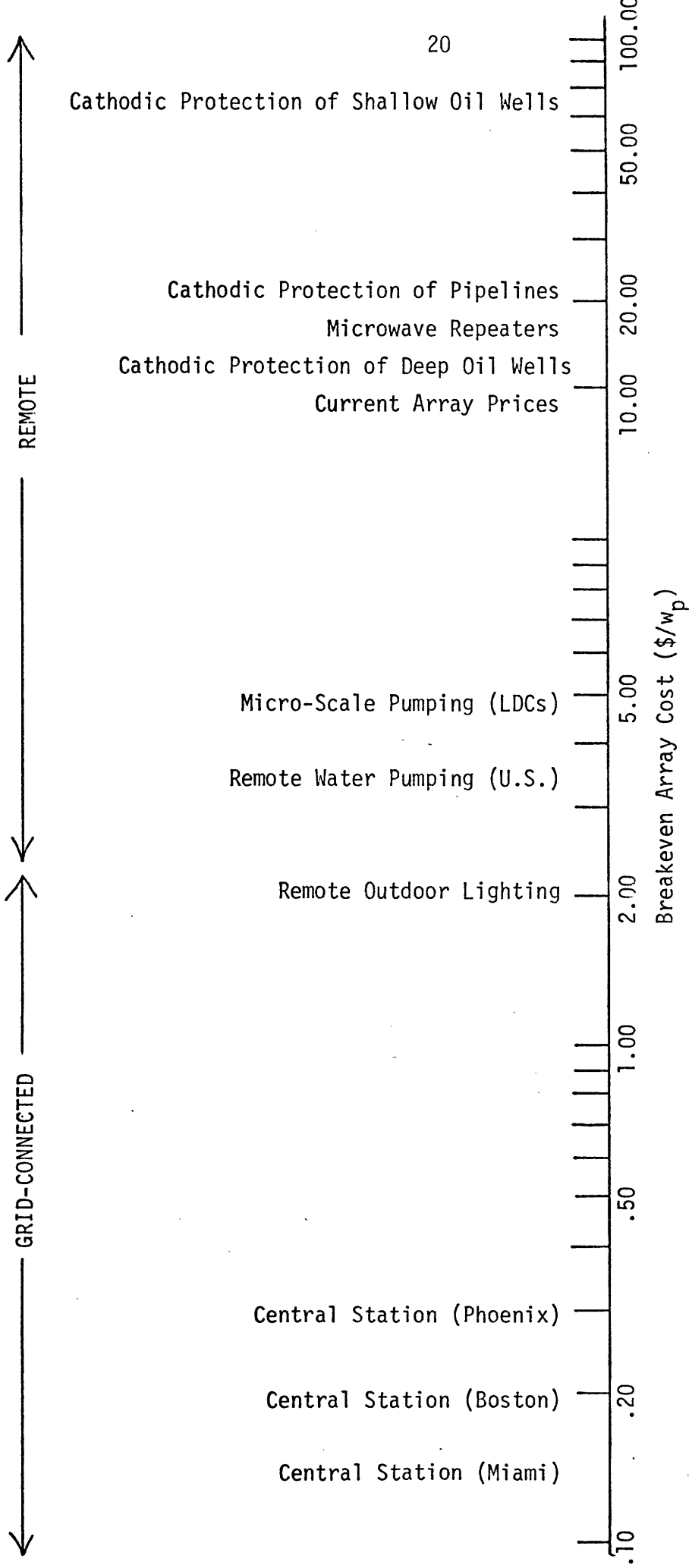


FIGURE 1

PHOTOVOLTAIC APPLICATIONS AND BREAKEVEN COSTS

Sources: BDM and Solarex estimates for ERDA  
 General Electric Co.  
 Douglas V. Smith

provided by the work of General Electric<sup>14</sup> and Westinghouse<sup>15</sup> with regard to the effect of central station photovoltaic plants on utility reliability and thus, costs. This valuation of the central station application was a reflection of the study authors' orientation as well as the focus of the Federal Program several years ago. The results of the central station studies show that photovoltaic power plants improve utility system reliability and thus do not require 100% backup; however, the breakeven prices calculated were low relative to the Program goals. It should be noted that these studies considered the residential application, but their analysis required utility ownership of the systems and thus the framework in which their financial analysis was performed failed to capture many of the potential advantages of residential, user-owned systems which will be elaborated upon later. General Electric, in its Requirements Assessment study, recognized this fact:

It is not possible to define the breakeven capital cost for a user-owned PEPS (Photovoltaic Electric Power System) plant in the same way as has been done for utility-owned plants. This is because the economic incentive to purchase and install such a plant lies in the savings in purchased electricity costs accruing to the user.<sup>16</sup>

Given the importance of the grid-connected market to the achievement of the long-term goals of the Photovoltaics Program, it is argued here that before the Nation commits itself to a very large technology commercialization enterprise such as the initiative proposed, several questions need to be answered about the economics of the long-term market for photovoltaics.

- . Are there advantages of user-owned, residential systems that are reflected in the value of the system to the user?
- . How should one go about valuing the worth of a photovoltaics system to a user/owner?
- . Should the residential market be pursued by an aggressive commercialization program? Does this application minimize the subsidy required to accelerate photovoltaics penetration in the long-term market?
- . What is the impact of these systems on electric utilities and how will/should they respond?

#### 1.4. SCOPE OF THIS STUDY

The purpose of this study is twofold. First, it examines the question of the dispersed, residential market for photovoltaics from a regional and user-ownership perspective. It attempts to determine at what price the user would be economically indifferent between having a photovoltaic system and not having a system. To accomplish this, the study first defines a uniform methodology for examining the value to the user-owner of weather-dependent electric generation technologies. This methodology is general enough to be applied to other on-site technologies such as wind systems. To make this calculation, two models are implemented for three regions of the United States. The first is a simulation model of a photovoltaic residence, developed by Jesse Tatum of the MIT Energy Laboratory.<sup>18</sup> The second is an economic valuation

model, required to translate the outputs from the simulation into breakeven array prices. Special care is taken to specify the input assumptions used in the models. The accompanying analysis includes a method to analyze the year-to-year variation in hourly solar radiation data, a discussion of the appropriate discount rate to apply to homeowner investments in photovoltaic systems, and a discussion of the use and determination of marginal cost based rate structures for PV system valuation. Second, this study evaluates the implications of the resulting partial equilibrium price<sup>17</sup> for the Federal Photovoltaics Program and it identifies a program of follow-on research to fill more completely the gaps in the knowledge of the long-term market for photovoltaic cells.

The normative nature of the results of this study must not escape the notice of the reader. The valuation will be derived on the basis of assumptions about rate structures and consumer discount rates. Specifically, the rate structures employed are based upon marginal costs (see Section 3.3.4) and the discount rates used were developed through application of the capital asset pricing model (see Section 4.2) which assumes rational consumers, and perfect financial markets. Insofar as these assumptions about how utility companies and consumers ought to behave prove unfounded, the results resting upon them will also be in error. This fact is, however, typical of any analysis which attempts to explain consumer behavior purely in economic terms.

## 1.5 FOOTNOTES

1. See Neff, Thomas, Social Cost Factors and the Development of Photovoltaic Energy Systems, MIT Energy Laboratory, Cambridge, MA (forthcoming).
2. The \$0.50/watt(peak) goal is in contrast to current array costs of \$10.00 to \$15.00 per watt(peak). One kW (peak) corresponds to the amount of solar radiation falling on one square meter of a horizontal surface on a clear day with the sun directly overhead at one atmosphere pressure and at 28°C.
3. Bleiden, H.R., "A National Plan for Photovoltaic Conversion of Solar Energy," in Workshop Proceedings, Photovoltaic Conversion of Solar Energy for Terrestrial Applications, Vol. 1, October 23-25, 1973, Cherry Hill, NJ, NSF-RA-N-74-013.
4. Energy Research and Development Administration, Division of Solar Energy, Photovoltaic Conversion Program Summary Report, Washington, D.C., November 1976.
5. Although the LSSA Project charter is now being expanded to encompass nonsilicon technologies as well.
6. Low-Cost Silicon Solar Array Project, "Division 31 Support Plan for FY77 Project Analysis and Integration Activities," Jet Propulsion Laboratory, California Institute of Technology, Pasadena, CA, April 25, 1977.
7. Aerospace Corporation, Mission Analysis of Photovoltaic Solar Energy Conversion, for ERDA/Sandia, SAN/1101-77/1, March 1977.
8. ERDA, op. cit., p. 2.
9. U.S. Department of Energy, Division of Solar Technology, National Photovoltaic Program Plan, Washington, D.C., February 3, 1978.
10. Information memorandum, December 21, 1977, to the Undersecretary from the Acting Program Director for Solar, Geothermal, Electric, and Storage Systems concerning "A Strategy for a Multi-Year Procurement Initiative on Photovoltaics," (Acts No. ET-002).
11. U.S. Department of Energy, op. cit., pp. 6-7.
12. For discussion of the technical aspects of grid connection, see Office of Technology Assessment, U.S. Congress, Application of Solar Technology to Today's Energy Needs, Washington, D.C., 1977, Vol. I, Chapter V.

13. The previous photovoltaics market assessment studies known to the authors include the following:

Remote Market:

Aerospace Corporation, Mission Analysis of Photovoltaic Solar Energy Conversion, for ERDA/Sandia, SAN/1101-77-1, March 1977, Vol. II, "Survey of the Near Term (1976-1986) Civilian Applications in the U.S."

BDM Corporation, Photovoltaic Power Systems, Market Identification and Analysis, Draft Final Report, November 1977, DOE Contract EG-77-C-01-1533.

BDM Corporation for FEA Task Force on Solar Energy Commercialization, DOD Photovoltaic Energy Conversion Systems Market Inventory and Analysis, Washington, D.C., June 1977.

InterTechnology Corporation, Photovoltaic Power Systems, Market Identification and Analysis, Draft Final Report, 1977, DOE Contract EG-77-C-01-4022.

MIT Lincoln Laboratory, The Economics of Adopting Solar Photovoltaic Energy Systems in Agriculture, Report #C00/4094-2, July 1977.

Smith, Douglas V., Photovoltaic Power in Less Developed Countries, MIT Lincoln Laboratory, Lexington, MA, March 1977.

Grid-Connected or Grid-Competing Market:

Aerospace Corporation, Mission Analysis of Photovoltaic Solar Energy Conversion, for ERDA/Sandia SAN/1101-77-1, March 1977, Vol. III, "Major Missions for the Mid Term (1986-2000)."

General Electric Corporation, Conceptual Design and Systems Analysis of Photovoltaic Systems, GE Space Division for ERDA/Sandia, Albuquerque, NM, March 1977.

Westinghouse Electric Corporation, Conceptual Design and Systems Analysis of Photovoltaic Systems, ERDA Contract E(11-1) 2744, April 1977.

With regard to residential applications, Westinghouse limited their analysis to stand-alone (non grid-connected) houses. The work of the Aerospace Corporation is perhaps the pioneering work with regard to residences, but the methodology which employs leveled

busbar costs fails to capture many of the important features of user-ownership of the PV devices. The valuation was performed by comparing the rooftop arrays (performance of which was determined by hourly simulation) with a single type of conventional utility generation plant (i.e. the value of the PV was not rate structure determined). See Chapter II for further discussion of methodologies.

14. General Electric Co., Requirements Assessment of Photovoltaic Electric Power Systems, RP 651-1, for Electric Power Research Institute by GE Electric Utility Systems Engineering Department, Schenectady, NY, Draft Final Report, June 1, 1977.
15. Chowanic, C.R., Pittman, P.F., and Marshall, B.W., "A Reliability Assessment Technique for Generating Systems with Photovoltaic Power Plants," IEEE PAS, April 21, 1977.
16. General Electric Co., Requirements Assessment of Photovoltaic Electric Power Systems, op. cit.
17. By "partial equilibrium price" we mean the price at which photovoltaics will initially penetrate the market. (Note that this is not the standard meaning of "partial equilibrium" as used in formal economics.) It is assumed that such initial penetrations will have minimal effect on existing electric utilities. See discussion of utility response to larger penetrations in Section 6.4.
18. See Tatum, Jesse, A Parametric Characterization of the Interface Between Dispersed Solar Energy Systems and the Utility Network, unpublished MIT master's thesis (forthcoming); Kaplow, R., Tabors, R., Tatum, J., Photovoltaic/Hybrid Simulation Model for Grid-Interconnected Residential Applications, MIT Energy Laboratory, Cambridge, MA (forthcoming).

## II. A UNIFORM ECONOMIC VALUATION METHODOLOGY

### 2.1 INTRODUCTION

As General Electric mentioned in the recently completed Requirements Assessment study quoted above,<sup>1</sup> traditional methods of valuing utility-generated power do not apply to a user-owner of a grid-connected technology. It is the purpose of this chapter to describe a general methodology to perform this function. There are at least three major requirements or features which this methodology must exhibit. These issues, listed here, will be more fully elaborated in the course of the following discussion:

A) There is a need for a methodology that provides full economic valuation for the unique features of weather-dependent technologies. As will be seen, the sunlight dependence of solar systems results in both advantages and disadvantages to the user. The methodology, whether it involves analytics or simulation, must explicitly value these effects.

B) The methodology should be able to allow for the direct comparison of alternative technologies on "equal footing." The comparison should not be influenced by scale, region, or climate beyond the influence of these variables on the economics of the system in its applications environment.

C) The methodology should allow for the consideration of various government policy actions. The great disadvantage of cost goals is that they do not allow for the effects of policy on the demand side. (Cost

reduction is accomplished only through supply side progress, while commercialization policy is primarily aimed at stimulating demand.)

If a methodology can be agreed upon that exhibits the three features suggested above, then it will provide two chief benefits, the first of which is a market-related technology R&D investment goal. This goal will be meaningful in that it will provide a benchmark for the achievement of true economic competitiveness with current technology. In the case of the Federal Photovoltaics Program it can be a valuable input to the JPL technology development project since it not only indicates a cost target, but it also indicates the particular configuration of the technology, such as residential shingles, flat plates, concentrators, etc., which applies to that cost.

Second, the methodology will provide the parameters necessary to make comparisons between technologies. One important component of R&D investment decisions is the economic benefits which a given technology will exhibit in its applications environment. Comparison of these demand-side benefits between technologies is at least as important as the consideration of supply-side progress. Of course, the combination of the demand-side benefit measure with a supply-side cost measure would provide the best economic viability measure for differing technologies. For technologies at or near the commercialization stage, government investment decisions can and probably should be made based on the distance certain technologies are from economic viability. For the

moment, this appears to be a more important criteria than ultimate market penetration and is motivated by the increased concern in the Department of Energy that the government get out of the technology development business as soon as the technology is able to compete in the private sector. Dr. Henry Marvin, Director of the ERDA Division of Solar Energy, has suggested that the Photovoltaics Program be restructured to focus on near-term goals under the assumption "that the market will enter an explosive self-sustaining growth phase at an array price of \$1 to \$2 per peak watt."<sup>2</sup> Dale D. Myers, Undersecretary of DOE, who is responsible for overseeing the development of technology, recently stated, "My objective is to move it (new energy technology) all into the industry and get the hell out of the business."<sup>3</sup> Both of these statements indicate the importance of understanding in advance not only the nature of the long-run markets for photovoltaics, but more importantly, the price at which new technologies become competitive with current ones, and the uncertainties associated with those prices.

The remainder of this chapter evaluates the economic valuation approaches that will meet the requirements discussed above. The section which immediately follows describes the nature of the economic valuation question.

## 2.2 ECONOMIC VALUATION OF PHOTOVOLTAICS

The term economic "benefits" or "valuation," as used in this report, is meant to be device-ownership specific, in that it is a valuation based

on the fuel bill saved for the owner. Specifying the valuation in this manner implies that it takes into account three things.

A) It is owner-specific in that it values the photovoltaic energy based on the alternative fuel source which that particular consumer faces and it is also configuration-specific in that it requires that the particular application be described.

B) It is region-specific in that it is a valuation based on the local cost of alternative fuels and local insolation.

C) It also includes a measure of the foregone cost of electric generation capacity (if any) and the value of improved (or degraded) utility system reliability and generation and transmission efficiency.

This valuation does not claim to indicate whether or not the photovoltaic systems will actually be purchased. The purchase decision is more complex than simple comparative life-cycle costs would indicate.<sup>4</sup> Furthermore, one can argue that the economic valuation of a new technology should be made in the context of some future environment, such as in comparison with other renewable resources.<sup>5</sup> In this report economic valuation is interpreted to mean the result of an economic comparison of photovoltaic devices with current electric generation technologies. Finally, the benefits measured here do not include potential social, environmental, or national security benefits.

### 2.3 UNIQUE FEATURES OF PHOTOVOLTAICS WHICH AFFECT ECONOMIC VALUATION

There are several characteristics unique to photovoltaic technology which bear examination because they have a direct impact on how one goes

about valuing the worth of the technology.

The modularity of photovoltaic arrays is notably uncharacteristic of conventional means to generate electricity and as a result, methods of calculating the value of the energy produced by photovoltaics cannot be divorced from the particular applications in which they are configured. This makes simple analytic valuation methods intractable, requiring instead more detailed simulation.

The second, often overlooked, feature of photovoltaics is that its energy output (a function of solar radiation) is generally coincident with the peak demand periods for electricity. This correlation is particularly important for air-conditioned residences, most schools, and summer-peaking utilities. The fact that photovoltaic output tends to be present at peak demand periods means that there is a "quality" component in the energy that must be specifically valued by the methodology. The implication is that the calculations must be made for short time slices, perhaps by the hour, and that methodologies which employ average solar insolation values together with an overall system efficiency are likely to misrepresent the potential economic impact of the solar devices.

Third, in applications that are utility grid-connected, the electric utility will have no direct control of the output of the photovoltaic device. This is analogous to the situation utilities confront with respect to "run-of-the-river" hydroelectric power. The valuation method for calculating the impact of the devices on utilities must be

sophisticated enough to account for the effects of this "run-of-the-sun" feature. As we shall see, this also impacts how one calculates the "buy-back" price at which utilities are willing to buy surplus power fed back into the grid from user-owned systems.

The last feature that bears acknowledgment is the site-dependence of photovoltaics, mentioned earlier. Since the value of the device is so heavily dependent on the local climatic conditions and utility environment, the calculations must be performed initially only for specific device configurations in particular regions for specific utilities. The aggregation effects of photovoltaic devices on utilities is thus a nontrivial problem that requires explicit consideration in the methodology, perhaps through stochastic processes.<sup>6</sup>

In summary, specific characteristics of photovoltaic systems make the economic valuation question more complicated than the question of the value of conventional technologies. In the next section, we will examine some of the approaches to measuring the economic value of alternative electric-generation technologies to see if they fit these requirements and needs.

#### 2.4 PREVIOUS APPROACHES TO ECONOMIC VALUATION

All of the methodological approaches that have been used to date to evaluate the economic worth of photovoltaics were developed originally under the assumption of utility ownership. As we shall see, this presents problems when the methodology is applied to non-utility

ownership cases. The two approaches to be discussed in this section are the Levelized Busbar Cost approach<sup>7</sup> used by the Aerospace Corporation<sup>8</sup> in its Photovoltaics Mission Analyses<sup>7</sup> and the Total System Cost approach<sup>9</sup> used by both General Electric and Westinghouse Corporations in their Photovoltaics Requirements Assessment Studies<sup>10,11</sup>.

#### Levelized Busbar Costs

As the name implies this is a costing not a valuation methodology. In this method the cost of supplying electricity from a single generating plant, or photovoltaic device, is calculated independently of any other plants in the system at a specified annual capacity factor. Thus, in any configuration where the energy producing device is connected to the grid, the rest of the plants in the system are ignored. The costs are calculated in mills per KWH according to the following formula:

$$\overline{\text{BBEC}} = \frac{C_t \cdot \text{FCR}}{8.76 \cdot \text{PCF}} + \overline{\text{O \& M}} + \overline{\text{FL}}$$

Where:

$C_t$  = Capital cost at time t, in dollars

FCR = Fixed charge rate, per unit

8.76 = constant to convert years to hours and dollars to mills

PCF = Plant capacity factor, annual

$\overline{\text{O \& M}}$  = Annualized O & M costs, in mills/KWH

FC = Annualized fuel costs, in mills/KWH

(FC would be zero for photovoltaic plants)

Notice that this is not an economic valuation measure as we have defined the term. It allocates capital costs over a specified lifetime implicit in the fixed charge rate. The performance characteristics of the plant are contained within the single plant capacity factor number.

There are a number of reasons why levelized busbar cost is an inadequate methodology for the economic comparison of two methods of supplying electricity. First, in order to be valid the capacity factors must be the same for the two systems being compared. Capacity factor is defined as the ratio of the average load on a machine or equipment for the period of time considered, to the rating of the machine or equipment. Thermal power plants have capacity factors lower than 100 percent due to unexpected or planned system outages. Photovoltaic plants generally have very low capacity factors since here the capacity factor is a function of sunshine availability. "It is impossible therefore for a (photovoltaic) plant to have a capacity factor as high as the highest of conventional thermal plants..."<sup>12</sup> Of course, comparisons could be made over a range of capacity factors, holding them the same for both plants, but even this would not allow one to choose the appropriate systems because the answer will change as the capacity factor changes.

Second, busbar costs do not account for the "effective" capacity of the two plants. Effective capacity has been defined as the amount of

conventional capacity that would be displaced upon the installation of a photovoltaics plant of a certain rated capacity. This is related to the discussion earlier where it was argued that photovoltaic energy has a "quality" component related to the time of day. "The insolation tends to be available at a time in the daily work cycle when the loads are highest; and depending upon the relationship of the timing of the insolation peak and the daily load peak, (photovoltaic plant) effective capacity can be considerably higher than capacity factor."<sup>13</sup>

Finally, busbar costs do not place a valuation on the impact of the power plant on the total utility system. It is never the case that one is just comparing a photovoltaics plant with a coal plant, in isolation. A photovoltaics plant will behave very differently with respect to the utility system when it is installed than would a coal plant, even if they had the same capacity factor. Thus, busbar cost is not a sufficiently detailed method to determine the value of a photovoltaic system to its utility owner. It is also questionable whether the results it gives even allow the decision-maker to make rough-cut, technology rankings.

#### Total Utility Systems Cost

In contrast to busbar cost, which is a purely analytic method, Total Utility Systems Cost is a method that relies upon simulation. As we shall see, this method, when implemented correctly, is the type of analysis needed to perform the economic valuation of photovoltaics from the utility point of view. If the photovoltaic system is utility-owned, then we can stop here. If the systems are user-owned, however, total

systems costs provides only one part of the ultimate analysis (see Section 6.4).

The Total Systems Cost Methodology involves a detailed hourly stochastic simulation of the utility system reliability. This is accomplished in terms of the widely-used expected value of systems outage known as the loss of load probability (LOLP). The economic valuation of a photovoltaic plant is calculated based on its ability to contribute to the overall generation system reliability. A photovoltaic plant is added to a "base" utility system, its output being considered a negative load on the system, and conventional capacity is retired from the system until reliability returns to its base LOLP value. This amount of conventional capacity "displacement" is referred to as the photovoltaic plant "effective capacity". The economic valuation is completed by summing the value of the fuel costs displaced and the value of this effective capacity. In order to assess the energy displacement characteristics of a photovoltaic plant it is necessary to analyze the entire utility generation system operation through a production cost simulation model. This model dispatches generating capacity to meet the total system load at minimum cost. Since the photovoltaic plant output is sunlight dependent ("run-of-the-sun"), it must first be modeled and then the rest of the utility plants are dispatched around it in the simulation. Running the simulation with and without the photovoltaic plant addition yields a valuation which includes both the displaced conventional

capacity and the displaced energy all at constant system reliability.<sup>14</sup>

This approach was used successfully by General Electric in their Requirements Assessment of Photovoltaic Electric Power Systems<sup>14</sup> to show that photovoltaic plants did not necessarily require 100 percent conventional capacity backup, as was widely asserted by many commentators. There are, however, several necessary conditions that must be accounted for in this methodology, conditions that General Electric did not meet in their study:

A) The solar insolation data which determines the output of the photovoltaic plant must be matched on an historical basis with the utility system load data. This could be especially critical for summer-peaking utilities where the presence of sunshine will increase the air conditioning load. Energy demand and insolation are not independent variables.

B) This methodology is not sufficient by itself for dispersed, utility-owned systems. Explicit consideration must be taken of transmission-distribution loss and reliability improvements that will be enjoyed with dispersed photovoltaic systems.<sup>15</sup>

C) As alluded to earlier, the use of the total utility system cost methodology by itself to calculate the economic value of photovoltaic systems implies necessarily that utilities own the systems.

