150
1-4-80

Sh. 472

DOE/CS/8720-1

SOUTHWEST PROJECT
RESOURCE/INSTITUTIONAL REQUIREMENTS ANALYSIS

MASTER

VOLUME I
EXECUTIVE SUMMARY

DECEMBER 1979

Prepared for:
U.S. Department of Energy
Assistant Secretary for Conservation
and Solar Energy
Office of Solar Applications

DISTRIBUTION OF THIS DOCUMENT IS UNLIMITED

DISCLAIMER

This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency Thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

DISCLAIMER

Portions of this document may be illegible in electronic image products. Images are produced from the best available original document.

The following pages are an exact representation of what is in the original document folder.

NOTICE

This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States nor any agency thereof, nor any of their employees, makes any warranty, expressed or implied, or assumes any legal liability or responsibility for any third party's use or the results of such use of any information, apparatus, product or process disclosed in this report, or represents that its use by such third party would not infringe privately owned rights.

Printed in the United States of America
Available from
National Technical Information Service
U.S. Department of Commerce
5285 Port Royal Road
Springfield, VA 22161

NTIS price codes
Printed copy: \$6.80
Microfiche copy: A01

SOUTHWEST PROJECT

RESOURCE/INSTITUTIONAL REQUIREMENTS ANALYSIS

DISCLAIMER

This book was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise, does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

VOLUME I

EXECUTIVE SUMMARY

DECEMBER 1979

Prepared by

ARIZONA POWER AUTHORITY — 951 0200 ✓
ARIZONA PUBLIC SERVICE COMPANY — 950 0732 ✓
EL PASO ELECTRIC COMPANY — 950 9936 ✓
NEVADA POWER COMPANY
PORTLAND GENERAL ELECTRIC COMPANY
PUBLIC SERVICE COMPANY OF COLORADO
PUBLIC SERVICE COMPANY OF NEW MEXICO
SALT RIVER PROJECT
SAN DIEGO GAS & ELECTRIC COMPANY
SIERRA PACIFIC POWER COMPANY
SOUTHERN CALIFORNIA EDISON COMPANY
SOUTHWESTERN PUBLIC SERVICE COMPANY
UTAH POWER & LIGHT COMPANY

AND

STONE & WEBSTER ENGINEERING CORPORATION — 599 1000

Prepared for:

U.S. Department of Energy
Assistant Secretary for Conservation
and Solar Energy
Office of Solar Applications
Washington, D.C. 20585

Under

CONTRACT NO. EM-77-C-01-8720

DISTRIBUTION OF THIS DOCUMENT IS UNLIMITED

SOUTHWEST

SUMMARY TABLE OF CONTENTS

VOLUME I
EXECUTIVE SUMMARY

Section

1. Introduction
2. Summary
3. Findings and Conclusions
4. The State-of-the-Art of Solar Electric Generating Plants
5. System Integration Studies
6. Institutional Studies

VOLUME II
TECHNICAL STUDIES

Section

1. Introduction
2. Summary
3. The State-of-the-Art of Solar Electric Generating Plants
4. Technical Requirements of the Electric Utility Industry
5. Capital Investment, Operation, and Maintenance Cost Estimates for Representative Solar Electric Generating Plants
6. Cost of Representative Conventional Electric Generating Plants

VOLUME III
SYSTEMS INTEGRATION STUDIES

Section

1. Introduction
2. Summary
3. Generation Expansion Plans
4. Computer Models
5. Economic Factors
6. Analysis of Solar Plans

VOLUME IV
INSTITUTIONAL STUDIES

Section

1. Introduction
2. Summary
3. The Southwest Region and the Electric Utility Industry
4. Financial and Economic Factors in Commercialization
5. Governmental Factors
6. Institutional Arrangements
7. Legislative Needs to Support Commercialization
8. The Role of the Electric Utilities in Commercialization

SOUTHWEST

PREFACE

This document is Volume I of the four-volume Southwest Project Resource/Institutional Requirements Analysis Report. The complete report consists of the following volumes:

- I. Executive Summary
- II. Technical Studies
- III. Systems Integration Studies
- IV. Institutional Studies

Refer to the Summary Table of Contents for a delineation of the specific contents of Volumes II, III and IV.

