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Economic Assessments of Intermittent, Grid-Connected Solar Electric Technologies: A Review of Methods

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ECONOMIC ASSESSMENTS OF INTERMITTENT, GRID-CONNECTED SOLAR ELECTRIC TECHNOLOGIES: A REVIEW OF METHODS

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SERI report

PREFACE

This report was prepared by the Solar Energy Research Institute (SERI) under Subtask 1105.20. It reviews the methods used for economic assessments of intermittent solar electric technologies in applications that are connected to conventional utilities. This effort was requested by the Planning and Technology Transfer Division of DOE. Because DOE must estimate solar technology cost goals, it is imperative that the advantages and limitations of the various assessment methodologies are understood. Potential users of solar electric technologies, particularly utilities and public service commissions, also should find this report useful. Theresa Flaim, a senior economist at SERI, is project leader. Timothy J. Considine, a Ph.D. candidate in the Department of Agricultural Economics at Cornell University and a graduate student intern at SERI during the summer of 1979, wrote Sec. 4.0. Robert Witholder, SERI, is co-author of Sec. 2.0. Michael Edesses, SERI, contributed to Secs. 1.0, 3.0, 4.0, and 6.0.

Several other SERI staff members should be acknowledged for their contributions to this report. Roger Taylor and David Percival read several drafts and made substantial contributions to Sec. 4.0. Gregg Ferris and Susan Christmas made suggestions that were useful throughout the report. George Fegan, Dean Nordman, and Ron Larson were helpful, particularly in the early stages of the project. Jack Cadogan, DOE, served as project monitor. He participated in all stages of the research and his contributions are evident throughout this report.

A working meeting on value analysis of solar electric technologies was held in Denver, Colorado, on May 17-18, 1979, that identified many of the issues discussed in this report. Comments made by individual participants are referenced in the text. In addition to SERI staff mentioned above (excluding Susan Christmas), participants included: Gerry Bennington (MITRE Corp.); Jack Cadogan (DOE); Jacques Gros (Policy and Evaluation, DOE); Ann Herlevich (SERI); Dennis Horgan (SERI); Edward Kahn (Lawrence Berkeley Laboratory); Bob McConnell (SERI); Walter Melton (Aerospace Corp.); Peter Moretti (Oklahoma State University); Gerald Park (Michigan State University); Thomas Reddoch (University of Tennessee); Jeffrey Rumbaugh (Electrical Energy Systems, DOE); Napoleon Salvail (Aerospace Corp.); and Jack VanKuiken (Argonne National Laboratory).

Theresa Flaim

Theresa Flaim, Leader
Economic Assessments of Intermittent, Grid-Connected Solar Technologies Subtask

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SUMMARY

Objective:

To review methods of economic assessment of intermittent solar technologies in applications that are connected to conventional utility systems. This report concentrates on research and development planning. More specifically, it concentrates on the problem of identifying solar electric technology cost goals--the system costs at which solar electric systems will compete with conventional technologies.

Despite this technology assessment perspective, utility analysts and public utility commissions should find the information in this report useful because of recent changes in regulations affecting the utility industry. The Public Utility Regulatory Policies Act of 1978 (PURPA) and related rules governing its implementation require utilities and utility commissions to consider rate reform and establish rates for power purchased from solar and other qualifying facilities. The problems associated with assessing grid-connected solar technologies are inextricably related to the problems associated with establishing rate-design policies for solar customers.

Discussion:

The report identifies factors that must be considered in assessing intermittent technologies. These factors include the timing of energy produced, the correlation between energy production and the customer's or the utility's load, and the resulting impacts on the utility system. A conceptual and graphic overview of these factors and their potential impacts on utilities is contained.

The report also reviews the methods that have been used in technology assessment studies. Average annual energy costs are examined; they are, however, inadequate for comparing intermittent and conventional technologies. Problems associated with assessing technologies from the utility customer's viewpoint are also discussed. Actual rate data are needed for these assessments; it is difficult to predict future rates because of the trend toward rate reform. Even if marginal cost pricing of electricity is adopted, it is not clear that utility planning models would provide more accurate estimates of value to the end user than would existing rate data, because utility planning models do not estimate rates per se, but rather the basic input needed to establish rates. The recommended procedure varies, depending on the type of customer considered. Utility planning models do, however, provide the most accurate estimates of the impact of solar customers on utilities.

The methods used to assess utility applications of solar electric technologies are also reviewed. The report identifies qualitatively the trade-offs among methods relative to accuracy and simplicity, and describes data problems and deficiencies in existing techniques, especially with respect to estimating reliability impacts and capital savings. The conclusion is that the best available method for estimating the value of solar technologies to utilities

is to apply production cost, reliability analysis, and capacity expansion models, but there is also a need for basic methodological development.

This report also discusses the types of economic assumptions and figures of merit used in the studies surveyed. Five major conclusions are drawn. First, input assumptions probably have the largest impact on the estimated value of a solar technology. Second, because economic assumptions are often unclear and inconsistent across studies, it is extremely difficult to interpret and compare results. Third, the dispute over whether residential customers weight first-year costs and savings more heavily than life-cycle costs is actually a dispute over the customer's discount rate. Considerable evidence suggests that residential users do weight first-year costs and savings heavily when making purchase decisions about durable goods, which usually means that the user's cost of borrowing is lower than the user's rate of time preference or the user's discount rate. Fourth, value estimates provide basic information needed to identify cost goals for particular technologies. Finally, combined cost-value measures are needed to compare different technologies and applications.

Unresolved issues common to all methods of assessment are described in the last section of the report.

Recommendations:

Two recommendations emerged from this study. First, basic methodological development should continue to resolve the problems common to all methods of assessment. This development is necessary to provide utilities with the tools needed to evaluate investments in intermittent technologies. Second, because assessments using utility planning models are too expensive to be used in many situations, two activities should be pursued to meet Department of Energy research and development planning needs: (1) a normalization and synthesis of the results of existing studies, and (2) the improvement and validation of simpler methods of assessment.

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INTRODUCTION

Economic assessments of intermittent, grid-connected solar electric technologies* provide useful information to research and development (R&D) planners. U.S. Department of Energy staff have identified specific types of economic information and techniques that would greatly facilitate R&D planning. These include (1) an understanding of what solar electric technologies will have to cost to compete with conventional technologies, (2) techniques for performing sensitivity analyses of certain economic policy variables, (3) economic measures and methods of displaying results that will facilitate communication of results to DOE managers, and (4) an understanding of the social costs and benefits of solar electric technologies. Of these four information needs, DOE's first priority is to understand solar technology cost goals; in this case, to understand what certain users can afford to pay for intermittent solar electric technologies, based on performance and on the cost of the alternatives against which they will have to compete.

This report addresses the first three planning needs. Additional problems associated with estimating the social costs and benefits of solar electric technologies are beyond the scope of this study. Generally, this report assesses methods that have been used for economic assessments of intermittent, grid-connected solar electric technologies and, based on that review, suggests alternative approaches to meeting these planning needs.

This report is directed primarily to DOE planners, SERI staff, and other analysts attempting to assess solar electric technologies and, hence, to understand technology cost goals. Despite this technology assessment perspective, utility analysts and public utility commissions (PUCs) should find the information in this report useful because of changes in regulations affecting the utility industry. The Public Utility Regulatory Policies Act of 1978 (PURPA) and related rules governing its implementation require utilities and PUCs to both consider general rate reform and establish rates for power purchased from solar and other qualifying facilities. The problems associated with assessing grid-connected solar technologies are inextricably related to the problems associated with establishing rate design policies for solar customers.

1.1 DEFINITIONS OF BASIC CONCEPTS

Before describing factors that should be considered in assessing solar electric technologies, we will define the following basic concepts: (1) cost and

*Grid-connected solar electric technologies are those which are connected to a conventional electric utility. Intermittent solar electric technologies are those which convert wind or insolation to electric energy and include wind energy conversion, photovoltaic, and solar thermal electric systems. The studies reviewed in this report include assessments of both utility-owned central station applications and dispersed applications located on the customer's side of the meter.

value, (2) electricity supply costs, and (3) rate design and average cost pricing.

1.1.1 Cost and Value

The cost of a technology is the amount users would have to pay if they adopted a particular technology system. Costs are calculated across studies in a variety of ways. Differences in reported costs occur largely because different reports will exclude some cost items that are associated with using a particular device. For example, some studies will calculate the average cost of energy produced by the device; others will calculate the total cost of electric service to a user. The former measure is typically calculated by dividing the annual capital and operating costs of a system by its annual energy production, yielding an average annual cost of electricity generated by the device in dollars per kilowatt-hour (kWh). This calculation ignores other potential costs to the user. For example, the device may generate electricity during times when it is not needed or the user may have to purchase electricity from the utility to meet demands that occur when the device is not operating.

The total cost of electric service for a residential user would include not only the capital and operating costs of the solar technology system but also the cost of backup energy purchased from the utility. Revenues earned by selling excess power back to the utility would be subtracted from the user's cost. In other words, this measure would include all costs to the user, associated with meeting his electric demands, using a particular technology system.

The value of a technology is the amount a user can afford to pay for the technology, based on its performance and the cost of the alternative displaced.* For example, suppose a residential customer considers purchasing a solar hot water system as a means of reducing his electricity costs. The performance of the hot water system would be determined by the type and size of the system, and by the availability of insolation at the customer's house. System performance determines the amount of hot water produced which, in turn, determines the reduction in the kilowatt-hours (kWh) of electricity the customer must purchase to meet his hot water needs. Electricity purchased from a utility is the alternative that is displaced by the solar hot water system. The value of the hot water system to the customer is calculated from the difference in the customer's electric bill, with and without the solar water heater. Thus, value estimates provide basic information for identifying technology cost goals.

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*In this context, value is equivalent to avoided cost, the term the Federal Energy Regulatory Commission (FERC), uses to define the basis that should be used to calculate rates for power purchased from qualifying facilities. In other words, the value to the utility of power purchased from qualifying facilities is the fixed and variable costs the utility can avoid as a result of obtaining energy or capacity from qualifying facilities (FERC 1980).

The concepts of value and cost are closely related. The cost of the displaced alternative determines the value of the technology with which it is compared. Determining which measures of cost and value are sufficient for estimating solar electric technology cost goals is a major purpose of this report. A specific question is whether it is appropriate to use average annual energy costs to compare different technology systems. The answer to that question depends on how similar the operating and availability characteristics of the two systems are. Stated differently, it depends on whether the costs excluded from average annual energy costs are common to the alternatives compared.

1.1.2 Electricity Supply Costs

Electricity supply costs can be separated into four broad categories: generation, transmission, distribution, and customer-related expenses such as metering and billing. Each category has two components: fixed or capital costs and variable costs (such as fuel, operation, and maintenance). Throughout this report, the discussion of the impact of intermittent technologies on electric utilities refers primarily to generation impacts, for two reasons. First, cost impacts associated with transmission and distribution are likely to be very small relative to generation cost impacts (Kaupang 1980). Second, generation costs are becoming a larger proportion of total electric supply costs. Costs associated with generation increased from 45% of construction expenditures for investor-owned utilities in 1968, to 71% in 1978 (Edison Electric Institute 1979, p. 59).

In planning and operating generation capacity, a utility's basic objective is to supply minimum-cost electric power at high levels of service reliability. The amount of power a utility must supply (the utility's load) usually will vary by time of day and by season of the year. Figure 1-1 shows a daily load curve for a typical utility, or a utility's average hourly load by hour of the day. Variations in load determine variations in electricity production, because electricity cannot be stored inexpensively and because supply must equal demand at all times.

From hourly load data, an annual load duration curve can be constructed. An annual load duration curve describes the number of hours in the year that the utility's load equals or exceeds a given level, as illustrated in Fig. 1-2. (Unlike that in Fig. 1-1, which shows the chronological occurrence of loads, the load duration curve (LDC) ranks loads from highest to lowest, according to the number or percentage of hours that each level of load occurs.)

Given the load duration curve, a utility will attempt to install the sizes and types of generating units that minimize total system costs. For example, to supply its baseload--the minimum load a utility must be able to supply year round--a utility typically will install large units that are characterized by high capital costs, high fuel efficiencies, and low fuel costs--making them least expensive when operated a large proportion of the time. To meet intermediate and peak loads--loads that exceed the baseload but that must be met for relatively short periods of time--a utility will install smaller units with lower capital (and higher operating) costs, operated most economically operated for shorter periods of time (U.S. Congress, Office of Technology Assessment 1978, pp. 161-168).

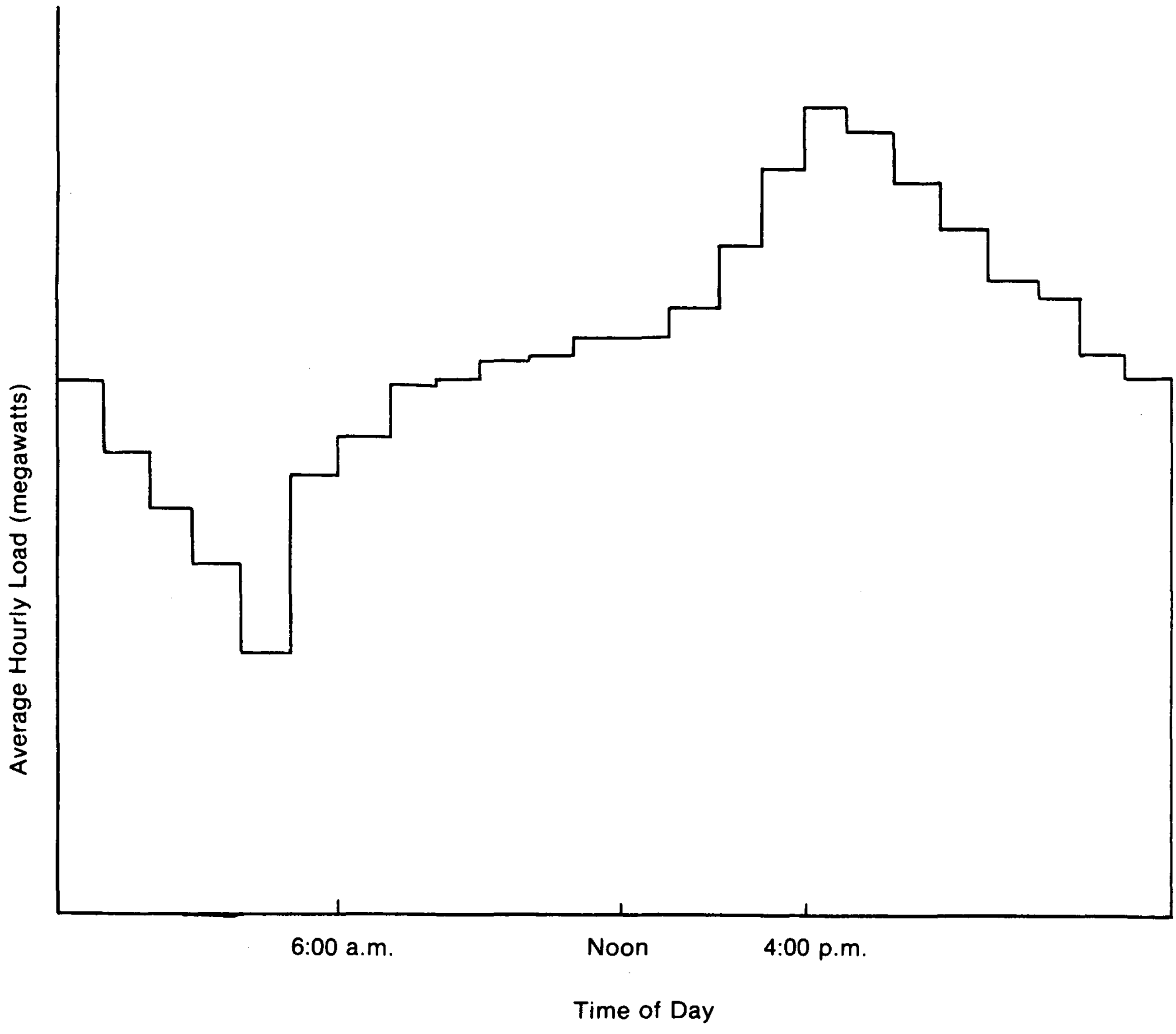


Figure 1-1. Daily Load Curve for a Typical Utility, Summer Peak Weekday

Source: (Whitaker 1977, pp. 6-7)

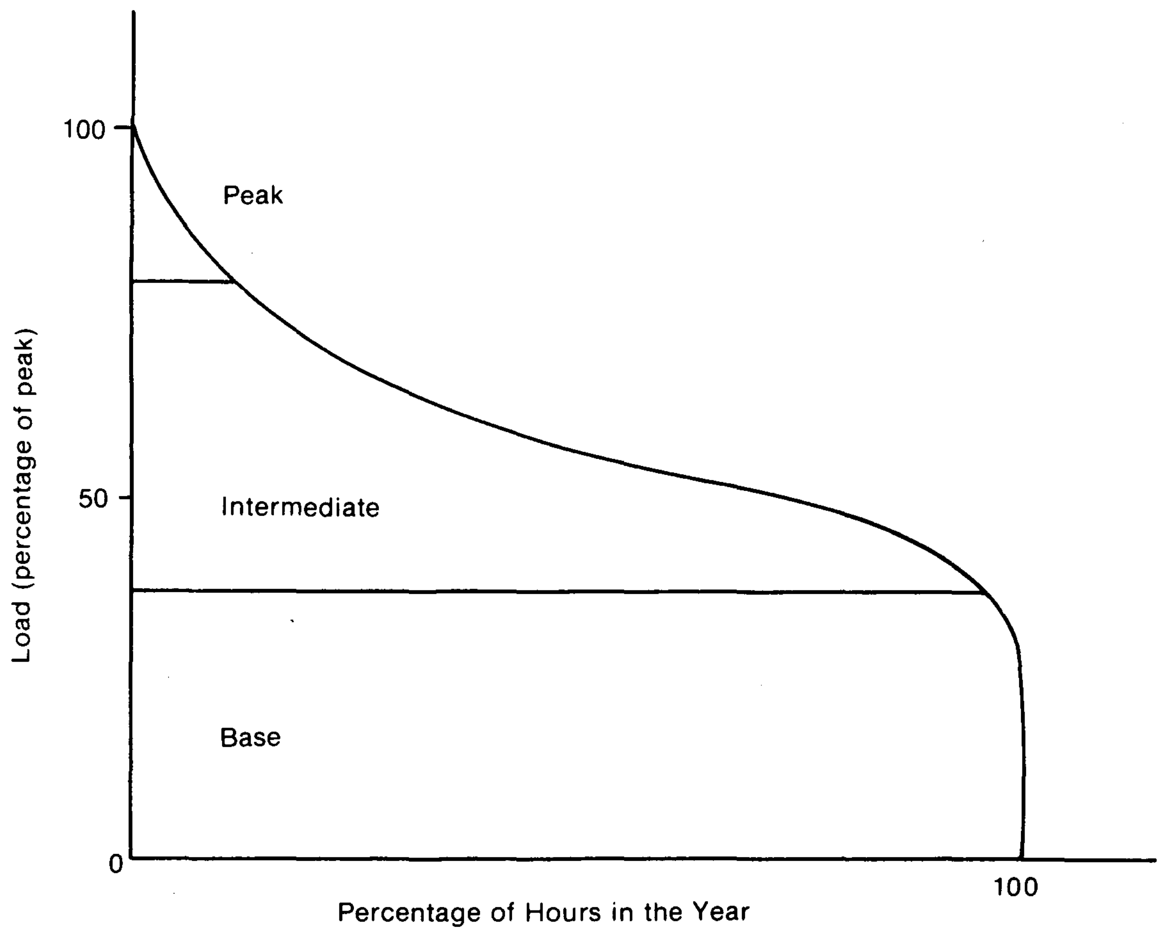


Figure 1-2. Annual Load Duration Curve for a Typical Utility

The utility's peak load, plus a reserve margin for reliability, determines the total amount of capacity that a utility must install. The reserve margin is needed to cover the possibility of either a unit breaking down and being forced out of operation or the load becoming unexpectedly high. The size of reserve margin needed to meet the utility's reliability standard will be determined by the characteristics of the generating units in the utility's system.

Given an installed mix of units, a utility will operate them to minimize fuel, operation, and maintenance costs. Hourly, daily, weekly, and seasonal variations in loads will affect the time that units are scheduled for operation and when they are scheduled for maintenance. A utility will try to operate baseload units with lower fuel costs whenever they are available and will try to minimize the use of peaking units with higher fuel costs. Stated differently, they will turn on their cheapest units first and their most expensive units last.

From this, we can see that the time profile of loads will affect the utility's cost of serving that load. Similarly, the time profile of power produced by a qualifying facility will determine the utility's avoided cost.

1.1.3 Rate Design and Average Cost Pricing

Electric utilities are regulated by state and federal agencies. Many regulatory policies apply to the industry, but the one that has a major impact on economic comparisons of solar and conventional technologies in dispersed applications is the general policy of fully distributed or average cost pricing. Average cost pricing is used here to mean pricing based on average, non-time differentiated accounting costs. Under average cost pricing, the utilities' costs for providing service are averaged together to determine the utility's revenue requirements. These costs include investment costs of existing generating, transmission, and distribution facilities (sunk costs); investment costs of new capacity as it is added to the system; fuel, operation, maintenance, and other expenses; and an allowance for a rate of return on investment. These revenue requirements are then allocated among consumer classes by various methods to determine the rates charged to users (Kaufman 1976, pp. 220-222).

Two characteristics of average cost pricing should be emphasized. First, this rate policy averages the cost of cheaper existing or embedded capacity with the higher cost of new capacity additions. Second, fuel costs are similarly averaged. Even though a utility may burn significant quantities of oil during hours of peak consumption and only coal during off-peak hours, rates generally are based on the utility's total annual average cost of fuel. Thus, average cost rates typically reflect neither the utility's short-term fuel costs nor the long-term capacity costs associated with serving loads at any point in time.

Title I of PURPA requires that utilities and public utility commissions consider adopting rates "designed to the maximum extent practicable to reflect the costs of providing service to that class" (Department of Energy, Economic

Regulatory Administration 1979). However, most utilities' rates still are based on average cost pricing.

1.2 OVERVIEW OF THE IMPACT OF INTERMITTENT TECHNOLOGIES ON ELECTRIC UTILITIES

Intermittent solar electric technologies depend on either wind or insolation, neither of which is available continuously. The user then has minimal control over when energy is produced. This constitutes the major difference between intermittent solar and conventional electric technologies. This intermittent nature of solar electric technologies makes them more difficult to assess.

Determining the impact of intermittent technologies on electric utilities involves three basic steps: (1) estimating the performance of the solar energy system, (2) determining the correlation between the time profile of energy produced by the solar facility and the time profile of the utility's load, and (3) calculating the resulting change in the utility's production costs. The amount and timing of energy produced by a solar technology will be determined by two factors--the availability of solar resources and the characteristics of the solar energy system. The availability of wind or insolation will vary according to region and site. System characteristics include equipment design, amount of storage, and operating strategy.

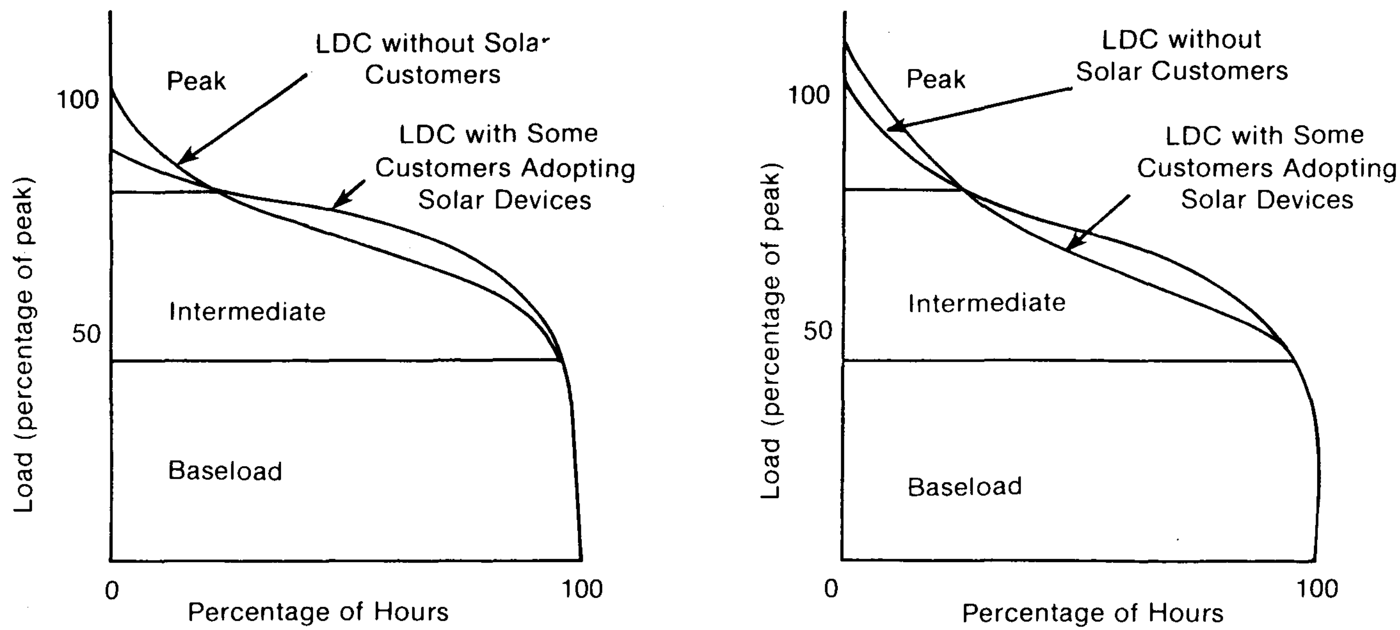
Given the estimated performance of the solar device, the next step is to adjust the utility's base-case load data to reflect the time profile of solar energy production or the time profile of solar customer loads. All other things being equal, a solar energy system with a time profile of energy production that is highly correlated with the time profile of energy consumption will be worth more to a user than a system for which the correlation between energy production and consumption is low.

After the utility's load data are changed, the resulting change in the utility's production costs can be calculated. The impacts of dispersed and utility applications on an electric utility are discussed separately.

1.2.1 Impact of Dispersed Applications on Utilities

Customers using solar electric energy will need to purchase auxiliary power from a utility and will have excess power to sell, depending upon when the customer consumes electricity and when the solar device is generating electricity. To simplify the discussion, the cost impacts associated with providing auxiliary power are discussed in this section. The cost impacts associated with utility purchases of excess power are described in Sec. 1.2.2.

The potential changes in a utility's production costs associated with serving customers of solar energy can be illustrated using an annual load duration curve. Figure 1-3 illustrates two types of changes in a utility's LDC that might occur if a number of customers adopted solar devices. Case I involves a situation where a number of customers who formerly consumed electricity during peak hours began using solar devices that require auxiliary power only during off-peak hours. This case is analogous to the impact of load management systems (Whitaker 1977). In the short-run, the utility could reduce fuel



Case I **Case II**

Figure 1-3. Potential Changes in the Annual Load Duration Curve (LDC) Resulting from Utility Customers Adopting Solar Devices (Dispersed User Applications)

costs by using high-cost peaking units less and low-cost intermediate-load units more frequently. In the long run, the utility could increase the proportion of efficient baseload capacity.

Case II illustrates the reverse situation: customers who formerly consumed energy during off-peak hours began to use solar devices that require auxiliary power during peak hours. In this situation, the utility's fuel costs are higher because peaking units are used more and intermediate units are used less. In addition, the utility's peak load has increased, which necessitates the installation of more capacity to maintain reliability. If the total number of kWh generated does not increase proportionately, the utility's average cost per kWh will increase because more fixed costs will be required to produce the same quantity of output.

As these two cases illustrate, a utility's cost of supplying electricity may change as customers adopt solar technologies. The direction and magnitude of those cost changes will vary from situation to situation, depending on the interaction of all the factors described here: the type of solar technology systems adopted, the availability of solar resources, the number of customers involved, the coincidence of the solar customers' loads and the utility's load, and the type of generating capacity in the utility's system.

A change in a utility's cost of supplying electricity, resulting from customer use of solar technologies, is not a problem per se. Even without the penetration of solar technologies, a utility's supply costs will change as fuel and capital costs change, as well as because of normal variations in load patterns.

However, two problems arise because average cost rates do not reflect the utility's short-run fuel costs or long-run capital costs associated with serving loads at different times. First, to the extent that rates fail to reflect the utility's actual costs, the value of a solar technology to the user will differ from the value of the technology to society. Electricity rates determine the value of a solar investment to the customer. Customer savings associated with the investment will be determined by the difference in the customer's electric bill, with and without the solar investment. Under average cost pricing, solar customers in Case I of Fig. 1-3 will pay rates that are too high, that do not reflect the full savings to the utility. The solar investment will be worth more to society than it will to the customer because some of the cost savings will accrue to other customers or to the utility.

The reverse situation is true for Case II in Fig. 1-3. Solar customers will pay rates that are too low and the investment will be worth less to society than it is to the customer because other customers will have to bear part of the increase in the utility's production costs.

The second problem associated with average cost pricing exists because of pressure to consider rate reform: existing rates may not reflect future rates and future rates are difficult to predict. This creates problems for assessing the value of solar technologies to end-users, particularly for those technologies not likely to be commercially available soon. Both problems are discussed in greater detail in Sec. 3.0.

Note that the problems associated with average cost pricing apply to assessing the value of any investment that affects electricity consumption. They are not unique to solar technologies.

1.2.2 Impact of Solar Technologies in Utility Applications

In utility applications, the time profiles of power produced from the solar plant (or power purchased from solar qualifying facilities) and the utility's load will determine the extent to which a solar plant can displace conventional fuel and capacity costs. As for dispersed applications, the potential changes in the utility's supply costs can be illustrated using an annual load duration curve.

Intermittent solar electric technologies are generally characterized by higher capital costs per kilowatt (kW) of capacity and by lower variable costs per kWh than conventional units. As a result, once solar plants are installed, the utility would minimize operating costs by using power from the solar plant whenever possible. The solar plants would be operated first, so the savings to the utility usually are estimated by first subtracting power generated by solar plants from the utility's load duration curve.* Short-run fuel cost savings can then be estimated by dispatching the conventional units in the system against this "reduced" LDC. Long-run fuel and capacity cost savings can be estimated by reoptimizing the utility's generating mix against the reduced LDC.

Figure 1-4 illustrates two types of changes that could result from subtracting solar generation from the utility's load duration curve. In Case I, the time profile of solar generation is highly correlated with the utility's peak loads, allowing the utility to displace some of its more expensive fuels. In addition, if there is a high probability that solar resources will be available when the utility's loads are highest, the utility can serve an increased peak load at the same level of reliability, saving capacity costs by deferring or eliminating the need for some conventional capacity.

In Case II, solar generation usually is available only during the utility's off-peak hours. Short-run fuel cost savings are lower than for Case I because the solar plant is displacing less expensive fuel. The utility cannot defer capacity needed to meet increases in peak loads, because solar generation is not correlated with peak loads. However, the utility may be able to save fuel and capacity costs in the long-run by reoptimizing its generating mix--by substituting peaking units for baseload capacity, for example.

*Utilities are required to purchase power from qualifying facilities at all times except under special circumstances (FERC 1980). Thus, this general procedure is also appropriate for estimating the utility's avoided costs resulting from purchases from qualifying facilities.