In the next section a methodology will be suggested that calculates the economic value of user-owned photovoltaic plants.

## 2.5 SUGGESTED USER-OWNED ECONOMIC VALUATION METHODOLOGY

It is important at the outset to distinguish between the methodology in general and the particular way in which it will be configured to examine user-owned photovoltaics. In general, the methodology defines two numbers. The first is called the "breakeven" capital cost and is calculated by finding the difference between the user's electricity bills with and without the PV device according to the following formula:

$$BECC = \left[ \sum_{J=1}^n \frac{\sum_{i=1}^{8760} (x_{0i} - x_{Di}) \cdot EFACT(J) \cdot DFACT(J)}{(1 + \rho)^J \cdot ACOL} \right] - \frac{FIXEDC}{ACOL} + VARC$$

$\frac{\quad}{n_{\text{system}} \cdot 1000}$

Where:

- BECC = Breakeven capital cost in \$/W\*
- $x_{0i}$  = Utility bill for hour i without device in \$
- $x_{Di}$  = Utility bill for hour i with device in \$
- EFACT(J) = weighted fuel price escalation factor for year J based on fuel price component of rate structure
- DFACT(J) = benefits degradation factor for year J based on module degradation
- $\rho$  = discount rate appropriate to user
- n = lifetime of device
- ACOL = collector area in  $m^2$
- FIXEDC = fixed subsystem costs (including installation, power conditioning, lightning protection, etc.) in \$

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\*See Foreword and Appendix A.

VARC = variable subsystem costs (including installation  
O&M, markups, insurance, taxes, etc.) in \$/m<sup>2</sup>

$\eta_{\text{system}}$  = system efficiency.

BECC can be considered an economic indifference value - that price at which the user would be economically indifferent between having and not having the device. This formula contains a number of features. First, the valuation which is the difference in the utility bills to the user, is determined by the utility rate structure and whatever the utility is willing to pay for surplus energy supplied by the owner to the grid. If the rate structure reflects the load demand on the utility (as under peak-load pricing), then this valuation explicitly values the "quality" component of the energy supplied by the device. Second, it is a figure defined in dollar units. This automatically adjusts for the scale of the device and allows direct comparison between two devices in the same application.

The second number that this methodology allows one to calculate is a dimensionless "break-even index". It is calculated by dividing the break-even capital cost by the cost at which the technology is available today for that particular application:

$$\text{BEI} = \frac{\text{BECC}}{\text{CC}}$$

where

BEI = breakeven index

BECC = breakeven capital cost

CC = current capital cost.

This measure is an attempt to implement in a simple manner the demand-side, supply-side interaction mentioned earlier. The numerator, BECC, constitutes the demand-side benefit measure while CC represents the supply-side cost measure which indicates availability.

In a situation where future costs (CC) were perfectly known, this index would allow one to compare different technologies in the same application (what the busbar energy cost figure claims to do). BEI would, under these circumstances, tell the investment decision-maker "how far away" the technology is from break-even. Unfortunately, CC is not known with certainty, and thus this measure is also imperfect. But by introducing judgements as to possible future supply costs with probabilistic distributions around these costs, it may be possible to use this index for technology comparison.<sup>16</sup>

While there is a fine line between what one would call an analytic model and a simulation model, the fact that this methodology requires hour-by-hour analysis suggests the necessity of simulation.

## 2.6 FOOTNOTES

1. General Electric Co., Requirements Assessment of Photovoltaic Electric Power Systems, RP 651-1 for EPRI by GE Electric Utility Systems Engineering Dept., Schenectady, NY, Draft Final Report, June 1, 1977.
2. H.H. Marvin, Letter to Photovoltaic Program participants on "Photovoltaic Program Plan Restructure," August 5, 1977.
3. Dale D. Myers, Quoted in The New York Times, December 5, 1977, p. 61.
4. For discussion of the photovoltaics purchase decision and a methodology to measure the factors involved, see: Gary L. Lilien, The Diffusion of Photovoltaics: Background, Modeling and Initial Reaction of the Agricultural-Irrigation Sector, MIT Energy Laboratory Report MIT-EL 76-004, Cambridge, MA, March 1978.
5. Amory Lovins, Soft Energy Paths, Ballinger Publishing Company, Cambridge, MA, 1977, p. 69.
 

" Since we are obliged to begin committing resources now to the long-term replacement of historically cheap fuels, we must compare all potential long-term replacement technologies with each other, not with the cheap fuels, in order to avoid a serious misallocation of resources." (emphasis in original)
6. Work is currently under way to analyze this load aggregation problem by Prof. Fred C. Schweppe et al. of the MIT Electric Power Systems Engineering Laboratory.
7. J.W. Doane, et al., The Cost of Energy from Utility-Owned Solar Electric Systems, JPL/EPRI-1012-76/3, Jet Propulsion Laboratory, Pasadena, CA, June 1976.
8. Aerospace Corporation, Mission Analysis of Photovoltaic Solar Energy Conversion, for ERDA/Sandia, JAN/1101-77/1, March 1977.
9. C.R. Chowanec, P.F. Pittman, D.W. Marshall, "A Reliability Assessment Technique for Generating Systems with Photovoltaic Power Plants," IEEE PAS, April 21, 1977.
10. General Electric Co., op. cit.
11. Westinghouse Electric Co., Utility Assessment of Photovoltaic Electric Power Systems, Follow-on Project under ERDA Contract

E(11-1)-2744 "Conceptual Design and Systems Analysis of Photovoltaic Power Systems," 1977.

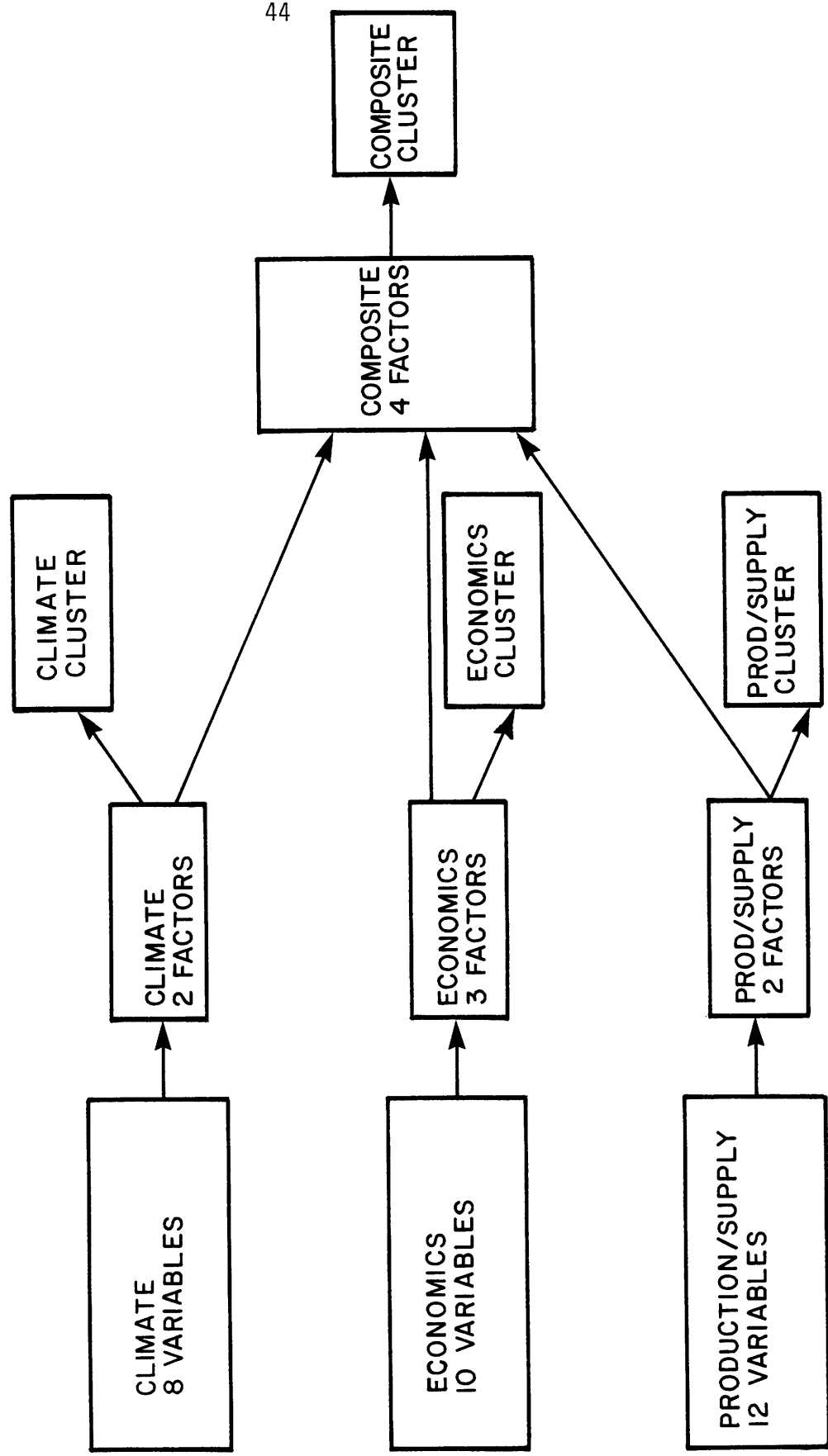
12. General Electric Co., op. cit., p. L-3.
13. Ibid., p. L-4.
14. For a more detailed description of the total systems cost methodology, see GE, op. cit., Appendix F.
15. The so-called residential shingle scenario studied by General Electric is a misnomer, because no effort was made to model the transmission-distribution system. The answer would have been the same if all of the dispersed shingles had been aggregated in a central power plant, except for differences in subsystem costs.
16. It must be emphasized that this index provides only a part of the information necessary to make R&D investment choices and decisions. No one measure can make these decisions in isolation since it is necessary to understand how alternative R&D budget allocations affect future technology development along many dimensions. The claim is made, however, that knowledge of the point at which technologies reach economic "breakeven" in the marketplace is a vital piece of the information that is needed.

### III. SIMULATION MODEL DESCRIPTION AND INPUT ASSUMPTIONS

#### 3.1 REGIONAL DEFINITION

The choice of regions in which to perform the analysis is based on the work of Carpenter and Tabors.<sup>1</sup> This regional definition study was performed in recognition of the fact that most existing regional schema for energy analysis are not well suited to data collection<sup>2</sup> or are improperly constructed to reflect solar energy and climatic characteristics. The methodology employed by this analysis was a multivariate statistical method called two-stage factor analysis coupled with cluster analysis of cases. Using states as regional building blocks, this methodology examines groups of variables and their correlations and based on these correlations constructs linear combinations of variables, called factors. This technique isolates the underlying dimensions in the data and allows one to condense many variables into a few "factored" variables. Each state has a corresponding score for each of these factors and these factor scores are then used by the cluster analysis to group similar states and differentiate dissimilar states. Homogeneous regions are thus constructed based on many underlying variables.<sup>3</sup> Figure 2 is a box diagram depicting this two-stage process. As indicated, the data set consisted of 8 climate variables representing solar radiation availability and heating and cooling requirements, 10 economic variables measuring energy consumption, income, value added and growth, and 12

**FIGURE 2**  
**REGIONAL DEFINITION - FACTOR ANALYSIS PROCESS**



production-supply variables reflecting fuel prices, refinery capacity and energy production.

The final regional breakdown is illustrated in Figure 3. Because of their homogeneity, each region can be unambiguously defined based on the final factors which are linear combinations of the above variables. For example, Region V, the Southwest, is characterized by high consumption, sunny climate, affluence and high energy prices. (See Carpenter and Tabors<sup>1</sup> (1978) for a more detailed summary and quantitative description of the regions). Due to time and data limitations, three of these seven regions were selected for the analysis presented in this document; those regions which include Boston, Omaha, and Phoenix. It was felt that these three areas provided a sufficiently broad cross-section to be representative of typical results for all regions.

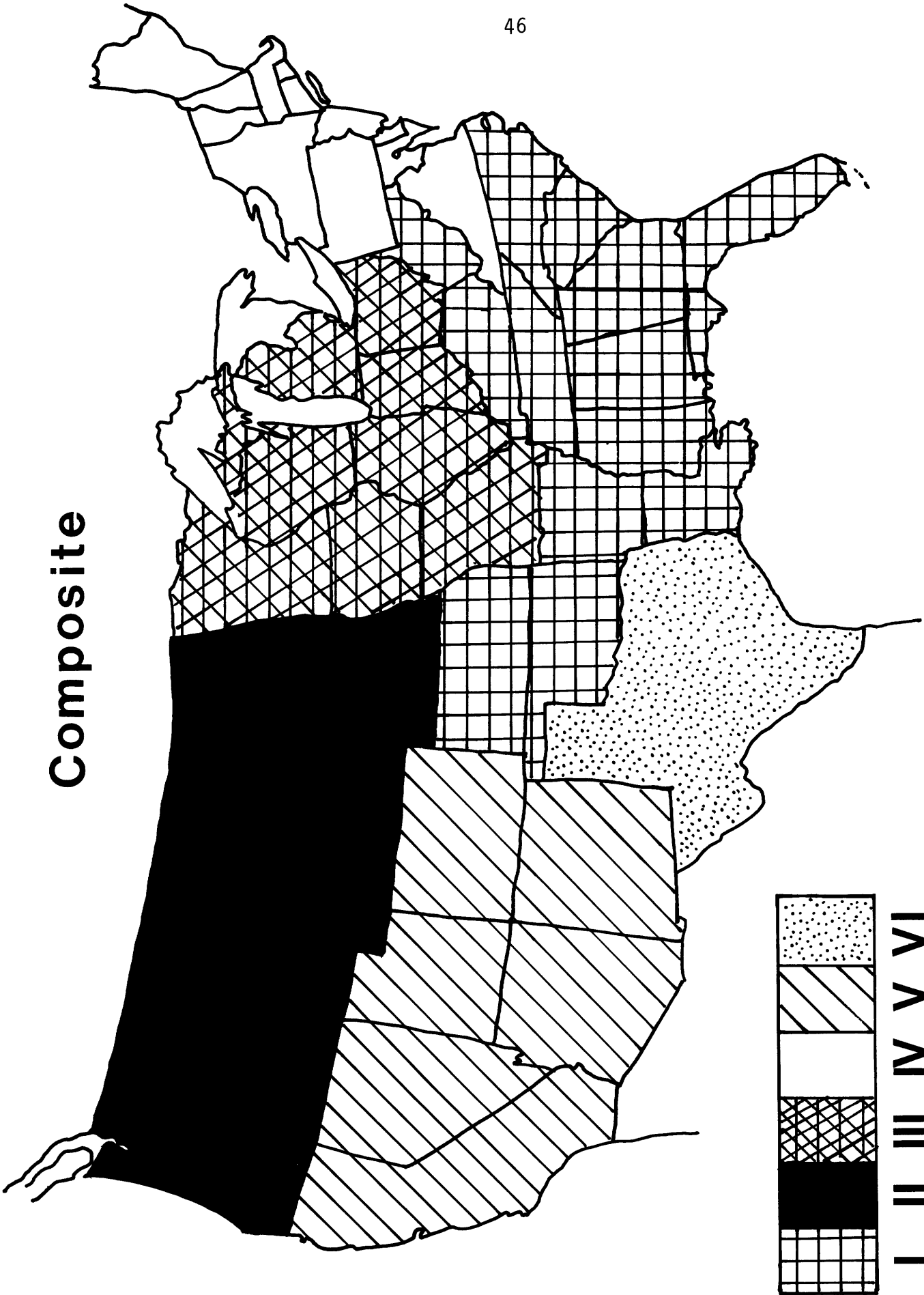
### 3.2 VALUATION MODEL

The model employed to value PV systems in this study can be conceptualized as three separate models: A) a photovoltaic array simulation model B) a load-scheduling simulation model, and C) an economic valuation model.

#### PV Array Model

This model provides an application and location-specific simulation of the output of a photovoltaic system. Specific system configurations are input by means of design parameters such as array size, packing factor, efficiency, loss factors, array tilt, etc. Location specificity

# Composite



**I II III IV V VI**

FIGURE 3

is achieved by the designation of latitude and the use of local data for insolation and temperature. Thus, given system configuration, latitude, and hourly weather data, the simulation provides hourly PV system (i.e. conditioned A/C) electric power levels.<sup>4</sup>

#### Load-Scheduling Model

Residential usage of electricity is determined on the basis of appliance load and electricity price inputs and the availability of electricity from the solar array model. Appliance energy consumption and use assumptions are input to the model in the form of vectors described below in Section 3.3.3. Price information is in the form of utility rate structures. Output from the array simulation determines the availability of photovoltaic energy.

Scheduling is accomplished through a process intended heuristically to optimize use of the PV array output.<sup>5</sup> Each half-hour the scheduling heuristic proceeds through five steps summarized in Figure 4, first constructing a prioritized list of loads with "must run" loads at the top and other "runnable" loads in descending order of total cost.<sup>6</sup> Available PV system output is then dispatched to cover as many of the loads as possible. If array output is more than needed to cover all the "runnable" loads in a period, excess is sold back to the utility grid at a designated price. When solar electricity is insufficient to cover the entire list, the remaining loads are postponed except for those designated "must run," which are then scheduled using electricity

Figure 4

## SIMULATION MODEL SCHEDULING HEURISTIC

1. IS LOAD IN MUST-RUN PERIOD? RUN THOSE LOADS THAT MUST BE RUN.
2. IS LOAD "RUNNABLE"? A LOOK-AHEAD IS PERFORMED FOR RUNNABLE LOADS WHICH ATTACHES COSTS TO THE LOADS IN VARIOUS RUN SCENARIOS BASED ON THE AVERAGE UTILITY PRICE OVER THE RUN PERIOD. LOADS ARE RANKED IN ORDER OF MOST EXPENSIVE AND, IF THERE ARE TIES, BY LARGEST LOAD.
3. IS THERE SOLAR AVAILABLE? RUNNABLE LOADS ARE SWITCHED ON IN PRIORITY ORDER WHILE EXCESS SOLAR EXISTS. IF INSUFFICIENT SOLAR EXISTS TO COVER FULL LOAD THEN LOAD IS SWITCHED ON WHILE THE WEIGHTED PRICE OF SOLAR PLUS UTILITY POWER IS LESS THAN A PRE-SET LIMIT.
4. LEFT-OVER SOLAR IS SOLD BACK TO UTILITY.
5. IF NO SOLAR THEN LOADS OTHER THAN "MUST-RUN" ARE POSTPONED.

purchased from the utility grid at the price (determined by the rate structure) prevailing for that particular time period. Records are kept accounting for all PV output and all electricity purchased from the utility, as well as the total utility bill incurred and what that bill would have been had consumption remained unchanged and had all energy been purchased from the utility grid.

#### Economic Model

The economic valuation model performs two functions. The first is necessitated by the fact that the first two sections described above, which simulate the PV residence, are run for only a single year. Since these single-year results would not be expected to remain stable through time, evaluation requires that the one-year figures be projected over the lifetime of the system. This is accomplished by applying degradation<sup>7</sup> and fuel escalation<sup>8</sup> assumptions through time to develop a twenty-year profile of PV benefits. The second portion of the model simply performs a net present value calculation by the application of a discount rate to yearly energy savings\* to arrive at a gross market breakeven value. Subsystem, operation and maintenance, shipping and distribution, and other relevant costs<sup>9</sup> as well as profit margins etc. are then

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\*It should be mentioned here that the utility bill with solar was compared to the time-of-day bill that would have resulted without solar. This was done to assure that savings resulting from behavioral shifts motivated by the time-of-day structure alone were not capitalized into the value of the PV system.

subtracted to arrive at the net breakeven figures presented. See formula in Section 2.5 and computer program in Appendix C. The input assumptions and sensitivity analysis scenarios for the economic valuation model are presented in Chapter IV.

### 3.3 MODEL INPUTS

The following sections describe the specific assumptions and data inputs for each segment of the array and load scheduling models described above.

#### 3.3.1 SYSTEM CONFIGURATION

The system configuration assumptions for the base case are presented in Figure 5. Mismatch and inverter efficiencies as well as packing factor remained constant through the entire analysis. The array tilt

Figure 5

#### SYSTEM CONFIGURATION ASSUMPTIONS

Array Size:	35 m <sup>2</sup>
Cell Efficiency:	.12
Wiring and Mismatch Efficiency	.95
Inverter Efficiency:	.88
Packing Factor:	.80
Array Tilt Angle:	Latitude less 10°
Storage:	None

angle was set to optimize year-round performance<sup>10</sup> and also was not varied. Virtually all analysis was done without storage and this factor deserves more detailed comment.

Storage was omitted from the analysis primarily for two reasons. The first is the problem storage causes in array-size optimization.

Without marginal cost functions for array and storage equipment it was not possible strictly to optimize the PV system. It was hoped that over the range of array sizes relevant to the residential application there would be a peak in the per unit net breakeven value<sup>11</sup> (\$/m<sup>2</sup>) which would proxy as an optimum assuming constant cost per m<sup>2</sup> of array.<sup>12</sup> The inclusion of storage would have made such a determination much more complex. A much more serious problem which provided the second reason for storage exclusion is the fact that benefit allocation becomes more difficult when storage is included. Since storage can reduce electricity bills given a time-of-day pricing structure with or without a PV array,<sup>13</sup> the benefits to a combined system could accrue to the PV array, to the storage, or to the interaction of the two. This allocation difficulty underscores the fact that photovoltaics and storage, rather than being complementary as is commonly believed, appear in fact to be competitive or substitute devices for grid-interfaced systems.<sup>14</sup>

Both array size and cell efficiency have been varied from the base case in parametric analysis. The 35 m<sup>2</sup> array size was in fact selected as the base size because of its apparent optimality, given location and buy-back rate possibilities (see Section 5.1) in the sensitivity runs. The range on size, 5-85 m<sup>2</sup>, covers those thought reasonable in residential applications. Cell efficiency was set at .15 on sensitivity runs because, while present efficiencies are around .12, the higher figure is projected cell performance for 1986.<sup>15</sup>

### 3.3.2 INSOLATION DATA

Historically, hourly solar radiation data have suffered from neglect and have contained serious errors resulting from gaps in collection and calibration and instrumentation problems. Recently, these data have been rehabilitated for 27 of the weather stations across the country and have been formatted with other hourly meteorological measurements in the so-called Solmet format, now available on magnetic tape from the National Climatic Center of the National Oceanic and Atmospheric Administration.<sup>16</sup>

While the quality and amount of data vary from station to station, most of the stations for which there is Solmet data report at least 15 years of historical hourly solar radiation data.

Since it was hypothesized that the simulation valuation would depend heavily on the amount of solar radiation in a given year, care was taken to define "typical," "best," and "worst" years for solar radiation in each of the three areas analyzed.<sup>17</sup> Because each tape contains approximately 175,000 individual hourly readings for each city, analysis of variance using available statistical routines proved intractable. And while it would be ideal to have a summary statistic concerning insolation variation on an hour-by-hour basis, the extreme volume of information to be analyzed made its analysis beyond the scope of this study. Instead, a set of computer programs was designed (see Appendix B) to compute and analyze the variation in monthly-hour insolation averages. This involved

the creation of a 12 x 24 matrix for each year relating average insolation by hour of the day to month of the year. Each corresponding cell of the yearly matrices were then analyzed for variation and the year whose monthly-hour averages were most similar to the mean year was selected. This method is crude in the sense that variation within any particular month is washed out, but on the other hand it does allow one to select objectively a typical year based on some global criteria. Table 1 presents the "typical," "best," and "worst" years for each area as defined by the analysis.

Table 1

## ANALYSIS YEARS SELECTED BASED ON STATISTICAL ANALYSIS

	<u>Boston</u>	<u>Omaha</u>	<u>Phoenix</u>
"Typical" Year	1953	1975	1959
"Best" Year	1963	1966	1955
"Worst" Year	1958	1969	1960

Once the analysis years were selected, it was necessary to read, interpret, and modify the data from the tape so as to be suitable for use by the PV array model. Two computer programs were designed (see Appendix C) to perform this function. The first merely reads the relevant year from the tape and transfers this block of data to disc. The second program converts the data from solar time to standard time through linear interpolation and also converts the direct-normal and the total-

horizontal insolation measurements to direct and diffuse insolation on a horizontal surface through standard geometry.<sup>18</sup>

### 3.3.3 APPLIANCE LOADS AND BEHAVIORAL ASSUMPTIONS

Figure 6 summarizes the appliance loads and use patterns which were scheduled in the simulation model. Appliance ratings (power requirements) and yearly consumption figures (energy usage), excepting those for lighting<sup>19</sup> and air conditioning,<sup>20</sup> were taken from data compiled by General Electric Co. for their study titled Conceptual Design and Systems Analysis of Photovoltaic Systems.<sup>21</sup> Division of yearly consumption by appliance ratings yielded hours of use on a yearly basis. Hours of use were then distributed on a daily and weekly basis so as to reasonably approximate normal usage.