The work described herein was initiated in October 1976 and was conducted in accordance with Federal Energy Administration (FEA), now Department of Energy (DOE), contract number EM-77-C-01-8720.

The contract authorized Stone & Webster Engineering Corporation (S&W) to undertake, with the assistance of 13 electric utilities, a study whose purpose was to investigate ways to accelerate the commercialization of solar electric generating plants and their expected market penetration into the electric utility network of the southwestern United States through the year 2000.

In accordance with the contract, the study was conducted primarily from a utility perspective and included the utility view of the technical, legal, economic, and institutional considerations necessary to make central station generation of electricity from solar power commercially successful. No dispersed uses of solar electric generation were addressed.

This report provides a basis from which periodic updates can be made to analyze the effect of economic trends and technology developments on the utilization of solar and/or conventional electric generation as technology continues to progress in future years. The basis established in this report utilized current state-of-the-art technology for solar and conventional electric generating plants. Also, 1977 costs of conventional electric generating plants were utilized. The cost of first generation commercial solar electric generating plants was based on assumptions reflecting large scale manufacturing of components by a mature industry.

Certain cautions should be observed when using the data contained in this report for any purpose other than that intended by the Southwest Project. The costs of

solar electric equipment, other forms of electric generating equipment, and fuel have been developed based on specific assumptions and are adjusted to reflect Southwest regional costs. The results of system integration modeling efforts were developed from specific utility system information and are not readily transferable to another region or utility system in all their aspects. Similarly, statements contained in this report may not be directly applicable to any single "typical" utility.

Lastly, institutional study data may be used as models, but are not readily transferable to other situations because they are either state or utility specific. While methodologies described in this study can be applied to other regions or situations, the specific data developed with these methodologies are directly applicable only to the region of interest. General conclusions can be drawn, however, which are applicable to the country as a whole.

The contract technical direction was under the supervision of Mr. Alex Haynes and Ms. Elaine Smith, DOE, Conservation and Solar Applications Division.

The Southwest Project Resource/Institutional Requirements Analysis Study and Report was primarily developed by the following personnel representing the organizations indicated:

Arizona Power Authority (APA)	L.S. Ormsby T.G. Sawyer
Arizona Public Service Company (APS)	Dr. M.L. Brown L.L. Daviet II E.R. Weber
El Paso Electric Company (ELP)	J.E. Brown
Nevada Power Company (NPC)	J.W. Arlidge H.R. Novak
Portland General Electric Company (PGE)	Norman Sanesi
Public Service Company of Colorado (PSC)	H.C. Klaiman D.T. Spangenberg, Jr.
Public Service Company of New Mexico (PSNM)	D.J. Groves J.D. Maddox

SOUTHWEST

Salt River
Project (SRP) R.M. Hayslip
 G. Ijams

San Diego Gas
and Electric
Company (SDGE) R.G. Lacy
 J. Montgomery

Sierra Pacific
Power Company (SPP) J.A. Carito

Southern
California
Edison Company
(SCE) J.W. Ballance
 C.F. Bluemle
 D.N. Smith
 M.C. Wehrey

Southwestern
Public Service
Company (SPS) K.L. Ladd

Utah Power &
Light Company
(UPL)

Stone & Webster
Engineering
Corporation

Dr. S.K. Evans

D.H. Guild,
Project Manager

B. Brodfeld
J.A. Cleveland
K.L. Hicks
M.W. Noga
A.M. Ross

S&W would also like to acknowledge the assistance and information provided by the State Energy Offices of Arizona, California, Colorado, Nevada, New Mexico, Oklahoma, Texas, and Utah, and by J.E. Bigger of the Electric Power Research Institute (EPRI).