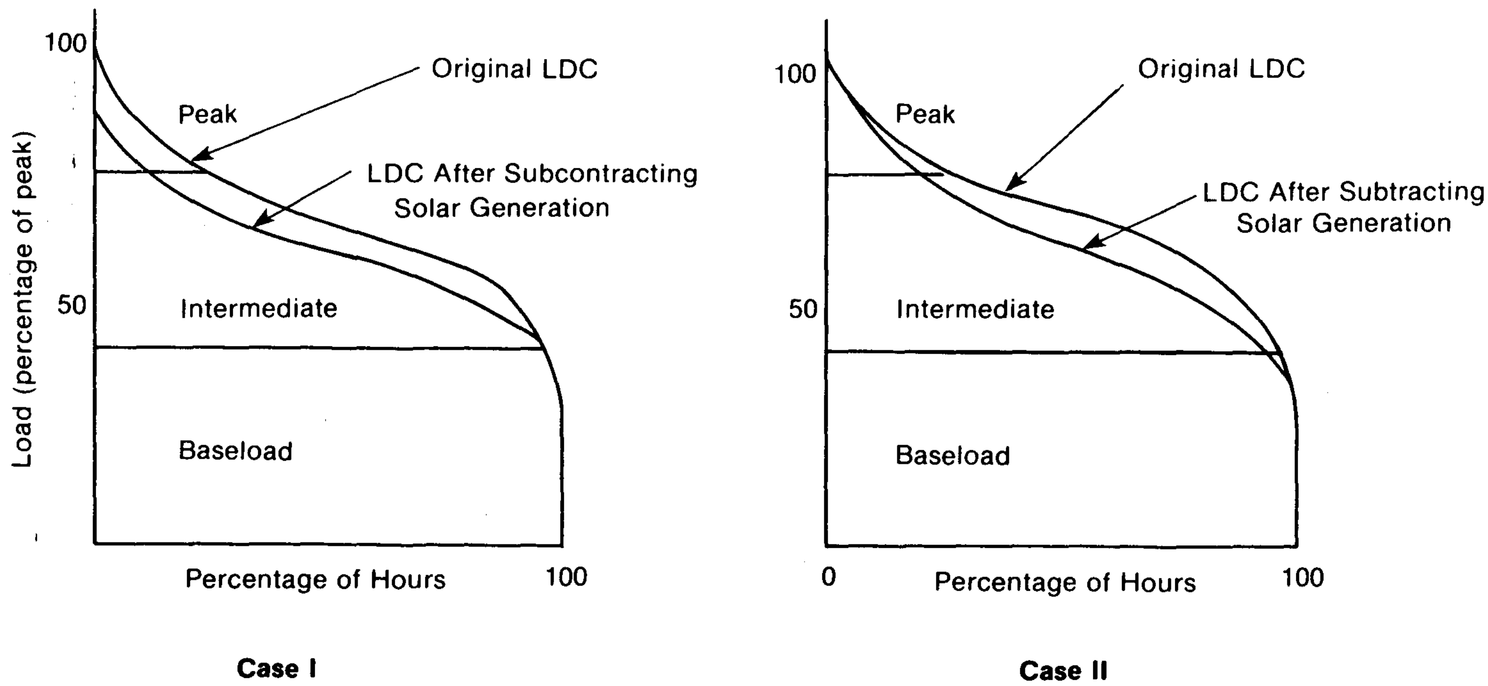


Figure 1-4. Potential Changes in the Annual Load Duration Curve (LDC) After Subtracting Generation from Solar Plants (utility applications)

These two cases illustrate that the value of a solar plant--or of power purchased from solar qualifying facilities--will vary, depending on the correlation between solar generation and the utility's load as well as on the type of conventional units in the utility's system. The value of the solar plant is equal to the incremental capital and operating costs that the utility would have incurred without the addition of the solar plant. The problems associated with average cost pricing do not apply to utility applications because the relevant comparison is to the actual costs the utility would incur without the solar plant.*

1.3 BACKGROUND

In the past, three general categories of methods have been used for economic assessments of solar electric technologies: (1) simple methods that base economic comparisons on annual average energy costs, (2) simulation techniques applied to dispersed user applications, and (3) utility planning models applied to utility applications. These categories are descriptive rather than definitive but are useful for distinguishing among the types of approaches that have been applied in various studies.

Category 1 includes those studies that have compared solar and conventional electric generating technologies on the basis of their energy costs. Energy costs are calculated by dividing the annual capital and operating costs for a plant or device by the plant's expected annual energy production. The intermittent availability of solar resources is reflected, approximately, through the plant's capacity factor, which is typically lower for a solar plant than for a conventional plant. This method has been applied to both utility and end-user applications of solar technologies. It is also the approach outlined in The Cost of Energy from Utility-Owned Solar Electric Systems, a Required Revenue Methodology for ERDA/EPRI Evaluations (Doane et al. 1976).

Category 2 includes studies that have used simulation techniques to assess solar electric and space conditioning applications that are adopted by consumers connected to an electric utility for auxiliary power. It is difficult to speak generally about the diverse approaches used in these studies, but they do share the following broad characteristics:

- they modeled the performance of the solar energy system;
- they determined the consumer's load patterns for the applicable energy service; and
- they usually calculated both the consumer's total annual costs associated with meeting energy needs, with and without the solar device, and the utility's actual costs of serving the solar customer compared to the cost of serving a conventional customer.

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*The same definition of value also applies to calculating rates for power purchased from solar qualifying facilities because the FERC's final rule implementing Section 210 of PURPA states that "the utility's avoided incremental costs (and not average system costs) should be used to calculate avoided costs" (FERC 1980, p. 12216).

Existing rate data are typically used to calculate the consumer's annual costs. The utility's actual costs to serve were estimated using widely varying methods, ranging from obtaining a utility's cost-to-serve estimates to using a generation expansion model.

Category 3 includes studies that have employed utility planning models to assess utility applications of wind, photovoltaics, and solar thermal electric systems. It has been used primarily in detailed application studies, such as General Electric's Requirements Assessment of Photovoltaic Power Plants in Electric Utility Systems (General Electric 1979). This approach typically has involved the use of several computer models, including a solar performance model, a utility production cost model, and, in some cases, a generation expansion model. The studies in this category usually have reported both values and costs for the solar electric technology.

1.4 STUDY APPROACH

The study approach involves (1) the identification of relevant studies, (2) the development of criteria by which the methods of economic assessment will be compared, (3) a comparative review of the methods used in existing studies, (4) a review of the figures of merit and cost computation techniques employed, (5) an assessment of the trade-offs among methods based on ease of use and credibility of results, (6) the identification of an approach to be adopted or developed, and (7) the development and application of the selected approach.

This is an interim report that describes the results of activities (1) through (5). In addition, it suggests a range of alternatives that could be pursued to meet the DOE planning needs described above, and discusses their advantages and limitations. The final selection of an approach will be based on reviews by DOE staff and other analysts.

1.4.1 Identification of Relevant Studies

More than 100 reports and articles related to economic assessments of grid-connected solar technologies were identified. These include mission analyses, design studies, venture analyses, and detailed application studies related to utility or end-user applications of photovoltaics, wind, solar thermal electric, total energy, hybrid, and solar thermal technologies. Many of these reports and articles are not directly relevant to this study; therefore, approximately 30 reports were reviewed in detail. A complete list of the reports and articles is presented in Appendix A.

Note that, although this study is concerned with methods of assessing solar electric technologies, several reports on solar thermal applications also were reviewed in detail. These reports were included because few studies have been completed on end-user, grid-connected solar electric applications that attempt to analyze the impact on the electric utility,* and because the methods

*The Electric Power Research Institute sponsored studies of grid-connected, distributed applications of wind and photovoltaics, including both user- and utility-owned systems. These studies were in progress when this study was completed and reports were not available for review.

required for determining the cost of providing back-up service probably will be similar for both types of applications. Studies that calculated back-up costs using utility rate data only were not reviewed in detail. However, the advantages and limitations of this approach are discussed in Sec. 3.0.

1.4.2 Criteria for Comparing Methods of Economic Assessment

1.4.2.1 General Criteria: Simplicity vs. Credibility

Selecting an appropriate economic assessment technique may involve a compromise between simplicity and credibility of results. The distinction between simplicity and credibility is somewhat arbitrary. To the extent that a simple method is readily understood by a wide audience, credibility and simplicity are positively related. Basically, the simplicity of a method is measured by how easy it is to use, how much it costs, and whether it can be readily understood. The credibility of a method must be defined as to how it relates to a particular audience, how the results will be used, and how accurate the value estimates are.

The relative accuracy of value estimates is ascertained by noting whether the estimates are within acceptable limits. Accuracy will be affected not only by the methodology employed but also by the input data and other assumptions used. As a result, assessing the accuracy of particular value estimates is beyond the scope of this report. Instead, two questions are addressed in assessing which methods are appropriate for estimating values: (1) Does the existing literature indicate that detailed simulation methods are the best available techniques for analyzing the major determinants of value? (2) If so, to what extent will simpler methods result in a loss of precision in the estimates of value? These two questions provide an overall framework within which existing methods of assessment are reviewed.

1.4.2.2 Specific Characteristics of Methods

Methods of assessment are compared according to how particular factors affecting value are analyzed. These specific characteristics can be divided into three areas (technical, economic, and general characteristics) and are summarized in Table 1-1. Technical factors include solar performance characterization and the analysis of the interaction between the solar technology and the conventional power system. The economic factors considered are types of input assumptions, techniques of computation, and figures of merit. These criteria are explained in greater detail in Secs. 2.0 through 5.0.

1.4.3 Review of Methods

The characteristics of each study reviewed are summarized and compared according to how each factor listed in Table 1-1 is analyzed within the study's methodology. This information is used to compare the methods that have been employed in economic assessments of solar electric technologies.

Table 1-1. Specific Characteristics to be Used for Comparing Methods Applied in Economic Assessments of Intermittent, Grid-Connected Solar Electric Technologies (Utility and End-User Applications)

I. TECHNICAL
- A. Solar performance
  - 1. Resource data
    - a. Degree of detail
    - b. Number of years of data
  - 2. Solar technology
    - a. Performance computation
    - b. Operating strategy
- B. Utility Applications
  - 1. Utility characterization
    - a. Load data
    - b. Generation mix
    - c. Transmission and distribution
  - 2. Impact of solar technology on utility
    - a. Method of analysis
    - b. Factors considered
      - (1) Fuel savings
      - (2) Capacity credit
      - (3) Reoptimized generating mix
      - (4) Spinning reserve requirements
      - (5) Solar share of system capacity
- C. End-user applications
  - 1. User characterization
    - a. Load data
      - (1) Degree of detail
      - (2) Number of years of data
    - b. Number of users--aggregation and load diversity
  - 2. Impact of solar technology on utility
    - a. Back-up costs
      - (1) Calculated cost to serve
      - (2) Flat rates (existing rates)
    - b. Sell-back rates
      - (1) Calculated value to utility
      - (2) Assumed rates
    - c. Market penetration level

II. ECONOMIC
- A. Input assumptions
  - 1. Finance costs
  - 2. Taxation rates
  - 3. Cost escalation rates
  - 4. Resource costs
- B. Techniques of computation
  - 1. Present values of costs and savings
  - 2. First-year costs
  - 3. Constant vs. nominal dollars
- C. Decision variables (figures of merit)
  - 1. Solar value
    - a. Break-even capital costs
    - b. Break-even energy costs
  - 2. Solar costs
    - a. User's total costs of service
    - b. Energy costs
  - 3. Combined cost-value measures
    - a. Cost/value ratio
    - b. Net value

III. GENERAL
- A. Responsiveness to planning needs
  - 1. Ability to estimate values of photovoltaic, wind, and solar thermal electric technologies
  - 2. Precision of value estimates
  - 3. Simplicity
    - a. Ease of use
    - b. Comprehensibility
- B. Resource requirements
  - 1. Labor
  - 2. Computer

1.4.4 Assessment of the Trade-offs Among Methods

The trade-offs among methods of economic assessment are identified in the following manner. First, methods that are believed to yield the most accurate estimates of value are identified. In other words, if you need to know, with maximum accuracy, the value of a particular device in a particular application, what factors should be considered (according to the literature) and which modeling techniques should be used? Data problems, deficiencies in existing techniques, and unresolved methodological problems are also identified. This information provides the basis for identifying the trade-offs between simplicity and credibility of results.

Second, the techniques used to assess each of the factors affecting value are identified and categorized according to complexity, computation cost, and ease of use. The authors assess qualitatively the extent to which simpler methods result in a loss of accuracy.

Based upon the information gathered, a range of alternatives emerge for adopting or developing economic assessment techniques; and their advantages and limitations are described. Final selection of the methods to be adopted or developed will be based upon reviews by DOE staff and outside consultants through a series of working meetings.

1.5 CONTENTS OF THIS REPORT

In this section, we have outlined the study objectives and approach. Section 2.0 reviews methods that base economic comparisons on average annual energy costs, discussing their advantages and limitations. Section 3.0 describes and assesses simulation techniques applied to dispersed user applications. Section 4.0 reviews planning models that have been applied to utility applications of solar electric technologies. Section 5.0 discusses the types of economic assumptions, computation techniques, and figures of merit used in the studies reviewed. Section 6.0 summarizes the best available techniques, discusses the unresolved problems common to all methods of assessment, and suggests a range of strategies that could be pursued to meet DOE planning needs.

Appendix A contains a list of reports and articles that relate to economic assessments of grid-connected solar technologies. Appendix B is a glossary of terms pertinent to this study. Appendix C contains a detailed description of the studies of dispersed applications.

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SECTION 2.0

SIMPLE METHODS FOR ECONOMIC COMPARISONS

Among the studies surveyed, two relatively simple methods for economic comparisons of solar and conventional electric technologies were found. The first calculates electric energy costs and has been used widely in design studies, mission analyses, and market penetration studies (Doane et al. 1976; McDonnell Douglas Astronautics Co. 1977; Ramakumar et al. 1976; Rattin 1977; Todd et al. 1977; Spectrolab 1977; Hightower and Watts 1977; Lindley 1977; Brulle 1977; MITRE 1977; Kaman Aerospace Corp. 1976). The second method involves designing a solar energy system comparable to a conventional system so that direct energy cost comparisons can be made. Each of these methods is described in the following sections, and its usefulness for comparing solar with conventional technologies is assessed.

2.1 CALCULATION OF AVERAGE ANNUAL ENERGY COSTS

Energy costs are those associated with producing electricity from a particular plant or device. They are calculated by dividing the annual costs associated with an energy system, such as a photovoltaic or coal-fired power plant, by the annual energy production of that plant. Included in the computation of annual costs are all capital and operating costs associated with the plant or device. All other costs associated with electricity service are excluded, including transmission and distribution costs and costs associated with maintaining reliability of supply.

Although the cost calculations used in different studies have varied, they are basically determined by calculating the present value of total costs over the lifetime of the system. Given the present value of costs, annualized costs can be calculated by finding the annuity (annual payment) whose present value is equivalent to the present value of total costs (Doane et al. 1976, pp. III-11 through III-13). When annualized system costs are divided by annual energy production, the levelized costs per unit of energy produced are calculated.

The ERDA/EPRI required revenue methodology for evaluating utility-owned solar electric systems is one of the most widely used approaches for calculating energy costs. It was developed to eliminate inconsistencies in study results that occurred because contractors were using different costing methods and financial parameters (Doane et al. 1976, p. iii). The methodology calculates the present value of system costs over the lifetime of the system, and then converts this value to a levelized cost per unit of energy produced. The input data and computations used in the ERDA/EPRI methodology are illustrated in Fig. 2-1. The levelized energy cost calculated using this methodology "can be interpreted as the minimum price at which energy from the system could be sold and still produce revenues sufficient to recover all system-resultant costs" (Doane et al. 1976, p. III-1).

The performance of the solar technology is not computed as part of the methodology but is a required input. The user (in this case, a utility) is

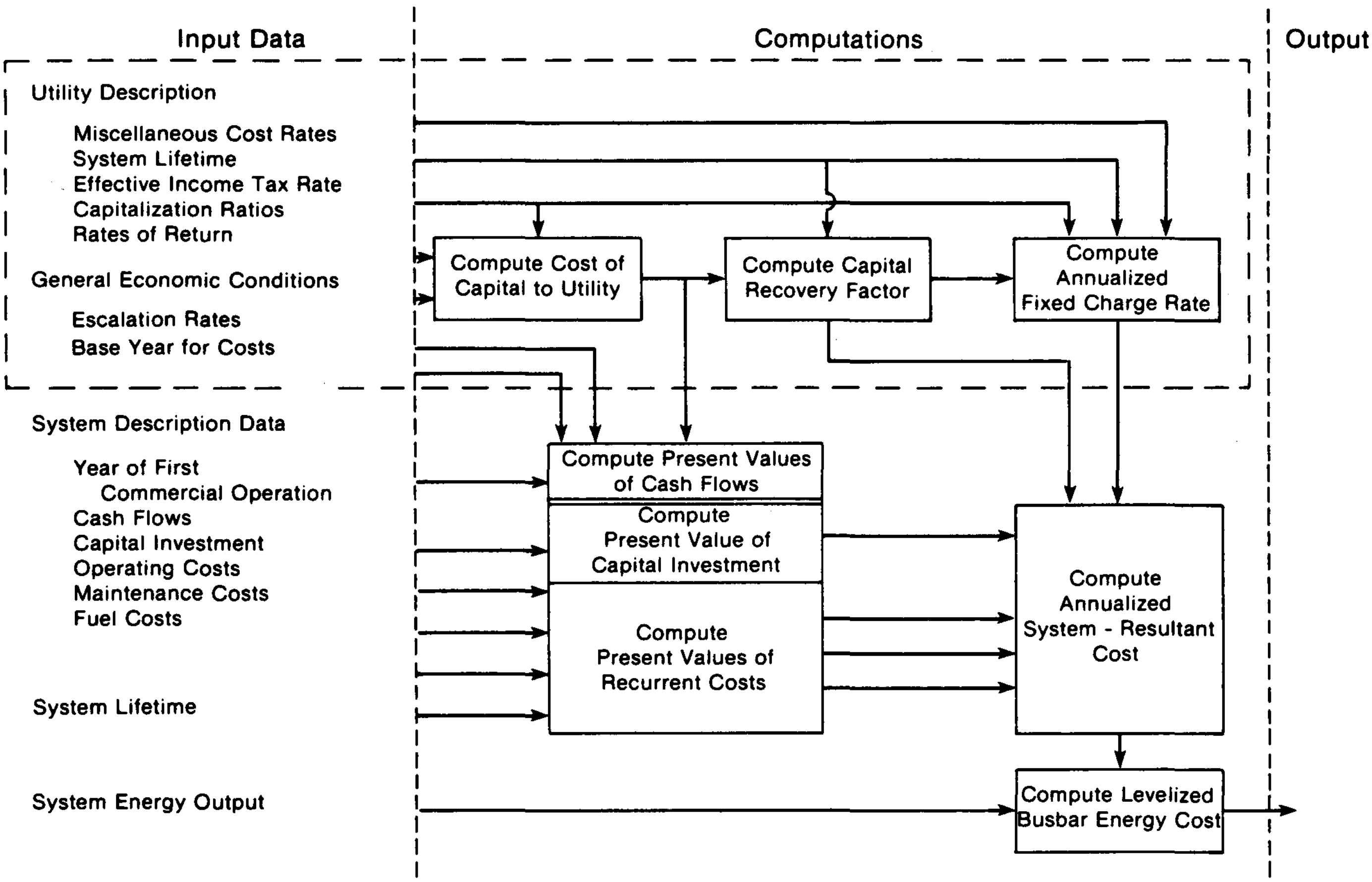

Figure 2-1. Structure of the ERDA/EPRI Required Revenue Methodology

characterized in terms of economic parameters (effective income tax rate, capitalization ratios, cost of capital, and general cost conditions). The user is not characterized in terms of load data, existing generation mix, and so on.

Studies that have used this general approach assess solar electric technologies by simply comparing the average energy costs of the solar device either to the energy costs associated with a conventional generating unit or to the price a customer would pay for electricity purchased from a utility.

Though estimating energy costs for a solar electric technology is not a trivial matter, it is the simplest of the economic assessment methods reviewed. Its calculation is straightforward and the result is widely understood by researchers, planners, and potential consumers.

The major disadvantage of the method is that using it to compare technologies implies that each kWh generated is of equal value to the user. As a result, it is most valid for comparing generating sources with identical operating and availability characteristics (Day 1979, p. 7). Jordan et al., argue that levelized energy costs form a valid basis for comparing alternate generating technologies only if the following conditions hold:

- All alternate generating sources have the requisite ability to start, stop, and follow the utility load curve.
- All alternate units have the same impact on system requirements for reserve capacity; i.e., their combination of unit size, maintenance time, and forced outage rate produces equal effective capacity as determined by probabilistic analyses.
- All alternate sources operate on the utility system at the same capacity factor throughout their lives. For this to be true, they must not only have sufficient operating flexibility but similar economic characteristics with respect to unit commitment and equal incremental fuel, operation, and maintenance costs. (Jordan, Marsh, and Oplinger 1978, p. 345).

Jordan et al., recognized that if the above criteria were strictly applied, levelized energy costs could never be used to compare generating alternatives. That study also observed that energy costs are useful for making preliminary comparisons of reasonably similar technologies. However, they are less valid for comparing technologies with widely different operating and availability characteristics, such as intermittent solar electric and conventional electric technologies (Jordan, Marsh, and Oplinger 1978, p. 346). A major problem is that the calculation of energy costs excludes other costs that a user or utility might incur as a result of using a particular device. An example discussing the value of wind turbines in a utility application will illustrate.

Suppose that the objective of a study is to assess the value of a wind turbine for a utility that has two types of generating units, oil and coal; that oil is three times more expensive than coal; and that the utility intends to use the wind turbine to displace fuel only. The analyst has the option of comparing the energy cost of the wind turbine to the energy cost of the oil units, or the energy cost of the coal units, or to some combination of both.* The actual value to the utility will depend on when the wind turbine is generating electricity relative to when oil and coal units are operating the system. If a detailed analysis of wind turbine performance and utility system operation indicates that the turbine would displace equal amounts of oil and coal, then a comparison of wind turbine energy costs to oil unit energy costs alone would overestimate the value of the wind turbine, because it would imply greater oil displacement than would actually be realized. A direct comparison to coal unit energy costs would underestimate the value of the turbine for similar reasons.** Thus, comparisons of energy costs can provide seriously misleading estimates of the value of intermittent technologies.

The accuracy of energy cost comparisons depends on how similar the operating and availability characteristics of the two systems are. Alternatively, it depends on whether the costs excluded from the calculation are common to the alternatives being compared.

2.2 ENERGY COST COMPARISONS BASED ON COMPARABLE SYSTEMS

An intermittent solar energy system must be designed with sufficient storage or backup power to make its operating and availability characteristics comparable to those of a particular conventional generating unit (MITRE 1977, p. 6). Once comparable systems are designed, a direct comparison of their energy costs can be made and the value of the solar technology can be computed based on the relative energy costs of the two systems. Variations on this approach have been used by Bradley and Costello (1977) and by MITRE Corporation (1977).

Bradley and Costello examined the economic feasibility of central photovoltaic plants in terms of what a utility could afford to pay for the system based on fuel and capital savings. They assumed that a photovoltaic plant "plus gas turbines for backup creates generating capacity which has nearly the same performance and reliability aspects as an intermediate coal-fired plant" (Bradley and Costello 1977, p. 701). Thus, the value of the solar plant to the utility, which Bradley and Costello call the maximum acceptable price of the solar system in $/kW, is defined by the following equation:

$$\begin{array}{l}\text{Value of} \\ \text{Solar Plant (\$/kW)}\end{array} = \left[\begin{array}{l}\text{Present Value of Displaced} \\ \text{Variable Operating Costs}\end{array}\right] - \left[\begin{array}{l}\text{Present Value of Solar} \\ \text{Operation and Maintenance} \\ \text{Costs}\end{array}\right] + \left[\begin{array}{l}\text{Intermediate Coal} \\ \text{Capacity Costs}\end{array}\right] - \left[\begin{array}{l}\text{Gas Turbine Backup} \\ \text{Capacity Costs}\end{array}\right]$$

*Note that an analyst calculating only the energy costs of two generating units will not be able to determine the actual combination of oil and coal displaced. Such a calculation would necessarily involve some analysis of the time profile of wind energy production, and the time profile of unit operation on the utility system.

**Stated differently, the oil-wind energy cost comparison implies a lower balance-of-utility-system cost than would actually be the case. The coal-wind comparison implies a higher-than-actual balance-of-system cost.

The value of the solar technology is expressed in dollars per kilowatt of installed solar capacity, and is equivalent to the break-even capital cost discussed in Sec. 5.2.3.3.

According to Bradley and Costello, the major portion of the value of a photovoltaic plant to a utility is reduced operating costs, derived mainly from reduced fuel consumption. They represent operating costs as a levelized, weighted average for each utility and plot the value of solar against average utility operating costs, as illustrated in Fig. 2-2. This figure shows "that a utility in the Southwest having a levelized fuel cost of 20 mills per kWh would be willing to pay approximately $800 per installed kW, while a utility in the Northeast with the same fuel cost would only be willing to pay approximately $600 per installed kW" of photovoltaic electric power system capacity (Bradley and Costello 1977, p. 704).

The MITRE Corporation also uses a comparable system design approach for several of the applications considered in SPURR (System for Projecting the Utilization of Renewable Resources) (MITRE 1977). SPURR is a market simulation model that was designed to analyze the impact of policies aimed at accelerating the commercialization of solar technologies. It covers four general market sectors: heating and cooling of buildings, agricultural and industrial process heat, centralized electricity generation, and synthetic fuels and products. Wind, photovoltaic, and solar thermal electric technologies are included in the utility sector.

Designing solar energy systems to have operating and availability characteristics comparable to conventional systems is the approach for certain types of electricity generating units and is implied in their calculation of costs for the building sector. SPURR considers two types of solar electric plants: comparable systems and fuel savers. MITRE separated electricity generating units into four types: base, intermediate, semipeak, and peak, which are assumed to have capacity factors of 70%, 50%, 30%, and 8%, respectively. The solar electric plants were then designed with sufficient storage or backup power so that their capacity factors would be 70%, 50%, 30%, or 8% depending on the type of conventional system displaced. Costs of the solar electric systems designed at different capacity factors were primarily obtained from various design studies (Miller 1977, p. xii). The solar and conventional electric technologies were then compared on the basis of their levelized energy costs (MITRE 1977, p. 6).

"Fuel Saver" is the term MITRE uses to describe solar electric plants without storage or backup power. The economic figure of merit computed for fuel savers in SPURR is:

$$\begin{matrix}\text{Net Cost of}\\\text{Fuel Saver}\end{matrix} = \begin{bmatrix}\text{Present Value of}\\\text{Revenue Requirements}\\\text{of the Solar Plant}\end{bmatrix} - \begin{bmatrix}\text{Present Value of}\\\text{Capacity Credit}\\\text{Savings}\end{bmatrix} - \begin{bmatrix}\text{Present Value of}\\\text{Fuel Savings}\end{bmatrix}$$

Fuel savings from conventional base, intermediate, and peak load units are estimated "from an average daily utility load curve . . . and from the average portion of each hour in the day the fuel saver will be in operation." The

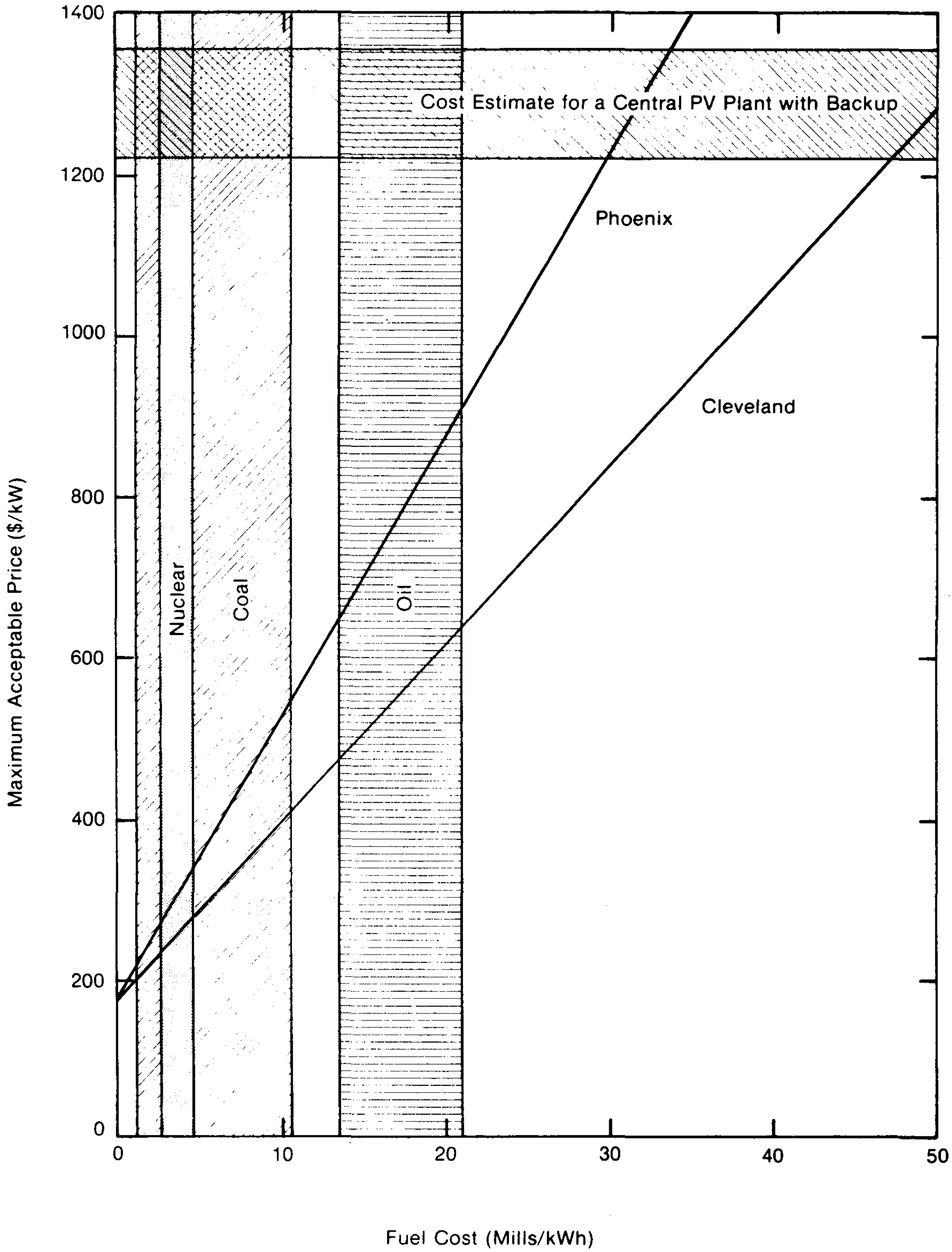

Figure 2-2. Comparison of the Cost of Central PV Plant to Its Maximum Acceptable Price

SOURCE: Spectrolab (1977), Vol. IV, p. 92-5.

calculations involved in computing the distribution of fuel savings were not described. The capacity credit for fuel savers was defined as that portion of solar capacity "that can be counted on to provide energy when needed." Capacity credits were assumed to be 10%, 38%, and 70% for wind, photovoltaics, and solar thermal electric plants, respectively (MITRE 1977, pp. 24-25). Capacity credit savings are based on the most expensive capacity for which there are any fuel savings. For example, if 20% of the fuel savings to the utility resulting from operating a wind machine is from fuel for baseload units, the capacity savings for the wind machine are calculated by applying the WECS capacity credit to baseload capacity. If no fuel savings accrue from baseload units, capacity savings are based on the next highest capacity type from which fuel savings are available (Bohanan 1979).

Finally, a comparable systems approach is implied for the building sector of SPURR, as well. For each of the 16 regions in the buildings component of the model, five types of generic solar energy systems (for hot water and space conditioning with electric backup), based on the systems that minimize life-cycle costs, were selected. Unlike the solar electric technologies for which design, cost, and performance data were obtained from other studies, MITRE used simple methods to optimize solar energy designs for these applications. The methods were based on regional climate, estimated building heating and cooling demands, and solar performance. Collector areas were optimized using design charts developed at the University of Wisconsin Solar Energy Laboratory (MITRE 1977, pp. 8-10).

A comparable systems approach is implied in the building sector because the first-year and life-cycle total costs of service for both the solar and conventional systems were computed. The solar life-cycle costs included the cost of electric backup. The way that backup costs were determined was not specified.

The figure of merit for residential homeowners was a function of the initial costs of the solar system and the first-year savings to the homeowner "because residential home buyers place more emphasis on initial costs and early savings rather than life-cycle cost" (MITRE 1977, p. 12).

The figure of merit for commercial buildings was the ratio of the life-cycle costs of the conventional system to the life-cycle costs of the solar system. The advantages and limitations of particular figures of merit are discussed in Sec. 5.0.

Developing an engineering design for a solar plant with availability characteristics comparable to a conventional plant has an important advantage. It permits comparisons between solar and conventional electric technologies on the basis of average annual energy costs. This approach eliminates the need to use utility system planning and other models to assess alternative technologies.