The figures for the refrigerator, for example, indicate  $1829 \text{ KWh}/615\text{W} = 2974$  hours of use per year for an average of slightly over 8 hours per day. People obviously do not turn their refrigerators off for 16 hours a day so this implies that the thermostatic control of the unit causes it to operate in on/off cycles in which the unit is "running" (drawing energy) about one-third of the time. For the remainder of the cycle the unit is automatically placed in a "hold" mode which uses no (or negligible) energy. Consequently the refrigerator has been modeled as if it ran 20 minutes each hour.<sup>22</sup> This results in a very static load which cannot be shifted to any significant degree. The scheduling routine in the simulation can move the 20-minute "on" period

Figure 6

## APPLIANCE USE AND BEHAVIORAL ASSUMPTIONS

<u>Load #</u>	<u>Appliance</u>	<u>Rating</u>	<u>Yearly Consumption</u>	<u>Comments</u>
1	Refrigerator	615W	1829kWh	Unit is on continuously but draws load (i.e. is running) only one-third of the time to maintain proper temperature (runs only 20 min. each hour).
2 & 3	Dryer	4850W	1008kWh	Eight half-hour loads. May be run at any time during day/night but four loads must be run in each half of each week.
4 & 5	Washer	500W	103kWh	Same as dryer.
6	Water heater	2500W	4270kWh	Unit is on from 6 a.m. to midnight but runs only one-fourth of each hour to maintain temperature.
Range loads			1205kWh	Meal loads represent different combinations of oven, broiler, and range-top burners that might be used for each meal. Each load is 30 min. in duration. Breakfast, lunch, and dinner start times are 6-7:30 a.m., 11:30-12:30 p.m., and 6-8 p.m., respectively.
7.	Dinner	9100W		
8.	Lunch	2400W		
9.	Breakfast	2700W		

Figure 6

## APPLIANCE USE AND BEHAVIORAL ASSUMPTIONS (continued)

Load #	Appliance	Rating	Yearly Consumption	Comments
10	TV	200W	440kWh	Unit runs for 6 hours per day beginning in the late afternoon or early evening.
11	Dishwasher	1250W	363kWh	Runs consist of two 30-min. or one 1-hour cycle each day. May be run after either breakfast or dinner.
12	Lighting	2400W	1314kWh	Lighting for a 6-7 room home. Roughly one-fourth of the lights are on at any time during evening lighting hours.
13	Central Air Conditioning	5000W	Variable	A/C mode is triggered by two days with temperatures greater than 25.5°C. Once in A/C mode unit is turned on when temperature reaches 21.9°C and runs continuously until house is cooled to 20.9°C.

within each hourly cycle.

Other loads are much more flexible. The clothes dryer is used  $1008\text{kWh}/4850\text{W} = 207$  hours per year or about 4 hours per week. This represents eight 30-minute loads which need not be run at any particular time. Therefore the only constraint placed upon these loads is that they not be run all on the same day. This was accomplished by requiring four loads to be run in each half of a weekly cycle. Because of the technical design of the simulation model this required the use of the two separate dryer loads which appear in Figure 6.<sup>23</sup>

Once characterized as in Figure 6, load and behavioral information for each appliance was input to the model by means of a 24-entry vector like those shown for the refrigerator and dryer in Figure 7. The second and twelfth entries contain the appliance rating and cycle length discussed earlier. Entries 3 and 4, along with the cycle length, define energy consumption and represent average consumption while "on" and the run duration respectively. For the refrigerator these entries indicate that each hour (entry 12) the unit must run for one half-hour (entry 4) at an hourly consumption rate of 420W (entry 3). Thus each hour the refrigerator uses  $420\text{W} \times 0.5 \text{ hr} = 210 \text{ Wh}$  of energy.<sup>24</sup> Other entries control when and how often a load can be interrupted (5-11), how much the load's scheduled start time (identified in entry 13) can be advanced (14) or delayed (15) and what percentage of the time the load can be foregone, or avoided altogether (16, 17).<sup>25</sup> The remaining entries are essentially bookkeeping locations for the computer.

Figure 7

## SAMPLE APPLIANCE LOAD VECTORS

	<u>1</u>	<u>2</u>	<u>3</u>	<u>4</u>	<u>6</u>	<u>7</u>	<u>8</u>	<u>9</u>	<u>10</u>
Refrigerator	1.0	615	420	0.5	0	0	0	0	0
Dryer #1	1.0	4850	4850	2	28	0	24	0	4

	<u>11</u>	<u>12</u>	<u>13</u>	<u>14</u>	<u>15</u>	<u>16</u>	<u>17</u>	<u>18</u>	<u>19</u>
Refrigerator	0	1.0	0	0	0.5	1.0	1.0	5	3
Dryer #1	0	168	-143	24	24	1.0	1.0	5	5

	<u>20</u>	<u>21</u>	<u>22</u>	<u>23</u>	<u>24</u>
Refrigerator	0	0	0	0	0
Dryer #1	0	0	0	0	0

### 3.3.4 RATE STRUCTURES

Energy delivered by the photovoltaic system simulated was valued through application of time-of-day rates which reflect marginal costs for each of the utility systems studied. While none of the utilities presently charges consumers on the basis of such rates, they have been used in the analysis because they more accurately reflect energy costs both to the utility companies and society at large than do present block rate structures. Utility companies, threatened by the rapid rise in electricity production costs<sup>26</sup> and consumer resistance to spiraling utility bills,<sup>27</sup> have become cognizant of the fact, long recognized by economists, that rate structures which do not accurately reflect electrical production costs<sup>28</sup> present price signals to consumers which lead to inefficient resource allocations. This inefficiency has evidenced itself in declining load factors<sup>29</sup> and rising reserve margins.<sup>30</sup> The falling utilization of capacity is caused by the fact that peak demand is growing faster than average demand,<sup>31</sup> a phenomenon which can be attributed to block rates which essentially undercharge peak users and overcharge off-peak users.<sup>32</sup> The use of time-of-day rates based upon marginal costs avoids capitalizing economic distortion inherent in declining block structures into the valuation of the PV system and furthermore, time-of-day rates are what the PV system owner of the future is most likely to encounter given current utility industry and governmental initiatives.<sup>33</sup>

The rates used in the simulation were developed through a two-step process. First marginal generating costs were determined for each of the utilities studied. The second step occurred after initial simulation runs and consisted of adjusting the rates up or down to equalize the bills that time-of-day and declining block structures produce for consumers with similar consumption levels.

Marginal costs for the New England Electric System and for Arizona Public Service were those derived by Feldman and Anderson<sup>34</sup> for their solar space conditioning (SHAC) study. Costs were derived for the Omaha facility using the "peaker" method similar to that outlined by Cicchetti and Gillen in their study of the Central Maine Power Company<sup>35</sup> which consists of three basic steps described below.

1. Marginal Generating and Transmission Costs

First the marginal generating unit is identified. Here, as in most utilities, the marginal generating unit is a 50 MW gas combustion turbine. The per KW installed cost of the unit is adjusted for outage rate and annualized by application of a capital recovery factor and added to annual operation and maintenance costs per KW to arrive at a total yearly cost per KW generated. This figure is adjusted upward to cover reserve margin and line losses to develop a generating capacity cost per KW used by the consumer. To this generating capacity cost are added marginal transmission and distribution costs<sup>36</sup> to get a total capacity cost per KW consumed at the margin.

## 2. Determination of Pricing Periods

Since capacity costs must be spread over those periods in which demand taxes the utility's generating equipment, it is necessary to identify such periods. The ideal way to make such a determination is to select those periods with significant loss-of-load probabilities (LOLP - the expected value of system outage) as peak or shoulder periods. Data for these determinations, EPRI's Synthetic Electric Utility Systems for Evaluating Advanced Technologies,<sup>37</sup> however, did not provide LOLP information. Since LOLP is related to system load<sup>38</sup> it is possible to make the allocations based upon hourly loads which were available.<sup>39</sup> Once capacity costs and rate periods have been determined the capacity costs applicable to each period are merely divided by the number of hours in the period to arrive at a kWh rate for capacity in each period.

## 3. Calculation of Period Energy Costs

This consists of selecting the relevant (most costly to operate) unit in each of the rating periods, which, along with the combustion turbine "peaker" included a 200 MW oil unit in the shoulder period and a 400 MW coal-fired plant during the base or off-peak period, and then using the applicable fuel costs and heat rates for these machines to arrive at cost per kWh generated. This is adjusted for line losses to arrive at a cost per kWh delivered to the end user. Heat rate data were taken from the EPRI Synthetic Utility data, and Nebraska fuel prices were found in the Edison Electric Institute's Statistical Yearbook, 1976.<sup>40</sup>

Costs per kWh for capacity and energy are then summed for each period to arrive at the marginal cost. Rates used for each utility simulated are summarized in Tables 2-4. These rates are not strictly the marginal costs calculated above but rather the marginal costs adjusted in the second step of the procedure mentioned earlier. This adjustment was necessary for two reasons. First, our method of calculating marginal costs ignored what are often called consumer-related charges such as the cost of metering, etc. Second, adjustment was thought to be necessary to assure that utility revenues would not fall or rise substantially in the short run. Since the utility companies' capital commitments would not be altered in the short run because of a shift to a time-of-day rate, their revenue requirements to cover expenses, investor return, etc. would also be unaltered. Marginal costs are determined without regard to revenue requirements, and thus rates based solely upon marginal costs might result in short-run revenue deficiencies.<sup>41</sup>

In order to make the necessary adjustment the simulation model was run with a rate structure reflecting only marginal costs. On this basis a utility bill for the simulated owner's entire energy consumption (this required pricing of the energy used from the PV system as if it were purchased instead from the utility company) was calculated and compared to the typical utility bill for a customer of the same utility company (based on existing declining block rates) in a comparable monthly consumption range as reported in the FPC's Typical Electric Bills,

Table 2

## BOSTON TIME-OF-DAY RATE STRUCTURE

	<u>Peak</u>	<u>Base</u>
Total Price (¢/kWh)	6.73	2.60
Capacity	4.04	.32
Fuel	2.69	2.28
Year-Round:	<u>Peak</u>	<u>Base</u>
Weekdays	7 a.m. - 9 p.m.	10 p.m. - 6 a.m.
Weekends		All day
Holidays		All day

Table 3

OMAHA TIME-OF-DAY RATE STRUCTURE			
	<u>Peak</u>	<u>Shoulder</u>	<u>Base</u>
Total Price (¢.kWh)	4.70	2.26	0.84
Capacity	3.36	0.67	0.00
Fuel	1.34	1.59	0.84
Spring: 3/1 - 5/31			
	<u>Peak</u>	<u>Shoulder</u>	<u>Base</u>
Weekdays		7 am - 12 m	1 am - 6 am
Weekends		7 am - 12 m	1 am - 6 am
Holidays		7 am - 12 m	1 am - 6 am
Summer: 6/1 - 8/31			
	<u>Peak</u>	<u>Shoulder</u>	<u>Base</u>
Weekdays	10 am - 9 pm	8 am - 9 am, 10 pm - 12 m	1 am - 7 am
Weekends		8 am - 12 m	1 am - 7 am
Holidays		8 am - 12 m	1 am - 7 am
Winter: 9/1 - 2/28			
	<u>Peak</u>	<u>Shoulder</u>	<u>Base</u>
Weekdays	9 am - 10 pm	6 am - 8 am, 11 pm - 12 m	1 am - 5 am
Weekends		6 am - 12 m	1 am - 5 am
Holidays		6 am - 12 m	1 am - 5 am

Table 4

## PHOENIX TIME-OF-DAY RATE STRUCTURE

	<u>Peak</u>	<u>Base</u>
Total Price (¢/kWh)	20.05	2.43
Capacity	16.82	.38
Fuel	3.23	2.05
Winter: 11/1 - 3/31	<u>Peak</u>	<u>Base</u>
Weekdays		All day
Weekends		All day
Holidays		All day
Summer: 4/1 - 10/31	<u>Peak</u>	<u>Base</u>
Weekdays	2 pm - 5 pm	6 pm - 1 pm
Weekends		All day
Holidays		All day

1976.42 If the simulated bill was below (above) the typical bill the rates were adjusted upward (downward), while maintaining constant period-to-period price ratios, so that the bills were equalized. Figure 8 presents the adjustment formula and Figure 9 demonstrates the adjustment calculation for the Boston rate structure.

Figure 8

## FORMULA FOR REVENUE RETURN EQUALIZATION

DATA: TB = ¢/KWH (TYPICAL ELECTRIC BILLS FOR JANUARY FOR A  
SPECIFIC CITY)

B/P = BASE-LOAD TO PEAK-LOAD PRICE RATIO

PBUY = KWH BOUGHT ON-PEAK

PSTL = KWH SOLAR-TO-LOAD ON-PEAK

BBUY = KWH BOUGHT OFF-PEAK

BSTL = KWH SOLAR-TO-LOAD OFF-PEAK

$P_P$  = PEAK PERIOD PRICE

$P_B$  + BASE PERIOD PRICE

THEN:

$$P_P = \frac{(TB)(PBUY + PSTL + BBUY + BSTL)}{(PBUY + PSTL) + \left(\frac{B}{P}\right)(BBUY + BSTL)}$$

$$P_B = \left(\frac{B}{P}\right)P_P \cdot$$

Figure 9

## RATE STRUCTURE ADJUSTMENT CALCULATION FOR BOSTON

$$TB = 4.48 \text{ ¢/KWH}$$

$$B = 1.94 \text{ ¢/KWH}$$

$$P = 5.01 \text{ ¢/KWH}$$

$$B/P = .387$$

$$P_P = \frac{(4.48)(1153.2)}{(5064.2) + (.387)(6089)} = 6.73\text{¢/KWH}$$

$$P_B = (.387)(6.73) = 2.60\text{¢/KWH}$$

$$PCAP = 4.04$$

$$PFUEL = 2.69$$

$$BCAP = 0.32$$

$$BFUEL = 2.28$$

ASSUMES ADJUSTMENT IS EQUALLY DISTRIBUTED

BETWEEN CAPACITY AND FUEL COMPONENTS

## 3.4 FOOTNOTES

1. Carpenter, Paul, and Tabors, Richard, Solar Photovoltaic Planning Regions, MIT Energy Laboratory, Cambridge, MA (forthcoming).
2. For example, the National Electric Reliability Council electric power regions are hopelessly gerrymandered, cutting across numerous state boundaries.
3. For a detailed description of the theory underlying factor analysis and its use, see R.J. Rummel, Applied Factor Analysis, Northwestern University Press, Evanston, IL, 1970.
4. This model was adapted by Jesse Tatum of the MIT Energy Laboratory from the array model developed by General Electric Co. in their study, Requirements Assessment of Photovoltaic Electric Power Systems, RP-651-1 for Electric Power Research Institute, Final Report, June 1977.
5. This is not an optimization in the strict sense, which would require a weather-forecasting capability, but rather a simple procedure to make reasonably efficient use of the solar electricity.
6. A load's condition (i.e. "runnable," "must run" etc.) is determined by behavioral parameters in the load vector (discussed below) and whether or not the load has already been supplied.
7. These assumptions are described in detail in Section 4.1.
8. These assumptions are described in detail in Section 4.1.
9. Subsystem cost assumptions are outlined in Section 4.3.
10. Boes, E.C. et al. Availability of Direct, Total, and Diffuse Solar Radiation to Fixed and Tracking Collectors in the U.S.A., Sandia Laboratories, Report No. SAND77-0885, 1977.
11. It must be remembered that the "net" figure has all fixed subsystem costs removed, an unfortunate reliance on estimated costs.
12. This seems an entirely reasonable assumption over the narrow range of relevant array sizes.
13. By charging storage at low rates (i.e. off-peak) and using the energy to displace expensive peak consumption.

14. This relationship would persist so long as both are competing as peak-shaving devices. Should PV ever compete as baseload generation, storage would become a complementary device.
15. U.S. Department of Energy, Division of Solar Technology, National Photovoltaic Program Plan, Washington, D.C., February 2, 1978, p. 18.
16. National Oceanic and Atmospheric Administration, U.S. Department of Commerce, Hourly Solar Radiation - Surface Meteorological Observations SOLMET Vol. 1 - User's Manual, NOAA Environmental Data Service, Asheville, N.C., December 1977.
17. While typical insolation years were selected, no effort was made to evaluate the typical years from a thermal or cooling perspective. There is some a priori reason to suspect that years with high insolation would have high cooling requirements, but this certainly depends on the region.
18. Equations taken from Boes, E.C., et al., op. cit.
19. Lighting loads were developed from information contained in Federal Energy Administration, A Study of the Electric Utility Industry Demand, Costs, Rates, Washington, D.C., Conservation Paper No. 53, July 1976, and Dole, Stephen H., Energy Use and Conservation in the Residential Sector: A Regional Analysis, R-1641-NSF, Rand Corporation, Santa Monica, CA, June 1975.
20. The air-conditioning load (unlike other loads) is simulated in the manner summarized in Figure 6 so that the load is dependent upon the weather. Information on consumption and thermal integrity factors for residences used in the simulation was obtained from Dole, Stephen H., Ibid.
21. General Electric Co., Conceptual Design and Systems Analysis of Photovoltaic Systems, G.E. Space Division for ERDA/Sandia, Albuquerque, NM, March 19, 1977.
22. Because of model limitations the unit was simulated to run one half hour each hour at a rate lower than 615W to approximate the correct consumption. See explanation in note 24 below.
23. See Section 3.3.3.
24. Since the smallest time increment recognized by the model was 30 minutes, it was not possible to directly schedule the 20 minute/hour load for the refrigerator discussed above. Scheduling for a 30-minute load at a lower consumption rate accomplishes the same result.  $615W \times 20+ \text{ min/hr} = 210 \text{ W/hr.}$

25. The "forego" option was not used for any of the loads used in this study because its use implies energy conservation on the part of consumers (the obvious result of not using an appliance) and because we wanted to remain on the conservative side vis-a-vis consumer flexibility of consumption. The option could be used to simulate very flexible consumers.
26. See Uhler, Robert G., Electric Utility Rate Design Study, Rate Design and Load Control, Palo Alto, CA, September 1977, Chapter 1, pp. 9-10.
27. Prices to consumers in the 500-1000 KWh/month range (average consumers) have risen 85-90% from 1970 to 1976, or 10-11% per year. See Federal Power Commission, Typical Electric Bills, 1976, Washington, D.C., 1976, p. xi.
28. See Uhler, Robert, op. cit. Also Cicchetti, C.J. and Gillen, W.J., A Marginal Coast Analysis for Electricity, A Case Study of the Central Maine Power Co. for the Attorney General of Maine under a grant from the New England Regional Commission, January 1977, pp. 7-9.
29. Load factor is the ratio (expressed as a percentage) of average demand to peak demand. The load factor for the utility industry has declined fairly steadily from 64.1 in 1969 to 61.4 in 1975. See Federal Energy Administration, Electric Utility Rate Design Proposals, Washington, D.C., February 1977, p. 53.
30. Reserve margin is the ratio (expressed as a percentage) of unused capacity to peak load. U.S. utility reserve margins rose from 46.4 to 50.0 in the period 1970-1976. See Uhler, Robert, op. cit., p. 15.
31. Federal Energy Administration, Electric Utility Rate Design Proposals, op. cit., p. 53.
32. Federal Energy Administration, A Study of Electric Utility Rates and Demands, Costs, and Rates, op. cit., Sections I and II.
33. See the Energy Conservation and Production Act (Pub. L. 94-385) Title SS 203(a).
34. Feldman, S.L. and Anderson, B., Utility Pricing and Solar Energy Design, Clark University, Worcester, MA, NSF/RANN-760406, September 1976.
35. Cicchetti, C.J. and Gillen, W.J., op. cit., pp. 49-64.

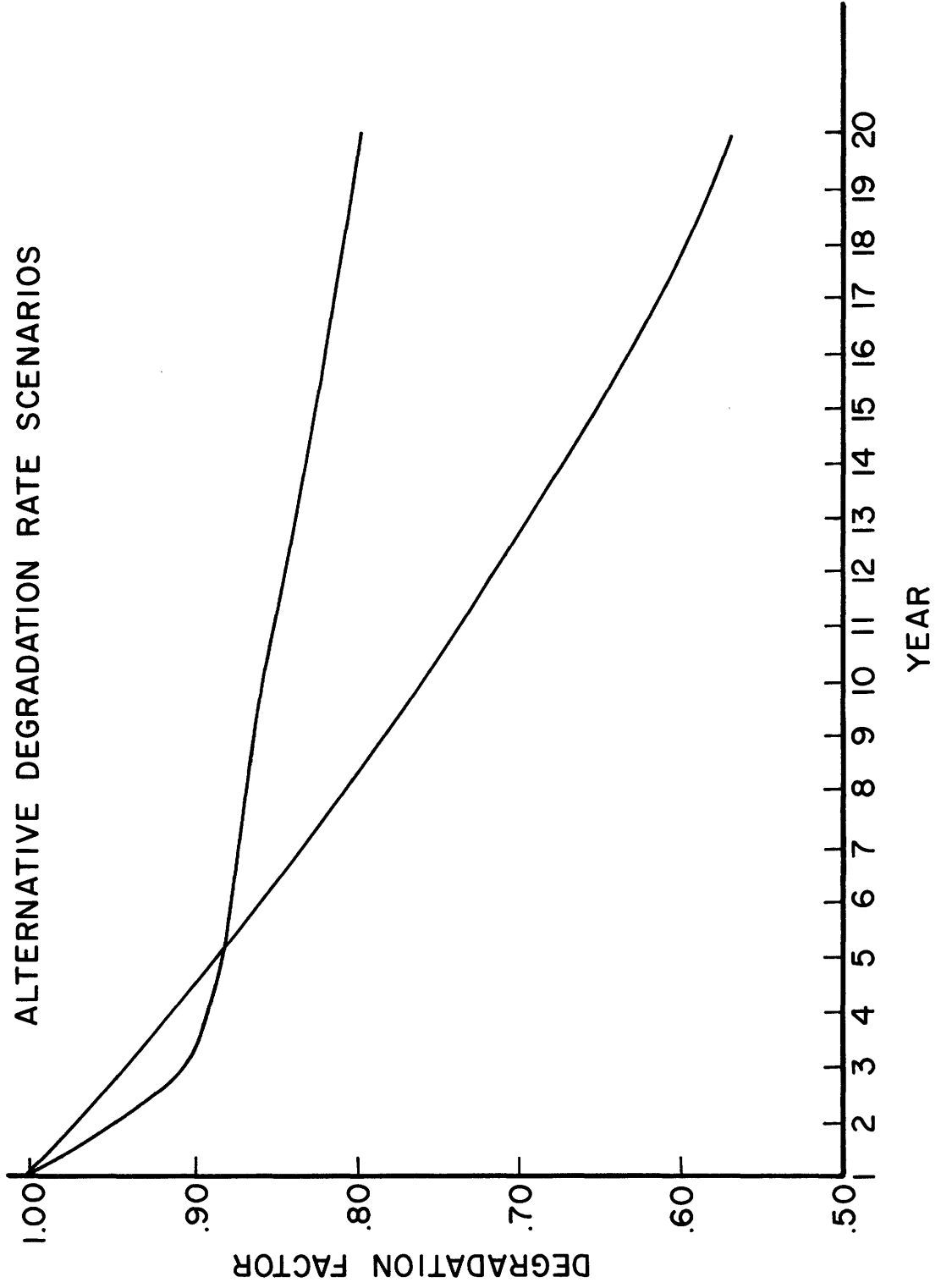
36. Since transmission and distribution costs differ substantially across classes of consumers, marginal T&D costs are normally calculated by regressing new (as opposed to replacement) capacity investments against demand by consumer class over some historical period to achieve proper classwise allocation of costs. This was impossible since the EPRI data (see note 37) had no historical cost or demand information so T&D costs were simply estimated.
37. Electric Power Research Institute, Synthetic Electric Utility Systems for Evaluating Advanced Technologies, prepared by Power Technologies, Inc. for EPRI, Palo Alto, CA, February 1977. A synthetic utility approximating the Omaha system was used rather than actual data because time did not allow collection of the latter and only a reasonable facsimile of the appropriate rates was necessary.
38. The relationship is nonlinear with LOLP falling off very rapidly as load declines.
39. Demarcations were made at approximately 80% and 50% of yearly peak load for peak and shoulder periods respectively.
40. Edison Electric Institute, Statistical Year Book of the Electric Utility Industry for 1976, 90 Park Avenue, NY 10016, October 1977.
41. Such deficiencies would be expected to disappear in the long run as shifting consumer demand patterns allowed more efficient use of existing plant and alteration of the generation mix itself.
42. Federal Power Commission, op. cit.