The difficulty with this method involves determining whether the operating and availability characteristics of the solar plant are indeed comparable to those of the conventional plant. In one study, a photovoltaic plant with a gas turbine backup was assumed to have the same characteristics as an intermediate coal-fired power plant. In another a solar plant with a 50% capacity factor was assumed to be comparable to a conventional plant operated at a 50% capacity factor. Neither approach is sufficient. In particular, it is quite possible that a solar plant with a 50% capacity factor could have widely different operating and availability characteristics than a conventional plant operated at a 50% capacity factor. The greater the difference in availability characteristics, the less valid the comparison of energy costs.

To judge whether the characteristics of a solar and conventional plant are comparable, we need to examine hourly solar performance data and the hourly loads that the conventional plant is expected to meet. Unfortunately, hourly loads for the conventional plant cannot be determined independent of the utility system in which the conventional plant is operated. Finally, even if the operating and availability characteristics for the two plants are comparable, value estimates will necessarily reflect the value of a solar plant only in a specific configuration; i.e., a solar plant designed with sufficient backup or storage so that it is similar to a conventional plant. Designing a solar plant with these features could cause the cost/value ratio for the solar plant to be higher than it would be if the solar plant were not designed to be comparable to a conventional plant and its value were determined on the basis of total savings to a utility system.

The disadvantage of assuming a capacity credit for an intermittent solar electric technology is that it will yield arbitrary estimates of value. The capacity credit for a particular device will be determined by many factors that can vary widely from situation to situation.

2.3 CONCLUSIONS

Two relatively simple methods for making economic comparisons of solar and conventional electric technologies were reviewed. The first was the calculation of average annual energy costs and the second involved designing comparable solar and conventional plants so that direct energy cost comparisons can be made.

There are serious problems with using average energy costs to compare an intermittent, solar electric technology with a conventional technology because operating and availability characteristics of the two differ greatly. Solar and conventional plants with comparable availability characteristics can be compared on the basis of energy costs. However, determining whether their characteristics are the same is no easy task and the utility system in which the conventional plant is operated cannot be ignored. The advantages and limitations of the comparable system approach should be explored in greater detail.

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SECTION 3.0

SIMULATION TECHNIQUES APPLIED TO DISPERSED USER APPLICATIONS

Electricity supply costs and average cost pricing were described briefly in Sec. 1.0. Section 1.2.1 made two major points. First, utility production costs may change as customers adopt solar devices, but this result is not, by itself, a problem. Second, because electric rates based on average costs do not reflect very precisely a utility's costs of production, average cost pricing creates two problems for assessing customer investments in solar technologies: (1) the value of the device to the user will differ from the value of the device to society; and (2) existing rates may not reflect future rates because there is pressure to consider rate reform (i.e., assessments based on current rates may yield inaccurate estimates of the value of the investment to the owner in future years).

The first problem is relevant to a wide range of policy issues such as rate reform and designing incentives to stimulate investments in renewable technologies. However, if the objective of the analysis is to assess the value of a particular system to a particular user, then only the second problem is relevant. This is true because actual rates will determine cost and value to a utility customer.

The purpose of this section is to assess the methods that have been used for economic assessments of solar technologies in dispersed applications located on the customer's premises. The studies reviewed are those that attempt to both (1) assess the value of a system to a user, and (2) assess the impact of the technology on the utility's cost of supplying electricity.*

This review of methods will focus on two specific questions. First, in what detail is it necessary to characterize solar performance and user load data? Second, given that average cost rates typically reflect neither a utility's short-run fuel nor long-run capacity costs, and given that there is a general move toward rate reform, is it better to use current rate data or utility planning models to assess the value of a solar investment to a utility customer? Unfortunately, the answer to the latter question will not be straightforward. Problems associated with assessing grid-connected solar technologies are inextricably related to the problems associated with establishing rate

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*Although this study is concerned with solar electric technologies, methods applied to solar hot water and space conditioning applications are also reviewed, for two reasons. First, few assessments of the impact of solar electric technologies on utilities were available at the time this study was completed. Second, the methods required to determine the cost of providing backup power probably will be similar for both types of applications. Studies of dispersed solar electric technologies that based economic comparisons on average energy costs alone were discussed in Sec. 2.0. Studies that calculated backup costs by using only current rate data are not reviewed in detail. However, the advantages and limitations of using current rate data for technology assessments are discussed in this section.

design policies. Rate design policies are influenced by a number of political and institutional concerns as well as by economic issues.

This section is organized in three basic parts. Section 3.1 provides background information on current rate design practices and proposals for reform. Section 3.2 is a summary and assessment of the methods surveyed. Section 3.3 contains conclusions and offers recommendations.

3.1 RATE DESIGN PRACTICES AND PROPOSALS

This section provides information needed to assess the methods surveyed in Sec. 3.2. The following subjects are discussed: (1) objectives and issues in rate design, (2) average cost pricing, (3) marginal cost pricing, and (4) the trend toward rate reform.

3.1.1 Objectives and Issues in Rate Design

There are two broad objectives of rate design policy, equity and efficiency. Equity relates to the basic concept of fairness. Typical interpretations of the equity objective have resulted in judicial and statutory injunctions that rates be "just and reasonable" and that they not be "unduly discriminatory" (Kahn 1970, p. 54). Thus, equity has political and ethical as well as economic interpretations.*

In contrast to equity, efficiency is strictly an economic concept. The objective is to ensure that maximum economic benefit is derived from society's limited resources. Broadly speaking, efficiency is achieved when the marginal costs of producing goods are equal to the benefits consumers derive from those goods. Stated differently, "if a consumer is willing to pay the marginal cost of his consumption, then both his consumption and the attendant costs are economically justified" (Uhler 1977, p. 35).

The objectives of equity and efficiency have been used to develop policies related to the two basic issues in rate design, total revenues and rate structures. Before we examine these issues in greater detail, note that "the twin objectives of equity and efficiency do not necessarily yield the same result. They might or they might not. In practice, the role of efficiency in the use of resources must be tempered by requirements of fairness; that is, by equity" (Cicchetti et al. 1977, p. 91).

Determining a utility's total or required revenues involves many activities. Kahn describes three basic issues related to determining revenues: (1) supervising and controlling operating costs and capital outlays, (2) determining

*As Alfred Kahn has pointed out, from an economic point of view "subject to important qualifications . . . prices should be equated to marginal costs. In this scheme, there is no room for separate considerations of 'fairness'. Or, to put it another way, fairness is defined in strictly economic terms: those prices are fair that are equal to marginal costs, those unfair that are not equal" (Kahn 1970, p. 56).

the rate base, and (3) selecting the allowed rate of return. Controlling operating costs and capital outlays involves scrutinizing particular cost items and determining whether it is appropriate to include them in the utility's revenue requirements. Determining the rate base involves calculating the utility's aggregate investment or the basis upon which the utility is allowed to earn a rate of return. Selecting the allowed rate of return involves a range of issues related to measuring the cost of capital and determining appropriate earnings for the utility (Kahn 1970, pp. 25-54).

The second basic issue in rate design is the structure of rates or the particular types of prices that utility customers face. The types of rate structures generally used today and proposed alternatives are described in the sections that follow.

3.1.2 Average Cost Pricing

The term average cost pricing is used here to mean pricing on the basis of non-time-differentiated accounting costs. Under current practices, the procedures for establishing average cost rates involve two basic steps, a cost-of-service study and the calculation of rates.

Cost-of-service studies typically involve four basic steps (Uhler 1977, pp. 22-23). First, the utility's accounting costs* for a relevant test year are estimated for the functions of generation, transmission, and distribution. Second, costs are classified for each function according to demand, energy, and customer-related expenses. Demand costs are capacity or investment costs. Energy or variable costs are primarily fuel and operation and maintenance expenses. Customer-related costs are those associated with serving individual customers, and can include certain distribution costs as well as metering and billing expenses.

Third, costs by function and by classification are allocated to customer classes "in proportion to each class's responsibility for each" (Uhler 1977, p. 25). Allocation of costs to customer classes requires a great deal of judgment, particularly for fixed costs (Uhler 1977, p. 26; Kaufman 1976, p. 221). The final step involves converting costs "into costs per unit of service: costs per customer, costs per unit demand (per kilowatt), and costs per unit of energy consumption (per kilowatt hour)" (Uhler 1977, p. 26).

After the cost-of-service study is completed, rates are established for each customer class. Under current rate design practices, residential users receive declining block rates. They are charged higher rates for the first one or two blocks of kWh consumed to recover fixed costs and lower rates in later blocks to reflect variable costs. Industrial and commercial users are typically charged a two-part rate: a demand charge to cover fixed costs and an energy charge to cover variable costs. "The demand charge is determined by

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*Accounting costs in this context are "items that appear as cost entries in the records of a utility (or in statements derived from them) and that are determined in accordance with regulatory accounting principles. They include the earnings available to stockholders" (Uhler 1977, p. 23).

the highest use in some unit of time during the billing period, usually use over fifteen minutes in one month" (Kaufman 1976, p. 220).

These basic pricing structures were implemented around the turn of the century. According to Cicchetti, Gillen, and Smolensky, they were adopted because they adequately reflected the costs of serving most customers: utility service territories were small, electricity was used primarily for lighting, typical load patterns were easy to detect, and few customers deviated from the average load pattern. It is interesting that "the rationale offered for these tariff designs at their inception is quite similar to the argument now being advanced to abandon them, at least as they are presently applied" (Cicchetti et al. 1977, p. 88).

3.1.3 Marginal Cost Pricing

Economic theory indicates that, subject to a restrictive set of assumptions, economic efficiency is achieved when prices are set equal to marginal cost. Marginal cost is the change in costs associated with producing one more (or less) unit of electricity.

Although the concept of marginal cost is quite simple, defining, measuring, and applying marginal cost to rate design is complex--in part because supplying electricity involves a complex production process (Cicchetti et al. 1977, pp. 92-93; Kahn 1970, pp. 63-86). In fact, there are so many issues involved in defining, measuring, and applying marginal cost to rate design that it is not feasible to describe or discuss them within the scope of this report. However, one issue--whether short-run or long-run marginal costs should be reflected in rates--is particularly important for assessing dispersed applications, and it should be addressed.

More specifically, economic theory suggests that efficiency is achieved when prices are set equal to short-run marginal costs (again, subject to important qualifications). The short-run is the time period during which capital costs are fixed; in the long-run, all costs including capital are variable. If electricity prices were set equal to short-run marginal costs, capacity costs would not be reflected directly in rates.* However, two arguments usually are made for using long-run marginal cost as the basis for determining rates.

First, the short-run marginal cost of electricity is the variable cost (fuel, operation and maintenance) associated with serving load plus outage costs to consumers if demand exceeds supply.** Because utilities typically add extra

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*Mathematically, marginal cost is estimated by differentiating the total cost function. Since capital costs are fixed in the short-run, and since the derivative of any function with respect to a constant is zero, capital costs would not be reflected in short-run marginal costs. Pricing on the basis of short-run marginal cost will not necessarily generate revenues insufficient to recover costs. See Kahn (1970), pp. 73-74.

**Using the example of bridge crossing, Kahn describes marginal congestion or opportunity costs to consumers during peak hours (1970, pp. 87-89).

capacity to prevent outages, capacity costs should be reflected in rates as a proxy for the cost of reliability.* Second, pricing on the basis of short-run marginal costs alone is impractical in many situations. Kahn describes three reasons why it might be infeasible or undesirable to base rates on short-run marginal costs. First, it could lead to unacceptable fluctuations in rates over time. Second, it would be too difficult, annoying, or expensive to measure outage or congestion costs to consumers and base rates on them. Third, pricing on the basis of short-run marginal costs alone might generate revenues insufficient to recover total costs to the utility (Kahn 1970, p. 88).

Some of the problems associated with defining, measuring, and applying marginal cost to rate design will be discussed in greater detail in Sec. 3.2. For the moment, it is sufficient to note that rates based on marginal cost are more likely than average cost rates to reflect the incremental variable and capital costs to the utility of serving load at different times. Thus, they are also more likely to achieve the goal of economic efficiency.

3.1.4 The Trend Toward Rate Reform

Despite the economic merits of basing rates on marginal cost, marginal cost pricing of electricity has not been adopted widely in the United States for a number of reasons. First, other concerns were judged to be more important in the past (Turvey and Anderson 1977, p. 3; Cicchetti et al. 1977, p. 89). Kahn points out that regulators and economists paid far more attention to revenue concerns, such as the rate base and the rate of return, than to rate structures (1970, pp. 54-57). Second, until 1971, the long-run average price of electricity was declining in real terms because of technological progress and increasing returns to scale in electricity generation. "As recently as 1973, regulatory commissions were regularly advised that the price of electricity was still such a small item in the budget of firms and households that tariff structure did not significantly influence consumer demands" (Cicchetti et al. 1977, p. 89). Third, Turvey and Anderson argue that marginal cost pricing has been slow to win the confidence of the industry and its regulators because "most of the industry's engineers, accountants, financial analysts, and administrators do not understand marginal cost pricing and most have concepts about the aims and equity of tariffs that are quite different from those of economists" (1977, p. 3; see also Kahn 1970, p. 56).

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*Turvey describes the functional relationship between the risk of load reduction and the planned level of installed capacity. He notes, "Given this functional relationship and given the addition to system costs resulting from a small increase in generating capacity, the cost at the margin of reducing the risk of load reduction can readily be determined. . . . With impeccable logic the French treat this as the implicit marginal cost of supply interruptions . . ." (Turvey 1968, pp. 83-84). Cicchetti et al. note that "there are times when additional consumer demand requires the expansion of facilities and times when additional consumer demand requires little more than an expenditure for fuel . . ." (1977, p. 93).

During the past decade, however, there have been increasing concerns that average cost pricing is seriously inadequate for achieving the goal of economic efficiency. The cost of new generating capacity has risen rapidly and oil prices have increased dramatically relative to the prices of other utility fuels. Thus, the concern is that average cost pricing yields insufficient incentives for customers to conserve, alter their consumption patterns, or make rational decisions about investments affecting electricity consumption. For these reasons, the costs and benefits of marginal cost pricing are being evaluated by many states as well as the federal government.

Recent cost changes in the industry and the rising cost of imported oil have also increased the desire to encourage investments in renewable and more efficient generating technologies, to reduce oil imports and attain energy self-sufficiency. Increased national interest in marginal cost pricing and renewable generating technologies took on a more definitive shape with the passage of the Public Utility Regulatory Policies Act of 1978 (PURPA).

3.1.4.1 Retail Rates--Title I of PURPA

Title I of PURPA requires nonregulated utilities and PUCs to consider rates that are "designed to the maximum extent practicable to reflect the costs of providing service to that class." Estimates of the costs to serve users should "take into account the changes in costs associated with (1) daily and seasonal time of use, and (2) adding more capacity and delivering additional kilowatt-hours" (U.S. Department of Energy, Economic Regulatory Administration 1979).

More specifically, Section 111 of PURPA requires nonregulated utilities and PUCs to consider six rate-making standards; Section 113 requires them to consider five regulatory standards. The six rate-making standards are (1) rates based on the cost of providing service for each customer class; (2) the elimination of declining block rates that are not cost-based; (3) the establishment of time-of-day rates, if appropriate and cost-effective; (4) the establishment of seasonal rates if costs vary seasonally; (5) the establishment of interruptible rates for commercial and industrial customers; and (6) the use of load management techniques if cost-effective (U.S. Department of Energy, Economic Regulatory Administration 1980, p. 3).

The Economic Regulatory Administration reported that states had made only limited progress in implementing the rate-making and regulatory standards as of June 30, 1979 (U.S. Department of Energy, Economic Regulatory Administration 1980, p. 1). More recently, the National Association of Regulatory Utility Commissioners (NARUC) conducted a survey of 40 state commissions and the Tennessee Valley Authority and concluded that progress in implementing the PURPA regulations had been substantial since June 1979 (Electrical Week 1980, p. 7). The results of the NARUC survey of activities related to the rate-making standards are reported in Table 3-1. Of the 40 states surveyed, 16 (or 40%) had adopted or implemented one or more of the six rate-making standards.

Table 3-1. **NARUC Survey: Status of State's Compliance with PURPA on Rate-Making Standards**

State	Cost of Service	Declining Block	Time of Day	Seasonal Rates	Interruptible Rates	Load Management
Alabama	UC[a]	UC	UC	UC	UC	UC
Alaska	UC	UC	UC	UC	UC	UC
Arizona	UC	UC	UC	UC	UC	UC
California	A&I	A	A&I	A&I	A&I	A&I
Colorado	I	I	A	A	A	A
Connecticut	UC	UC	I	UC	UC	UC
District of Columbia	UC	A	A&I	A	UC	UC
Florida	UC	A&I	UC	UC	UC	UC
Georgia	UC	UC	UC	UC	UC	UC
Hawaii	UC	UC	UC	UC	UC	UC
Idaho	UC	UC	UC	UC	UC	UC
Illinois	UC	UC	UC	UC	UC	UC
Iowa	UC	UC	UC	UC	UC	UC
Kansas	UC	UC	UC	UC	UC	UC
Kentucky	UC	UC	UC	UC	UC	UC
Louisiana	UC	UC	UC	UC	UC	UC
Maryland	UC	UC	UC	UC	UC	UC
Massachusetts	A	A	A	A&I	A	A
Michigan	A&I	A&I	A&I	A&I	A&I	A&I
Minnesota	A&I	A&I	A&I	A&I	A&I	A&I
Montana	UC	UC	UC	UC	UC	UC
Mississippi	-	-	-	-	-	-
Nebraska	-	-	-	-	-	-
Nevada	UC	UC	UC	UC	UC	UC
New Hampshire	UC	UC	UC	UC	UC	UC
New Jersey	UC	UC	UC	UC	UC	UC
New Mexico	UC	UC	UC	UC	UC	UC
New York	A&I	A&I	A&I	A&I	UC	A
North Carolina	UC	UC	UC	UC	UC	UC
North Dakota	UC	UC	UC	UC	UC	UC
Ohio	A	A	A	A	A	A
Oklahoma	UC	UC	UC	A&I	UC	UC
Oregon	A&I	A&I	A&I	A&I	A&I	UC
Rhode Island	UC	UC	UC	UC	UC	UC
South Carolina	A	A&I	A&I	A&I	A&I	A&I
TVA	UC	UC	UC	UC	UC	UC
Texas	-	A&I	-	A&I	-	-
Vermont	I	I	I	I	I	I
Virginia	UC	UC	UC	UC	UC	UC
Washington	UC	UC	UC	UC	UC	UC
Wisconsin	A&I	A&I	A&I	A&I	A&I	I

SOURCE: Electrical Week (1980), p. 8.

[a]Symbols denote the following: UC--under consideration; A--adopted; I--implemented.

3.1.4.2 Rates—Title II of PURPA

Title II of PURPA contains provisions to encourage renewable and more efficient generating technologies. The Federal Energy Regulatory Commission (FERC) issued its final rules implementing Sections 201 and 210 of PURPA in February and March of 1980.

FERC's rule implementing Section 201 establishes requirements and procedures for determining qualifying status for small power production and cogeneration facilities (FERC 1980b). Qualifying facilities (QFs) can obtain the rate benefits and exemptions from regulations established in FERC's rule implementing Section 210 of PURPA.

The rule implementing Section 210 requires utilities to interconnect with, buy power from, and sell power to QFs, and exempts QFs from certain state and federal regulations affecting electric utilities. The rule states that rates for utility purchases from QFs must equal the utility's avoided incremental cost and not average system cost. Avoided incremental costs are "the costs to an electric utility of energy or capacity or both, which, but for the purchase from a qualifying facility, the electric utility would generate or construct itself or purchase from another source" (FERC 1980a). The rule also requires utilities to sell power to QFs at nondiscriminatory rates and contains provisions related to other issues such as interconnection costs. Nonregulated utilities and PUCs were directed to begin implementing these regulations by March 1981.

3.2 REVIEW OF EXISTING METHODS

This section reviews the assessment methods used in seven reports. Appendix C contains more detailed information about each study and its methodology. Table 3-2 summarizes their major methodological characteristics.

Broadly speaking, most studies used a procedure that involved the following steps: (1) energy produced by the solar device was estimated on an hourly basis; (2) hourly load data for the customer type being considered were estimated or obtained; (3) hourly energy production from the solar device was subtracted from the customer's hourly load to obtain a residual customer load (if applicable, power available for sale to the utility was determined in a similar fashion); (4) the utility's cost of supplying backup power (and, if applicable, the value of sell-back) was calculated and the utility's cost of supplying a comparable conventional customer was also calculated; and (5) total annual costs associated with meeting the customer's energy needs, with and without the solar device, were calculated.

In the sections that follow, the reports are compared according to their analysis of solar performance, user load data, backup costs, and sell-back rates.

3.2.1 Analysis of Solar Performance

The performance of a solar energy system is determined by the quality and quantity of available solar resources and by the relative efficiency with

Table 3-2. Overview of Simulation Techniques Used To Assess End-User Applications of Grid-Connected Solar Technologies

Characteristics	OTA	Leonard	Bright	Burke	Cretcher	Feldman	Lorsch
	Author of Study						
	Electricity		Hot Water and Space Conditioning				
I. SOLAR PERFORMANCE							
A. Resource data							
1. Degree of detail	Hourly	Hourly	Hourly	Hourly	Hourly	Hourly	Hourly
2. Years of data	One	One	One	One	One	One	One
3. Availability treatment	Determ.[a]	Determ.	Determ.	Determ.	Determ.	Determ.	Determ.
B. Method of performance computation	OTA model	Aerospace	TRNSYS	EMPSS	TRNSYS	TRNSYS	TRNSYS
II. USER CHARACTERIZATION							
A. Determination of load	E-Cube	Est.	Est.	Est.	Est.	Est.	Est.
B. Load diversity	Est.	NS	NS	NC	Est.	Est.	Est.
III. IMPACT ON UTILITY							
A. Backup costs							
1. Calculated							
a. Utility production cost model		X			PTI	X	PRODCOST
b. Utility capacity expansion model			WASP II				
c. LOLP model		X			PTI		
d. Static breakpoint analysis	X						
e. Marginal cost estimation model						CGS	
f. Utility-supplied cost of service data				X			X
2. Assumed average or existing rates	X			X		X	X

Table 3-2. **Overview of Simulation Techniques Used to Assess End-User Applications of Grid-Connected Solar Technologies** (Concluded)

Characteristics	OTA	Leonard	Bright	Burke	Cretcher	Feldman	Lorsch
	Author of Study						
	Electricity		Hot Water and Space Conditioning				
B. Sell-back rates		NC	NA	NA	NA	NA	NA
1. Calculated value to utility--break-point analysis	X						
2. Assumed rates	X						
C. Market penetration							
1. Static analysis	X	X		X	X	X	X
2. Dynamic analysis			X				

SOURCES: U.S. Congress, OTA (1978); Leonard et al. (1977); Bright and Davitian (1978); Burke et al. (1977); Cretcher and Melton (1978); Feldman et al. (1976); Lorsch et al. (1976).

[a]Symbols denote the following:

Aerospace = a photovoltaic system performance model developed by Aerospace Corp.
CGS = a marginal cost estimation model developed by Cicchetti, Gillen, and Smolensky.
Determ. = deterministic.
Est. = estimated.
E-Cube = a user load model developed by the American Gas Association.
EMPSS = a solar performance model developed by A. D. Little.
NA = not applicable.
NC = not considered.
NS = not specified.
PRODCOST = a utility production cost model developed at the University of Pennsylvania by S. T. Matrascek (M.S. thesis).
PTI = Power Technologies, Inc.
TRNSYS = a solar performance model developed at the University of Wisconsin.
OTA = Office of Technology Assessment, U.S. Congress.
WASP II = a capacity expansion program developed for the International Atomic Energy Agency.
X = study methodolgy included the indicated feature.

which the system components convert available resources into useful energy. Insolation data* are generally represented in two ways: (1) the total radiation (direct and diffuse) reaching a horizontal surface, and (2) direct normal radiation (that is, the amount of energy received by a collector that tracks the sun, keeping the sun perpendicular to the receiver surface) (U.S. Congress, OTA 1978, Vol. I, p. 291).

Several authors stated that existing insolation data were of poor quality. For instance, some places collected insolation data only during sunny intervals. The Office of Technology Assessment points out that, at the time of this study, total insolation data were available for roughly 80 locations in the U.S. Direct normal radiation data existed for three cities but even these were incomplete (U.S. Congress, OTA 1978, Vol. I, p. 291). Statistical techniques have been developed for estimating direct normal and total radiation data from the percent possible radiation**, and better insolation data are now being collected. However, more data on actual direct normal radiation are required to validate the statistical estimates (Melton 1978, p. 21). Except for Bright and Davitian (1978, p. 6), all authors stated that either they had to choose locations for which insolation data were readily available or they had to synthesize data statistically.

As Table 3-2 indicates, the reports are similar in the analyses of solar performance. All the authors used hourly insolation data for a single year to estimate solar performance. Resource availability was analyzed in a deterministic fashion in the sense that hourly data were read directly into a solar performance model. Solar performance models simulate the operation of the solar energy system to determine useful energy output.

Major problems associated with analyzing solar performance relate to the poor quality of existing insolation data and the limited amount of actual operating experience, especially with solar electric technologies. Actual operating data are needed to validate the production estimates obtained using the models. Finally, because insolation varies continuously, it is not clear whether hourly data are sufficient for characterizing the performance of solar energy systems. Data for smaller time intervals may be required to characterize the operating and availability characteristics of solar electric technologies, and their resulting impacts on the utility.

The relative importance of analyzing solar performance and user load data on an hourly basis is assessed in the next section.

3.2.2 User Load Characterization

Two issues are relevant in characterizing the customer's load, the degree of detail needed and the treatment of load diversity.

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*Wind resources are discussed in Sec. 4.0.

**Percent possible radiation is the amount of total radiation that is actually received divided by the amount that would theoretically be available on a clear day (U.S. Congress, OTA 1978, Vol. I, p. 303; Melton 1978, pp. 3-21).

The reports are similar in the degree of detail used to represent the customer's load. They all either estimated loads on an hourly basis using a computer program, or they obtained hourly load data from published sources or from utilities.

Is it necessary to analyze solar performance and user load data on an hourly basis to obtain the most accurate estimates of the value to the customer of a solar device? The answer depends on two factors: the relative precision of the estimates of energy production and consumption, and the type of rate structure the consumer receives from the utility.

Since the performance of a solar technology and user loads can vary substantially from hour to hour, it is clear that hourly calculations should provide more precise estimates of energy production and consumption than analyses based on more aggregate time intervals. However, it is not certain yet how much accuracy has been gained by hourly modeling, again because of the limited availability of solar resource data and the limited amount of actual operating experience against which performance models can be validated.

The second factor concerns the rate structures themselves. If consumption is metered by time of use (for example, for two or three time periods during the day), and if the rates vary substantially depending on when electricity is purchased, then to assess the value of the investment to the user it is important to know when the load occurs. Hourly performance modeling and user load data would undoubtedly yield more accurate estimates of value than average daily, weekly, or monthly estimates of production and consumption. If, on the other hand, rates vary only as a function of the total kWh consumed in the month, then hourly performance and load data are less important because the user's cost will not vary as a function of the timing of the load.

The second issue relevant to characterizing user loads is the treatment of load diversity. Load diversity is the difference between the sum of the peak loads of two or more individuals and the combined maximum load for those individuals. Peak load is the maximum amount of electric power consumed in a given time interval (see Appendix B). Diversity in load patterns among end-users occurs not only because of differences in building structures and energy systems but also because of varying life styles and energy consumption patterns. Load diversity means that the aggregate peak load facing an electric utility will be lower than the sum of the individual peak loads for each customer served. According to Cretcher and Melton, diversity factors (the ratio of the sum of individual peaks to the actual peak) are in the range of 1.2 to 1.6, based on utility data (Cretcher and Melton 1978, Vol. 1, p. 31).

Four of the seven reports reviewed stated that they considered load diversity in their aggregation of load data for large numbers of customers. Because "the effects of . . . diversity on the aggregate utility demand is significant in terms of the lowering of peaks and raising of valleys" (Cretcher and Melton 1978, Vol. 3, p. 123), load diversity should be taken into account when calculating the utility's cost of supplying electricity to solar and conventional customers. One of the major problems with accounting for load diversity is that insufficient data exist to determine load diversity factors for solar system users. The reports that analyzed load diversity had to rely on estimates for consumers using conventional equipment.

Despite the importance of taking load diversity into account when calculating the utility's cost of supply, load diversity is obviously not relevant in calculating the value of an investment to a customer based on actual rate data. This is true because customers are metered and billed for their own consumption.

3.2.3 Calculation of Backup Costs

Although their analyses of solar performance and user load characterization were fairly similar, the studies used widely different methods to calculate backup costs. Basically, seven different approaches were used: (1) a utility generation expansion model, (2) some type of utility production cost model, (3) reliability analysis models, (4) utility breakpoint analysis, (5) a marginal cost estimation model, (6) utility-supplied cost of service data, and (7) assumed average or existing rates. The studies that used each of these techniques are summarized in Table 3-2 and described in detail in Appendix C.

Approaches (1) through (4) are utility planning models. Approach (5) is a method of estimating marginal costs that can be used to establish rates. Approaches (6) and (7) involve obtaining data from either a utility or some other source. The advantages and limitations of these approaches for calculating the utility's supply costs are summarized in Table 3-3; Table 3-4 assesses their usefulness for estimating costs to utility customers.

3.2.3.1 Utility Planning Models

Utility planning models are discussed in greater detail in Sec. 4.0 as well as Appendix C. In this section, the models are assessed from two perspectives: their usefulness for estimating a utility's cost of supplying electricity, and their usefulness for estimating customer costs.

Estimation of Utility Supply Costs. Utility generation expansion models estimate backup costs on the assumption that the utility attempts to change its generation mix over time to minimize total generation costs, given changing load patterns. They are useful for analyses of long-term changes in the characteristics of electric utilities, including changes in both generation mix and load patterns. However, capacity expansion models can be complex and expensive to use.

Utility production cost models permit detailed analyses of changes in utility variable costs as a function of changes in utility load patterns. Because production cost models typically characterize the hourly operation and scheduling of units, they yield more accurate estimates of a utility's fuel and operating costs than do capacity expansion models.* However, production cost models are not designed to optimize the utility's generating capacity; rather,

*The distinction here between generation expansion and production cost models is somewhat arbitrary because some expansion models either contain or are used in conjunction with production cost models.

Table 3-3. Review of Methods Used To Calculate Utility Supply Costs

Type of Method	Advantages	Limitations
Utility Planning Models		
Generation Expansion Models	1. Allow changes in utility supply costs to be estimated on the assumption that the utility optimizes its generating mix to meet changing load patterns. 2. Useful for analyses of long-term changes in utility systems.	1. Complex and expensive. 2. Estimates of fuel and operating costs are not as precise as those obtained with production cost models. 3. Ignore transmission, distribution, and customer-related expenses.
Production Cost Models	1. Allow the most detailed analysis of changes in operating costs as a function of changing load patterns.	1. Complex and expensive. 2. Not designed for optimization of capacity. 3. Ignore transmission, distribution, and customer-related expenses.
Reliability Analysis Models	1. Calculate the change in system reliability associated with the change in load patterns; from these data, needed changes in capacity can be calculated.	1. Not designed for any type of cost calculation; must be used in conjunction with other models. 2. Complex and expensive.
Breakpoint Analysis	1. Simple approach for identifying major changes in total production costs as a function of changes in the load duration curve.	1. Static technique--impacts are estimated assuming utility capacity is instantaneously reoptimized. 2. Linear cost functions--variable cost estimates are not as precise as those from production cost models. 3. Excludes transmission, distribution, and customer-related costs.
Marginal Cost Estimation Models	1. Accuracy roughly comparable to utility planning models. 2. Include transmission, distribution, and customer-related expenses.	1. Can be expensive. 2. Some loss of precision may result from averaging costs for more aggregate time intervals.

Table 3-3. Review of Methods Used To Calculate Utility Supply Costs (Concluded)

Type of Method	Advantages	Limitations
Rate or Cost of Service Data	1. Ease of use; data are readily available. 2. Include transmission, distribution, and customer-related expenses.	1. Given current rate design practices, this approach is the least accurate for representing the utility's supply costs.