#### IV. ECONOMIC MODEL INPUTS AND SENSITIVITY ANALYSIS ASSUMPTIONS

##### 4.1 FUEL PRICE ESCALATION AND CELL DEGRADATION RATE

The one-year results of the residential simulation were adjusted to take into account rising electrical prices and declining cell output (or degradation) over the life of the PV system. Forecasting future electrical rates in utility systems is a difficult dynamic problem discussed later in the study.<sup>1</sup> To avoid this problem a constant utility generating mix has been assumed and rates have been projected by applying a fuel-escalation factor to the portions of the time-of-day rates which reflect fuel costs. The base case assumes that fuel costs will climb at a 3% per year real rate (above inflation). For comparison purposes runs were also done at a 0% real growth rate in fuel prices. Cell degradation is a fairly unknown factor at this stage of PV development.<sup>2</sup> It is known that degradation occurs, but data are insufficient to determine accurately its pattern over the array lifetimes presently contemplated. For our base case calculations, available output was calculated to decline 3% each year. Thus, at the end of the 20-year period the array is delivering only about 56% of its original performance<sup>3</sup>. The baseline results are thus fairly conservative. A less conservative yet likely scenario,<sup>4</sup> depicted graphically in Figure 10, was run as a comparison. In this version array output declines rapidly in the earlier years (5% in the second and third years) and then stabilizes with a very slow decline (.7% per year) thereafter so that the

FIGURE 10  
ALTERNATIVE DEGRADATION RATE SCENARIOS



array is producing approximately 80% of its original output after 20 years.

#### 4.2 DISCOUNT RATE

Discounting of future costs or energy savings can be treated in various manners. Studies concentrating on utility ownership scenarios even though applications were dispersed<sup>5</sup> have naturally relied upon utilities "cost of capital."<sup>6</sup> Residential studies have used the mortgage interest rate as a discount rate.<sup>7</sup> Some might argue that since the ultimate concern of this study is government expenditure policy, a social discount rate should be applied in comparing outlays and benefits.<sup>8</sup> Finally, current finance theory would suggest the use of the investors' opportunity cost of capital as the appropriate rate.

The market indifference point methodology used in this analysis eliminates consideration of both the utility cost of capital and the social discount rates for valuation purposes. While the PV system is utility-grid integrated, the homeowner is making the investment decision, not the utility company. The utility cost of capital has no relevance. A social discount rate is similarly irrelevant because the immediate concern is not societal but rather individual investment decisions. Understanding these individual investment decisions will, it is hoped, shed light on governmental subsidy expenditure options which should be evaluated on the basis of the social rate. For now, however, the individual homeowner is the primary concern.

Studies to date of dispersed residential user-owned units<sup>9</sup> have employed the mortgage interest rate as a discount rate.<sup>10</sup> The justification for such an approach appears to be the assumption that this would be the cost of capital to the homeowner in a scenario where the solar investment is financed with a standard home mortgage as part of a new-home purchase. Insofar as this approach relies upon the investor's marginal borrowing rate to establish an opportunity cost, it is not theoretically sound, because the investor's opportunity cost depends not upon the source of funds but rather upon alternative uses. The opportunity cost is the return that might be obtained through an alternative investment with risk characteristics similar to the one under consideration.<sup>11</sup> Use of the mortgage rate would be justified, then, only if the risks inherent in the PV investment<sup>12</sup> were identical to those found in home mortgage investments generally.<sup>13</sup> Thus we are faced with the question of whether or not there are differential risks between the two types of investment, or stated alternatively, whether or not there are risks inherent in the PV investment which do not apply to normal mortgage investments and which therefore imply use of some other higher or lower opportunity cost as a discount rate.

Before pursuing this question any further a discussion of the nature of risk and the risk/return relationship is in order. On an intuitive level it seems obvious that investors would expect greater returns for relatively riskier investments, i.e., as an investment becomes riskier,

investors will demand greater inducements (in the form of returns) to hold on to the investment. Current finance theory has added two refinements to this intuitive picture to derive a valuation formula for investments called the capital asset-pricing model (CAPM).<sup>14</sup> The first refinement is simply a working definition of the concept of risk. Risk is represented by the variance in the returns inherent in the asset or assets underlying the investment. A risky asset then is one with a good deal of uncertainty about its return due to a wide variation in possible outcomes.<sup>15</sup> The second deviation from the intuitive picture concerns diversification and the separation of risk into two components called systematic risk and unsystematic risk. Because uncorrelated variances are not additive<sup>16</sup> it is possible to "diversify" away risk while not sacrificing return by holding combinations or portfolios of assets or investments.<sup>17</sup> Since the investor can shed, or diversify away, risk at no cost, current theorists reason that bearing "diversifiable" risk does not command increased return.<sup>18</sup> There is a limit, however, to risk reduction through diversification.\* Theoretically this limit is exemplified by a portfolio containing all possible investments in proportion to the ratio of their value to the sum of the values of all investments, the so-called market portfolio. In practical terms this

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\*Risk (variation) can be lowered beyond this limit but only at the expense of reduced return. A riskless asset, in fact, has no risk -- its return is certain.

means that risk (i.e. variance in returns) which is correlated to the risk inherent in the economy (represented by the market portfolio) as a whole cannot be shed through diversification. Thus there exists a distinction between risk correlated with market (or macroeconomy) returns, called "systematic," and "unsystematic" risk which is uncorrelated to market returns. It is only the systematic component of the risk inherent in an investment (i.e. that which can't be diversified away) and not its total risk which commands or earns increased returns. Thus the relationship between risk and return is expressed by the familiar CAPM equation

$$\bar{R}_i = R + \beta(\bar{R}_m - R)$$

where:

$\bar{R}_i$  = the expected rate of return required or allowed on investment I

R = the rate of return on "riskless" assets such as government treasury bills

$\bar{R}_m$  = the expected rate of return on the market portfolio

$\beta$  = systematic risk =

$$\frac{\text{cov}(i,m)}{\text{var}(m)} = \frac{\rho_{im} \sigma_i}{\sigma_m}$$

and

$\rho_{im}$  = the correlation coefficient between the returns of investment I and the returns on the market portfolio

$\sigma_i$  = standard deviation of the returns to investment I

$\sigma_m$  = standard deviation of the returns to the market portfolio.

When  $\beta = 0$  (when there is no systematic risk)  $\bar{R}_i = R$ , the riskless rate. When  $\beta = 1$  (when the variance of the returns to investment  $i$  is both equal to and perfectly correlated with the market return)  $\bar{R}_i = \bar{R}_m$ .

The significance of this theoretical digression is that  $R_i$  represents the opportunity cost of capital for an investment and hence the appropriate discount rate to be applied to the cash returns to that investment. In an efficient financial market all investments with similar risk characteristics (i.e. with equal  $\beta$ 's) should garner this same return. Returning to our concern about the appropriateness of the mortgage interest rate as a discount rate, the clear implication of the preceding discussion is that such an application is appropriate only if the  $\beta$  of the PV investment is equal to the  $\beta$  of mortgage-type investments in general. This depends upon whether or not there is systematic risk inherent in the PV system not common to the assets to which the mortgage rate is now normally applied. The existence of such differential systematic risk would imply the use of some discount rate other than the mortgage rate.<sup>19</sup>

Variation in the returns to a PV system which would not affect mortgage assets generally are of two types: variation in physical output

and variation in the value of PV system output. The primary determinants of uncertainty as to system output are insolation and various forms of technical failure of the PV system. System output depends upon available sunlight (insolation) in the locality, an extremely variable commodity. Since the relevant factor is local insolation in a very narrow sense (strictly that falling upon the specific PV array being valued), the associated risk has been assumed to be unsystematic and uncorrelated to economic activity in general. This assumption has also been applied to output variance due to technical factors. System lifetime might be shorter than anticipated. Degradation<sup>20</sup> might be higher than expected. Myriad component failures are possible, but all such deficiencies are hardware-related and would be completely determined by factors internal to the system itself. Hence an assumption of unrelatedness to market activity seems entirely reasonable.

Variation in the valuation of the physical output of the PV system presents a more complex problem. Output valuation depends upon the electricity prices faced by the potential PV owner. Since it is not at all difficult to imagine that there might be some connection between electricity prices charged by utility companies and economic activity generally, it is necessary to abandon simple assumptions and attempt to quantify any relationship that might exist. As noted earlier system returns or benefits depend upon electricity prices. If it is assumed that this relationship is proportional,<sup>21</sup> then historical changes in

the price of electricity provide a reasonable proxy for variations in return from the PV investment, and the correlation between PV and market returns can be estimated through regression analysis of historical time series of electricity prices and market returns.

Data on market returns for this analysis were taken from the work by Ibbotson and Sinquefeld<sup>22</sup> and consist of historical returns on a market portfolio<sup>23</sup> from 1926-1974. Electrical prices for the relevant years were obtained from the Federal Power Commission's Typical Electric Bills 1976.<sup>24</sup> These prices represent the national weighted average cost per kilowatt hour paid by residential consumers using approximately 500 kWh/month. Since the setting of electrical prices is regulated and there may be substantial delays in the regulatory process, electricity prices cannot be expected to respond quickly to economic changes.<sup>25</sup> This requires that movements in market returns be compared to electricity prices not only in the current year but also to prices for several years following to compensate for the lag in price response. Fortunately this creates few analytical problems since separate regressions can be run with the relevant lags and the resulting regression coefficients summed to get  $\beta$ .

Regressions were run representing price lag times from zero through four years and it appears that while there are delays in electrical price response, the delay does not generally exceed two years. The results, summarized in Table 5, show price movements correlated to market changes

Table 5

## REGRESSION RESULTS, ZERO TO FOUR YEAR LAG

Lag	Regression Coefficient	T-Statistic	R2
0	-0.059	-1.82	0.13
1	-0.161	-2.96	0.28
2	-0.123	-1.88	0.13
3	-0.016	-0.21	0.00
4	-0.036	-0.50	0.01

Table 6

## REGRESSION RESULTS, FUEL CRISIS COMPENSATED

Lag	Regression Coefficient	T-Statistic	R2
0	-0.002	-0.05	0.46
1	-0.080	-1.90	0.64
2	-0.078	-1.79	0.64

for two years following the market movements but little of significance after that time. Inspection of the residuals showed 1974 and 75 to be substantial outliers. This led to the inclusion of a dummy variable representing the fuel crisis in 1973-75.<sup>26</sup> The results from this procedure with up to 2 years lag time are shown in Table 6. As is obvious from the R<sup>2</sup> figures the addition of the fuel crisis variable improved the fit of the regression line but in doing so reduced both the magnitude and significance of the coefficients for the market returns. Summing the significant<sup>27</sup> coefficients estimated with the two approaches results in  $\beta$ s of  $-.16$  and  $-.34$  respectively including and not including the fuel crisis dummy. It is clear that what correlation there is is negative.

The implication of negatively correlated variation (i.e. negative  $\beta$ ) is that the return to the PV investment dependent upon electrical prices tends to behave just the opposite of the economy as a whole: its value goes up just when everything else tends to be going badly. A possible explanation for this might be that rising electricity prices, while increasing the value of a PV system, tend to depress the economy in general. Investment in a PV system in a sense can be viewed as an insurance policy or hedge against rising electricity prices. An investor might be expected to pay for such protection or insurance by accepting a lower return on the investment. Returning to the CAPM equation presented on page we find this to be exactly the case. With positive risk

premia<sup>28</sup> (i.e.  $\bar{R}_m - R$ ), negative  $\beta$ s result in an appropriate PV discount rate which is lower than the riskless rate,  $R$ .<sup>29</sup>

Given the difficulty in estimating  $\beta$  accurately and the fact that great caution should be used in the extrapolation of historically derived parameters to future events, it should not be argued that the  $\beta$  estimates determined in the regression analysis allow definitive identification of an appropriate PV discount rate.<sup>30</sup> On the other hand, the establishment of an upper bound for a discount rate does seem justifiable under the circumstances. The apparent value of a PV system as a hedge against rising fuel prices substantiated by the negative correlation of the PV system returns to market returns suggest that the appropriate rate would certainly be no higher than the riskless rate, or approximately 6% (nominal). Use of a higher rate such as the mortgage interest rate would underestimate the true value of the PV investment to the consumer/owner.

The discussion to this point has concerned itself with nominal before-tax rates of return. Since returns to the photovoltaic system come in the form of savings (i.e. reductions in the utility electric bill), they are not subject to taxation and thus represent after-tax cash flows which should be discounted at an after-tax rate.\* Interest

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\*This discussion involves only personal income taxes. Property taxes would be relevant to PV breakeven values but these have been presumed to be zero because: 1) these will vary from region to region and 2) state and federal legislators are moving to exempt solar investments from property taxes.

payments are tax-deductible to the individual investor, so the pre-tax rate is normally reduced in proportion to the investor's marginal tax rate to obtain the after-tax rate.<sup>31</sup> This is proper adjustment only where the PV system cost is financed entirely by the mortgage loan,<sup>32</sup> however, and since 100% financing is not generally the case (i.e. a "down payment" of a material size is required) such an adjustment overstates the tax subsidy by lowering the discount rate too far. Since only that portion of the cost financed with debt receives a tax subsidy, the appropriate adjustment is  $r = R_i(1 - \lambda T)$  where  $\lambda$  represents the proportion of the investment covered by the mortgage and/or other loans. Where, for instance, a 10% down payment is made and investor's marginal tax rate is 25%, the adjustment becomes

$$r = R_i [1 - .9(.25)] = .775R_i$$

A final adjustment necessary to arrive at the rate to be applied to energy savings is the conversion from a nominal to a real rate. The savings calculated by the simulation model are in constant dollars (1976) and should therefore be discounted at a real rate. To this end an adjustment of the form

$$\rho = \frac{1 + r}{1 + I} - 1$$

where  $r$  is defined as above and  $I$  is the inflation rate. Thus the combined adjustment to convert to a real, after-tax discount rate is

$$\rho = \frac{1 + R_i(1 - \lambda T)}{1 + I} - 1$$

where, again,  $R_i$  represents the return rate which properly reflects the risk of the investment.

Table 7 contains values of  $\rho$  over the conceivable ranges of  $\lambda$  and  $T$  for the riskless rate discussed above as an upper limit for  $R_i$ . Values range from 1%-4%,<sup>33</sup> and for typical values of  $\lambda$  and  $T$  (the unshaded portion of Table 7),  $\rho$  falls between approximate values of 0% and 2.5%. Thus for most investors the real after-tax discount rate is 0% or negative. Table 8 shows the estimates for  $\rho$  resulting from the use of the mortgage interest rate as a value for  $R_i$ , and with this higher rate  $\rho$  is bracketed by 2.2% and -1.2% for reasonable values of  $\lambda$  and  $T$ . Because of the controversial nature of valuation with a zero or negative discount rate, the base case includes a 3% real rate which reflects the higher end of the range of values of  $\rho$  using the mortgage interest rate. Sensitivity analysis includes valuation using a real discount rate of 0.0% which actually appears to be the more appropriate of the two, given the available evidence.

#### 4.3 SUBSYSTEM COSTS

All non-array costs have been collected in this inaccurately named parameter. The classification includes hardware needed to complete the PV system (power conditioning, wiring, switches and etc.) and install it (support structure, safety devices, and etc.). Shipping (packaging, freight, insurance), distribution (storage, distribution and dealer mark-ups) and installation costs (architectural and engineering designs,

**TABLE 7**  
**DISCOUNT RATES REFLECTING TAX**  
**AND INFLATION ADJUSTMENTS:**  
**RISK-ADJUSTED BASE**

MARGINAL TAX RATE, T

$\lambda$ \ T	0	.25	.50	.70
1.00	.010 * .000	-.005 -.010	-.019 -.028	-.035 -.041
.95	.010 * .000	-.004 -.013	-.018 -.030	-.029 -.038
.90	.010 * .000	-.003 -.013	-.016 -.026	-.027 -.036
.75	.010 * .000	-.001 -.011	-.012 -.021	-.021 -.030
.50	.010 * .000	.002 -.007	-.005 -.014	-.011 -.020

$R_f = .06$

PROPORTION OF COST FINANCED,  $\lambda$

\* UPPER AND LOWER SECTIONS OF EACH BOX REFLECT RESPECTIVELY 5% AND 6% INFLATION RATES

**TABLE 8**  
**DISCOUNT RATES REFLECTING TAX**  
**AND INFLATION ADJUSTMENTS:**  
**MORTGAGE INTEREST BASE**

MARGINAL TAX RATE, T

$\lambda \backslash T$	0	.25	.50	.70
1.00	.038 * .028	.017 .007	-.005 -.014	-.022 -.031
.95	.038 .028	.018 .008	-.003 -.012	-.019 -.028
.90	.038 .028	.019 .009	.000 -.010	-.016 -.025
.75	.038 .028	.022 .012	.006 .004	-.007 -.016
.50	.038 .028	.027 .018	.017 .007	.008 -.001

$R_i = .09$

PROPORTION OF COST FINANCED,  $\lambda$

\* UPPER AND LOWER SECTIONS OF EACH BOX REFLECT RESPECTIVELY 5% AND 6% INFLATION RATES

building contractor), while not subsystems, are nevertheless also included. These costs must be reflected in any breakeven system cost and must therefore be subtracted out in reaching array costs.

As the length of the list above suggests, these costs are nontrivial in magnitude. As array costs are reduced, subsystem costs have a proportionately larger impact upon breakeven costs.<sup>34</sup> At some point subsystem costs rather than array costs may be the obstacle in the attempt to deliver PV systems at a competitive price to the consumer.

For the purposes of developing array breakeven figures, subsystem costs were reduced to fixed and variable components which were subtracted from gross system valuation figures. In the base case fixed costs were set at \$500 and variable costs at \$11/m<sup>2</sup>.<sup>35</sup> Because of the difficulty in estimating the various costs and because it was felt that the base levels might easily be too low, comparison runs were made at 150% of the base case fixed and variable figures, \$750 and \$16.50/m<sup>2</sup> respectively.

## 4.4 FOOTNOTES

1. See Section 6.4.
2. Degradation has in fact been ignored in previous studies of which the authors are aware.
3. Early discussions concerning definition of array lifetime included the concept that lifetime would be reached when the array was performing at 50% of its original output. The 3% is a straight line rate which accomplishes such a result over a twenty-year period used as a lifetime in simulation scenarios.
4. This version was suggested by Dr. Jeffrey L. Smith of the Jet Propulsion Laboratory's LSSA project.
5. See e.g., General Electric Co., Requirements Assessment of Photovoltaic Electric Power Systems, RP-651-1, for the Electric Power Research Institute by G.E. Electric Utility Systems Engineering Dept., Schenectady, NY. Draft Final Report, June 1, 1977.
6. This is a product of the utility's tax rate, leverage (i.e. debt-to-value ratio) and the returns required by utility equity holders. See e.g. Miller, M.H. and Modigliani, F., "Some Estimates of the Cost of Capital to the Electric Utility Industry," American Economic Review, Vol. 56, June 1966.
7. See e.g. Aerospace Corporation, Mission Analysis of Photovoltaic Solar Energy Conversion, for ERDA/Sandia, San/1101-77/1, Vol. No. 2, March 1977.
8. Social discount rate now applied by OMB fiat is 10% (real). See Office of Management and Budget Circular A94, Discount Rates to be Used in Calculating Time-Distributed Costs and Benefits.
9. E.g. Aerospace Corporation, op. cit.
10. A nominal rate not adjusted for taxes.
11. A discussion of the risk-return relationship follows in the context of the capital asset pricing model (CAPM).
12. The risk is determined by the nature of the assets underlying the investments.

13. Assuming that individual investors would expect the same return from mortgage type investments that institutional investors do. This is not a very heroic assumption if there are perfect financial markets.
14. The CAPM is based upon the work of Sharpe, Linter and Mossin. See e.g. Sharpe, W.F., "Capital Asset Prices: A Theory of Market Equilibrium under Conditions of Risk," Journal of Finance, September 1964; Linter, J., "The Valuation of Risk Assets and the Selection of Risky Investments in Stock Portfolios and Capital Budgets," Review of Economics and Statistics, February 1965; Mossin, J., "Equilibrium in a Capital Asset Market," Econometrica, October 1966.
15. There is some deviation from the intuitive here, perhaps, since risk is not equated with the probability of a "loss" or negative return. Indeed a safe investment (i.e. low variance) may be more likely to have a negative return than a risky investment with a high expected or mean return.
16. Since some of the outcomes of each of the two investments in effect cancel each other out, the variance of the combined return is less than the sum of the individual variances. See Haley, C.W. and Schall, L.D., The Theory of Financial Decisions, McGraw-Hill, Inc., New York, NY, 1972, pp. 115-117.
17. See Pogue, G.A. and Lall, K., "Corporate Finance: An Overview," Sloan Management Review, Vol. 15, Spring 1974.
18. An efficient market would not offer an inducement in terms of increased return for risk that can be avoided through diversification.
19. The current mortgage rate of around 9% implies a positive but it can be argued that the difference between the riskless rate and the mortgage rate reflects transaction and monitoring costs, maturity premia, and etc. and that the returns to land, at least, are uncorrelated with the market.
20. Degradation is the progressive decline in module efficiency over time. As yet engineers have not quantified the rate and timing to be expected.
21. Benefits/Benefits = Price/Price.
22. Ibbotson, R.G., and Sinquefeld, R.A., "Stocks, Bonds, Bills, and Inflation: Year-by-Year Historical Returns (1926-1974)," Journal of Business, January 1976, pp. 11-47.

23. Since there is no measure of the return on the entire economy, returns on the New York Stock Exchange are commonly used instead. See e.g. Ibbotson & Sinquefeld, op. cit.
24. Federal Power Commission, Typical Electric Bills 1976, FPC R88, Washington, D.C., 1976.
25. Fuel adjustment clauses in many states have made prices more responsive to certain costs but lags still exist. See Federal Energy Administration, Electric Utility Rate Design Proposals, Washington, D.C., February 1977.
26. Another independent variable was added to the regression which was one in years 1973-75 and zero in all other years. This approximates an exogenous shock in 1973 (presuming the market, at least, reacted instantly to the fuel crisis) and has continuing impact thereafter.
27. Probability (C = 0) = .9 has been used as the level of significance.
28. Nominal risk premia have historically averaged around 6%. See Ibbotson and Sinquefeld, op. cit.
29. R is generally assumed to be approximated by the return on U.S. Treasury bills which has historically just matched inflation at an average of 2.2%. In the period 1969-1974, however, the treasury bill return averaged about 6% (nominal) and this would seem to be the more appropriate value. See Ibbotson and Sinquefeld, op. cit.
30. One could easily substitute values into the CAPM equation to get what appear to be very precise values for  $R_i$ . The accuracy of such values, however, can be not better than the estimates.
31.  $r(\text{net}) = R(1 - \text{tax rate})$ .
32. Or in the case of net lenders that their investment alternatives could be completed debt-financed, an even rarer occurrence than 100% mortgage financing where the down payment is occasionally financed through a separate loan.
33. Inflation is projected at both 5% and 6%.
34. Table 14 and Tables 9, 10, and 11 demonstrate this situation. Despite the fact that smaller (5 and 15 m<sup>2</sup>) arrays are much more efficiently used by the household (and hence these smaller arrays deliver more benefit per unit), this effect is swamped by fixed sub-system costs so that breakeven figures for the smaller arrays are lower than those for larger units.

35. These figures were derived from the OTA report: Office of Technology Assessment, U.S. Congress, Application of Solar Technology to Today's Energy Needs, Washington, D.C., 1977.

## V. RESULTS AND INTERPRETATION

### 5.1 BASIC RESULTS BY ARRAY SIZE

Tables 9, 10, and 11 indicate the kWh energy transfers from solar-to-load (STL) and solar-to-grid (SELL) and as a function of array size, by time-of-day for each of the three areas examined. For the particular household loads described earlier, which are by no means small in total electricity requirements, a saturation of solar-to-load is reached in all three regions at a fairly small array size (35-45m<sup>2</sup>). Table 12 and Figure 11 present this information more precisely. In all regions a 35-45m<sup>2</sup> array provided approximately 30% of the home's electrical needs. The initial runs of the model were performed parametrically on array size since it was felt that array size optimization should be a function of economics and not of any physical "rules of thumb" concerning the home's requirements, such as the setting of peak array output equal to the peak electricity requirements. It was also thought that the economically "optimal" array size might vary by region. Interestingly, despite the wide range of air-conditioning requirements, as indicated in Table 13 and depicted in Figure 12, "optimal" array size, when the utility purchased the solar-to-grid energy at 50% of its value at the time, was approximately 35m<sup>2</sup> for all regions examined. This is in contrast to previous studies which indicated the desirability of 85-100m<sup>2</sup> array sizes for similar residential loads.<sup>1</sup> Most of these studies included electric storage in the configuration,

Table 9

ENERGY TRANSFERS FROM SOLAR ARRAY TO LOAD AND GRID  
BY TIME-OF-DAY PERIOD AND BY ARRAY SIZE: BOSTON

Array Size in m <sup>2</sup> :	5	15	25	35	45	85
KWH Transfers						
PSTL	383.3	1019.5	1482.4	1744.4	1931.0	2393.1
BSTL	121.6	418.1	688.9	887.4	1043.6	1520.9
TOTAL STL	504.9	1437.6	2171.3	2631.8	2974.6	3914.0
PSELL	30.5	148.5	464.2	980.9	1572.9	4641.1
BSELL	51.9	74.5	132.0	261.9	434.1	1427.6
TOTAL SELL	82.4	223.0	596.2	1242.8	2007.0	6068.7
TOTAL TRANSFERS	587.3	1660.6	2767.5	3874.6	4981.6	9982.7
PERCENT SOLAR GOING TO LOAD	86.0	86.6	78.5	67.9	59.7	39.2

## KEY:

PSTL: Peak-period solar-to-load transfers  
 SSTL: Shoulder-period solar-to-load  
 BSTL: Base-period solar-to-load  
 PSELL: Peak-period sellback to grid  
 SSELL: Shoulder-period sellback  
 BSELL: Base-period sellback

Table 10

ENERGY TRANSFERS FROM SOLAR ARRAY TO LOAD AND GRID  
BY TIME-OF-DAY PERIOD AND BY ARRAY SIZE: OMAHA

Array Size in m <sup>2</sup> :	5	15	25	35	45	85
KWH Transfers						
PSTL	323.4	861.2	1170.3	1359.1	1492.6	1868.1
SSTL	377.6	1069.4	1529.3	1799.2	1999.5	2518.9
BSTL	11.6	34.8	58.0	81.7	110.7	187.6
TOTAL STL	712.6	1965.4	2757.6	3240.0	3602.8	4574.6
PSELL	3.1	118.4	462.3	926.6	1446.0	3694.4
SSELL	15.6	110.2	436.8	953.3	1539.3	4156.0
BSELL	1.9	5.7	9.4	12.6	10.7	37.0
TOTAL SELL	20.6	234.3	908.5	1892.5	2996.0	7887.4
TOTAL TRANSFERS	733.2	2199.7	3666.1	5132.5	6598.8	12462.0
PERCENT SOLAR GOING TO LOAD	97.2	89.3	75.2	63.1	54.6	36.7

Table 11  
 ENERGY TRANSFERS FROM SOLAR ARRAY TO LOAD AND GRID  
 BY TIME-OF-DAY PERIOD AND BY ARRAY SIZE: PHOENIX

Array Size in m <sup>2</sup> :	5	15	25	35	45	85
KWH Transfers						
PSTL	117.7	317.7	491.8	646.4	783.3	1258.0
BSTL	662.1	2296.4	3493.5	4256.5	4873.2	7287.6
TOTAL STL	779.8	2614.1	3985.3	4902.9	5656.5	8545.6
PSELL	0.0	35.4	96.8	177.6	276.2	743.3
BSELL	187.8	253.3	756.0	1692.8	2775.9	7160.6
TOTAL SELL	187.8	288.7	852.8	1870.4	3052.1	7903.9
TOTAL TRANSFERS	967.6	2902.8	4838.1	6773.3	8708.6	16449.5
PERCENT SOLAR GOING TO LOAD	80.6	90.1	82.4	72.4	65.0	52.0

Table 12

CONTRIBUTION OF SOLAR ELECTRICITY TO  
RESIDENTIAL ELECTRICITY NEEDS (PERCENT)

<u>Array Size (m<sup>2</sup>)</u>	<u>Boston</u>	<u>Omaha</u>	<u>Phoenix</u>
5	4.6%	6.0%	4.3%
15	12.9	16.4	14.5
25	19.5	23.0	22.0
35	23.6	27.0	27.0
45	26.7	30.0	31.2
85	35.0	38.1	47.0

FIGURE II

CONTRIBUTION OF SOLAR TO RESIDENTIAL LOAD VS. ARRAY SIZE  
(NO STORAGE)

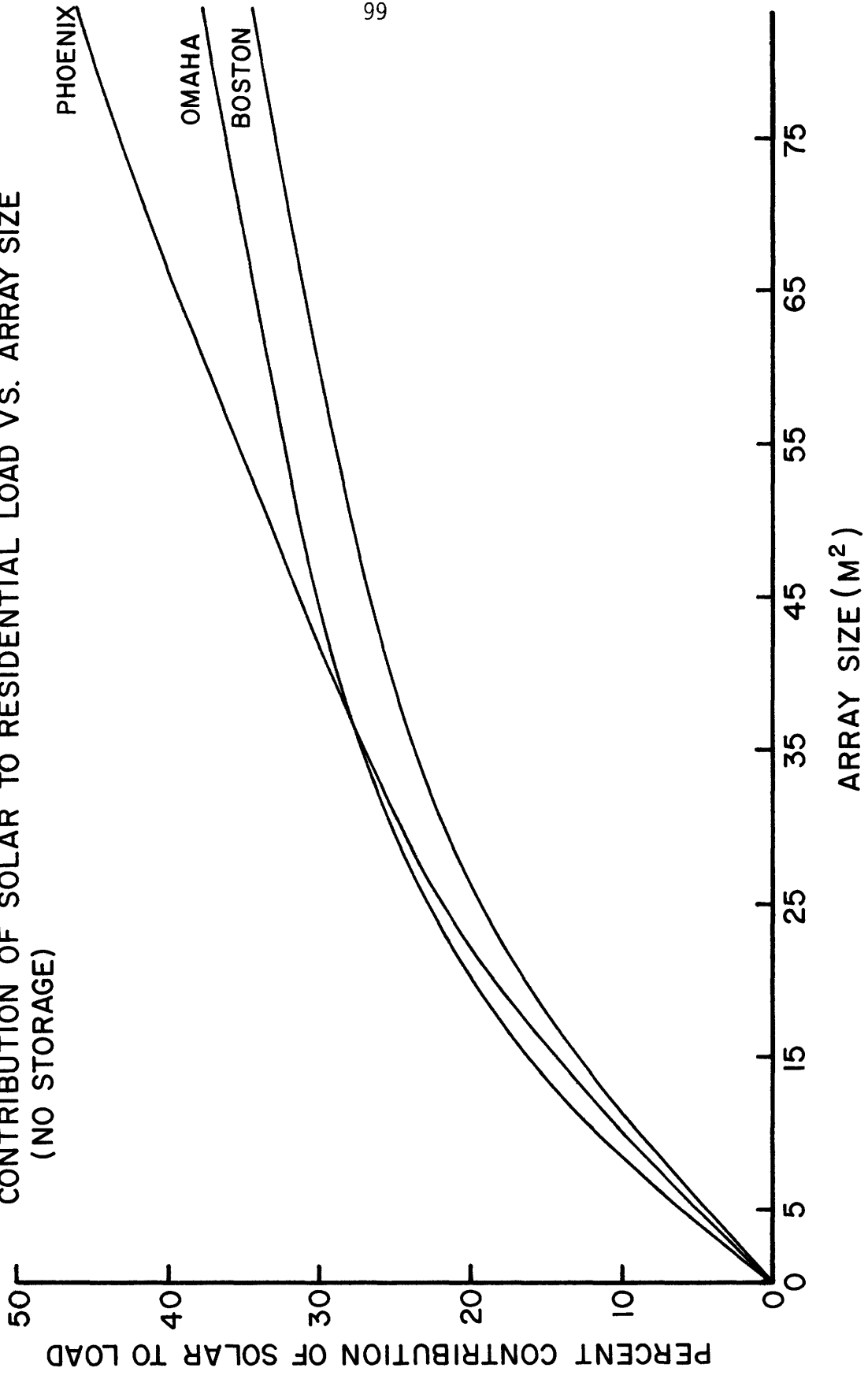


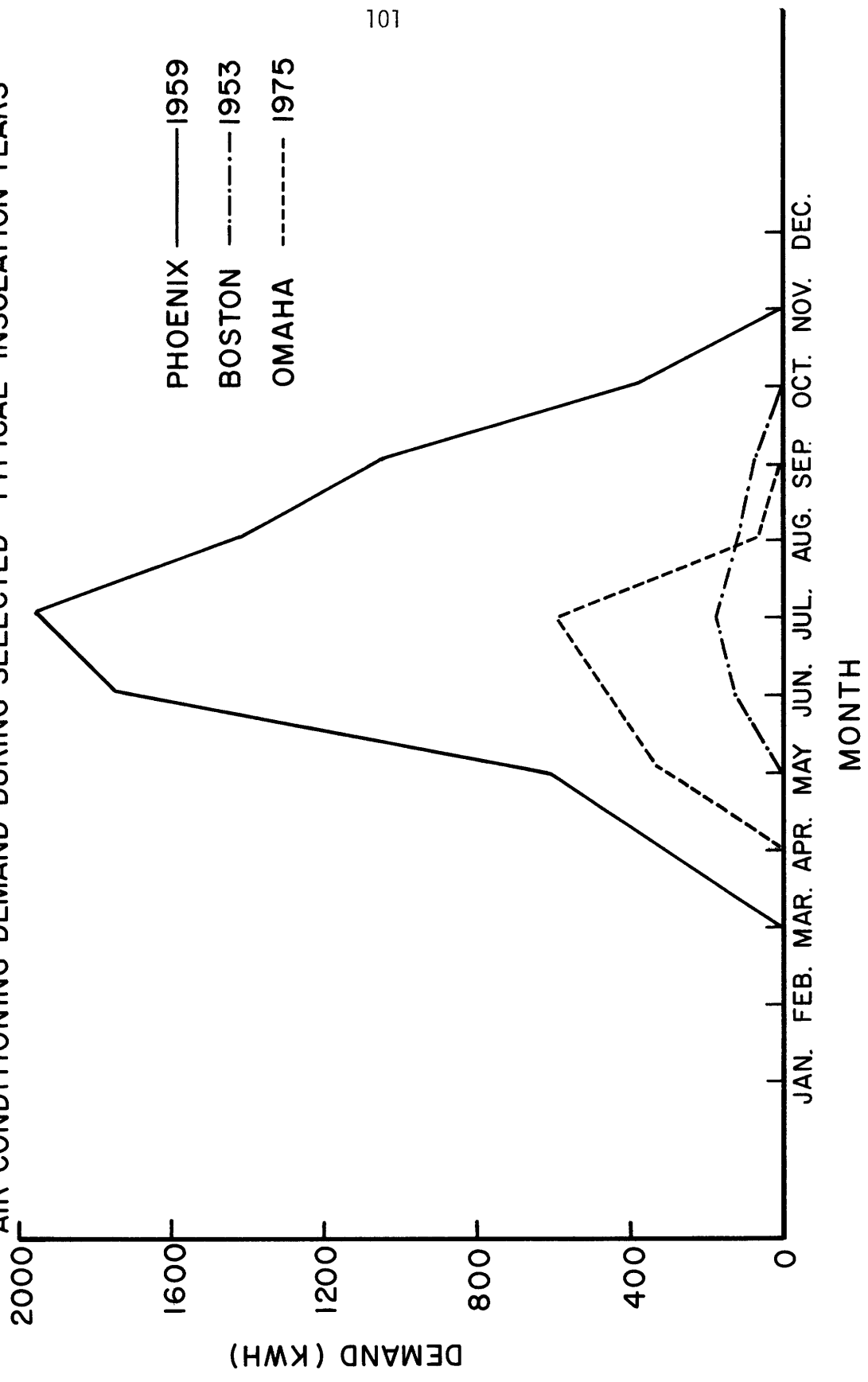
Table 13

MONTHLY AIR-CONDITIONING DEMAND DURING  
"TYPICAL" SOLAR RADIATION YEARS

Month	Boston <u>(kwh)</u>	Omaha <u>(kwh)</u>	Phoenix <u>(kwh)</u>
Jan.	0	0	0
Feb.	0	0	5
Mar.	0	0	0
Apr.	0	0	315
May	5	320	630
June	138	465	1750
July	170	490	1955
Aug.	130	55	1412
Sept.	78	15	1078
Oct.	0	0	370
Nov.	0	0	0
Dec.	0	0	0
TOTAL	520	1345	7515
U-Value <sup>1</sup> (w/°C)	259	275	404
Cooling Deg. Hrs.	9241	16593	44927

<sup>1</sup>Calculated based on Dole (Ref. 13) for typical thermal integrity factors of homes in each region.

FIGURE 12  
 AIR CONDITIONING DEMAND DURING SELECTED "TYPICAL" INSOLATION YEARS



however, and thus these results would indicate that the absence of storage would have a significant effect upon optimal array size.

Table 14 and Figures 13, 14, and 15 present these results for two scenarios, 50% sellback and 0% sellback (meaning that excess energy is wasted from the homeowner's point of view). Recall that the numbers presented in these tables represent module breakeven capital costs which are net of installation, subsystem, O&M, and product markup costs. With 0% sellback the "optimal" array size in each of the three regions is somewhat smaller (as might be expected), approximately 25m<sup>2</sup>. This implies that the utility response in the form of willingness to purchase power fed back into the grid by the homeowner may have a significant impact upon array size and thus ultimate penetration (in terms of module quantities) of the technology into the long-term market.

All results reported to this point have utilized the baseline assumptions described previously. There is a very wide range in breakeven capital costs between the regions selected. The Phoenix residential market will break even at module prices of approximately \$1.27/w(p), given the set of assumptions which went into that number, while Boston and Omaha follow at \$.68/w(p) and \$.43/w(p) respectively. While Omaha receives more sunlight in a typical year than Boston, fuel prices in Boston are significantly higher, as reflected in the rate structures. Phoenix has very desirable sunshine characteristics and the enormous cooling requirement allows the homeowner in Phoenix to take

Table 14

ARRAY SIZE VS BREAKEVEN CAPITAL COST  
EFFECT OF VARYING UTILITY BUY-BACK RATE

Array Size (m <sup>2</sup> )	BREAKEVEN CAPITAL COST (\$/wp)*					
	1953 Boston		1975 Omaha		1959 Phoenix	
	50%	0%	50%	0%	50%	0%
5	-.51	-.59	-.80	-.82	-.02	-.13
15	.50	.42	.26	.20	1.10	1.01
25	.66	.51	.40	.27	1.26	1.09
35	.68	.46	.43	.23	1.27	1.03
45	.68	.40	.44	.19	1.27	.96
85	.68	.24	.43	.09	1.24	.82

\*Note: (\$/wp) refers to system watts. See Foreword and Appendix A for more detail.

FIGURE 13

BREAK-EVEN CAPITAL COST VS. ARRAY SIZE : BOSTON

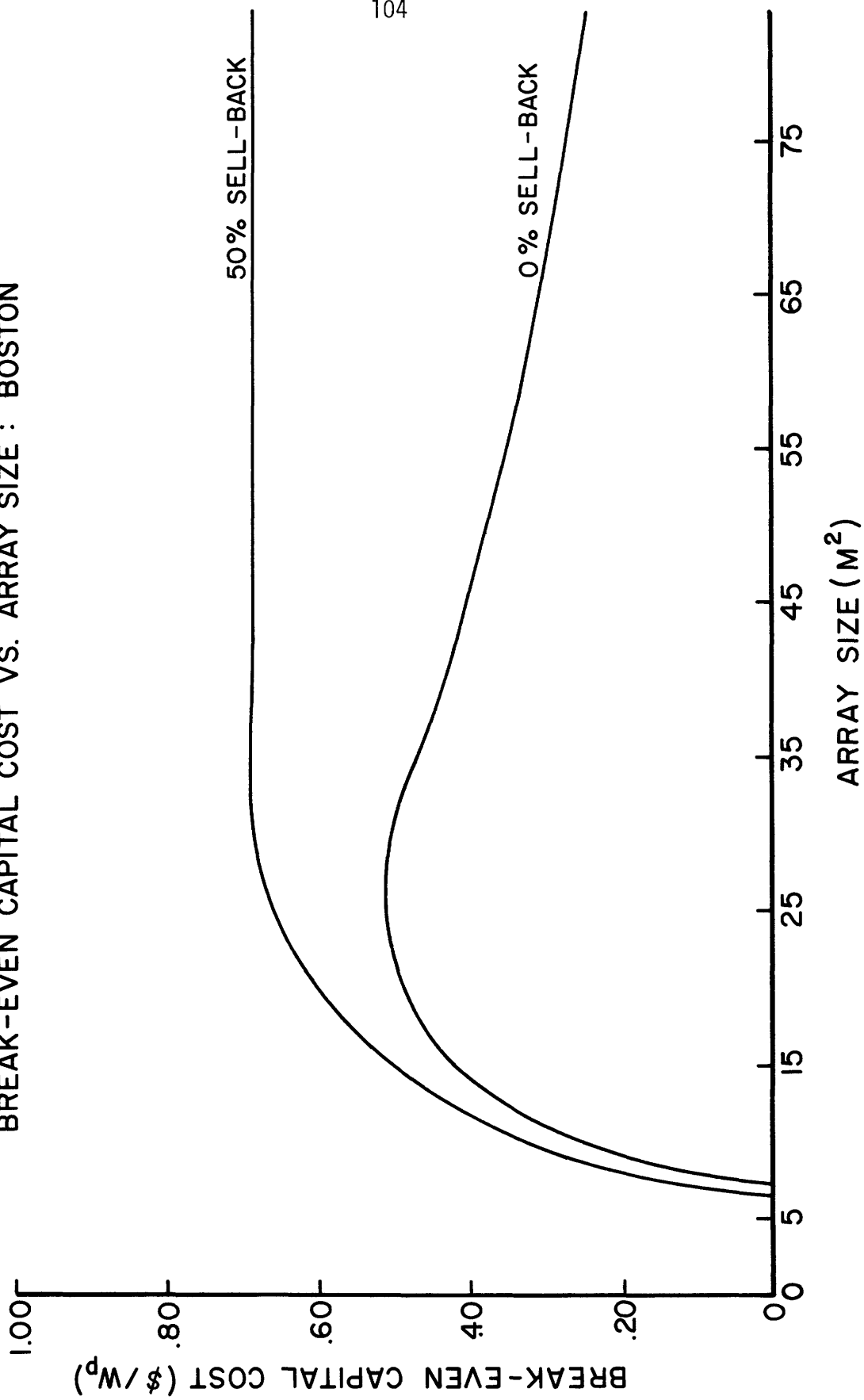


FIGURE 14

BREAK-EVEN CAPITAL COST VS. ARRAY SIZE : OMAHA

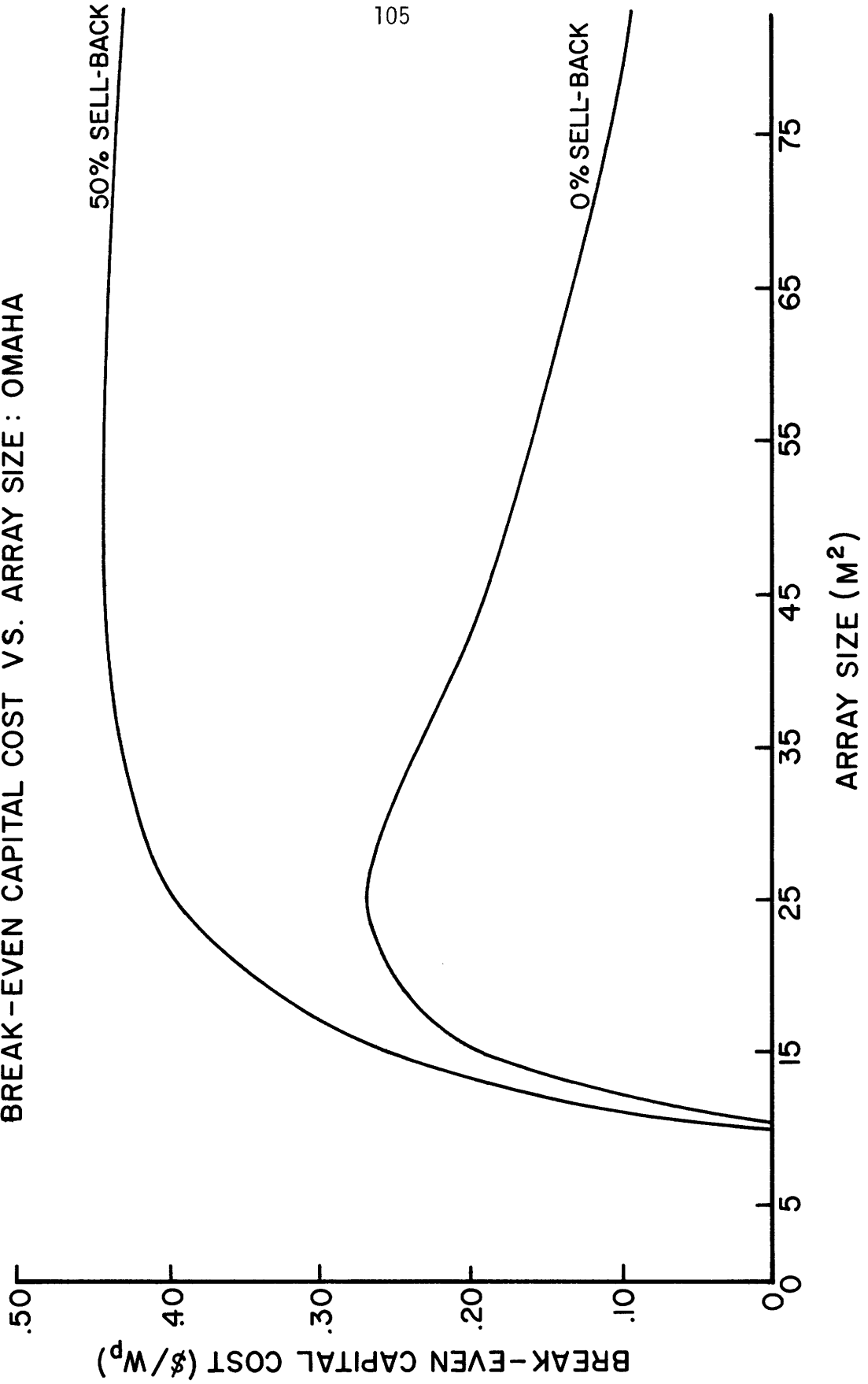
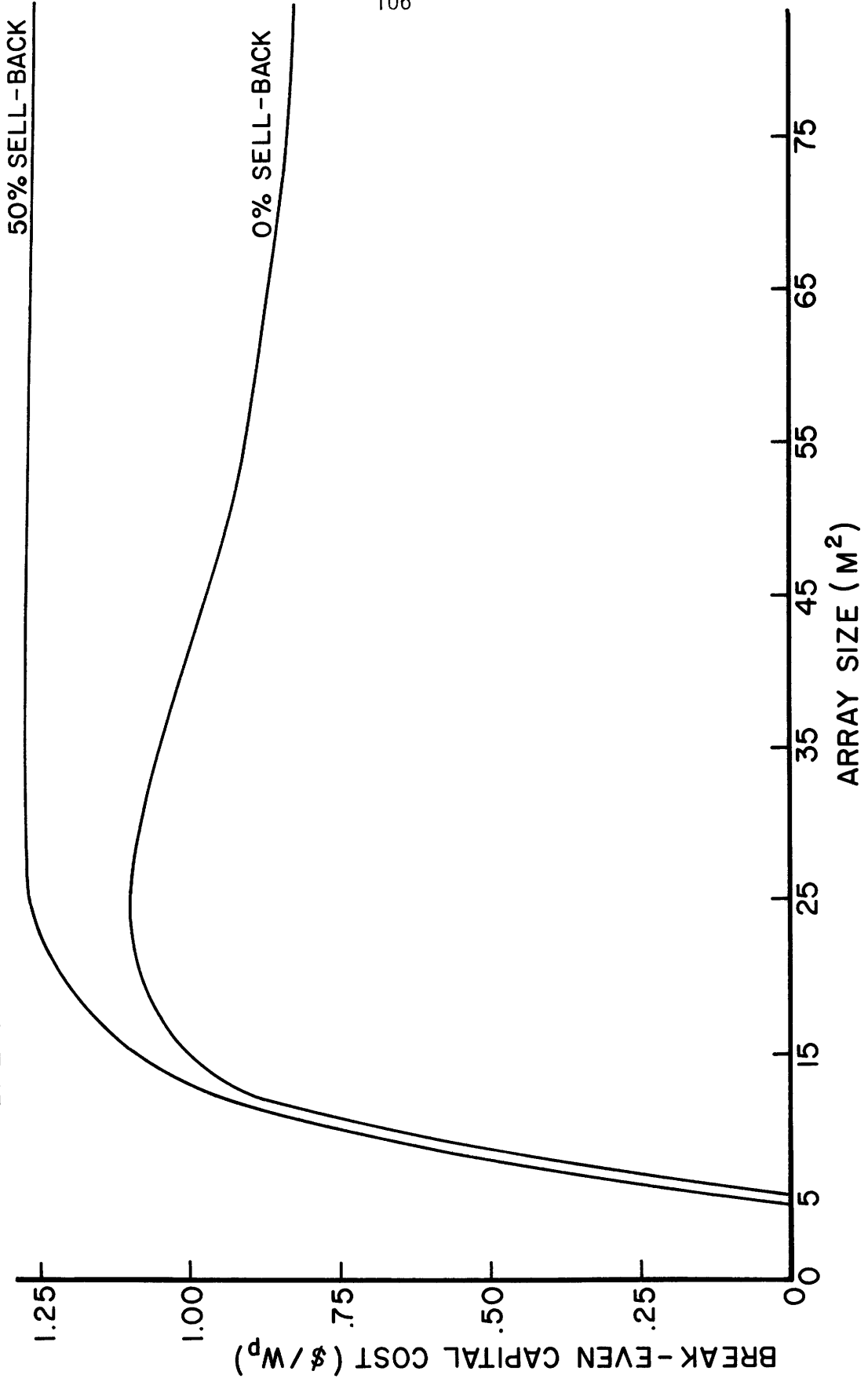


FIGURE 15

BREAK-EVEN CAPITAL COST V.S. ARRAY SIZE : PHOENIX



advantage of the large amounts of photovoltaic-generated electricity during peak-load hours.