Table 3-4. Review of Methods Used To Calculate Costs to Utility Customers

Type of Method	Advantages	Limitations
Utility Planning Models	1. Might be more accurate than current rates if utilities adopt marginal cost pricing.	1. Complex and expensive. 2. Inaccurate under current rate design practices; might be inaccurate for some customers even if marginal cost pricing is adopted.
Marginal Cost Estimation Models	1. Likely to be more accurate than current rate data if utilities adopt marginal cost pricing.	1. Relatively complex. 2. Inaccurate under current rate design practices; might be inaccurate for some types of customers even if marginal cost pricing is adopted.
Rate or Cost of Service Data	1. Ease of use; data are readily available. 2. Most accurate for estimating the value of a solar investment given current rate design practices.	1. Current rates will not be accurate if utilities adopt marginal cost pricing. 2. Future rates are extremely difficult to predict.

they determine the costs of production given a specified generating mix. The result is that backup costs can be overestimated using production models. For example, assume that an existing utility's generation mix is optimal (least cost) given its existing load patterns. If the cost of providing backup power to solar users is then estimated using a production cost model based on the change in the utility's load patterns, backup costs are likely to be higher than they would be if the utility's generation mix were reoptimized to meet the new load patterns. Utility production cost models are more useful for analyzing short-term changes in a utility's cost of production. Generation expansion models are more useful for analyzing long-term changes in production costs. Like generation expansion models, utility production cost models can be complex and expensive to use.

Reliability analysis models are used to calculate the reliability of a utility's generation capacity. Reliability usually is expressed as the loss of load probability (LOLP), or the probability that the utility's load will exceed the utility's available generating capacity. These models require hourly load data as input, particularly for those hours in the year when there is a high risk that the load will exceed the available capacity.

The advantage of reliability analysis models is that they can be used to calculate changes in generating capacity needed to maintain a particular reliability criterion. They provide basic information needed to determine when it is necessary to add new capacity or when excess capacity can be sold. However, reliability analysis models are not designed to analyze the cost of these capacity additions or reductions. Thus, it is necessary either to assign dollar values to the calculated changes in capacity requirements, or to use a generation expansion model to determine the capacity additions that minimize total costs over the planning horizon.

Utility breakpoint analysis is a simpler method of identifying major changes in total production costs as a function of changes in the load duration curve. However, the technique is static; it estimates production cost changes on the assumption that capacity is instantaneously reoptimized. Reliability is not explicitly analyzed. Finally, total cost estimates are not as precise as those obtained with production cost models because the linear cost functions cannot precisely describe variations in production costs resulting from different operating strategies, the age distribution of units, and so on.

All models reviewed in this section are generation planning models. They do not account for transmission, distribution, or customer-related expenses that are also components of rates. Figuring the total cost for the utility to serve customers would require additional computations. For the purpose of comparing solar with conventional customers, ignoring these costs is a limitation only to the extent that they differ for the two customer types.

Finally, each of these types of models was designed for a special purpose and many utilities will use two or more of them in conducting a generation planning study. For this reason, it is slightly misleading to assess each model type separately.

Estimation of Costs to the Utility Customer. To emphasize an earlier point, actual rates will determine the cost and value of a solar investment to a utility customer. If customers actually pay rates based on average costs, then using utility planning models to assess the value of a solar investment to a customer would not only be unnecessarily expensive, but also would yield an inaccurate assessment.

Choosing between utility planning models and existing rate data is a problem because there is a general trend toward rate reform. Broadly speaking, Title I of PURPA calls for the abandonment of average cost pricing and for the adoption of rates that more closely reflect the utility's marginal cost of supplying electricity. Given the situation, is it better to use current rate data or utility planning models to assess the value of a solar investment to a utility customer? Before we can answer this question, we must examine more closely the relationship between the results obtained using utility planning models and rates based on marginal costs.

Production cost models can be used to calculate the incremental (or marginal) fuel cost associated with a change in the load for each hour of the year. Similarly, reliability analysis models can be used to calculate the change in system reliability associated with a change in the load for each hour of the year. From these results, the marginal capacity costs associated with a change in hourly loads could be inferred or calculated using a generation expansion model. In other words, utility planning models could be used to calculate marginal fuel and capacity costs for the 8760 hours of the year. It would also be possible to set rates equal to these 8760 marginal costs. However, estimating these marginal costs is only the beginning (Kahn 1970, p. 67; Turvey and Anderson 1977, pp. 3-4). It is not possible or desirable to establish such a complex set of tariffs, for the following reasons:

(1) It would be prohibitively expensive to calculate these marginal costs and to update them continually as demand and production costs change over time (Kahn 1970, pp. 83-84).

(2) A complex rate structure would actually impair the customer's ability to make rational consumption and investment decisions.* According to Boiteux, it would be practicably impossible to introduce a "tariff whose prices varied from hour to hour. Certain averages should be used to reduce the 8760 marginal prices--one for each hour of the year--to about ten prices at most" (Boiteux 1964, p. 21).

(3) The cost of metering consumption on an hourly basis would be prohibitive for some types of customers.

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*According to Kahn, rapidly changing rates would be "highly vexatious to buyers, who would be quick to find discrimination in departures from uniform prices, who would be put to great expense to be informed about prices that were constantly changing, and whose ability to make rational choices and plan intelligently for the future would be seriously impaired" (Kahn 1970, p. 84).

For these reasons, establishing tariffs based on marginal cost generally involves three steps that are outlined by Turvey and Anderson:

> We always begin with an analysis of daily and seasonal fluctuations of demand on the system, of demand growth, and of system operation and expansion plans. This enables us to estimate marginal costs of supply at various points in time. The next step is to decide what kind of tariff and metering system would best reflect these marginal costs to various consumer groups, allowing for the costs and practicalities of metering. This step gives us an "ideal tariff," so to speak, from an economic point of view. The third step is to adjust such elements in this "ideal tariff" structure as proves necessary for reasons of finance, fairness, or acceptability. (Turvey and Anderson 1977, pp. 3-4.)

The process of establishing tariffs based on marginal cost involves simplifying the detailed results obtained from utility planning models. Hourly marginal cost data typically will be averaged for more aggregate time intervals. Stated differently, even though rates based on marginal cost would more accurately reflect the utility's incremental cost of supplying electricity than would rates based on average cost, they would necessarily be less precise than hourly marginal costs estimated with utility planning models.

As a result, even though there is a general trend toward rate reform, it is not clear whether it is better to use current rate data or utility planning models to assess the value of a solar investment to a utility customer.

3.2.3.2 Marginal Cost Estimation Models

It is difficult to generalize about the diverse types of models that could be classified as "marginal cost estimation models." In fact, the generation planning models described above are marginal cost estimation models. The distinction here between utility planning and marginal cost estimation models is somewhat arbitrary. The term "marginal cost estimation models" is used to represent models that were developed to estimate marginal costs that could be used in rate design. These models would estimate marginal costs for more aggregate time intervals than would production cost models. They also would account for the marginal costs of generation, transmission, distribution, and customer-related expenses. Marginal cost estimation models are either identical or complementary to utility planning models. They are reviewed in the sections that follow according to their usefulness for estimating a utility's supply costs and costs to customers.

Estimation of Utility Supply Costs. One of the first steps involved in estimating marginal costs for the purpose of rate design is to define relevant costing periods (those time periods between which the utility's production costs vary significantly). For many utilities, these costing periods would involve two or three time periods within a weekday (peak, intermediate, and off-peak hours), a distinction among weekdays and weekends, and a distinction among two or three time periods in the year to account for seasonal variations in supply costs.

Given these costing periods, the models would calculate the marginal fuel and capital costs associated with a change in the load in each costing period. Some marginal cost estimation models contain production cost, reliability, and capacity expansion modules (Temple, Barker, and Sloane 1979); others take output from utility planning models to calculate marginal costs for each time period.

There are several advantages to using marginal cost estimation models. First, because they are either identical to or used in conjunction with generation planning models, their accuracy is comparable even though some precision may be lost in aggregating hourly data for the costing periods. Second, they take into account transmission, distribution, and customer-related expenses. However, they are not designed for long-term planning. They are designed rather to estimate marginal costs at a specific point in time. Thus, long-term impacts on the utility would have to be estimated separately.

Estimation of Costs to the Utility Customer. The advantages to and problems encountered in using marginal cost estimation models to assess the value of a solar investment to a customer are similar to those for utility planning models. If customers actually pay rates based on average costs, then these methods will both be unnecessarily expensive and yield an inaccurate assessment. If utilities adopt marginal cost pricing, these models should more accurately reflect costs to certain types of customers than would planning models. However, marginal cost models might yield inaccurate assessments for other types of customers--for example, customers for whom metering costs would be too prohibitive to implement time-of-use rates.

3.2.3.3 Rate and Cost-of-Service Data

One alternative to using the models described in the preceding sections is to obtain rate or cost-of-service data from utilities or from other sources. Here, we review this approach in relation to its usefulness for estimating a utility's supply costs and costs to the customer.

Estimation of Utility Supply Costs. This approach is the least accurate of the methods reviewed for estimating a utility's costs of production for reasons given in Secs. 1.1.3 and 3.1. Under current rate design practices, neither cost-of-service studies nor rates reflect a utility's short-run fuel or long-term capital costs associated with serving load at different points in time (see Sec. 3.1.2).

Estimation of Costs to the Utility Customer. There are two advantages to using rate and cost-of-service data in estimating the value of a solar investment to a utility customer. First, it is the simplest and second, the most accurate of the approaches reviewed for assessing solar technologies under current rate design practices. The disadvantage of using current data is that future rates might change because there is a trend toward rate reform.

Ideally, one would employ current rate data to assess the near-term value of a solar technology, using probable future rates to assess the technology in future years. Unfortunately, it is extremely difficult to predict future rates. Even if most utilities eventually adopt marginal cost pricing, rate structures will be determined not only by the structure and magnitude of marginal costs, but also by the costs and feasibility of administering different tariff structures, as well as by revenue and equity concerns.

3.2.4 Calculation of Sellback Rates

Only one of the reports examined attempted to calculate the value of sell-back power to the utility, or of power purchased by the utility from generating customers. The problems associated with estimating the value of sell-back to the utility and with estimating revenues to utility customers are assessed in the following sections.

3.2.4.1 Estimating the Value of Sell-back to the Utility

The OTA report attempted to calculate the value* of sell-back power to the utility. OTA used breakpoint analysis; the advantages and limitations encountered when this method is applied to the calculation of backup costs (described in Sec. 3.2.3.1) also apply when it is used to calculate the value of sell-back. However, any of the utility planning or marginal cost estimation models described in previous sections also can be used.

The advantages and limitations of each type of model are basically the same as those listed in Sec. 3.2.3. Production cost, reliability analysis, and capacity expansion models can provide detailed estimates of the fuel and capital cost savings that accrue to a utility as generating customers make power available. As is the case for marginal cost rates for conventional service, these models do not estimate rates per se, but rather the basic input needed to establish rates. Hourly marginal cost data must be averaged for more aggregate time intervals to produce rates that are practicable, given metering costs, and acceptable to consumers.

In addition to these issues associated with estimating the value of and establishing rates for purchases from generating customers, there are two other issues associated with sell-back that should be discussed: estimating the reliability of sell-back power and determining interconnection costs.

Utility system reliability analysis is usually applied to the bulk generation system alone. In conventional utilities, power is generated at a plant and is transmitted through the transmission system to the distribution system and then to the individual customer. Power produced by users, however, will have to be transmitted back through the distribution system to make it available to the utility for dispatch to other consumers. Consequently, evaluating the reliability of sell-back should take into account the reliability of the

*The term "value" as it is used here is identical to the term "avoided cost," which is used by FERC.

generation, transmission, and distribution networks as an integrated system (Reddoch 1979a).

Evaluating the reliability of the combined power system is difficult. Analytical methods are not well developed; Monte Carlo simulation techniques can be used (Patton and Ayoub 1975, p. 283) but are expensive. Moreover, data problems exist because, unlike the situation generating units, "no centralized data file exists on performance records for transmission and distribution components" (Patton and Ayoub 1975, p. 284).

FERC's final rule implementing Section 210 of PURPA requires qualifying facilities to pay for the reasonable costs of interconnection* associated with selling power back to the utility. Since these costs will have to be borne by the customer, they could have a major impact on the value of the solar investment. These interconnection costs arise from additional hardware requirements to ensure adequate protection of equipment, power conditioning, control of production sources, and voltage regulation--the hardware that will be required because the distribution system will have to accept bidirectional flows of energy (Reddoch 1979b).

Unfortunately, interconnection costs are now extremely difficult to estimate. One survey of utilities stated that few utilities had adopted written interconnection policies, and that differences in protection practices were found across utilities for the following reasons:

> There are many ways to achieve a single protection goal. The relaying practices of one utility, suitable for its system, may not be applicable to another system. Furthermore, the protection practices were found to be highly situation-dependent for a utility with a large variety of possible interconnection conditions. (Patton 1980, p. 1-4)

3.2.4.2 Estimating Revenues to Generating Customers

Having actual rate data, in estimating revenues earned by generating customers, is the ideal situation, because the rates that utilities set for purchases will determine the customer's actual earned revenues. In the absence of purchase rate data, planning and marginal cost models should be reasonably accurate tools, because FERC's regulations state that rates for purchases must equal the utility's avoided cost of energy and capacity. However, two caveats should be mentioned.

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*Interconnection costs are defined as "the reasonable costs of connection, switching, metering, transmission, distribution, safety provisions, and administrative costs incurred by the electric utility directly related to the installation and maintenance of the physical facilities necessary to permit interconnected operations with a qualifying facility, to the extent such costs are in excess of the corresponding costs which the electric utility would have incurred if it had not engaged in interconnected operations" (FERC 1980a, pp. 12216-12217).

First, FERC's rule implementing Section 210 of PURPA allows states to establish rates that are higher than the utility's avoided cost (FERC 1980a, p. 12221). If states choose to subsidize solar qualifying facilities, then planning and marginal cost models would underestimate revenues earned by customers. Second, public utility commissions are required to set standard rates for qualifying facilities smaller than 100 kW (FERC 1980a, p. 12223). Planning and marginal cost models might yield inaccurate estimates of the revenues earned by these generating customers if, for example, these facilities are so small that time-of-purchase metering would be too costly.

3.3 CONCLUSIONS

Analyzing solar performance and user loads on an hourly basis should yield more accurate estimates than analyses based on more aggregate time intervals. However, the relative importance of using hourly load and performance data when assessing the value of an investment to a particular user depends on whether customers face time-of-use rates. If rates vary only as a function of the total kWh consumed in the month, then hourly load data are far less important than they would be if rates varied substantially by time of use.

Utility planning models are the best available methods for assessing the impact of solar customers on utility supply costs. To estimate the value of an investment to a utility customer, actual rate data are needed. A problem exists in assessing the value of future investments because there is a trend toward rate reform. Even if marginal cost pricing of electricity is adopted, it is not clear that utility planning models would yield accurate estimates of the rates customers would pay. Therefore, their use in assessing customer investments is not recommended.

The appropriate procedure varies, depending on the customer type under consideration. For most residential customers, it is unlikely that time-of-use rates could be adopted because metering costs would be prohibitive. Therefore, using existing rate data is probably the best method now available for assessing the value of future solar investments. For large industrial customers, both existing rate data and marginal cost estimation models could provide a reasonable range of value estimates for the solar investment. However, the uncertainty surrounding future utility rates makes it impossible to identify a single approach that would provide the most accurate economic assessment from the customer's viewpoint.

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SERI

SECTION 4.0

PLANNING MODELS USED FOR ASSESSMENT OF UTILITY APPLICATIONS OF SOLAR ELECTRIC TECHNOLOGIES

T. J. Considine*

4.1 INTRODUCTION

The objective of electric utility planning is to provide electric service at high levels of reliability and at minimum cost. To attain this objective, two facets of electric utility planning must be considered: operation and capacity expansion. Existing generating units must be dispatched to minimize fuel and operating costs and to meet the utility system's reliability standard. In addition, a long-term capacity expansion plan must be selected that minimizes variable costs and capital costs (i.e., total system costs). Both facets are important in estimating accurately the value of a solar power station to a utility.

This section reviews the models that have been employed to analyze the economic impacts of utilizing wind, photovoltaic, or solar thermal electric generators in a central-station configuration. Obviously, these impacts are specific to individual utility economics and do not reflect broader economic and social considerations. Our objective here is to survey and critique these models and suggest ways of simplifying the problem of calculating the value a utility would place on a solar device.

The section is organized as follows. First, we present a general description of models used for utility planning and the necessary modifications to accommodate solar generators. Next, we summarize and assess the methods used in 13 studies of utility applications. Finally, we draw conclusions and make recommendations based on our findings.

4.2. SOLAR UTILITY PLANNING

4.2.1 Overview

In this overview, we present a general framework for assessing the different methods of calculating the value of solar electric technologies. Its purpose is to discuss the relevant factors that must be considered in solar value determination, and the methods that should be used to analyze those factors for maximum accuracy of value estimates. This discussion will provide a baseline description of the best available, currently acceptable techniques for assessing solar electric technologies in utility applications. From such

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a discussion, a qualitative appraisal can be made of the trade-offs between credibility of results and simplicity of the methodology.

As described in Sec. 1.0, the value of a solar plant will be determined by the variable and capital cost savings that accrue to the utility as a result of operating the solar plant. Fuel savings occur either through reduction in the operation of existing generating units, or through change in the mix of generating units and, therefore, of fuels that are used. Capital savings can be realized from the displacement of additional conventional generating units required to meet load growth, or through a long-term change in the utility's mix of generating units. Thus, capital and fuel savings are functions of the impact of the solar device on system reliability. To capture these effects and their impact on the value of solar units, utility planning methods have been adapted to study solar technologies.

There are other factors that motivate the extension of utility planning models for examining the impact of solar technologies on electric utilities. The first factor is the stochastic nature of the solar resource in terms of intensity and duration. Solar units are subject to both equipment and weather outages. Second, utility loads are essentially random variables that depend on climatic, demographic, economic, and technical factors that are not controlled by the utility. The level and pattern of loads change over time; econometric models are often used to predict these changes. Third, the reliability of a generation system depends on the characteristics of all the units in the system. Different generating units have different frequencies of equipment breakdowns or forced outage rates, and they vary in size. Thus, the load-carrying capability* of a new generating unit is an amount less than its full tested capacity because a certain amount of power must be committed from other units to cover possible outage. Finally, the mix of generating units, the solar resource, and loads vary by utility service area. All of these factors are relevant to power systems that plan with solar units. Each component can be modeled separately and linked together in a systematic way.

Since intermittent technologies cannot be represented directly in generation planning models, they must be assessed by first analyzing a base-case and then an alternate case that includes solar electric technologies. Assessing the alternate case involves calculating the change in total costs that results from installing a given number of solar generating units. The value of the solar units to the utility is the difference in the cost of the base case and the alternate case.

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*Effective load-carrying capability (ELCC) is defined by some as "the probabilistically calculated allowable increase in system peak load resulting from the installation of a generating unit" (General Electric Co. 1979). However, Jack VanKuiken pointed out in his review of an earlier draft of this report that "it should be noted that generating units may be unavailable at the time of the system peak load and still have positive ELCC. . . . The loss of load probability (LOLP), determined from a probability calculation, is affected primarily by changes in loads or available capacity at, perhaps 100-300 hours per year, not just the peak hour" (VanKuiken 1980, p.3).

The basic steps involved in assessing solar electric technologies are as follows:

- specifying or estimating the base-case load forecast and the generating sources (and associated capacity and fuel costs) needed to serve the load;
- analyzing the performance of the solar unit(s);
- modifying the utility's base-case load data by subtracting solar generation;
- estimating the conventional fuel and capacity costs needed to serve the "reduced" load (three types of models used for this step are production cost, reliability analysis, and generation-expansion models);* and
- subtracting the total costs associated with the solar case from the total costs associated with the base case.

Figure 4-1 illustrates the overall logic in calculating a value for a particular solar technology. Although not all production cost models include reliability analysis, in Fig. 4-1 these two models are combined into one component for the sake of brevity. This flow chart is heuristic and is not intended to represent any specific technique; not all of the studies surveyed include all the steps outlined in Fig. 4-1.

For the solar case, the analysis begins by estimatng the power output from a solar technology using a solar performance model. This step requires data on the intensity and duration of the solar resource, as well as the technical specifications of the solar device and the number of solar units to be added. The next step is to subtract generation from the solar units from the base-case load data. The third step is to determine the fuel and capital costs associated with using the utility's conventional units to meet the reduced or residual load.

Three types of models typically are used to estimate these conventional generation costs, production cost models, reliability analysis models, and generation expansion models. In general, production cost models are designed to develop a strategy for operating a specified mix of generating units so that two objectives are satisfied: (1) the utility's reliability criterion is maintained, and (2) the total of fuel, operation, and maintenance costs is minimized. Reliability analysis models are used to assess the reliability of the generation system as a whole. A common measure of reliability is the loss of load probability, which is defined as the probability that the load exceeds the available capacity over some predetermined interval--for example, one year. Generation expansion models are designed to determine the additions to existing capacity that will minimize the total costs of supplying electricity, subject to a variety of constraints. The planning horizon for expansion planning is usually 20 to 30 years.

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*These models are also used for assessing the costs associated with the base-case.

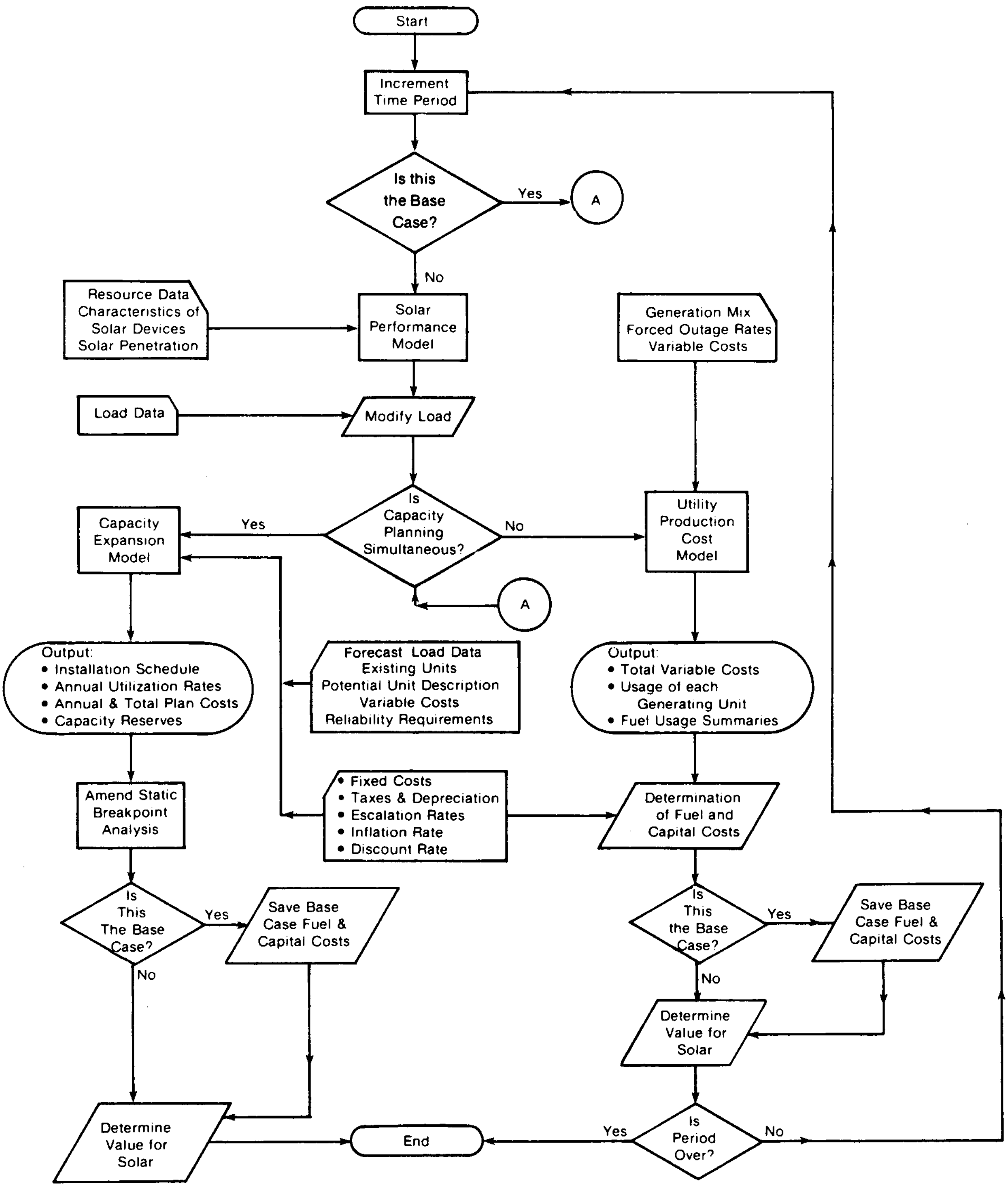

Figure 4-1. Flow Chart of Possible Utility Planning Logic With and Without Solar Devices

Before describing these models in greater detail, it is important to note that it can be misleading to discuss them separately. Some production cost models either perform reliability and production cost analysis simultaneously, or contain reliability analysis models. Likewise, some models that were developed primarily for reliability analysis also contain production cost models. Generation expansion models might contain simplified production cost and reliablity analysis models, or be used in conjunction with these models.

The next four sections provide more detailed, generic descriptions of solar performance analysis, utility production, reliability analysis, and generation capacity expansion models. Note that the following description is general and relates to the best available techniques. Details of specific methods used in the studies surveyed for this chapter follow in later sections.

4.2.2 Solar Performance Analysis

The operation of wind energy conversion systems (WECS), photovoltaic plants (PV), and solar thermal electric power plants (STEP) have been simulated by many different models. Although it is difficult to generalize, there are four basic steps in representing the performance of the solar system:

(1) resource assessment,

(2) system design,

(3) simulation of operation, and

(4) parametric analysis.

Each of the first three steps is complicated by uncertainties and this, in part, explains the existence of step 4.

Determining available resources is fundamental to solar value determination. The problems of solar resource assessment are discussed in Sec. 4.3.2. Resource assessment is the determination of the intensity and duration of the solar resource. The main problem is that solar resource availability is stochastic. Hence, the power available for conversion at any time is random. There are two ways to analyze this problem. Solar resource availability can be analyzed in a deterministic manner by taking actual solar resource time series data and using it as input to step 3. This is the most common method. The data can also be analyzed stochastically. This method might involve positing the existence of a probability density function for the solar resource, estimating its parameters (mean and variance), and then taking random samples from the density function to determine resource availability and, hence, power output (Deaton et al. 1978).

System design involves the selection and sizing of the many components of a solar energy system to be compatible with the resource, the site, and the utility. Storage (both thermal and electric) is an important element to system design since it can be used to postpone the use of solar energy to a time when its value might be higher. The amount and type of storage must be determined in light of its cost and value.

The third step involves building a simulation model to describe the operation of a solar electric system. Such models involve equations that predict energy losses in and between each system component to predict net power output. Also, dispatch of storage or use of fossil fuel in hybrid systems can be determined. Parametric analysis is often conducted to indicate the sensitivity of power output with respect to solar resource levels, storage, and technical features of the solar device under study. The most important output of a solar performance simulation is a prediction of the power delivered from the solar plant into the electric grid.*

4.2.3 Utility Production Cost Models

The utility production cost model is the most common tool used to solve for a conventional system operating strategy that minimizes variable costs while simulating the fulfillment of reliability and operating criteria. Minimization of operating costs, although central to UPC models, is sought in light of the reliablity constraint. These models are not designed to assess the relative benefits of different levels of system reliability. Consequently, minimization of operating costs may be viewed as a secondary objective in the application of these models.

There are many UPC models. Almost all of them are simulation models that examine annual operations in hourly, daily, or monthly time increments. They operate by taking a representation of the load as given and sequentially assigning generating units until the system generation capacity equals total system load plus a spinning reserve margin. Representation of the load is often given as the expected load duration curve (LDC). Figure 4-2 illustrates an LDC. The LDC is a curve showing the power required plotted against the total time that this requirement is equalled or exceeded during the period covered (in this case, one year or 8760 hours). By definition, the area under an LDC equals the total system energy usage during the year. The expected load duration curve can be obtained from electricity demand forecasts and historical load profiles.

To assign generating units to meet expected loads, most UPC models require a specification of the utility system configuration for each time interval considered. In other words, the user must identify all existing generating units, power sharing arrangements, planned capacity additions, and planned retirements. Also required is information on the timing and length of planned maintenance. The amount of information required depends on the UPC model under consideration. Some models require the user to derate each generating unit manually to account for planned maintenance. More accurate UPC models develop a planned maintenance schedule internally, based on the annual load profile and characteristics of the generation mix.

To determine the operation and fuel usage of each generating unit, production data on each one must be input to the UPC model. First, the forced outage

*Most generation performance models used for planning are based upon the assumption that the generation plant is stable and that its output is constant over an hourly time interval.

rate (FOR) of each generating unit is required. Second, the amount of energy needed to produce a kWh of electricity is input. This relationship is usually specified as a heat rate curve which is often estimated on the basis of very limited data. Some UPC models develop operating schedules and estimate the number of times each generating unit would need to be started. With data concerning the amount of fuel needed to bring a unit on line, the total unit fuel usage is adjusted accordingly.

Most UPC models, but not all, require data on spinning reserve policies to maintain system reliability. Spinning reserve is the amount of generating capacity that must be operating (spinning) in excess of system load at any one time. The intent of spinning reserve is to be able to meet unexpectedly high loads and the load that is left unsupplied in the time interval between generating unit failure and start-up of a reserve unit (Endrenyi 1978, p. 114). Most UPC models take the spinning reserve policy as requiring either a specific amount of unused capacity, a fraction of the peak demand, or an amount equal to the largest unit on the system plus some fixed amount of capacity.

After the above data requirements are satisfied, the UPC model is then used to estimate the operation of each generating unit. The load probability distribution, shown in Fig. 4-3, is derived from the LDC and can be integrated to estimate the expected generation of each unit (Jenkins and Joy 1974, p. 15):

$$E(G_i) = T \int_{a_i}^{b_i} F(L)dL$$

where:

$E(G_i)$ = expected generation of the ith unit (kWh),

T = time period represented by the load duration curve (hours),

$F(L)$ = load probability distribution (probability versus MW),

a_i = system capacity for units 1, 2,. . . i − 1 (MW), and

b_i = system capacity for units 1, 2,. . . i (MW).

The order in which the generating units are added to the system is determined by marginal operating costs (fuel costs plus operating and maintenance costs).* Hence, operating costs are minimized since plants with higher operating costs will be operated the least (Anderson 1972, p. 270). This optimization was not designed for capacity expansion planning since only variable costs are considered.

*During normal operations of a utility, a similar program is used to assign the output of generating stations on a real-time basis. Additional and significant technical operating constraints are added for this application.

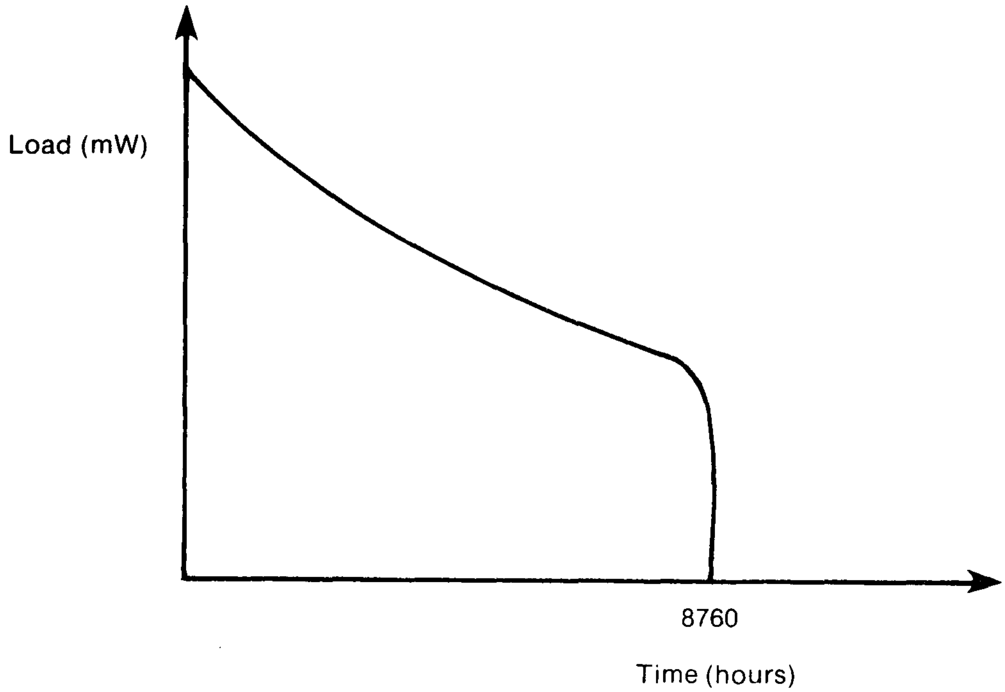

Figure 4-2. Expected Load Duration Curve for One Year

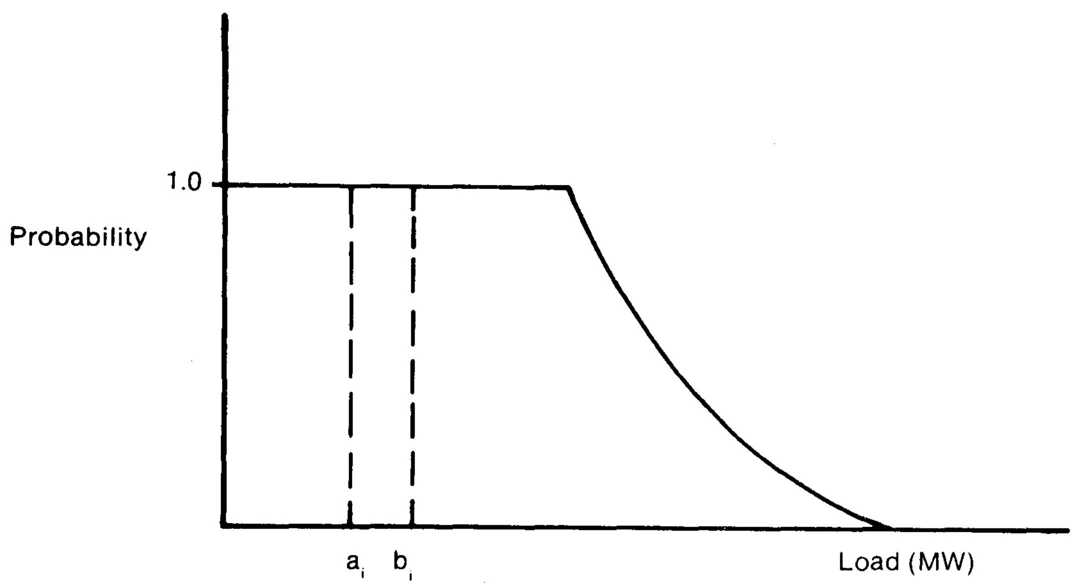

Figure 4-3. Load Probability Distribution

Generating unit forced outages affect estimated fuel consumption as well as the reliability of the utility system. Forced outages can be analyzed deterministically or stochastically. One deterministic method is to derate the capacity of each generation unit to account for random forced outages (and sometimes for planned maintenance as well). The UPC model would then simulate the operation of the generating system recursively by adding one generator at a time, based on these derated capacities. Analyses which use UPC models that are based on the derating method must calculate system reliability in a separate computer program (e.g., JBF Scientific Corp. 1978; Lindley and Melton 1979; General Electric 1978; Leonard et al. 1977; General Electric 1979). The stochastic treatment of forced outages is probably the most widely used approach today, largely because it yields more accurate estimates of fuel consumption (particularly peaking fuel). Stochastic UPC models also compute reliability indices simultaneously.

The primary outputs from UPC models include the total variable (fuel, operation, and maintenance) costs of meeting the load, the usage of each generating unit, and fuel usage summaries. As mentioned above, some UPC models also compute reliability indices. Reliability analysis is the subject of the following section.

4.2.4 Reliability Analysis Models

A commonly used index of generation system reliability is loss of load probability (LOLP) which is the probability that the load exceeds the available generating capacity. LOLP is used to indicate the expected number of events in which load is greater than available capacity, and is often expressed in terms of hours or days per year. LOLP calculations can be based on a variety of time periods, up to every hour of the year. The LOLP in hours per year is estimated by summing the probabilities of a loss-of-load event for each hour. Another approach is to consider only the peak hour of each day. In this case, LOLP is calculated by summing the probabilities of a loss-of-load event for the worst hour of each day of the year.

Many utilities use the latter method. Since the peak hour of each day is the period in which the risk of a loss of load is highest, the method provides a reasonably accurate measure of the LOLP. In addition, it reduces substantially the number of calculations required. However, assessing intermittent technologies, especially wind turbines, requires calculating LOLP for every hour of the year to obtain accurate estimates of the effective load-carrying capability of the solar plant.

There are two major problems with LOLP: (1) it gives no information on the magnitude of the load lost, given a capacity shortage, and (2) it ignores the effects of operating policies and constraints and, as a result, does not give the actual risk of capacity shortage (Patton and Ayoub 1975, p. 276).

Transmission and distribution reliability are considered separately, since LOLP analysis considers only generation reliability. In effect, the transmission and distribution systems are considered perfectly reliable with respect to generation. In a strict sense, the transmission system may be tested to show that if it is a viable link between production and load, then it can be considered perfectly reliable with respect to generation.

Stochastic UPC methods recognize explicitly that all generating units are subject to random outages. These methods can be separated into two general categories: analytical methods and Monte Carlo simulation methods. The latter methods simulate system operation on a digital computer and then compute reliability indices (often LOLP) from the simulation results (Patton and Ayoub 1975, p. 278). Analytical methods are based on the axioms and theorems of probability theory to directly compute system reliability. The discrete-state, continuous-transition Markov process has been found to be a useful analytical method for computing system reliability (Patton and Ayoub 1975, p. 277). Another approach now gaining acceptance is the Baleriaux-Booth method (Baleriaux et al. 1967; Booth 1971). This method employs probability distributions to describe the system loads, generating unit forced outages, and the mathematical combination of these distributions to calculate the expected values of electricity generation and its cost. It computes system reliability recursively, that is, after each generating unit is added to the utility system. However, models that use this approach usually report reliability indices only after all units have been committed to service. The indices are loss of load hours and expected unserved energy.

The importance of the reliability criterion itself can easily be forgotten in using a UPC model or LOLP calculations to determine the value of a solar plant. The chosen level of reliability varies by utility. However, a common planning standard is one day of loss of load every 10 years. This standard was accepted by utility planners, based on their professional judgment and their perception of the risks associated with adverse public reaction to power outages. The problem with assuming a particular criterion is that the costs and benefits of alternative levels of reliability are not explicitly considered. Specifically, the cost effectiveness of system investments in improving reliability performance and the reliability needs of consumers are not specifically addressed. This is admittedly a difficult problem since it is affected by utility regulatory policy as well as complex technical and economic factors. However, it has been addressed by some economists and systems planners in recent years (Telson 1975; Kahn 1977). Their main contention is that the above reliability target (one day in 10 years) is uneconomically high. This is relevant for solar value determination because an uneconomically high reliability standard would result in a higher cost generating mix and, hence, might lower the value of solar plants.

4.2.5 Generation Capacity Expansion Planning

The second aspect of power systems planning is long-term capacity expansion, which involves an attempt to find a minimum cost balance of power plants in a utility system. This optimum balance not only depends on future relative capital and operating costs associated with particular plants, but also on the inherited and expected structure of the power grid (Turvey and Anderson 1977, p. 246). Consequently, generation capacity planning should take into account past investment decisions as well as the future impacts of the investment decisions under consideration.

An optimal investment plan minimizes the discounted present value of operating costs and capital charges incurred during the planning period. This minimization must consider two interrelated problems: (1) the determination of a least-cost mix of generating units and (2) the determination of a least-cost operating schedule for each plant.

Several approaches have been used for expansion planning. The first is a trial-and-error procedure in which several different types of capacity additions would be postulated without the use of a computer model. Such a selection might be based on fuel supply, site availability, environmental restrictions, and technical constraints. Then, a production cost model would be used to calculate the fuel, operation, and maintenance costs associated with each of the prespecified expansion scenarios. Capital costs would be calculated separately and added to the estimated operating costs to permit total cost comparison, needed to determine the minimum cost plan. Operating costs can be estimated on the basis of one year's cost data. An alternative is to use a "look-ahead" procedure to take into account general inflation and fuel-cost escalation. An example of this approach is found in a General Electric report on wind power plants in utility systems (1979, Vol. 2, pp. F-3 through F-6).

The second technique is breakpoint analysis. Breakpoint analysis is a relatively simple graphical technique that determines, for a single year, the least-cost mix of peaking, intermediate, and base-load generating units given annualized fixed and variable costs, and the annual load-duration curve.

A third method is marginal analysis, which starts with an initial reference solution and seeks to improve it by marginal substitutions (Turvey and Anderson 1977, p. 255). This technique is cumbersome because calculating operating costs is complex (Sec. 4.2.3) and the number of possible plans can be large.

The fourth approach is to use mathematical optimization techniques to determine the expansion plan that minimizes total costs for the entire planning horizon. This approach often entails the formulation of an explicit objective function (cost) which is minimized subject to a number of system constraints. The constraints should include economic, environmental, technical, and regulatory factors. They typically include the following: (1) sufficient plants must exist to meet power demand, (2) no plant can be operated greater than its capacity, (3) power capacities must equal initial capital stock, and (4) installed capacity must meet system load plus a margin of reserve capacity. Linear, nonlinear, and dynamic programming algorithms have been used in applications of this approach. These methods, as they have been used in the studies surveyed, are assessed in the sections that follow.

4.3 SURVEY AND EVALUATION OF EXISTING METHODS

4.3.1 Overview

Thirteen economic and technical assessment studies of grid-connected solar electric technologies are examined in this section. These studies are quite diverse in quality, scope, and level of detail. The characteristics of these analyses can be separated into two major sections: solar performance calculations and the interaction of the solar plant with the utility system. The methods employed in both of these areas for each of the studies are summarized in Tables 4-1 and 4-2. Problems associated with these methods are discussed in the following sections. To place this discussion in perspective, an overview of methods employed in the studies is presented.

As Table 4-1 indicates, most of the studies used some sort of solar performance model to estimate the power output from the solar device. Naturally, these models differed depending on whether wind, photovoltaic, or solar thermal electric plants were considered. Nine of the studies used deterministic methods to analyze resource availability. Only two studies did not use a utility production cost model to determine fuel savings (see Table 4-2). Capacity credits (defined in Sec. 4.3.3) are determined in nine studies through LOLP models. The methods used to estimate the capacity remix value of solar plants are quite different. Capital savings attributed to solar power plants are determined by their capacity credit and capacity remix values. Definitional and methodological problems in each of these areas are discussed in Secs. 4.3.3 and 4.3.4. Spinning reserve requirements are considered in only six of the studies surveyed.

Before discussing the relative merits of the methods used in each of the studies, a problem common to all the studies surveyed should be addressed. Many of the studies lacked a clear statement of the assumptions underlying application of the models, and the extent to which those assumptions affected the results. An example of this problem is illustrated in the JBF Scientific Corporation's analysis of wind turbines applied to the New England Gas and Electric Association (NEGEA). Apparently, the intent of this study was to estimate the value of wind turbines to an isolated utility, although that intention was not clearly stated. For example, wind power in excess of load requirements was given zero value because NEGEA was assumed ineligible for reimbursement for such power. This assumption contradicts their reliability analysis, which was based on power pooling arrangements. In addition, the cost of spinning reserve associated with wind turbines was assumed to be equal to the average fuel cost of NEGEA's oil-fired steam units operating at idle capacity, which is charged against wind turbines half the time. The implied assumption is that base-load units will not contribute to spinning reserve.

Input assumptions will affect substantially the estimated value of solar power plants. Because input assumptions are not always clearly stated, interpreting study results is difficult.

4.3.2 Solar Resource Assessment

Insolation and wind resource data are required to estimate the performance of solar thermal, photovoltaic, or wind power plants. Most of the resource data available have been collected by the National Weather Service, the National Climatic Center, and the National Oceanic and Atmospheric Administration. Because the data were collected for other purposes, we can encounter serious problems in using them for estimating solar performance.

Table 4-1. Overview of Methods Used to Assess Solar Performance in Utility Applications of Solar Electric Technologies

Characteristics of Analysis	JBF Scientific	Lindley & Melton (Oahu)	Argonne	Westinghouse Aug. 1978 (Methodology)	Aerospace (STEP outside Southwest)	Westinghouse May 1977	Southwest Research Institute	Honeywell	Southern California Edison	GE (EPRI) June 78	Michigan State University	Aerospace May 1977	General Electric Jan. 1979
I. Type of Solar Electric Technology													
A. Photovoltaic (PV)						X				X		X	
B. Solar Thermal Energy Power Plant (STEP)				X	X				X				
C. Wind Energy Conversion System (WECS)	X	X	X				X	X			X		X
II. Solar Performance Calculations													
A. Solar Performance													
1. Simulation Model	X	X	X	X	X	X		X	X	X	X [e]	X	X
2. Ad Hoc Procedure							X [c]						
B. Solar Resource Data													
1. Time Interval	Hourly	Hourly	Hourly	Hourly	Hourly	Hourly	Hourly	Monthly	Hourly	Hourly	Hourly	Hourly	Hourly
2. Number of Years	5	1	19	1	1	1	10	10	5	1	10	2 [f]	15
C. Determination of Resource Availability													
1. Deterministic		X	X	X	X	X				X	X	X	X
2. Stochastic	X						X	X [d]	X				
D. Storage Options			[a]	X [b]	X	X				X		X	X
1. Dedicated Storage									X		X		
2. Utility System Storage							X [h]	X [g]			X [g]		

Notes:

a. Cannot be determined from report.
b. If the solar power is not needed then it is dispatched to storage and the operating schedules for other plants are changed to minimize total operating costs.
c. Average power output from WECS was determined from generated wind speed-duration curves and wind turbine generator (WTG) performance characteristics.
d. The wind power output was determined by a method based on the Weibull probability distribution.
e. WECS power output is modeled by a linear interpolation between cut in and maximum power wind velocities. No dynamics are considered and implicit in their models is that the wind blows at the recorded velocity for the hour.
f. Hourly data for 2 years at 33 locations in the U.S. were used in the analysis.
g. Schedulable water with water limited hydro
h. Compressed air storage.

Table 4-2. Overview of Methods to Assess the Interactions of Solar Technologies and Utility Systems

Characteristics of Analysis	JBF Scientific	Lindley & Melton (Oahu)	Argonne	Westinghouse Aug. 1978 (Methodology)	Aerospace (Solar Thermal Outside Southwest)	Westinghouse May 1977	Southwest Research Institute	Honeywell	Southern California Edison	GE (EPRI) June 1978	Michigan State University	Aerospace May 1977	GE (EPRI) Jan 1979
I. Interaction of Solar Technology and Utility System													
A. Determination of Operating Cost Savings													
1. Utility Production Cost Model	X	X	X	X[c]		X	X	X	X	X	X		X
2. Breakpoint Analyisis					X[d]							X[k]	
3. Ad Hoc Procedure													
B. Determination of Capacity Credits											i		
1. Utility Production Cost Model								X					
2. LOLP Model	X	X	X	X		X	X		X	X		X	X
3. Ad Hoc Procedure					X[e]								
C. Determination of Capacity Remix Value							g	h			j	l	
1. Interative Search Using a Utility Production Cost Model			X						X	X			X
2. Breakpoint Analysis	X				X								
3. Linear Programming				X									
4. Ad Hoc Procedure		X[b]				X[f]							
D. Determination of Spinning Reserve Requirements													
1. Utility Production Cost Model		X		X					X	X			
2. Ad Hoc Procedure	X[a]										X		

Notes:

a. The amount of additional spinning reserve required by the addition of WECS was assumed to be equal to the difference between the operating reserve required because of total uncertainty in load prediction (load forecasting errors plus errors in predicting wind power output) and the without-WECS operating reserve.

b. The amount of capacity displacement was determined by comparing the LOLP of various combinations of WECS penetration plans with the LOLP of the conventional generation capacity plan.

c. Note that the Westinghouse report is a description of a methodology.

d. Fuel savings are determined by taking the difference in fuel cost between the base case (no solar) and the solar case. The fuel costs (actually fuel and operating and maintenance costs) for each case are approximated by integrating the appropriate load duration curve.

e. The capacity credit is assumed to be equal to the capacity factor of the STEP.

f. Modified daily load curves were generated for two levels of solar penetration and conventional coal generation was removed. Reliability analysis was then performed to determine additions to peak generating capacity.

g. Cannot be determined from report.

h. A specific capacity expansion plan (for 10 years) is stated at the outset of the study. The authors note that the potential savings (fuel and operating costs) of WECS decrease as the new conventional units are brought on line.

i. Capacity credits were not calculated.

j. The study is an assessment of WECS for a small municipality which depends on diesel generators and purchased power. The authors assume that all WTGs and new diesel units come on line at the same time.

k. Instead of directly calculating fuel savings, a breakeven fuel cost is determined based on total solar plant costs (including backup capacity), a plant capacity factor, and per unit fuel costs.

l. Capacity remix value was not calculated.

Problems associated with existing insolation data were described in Sec. 3.2.1. Problems associated with available wind data are even more severe. Data on wind velocities are not appropriate for evaluating wind turbines because either the anemometer was placed at the wrong height (often too low) or only instantaneous readings were made. Although various approximations have been made to correct for the height distortion, their accuracy can be assessed only when adequate data are collected. Most available wind speed data are single one-minute averages recorded once an hour; they do not indicate how wind might vary within the hour.*

There are two issues associated with wind-resource data that are particularly important in assessing the reliability impacts of wind turbines. The first is whether wind availability is correlated with the time of day and the second is the extent to which within-hour variability in wind resources will affect calculated reliability indices.

Fegan and Percival (1979) contrast two methods of constructing the load-duration curve (LDC) for a utility system with wind turbines. The technique used in all but one of the studies surveyed is to form the residual LDC by subtracting hourly wind energy output from the utility's hourly load. The alternative is to treat the wind energy as a completely random variable. In this case, the wind generation could be treated in the same fashion as all other generation sources in a standard Baleriaux-Booth (BB) code. The authors illustrate with an example that shows that the LDCs derived from each method are quite different. The correctness of either method depends on whether wind availability is correlated with the time of day. The standard method, subtracting wind energy from the load, is correct if the time of day is correlated with wind availability. The alternative method is correct only if wind energy is independent of the time of day. Because, as the authors argue, wind velocity is correlated with the time of day, the hourly variation in wind generation should be incorporated into BB codes.

As indicated in Table 4-1, all but one of the studies surveyed used hourly resource data in their performance calculations. The use of hourly averages of wind velocities in estimating WECS power output is controversial. Some engineers and systems planners contend that the variation in wind speed within the hour is large and, therefore, is an important factor in determining system reliability. Figure 4-4 shows two-minute wind velocities measured during one day at the San Gorgonio, Calif., site versus the calculated hourly average wind speed. These data clearly indicate that neither calculated hourly average wind speeds nor one-minute wind speeds measured every hour are adequate.

Fegan and Percival (1979) discuss the impact of within-hour variations in wind velocity on calculated reliability indices. By hypothesizing an example based on hourly load and wind resource data, they illustrate that a very different LOLP can be obtained from hourly averages of load - wind energy output

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*Without detailed technical (stability) models of wind generators, the effects on power output of minute-by-minute wind fluctuations cannot be assessed since wind generator controllers are very complex (especially near cut-in, rated, and cut-out velocity). Spinning reserve can be used to smooth the effect of short-term wind velocity fluctuations (Park et al. 1979).

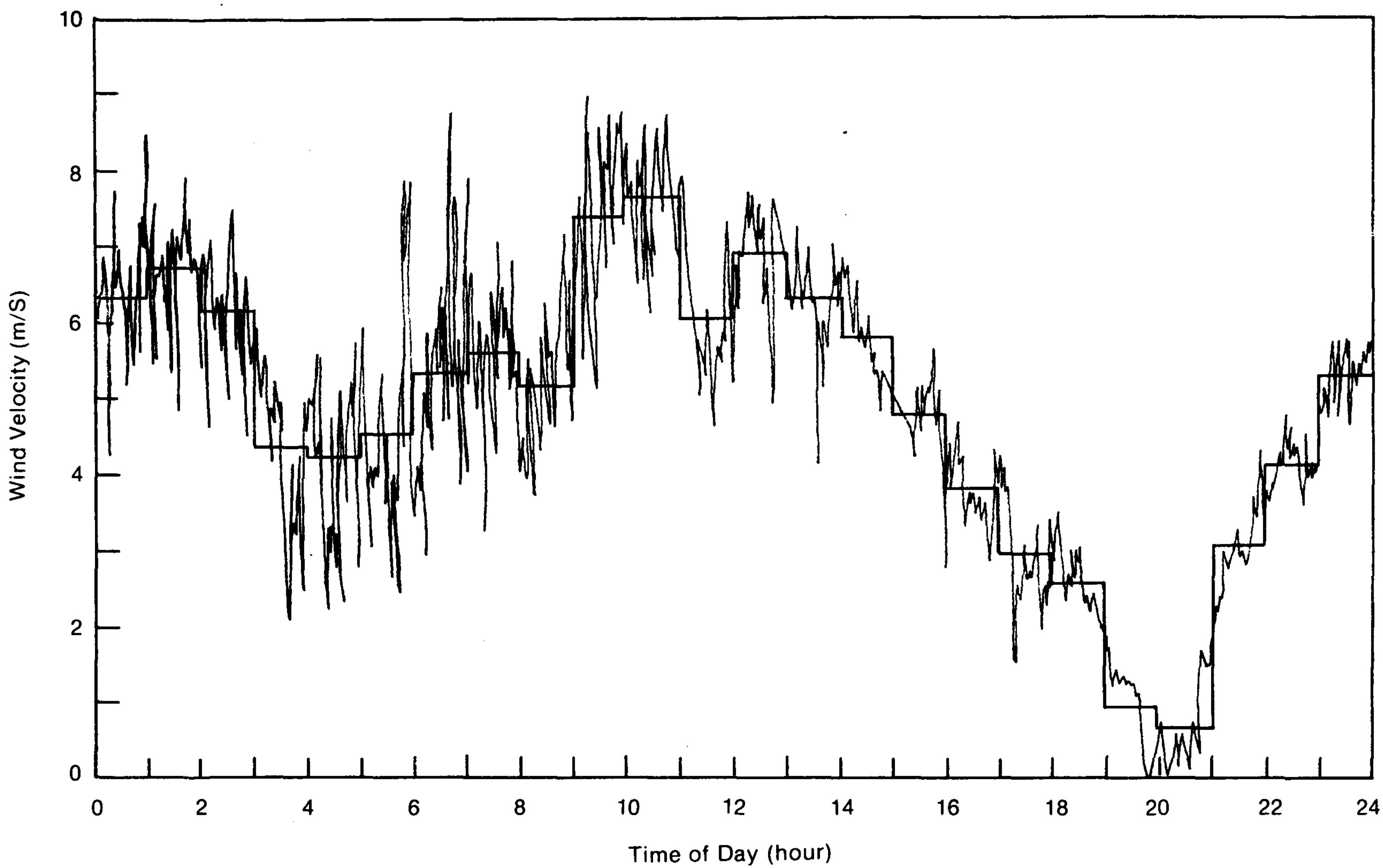

Figure 4-4. Hourly Average vs. Two-Minute Wind Data: San Gorgonio, Calif., June 1, 1979

compared with quarter-hour intervals. In fact, because of the extreme nature of the example, they get a zero LOLP based on hourly values and a positive LOLP based on quarter-hour intervals. The authors conclude that any capacity credit based on average hourly wind velocities will not be correct, and that a probability distribution of wind speed for each hour is needed to obtain an accurate estimate of LOLP. Fegan and Percival have expressed a fundamental problem in assessing the value of wind turbines that might be resolved once we obtain adequate operating experience with wind systems.

Better solar resource data are being collected that should yield better estimates of the performance of intermittent technologies. Because the nature of intermittent resources can alter estimated utility system impacts substantially, the need to obtain better resource data cannot be overemphasized.

4.3.3 Determination of Operating Cost Savings

As shown in Table 4-2, UPC models were used to determine operating cost savings in eleven of the studies. Eight of the studies were similar in that they used a UPC model to calculate operating cost savings and an LOLP model to analyze system reliability. The specific techniques used in these models were not evaluated here because many of the models are proprietary, or sufficient detail was not given to determine which techniques were utilized in the models, or both.

Although in several of the studies the manner in which the UPC models were employed to calculate these savings is not clear, we can outline a general procedure. The first step in these analyses was to calculate system LOLP and operating costs for the base case (without solar units). Second, the output of the solar plant was estimated with a solar performance model and the solar plant's electrical output was subtracted from the assumed utility load to obtain a new load. These calculations should be hourly. The third step was to compute system reliability and operating costs for the utility system with the solar plant. The difference in operating costs between these two cases constituted operating cost savings.

4.3.4 Determination of Capital Cost Savings

In several assessment studies, wind turbines were assumed to be so unreliable that they could be used only to displace fuel (Lindquist and Malver 1976; Asmussen et al. 1978). This assumption ignores the fact that capital savings can accrue to the utility as a result of installing intermittent technologies.

Capital savings may occur from two sources that are not clearly defined in the existing literature. The first source is the capacity credit associated with the solar plant. In most of the studies surveyed, capacity credits were estimated by first recalculating system LOLP after subtracting solar generation from the utility's base-case load data. The change in LOLP determines the effective load-carrying capability (ELCC) of the solar plant, which was typically defined as the increase in system peak load which could be met as a result of installing the solar unit.*

The credit or dollar savings associated with the ELCC of the solar unit can be approximated by comparing the ELCC of the solar unit with the ELCC of a hypothetically displaced conventional unit. For example, if a photovoltaic plant has an ELCC of 50% of its rated capacity, and a 100 MW gas turbine has an ELCC of 90%, then the capacity displacement of the photovoltaic plant is roughly equal to 55 MW of gas turbine (100 × 0.5/0.9). The capital value or credit of this capacity displacement can then be estimated by multiplying 55 MW by the capital cost per MW of the gas turbine.

Even if the capacity credit of the solar plant is zero, capital savings may still accrue to the utility if installing the solar plant would change the utility's optimal mix of conventional units. This second source of capital savings has been referred to as capacity remix and is the net capital investment the utility can save by reoptimizing its generation mix (for example, by substituting cheaper peaking units for more expensive baseload capacity). (Changing the generation mix will also affect fuel consumption; therefore, fuel savings would also have to be recomputed.)

The concepts of capacity credit and capacity remix are obviously related. System reliability is a major determinant of the need to add new capacity. Thus, the determination of capital savings is essentially a capacity planning problem. Adding solar units can result in a cancellation or deferral of a planned unit, cause the construction of a different type of unit, or result in the early retirement of an existing unit. The dollar savings associated with each of these options will differ, as will the timing of the savings. A major source of confusion in the studies surveyed is the manner in which the dollar value associated with capacity displacement was determined.

Three methods were used in the studies surveyed to estimate capital savings: (1) reliability analysis models, (2) breakpoint analysis, and (3) linear programming.

4.3.4.1 Reliability Analysis Models

Six studies used reliability models to estimate capital savings (General Electric Co. 1979; VanKuiken et al. 1980; Southern California Edison Co. 1976; General Electric Co. 1978; Lindley and Melton 1979; Westinghouse 1977). Although the details vary by study, the approach basically involves using a reliability model to calculate the system LOLP for the base case and the LOLP for the solar case. The load-carrying capability of the solar units is then calculated or inferred from the difference in LOLP for the two plans.

*In his review of an earlier draft of this report, Jack VanKuiken pointed out that a unit may have positive ELCC, even if it is unavailable during the utility's peak hour. "LOLP . . . is affected primarily by changes in loads or available capacity at perhaps 100 to 300 hours per year, not just the peak hour" (VanKuiken 1980, p. 3).

The manner in which dollar values were assigned to the MW of load-carrying capability is not clear in many studies. In some cases, assumptions about which type of conventional capacity is displaced appear to be arbitrary. In others, the most expensive type of capacity was assumed. One study attempted to estimate a range by calculating values based on the least and most expensive capacity that could be displaced.

Lindley and Melton (1979) inferred the amount of conventional capacity displaced by comparing the LOLP of various penetrations of wind turbines with the LOLP of the conventional expansion plan. Westinghouse (1977) assumed that conventional coal generation was removed. Reliability analysis was then performed to determine additions to peaking units needed to accommodate two different levels of solar penetration. General Electric (1979) calculated the LOLP of the base case and the solar case and found that, for the Kansas Gas and Electric system, "163 MW of wind power plants have the same effective capacity as 76 MW of coal plants or 71 MW of gas turbine plants." They reported capacity values based on the displacement of coal capacity because "in all cases, the coal displacement resulted in the greatest overall value" (General Electric 1979, Vol. 2, pp. H-34, H-47, H-49).

Argonne applied their reliability analysis model RELCOMP* to assess the reliability impacts of wind turbines (VanKuiken et al. 1980). They calculate the firm-capacity equivalents (similar conceptually to ELCC) associated with different penetrations of wind turbines, and determine the value of the firm-capacity equivalent with the following formula:

$$V = [(C_N \times R) + O] \times S/E_c$$

where:

V = value of firm-capacity equivalent (\$/kW-yr),

C_N = capital cost of conventional unit being displaced (\$/kW$_e$),

R = annual fixed charge rate (fraction/yr),

O = levelized fixed operation and maintenance costs for capacity being displaced (\$/kW$_e$-yr),

S = size of new unit being displaced (kW$_e$), and

E_c = firm-capacity equivalent of unit being displaced (kW$_e$).

Argonne calculated these values for both combustion turbines (peaking units) and an equal mix of coal and nuclear baseload units. In all cases, the value based on peaking capacity was roughly half the value based on baseload

*RELCOMP is a modification of SYSREL. It contains a production cost code (VanKuiken 1980, p. 4).

capacity (VanKuiken et al. 1980, pp. 40, 49). Argonne's rationale for this approach is as follows:

> Because of the immense computational difficulties associated with the "proper" remix problem, and because we have focused on small penetration levels, we have opted for the simpler method of selecting displacement capacity that would result in the highest and lowest capacity value for solar plants. The objective here is to place reasonable bounds on the remix capacity value in lieu of determining the single best strategy for displacing conventional capacity over long planning horizons. (VanKuiken 1980, p. 4)

The advantage of using a reliability analysis model to calculate ELCC and then inferring or assigning a dollar value to the capacity displaced is its computational savings. Most studies that used this approach stated that a capacity expansion analysis was beyond the scope of the study's resources. The problem with this approach is that capital savings estimates are sometimes arbitrary, might be inaccurate, or can yield ranges so large that they are not informative. Moreover, the change in variable costs associated with a change in unit types cannot be determined.

4.3.4.2 Breakpoint Analysis

Melton (1978) used breakpoint analysis to assess the value of solar thermal electric plants (STEPs). JBF Scientific (1978) also used breakpoint analysis to determine the value of capacity remix. However, the discussion of the procedures used is not as clear as in Melton's report. Breakpoint analysis is a relatively simple graphical technique for approximating a least-cost generating mix. The first step in this approach is to find the optimum mix of units for a base case. A common assumption is that there are three types of units: peaking, intermediate or cycling, and baseload.

The annualized cost ($\$/kW_e$) for each type of generating unit can be expressed as a function of the annual hours of operation. These relationships are illustrated in Fig. 4-5(a). The different intercepts for each type of generating unit merely indicate different fixed costs. Similiarly, the slopes of the cost lines are not the same because the generating unit types have different operating costs. For instance, Fig. 4-5(a) indicates that peaking units have lower fixed costs but higher variable costs than baseload units. Note that, in this graph, variable costs are expressed as a function of the number of hours per year the unit is operated. Thus, peaking units have lower annualized costs per kW_e than baseload units if they are operated a relatively small proportion of the time.