## 5.2 SENSITIVITY ANALYSIS

### 5.2.1 CHOICE OF YEAR

It was hypothesized that the selection of a particular insolation year would have a significant impact upon the breakeven capital cost. To test this hypothesis, "best" and "worst" insolation years were selected for each area and runs were performed for 35m<sup>2</sup> arrays holding all other parameters constant. Table 15 presents the results of this analysis. In each case there was little more than a 10% variation in breakeven capital costs from the "best" to "worst" years. Notice, however, that the variation is not just a function of insolation but it is also a function of cooling requirements. Generally, the greater the cooling requirements, the higher the breakeven cost. This explains the small variation between "best" and "worst" years in Phoenix, Omaha and Boston, since in these cities annual cooling requirements do not appear to be correlated with annual sunshine availability. This is indicated in Table 16 which shows air conditioning requirements for the three areas during the "best" and "worst" years. It can be concluded from this analysis that the economics of the residential photovoltaic system (particularly for homes that are air-conditioned) is not sizeably dependent on the choice of year for simulation purposes. This would also seem to obviate the need to worry about the effect of long-term changes in weather and

Table 15

SENSITIVITY OF BREAKEVEN CAPITAL COST  
TO CHOICE OF SOLAR RADIATION YEAR

	<u>BOSTON</u>	<u>OMAHA</u>	<u>PHOENIX</u>
Baseline			
BECC (\$/wp)*	.68	.43	1.27
"Best" year	1963	1966	1955
BECC (\$/wp)*	.82	.47	1.30
Percent change	20.6	9.3	2.4
"Worst" year	1958	1969	1960
BECC (\$/wp)*	.69	.38	1.23
Percent change	1.5	-11.6	-3.1

\*Note: (\$/wp) refers to system watts. See Foreword and Appendix A for more detail.

Table 16

MONTHLY AIR-CONDITIONING DEMAND DURING  
 "BEST" AND "WORST" SOLAR RADIATION YEARS

MONTH	BOSTON		OMAHA		PHOENIX	
	<u>"Best"</u>	<u>"Worst"</u>	<u>"Best"</u>	<u>"Worst"</u>	<u>"Best"</u>	<u>"Worst"</u>
Jan.	0	0	0	0	0	0
Feb.	0	0	0	0	2	0
Mar.	0	0	5	0	2	10
Apr.	0	0	0	2	65	165
May	15	5	10	45	605	728
June	125	48	232	88	1252	1686
July	238	135	522	468	1398	1858
Aug.	75	138	88	345	1335	1600
Sept.	0	8	15	40	1065	1260
Oct.	0	0	0	8	502	205
Nov.	0	0	0	0	0	0
Dec.	0	0	0	0	0	0
TOTAL	452	332	872	995	6225	7510
U-Value (w/oc)	259	259	275	275	404	404
Cooling Deg. Hrs.	9984	7023	13218	13264	37966	46046

solar radiation on the economics of residential photovoltaics.

### 5.2.2 DISCOUNT RATE

Table 17 presents the results of performing the valuation with a zero percent real discount rate (see Section 4.2 for a discussion of the appropriateness of this rate).

Table 17

#### EFFECT OF VARIED DISCOUNT RATE ON BREAKEVEN COST

	BOSTON <u>\$/w(p)*</u>	OMAHA <u>\$/w(p)*</u>	PHOENIX <u>\$/w(p)*</u>
Baseline (3% real rate)	.68	.43	1.27
0% real discount rate	1.04	.71	1.83
Percent change	52.9	65.1	44.1

\*Note: (\$/wp) refers to system watts. See Foreword and Appendix A for more detail.

The choice of discount rate clearly has a significant effect on breakeven cost. Depending on how one views the financial assumptions underlying the 0% rate (see Section 4.2), these results may be more appropriate than the rather conservative 3% real rate.

### 5.2.3 DEGRADATION RATE

Sensitivity analysis results based on the altered degradation curve

presented in Chapter IV are indicated in Table 18.

Table 18

	SENSITIVITY OF BREAKEVEN COST TO ALTERED DEGRADATION RATE		
	BOSTON <u>\$/w(p)*</u>	OMAHA <u>\$/w(p)*</u>	PHOENIX <u>\$/w(p)*</u>
Baseline (3% yr)	.68	.43	1.27
Altered	.82	.54	1.48
Percent change	20.6	25.6	26.5

\*Note: (\$/wp) refers to system watts. See Foreword and Appendix A for more detail.

This curve declines much more rapidly during initial years than the baseline curve, but flattens out at a higher level of performance over the long term. The results do not appear to be overly sensitive to the larger initial degradation which is counterbalanced by the relatively low degradation rate in later years.

#### 5.2.4 CELL EFFICIENCY

The 12% baseline cell efficiency was changed to 15% and simulation runs were performed. As mentioned earlier, the 15% figure represents a projected future silicon-cell efficiency target. Table 19 presents the results in comparison with the baseline figures. A 3% improvement in cell efficiency implies, as indicated, a 10-20% increase in breakeven cost.

#### 5.2.5 FUEL PRICE ESCALATION

The sensitivity of breakeven cost to fuel price escalation was examined by applying a zero rate (as contrasted with the 3%/yr baseline assumption). Results are shown in Table 20.

Table 19

SENSITIVITY OF BREAKEVEN COST  
TO INCREASED CELL EFFICIENCY

	<u>BOSTON</u> \$/w(p)*	<u>OMAHA</u> \$/w(p)*	<u>PHOENIX</u> \$/w(p)*
Baseline (12%)	.68	.43	1.27
Altered (15%)	.82	.51	1.40
Percent change	20.6	18.6	10.2

Table 20

SENSITIVITY OF BREAKEVEN COST  
TO ALTERED FUEL PRICE ESCALATION

	<u>BOSTON</u> \$/w(p)*	<u>OMAHA</u> \$/w(p)*	<u>PHOENIX</u> \$/w(p)*
Baseline (3% yr) 1.27	.68	.43	
0%/yr fuel price 1.08 escalation	.56	.34	
Percent change	-17.6	-20.9	-15.0

\*Note: (\$/wp) refers to system watts. See Foreword and Appendix A for more detail.

As indicated a 3%/yr decrease in the fuel price escalation rate implies a 15-20% decrease in breakeven cost.

#### 5.2.6 SUBSYSTEM COSTS

As discussed above, it was feared that the subsystem cost estimates used in this analysis were overly optimistic, requiring the forecasting of substantial economies of scale, for example, in the production of inverters. To test the significance of this parameter, runs were made with subsystem costs increased by 50% to \$750.00 (fixed) and \$16.50/m<sup>2</sup> (variable). Table 21 presents the results.

Table 21

	SENSITIVITY OF BREAKEVEN COST TO SUBSYSTEM COST ESTIMATES		
	BOSTON \$/w(p)*	OMAHA \$/w(p)*	PHOENIX \$/w(p)*
Baseline (\$500., \$11/m <sup>2</sup> )	.68	.43	1.27
\$750, \$16.50/m <sup>2</sup>	.47	.22	1.06
Percent change	-30.9	-48.8	-16.5

\*Note: (\$/wp) refers to system watts. See Foreword and Appendix A for more detail.

As noted, subsystem costs appear to have a significant effect on ultimate breakeven costs. This should be a definite area of concern for R&D policy makers, since subsystem costs take on greater importance as breakeven array costs fall. Of all of the assumptions required to "back out" breakeven array costs, this is the most uncertain and thus critical to achieving cost goals.

### 5.3 COMPARISON OF RESULTS TO UTILITY STUDIES

The results summarized above raise the question of why the breakeven array costs derived herein are so much higher than other studies of long-term (grid-connected) markets such as the General Electric Requirements Assessment study.<sup>4</sup> GE's analysis which included both Arizona Public Service Co. (APS) (Phoenix) and New England Electric System (Boston) indicated a breakeven cost of \$.30/Wp for APS-Phoenix (the highest breakeven for any city studied) with the Boston value somewhat lower. Our baseline results of \$1.27 and \$.68 for Phoenix and Boston respectively, with figures from plausible alternative scenarios significantly higher still, suggest the magnitude of the gap involved.

Some obvious differences in approach can be identified which account for part of the discrepancy. The GE study, for instance, fails to adjust the value of photovoltaic systems on residences for the fact that such a configuration avoids transmission and distribution losses. This procedure does not capture the savings the utility would realize in terms of capacity requirements and fuel consumption because the electricity is generated on site. This is especially true where the photovoltaic systems deliver their power in peak periods when both energy and capacity losses are greatest.<sup>5</sup> The approach used in this study captures this value of the residential PV system through the use of a marginal cost based rate structure. Since marginal costs reflect the transmission and distribution losses relevant to each of the rating periods the use of

rates reflecting these costs to value energy displaced by the PV system assures capitalization of the transmission and distribution savings into the PV breakeven figure.

Another obvious difference is the discount rates. The GE study used a 4% real (10% nominal) rate while this study has used 3% and 0% rates. The use of the 10% rate was no doubt justified on the basis of the utilities' cost of capital which reflects the return rates presently demanded by utility bond and equity holders. While such an approach is valid for investments in conventional generating equipment<sup>6</sup> it is not appropriate for PV investments which present risk profiles substantially different from those of utility companies as presently constituted. This is especially true if the systematic risk inherent in the utility industry is a function of fuel prices as one would expect. In such a case utility companies and their investors should be willing to pay (by accepting a lower return) for the hedge against fuel cost increases offered by photovoltaic systems.

Other sources of difference are more subtle. The GE approach did not pick up the value of the PV system resulting from shifts in consumer behavior and the interrelatedness of PV array output and utility load especially in summer-peaking utilities. Both the correlation of heavy air-conditioning loads to array output (since sunlight and outside

temperatures are related) and the shifting of loads to take advantage of available solar energy<sup>7</sup> added to the value of the PV system determined in this study because of the interaction of time-of-day rate structures and flexible load simulation. Utility ownership of arrays in the GE scenario<sup>8</sup> and the use of fixed average load data in the GE simulation model<sup>9</sup> effectively eliminated these aspects of the potential value in residential applications.

A final possible source of variation in the results of the two analyses involves the impact of photovoltaic output on conventional generation. In the GE approach photovoltaic arrays displaced one particular type of generation equipment from the utility generation mix. In the simulation used in this study the PV array impacted upon the entire equipment and fuel mix of the utility through the operation of a marginal cost based rate structure. There is no way to determine which of these approaches is more accurate without the use of a complete residential/utility dynamic model<sup>10</sup> and it can only be noted that this is a potential cause of some discrepancy between the two approaches.

## 5.4 FOOTNOTES

1. In the development report for their shingle-type solar cell modules, General Electric suggested 85 m<sup>2</sup> of modules as a representative array size. See General Electric Co., Development and Testing of Shingle-Type Solar Cell Modules, G.E. Space Division for JPL, Quarterly Report #2, DOE/JPL-954607-78/1, January 1978, p. 4-1. Aerospace used an even larger array, 114 m<sup>2</sup>, for its representative residential results. This analysis included electric storage, however. See Aerospace Corp., Mission Analysis of Photovoltaic Solar Energy Systems, Vol. II, ATR-76 (7476-01)-1, El Segundo, CA, December 1975, p. ix.
2. General Electric Co., Requirements Assessment of Photovoltaic Electric Power Systems, RP 651-1 for EPRI by G.E. Electric Utility Systems Engineering Dept., Schenectady, NY, Draft Final Report, June 1, 1977.
3. If Cicchetti's reasonable loss multipliers are correct, such losses on-peak are around 14% for capacity and 25% for energy.
4. General Electric Co., Requirements Assessment of Photovoltaic Electric Power Systems, RP 651-1, for the Electric Power Research Institute by G.E. Electric Utility Systems Engineering Dept, Schenectady, NY, Draft Final Report, June 1, 1977.
5. See Ciucchetti, C.J. and Gillen, W.J., A Marginal Cost Analysis for Electricity, a cause study of the Central Maine Power Co. for the Attorney General of Maine under grant from the New England Regional Commission, January 1977. In the course of their discussion the authors present representative transmission and distribution loss multipliers which reflect on peak losses of 14% and 25% respectively for capacity and energy.
6. As discussed in Section 4.2 the opportunity cost of capital should reflect uses rather than sources of capital, but in an efficient financial market a source-determined rate should reflect the appropriate rate for investments in assets with risk characteristics similar to those already held by the company (in this case conventional generating equipment).
7. Such shifts would occur even if the consumer faced traditional declining block rate structures because the solar array in effect creates a time-differentiated rate structure. The price of electricity is zero when PV electricity is available and the normal price at other times, and price-conscious consumers would alter consumption patterns to take advantage of the low solar rate.

8. Behavior is shifted only if the consumer can capture some advantage by altering consumption. This requires a time differentiated price structure (it matters not how the price differentiation is accomplished). The G.E. approach of utility ownership of arrays dispersed on the roofs of residential units (the utility would pay some sort of roof rental fee) makes the output of the rooftop units property of the utility company to be purchased by the homeowner-consumer as if it were undifferentiated from electricity generated at the utility company's central plant. Thus the homeowner facing block rates has no incentive to alter behavior if the utility company owns the PV system even though it is located upon the roof of his/her home.
9. The use of average household loads means that the GE simulation failed to take advantage of the quality component of PV output discussed earlier in this paper. Consumption behavior was fixed so that use of low-cost solar power was not maximized from a consumer (or load management) point of view. Average load data also missed the correlation between sunlight and air-conditioning demand.
10. See the discussion of such a model in Section 6.4.

## VI. POLICY IMPLICATIONS AND CONCLUSIONS

### 6.1 NEW INFORMATION

It is now possible to update the price-quantity curve presented in Figure 1 to reflect the new information obtained for the residential market. This new information is shown in Figure 16. It appears, based on the results of this study, that the residential market will become a viable market for photovoltaics some time before central stations. This is not to say that in the long run larger penetration into the grid will be achieved by the residential market, but it does say that of the long-term grid-connected applications, the residential application can be considered a bridge to large penetrations. In addition, information as to the regional competitiveness of residential applications has been generated. The regions which encompass Phoenix and Boston will reach economic viability before the Omaha area does, implying a strategy for tests and applications subsidies (see Section 6.3).

### 6.2 IMPLICATIONS FOR THE LONG-TERM MARKETS

In Chapter I the long-term market for photovoltaics was defined as the grid-connected market because none of the other configurations reviewed exhibited large-scale energy displacement potential. The results presented above allow one to refine this definition a bit further.

There is one central variable that can be used to describe success in this market and that is percent penetration into the grid. Penetration can be accomplished by any of the applications that are

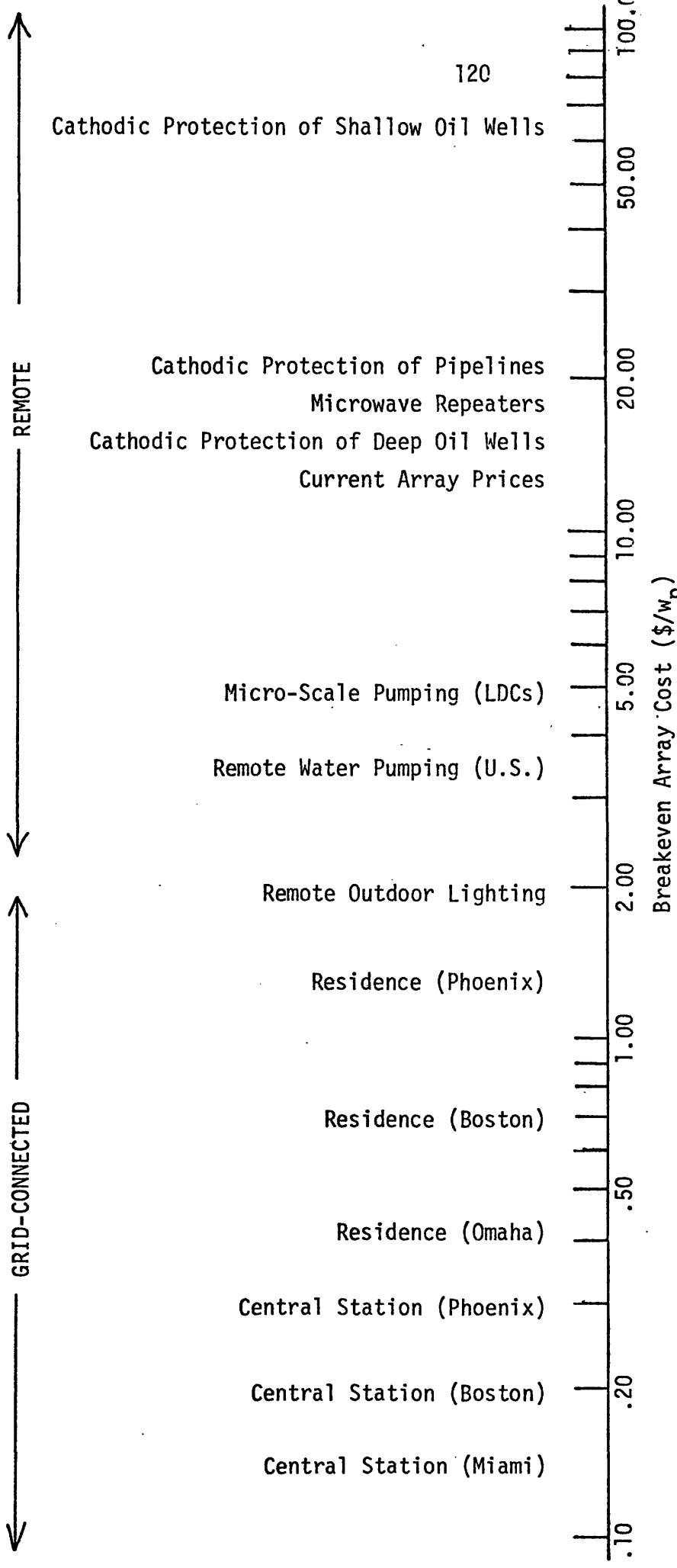


FIGURE 16

PHOTOVOLTAIC APPLICATIONS AND BREAKEVEN COSTS

Sources: BDM and Solarex estimates for ERDA  
 General Electric Co.  
 Douglas V. Smith  
 Carpenter/Taylor

grid-connected, but it now appears that if prices of photovoltaic arrays exhibit the expected downward progression, initial penetrations into the grid will be accomplished by residences, particularly new homes, since non-array costs associated with photovoltaic retrofit are somewhat greater. The central station utility studies have indicated that as penetration into the grid increases, the marginal benefit of this power to the utility decreases.<sup>1</sup> Thus, there will be a point at which added penetration will be harmful to the utility in terms of causing peak-load problems and this harm would be expressed by the utility rate structure, effectively preventing further penetration. It is hypothesized here that the volume of home construction will not be large enough over time to reach this barrier before the price of photovoltaic cells falls far enough to stimulate central station construction of photovoltaic arrays, thus completing the penetration scenario before widespread home-retrofit is accomplished.<sup>2</sup> If the retrofit is accomplished, the retrofit market will likely be represented by a dislocation on the demand curve since retrofit costs and financial barriers are somewhat greater. It must also be remembered that photovoltaics will be competing strongly for a fixed roof supply with some other solar technologies, notably solar thermal. Thus it would be difficult to predict penetration into the grid by either the residential or central station applications simply by utility-response analysis. This type of analysis defines penetration potential, not actual penetration. It is also the case that the market

penetration (logistic curve diffusion) models currently employed to perform this kind of calculation have not yet produced credible results.<sup>3</sup> More test information on consumer response is necessary.

### 6.3 IMPLICATIONS FOR SYSTEMS TESTS AND APPLICATIONS (ST&A) POLICY

In the introduction to this study two criteria for a tests and applications selection process were suggested. First, an application's potential for an orderly progression in the acquisition of practical experience with the technology as well as in market and production growth was considered important. Second, an application's commercial potential and speed with which competitiveness could be achieved was identified as a criterion. The results above permit the evaluation of these criteria with regard to the residential market.

The residential market fulfills the first criterion because it can act as a bridge<sup>4</sup> to all of the long-term grid-connected market. It provides the initial stages of information necessary to cope with the technical and institutional problems associated with integrating photovoltaics into the utility grid on a large scale. With regard to the second criterion, the residential application, because of its large potential market as well as early breakeven cost, will minimize the government subsidy over the long run while maximizing the payoff in terms of penetration into the grid.

Unfortunately, the National Photovoltaic Plan, as described earlier, does not address these criteria, and relegates testing in the residential

market to well past 1980. The initial series of flat-plate PRDAs specifically exclude residential applications<sup>5</sup> (20 KW is the minimum size project) and thus larger subsidies will be required to obtain less timely market information. In addition, the larger load center and central station tests do not help to overcome barriers in the product distribution channels to the residential market, delaying the prospects for a self-sustaining market for grid-connected applications. Finally, PRDAs, per se, do not guarantee well-designed and instrumented applications. While the private sector may be better able to sustain a competitive market, there is little evidence that they have testing and information dissemination capabilities superior to those of the public sector. Since the ultimate goal must be to achieve the largest photovoltaic penetration with the least amount of taxpayer subsidy, it seems logical to pursue the long-term market segments that will break even first through an aggressive test and applications program in the residential sector.

#### 6.4 UTILITY RESPONSE AND INTERACTIVE MODELS: FURTHER RESEARCH

As indicated in the discussion above<sup>6</sup> utility response to photovoltaic systems will play a critical role in the ultimate success of such systems in the long term. Electricity prices impact heavily upon the value of grid-interfaced systems and buy-back rates affect not only system value but also optimal system size. These two factors, system size and price, in turn determine photovoltaic penetration (i.e., numbers and size of systems) into the generating grid.

This analysis has confined utility response by assumption to a very narrow range of those actually possible. Marginal cost-based time-of-day rate structures with buyback rates of from 0-50% represent only one (though arguably a very likely one) from a range of responses which could run from outright refusal of service<sup>7</sup> to utility company promotion of photovoltaic systems.<sup>8</sup> One would expect each utility's reaction to photovoltaic households to be a function of the nature of the impact PV devices have upon such factors as utility system reliability and total costs. Work to date in assessing these impacts<sup>9</sup> has indicated that photovoltaic penetrations at relatively low levels may improve system reliability and reduce system operating costs.<sup>10</sup> The positive contributions of photovoltaics decline, however, with increasing levels of penetration, and at some point the addition of PV systems would have no or even negative marginal impact upon the utility company. Therefore utility companies might be expected to welcome additional PV systems until this "saturation" point is reached<sup>11</sup> and then to discourage further penetration or at least be indifferent to further penetration. In attempting to assess the long-term market for grid-connected systems further study is necessary to establish the penetration levels at which utility grid systems would become saturated and market potential essentially exhausted.<sup>12</sup> This approach to determining market potential realistically reflects the interactive role of the utility companies in the development of a PV market, a factor which is ignored in models which

make arbitrary assumptions about PV penetration of housing stocks or PV system installation on various percentages of new homes built.

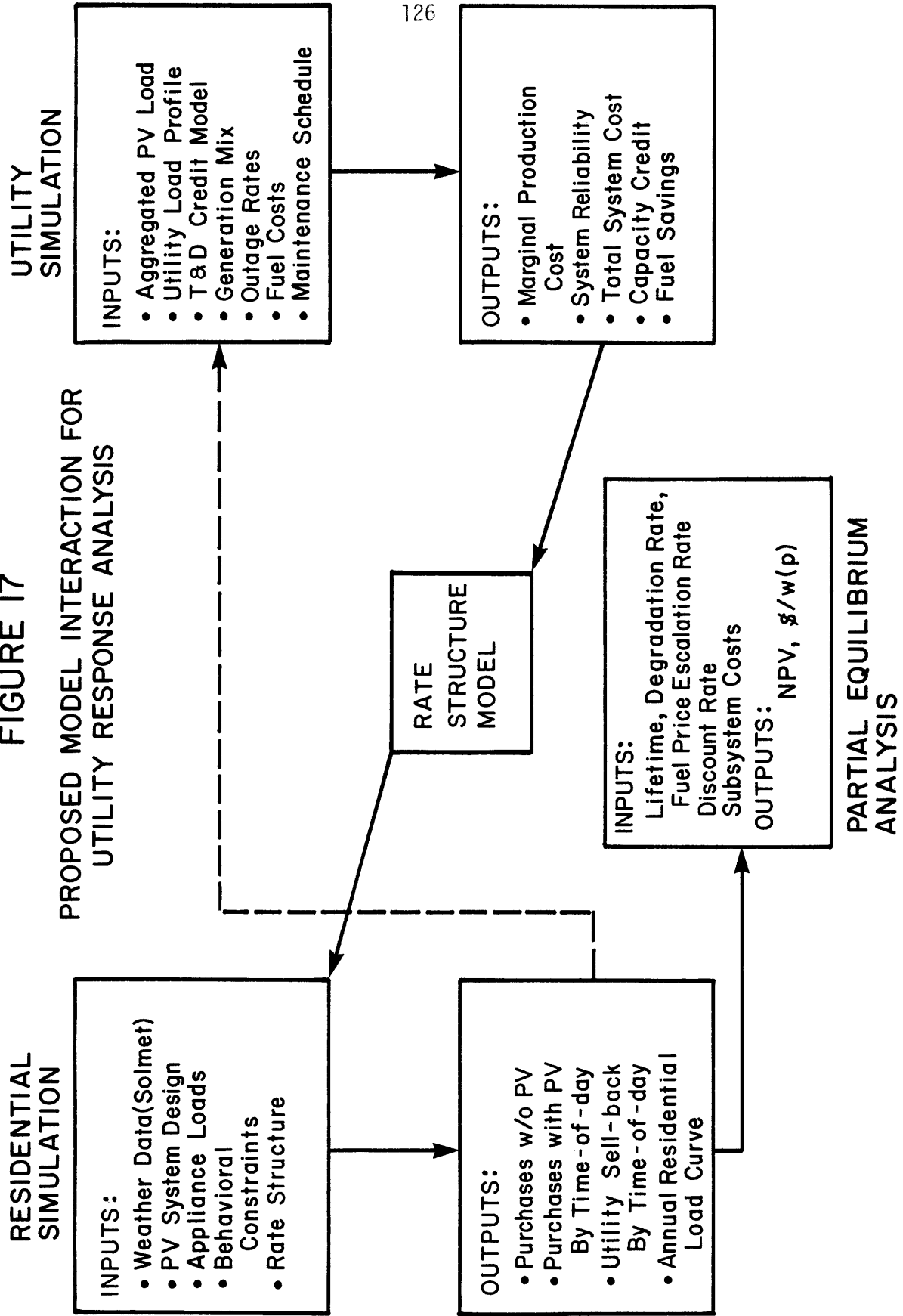
The difficulty in determining saturation levels is that the problem is dynamic with PV penetration altering utility marginal costs, marginal costs affecting rate structures and rate structures impacting the economic viability of further investment in PV systems. One possible method of reaching a solution is to expand upon the approach applied in this study as illustrated in Figure 17. In essence, outputs of the residential simulation would be used to develop inputs to a utility simulation model to assess the impact of PV penetration upon utility marginal costs. These costs would be the basis of new rate structures which could close the dynamic loop as inputs to the residential simulation/valuation model. Penetration would effectively end<sup>13</sup> when the marginal contribution of additional PV generation to system reliability becomes zero or negative<sup>14</sup> or when marginal costs result in time-of-day rate structures which make the PV investment unattractive.<sup>15</sup>

## 6.5 CONCLUSION

In Section 1.3 of this report, four questions were asked, the answers to which needed to be provided before conclusive statements could be made regarding the economics of the long-term market for photovoltaics. Three of the four questions have been answered, the fourth only partially, with a suggestion for how to approach it.

FIGURE 17

PROPOSED MODEL INTERACTION FOR UTILITY RESPONSE ANALYSIS



. Are there advantages of user-owned, residential systems that are reflected in the value of the system to the user?

In this study, we have identified several features of the technology which make it relatively more valuable (meaning a higher breakeven capital cost) from a residential user-ownership perspective. These features include: the ability of the homeowner to alter his behavior to take advantage of the solar electricity when it is available; the correspondence between air-conditioning requirements and solar radiation availability in some regions; decreased transmission line losses of utility-supplied electricity; the availability of solar energy during utility peak-load periods (what we call the "quality" component of solar electricity); and finally, the relatively lower cost-of-capital to the homeowner due both to the mortgage interest rate and tax shield, and to the risk-bearing nature of PV systems as hedges against future fuel price escalation and/or supply interruption.

. How should one go about valuing the worth of a photovoltaics system to a user/owner?

A methodology has been presented which explicitly values the features of user-owned systems listed above. The methodology can be applied in similar fashion to other user-owned, weather-dependent generation technologies such as wind systems or perhaps even storage.

. Should the residential market be pursued by an aggressive commercialization program? Does this application minimize the subsidy required to accelerate photovoltaics penetration in the long-term market?

While we do not propose to argue in this report that an aggressive commercialization program should be undertaken for photovoltaics (that is a policy decision of much broader scope), if one is undertaken (all current indications point to it) then the nature of the breakeven cost of the residential application and its long-term market potential make it appropriate for immediate focus by the tests and applications program. As argued above, this application will minimize the amount and duration of the necessary federal government commercialization subsidy.

. What is the impact of these systems on electric utilities and how will/should they respond?

At numerous points in this report we have referred to the studies of central station utility applications of photovoltaics which have used simulation to measure this impact. As has been discussed, the central station applications have positive load-management attributes up to a certain penetration. It has been shown in these studies that initial penetrations of residential systems will also have this positive impact, but since the ownership scenarios and valuation techniques were different in these studies we have suggested a combination of the two methodologies which will help answer this last question in a dynamic fashion.<sup>16</sup>

## 6.6 FOOTNOTES

1. See General Electric Co., Requirements Assessment of Photovoltaic Electric Power Systems, RP 651-1, for EPRI by G.E. Electric Utility Systems Engineering Dept., Schenectady, NY, Draft Report Vol. I, p. 97 for sample curves showing decreasing marginal returns to increased penetration in the Arizona Public Service Co. grid.
2. Further analysis is required to test the effect of penetrations of photovoltaic residences on the utility grid. See Section 6.4 for discussion and suggested approach.
3. See discussion of the MITRE Spurr model in Dennis Schiffel, Dennis Costello, et al., The Market Penetration of Solar Energy: A Model Review Workshop Summary, Solar Energy Research Institute, Golden, CO, January 1978.
4. The residential market uniquely enables the technology to be "rolled out" on a regional basis in accord with the differing regional breakeven costs. This allows for an orderly progression in market diffusion on both the demand side and the supply/distribution side.
5. Department of Energy, Program Research and Development Announcement (PRDA), Solar Photovoltaic Flat Panel Applications Experiments, EM-78-D-04-0038, Albuquerque, N.M., 1978. (Letter to prospective offerers). "Applications involving ... single or multiple unit residences are specifically excluded."
6. See discussion in Section
7. This is very unlikely given a utility company's legal obligation to provide service.
8. Through lease programs, for example, or promotional rates.
9. Chowaniec, C.R., Pittman, P.F., and Marshall, B.W., "A Reliability Assessment Technique for Generating Systems with Photovoltaic Power Plants," IEEE PAS, April 21, 1977; General Electric Co., Requirements Assessment of Photovoltaic Electric Power Systems, RP 651-1, for EPRI by G.E. Electric Utility Systems Engineering Dept., Schenectady, NY, Draft Final Report, June 1, 1977.
10. Because of their high cost, however, the G.E. study indicated that photovoltaics would not be economic for central utility investment for 15-20 years.

11. If the price of PV systems drops sufficiently, the utility companies themselves might be installing PV generation.
12. Of course there might be other, grid competing markets still untapped.
13. This limit applies only to PV systems without storage. At this point PV storage systems become complementary, and further penetration might be achieved with combined systems.
14. In this situation utility companies could justify discriminatory rates which would discourage further PV investment.
15. PV penetration could shift system peaks to night time hours (when there is no PV contribution). If marginal cost-based rates shifted to reflect this, PV systems, instead of displacing peak electricity would displace relatively cheaper off-peak or shoulder energy, thus lowering the value of the systems.
16. This work is currently being undertaken by Susan Finger of the MIT Energy Laboratory Photovoltaics Project. cf. Susan Finger, The Integration of Decentralized Weather-Dependent Generators with the Electric Power Grid, MIT Energy Laboratory, Cambridge, MA (forthcoming).

APPENDIX A

The materials presented below represent a compilation of most likely values in a 1986 time frame for photovoltaic modules when used in residential applications in Boston, Omaha and Phoenix. Values explicitly stated in this appendix, the assumptions contained and methodologies and definitions used are those of the main report. It should be noted that the changes in results presented in this appendix do not affect the relative sensitivity of results to changes in specific variables. The proportional changes may, in general, be applied to the results reported herein.

The definition of breakeven capital cost utilized in this appendix is

$$\text{Dollars/watt (peak) module} = \frac{\text{Dollars/m}^2}{\text{module} \times 1000 \text{ w/m}^2}$$

Table A-1 presents the assumptions incorporated in the results presented. Changes in both module and system efficiency reflect most recent information concerning 1986 technology. The assumption concerning degradation rate for module performance is based on present results from field tests of module performance.

Table A-2 and Figures A-1, A-2 and A-3 present the revised results of this analysis in \$/wp module.

Table A-1

## ASSUMPTIONS FOR RESULTS PRESENTED IN APPENDIX A

Lifetime = 20 years

Degradation = 5% in first two years (per year)  
7% thereafter (per year)

Discount rate = 3%

Fuel price escalation rate = 3%

Array size = 35 m<sup>2</sup>

Module efficiency = 12.7%

System efficiency = 10.2%

Appliance and behavioral assumptions  
as outlined in previous report

No storage

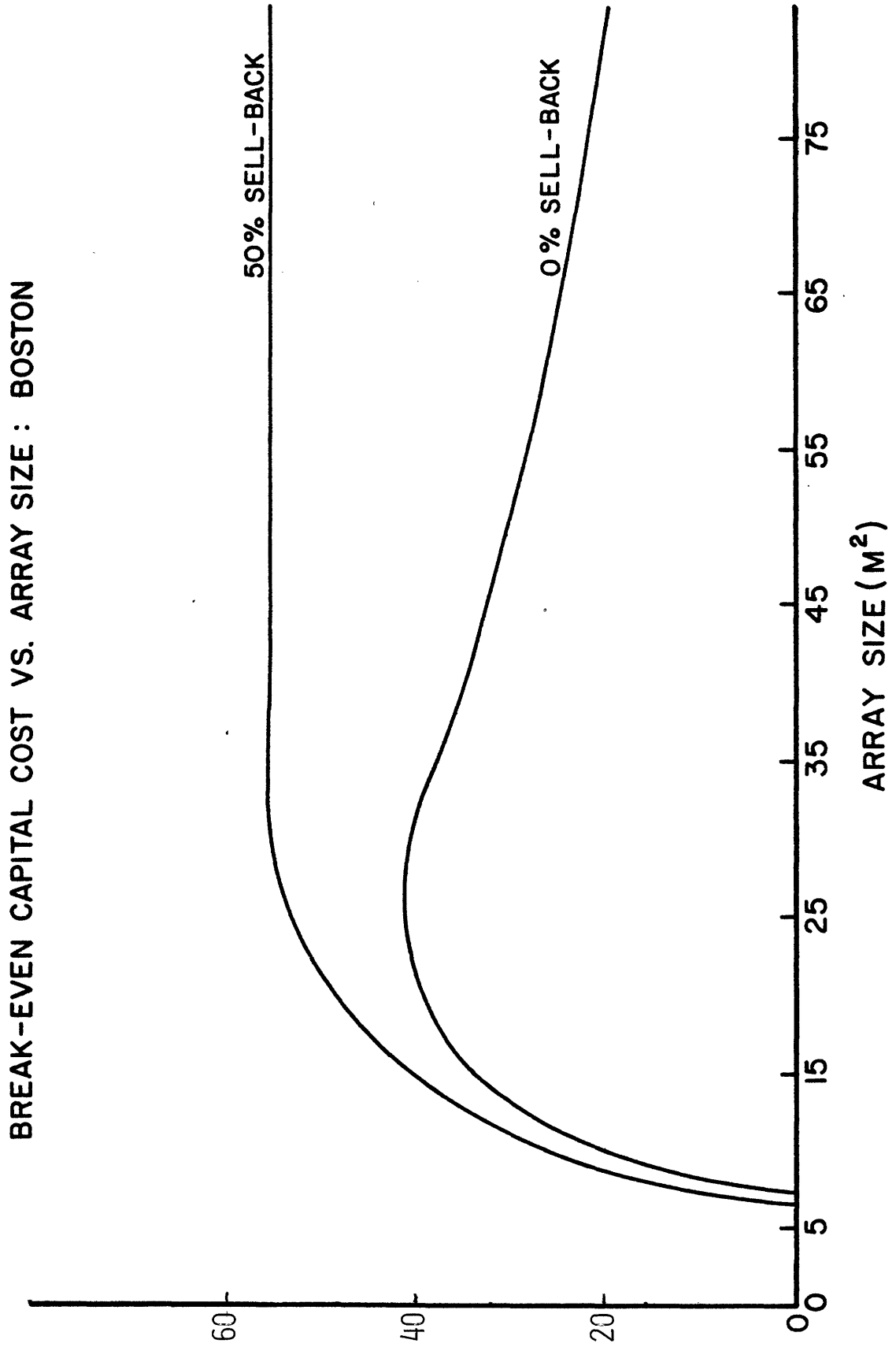
Table A-2

## REVISED BASE CASE RESULTS

	System Net Present Value	\$/wp Module*
Boston	3700	.42
Omaha	2900	.24
Phoenix	5800	.89

\*Assumes a balance of system cost of .41 per peak watt as reported for residential systems in: Costello et al., Photovoltaic Venture Analysis, Final Report No. 1, Solar Energy Research Institute, Golden, Colorado, July 1978, SERI/TR-52-040, page 126.

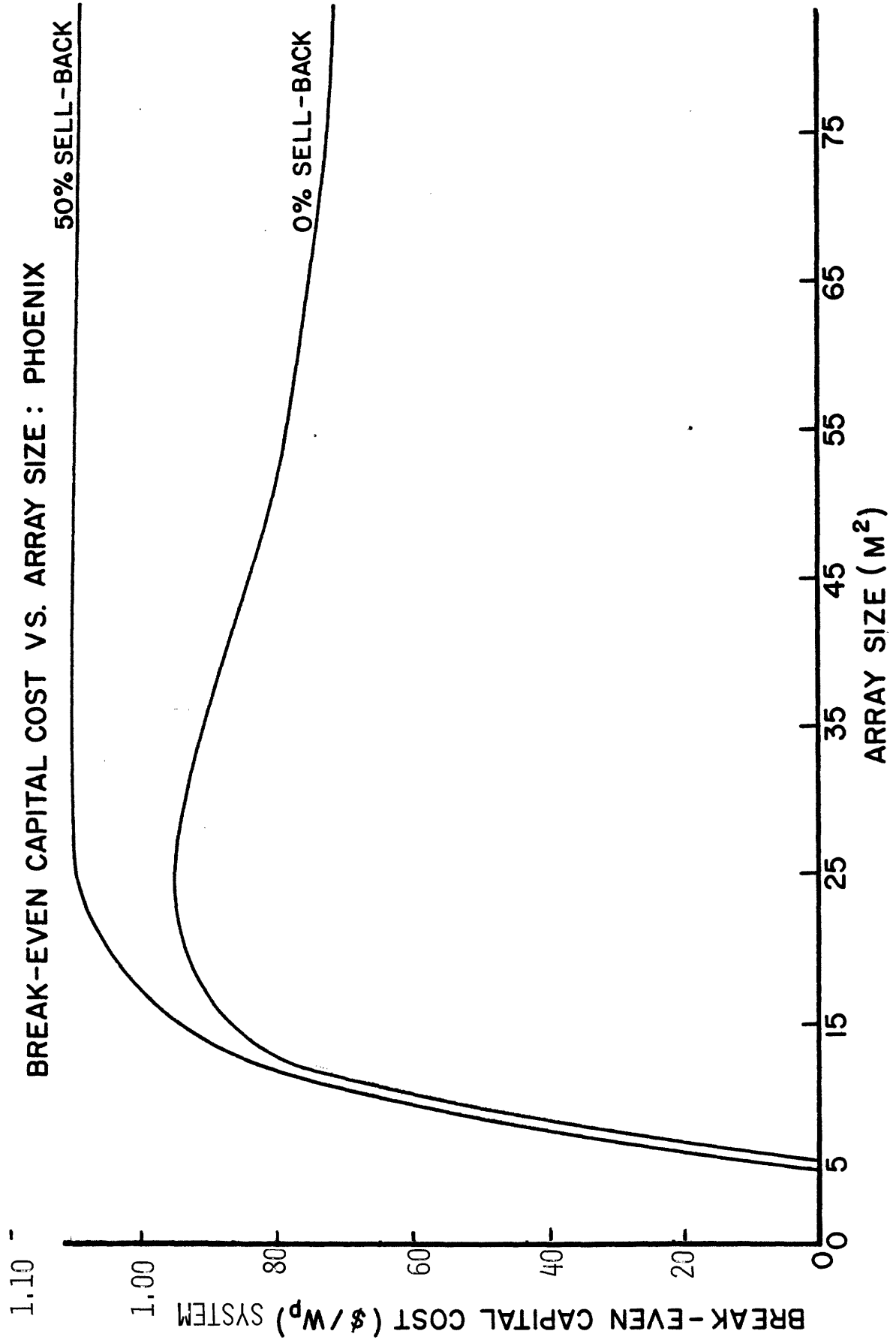
BREAK-EVEN CAPITAL COST (\$/W<sub>p</sub>) SYSTEM

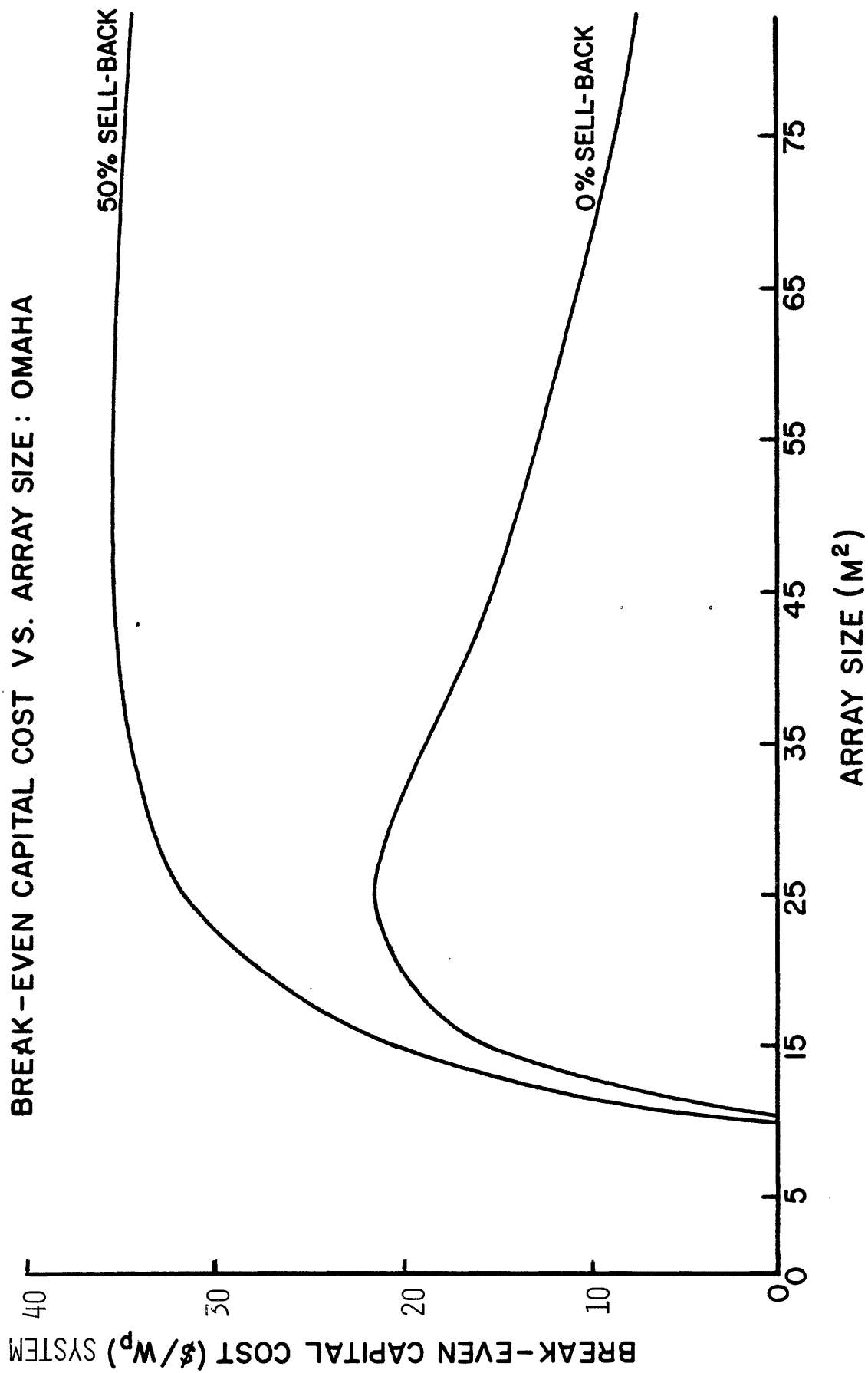


BREAK-EVEN CAPITAL COST VS. ARRAY SIZE : BOSTON

50% SELL-BACK

0% SELL-BACK





## APPENDIX B: VARIABLE DESCRIPTION

The following pages define and describe important variable names in PL/1 programs NPV, COMPARE, INSVAR, and SOLSTAT which follow:

Class

For clarification, variables have been broken down into these categories and subcategories:

## I. Input Parameters

1. Computed variables; usually from other programs
2. Parametric variables; estimates of future values, designed for parametric variation.

## II. Intermediate Parameters and Intermediate Output

1. Conceptually significant results of functions of input parameters; usually not aggregated over time or types and therefore not final output.

## III. Final Output

1. Initial results, to be used as computed input
2. Reported results, the end of the computing process

From NPV

<u>variable name</u>	<u>class</u>	<u>computational type</u>	<u>dimension (units)</u>
LIFETIME	parametric input	decimal	years
Expresses useful lifetime of array in years. Usual value is 20 years.			
DEGR	parametric input	decimal	percentage

DEGR is the degradation rate of the collector efficiency. It models collector output per unit energy input as decreasing over time. In early work, the rate was held constant at 3% to 5%. Later, a simple piecewise

linear function was inserted. I used a higher degradation (5% to 7%) the first 3 to 5 years, and a lower rate (1% to 3%) for the remaining collector life.