Once these cost relationships are established, the least-cost level of operation (in hours) is determined for each generating type. For example, baseload units are the economic choice for operation between 8760 and X_2 hours. To find the installed capacity requirements associated with optimal levels of operation for each generating type, the load duration curve (LDC) is used. The base-case installed capacity requirement for the baseload units is determined by taking the X_2 annual hours of operation and reading across Fig. 4-5(b) to find b MW of required baseload capacity. Intermediate-unit

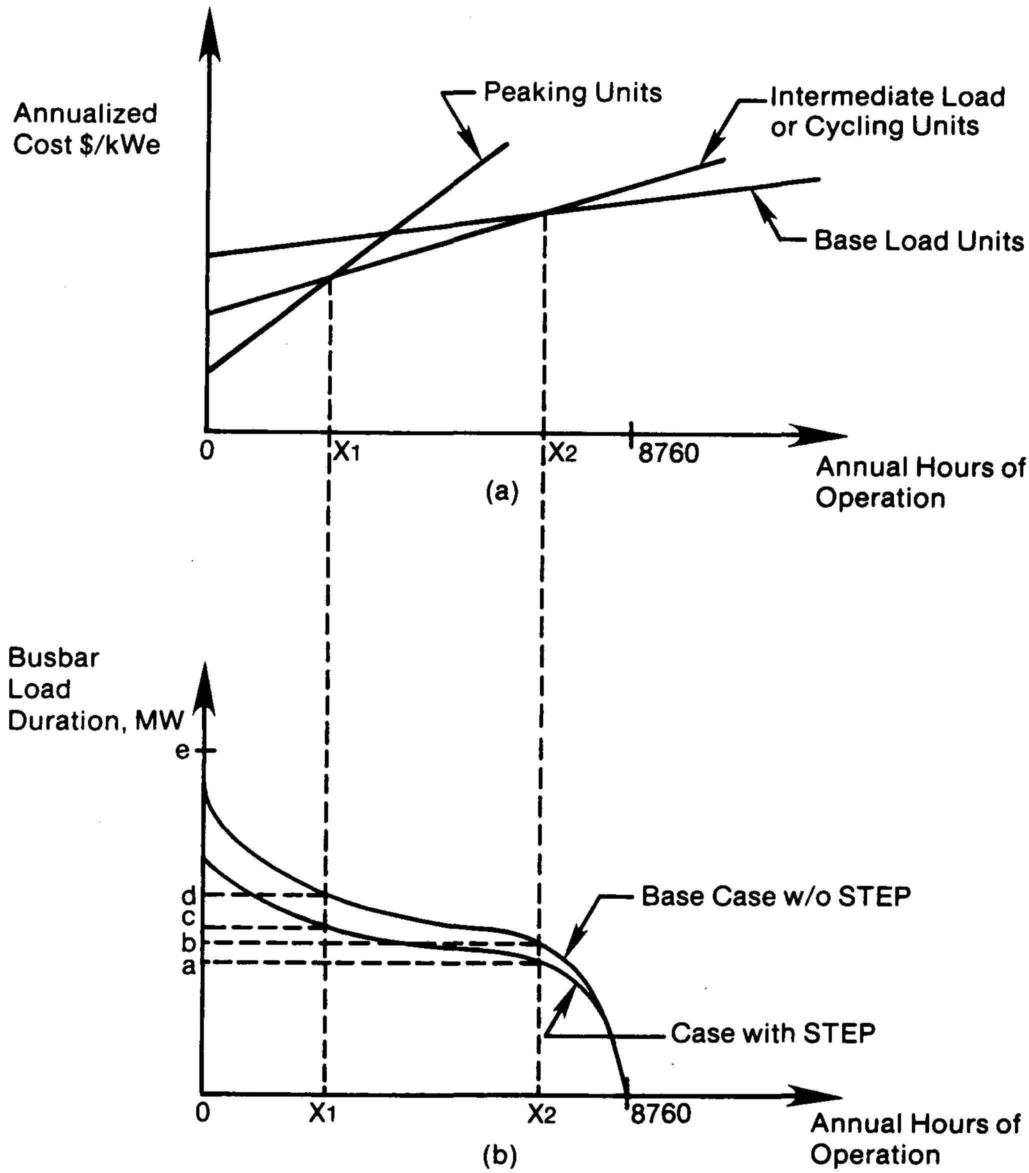

Figure 4-5. Breakpoint Analysis

capacity requirements are determined in a similar fashion; however, they amount to (d-b) MW since b of base capacity already exists. The peak capacity needed is determined from the remainder of the capacity required to meet the system peak. The reserve margin needed to maintain system reliability is assumed to be a fixed proportion of all capacity types.

To calculate the value of a STEP, the change in the annual load duration curve brought about by adding STEP to a utility system must be determined. In Melton's analysis, a solar performance model was used to estimate the power output from a STEP which was then subtracted from the original LDC. The result is illustrated in Figure 4-5(b). Notice that not only has the shape of the annual LDC changed for the case with STEP but also the annual peak has shifted downward. This result may depend on site-specific characteristics of the solar resource. As a result of these changes, baseload capacity requirements decrease to a while intermediate-load capacity requirements decrease to (c-a).

The capital value of a STEP is simply the difference between the capital cost of the base case and the capital cost of the reoptimized case with STEP. Melton expresses this capital value as follows (1978, p. 57).

$$\text{Capital value (\$)} = [ab(FC_B - FC_p) + bc(FC_I - FC_p)](1 + m) + (CC \times R_s \times FC_p)$$

where

ab and bc = the changes in base and intermediate capacity requirements, respectively (kW),

FC_B, FC_I, and FC_p = the fixed costs (including fixed O&M) of base, intermediate, and peak units, respectively ($/kW),

m = the reserve margin (%),

CC = the fractional capacity displacement* of the solar plant (%), and

R_s = the installed capacity of the STEP (MW).

*Melton calls this term the "capacity credit" of the STEP. The terminology has been changed here to avoid confusion with the terms defined in Sec. 4.3.4. Melton defines the fractional capacity displacement as the amount of conventional capacity with equivalent reliability impacts divided by the installed capacity of the STEP. He states: "When LOLP is calculated . . . for a small penetration of STEPs . . . into the mix, the improvement in the LOLP due to the addition of a STEP operating with a capacity factor CF is approximately equal to that which would be obtained with a conventional unit which has a nameplate rating of CF times that STEP nameplate rating. That is, the STEP fractional capacity . . . [displacement] CC is approximately equal to CF" (Melton 1978, p. 63).

The first term in brackets is that portion of the total capital value of a STEP attributed to the remix of conventional equipment. The second term in the above equation is the capacity credit of the STEP.

After conducting the breakpoint analysis to determine the capacity requirements for the two cases, and assuming a value of 15% for m, Melton calculates the remix value. To compute the capacity credit, Melton does not calculate LOLP but instead assumes that the fractional capacity displacement is equal to the capacity factor of the STEP. He maintains that this is a valid procedure for a small penetration of STEPs (<15%) into the generating mix based on the results of another study (Melton 1978, p. 63). The final fractional capacity displacement used for the analysis is increased by an allowance for the power output directed from storage.

Breakpoint analysis yields only an approximate optimum generation mix based on, in Melton's words: "(1) a simplified fiscal approach; (2) a singular representation of heat rate for each type of unit; (3) a neglect of production costs associated with unit startup, unit shutdown, and minimum unit running times; and (4) any consideration for existing equipment already installed (Melton 1978, p. 55). Another drawback of Melton's use of breakpoint analysis is that system reliability was not explicitly analyzed. The extent to which this procedure results in a loss of accuracy in value estimates is not known.

The breakpoint method for determining solar value could be considered a rough approximation to a long-run equilibrium value for solar technologies. This method would be a poor approximation for the present, short-run value for solar plants because the existing mix of generating units contains a certain amount of embodied inertia (i.e., plant lifetimes) and because, for many utilities, the current generation mix is suboptimal because of recent changes in oil prices (Westinghouse Electric Corp. 1979). In addition, breakpoint analysis may give biased estimates of long-run value since it does not consider the inherited and expected structure of the utility grid.

In sum, the advantage of breakpoint analysis is that it is a relatively simple approach for rapidly estimating the value of solar electric technologies. Its disadvantage is that its accuracy is in doubt, and should be assessed.

4.3.4.3 Capacity Expansion Models

Westinghouse (1978) developed a methodology for capacity expansion planning with solar technologies. This methodology was used for the value analysis portion of the Solar Thermal Repowering Strategy Analysis conducted by Westinghouse and SERI. The overall analysis involves three analytical models (Taylor et al. 1979, p. 113).

(1) a mixed integer linear optimization model used to obtain the least-cost generation expansion plan,

(2) a simulation of the solar plant operating with a utility system, using integrated economic dispatch (i.e., a UPC model), and

(3) an LOLP calculation to obtain a desired level of system reliability.

Westinghouse applied these models in two separate analyses: (1) a dynamic analysis of the impact of increasing the penetration of solar plants over 25 years, and (2) a static analysis to estimate the incremental value of a solar plant installed in a specified year (Taylor et al. 1979, pp. 113-114).

The unique feature of this analysis, relative to the other studies surveyed, is the first model, which was used to conduct the dynamic analysis. This expansion optimization selects the timing, size, and type of generation installations, which minimizes capital and operating costs (in present value terms) while satisfying system reliability constraints. The inputs to the program are similar to those of a UPC model; however, a generation expansion is the output, not an assumption. The input requirements include forecast load data, data on existing and potential generating units, economic data, and reliability requirements (Taylor et al. 1979, p. 120). The program finds the optimal, annual installation schedule, over a planning horizon, which minimizes total revenue requirements. Also, the annual capacity factors, annual and total costs, and capacity reserves are estimated. Sensitivity analysis can also be conducted to find out how the optimum strategy changes with shifts in load, economic, or technical projections (Westinghouse 1979, pp. 3-9).

The static analysis was intended to estimate the value of an additional solar plant installed in a particular year during the planning horizon. According to Westinghouse, this detailed information on a specific plant was not available from the dynamic analysis (Taylor et al. 1979, p. 114). The static analysis procedure involved the following steps:

(1) Simulate operation of utility system for the year of interest using the generation mix defined by the Generation Expansion Program, without solar plant, to obtain base-case operating cost and incremental operating cost for (2).

(2) Simulate operation of solar plant to obtain solar plant energy output (MWh) and net residual load (original load minus solar output).

(3) Obtain capacity required on remainder (nonsolar portion) of utility system to achieve desired reliability (LOLP) index. This is accomplished using an LOLP model.

(4) Use breakpoint analysis to determine the new mix of conventional generating plants that accommodates the solar plant. Using the capacity requirements established in (3), and the new generation mix, establish change in capital investment requirements for the conventional generation.

(5) With adjusted capacity from (3) and (4), simulate the operation of the conventional portion of the utility system using the net residual load from (2) as input (Taylor et al. 1979, pp. 149-151).

The remaining four steps involve calculating the difference in annual operating costs and the capital investment credit in present-value terms. From these calculations and assumptions on operating and maintenance costs for the solar plant, a break-even investment cost for the solar plant can be obtained.

The principal advantage of Westinghouse's static analysis procedure is that, by combining production cost, reliability, and breakpoint analysis, the impact of a change in the generation mix on the utility's variable costs is explicitly analyzed. However, its limitation is that changes in the generation mix over time are ignored. Value estimates are obtained by analyzing data for a single year, and then escalating and discounting those results over the assumed lifetime of the solar plant (normally 25 to 30 years). A utility's generation mix can change substantially during that time period, and a static analysis cannot incorporate the resulting impact on the value of the solar plant.

The principal advantage of Westinghouse's dynamic analysis procedure is that it can be used to calculate the value of solar devices by finding the expansion plan that minimizes total (capital plus operating) costs for both the base-case and the solar case over a specified planning horizon.* This approach is more accurate in that all costs are considered simultaneously. Reliability, the inherited generation mix, and future unit additions are all taken into account. The main limitations of the dynamic analysis procedure are its computational cost and complexity. However, the methodology is quite general in that it combines both expansion and production cost aspects of utility planning. This is important because solar value determination is currently being estimated with respect to utility systems that have, for the most part, a suboptimal generation mix.

4.4 CONCLUSIONS AND RECOMMENDATIONS

Estimating the value of solar electric technologies in utility applications requires the use of complex models for maximum accuracy, because complex engineering-economic interactions characterize utility systems and because special problems are encountered with intermittent solar resources. In general, the combined use of solar performance models and utility production cost models are the best methods for estimating variable cost savings associated with solar power plants. However, the methods used to determine the capital cost savings associated with solar units are not adequately developed, primarily because of the complex, dynamic nature of generation capacity planning.

The capacity value of solar plants will be affected by the optimum balance of conventional plants in a utility system. This optimum balance depends not only on future, expected relative capital and operating costs associated with particular plants, but also on the inherited and expected future structure of the power grid. Consequently, estimating the value of solar electric technologies in utility applications requires using a method that takes into account past utility investment decisions, estimates the reliability impacts of solar units, and explicitly considers both capital and operating costs in the search for the optimal mix of conventional units when solar plants are added to the system.

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*In the Solar Thermal Repowering Strategy Analysis, Westinghouse analyzed the value of increasing the penetration of solar plants over time. However, their dynamic analysis procedure could also be applied to assess the value of a given number of plants installed in a particular year.

While the methods used to determine the value of solar additions attributed to operating cost savings and capacity credits are fairly similar in many of the studies surveyed, a wider range of approaches was used to calculate that value as a result of changes in the utility's generating mix. Four of the studies used a UPC model in an iterative fashion, basically a trial and error procedure, to find the new generation mix. Obviously, UPC models are not designed to optimize a utility's generating mix, because intertemporal trade-offs between variable and capital costs are not explicitly analyzed. Breakpoint analysis is also limited because it ignores the inherited and expected structure of the utility grid. The Westinghouse dynamic analysis procedure is the only one surveyed that solved an explicit mathematical optimization problem to find the utility's least-cost conventional generating mix when solar plants were added to the system.

One disadvantage of the Westinghouse method is its high computational cost. Another, more important consideration is its complexity. Interpreting and evaluating the results of such large linear programming models is difficult because of the enormous number of interactions that take place in such a model. One possible way around this problem may be to consider the capacity remix problem with solar as a dynamic investment problem. Optimal control techniques could be used to formulate this problem. The potential advantage of this technique is that it would yield explicit analytical expressions for solar value in terms of the interperiod trade-offs between operating and capital costs for conventional generating units. Another alternative is to rely on breakpoint analysis, which is the the simplest and most intuitively appealing method surveyed. However, the accuracy of this method is in some doubt; value estimates obtained with breakpoint analysis should be assessed empirically, because the method could be used in situations when time and labor resources are limited.

None of the studies surveyed considered the effect of alternative levels of system reliability on the value of solar technologies. Because reliability standards will affect the value of solar technologies and because a number of analysts and public service commissions are beginning to question whether current standards are uneconomically high, the impact of alternative levels of reliability on the value of both conventional and solar electric technologies should be analyzed.

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SECTION 5.0

ECONOMIC ASSUMPTIONS AND FIGURES OF MERIT

The preceding sections have dealt primarily with technical factors affecting the value of solar electric technologies and the techniques required to analyze their interactions with maximum accuracy. In addition to the issues addressed in the preceding sections, there are three problems common to all methods of economic assessment: (1) estimating resource costs; (2) specifying financing costs, tax provisions, and other parameters subject to regulation; and (3) developing figures of merit which will convey the economic desirability of a technology to the user. The first two problems involve specifying the input assumptions to be used in the methods and models described in Secs. 2.0-4.0. Specifying appropriate input assumptions is important because they will affect the estimated quantities and types of fuel and capital the user will save. For example, if a capacity expansion model is used, the optimum utility mix will depend on assumed fuel and capital costs. The utility's mix of conventional units, in turn, will affect the value of the solar technology.

Given a set of input assumptions, the best available methods will provide the basic information needed for complete economic assessments of solar technologies relative to conventional ones: the present value of variable and capital cost savings that accrue to the user over the lifetime of the solar facility and the present value of the cost of the solar plant. Once this information is obtained, all that remains is to express this information in terms of a figure of merit which conveys the economic desirability of the technology to the user.

In the studies surveyed, different types of economic assumptions and figures of merit were computed. However, a basic computation technique common to most studies is present-value cost analysis. Because alternative technologies can require different amounts and timing of expenditures, cost streams must be discounted or weighted so they can be compared on a consistent basis. This was done usually by calculating the present value of costs or benefits that accrue over the lifetime of the solar plant. Many different models can be used to calculate the present value of costs. Most studies of utility applications used the ERDA/EPRI methodology (Doane et al. 1976). An alternative to life-cycle costs is to compare first-year costs, discussed in Sec. 5.2.3.5.

Section 5.1 describes the types of assumptions figures of merit used in the studies surveyed. Section 5.2 assesses the problems associated with estimating resource costs and specifying relevant regulatory policies. This section also discusses different figures of merit in terms of their usefulness for (1) estimating solar technology cost goals, (2) comparing solar technologies and applications, and (3) characterizing the likely purchasing decisions of potential consumers. In Sec. 5.3, the need to communicate economic information in a form useful to DOE planners is addressed. Section 5.4 contains the conclusions.

5.1 SUMMARY OF ECONOMIC ASSUMPTIONS AND FIGURES OF MERIT

The types of economic assumptions and figures of merit used in the studies of end-user applications surveyed are summarized in Table 5-1; those used in the studies of utility applications are summarized in Table 5-2. A word of caution: the studies surveyed frequently did not specify clearly assumptions or computation techniques employed. For example, some studies used a fixed-charge rate to determine annual capital costs, but did not state explicitly how finance and taxation costs were taken into account. For these cases, it was assumed that some provision was made for finance and taxation costs. Other studies stated that levelized costs were calculated but did not specify whether first-year or life-cycle costs* were calculated. Unless a report specified that first-year costs were calculated, it was assumed that levelized life-cycle costs were computed. As a result, the table entries are somewhat judgmental and should be interpreted accordingly.

In Table 5-1, we see that all the studies of dispersed, end-user applications calculated levelized life-cycle total costs of service to the end-user and all but one used this as the basis for comparing solar with conventional technologies.

In the studies of utility applications, input assumptions also differed. As shown in Table 5-2, roughly half the studies reported values and costs in nominal (current) dollars; half used constant (real) dollars. The base year in which dollars were reported ranged from 1975 to 1995. Most studies appear to have calculated required revenues, including tax provisions, but several appear to have ignored taxation effects. In Table 5-2, we see that most studies calculated required revenues after taxes. Finally, all but one study calculated the value of the solar technology. Value typically was expressed as the breakeven capital cost.

5.2 ASSESSMENT OF ECONOMIC ASSUMPTIONS AND FIGURES OF MERIT

Economic assessments require making assumptions about resource costs and cost parameters subject to regulatory policy. In addition, appropriate figures of merit must be selected and computed. Before discussing these problems in greater detail, we address the issue of whether costs should be expressed in nominal (current) or real (constant) dollars.

Calculating levelized costs in current or constant dollars will produce the same relative comparison as long as (1) the costs of all alternatives being compared are calculated in either current or constant dollars, and (2) the input assumptions (system lifetime and cost of capital) are consistent in both

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*First-year levelized costs as defined by Burke et al. are variable costs (operation maintenance, fuel, etc.) incurred in the first year of operation plus annualized capital costs. Life-cycle costs take into account total costs over the system lifetime and can include cost escalations for various components. Levelized life-cycle costs can be calculated by finding the annuity (annual payment) whose present value equals the present value of the total system costs (Burke et al. 1977, pp. III-11 through III-13).

Table 5-1. Economic Assumptions and Computation Techniques Used in Studies of End-User Applications

Economic Assumptions and Computation Techniques	Author of Report						
	OTA	Leonard	Bright	Burke	Cretcher	Feldman	Lorsch
I. Assumptions						NS	
A. Cost escalations for conventional	X	X	X	X	X		X
B. Cost escalations for solar					X		
C. Finance cost induced	X	X	X	X	X		X
D. Taxation effects included	X		X	X			
E. Values and costs in nominal $		NS		1975	NS		NS
F. Values and costs in constant $	1976	NS	1976		NS		NS
G. Experience curves (solar)			X		X		
II. Computation Techniques							
A. Present value life-cycle costs of total service							
1. Total present value							
2. Levelized	X	X	X	X	X	X	X
B. Levelized first-year costs of total service				X			
III. Comparison of solar with conventional							
A. Cost of service with solar compared with cost of service with conventional	X		X	X	X	X	X
B. Presentation of Solar Value							
1. Value not calculated	X		X	X	X	X	X
2. Breakeven capital cost		X					
3. Breakeven energy cost							
4. Payback times				X			

Sources: U.S. Congress, Office of Technology Assessment (1978); Leonard et al. (1977); Bright and Davitian (1978); Burke et al. (1977); Cretcher and Melton (1978); Feldman et al. (1976); Lorsch et al. (1976).

Note: NS = not specified. These studies were not always clear about types of assumptions or computation techniques employed. Thus, table entries are somewhat judgmental and should be interpreted accordingly.

Table 5-2. Economic Assumptions and Computation Techniques Used in Studies of Utility Applications

Economic Assumptions and Computation Techniques	Author of Study						
	JBF	Lindley	Argonne	Westinghouse	Melton	Pittman	SWRI
I. Assumptions							
A. Cost escalations for conventional capital	X	X	X	X	X	X	X
B. Cost escalations for solar			X				
C. Conventional capital priced @ marginal cost	X	X	X		X		X
D. Conventional capital priced @ average system cost				X	X	X	
E. Finance cost included	X	X	X	X		X	X
F. Taxation effects included	X	X	X	X		X	X
G. Values and costs in nominal $		1977	1990	1985		1990	1975
H. Values and costs in constant $	1985				1977		
II. Computation Techniques							
A. Required revenues (after tax)	X	X	X	X	X	X	X
1. Levelized first-year							
2. Levelized life-cycle		X	X		X		X
3. Total present value	X			X		X	
B. Required revenues (before tax)							
1. Levelized first-year							
2. Levelized life-cycle							
3. Total present value							
III. Presentation of Solar Value							
A. Break-even capital cost	X	X	X	X	X	X	X
B. Break-even energy cost	X						
IV. Presentation of Solar Costs							
A. Capital cost of equipment							
B. Capital cost of equipment plus O&M cost		X	X		X	X	X
C. Present value of system cost	X						
D. Levelized energy costs		X		X			

Sources: JBF Scientific Corp. (1978); Lindley and Melton (1979); VanKuiken et al. (1980); Day (1978); Melton (1978); Pittman (1977); Ligon et al. (1976); Lindquist and Malver (1976); Southern California Edison Co. (1976); General Electric Co. (1978); Asmussen et al. (1978); Leonard et al. (1977); General Electric Co. (1979).

Note: These studies were not always clear about types of assumptions or computation techniques employed. Thus, table entries are judgmental and should be interpreted accordingly.

Table 5-2. Economic Assumptions and Computation Techniques Used in Studies of Utility Applications (Concluded)

Economic Assumptions and Computation Techniques	Author of Study					
	Lindquist	Southern California Edison	GE/PV	MSU	Leonard	GE/Wind
I. Assumptions						
A. Cost escalations for conventional capital	X	X	X	X	X	X
B. Cost escalations for solar			X			X
C. Conventional capital priced @ marginal cost	X					
D. Conventional capital priced @ average system cost			X	X		
E. Finance cost included	X			X	X	X
F. Taxation effects included	X			X	X	
G. Values and cost in nominal $		1986	1995			1976
H. Values and costs in constant $	1975			1975	1975	
II. Computation Techniques						
A. Required revenues (after tax)	X			X	X	X
1. Levelized first-year						
2. Levelized life-cycle					X	
3. Total present value	X			X		X
B. Required revenues (before tax)		X	X			
1. Levelized first-year						
2. Levelized life-cycle		X				
3. Total present value						
III. Presentation of Solar Value						
A. Break-even capital cost	X	X	X	X		X
B. Break-even energy cost						
IV. Presentation of Solar Costs						
A. Capital cost of equipment						
B. Capital cost of equipment plus O&M cost	X	X	X	X	X	
C. Present value of system costs						
D. Levelized energy costs						X

Sources: JBF Scientific Corp. (1978); Lindley and Melton (1979); VanKuiken et al. (1980); Day (1978); Melton (1978); Pittman (1977); Ligon et al. (1976); Lindquist and Malver (1976); Southern California Edison Co. (1976); General Electric Co. (1978); Asmussen et al. (1978); Leonard et al. (1977); General Electric Co. (1979).

Note: These studies were not always clear about types of assumptions or computation techniques employed. Thus, table entries are judgmental and should be interpreted accordingly.

types of calculations. This is true because the present value of life-cycle costs for a single alternative will be the same regardless of whether the calculations are made in current or constant dollars* (Doane et al. 1976, p. D-6). Levelized life-cycle costs are determined by finding the annuity (uniform annual payment) whose present value is equal to the present value of the total system costs. This annuity can be expressed in current or constant dollars and is calculated by multiplying the present value of costs by the appropriate capital recovery factor. Similarly, because the value of a solar technology is based on the present value of total savings to the user, discounting costs in current or constant dollars will not affect value estimates such as the present value of total savings or breakeven capital cost.

Discounting in current dollars has a computational advantage relative to the treatment of depreciation. Because depreciation allowances are based on the original investment cost, the real value of depreciation in succeeding years will decline as a function of the general rate of inflation. Thus, if discounting is done in constant dollars, depreciation allowances must be deflated for succeeding years by the rate of inflation. If discounting is done in current dollars, depreciation allowances can be calculated directly from the original investment outlay.

5.2.1 Estimating Resource Costs

Resource costs are the costs of the materials, services, supplies, fuel, and labor required for the solar technology or for the conventional technologies solar displaces. Future resource costs must be estimated. For example, in utility applications, the value of a solar electric technology is determined by the present value of displaced fuel, operation, maintenance, and capital costs. Particular assumptions about fuel and capital cost escalation rates will affect the magnitude of estimated total savings. Likewise, assumptions about future electricity prices and types of rates will affect substantially the estimated value of solar technologies to users in dispersed applications.

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*That the present value of total system costs is the same regardless of whether calculations are made in constant or current dollars can be shown by examining the formula for calculating present value (PV) for discrete time discounting:

$$PV = \sum_{t=1}^{n} \frac{C_t}{(1+r)^t} = \sum_{t=1}^{n} \frac{(1+g)^t\ C_t}{[(1+r)(1+g)]^t}$$

where t = year; C_t = costs incurred in year t; r = the real rate of interest (net of general inflation); g = the rate general inflation. In the first expression, discounting is done in constant dollars; in the second, discounting is done in current dollars.

Resource costs and electricity prices will vary by region and utility. If the objective is to estimate the value of a technology to a specific utility or type of user in a particular region, then resource costs and electricity prices should be representative for that region and utility. Because future costs can only be estimated, sensitivity analyses using different assumptions about fuel and capital cost escalation rates are useful.

5.2.2 Specifying Parameters Subject to Regulatory Policy

In addition to basic resource costs, regulatory policies will affect the costs of conventional and solar technologies to utilities and end-users. These policies can be separated into two broad categories: (1) rate design policies, and (2) policies that affect the cost of capital and capital charges. Problems associated with rate design policy were described in Sec. 3.0.

The cost of capital is the cost of financing investment or the interest rates that must be paid to debt holders or stockholders, or both. The cost of capital is an important parameter that must be defined because it is used to calculate the discount rate.* The size of the discount rate will affect relative cost comparisons of technologies with different capital intensities. (Capital intensity is a measure of the proportion of capital relative to other inputs in a production process.) The higher the discount rate, the higher the present-value cost of capital-intensive technologies relative to less capital-intensive technologies.

Two types of policies affect the cost of capital: policies affecting the type and cost of financing available to users, and taxation policies. An example of the first type of policy would be federally guaranteed low-interest loans to finance solar technologies. If such programs are instituted, they will affect the present-value cost of solar technologies relative to conventional ones. The type and cost of available financing are factors that should be considered in computing figures of merit to characterize consumer purchasing decisions. They will be discussed in greater detail in Sec. 5.2.3.5.

The major tax provisions affecting capital charges include the tax-deductibility of interest on debt and depreciation provisions. Because interest on debt is tax deductible, the revenues required to cover costs are lower than they would be if this tax provision were ignored in computing present-value costs. Special depreciation provisions include accelerated depreciation and investment tax credits. Considering accelerated depreciation and investment tax credits results in a lower fixed charge rate than would assuming straight-line depreciation. The fixed charge rate when "multiplied by the present value of capital investment . . . (yields) the entire contribution of capital costs, income taxes, and miscellaneous costs to the annualized system-resultant cost" (Doane et al. 1976, p. III-9).

Required revenues calculated by dividing annualized total system costs by the annual energy output from the system "can be interpreted as the minimum price

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*The relationship between the cost of capital and the discount rate is explained in Sec. 5.2.3.5.

at which energy from the system could be sold and still produce revenues sufficient to recover all system-resultant costs" (Doane et al. 1976, p. III-1). Ignoring tax provisions in the calculation of required revenues will overestimate the minimum revenue required to exactly recover costs because the tax provisions reduce capital charges. For the purpose of comparing alternative technologies of similar capital intensities in similar applications, ignoring taxation effects should have only a negligible effect on relative cost comparisons. However, the greater the difference in capital intensity among the technologies being compared for similar applications, the more substantially taxation provisions will affect relative cost and cost-value comparisons.

Taxation provisions also can have a major impact on the relative costs of the same technology in different applications because residential consumers are not eligible for many of the tax preferences applicable to industries and utilities. In addition, taxation policy can affect the cost of conventional electric service if these policies affect the utility's investment decisions or if the tax preferences are reflected in rates to users.

5.2.3 Assessment of Figures of Merit

Figures of merit are defined as measures that indicate the relative economic worth to a user of a particular good or service. Among the studies surveyed, different figures of merit were calculated, including: (1) levelized energy costs; (2) total costs of service to end-users; (3) measures based on value, such as breakeven capital cost; and (4) combined cost-value measures. Each of these figures of merit is discussed in the following sections according to their usefulness for estimating cost goals for solar technologies and for comparing different solar technologies and applications. In Sec. 5.2.3.5, the problem of developing figures of merit that will indicate whether a potential user is likely to purchase a solar technology is described. In particular, the relevance of first-year versus life-cycle costs to residential users is discussed.

5.2.3.1 Levelized Energy Costs

The calculation of levelized energy costs is straightforward. For a particular plant, annual costs (annualized capital costs plus annual variable costs) are divided by annual energy production. The result is expressed generally in cents per kWh, or dollars per million Btu.

This figure of merit has several important advantages. First, it is the simplest figure of merit to calculate. Because the calculation is based on the cost and performance of a single unit or plant, no interaction with the utility system must be analyzed. Second, it can be useful as a screening tool; i.e., for making preliminary comparisons of different technologies. For example, Park et al. compare the energy costs of wind turbines and conventional technologies to determine whether a more detailed evaluation is warranted (Park et al. 1979, p. 59).

The major problem with this figure of merit is that it is a valid basis for comparing systems only if energy produced by all alternatives is of equal value. Table 5-3 shows different figures of merit calculated for a solar thermal electric plant with collector areas of three different sizes. The results indicate that, when the value of energy production differs, a comparison of energy costs alone will not be a correct indication of which system is preferred economically. Levelized energy costs do not provide sufficient information for identifying the cost goals necessary for intermittent solar electric technlogies to be cost-competitive with conventional technologies.

Table 5-3. Economic Figures of Merit Calculated for a Solar Thermal Electric Plant with Alternative-Sized Collector Areas

Performance and Economic Information	Plant Alternative		
	A	B	C
Annual energy production (GWh)	199	258	309
Present worth of revenue requirements			
Plant value (M$)	275	390	447
Plant cost (M$)	420	540	634
Economic figures of merit			
Levelized energy costs (mills/kWh)	242	241	236[a]
Net value (V-C)	-145[a]	-150	-187
Cost/value ratio (C/V)	1.53	1.38[a]	1.42

[a]Best alternative using this criterion.

Source: Day (1978), Table II.

5.2.3.2 The Customer's Total Cost of Service

The studies of dispersed applications surveyed in Sec. 3.0 basically calculated the total costs paid by solar and conventional customers to obtain an energy service such as hot water. These costs were calculated on either a monthly or annual basis. OTA, for example, calculated monthly energy bills associated with solar and conventional systems (U.S. Congress, Office of Technology Assessment 1978, Vol. II).

A solar customer's total monthly cost is calculated as follows:

$$TC_s = S_{co} + E_b - R_s$$

where

TC_s = the solar customer's total monthly cost;

S_{co} = monthly cost associated with owning and operating the solar energy system, including capital charges, operation, and maintenance;

E_b = monthly electric bill for backup energy; and

R_s = revenues earned through sales of excess power back to the utility. (For nongenerating customers, $R_s = 0$.)

The conventional customer's total monthly cost is:

$$TC_c = E_c$$

where

TC_c = conventional customer's total monthly cost, and

E_c = conventional customer's monthly electric bill.

This figure of merit has several advantages. First, the monthly or annual costs for solar and conventional systems can be compared directly because all costs are taken into account. Second, other measures, such as value, can be estimated directly. For example, the total savings resulting from using the solar system can be determined by calculating the present value of the customer's electric bill with and without the solar device (Tabors et al. 1978, p. I-6). The present value of savings would equal

$$E_c - (E_b - R_s),$$

discounted over the lifetime of the system.

The problem is that E_b, R_s, and E_c are difficult to predict because rate structures are likely to change in the future.