EFACT	parametric input	decimal	percentage
-------	---------------------	---------	------------

EFACT is the estimated fuel escalation rate for the collector life; usually 3%.

DSCT	parametric input	decimal	percentage
------	---------------------	---------	------------

DSCT is the estimated real economic discount rate; usually 3%.

xCAP	computed input	decimal	¢/KWh
------	----------------	---------	-------

"xCAP" is the capacity component of the adjusted marginal cost of electricity. The x indicates peak, P; shoulder, S; or base, B.

xFUEL	computed input	decimal	¢/KWh
-------	----------------	---------	-------

This variable is the fuel component of the adjusted marginal cost of electricity.

xSTL	computed input	decimal	KWh
------	----------------	---------	-----

This is the amount of electrical energy, from the solar device, used on site. It is computed in SOLOPS and differentiated between peak, shoulder and base.

xSELL	computed input	decimal	KWh
-------	----------------	---------	-----

This is the energy from the solar device in excess of the demand for electricity and presumed to have been sold back to the utility.

ACOL	parametric input	decimal	m <sup>2</sup>
------	---------------------	---------	----------------

This is the total collector surface area, flat plate assumed.

EFF	calculated input	decimal	percentage
-----	---------------------	---------	------------

This is the array efficiency, from calculations in SOLOPS.

FSUBCOST	parametric input	decimal	dollars
----------	---------------------	---------	---------

This is the fixed component of the costs associated with the collector support systems; that is the whole collector except the array. It assumes there is some base cost of collectors, regardless of size.

VSUBCOST	parametric input	decimal	dollars/m <sup>2</sup>
----------	---------------------	---------	------------------------

This is the component of collector support costs which depends on the collector size. It is assumed to be constant within the range of collector sizes used.

DFACT(i)	intermediate parameter	array	percentage
----------	---------------------------	-------	------------

This is the degradation factor for any year  $i$ , based on year one and the degradation rate.

variable	name	class	type	units
x	RATE (j)	intermediate parameter	array	¢/KWh

This is the adjusted marginal price of electricity for time-of-day period  $x$ , year  $j$ , based on year one and the fuel escalation rate.

TBENES (j)	intermediate output	array	dollars
------------	------------------------	-------	---------

This is the total benefits from the solar device for year  $j$ . One component is the solar energy used on site (multiplied by the adjusted marginal cost of electricity at that time of day). The other component is the energy sold back to the utility (multiplied by some fraction of the adjusted marginal cost of electricity). This fraction is known as the buy back rate, usually assumed to be .5.

NBENES (j)	intermediate output	array	dollars
------------	------------------------	-------	---------

This is TBENES( $j$ ) multiplied by the degradation factor for year  $j$ , DFACT ( $j$ ).

<u>variable name</u>	<u>class</u>	<u>type</u>	<u>units</u>
NPV	reported output	decimal	\$

This is the sum of NBENES over the lifetime of the collector, present valued back to the first year of calculation using the discount rate, DSCT.

VALUE	reported output	decimal	\$/pW
-------	-----------------	---------	-------

This is the break-even capital cost of the array, per peak watt of collector output. The costs of the support structure are subtracted from the total benefits, NPV, to yield the benefits of the array. The result is then divided by the peak output of the array using the array efficiency, EFF and assuming peak terrestrial irradiation of  $1000(p)W/M^2$ .

## APPENDIX C: PROGRAM: SOLSTAT

PURPOSE: To compute the monthly average insolation for each hour of the day, given a year of solar data.

INPUT: All input comes from SOLMET tape (see footnote 16, sec. 3.4). YEAR is the year of the data, MONTH is the month, HOUR is the hour of the day and TTOTAL is the total insolation on the horizontal for each hour in kilojoules per square meter.

METHOD: The insolation data is read into an array TOTAL such that TOTAL (i,j) is the sum of the insolation values for the ith hour and jth month (converted to  $W/m^2$ ). Array COUNTER is constructed such that COUNTER (i,j) is the number of values summed in TOTAL (i,j).

OUTPUT: The output is a matrix of average insolation values by hour and month. That is the i,jth cell of the output matrix is  $TOTAL (i,j) / COUNTER (i,j)$ .

This program computes monthly hour insolation averages based on SOLMET format.

```
SOLSTAT:  PROC OPTIONS(MAIN):
DCL SOLMET FILE INPUT RECORD ENV(FB RECSIZE(163)  BLKSIZE(3912));
DCL SOLDISK FILE OUTPUT ENV(F RECSIZE (130));
DCL (YRSUM,TOTAL)(24,12)  FIXED DEC(15,2)  INIT((288)0);
DCL (COUNTER, YRCOUNT)(24,12)  FIXED DEC(15,0)  INIT ((288)0);
DCL TTOTAL FIXED DEC(5)  INIT(0);
DCL BUFFER CHAR (163) INIT('');
ON ENDFILE (SOLMET) GOTO EOF;
/* STARTING YEAR MUST BE SPECIFIED AS LYEAR*/
LYEAR=53;
READ:  READ FILE (SOLMET) INTO(BUFFER);
GET STRING(BUFFER) EDIT(YEAR,MONTH,HOUR,TTOTAL)(X(9),2  F(2),X(2),
F(2),X(41),F(4),X(101));
/* THE FOLLOWING STATEMENT IS NECESSARY IF THE INITIAL YEAR HAS ONLY
PARTIAL DATA */
IF YEAR=52 THEN GOTO READ;
IF TTOTAL=9999 THEN TTOTAL=0;
IF YEAR=LYEAR THEN GOTO EOF;
CALC:
TOTAL (HOUR,MONTH)=TOTAL (HOUR,MONTH)+(TTOTAL/3.6);
```

```
COUNTER(HOUR,MONTH)=COUNTER(HOUR,MONTH)+1;
GOTO READ;
EOF:  PUT SKIP FILE(SOLDISK)  EDIT('AVERAGE MONTHLY INSOLATION (W/M2)
ON HORIZONTAL FOR 19',LYEAR, '.  COLUMNS ARE MONTHS, ROWS ARE HOURS.')
(A,F(2,0),A);
PUT SKIP FILE(SOLDISK);
DO I=1 TO 24;
      PUT SKIP FILE(SOLDISK)  EDIT((TOTAL(I,J)/COUNTER(I,J) DO J=1 TO 12))
(COL(1),12 F(10,2),SKIP);
DO J=1 TO 12;
      TOTAL(I,J)=0;
      COUNTER(I,J)=0;
END;
END;
LYEAR=YEAR;
/* THE FOLLOWING STATEMENT SPECIFIES ENDING YEAR.  ONLY NECESSARY IF
ENDING YEAR HAS ONLY PARTIAL DATA */
IF LYEAR=67  THEN GO TO STOP;
ELSE GO TO CALC;
STOP;
END SOLSTAT;
```

## APPENDIX D: PROGRAM: INSVAR

PURPOSE: To compute yearly variation in average insolation values, given hour by month matrices of average insolation (see program named SOLSTAT for computation of these matrices).

INPUT: The input is a set of 24 x 12 matrices. Each matrix corresponds to one year, and each cell of any matrix contains the average insolation (in watts/m<sup>2</sup>) for the corresponding hour of the day and month of the input year.

In INSVAR, the values of each matrix are written into an array, YRMEAN, such that YRMEAN (i,j) is the average insolation for the ith hour and jth month of any year. For clarity, we will refer to the sum of the average insolation values for a particular hour and month, over all the input years, as the cell total for that hour and month.

METHOD: The program reads the input matrices in one at a time, and sets YRSQR (i,j) equal to the square of YRMEAN (i,j). Cell totals are computed for YRSQR (i,j) and YRMEAN (i,j) and are assigned to YRSUMSW (i,j) and YRSUMS (i,j).

The variance in average insolation for any hour and month is computed using the cell totals and assigned to VAR (i,j). SIGMA (i,j) is the square root of VAR (i,j), that is the standard deviation across years of the average insolation values. COUNTER is the number of years of input matrices.

OUTPUT: Three matrices are output. First is the mean over years of the average insolation matrices; that is YRSUMS (i,j) divided by COUNTER for the ith hour and jth month.

Second, is the variance matrix, or VAR (i,j) for the ith hour and jth month. And last, is the standard deviation matrix, or SIGMA (i,j).

This program computes the mean, variance, and standard deviation of the yearly matrices computed by SOLSTAT.

```

INSVAR: PROC OPTIONS(MAIN);
/* INPUT FILE CONSISTS OF MATRICES FROM SOLSTAT */
DCL SOLDISK FILE INPUT ENV(F RECSIZE(130) BLKSIZE(130));
DCL SOLOUT FILE OUTPUT ENV(F RECSIZE(130) BLKSIZE(130));
DCL (YRMEAN,YRSQR,YRSUMS,YRSUMSQ,VAR,SIGMA)(24,12) FIXED DEC (15,4)
INIT ((288)0);
DCL DUMMY CHAR(1) INIT(' ');
DCL COUNTER FIXED DEC(5) INIT(0);
ON ENDFILE(SOLDISK) GOTO EOF;
READ:
DO H=1 TO 24;
    GET FILE(SOLDISK) EDIT ((YRMEAN(H,M) DO M= 1 TO 12))
(COL(1),12 F(10,2),SKIP);
DO M=1 TO 12;
    YRSQR(H,M)=YRMEAN(H,M)**2;
    END;
END;
COUNTER=COUNTER+1;
DO H=1 TO 24;
    DO M=1 TO 12;
        YRSUMS (H,M) =YRSUMS(H,M)+YRMEAN(H,M);
    
```

```

        YRSUMSQ(H,M) =YRSUMSQ(H,M)+YRSQR(H,M);
    END;
END;
GO TO READ;
EOF:  DO H= 1 TO 24;
        DO M= 1 TO 12;
            VAR(H,M) =(YRSUMSQ(H,M) - ((YRSUMSQ(H,M)**2)/COUNTER))/(COUNTER-1);
            SIGMA(H,M)=SQRT(VAR(H,M));
        END;
    END;
END;
PUT SKIP(2) FILE(SOLOUR) EDIT ('MEAN TOTAL HORIZTONTAL INSOLATION OVER
'COUNTER,' YEARS. ROWS ARE HOURS, COLUMNS ARE MONTHS:')(A,F(3,0),A);
PUT SKIP FILE(SOLOUR);
DO H=1 TO 24;
    PUT SKIP FILE(SOLOUR) EDIT ((YRSUMS(H,M)/COUNTER DO M=1 to 12))
(COL (1),12 F(10,2));
END;
PUT SKIP(2) FILE(SOLOUR) EDIT('VARIANCE IN THE ANNUAL MEANS:')(A);
PUT SKIP FILE(SOLOUR);
DO H=1 TO 24;
    PUT SKIP FILE(SOLOUR) EDIT ((VAR(H,M) DO M=1 TO 12))
(COL(1),12 F(10,2));
END;

```

```
PUT SKIP(2) FILE(SOLOUR) EDIT ('STANDARD DEVIATION OF THE ANNUAL MEANS:
')(A);
PUT SKIP FILE(SOLOUR);
DO H = 1 TO 24;
    PUT SKIP FILE(SOLOUR) EDIT((SIGMA(H,M) DO M=1 TO 12))(COL(1),12
F(10,4));
END;
END INSVAR;
```

## APPENDIX E: PROGRAM COMPARE

PURPOSE: To compute, for any yearly average insolation matrix, the difference between each matrix cell and the corresponding mean matrix cell in standard deviation units of that cell.

INPUT: An average insolation matrix from SOLSTAT and mean insolation and standard deviation matrices from INSVAR are read as ACTUAL (i,j), YRMEAN (i,) and SIGMA (i,j), where i is the hour of the day and j is the month of the year.

METHOD: For every i,j, DIST (i,j) is the difference between ACTUAL (i,j) and YRMEAN (i,j), divided by SIGMA (i,j). That is, DIST (i,j) is the difference between the average insolation for a particular year, hour of the day and month and the mean of the average insolation over several years for that same hour and month. It is measured in units of the standard deviation of the average insolation over several years for the particular hour and month.

GRAND is the sum of DIST (i,j) over all i,j. Note that the differences may cancel, as DIST is a directional measure of difference.

OUTPUT: The matrix DIST (i,j) is output, as well as the sum of DIST (i,j) over all i (that is, the monthly deviation), and GRAND.

This program computes number of standard deviations that each yearly matrix cell is from mean matrix.

```

COMPARE:  PROC OPTIONS MAIN);
/* INPUT FILE CONSISTS OF STANDARD DEVIATION MATRIX AND MEAN MATRIX FROM
INSVAR AND YEARLY MATRICES FROM SOLSTAT IN THAT ORDER */
DCL SOLDISK FILE INPUT ENV(F RECSIZE(130)  BLKSIZE(130));
DCL SOLOUT FILE OUTPUT ENV(F RECSIZE(130)  BLKSIZE(130));
DCL (ACTUAL,SIGMA,YRMEAN,DIST)(24,12)  FIXED BIN(15,4)  INIT((288)0);
DCL GRAND FIXED BN(15,4)  INIT(0);
DCL YEAR FIXED DEC(4,0)  INIT(0);
ON ENDFILE(SOLDISK)  GOTO EOF;
READ:  DO I=1 TO 24;
        GET FILE(SOLDISK)  EDIT ((SIGMA(I,M) DO M=1 TO 12))
(COL(1),12 F(10,4),SKIP);
END;
DO I=1 TO 24;
        GET FILE(SOLDISK)  EDIT ((YRMEAN(I,M) DO M=1 TO 12))
COL(1),12 F(10,2),SKIP;
END;
/*SET YEAR EQUAL TO STARTING YEAR-1 */
YEAR=1952;NEXT:  YEAR=YEAR+1;
DO I= 1 TO 24;
        GET FILE(SOLDISK)  EDIT ((ACTUAL(I,M) DO M=1 TO 12))

```

```

(COL(1), 12 F(10,2),SKIP);
END;
DO I=1 TO 24;
DO M=1 TO 12;
    IF SIGMA=0.00 THEN;
        DIST(I,M)=0.00;
    ELSE DO;
        ACTUAL (I,M)=ACTUAL(I,M)-YRMEAN(I,M);
        DIST(I,M)=(ACTUAL(I,M))/SIGMA(I,M);
    END;
NEXT2: END;
    END;
PUT SKIP(2) FILE(SOLOUR) EDIT('NUMBER OF STANDARD DEVIATIONS AWAY FROM
ALL YEAR MEAN',YEAR)(A,F(4,0));
PUT SKIP FILE(SOLOUR);
DO I=1 TO 24;
    PUT SKIP FILE(SOLOUR) EDIT((DIST(I,M) DO M=1 TO 12))(COL(1),12
F(10,4),SKIP);
END;
DO M=1 TO 12;
    DO H=1 TO 24;
        DIST (1,M)=DIST(1,M)+DIST(H,M);
    END;

```

```
        GRAND=GRAND+DIST(1,M);  
END;  
PUT SKIP FILE(SOLOUT):  
PUT SKIP FILE(SOLOUT)  EDIT ((DIST(1,M) DO M=1 TO 12))  
(COL(1),12 F(10,4),SKIP);  
PUT SKIP FILE(SOLOUT)  LIST (GRAND);  
GRAND=0;  
GOTO NEXT;  
EOF:  END COMPARE;
```

## APPENDIX F.

This program reads specified year from SOLMET tape and writes to disk.

```
INSTAPE: PROC OPTIONS(MAIN);
DCL SOLMET FILE INPUT ENV(FB RECSIZE(163) BLKSIZE(3912));
DCL SOLDISK FILE OUTPUT ENV(F RECSIZE(130));
DCL BUFFER CHAR(163) INIT(' ');
DCL DATA CHAR(2) INIT(' ');
DCL YR CHAR(2) INIT (' ');
DCL MO CHAR(2) INIT(' ');
ON ENDFILE(SOLMET) GOTO EOF;
RED: READ FILE(SOLMET) INTO (BUFFER);
GET STRING(BUFFER) EDIT(DATA)(A(130),X(33));
YR=SUBSTR(DATA,10,2);
/* SPECIFY YEAR AFTER DESIRED YEAR BELOW */
IF YR='54' THEN GOTO EOF;
/* SPECIFY DESIRED YEAR HERE */
IF YR='53' THEN DO;
WRITE FILE(SOLDISK) FROM(DATA);
END;
ELSE GOTO RED;
GOTO RED;
EOF: END INSTAPE;
```

This program converts year of data from INSTAPE to format appropriate for simulation.

```

SOL:  PROC OPTIONS(MAIN):
DCL SOLMET FILE INPUT ENV(F RECSIZE(130));
DCL SOLDISK FILE OUTPUT ENV(F RECSIZE(80));
DCL YEAR, LYEAR FIXED DEC(2)  INIT(0);
DCL DAY_NUMBER, HOUR_ANGLE FIXED DEC(6,2)  INIT(0);
DCL DECLINATION, ATTITUDE FLOAT DEC(15,2)  INIT(0);
DCL LATITUDE FIXED DEC(5,2)  INIT(0);
DCL TOTAL_NOR, NTOTAL_HOR, LTOTAL_HOR FIXED DEC(7,3)  INIT(0);
DCL DIFFUSE, DIRECT, NDIRECT, LDIRECT, DIRECT_HOR FIXED DEC(7,3)  INIT(0);
DCL HOUR, SOLHOUR, SOLMIN, STHOUR, STMIN, LSOLHOUR, LSOLMIN, LSTHOUR, LSTMIN
FIXED DEC(5,2)  INIT(0);
DCL ELAPSE FIXED DEC(6)  INIT(0);
DCL TEMP, WIND, LTEMP, LWIND FIXED DEC(6,2)  INIT(0);
ON ENDFILE(SOLMET)  GOTO EOF;
DAY_NUMBER=0;
LATITUDE=42.3;
GET FILE (SOLMET)
EDIT(LYEAR, LSOLHOUR, LSOLMIN, LSTHOUR, LSTMIN, LBIT, LDIRECT, LTOTAL
HOR, LTEMP, LWIND)(COL(10), F(2), X(4), 4
F(2), X(4), F(1), F(4), X(26), F(4), X(45), F(4), X(7), F(4), SKIP);
LSOLMIN=LSOLMIN/60;

```

```

LSTMIN=LSTMIN/60;
IF LDIRECT=9999 THEN LDIRECT=0;
IF LTOTAL_HOR=9999 THEN LTOTAL_HOR=0;
IF WIND=0000 THEN LWIND=0;
IF LTEMP=9999 THEN LTEMP=0;
IF LSTHOUR=1 THEN DAY_NUMBER=DAY_NUMBER+1;
READ: GET FILE(SOLMET) EDIT(YEAR, SOLHOUR,SOLMIN,STHOUR,STMIN,BIT,
    DIRECT,TOTAL_HOR,TEMP,WIND)(COL(10),F(2),X(4),$F(2),X(4),
    F(1),F(4),X(26),F(4),X(45),F(4),X(7),F(4),SKIP);
IF STHOUR=1 THEN DAY_NUMBER=DAY_NUMBER+1;
DISPLACE=LSTMIN;
SOLMIN=SOLMIN/60;
STMIN=STMIN/60;
IF DIRECT=9999 THEN DIRECT=0;
IF TOTAL_HOR=9999 THEN TOTAL_HOR=0;
IF TEMP=9999 THEN TEMP=LTEMP
IF WIND=9999 THEN WIND = LWIND;
HOUR=LSOLHOUR+LSOLMIN+DISPLACE;
NTOTAL_HOR=DISPLACE*(TOTAL_HOR-LTOTAL_HOR)+LTOTAL_HOR;
NDIRECT=DISPLACE*(DIRECT-LDIRECT)+LDIRECT;
CALC: HOUR_ANGLE=15*(12-HOUR);
DECLINATION=ASIN(.39795*COSD)(.98563*(DAY_NUMBER-172))*180/3.14159;
ATTITUDE=ASIN((COSD(LATITUDE)*COSD(DECLINATION)*COSD(HOUR

```

```
ANGLE)))+(SIND(LATITUDE)*SIND(DECLINATION)))*180/3.14159;
DIRECT_HOR=NDIRECT*SIND(ATTITUDE);
IF DIRECT_HOR 0 THEN DIRECT_HOR=0;
NTOTAL_HOR=NTOTAL_HOR/3.6;
DIRECT_HOR=DIRECT_HOR/3.6;
DIFFUSE=NTOTAL_HOR-DIRECT_HOR:
PRINT:  PUT SKIP FILE(SOLDISK)  EDIT(YEAR,ELAPSE,HOUR,STHOUR,BIT,
      NTOTAL_HOR,DIFFUSE,DIRECT_HOR,TEMP/10,WIND/10)
      (COL(1),F(2),X(2),F(6),X(2),F(5,2),X(2),F(5,2),X(2),F(1),
      5 (X(2),F(7,2)),X(8));
LYEAR=YEAR;
LTOTAL_HOR=TOTAL HOR;
LDIRECT=DIRECT;
LSOLHOUR=SOLHOUR;
LSTMIN=STMIN;
SOLMIN=SOLMIN;
LSTHOUR=STHOUR;
LTEMP=TEMP;
LWIND=WIND;
ELAPSE=ELAPSE+1;
LBIT=BIT;
GOTO READ;
EOF:  END SOL;
```

## APPENDIX G

This program computes the net present value and breakeven capital cost based on simulation result (interactive).\*

```

NPV:  PROCEDURE OPTIONS (MAIN);
DECLARE SYSIN FILE INPUT;
DCL OUTFILE FILE OUTPUT;
DCL (LIFETIME,DEGR)FIXED DEC(15,4)  INIT(0);
DCL (NPV,SELLR,EFACT,PCAP,PFUEL,SCAP,SFUEL,BFUEL,PSTL,SSTL,
BSTL,PSELL,SSELL,BSELL,DSCT,VALUE)  FIXED DEC(15,4)  INIT(0);
DCL (DFACT,PRATE,SRATE,BRATE,TBENES,NBENES) (30)  FIXED
DEC(15,4)  INIT((30)0);
DISPLAY('ENTER LIFETIME,DEGR,EFACT,PCAP,PFULE,SCAP,SFUEL,
BFUEL,DSCT');
GET FILE(SYSIN) LIST(LIFETIME,DEGR,EFACT,PCAP,PFUEL,SCAP,
SFUEL,BFUEL,DSCT);
DISPLAY('ENTER PSTL,SSTL,BSTL,PSELL,SSELL,BSELL');
GET FILE(SYSIN) LIST(PSTL,SSTL,BSTL,PSELL,SSELL,BSELL);
DISPLAY('ENTER ACOL,EFF,FSUBCOST,VSUBCOST');
DO I=1 TO LIFETIME;
DFACT(I)=(1-DEGR)**I/(1-DEGR);
END;
DO J=1 TO LIFETIME;
PRATE(J)=PCAP+PFUEL*((1+EFACT)**J/(1+EFACT));

```

---

\*Note: (\$/wp) refers to system watts. See Foreword and Appendix A for more detail.

```
SRATE(J)=SCAP+SFUEL*((1+EFACT)**J/(1+EFACT));
BRATE(J)=BFUEL*((1+EFACT)**J/(1+EFACT));
TBENES(J)=PSTL*PRATE(J)+SSTL*SRATE(J)+BSTL*BRATE(J)+
PSELL*0.5*PRATE(J)+SSELL*0.5*SRATE(J)+BSELL*.5*BRATE(J);
NBENES(J)=TBENES(J)*DFACT(J);
NPV=NPV+NBENES(J)/(1+DSCT)**J;
END;
VALUE=((NPV/100)/ACOL)-(FSUBCOST/ACOL+VSUBCOST)/(EFF*1000);
PUT SKIP FILE(OUTFILE) EDIT('PRATE',SRATE", 'BRATE', 'TBENES',
'NBENES') (X(7),A,X(7),A,X(7),A,X(7),A,X(6),A,X(16));
DO I= 1 to LIFETIME;
PUT SKIP FILE(OUTFILE)
EDIT(PRATE(I),SRATE(I),BRATE(I),TBENES(I),NBENES(I))(5)F(12,2));
END;
PUT SKIP FILE(OUTFILE) EDIT('NPV=',NPV/100)(A,F(12,2));
PUT SKIP FILE(OUTFILE) EDIT('VALUE=',VALUE)(A,F(10,2));
END NPV;
```

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