5.2.3.3 Measures Based on Value

Most of the studies of utility applications calculated the value of the solar technology where value was calculated from the amount the utility would save in displaced conventional fuel, operation, maintenance, and capital costs over the lifetime of the solar plant. This value was then expressed as a break-even capital cost--the amount the utility could afford to pay for the investment in solar equipment.

Break-even capital cost usually is calculated in one of two ways. The two methods are similar, but the first subtracts operation and maintenance from the solar plant before break-even capital cost is determined. Method 1 can be summarized as follows (Day 1978, p. 3-9):

$$SAV_{pv} = OP_{pv} + CAP_{pv} - OM_{pv}$$

where

SAV_{pv} = the present value of total savings to the utility as a result of operating the solar plant;

OP_{pv} = the present value of operating cost savings (fuel, operation, and maintenance) to the utility as a result of the solar plant. If additional spinning reserve requirements are required for the solar plant, they would be subtracted from operating cost savings to determine net operating savings to the utility;

CAP_{pv} = the present value of capital cost savings to the utility as a result of the solar plant. Capital cost savings would include those resulting from a reduction in total system capacity needed to meet LOLP criteria (i.e., the capacity credit of the plant) as well as the net savings resulting from a change in the utility's optimum generation mix (for example, if gas turbines are substituted for baseload coal capacity); and

OM_{pv} = the present value of operation and maintenance costs for the solar plant.

Once SAV_{pv} is determined, break-even capital cost is calculated by finding that capital investment for which present value is equal to the present value of savings to the utility (Day 1978, p. 3-9). For the ERDA/EPRI methodology, the formula for break-even capital cost is as follows:

$$CI_{be} = \frac{(SAV_{pv})\ (CRF)}{FCR}$$

where

CI_{be} = break-even capital cost for the solar plant,

SAV_{pv} = same as above,

CRF = capital recovery factor (Doane et al. 1976, p. III-9), and

FCR = fixed charge rate (Doane et al. 1976, p. III-9, III-10).

Method 2 is identical to method 1, except that operation and maintenance costs for the solar plant are not subtracted from the utility's savings. The advantage of method 2 is that it can be calculated without having to estimate the costs of the solar plant. Because costs associated with conventional capacity are known with greater certainty than costs associated with solar plants, method 2 is likely to be a more precise estimate of the savings to the utility. However, if break-even capital costs are to be calculated, solar operation and maintenance costs must be subtracted from savings. Otherwise, the value of the plant--the amount the utility could afford to pay for solar equipment--will be overestimated.

Another figure of merit related to break-even capital cost was calculated by JBF Scientific Corporation. JBF calculated break-even energy costs by first determining break-even capital costs, using a procedure similar to method 2 outlined above. Break-even energy costs were then computed by dividing the sum of annualized break-even capital costs and annual operation and maintenance costs by annual energy output* (JBF Scientific Corp. 1978, p. 8-37).

The usefulness of measures based on value for comparing a solar technology with the conventional technologies it can displace depends on the relative accuracy of estimated savings to the utility. If the different operating and reliability characteristics of the solar and conventional technologies have been analyzed properly, then value estimates will provide a good indication of what a utility could afford to pay for a particular solar electric technology application. Value estimates provide information needed to identify technology cost goals. However, value estimates alone are not sufficient for comparing different solar technology applications because, as Day, Reed, and Malone point out, the value of a solar plant can be increased by increasing its cost. They state: "This [value] by itself is not a good criterion for plant preferability since by increasing collector area, storage capacity, turbine-generator size, or just making a larger plant in general, the value will increase" (Day et al. 1979, p. 72).

5.2.3.4 Combined Cost-Value Measures

The authors of the reports by the Westinghouse Corporation calculated combined cost-value measures in addition to break-even capital cost. They considered two measures: the cost/value ratio** and net value. The cost/value ratio is

$$C/V = \frac{TC_{pv}}{TS_{pv}}$$

(Day 1978, p. 3-11), and net value is

$$V - C = TS_{pv} - TC_{pv}$$

where

TC_{pv} = the present value of total costs of the solar plant over its lifetime, including capital and operating costs, and

TS_{pv} = the present value of total savings to the utility as a result of operating the solar plant; e.g., the sum of OP_{pv} and CAP_{pv} defined above.

*Since JBF did not subtract solar operation and maintenance costs from the savings to the utility before calculating break-even capital costs, they overestimated break-even capital cost and break-even energy cost. See JBF Scientific Corp. (1978), especially pp. 8-11 through 8-13, and 8-37 through 8-39.

**Westinghouse calls this the cost/benefit ratio (Day 1978, p. 3-11). It is labeled the cost/value ratio here to avoid confusion with the cost/benefit ratio commonly used in analyses of public investment.

John Day calculated cost/value ratios, net values, and levelized energy costs for a solar-thermal power plant with three different sizes of collector areas. The results, reported in Table 5-3, indicate that these different measures give different rankings of which application is most attractive.

The limitations of levelized energy cost as a basis for comparison were discussed in Sec. 5.2.3.1. The inconsistent ranking between the net value measure and the cost/value ratio occurs when projects of unequal scale or size of investment outlay are compared and no attempt is made to standardize their investment outlays (Loose 1977, p. 79). In the analysis of public investment literature, several procedures have been developed to eliminate the problem of inconsistent ranking. The first procedure involves scaling projects up or down so that their investment outlays are comparable. Regarding projects for which actual scale cannot be changed to equal the scale of the alternatives, another procedure must be used. In this method, we assume that excess funds (the difference between the investment outlay of the largest project and the outlays of smaller projects) can be invested in the private sector and earn an appropriate rate of interest (the social opportunity cost of capital). Part of the benefits (value) from the smaller projects using this procedure will accrue from the rate of return earned on excess funds (Loose 1977, pp. 78-83).

Several problems can occur when we use these normalization procedures for assessing solar electric technologies. First, scaling projects up or down is valid only if benefits (values) can be scaled up or down proportionately. Because the value of a solar technology can diminish as the percentage of solar capacity in a utility system increases, the value of the technology cannot be assumed to increase in the same proportion that scale increases. For example, we cannot assume that if the scale of a solar plant is doubled, its value will also double. It appears that the second normalization procedure should be used, although some modifications might be necessary to evaluate private-sector decisions. At a minimum, the appropriate interest might vary for public and private investments.

Because the net value measure and the cost/value ratio can yield inconsistent rankings when no attempt is made to standardize investment outlays, we encounter a problem in assessing solar electric technologies because there is no clear reason to favor one measure over the other. Since combined cost-value measures provide a better basis for comparing the relative attractiveness of different solar technology applications than do levelized energy costs or value measures alone, the procedures needed to eliminate the ranking inconsistencies should be analyzed further.

5.2.3.5 Figures of Merit as Indicators of Consumer Behavior

In addition to identifying solar technology cost goals, it would be useful for DOE planning purposes to know at what cost and under what circumstances consumers would actually purchase solar technologies. Cost and value data are necessary, but they are not sufficient for predicting whether consumers will actually purchase a particular product. Therefore, it is useful to identify two criteria for assessing figures of merit as indicators of how consumers will behave. First, does the figure of merit express values and costs as the consumer would perceive them? Second, does the figure of merit indicate whether a purchase will actually occur?

Consumer Perceptions of Cost and Value. Determining whether a figure of merit expresses values and costs as the user would perceive them requires examining the economic circumstances and decision processes of the type of consumer being considered. Residential users and utilities are discussed here.

With respect to residential users, a major issue is whether first-year or life-cycle costs would more adequately express costs as the user is likely to view them. Before discussing this problem in detail, the term "discount rate" should be defined. There are two concepts behind the discount rate, the rate of time preference and the opportunity cost of capital. The rate of time preference expresses the user's preference for present versus future consumption (current savings). The opportunity cost of capital is the rate of return that could be earned on other investments in the private sector. For purposes of comparing the cost of alternative energy technologies, most researchers use the user's actual cost of borrowing to calculate the discount rate.

It should be emphasized that the discount rate is one of the most important parameters that must be identified in assessing the relative cost of different energy systems. For example, comparing a solar space heating system with an electric resistance heating system involves comparing a high-capital, low-operating-cost system with a low-capital, high-operating-cost system. For a consistent basis of comparison, the different cost streams must be discounted or weighted. Defining the correct discount rate is critical because, in this example, the higher the discount rate, the higher the present-value cost of the solar energy system relative to the conventional one.

Given this background on the discount rate, we can address the issue of life-cycle versus first-year costs. We must emphasize at the outset that there is no basic methodological difference between calculating life-cycle and first-year costs. Both involve discounting or weighting cost streams that differ as to quantity and timing of expenditures. The dispute about whether life-cycle or first-year costs reflect relative costs as the user would perceive them can be resolved by addressing two questions: (1) What are the actual economic circumstances of the user? In particular, what is the type and cost of available financing, and what is the resale value of the solar equipment? (2) What is the user's discount rate? In particular, does the user's cost of borrowing adequately reflect the user's time preference for current relative to future consumption?

That these issues need to be resolved can be illustrated by comparing OTA and MITRE approaches to the problem of representing relative costs as the residential user would perceive them. For certain residential new construction applications, OTA calculated the life-cycle costs of the solar energy system assuming mortgage financing to be available at a 9% interest rate. The user's discount rate was calculated from the mortgage interest rate. They then calculated the levelized monthly energy bills the consumer would receive with the solar system and a reference conventional energy system (U.S. Congress, Office of Technology Assessment, Vol II, pp. 19, 96). These monthly energy bills are one basis for comparing a solar with a conventional technology.

In contrast, the MITRE Corporation stated that a comparison of initial costs and savings more adequately reflects residential consumers' purchasing decisions than would life-cycle cost comparisons "because residential home buyers place more emphasis on initial costs and early savings rather than life-cycle cost" (MITRE Corp., METREK Div. 1977, p. 12). The figure of merit MITRE uses to characterize residential consumer decisions in the SPURR model is:

$$FOM = C_1 \frac{X_1}{X_2} + C_2X_1 - C_3X_2$$

where

X_1 = the fuel cost savings in the first year from a solar system,

X_2 = the initial cost of the solar system minus the initial conventional cost, and

C_1, C_2, C_3 = constants.

The constants reflect the residential consumer's relative weighting of initial capital cost and annual savings. MITRE estimated the values of C_1, C_2, and C_3 from data collected through an Energy Research and Development Administration survey of 244 families who were asked to specify the cost they would be willing to pay for a solar energy system given a range of monthly savings (MITRE Corp., METREK Div. 1977, p. 12). Note that asking consumers to specify an initial cost which they would be willing to pay to obtain a given monthly saving is equivalent to asking them to specify their rate of time preference for current relative to future consumption or their discount rate. In other words, we could also derive an implicit discount rate from the survey data.

The confusion about whether first-year or life-cycle costs are appropiate arises because most analysts use the customer's actual cost of borrowing to determine the discount rate. If a user weights first-year costs and savings heavily, the user's cost of borrowing does not adequately reflect the user's rate of time preference.

According to one study of energy-consuming durable goods, residential users do "behave in a manner which implies a much higher discount rate than can be explained in terms of the opportunity cost of funds available in credit markets" (Hausman 1979, p. 51). By examining data on purchases of air conditioners, Hausman derived the discount rates implied by the capital and operating costs of the various types of air conditioners purchased. He found that the average discount rate for the users surveyed was around 25%, which compares with an 18% rate of interest on credit card purchases, and that the discount rate varied from 9% to 39%, depending on income. Gately calculated implicit discount rates for different refrigerators and electricity prices and found a range of 45% to 300% (Gately 1980).

In summary, the debate about whether first-year or life-cycle costs express relative costs as the user would percieve them is a dispute about the user's rate of discount. In particular, it is a dispute about whether the user's cost of borrowing--defined by the type of available financing--reflects the user's rate of discount. Based on MITRE's results and the Hausman and Gately studies, it appears that the cost of capital yields a lower discount rate than consumer purchasing decisions would indicate. However, once the user's economic circumstances and discount rate are determined, it is appropriate to calculate the present value of costs of the alternative energy systems so that their cost streams can be compared on a consistent basis. This procedure will express relative costs as the user would perceive them.

Utility planners are a more homogeneous group of consumers than are other potential users. Moreover, because they are regulated, many parameters (like the cost of capital and taxation policies) are known with greater certainty than for other types of consumers. Finally, their planning horizons are typically 10-20 years for capacity expansion. All of the studies of utility applications appear to use life-cycle cost analysis--the discounted cost and value of the solar plant over its lifetime--to compare solar with conventional technologies. Given the characteristics of utilities, life-cycle costs appear to express relative costs as the utility planner would perceive them.

Predicting Purchasing Decisions. Cost data provide necessary, but not sufficient, information for determining whether purchases will actually occur. None of the figures of merit reviewed here provide enough information to determine when and under what circumstances purchases are likely to occur. For residential users, individual tastes and preferences, available product information, legal restrictions, and perceived risk and uncertainty will also affect the rate of a technology's adoption.

Perhaps the most serious limitation of the studies surveyed is that other options available to customers were not considered. If utility customers want to reduce their electric bills, they typically have many options. Depending on the individual house, a customer might add insulation, buy a solar hot water heater, install a wood stove, purchase a load-management system, buy energy-efficient appliances, or install solar-generating equipment. If solar hot water heaters are more cost-effective than solar-generating equipment, an assessment that compared only solar-generating equipment with conventional utility service would not provide enough economic information to assess likely purchase decisions.

Specific regulations will affect electric utilities' planning decisions. Costs arising from risk and uncertainty have increased in the industry, and are likely to have a major impact on investment decisions. Different types of plants pose different financial risks. For example, utilities can face severe cash-flow problems in capacity expansion involving plants with long construction intervals, if construction work in progress is not figured in the rate base. In addition, major uncertainties are associated with the likely performance of solar electric power plants because actual operating experience is limited. It is not clear whether public service commissions will allow utilities to pass certain costs on to rate payers. For example, suppose the performance of the solar technology exceeds the utility's expectations and the utility has a higher-than-necessary reserve margin. Alternatively, suppose the performance of the technology is poorer than expected and the utility must purchase power or use more oil and gas. The regulatory response to these possible outcomes will also affect the utility's willingness to purchase solar electric plants.

In summary, predicting the rate of solar technology adoption requires other information in addition to the relative cost of alternative technologies.

5.3 COMMUNICATING ECONOMIC RESULTS TO DOE PLANNERS

DOE staff need economic measures and methods of summarizing their sensitivity to key parameters to facilitate communication of results to DOE managers formulating R&D policy. Communication of results would be enhanced if (1) the analyses upon which economic measures are based could be readily explained and understood, and (2) the credibility of results could be demonstrated by showing that the major factors affecting value have been identified and analyzed using appropriate methods.

The simple approaches described in Sec. 2.0 can be readily explained and understood by a wide audience, but do not provide sufficient information to compare solar with conventional electric technologies. Even though the detailed analyses described in Secs. 3.0 and 4.0 are more complex and difficult to describe, it is relatively easy to explain why more comprehensive methodologies are necessary. In addition, economic measures such as cost/value ratios can be explained readily.

DOE staff have indicated that communication of results would be enhanced by sensitivity analyses; i.e., by the ability to demonstrate the sensitivity of measures of worth to key parameters. Sensitivity analyses, although useful, would be expensive with detailed methods for the following reasons. First, if a technical characteristic were changed, such as the mix of generating units in the system, the resulting fuel and capital cost savings would have to be reevaluated. Second, if economic parameters, such as fuel and capital cost escalation rates, were changed, the models described in Secs. 3.0 and 4.0 would have to be used to reevaluate the value of the solar electric technology. This is because the solution to a capacity optimization model will depend on the assumed capital and operating costs of alternative units. Similarly, dispatching units in a UPC model is determined in part by the fuel and operating costs of the units in the system. Consequently, if the economic parameters are changed, the quantities and types of fuel and capital that a solar plant could displace will also change.

Basically, the methods described in Secs. 3.0 and 4.0 can be used to determine the cost and value of the solar technology in a particular application--the present value of the variable and capital cost savings that will accrue to the user over the lifetime of the solar facility and the present value of the cost of the solar plant. Once this information is obtained, any of the figures of merit described here can readily be computed.

A remaining question to be addressed is, which figure of merit would best communicate the relative worth of solar technologies to DOE planners? If DOE planners need to understand solar technology cost goals--what a particular user could afford to pay for a particular technology in a specific application--then a value measure such as break-even capital cost will best convey this information. If DOE planners want to understand which applicaton of a particular technology is preferable, then a combined cost-value measure should be used.

5.4 CONCLUSIONS

Economic assumptions employed in assessing solar electric technologies will have a major impact on the estimated costs and values of solar electric technologies. Interpreting the results of existing studies is difficult not only because different assumptions were used but also because input assumptions were rarely specified clearly. For example, it was virtually impossible to tell what assumptions were made about tax allowances in most of the studies surveyed.

The basic economic information needed for a complete assessment of solar electric technologies is the present value of savings and costs. This information is obtained from the methods described in Secs. 3.0 and 4.0, based on the economic assumptions in the analysis. Once this basic information is obtained, any of the figures of merit described in Sec. 5.2.3 can be computed readily. Value estimates provide information needed to identify solar technology cost goals. For the purposes of comparing alternative solar technologies or applications, combined cost-value measures should be used.

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SECTION 6.0

SUMMARY AND CONCLUSIONS: ALTERNATIVE APPROACHES TO MEETING RESEARCH AND DEVELOPMENT PLANNING NEEDS

6.1 INTRODUCTION

This report is addressed to three Deparment of Energy research and development planning needs: (1) the need to understand solar electricity technology costs (i.e., the cost at which solar electric technologies will compete with conventional electric technologies), (2) the need to be able to perform sensitivity analyses of certain economic policy variables, and (3) the need for economic measures that will facilitate the communication of results to DOE managers formulating research and development policy. These planning needs are closely related. Meeting the first need poses the most difficult problems.

The purposes of this section are (1) to summarize the best available methods for estimating the values of intermittent, grid-connected solar electric technologies in utility and dispersed, user applications and to summarize data problems and deficiencies in existing techniques; (2) to summarize the unresolved issues common to all methods of assessment; and (3) to suggest alternative approaches that could be pursued to meet the research and development planning needs outlined here.

6.2 SUMMARY ASSESSMENT OF EXISTING METHODS

Determining the value of an intermittent, grid-connected solar electric technology involves three phases of analysis: estimating the performance of the solar energy system, characterizing user loads, and analyzing the impact of the solar technology on the conventional power system.

6.2.1 Analysis of Solar Performance

Based on the methods reviewed in Secs. 3.0 and 4.0, the most detailed analyses of solar performance provide the most accurate estimates of energy produced by the solar energy system. Solar performance is affected by the quality and quantity of available solar resources, the efficiency of the particular components of the system, and the specified operating strategy. The more precisely resource data and the system's components and operation are specified, the more precise the estimates of energy production will be. Similarly, because solar performance can vary from hour to hour, analyzing performance on an hourly basis allows for a more precise determination of energy production than would analyses based on more aggregate time intervals.

Four major unresolved problems are associated with analyzing the performance of intermittent solar electric technologies. First, most of the studies surveyed used hourly wind or insolation data. Because solar resources, particularly wind, vary continuously, hourly data may be insufficient for understanding the availability characteristics of solar electric technologies. Resource data for smaller time intervals may have to be collected or estimated statistically. Second, most of the studies used resource data for a single year, typically an average or representative year for the site studied. It is not clear that analyzing a single year is sufficient for estimating the value of the technology. For example, it may be necessary to analyze a worst year to estimate the capacity credit utilities and public service commissions would be willing to assign to a solar plant over its expected lifetime. Third, although relatively good data are available for a limited number of sites, existing resource data are generally of poor quality. Analyses of solar performance should improve as better resource data become available. Finally, actual operating experience with solar electric technologies is limited. Actual performance estimates are needed to validate the models used to predict the performance of solar electric technologies.

6.2.2 Characterization of User Loads

All of the studies surveyed in Sec. 3.0 estimated or obtained hourly load data for the customers studied. The relative importance of using hourly load data in assessing the value of an investment to a particular user depends on whether customers face time-of-use rates. If rates vary only as a function of the total kWh consumed in the month, then hourly load data are far less important than they would be if rates varied substantially by time of use.

Load diversity should be considered in calculating the utility's cost of supplying power to customers. A major problem encountered in estimating load diversity is that insufficient data exist to determine load diversity factors for solar customers. However, load diversity is obviously not relevant in calculating the value of an investment to a customer using actual rate data, because customers are metered and billed based on their own consumption.

6.2.3 Impact of Solar Technologies on Utilities: Dispersed, User Applications

6.2.3.1 Calculation of Backup Costs

The methods used to calculate backup costs range from using existing rate data to utility capacity expansion models. One of the major problems in assessing end-user applications is the need to predict future utility rates. Because there is a trend toward rate reform, existing rate data might not represent future rates. Unfortunately, it is impossible to tell what rate design policies will actually be adopted in the future. Given the uncertainty surrounding future rates, it is difficult to determine whether existing rate data, marginal cost estimation models, or utility planning models would provide more accurate economic assessments from the customer's viewpoint.

Utility planning models clearly provide the most accurate estimates of the impact of solar customers on utilities. Utility production cost and generation expansion models are not designed to analyze impacts on the utility's transmission and distribution system, nor are they designed to compute customer-related expenses. If these costs can be expected to be the same for solar and conventional system users, they can be ignored in estimating impacts on the utility.

6.2.3.2 Calculation of Sell-back Rates

A major problem in estimating the revenues customers will earn by selling power to utilities is that rates have not yet been determined. Federal law requires that utilities pay customers rates that are equal to their avoided costs, and utility planning models could be used to estimate avoided costs. However, as is the case for marginal cost rates for conventional service, these models do not estimate rates per se, but rather the basic input needed to establish rates. Hourly marginal cost data must be averaged for more aggregate time intervals to produce rates that are practicable (given metering costs) and acceptable to consumers. Fortunately, utility rates for purchases from customers should become available after March 20, 1981. These rates should be used in assessing the value of a solar electric investment to a utility customer.

The methods required to assess the impact of customer sales on utilities are the same as those required to assess the value of solar electric technologies in utility applications, which are discussed in the following section. In addition, there are two major unresolved problems associated with assessing the value of sell-back, which do not necessarily apply to central station applications. First, because users will feed power back to the utility through the distribution system, estimating the reliability of sell-back will require analyzing the reliability of the generation, transmission, and distribution networks as an integrated system. This is more difficult methodologically and empirically than evaluating the reliability of the bulk generation system alone. Second, there are unresolved technical problems associated with customer sales because the distribution system might have to be redesigned to accept bidirectional flows of energy.

6.2.4 Impact of Solar Technologies on Utilities: Utility Applications

The value of a solar electric plant or of power purchased from customers is equal to the displaced fuel, operation, maintenance, and capital costs that the utility saves as a result of operating the solar plant or purchasing power from customers. Utility production cost models are the best available methods for estimating fuel, operation, and maintenance costs.

Capital savings are more difficult to estimate. The determination of capital savings is essentially a capacity planning problem. Capital savings are functions of the solar technology's impact on both system reliability and the utility's optimum expansion plan. With respect to reliability impacts, basic methodological development is needed to analyze the within-hour variability of energy produced by intermittent technologies and the impacts on reliability indices. In addition, more operating experience with intermittent technologies connected to utility systems is essential. The best available methods for estimating capital savings are reliability analysis and capacity expansion models.

6.2.5 Unresolved Issues Common to All Methods of Assessment

The fact that this report identifies "best available" methods does not mean that all major problems have been resolved. In many respects, assessing solar electric technologies in applications that are connected to a conventional utility is an infant science. Conceptual and methodological problems exist that are not even well articulated.

Two concepts described by Thomas Reddoch in the Working Meeting on Value Analysis of Solar Electric Technologies provide a useful framework for understanding the unresolved issues (Reddoch 1979). Reddoch made a distinction between accommodation and complete integration of solar and conventional technologies. Accommodation is "the addition of new technologies to the utility system as it exists in its present form." Accommodation implies that the utility system structure essentially would be preserved in its present form and that existing utility planning models would be used for assessing solar electric technologies. Problems of accommodation are related to understanding how solar electric technologies can best fit the existing system structure and planning methods.

In contrast, complete integration is "the development of a fully integrated utility system which is designed [to be optimal] for a mix of [solar and conventional] technologies." Integration implies that new utility system structures and new assessment methodologies might be required. Problems of integration are not well understood.

6.2.5.1 Unresolved Issues Related to Accommodation

All of the studies reviewed in this report have dealt with the accommodation of solar technologies to existing system structures and models. Most of the specific problems described in the preceding sections relate to representing solar technologies in existing planning models, which are not designed to analyze the operating and availability characteristics of intermittent technologies or power produced by customers. There are additional problems associated with accommodation which were not addressed directly in any of the reports surveyed. These can be separated into two broad categories: issues related to assessing solar technologies using conventional utility planning models and issues that should be considered in a broader utility planning framework.

The economic assessment of solar electric technologies is a dynamic investment problem. Only two studies* attempted to assess the impact of solar technologies on the utility by using capacity expansion models--the existing models that are designed to analyze long-term investment decisions. The rest of the studies used some combination of short-term planning models and trial-and-error procedures to approximate a long-term optimal solution.

*Bright and Davitian's study of solar hot water systems described in Sec. 3.0 and Westinghouse's methodology for evaluating solar thermal power plants described in Sec. 4.0.

One problem in assessing solar technologies in a dynamic investment framework is representing solar technologies in capacity expansion models. Conventional technologies can be represented through their variable and capital costs. However, the operating and availability characteristics of solar electric technologies differ so greatly from conventional technologies that their cost and value to the utility cannot be evaluated in the same manner. The value of the solar plant to the utility is determined by the reduced load that the balance of the utility system must meet. The problem is that the value of this reduced load cannot be represented in standard capacity expansion models.

The approach used by Westinghouse and by Bright and Davitian was to determine an optimum capacity expansion plan for a base case (without solar). Then a specified number and type of solar plants were forced into the system, a reduced load curve was calculated and an optimum capacity expansion plan was recomputed. The value of the solar plants to the utility is determined by the difference in the costs of the two scenarios. This procedure is both cumbersome and expensive. Further research is needed to develop methods of representing solar electric technologies directly in capacity planning models.

A second problem concerns the extent to which a utility may actually save capital as a result of installing a solar plant. Capital savings include those resulting from the reliability impacts of the solar plant as well as the net capital investment saved through a change in the utility's optimum mix of conventional generating units. Suppose a reliability calculation indicates that a utility could displace 2 MW of conventional capacity by installing a given number of solar plants, but that the smallest conventional generating unit on the utility system is 50 MW. If the megawatts saved cannot be sold to another party, the fact that conventional units are added in large, discrete sizes may limit the extent to which utilities can actually save capital.

Another issue related to capital savings is the reliability criterion itself. Most studies define a specific reliability criterion and calculate the value of the solar plant assuming that the same criterion must be met. Preliminary results obtained by Richard Tabors and others at the M.I.T. Energy Lab indicate that the value of solar power plants to a given utility system "is more sensitive to small changes in loss of load probability . . . than had been previously estimated" (Tabors et al. 1979). Given that a number of analysts and public service commissions are arguing that current utility reliability criteria are uneconomically high, the impact of the reliability criterion on the value of solar plants should be analyzed further.

The second category of issues related to accommodation concerns determining how solar technologies should be evaluated in a broader planning context. Capacity expansion models consider only one aspect of the planning process: estimating the costs of alternative expansion plans. These models are deterministic in the sense that the input variables (capital and operating costs, forecasts of demand, and so on) are treated as known. Capacity expansion models are generally linear or dynamic programming models which do not explicitly treat uncertainty. Because the lead time required to construct power plants has increased in the past 10 years and because new capacity is now more expensive than existing capacity, both the probability and the cost of an error in planning have increased in the utility industry. Some public service commissions are arguing that uncertainty should no longer be ignored in planning for new capacity (New York State Public Service Commission 1978).

Uncertainty with respect to future supply, load, and the price of electricity is relevant to planning for both conventional and solar technologies. Supply uncertainty exists because it is more difficult to predict the time required to permit and construct new generating facilities as well as their likely costs. Greater uncertainty relative to future load growth exists because growth in recent years has deviated from the longer-term trend and because utility planners are now required to predict further into the future (Flaim 1979, pp. 86-95). Finally, uncertainty about the prices utilities will be allowed to charge users also exists. In particular, it is not clear whether public service commissions will allow utilities to pass on to consumers the costs that result from an error in planning.

Uncertainty should be taken into account in assessing the value of solar technologies and in assessing whether utilities will be willing to purchase them. Several specific questions need to be addressed. First, how sensitive are estimated values to the assumptions made about future conventional fuel and capital costs? Second, how sensitive are values to assumptions about future load growth? Finally, does the estimated value of the solar plant change if the public service commission is reluctant to charge consumers for costs that arise because of an error in forecasting? The last question is most difficult to analyze but will be an important factor affecting future utility investment decisions. For example, if commissions are reluctant to charge consumers for capacity that is brought on line before it is needed, there may be substantial financial advantages to the utility associated with building solar plants if they can displace conventional plants with larger construction lead times. Alternatively, if the utility cannot recover costs incurred because the performance of the solar plant differs from the utility's planning expectations, there may be financial penalties associated with installing solar plants because their performance is more difficult to predict. Further research is needed to understand how solar technologies should be evaluated in a broader utility planning framework.

6.2.5.2 Unresolved Issues Related to Complete Integration

The complete integration of solar and conventional technologies might require the development of completely new system structures and assessment methodologies. As Reddoch points out, the existing utility system structure has been optimized around the central-station concept to capture economies of scale in generation, transmission, and distribution. Existing utility planning models have been refined to characterize the operating and availability features of conventional units.

Although it is too early to make a final judgment, it appears that the optimal size for solar plants--the minimum size necessary to achieve all economies of scale in generation--will be substantially smaller than the optimal size for conventional units. We are only beginning to understand how small solar facilities might be accommodated to the existing system to minimize electricity supply costs. We know even less about designing completely new system structures that would be optimal for a mix of solar and conventional technologies. However, several potentially important issues concern the optimal siting of generation facilities, utility system operating strategies, and the potential for reducing costs through product differentiation.

There are three reasons why siting will affect the optimal design of new system structures. First, it might be desirable to site conventional plants at sites with maximum solar resource availability, because joint siting may reduce transmission as well as plant maintenance costs. Second, because solar plants are less polluting and likely to be smaller than most conventional plants, it might be possible to site them closer to load centers and reduce transmission costs. Remote siting is more often necessary for conventional plants because of their larger size, decreasing land availability near load centers, and increasing environmental restrictions. Third, greater geographical dispersion is likely to increase the reliability of solar plants because outages caused by intermittent resource availability are less likely to occur simultaneously. However, greater dispersion will also increase transmission costs.

The second issue concerns the utility system operating strategy. Conventional units are dispatched typically on an hourly basis. As Peter Moretti pointed out, hourly dispatch may not be adequate for a mix of solar and conventional technologies because solar resources vary continuously (Moretti 1979). Little is known about the feasibility and cost of alternative dispatching strategies.

Finally, utilities may be able to reduce costs by offering different types of service. Traditionally, utilities have taken loads as given, in part because they are required by law to provide service to all customers who wish to purchase it. As a result, they have offered essentially one product, electric service provided at a system-wide level of reliability. Reddoch (1979) argued that the current system may force some consumers to pay for a higher level of reliability than they actually need and that the utility may be able to decrease production costs and increase consumer welfare by differentiating among the types of service it is willing to sell. Interruptible and load-managed service are two examples.

The relative costs of the different types of service will affect consumer demand for the different service types. If different types of service are widely accepted, utility load patterns might change substantially. Changing load patterns, in turn, will affect both the total demand for new capacity and the optimal mix of solar and conventional technologies.

In summary, new system concepts are needed to understand the long-run economic potential of solar electric technologies. The process of accommodating solar technologies to existing systems might not yield the same system structure that would result if systems were originally designed to be optimal for a mix of technologies.

In addition to new system concepts, new assessment methodologies will be required. Existing utility planning models are not designed to analyze solar technologies. Current mothods of economic assessment basically involve manipulating utility planning models to derive a value for the solar plant. This indirect method of assessment is cumbersome and expensive. Ultimately, what we need are methodologies that can characterize all types of technologies and that can be used to determine directly an optimum mix of solar and conventional technologies.

6.3 RECOMMENDATIONS: GENERAL ALTERNATIVES FOR MEETING PLANNING NEEDS

Two general alternatives are outlined here that could be pursued to meet the need to obtain value estimates. The first alternative involves a continual review and synthesis of the results of detailed application studies as they become available. The second alternative would involve adopting or developing a number of models that could be used to estimate values directly. It is recommended that both alternatives be pursued.

6.3.1 Synthesizing the Results of Detailed Analyses

The existing economic assessments of intermittent, grid-connected solar electric technologies are an important source of information about technology cost goals for specific applications. Unfortunately, the results of these studies are difficult to compare because the reports were not consistent in their economic assumptions or in the presentation of their results.

As was shown in Table 5-2, the 14 studies of utility applications reported values and costs in units ranging from 1975 constant dollars to 1995 current dollars. Several of the reports on end-user applications do not specify the year in which dollars were reported, nor did they specify whether costs were in constant or nominal dollars. This single variation among studies makes it difficult to compare results, since $1.00 of spending power in 1975 would require $2.65 in 1995, assuming 5% annual inflation. At present, it is difficult to tell how much value estimates vary because of technical factors (such as regional resources, characteristics of the utility, etc.) and how much of the variation occurs because results are not reported consistently.

Synthesizing the results of detailed analyses would involve identifying the reasons why value estimates differ among studies and presenting the results of different studies consistently. This type of activity is similar to JBF's Summary of Current Cost Estimates of Large Wind Energy Systems, which summarizes the results of eight wind studies and attempts to normalize their results and account for the variations in cost estimates obtained by different authors (JBF Scientific Corp. 1977).

Normalizing the value estimates obtained in different studies would be more difficult than normalizing energy cost estimates. Energy cost calculations are based on the capital and operating costs of the solar plant and estimates of solar performance. The estimated value of the solar technology depends on many more factors than those affecting energy costs. Sources of variation in value estimates among the studies surveyed are summarized in Table 6-1. Value estimates vary because the authors (1) analyzed different technology applications, regions, and utilities; (2) used different analytical and economic assumptions (which were rarely specified clearly); (3) used different methods and models; and (4) were inconsistent in presenting their results.

Table 6-1. Sources of Variation in Value Estimates Across Studies

Technical Factors	Input Assumptions	Accuracy of Method and/or Models	Presentation of Results
Characteristics of solar technology application • Size and type of system • Amount of storage • Operating strategy Solar resource availability • Region • Site User load • Type of user • Load diversity Utility characteristics • Type and mix of generating units • Loads • Reliability criterion Market penetration level • Number of solar users in utility's service area • Solar capacity as a percentage of utility's total capacity	Analytical (examples:) • Energy produced by solar plant in excess of utility loads has zero value • Capacity credit for solar plant is zero • Backup rates equal existing utility rates to particular customer classes Economic • Finance costs • Taxation provisions • Conventinal fuel and capital costs • Cost escalation rates • Discount rates	Solar Performance Model User Load Model Utility-Supplied Cost of Service Data Utility Production Cost Model Method of Reliability Analysis Capacity Expansion Model Breakpoint Analysis	Figures of merit • Value measures: present value of savings break-even capital cost • Cost measures: present value of costs levelized energy costs user's total cost of service • Combined cost-value measures: cost/value ratio net value Monetary values • current dollars • constant dollars • base year in which dollars reported

Because value estimates will vary according to the specific characteristics of the technology, application, user, utility, and region in which the technology will be employed, it will not be possible to derive a single cost goal for a particular technology. DOE planners need to have estimates of the range of cost goals which would make solar technologies competitive with conventional technologies. Having this information would allow them to assess and communicate achievable goals and to assess the potential market size associated with each goal. Despite the difficulties associated with normalizing value estimates, one activity could be pursued that might prove useful. The presentation of results could be standardized. Monetary values could be converted to the same base-year dollars and comparable figures of merit could be calculated. For example, if the present values of total savings and costs could be obtained, any of the figures of merit reported in Table 6-1 could be readily computed.

Beyond normalizing the presentation of results, little else could be done without re-analyzing each study's data. Even sensitivity analyses of economic assumptions are of limited use without using the models employed in the surveyed studies. However, normalizing the presentation of results across studies would make the results of existing studies more useful to DOE staff. In addition, in the process of trying to identify sources of variation in value estimates, valuable insights could be gained about how to make the results of ongoing and future studies of technology cost goals more useful to DOE staff.

Because of its limitations, synthesizing the results cannot be viewed as a substitute for having the capability to do economic assessments of solar electric technologies. It should however, be a useful complementary activity.

6.3.2 Developing or Acquiring Methods for Economic Assessment

The results of existing studies do not provide sufficient information for DOE staff about solar technology cost goals. They also need to have access to methods that could be used to estimate values directly. The major limitation of the best available methods is that several person-years of effort and thousands of dollars in computer time often are required to assess a single technology application. As such, they are not well suited to situations in which time and resources are limited. Clearly, it will also be useful to improve and validate simpler methods of value analysis.

That simpler models can be developed that approximate the results of more complex models fairly closely is without question. Although, to the authors' knowledge, simpler models have not been developed to assess solar electric technologies, simpler solar performance models have been developed for solar space heating applications. An example is the model FCHART which is a simpler model based upon the detailed simulation model TRNSYS (Winn 1978, p. 21). FCHART was developed because TRNSYS, which yields good performance predictions,* is relatively expensive and complex to use as a design tool. The Solar Energy Laboratory at the University of Wisconsin correlated results obtained from TRNSYS to develop FCHART, which is simpler, much less expensive, and easier to use (Winn 1978, p. 21). One validation study found that "a comparison of FCHART and TRNSYS at 172 locations was good, standard deviations in the errors were small, and a maximum error was found on the order of 10 percent" (Knasel et al. 1978, p. 18).

As the example of FCHART and TRNSYS illustrates, simpler models that are fairly accurate can be developed. However, we must emphasize two points. First, developing and validating simpler models can be expensive and time-consuming. It is estimated that developing and validating a simpler performance model for a few applications of a single solar electric technology** could require several person-years of effort. Second, simpler, less detailed models do result in a loss of accuracy in the estimates of performance.

Despite these qualifications, several useful activities could be pursued. Steps could be taken to improve comparisons based on levelized energy costs. A major limitation of levelized energy costs as they are currently applied is that the analyst cannot determine the actual type of fuel and capacity that will be displaced by the solar unit (see Sec. 2.0). Fairly simple methods of approximating unit operation and the correlation between solar energy production and the utility's load can be developed that would greatly increase the usefulness of levelized energy costs (Taylor 1980).

Efforts could be undertaken to acquire or develop simpler performance models and to validate their performance estimates against the results obtained from more comprehensive models and, if available, actual performance models. At a minimum, capacity factors based on average annual resource availability alone could be validated against capacity factors calculated from models that simulate the operation of the system on an hourly basis for an entire year. These activities should improve the simple methods available for estimating solar performance.

Third, ways to improve value estimates obtained using breakpoint analysis should be explored. These efforts would include developing methods to represent solar technologies using this technique and comparing value results to those obtained from production cost and generation expansion models.

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*One validation study found that TRNSYS simulation results for daily performance of the Colorado State University Solar House I were within 5% of experimental performance data. Another found that TRNSYS results for a space heating, liquid collector system were close to experimental data when insolation was stable but were poor when insolation varied rapidly (Knasel et al. 1978, pp. 19-20).

**FCHART was developed for two types of systems: a liquid-based and an air-based solar heating system. It was not designed to analyze other systems, "such as solar cooling systems, solar assisted heat pump sytems, or low temperature applications such as swimming pool heating" (Winn 1978, p. 21).

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APPENDIX A

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APPENDIX B

GLOSSARY OF TERMS

B.1 GLOSSARY

AVAILABILITY - "The fraction of the time that the system is actually capable of performing its mission." The term usually refers to an individual generating unit (Institute of Electrical and Electronics Engineers 1972).

AVAILABILITY FACTOR - "The ratio of the time a generating unit or piece of equipment is ready for or in service to the total time interval under consideration" (Institute of Electrical and Electronics Engineers 1972).

BACKUP - The amount of auxiliary power a solar user must purchase from a utility; it is determined by the correlation between when energy is produced by the solar energy system and when it is consumed by the user. It has an energy (kWh) and a power (kW) component.

BREAK-EVEN CAPITAL COST - The maximum amount a user would be willing to pay for the capital investment associated with a technology, based upon the performance of the technology and the cost of the alternative displaced. Break-even capital cost is calculated from the present value of total savings that accrue to the user over the lifetime of the technology application. (See Sec. 5.2.3.3.)

CAPACITY CREDIT/CAPACITY DISPLACEMENT - "The amount of conventional generating capacity which may be omitted from a utility's planned requirements if a solar plant is planned. A function of effective capacity" (Marsh 1979).

CAPACITY FACTOR/PLANT FACTOR - "The ratio of energy produced divided by the product of rated capacity and the number of hours in the operating period" (VanKuiken et al. 1978).

CAPACITY REMIX SAVINGS - See Capital Savings.

CAPITAL SAVINGS - The savings in conventional capital costs that accrue to the user as a result of operating a solar plant over its lifetime. Capital savings to a utility may occur as a result of the capacity credit of the solar plant and/or due to a change in the utility's optimal (least-cost) generation mix. Capital savings that occur as a result of change in the utility's optimal generation mix have been called "fixed-cost savings" and "capacity remix savings."

DEMAND - "The rate at which electric energy is delivered, expressed in units of power, such as kilowatts, at a given instant or averaged over a designated period of time" (Electric Power Research Institute 1978).

EFFECTIVE CAPACITY/EFFECTIVE CAPABILITY - The probabilistically calculated allowable increase in system peak loads resulting from the installation of a generating unit (Marsh 1979). (See Sec. 4.3.4.)

FIXED COST SAVINGS - See Capital Savings.

FORCED OUTAGE - "An outage that results from emergency conditions directly associated with a component, requiring that component to be taken out of service immediately . . . or an outage caused by improper operation of equipment or human error" (Institute of Electrical and Electronics Engineers 1972). The forced outage rate is the fraction of time the unit is out of operation because of these conditions.

FUEL COST SAVINGS - The savings in conventional fuel costs that accrue to a user as a result of operating a solar plant over its lifetime. Fuel cost savings to a utility may occur through a change in the operation of existing units and/or through a change in the mix of generating units.

GRID-CONNECTED SOLAR ELECTRIC TECHNOLOGIES - Solar electric technologies that are connected to a conventional electric utility. They include both utility and dispersed, end-user applications, and may be owned by either party.

LOAD - "The amount of electric power delivered or required" (Electric Power Research Institute 1978).

LOAD DIVERSITY - "The difference between the sum of the maxima of two or more individual loads and the coincident or combined maximum load, usually measured in kilowatts over a specified period of time" (Institute of Electrical and Electronics Engineers 1972).

LOAD DIVERSITY FACTOR - The ratio of the sum of individual peak loads to the coincident peak load (Cretcher and Melton 1978).

LOAD DURATION CURVE - "A curve on a chart showing power supplied plotted against the total time of occurrence for each given magnitude of the load during the period covered" (Electric Power Research Institute 1978).

LOSS OF LOAD PROBABILITY (LOLP) - The probability that available generating sources will be unable to meet the load. "By multiplying this probability by the hours for which the load duration curve is applicable, one obtains the loss of load hours as a measure of (the) risk" of failure to meet the load (Fegan and Percival 1979).

PAY-BACK PERIOD - "The time required for cumulative (nondiscounted or discounted) annual operating savings to equal the incremental cost associated with a solar plant compared with a conventional plant" (Burke et al. 1977).

PEAK LOAD - "The maximum load consumed or produced by a unit or a group of units in a stated period of time. It may be the maximum instantaneous load or the maximum average load over a designated interval of time" (Institute of Electrical and Electronics Engineers 1972).

SELL-BACK - The amount of electric energy and/or capacity sold by an end-user to the utility.

SPINNING RESERVE - "The committed capacity in excess of the predicted hourly load; provided for security against unexpected load peaks or generation loss" (Marsh 1979).

VALUE - The amount a user could afford to pay for a technology, based upon the performance of the technology and the cost of the alternative being displaced. "Value" refers strictly to economic value based on market costs unless otherwise noted. Value is synonymous with "avoided cost" as used by the Federal Energy Regulatory Commission.

VARIABLE COST SAVINGS - The savings in conventional fuel, operation, and maintenance costs that accrue to the user as a result of operating a solar plant over its lifetime.

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APPENDIX C

SUMMARY OF METHODS USED TO ASSESS DISPERSED, USER APPLICATIONS

The simulation techniques used in seven studies are reviewed in detail. These are

- U.S. Congress, Office of Technology Assessment, Application of Solar Technology to Today's Energy Needs (1978).
- Leonard et al., Aerospace Corp., Mission Analysis of Photovoltaic Solar Energy Conversion, Vol. III, Major Missions for the Mid-Term (1986-2000) (1977).
- Bright and Davitian, Brookhaven National Laboratory, "The Marginal Cost of Electricity Used as Back-up for Solar Hot Water Heaters: A Case Study" (1978).
- Burke et al., Arthur D. Little, System Definition Study: Phase 1 of Individual Load Center, Solar Heating and Cooling Residential Project (1977).
- Cretcher and Melton, Aerospace Corp., SHACOB: Requirements Definition and Impact Analysis (1978).
- Feldman et al., Total Environmental Action, Inc., Utility Pricing and Solar Energy Design (1976).
- Lorsch et al., Franklin Institute Research Labs, Implications of Residential Solar Space Conditioning on Electric Utilities (1976).

The first two studies deal with solar electric technologies in end-user applications. The remaining five are concerned with solar hot water and space conditioning applications. All the reports analyzed some applications connected to a conventional electric utility for back-up power, and all attempt to estimate utility costs of providing back-up. None of the studies in this group analyzed wind technologies.

The OTA report analyzed solar thermal, photovoltaics, and solar thermal electric technologies for a wide range of applications, including hot water, process heat, space heating, air conditioning, electricity and total energy or cogeneration. All applications were on-site (no utility applications were considered) and types of users included residential, commercial, and industrial consumers, as well as a residential community. Some systems were grid-connected, others were stand-alone. The costs of service to particular users were calculated assuming that back-up rates were equal to existing utility rates for that region. However, the OTA report also analyzes separately what it would actually cost a typical utility to supply back-up and what it could afford to pay for sell-back.

The report by Leonard et al., is primarily concerned with utility applications but also examined a residential on-site application of photovoltaics. The reports by Burke et al. and by Cretcher and Melton were sponsored by the Electric Power Research Institute. They analyzed preferred designs for solar heating and cooling systems, based on designs that would minimize total costs to both users and utilities. The reports by Bright and Davitian, Feldman et al., and Lorsch et al., examined the impact of residential solar hot water and space conditioning applications on electric utilities providing back-up power.

The methods used in these studies are described in the following sections according to their treatment of solar performance, user characterization, and the impact of the solar technology on the electric utility.

C.1 ANALYSIS OF SOLAR PERFORMANCE

As Table 3-2 indicates, all reports used hourly insolation data for a single year to estimate solar performance. Three reports used average or representative years (Cretcher and Melton 1978, Feldman et al. 1976, Lorsch et al. 1976), and the remaining reports did not specify why a particular year was chosen. OTA stated that one limitation of their analysis was that the year analyzed was not a representative year for every location (1978, Vol. I, pp. 291-5). All reports analyzed resource availability in a deterministic fashion in the sense that hourly insolation data were read directly into a solar performance model. In addition, other weather data--such as temperature, wind velocity, and humidity--that will affect both solar performance and user loads were typical inputs.

All the reports used some type of solar performance model to determine the hourly output of the solar energy system. Basically, these models take insolation data as input, simulate the operation of the components of the system, compute energy losses, and determine useful hourly energy output. Some solar performance models are programmed to simulate user loads as well. Based upon a specified system operating strategy, auxiliary energy required can then be computed.

Four of the five reports on solar hot water and space conditioning applications used TRNSYS, a solar performance model developed by the University of Wisconsin Solar Energy Laboratory. TRNSYS is a computer model which simulates the thermal behavior of active solar heating and cooling systems. Separate subroutines are designed to simulate various components such as collectors, storage tanks, heat exchangers, and pumps. Load data can be computed or input separately (Solar Energy Research Institute 1979).

Burke et al. used the EPRI Methodology for Preferred Solar Systems (EMPSS), developed by Arthur D. Little for the Electric Power Research Institute. This model is capable of simulating the hourly performance of both solar and conventional residential heating and cooling systems. Hourly load data are computed internally. EMPSS was designed as a program to identify systems that minimize the user's total costs of service, including the cost of back-up purchased from the utility (Solar Energy Research Institute 1979).

Leonard et al. used a model developed by Aerospace Corp. to simulate photovoltaic systems. As in the above models, insolation and weather data are inputs. Energy intercepted by the collector is calculated and energy losses in various components (collectors, power conditioning equipment, storage, etc.) are determined. Hourly energy outputs are then compiled (Leonard et al. 1977).

OTA developed performance models to simulate the numerous systems they analyzed (Claridge 1979). Hourly insolation data are inputs. Techniques were developed to compute the net energy output from various collector designs, photovoltaic systems, storage, heat engines, and other energy systems (U.S. Congress, OTA 1978, Vol. I, pp. 303-326, 424, 488-495).

Although the system operating strategy was not always specified, most reports appear to assume a straightforward sequence of priorities. Typically, this was: (1) power is produced when the resource is available; (2) if not consumed directly, power goes to storage; (3) if solar device is not producing, storage (if applicable) is consumed; and (4) when storage is depleted to a specified level, system goes to back-up. Three reports also considered load management options for back-up. They assumed that sufficient storage could be charged in off-peak hours to offset loads on a cloudy day (Bright and Davitian 1978; Burke et al., 1977; Cretcher and Melton 1978).

OTA considered more complex systems; their operating strategies were correspondingly more detailed. For example, the operating strategy specified for their grid-connected cogeneration systems assumed the following priorities for energy consumption: "(1) meet on-site energy demands, (2) charge batteries, (3) charge high temperature storage, (4) sell electricity to the grid, and (5) charge low-temperature storage" (U.S. Congress, OTA 1978, Vol. II, p. 46). Storage is consumed in the reverse order.

C.2 USER LOAD CHARACTERIZATION

OTA used the E-cube program, developed by the American Gas Association to estimate heating and cooling loads based on weather data, building characteristics, and the energy system; they assumed patterns of occupancy, appliance usage, hot water demands, and other characteristics to estimate nonspace-conditioning loads (U.S. Congress, OTA 1978 Vol. II, pp. 43, 701-725). Leonard et al. did not specify how load data were obtained (1977, pp. 122-124).

Bright and Davitian used TRNSYS to simulate thermal demands and a simulation model to estimate electric demands (1978, p. 7). The remaining reports generally obtained hourly loads from published sources or utility data and adjusted them by assumptions about occupancy, types of use, building characteristics, and so on.

Of the seven reports reviewed, OTA, Cretcher and Melton, Feldman et al., and Lorsch et al. stated that they considered load diversity in their aggregation of load data for large numbers of customers. Burke, et al., stated that load diversity was not considered (1977, p. I-3), and the remaining two reports did not specify whether diversity was taken into account.

OTA assumed that hourly hot water and miscellaneous electric loads varied as a function of the spread in "start times" or "the spread during which people wake up in the morning, eat, and go to work which, in turn, was assumed to be the same as the spread of traffic during rush-hour peaks in major cities (i.e., a normal distribution with a standard deviation of approximately one hour)." However, they assumed no diversity in heating and air conditioning loads (1978, Vol. I, pp. 164-166). Cretcher and Melton accounted for diversity in total load by smoothing out the simulated demands with a normal distribution curve using one-hour standard deviations to characterize variations in energy use. Their estimated load diversity factor for resistance heating was 1.3 (1978, Vol. 3 pp. 123-4).

Lorsch et al. assumed that the load diversity factor for hourly demand from solar houses was equal to the diversity factor for the hourly demand for conventional houses. However, if the hourly demand in the conventional house was less than the demand in the solar house, or if the hourly demand in the solar house was zero, several hours of load data were averaged in order to estimate diversified demand (1976, pp. 5-3, 5-4). The method that Feldman et al. used to calculate diversified demand is not clear (1976, p. 45). However, they appear to have used a load diversity factor to calculate diversified peak demand where the diversity factors were obtained from estimates for conventional systems.

C.3 IMPACT OF SOLAR TECHNOLOGIES ON UTILITIES

All of the authors subtracted system energy output from load data to obtain hourly estimates of back-up energy required. These data were then added to the utility's base-case load data and back-up costs were calculated based on the new load profile. The utilities' cost to serve solar users typically were compared to the utilities' costs to serve conventional consumers. Sell-back* rates (which were calculated only by OTA) were estimated on a similar basis.

All but one of the studies surveyed analyzed the impact of solar users on utilities in a static or "snap-shot year" sense in that a level of solar market penetration was specified and the utilities' resulting costs were calculated, using a range of methods. The studies considered varying levels of solar users in the utility's service territory. Frequently, solar market penetration was not expressed as a percentage of total customers, but rather as the number of solar homes or as a percentage of new construction. If a future year (such as 1990) was considered, load growth projections were typically obtained from the utility being analyzed.

Bright and Davitian analyzed the impact of solar users on a utility in a dynamic sense, by specifying that solar market penetration levels would increase gradually over a period of 25 years. They used a generation expansion model to estimate the utility's costs, assuming that the utility would attempt to install the least cost generation mix to meet the changing load growth patterns, with and without solar users (Bright and Davitian 1978).

Section C.3.1 describes the methods used in each study to calculate utility costs of providing back-up and the method OTA used to calculate the value of sell-back.

*Sell-back is the electricity sold by the end-user to the utility.

C.3.1 Calculation of Back-up Costs

Basically, seven different approaches were used to calculate back-up costs. These include the use of (1) utility-supplied cost of service data, (2) a utility generation expansion model, (3) some type of utility production cost model, (4) a marginal cost estimation model, (5) reliability analysis models, (6) utility breakpoint analysis, or (7) assumed flat or existing rates.

C.3.1.1 Utility-Supplied Cost-of-Service Data

Burke et al. and Lorsch et al. used cost-of-service data provided by utilities. Costs were categorized according to demand-related charges (capital invested in generation, transmission, and distribution), energy-related charges (fuel, operation, and maintenance) and customer-related costs (billing, metering, etc.). Lorsch et al. examined customer loads to determine peak load for the individual user, multiplied this value by a load diversity factor and computed demand charges based on utility rates. Energy-related costs were based on a flat charge per kWh (1976, p. 6-11).

Burke et al. obtained hourly utility variable and fixed costs, both expressed in mills/kWh. Variable costs included fuel, operation, and maintenance; fixed costs were those attributable to systemwide load (such as base- and intermediate-load generation capacity, taxers, insurance, etc.). Costs to the end-user were calculated by multiplying the sum of variable and fixed costs times hourly electricity consumption. A monthly demand charge was also computed based on the user's level of consumption at the utility system's monthly peak. Annual back-up costs were determined by summing hourly energy and monthly demand charges for the year (Burke et al. 1977, pp. III-6 through III-10).

C.3.1.2 Utility Generation Expansion Models

Generation expansion models are described in greater detail in Sec. 4.2.4. Bright and Davitian utilized the WASP II generation expansion model. WASP II is a dynamic optimization model which determines the generation expansion plan that minimizes the present value of total system costs over a given planning horizon. The model first calculates annual system variable costs for a number of system configurations, each of which must meet certain reliability criteria; then, the plan that minimizes total (capital and variable) costs over the planning horizon is determined. They calculated the total costs for the utility system with and without solar hot water heaters. The difference in total costs divided by the difference in total electricity generated for each scenario was defined as the marginal cost of electricity for back-up (Bright and Davitian 1978, pp. 14-16).

C.3.1.3 Utility Production Cost Models

Cretcher and Melton, Feldman et al., and Lorsch et al. used a utility production cost model* to calculate the fuel, operation, and maintenance costs associated with providing back-up to solar users. These models basically simulate the operation of an electric utility (usually on an hourly basis) and account for the dispatching of units, scheduled maintenance, fuel, and operating costs. They may also account for system reliability, usually by calculating the loss of load probability (LOLP) associated with different system configurations and treating reliability as a constraint. Utility production cost models and LOLP calculations are described in greated detail in Sec. 4.2.3.

C.3.1.4 Marginal Cost Estimation Models

For all but one of the utilities they analyzed, Feldman et al. used the marginal cost estimation model developed by Cicchetti, Gillen, and Smolensky (CGS) (Feldman et al. 1976, p. 57; Cicchetti et al. 1977; Feldman and Wirtshafter 1980). The CGS model calculates the marginal utility system cost associated with serving an incremental change in load at different points in time. System costs include generation, transmission, and distribution capacity costs, energy costs and customer-related expenses, all of which are calculated for various voltage levels (Feldman et al. 1976, p. E1).

Feldman et al. applied the CGS model in the following manner. They first determined peak and off-peak hours for each utility system. Incremental energy costs for the time periods were estimated from production cost data obtained from the utilities participating as case studies.

Incremental capacity costs were calculated using the following procedure. First, they simulated the hourly demands of the solar and conventional houses for the several days surrounding the utility's annual system peak load. The peak demands of each house were averaged over the several consecutive hours surrounding the peak hour of the day. These average hourly demands were again averaged for the several peak load days, and this value was defined as the capacity requirement in kW for the building.

The cost of meeting this increment of capacity was calculated using the CGS model which assumes that the utility would respond to an increase in peak loads by bringing forward in time an existing capacity expansion schedule.

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*Cretcher and Melton used the production cost model developed by Power Technologies, Inc. (1978, Vol. 1, p. 48). Lorsch et al. used PRODCOST, a production cost model developed by S. T. Matrascek (MS thesis) at the University of Pennsylvania, as well as Pennsylvania Power and Light's production cost model (1976, pp. 5-11 through 5-15). Lorsch used the production cost models to determine the energy impacts on utilities. Energy costs to the user were calculated based on a flat charge per kWh consumed. Feldman used hourly production cost estimates for one case study to verify estimates obtained using the CGS model. (See Sec. C.3.1.4.)

The present value of the cost of accelerating the construction schedule is the incremental capacity cost of serving the increased load.*

C.3.1.5 Reliability Analysis Models

Two reports used utility system reliability models to calculate the change in capacity required to serve solar and conventional customers while maintaining the same level of reliability for the system. System reliability was expressed as the loss of load probability (LOLP) or the probability that the utility's load will exceed the utility's available generating capacity.

Cretcher and Melton calculated the incremental system capacity required to serve solar users. Cretcher and Melton used PTI's LOLP model to determine the total system capacity required to meet system demand with solar heating and cooling systems replacing a number of conventional systems. The reduction in utility system generating capacity required to meet demand at the same level of reliability with the SHACOB systems was called the capacity credit for the solar technology; its value was calculated assuming that the utility would be able to sell the excess capacity (1978, Vol. 1, pp. 47-49).

Leonard et al. used an approach similar to Cretcher and Melton's. A utility production cost model was used to calculate the variable costs associated with providing back-up power. An LOLP model was run to determine whether additional capacity was required. The cost of back-up was defined as the present value of the incremental fuel and capital costs (1977, pp. 125-6).

C.3.1.6 Utility Breakpoint Analysis

OTA used breakpoint analysis to determine the cost of providing back-up to solar users. This approach approximates an optimum mix of generating capacity given a utility load duration curve and the costs of producing electricity with each type of unit. Each type of generating capacity is characterized by a linear cost curve that shows the relationship between total annual production costs per generating unit as a function of the number of hours per year that the unit is operated.

The optimum mix of generating equipment is determined by finding the combination of base-, intermediate- and peak-load units that minimizes total generating costs. OTA accounted for reliability costs by assuming a 20% reserve margin for each type of capacity installed. Transmission and distribution costs were calculated by assuming that, for every dollar invested in generation capacity, $0.67 was invested in transmission and distribution (U.S. Congress, OTA 1978, Vol. I, Appendix V-A).

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*The capacity costs calculated by the CGS model also has an energy component for the following reason. If the utility responds to an increase in loads by accelerating the construction of a more efficient generating unit, the utility will realize fuel savings earlier. These fuel cost savings are subtracted from the incremental capital cost (Feldman et al. 1976, p. E2; Cicchetti et al. 1977, p. 96).

Load data for hypothetical utilities were constructed to be representative of the regions analyzed. An optimum generation mix was determined, using the procedure outlined above; all costs were based on the marginal costs of new capacity. Back-up costs for solar users were calculated by assuming that 1,000 solar buildings of a specified type were added to the region, and the generation mix was reoptimized to meet the new load duration curve. A similar calculation was performed assuming that 1,000 nonsolar buildings were added to the region. OTA reported the fractional difference between the costs of providing back-up energy and capacity for the two building scenarios (U.S. Congress, OTA 1978, Vol. I, Ch. V).

C.3.1.7 Assumed Average or Existing Rates

In addition to the techniques described above for computing the costs to serve back-up, four of the seven reports also used existing utility rates to compute back-up costs to the end-user. OTA used existing rates for computing the user's total cost of service for the specific applications analyzed (U.S. Congress, OTA 1978, Vol. II). Burke et al. used existing rates to determine how those rates would change preferred system designs (1977, p. V-1). Feldman et al. (1976, p. 71), and Lorsch et al. (1976, p. 6-11) compared the revenues the utility would collect by charging existing rates to their calculated costs to serve. They calculated the revenues the utility would collect from existing rates by multiplying the number of kWh consumed for back-up by the utility's existing rates to residential users. They compared these revenues to their estimates of what it would cost the utility to provide back-up power.

The approach of using an assumed flat rate per kWh was used by many authors whose reports were not reviewed in detail in this section. For example, Sandia Laboratory used this method to estimate the value of photovoltaic systems to dispersed users. They first define a utilization coefficient, which is the ratio of the energy that actually reaches the load (either for direct use or sell-back) to the amount of energy the array could produce under ideal conditions. They use a solar performance model to determine the amount of useful energy that is produced, taking into account available insolation, degradation effects, and energy losses in the system components. Given user load data, they determine the amount of energy that is consumed directly, and that which goes to storage and sell-back. The utilization coefficient is a number that summarizes the proportion of energy produced by the array that will actually displace electricity from the utility, either through direct use or sell-back. To estimate the value of the device to the user, they use existing utility rates for various regions of the country. The value of the power consumed directly is assumed equal to the existing rates. The value of sell-back is treated parametrically by assuming that sell-back is equal to 50% or 100% of the existing rates. The value of the device to the user can then be calculated from the present value of the cost of the displaced electricity (Jones 1979, Department of Energy 1979).

C.3.2 Calculation of Sell-back Rates

OTA was the only report surveyed that attempted to calculate sell-back rates. Their procedure for calculating sell-back rates was the same as the one used for back-up costs, utility breakpoint analysis. Given insolation data, user load data and the solar energy system operating strategy, hourly amounts of energy generated for sell-back were calculated. These data were then subtracted from the utility's load duration curve, the utility's generating mix was reoptimized, and the reduction in costs (fixed and variable) were calculated. OTA did not specify whether the impact of sell-back on the utility's transmission and distribution system was taken into account. Their basic objective was to determine what the utility could afford to pay for sell-back based upon the utility's fuel and capital savings as a result of having sell-back available. Again, all costs were based on the costs of new capacity.

To estimate sell-back rates, a similar calculation was performed to determine back-up costs for an identical solar building that did not sell electricity to the utility. The difference in utility system costs to serve the solar buildings with and without sell-back (the kWh supplied to the solar building not selling excess) minus net kWh sold to the building selling excess to the utility (Claridge 1979) was divided by the difference in kWh sold by the utility to each solar building. This number was defined as the purchase price for sell-back (in cents per kWh). It was then divided by the utility's average cost per kWh for total generation when no additional buildings were added to the system. This ratio of the purchase price to the utility's average cost was reported for the cities analyzed (U.S. Congress, OTA 1978, Vol. I, p. 155).

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15. Supplementary Notes

16. Abstract (Limit: 200 words)

This report reviews the methods that have been used for economic assessments of intermittent solar technologies in applications that are connected to conventional utility systems. It concentrates on the problem of estimating solar electric technology cost goals--the system costs at which solar technologies will compete with conventional systems. This report identifies the factors that must be considered when assessing intermittent technologies, and reviews the methods that have been used in technology assessment studies. It assesses qualitatively the tradeoffs among methods relative to ease of use and accuracy of results, and identifies the best available methods for use when maximum accuracy is desired. Data problems, deficiencies in existing techniques, and unresolved methodological issues are analyzed. Input assumptions and economic figures of merit are also evaluated.

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