SOUTHWEST

TABLE OF CONTENTS

<u>Section</u>	<u>Title</u>	<u>Page</u>	<u>Section</u>	<u>Title</u>	<u>Page</u>
PREFACE		P-1	4.3.3.1	Wind Energy Conversion Electric Generating Plants . . .	4-7
1 INTRODUCTION		1-1	4.3.3.2	Solar Thermal Central Receiver Electric Generating Plants	4-8
2 SUMMARY.		2-1	4.3.3.3	Retrofit Hybrid Solar Thermal Electric Generating Plants.	4-8
3 FINDINGS AND CONCLUSIONS		3-1	4.3.3.4	Solar Photovoltaic Electric Generating Plants . . .	4-9
3.1 GENERAL.		3-1	4.3.3.5	Solar Thermal Distributed Receiver Electric Generating Plants.	4-9
3.2 TECHNICAL CONCLUSIONS.		3-1	4.4	CAPITAL INVESTMENT AND OPERATION AND MAINTENANCE COSTS OF SOLAR UNITS.	4-10
3.3 SYSTEM INTEGRATION STUDIES . . .		3-2	4.4.1	Methodology and Assumption . .	4-10
3.4 INSTITUTIONAL CONCLUSIONS. . . .		3-4	4.4.2	Discussion of Capital Investment Costs	4-11
4 THE STATE-OF-THE-ART OF SOLAR ELECTRIC GENERATING PLANTS		4-1	4.4.2.1	Wind Energy Conversion Electric Generating Plants . . .	4-11
4.1 OBJECTIVE AND APPROACH OF THE TECHNICAL STUDIES.		4-1	4.4.2.2	Solar Thermal Central Receiver Electric Generating Plants.	4-11
4.2 ESTABLISHMENT OF CONCEPTUAL DESIGNS.		4-2	4.4.2.3	Retrofit Hybrid Electric Generating Plants.	4-11
4.2.1 Wind Energy Conversion Electric Generating Plant.		4-2	4.4.2.4	Solar Photovoltaic Electric Generating Plants . . .	4-11
4.2.1.1 Design		4-2	4.4.2.5	Solar Thermal Distributed Receiver Electric Generating Plants.	4-12
4.2.1.2 Operation.		4-2	4.4.3	Discussion of O&M Costs. . . .	4-12
4.2.2 Solar Thermal Central Receiver Electric Generating Plant. . .		4-2	4.5	COST OF REPRESENTATIVE CONVENTIONAL ELECTRIC GENERATING PLANTS	4-12
4.2.2.1 Design		4-2	4.5.1	Methodology and Assumptions. .	4-12
4.2.2.2 Operation.		4-3	4.5.2	Results.	4-13
4.2.3 Retrofit Hybrid Solar Thermal Electric Generating Plant. . .		4-3	5	SYSTEM INTEGRATION STUDIES	5-1
4.2.3.1 Design		4-3	5.1	INTRODUCTION	5-1
4.2.3.2 Operation.		4-4	5.1.1	Purpose.	5-1
4.2.4 Solar Photovoltaic Electric Generating Plant		4-4	5.1.2	Methodology and Assumptions. .	5-1
4.2.4.1 Design		4-4	5.1.3	Discussion of Results.	5-3
4.2.4.2 Operation.		4-5	6	INSTITUTIONAL STUDIES.	6-1
4.2.5 Solar Thermal Distributed Receiver Electric Generating Plant		4-5	6.1	GENERAL.	6-1
4.2.5.1 Design		4-5	6.2	COMMERCIALIZATION PROCESS. . . .	6-1
4.2.5.2 Operation.		4-6	6.3	SOUTHWEST REGION	6-2
4.3 EVALUATION OF ELECTRIC UTILITY INDUSTRY TECHNICAL REQUIREMENTS.		4-6	6.3.1	Population	6-2
4.3.1 Methodology.		4-6	6.3.2	Solar Resources.	6-2
4.3.2 Definition of Parameters . . .		4-6	6.3.3	Utilities.	6-2
4.3.2.1 Engineering Feasibility. . .		4-6			
4.3.2.2 Siting and Environment . . .		4-7			
4.3.2.3 Procurement.		4-7			
4.3.2.4 Construction		4-7			
4.3.2.5 Operability and Control. . .		4-7			
4.3.2.6 Maintenance.		4-7			
4.3.2.7 Availability		4-7			
4.3.3 Results of Technical Analysis.		4-7			

SOUTHWEST

TABLE OF CONTENTS (Cont)

<u>Section</u>	<u>Title</u>	<u>Page</u>	<u>Section</u>	<u>Title</u>	<u>Page</u>
6.4	INSTITUTIONAL ARRANGEMENTS . . .	6-3	6.7.4.5	Discussion	6-9
6.4.1	General.	6-3	6.7.4.6	Conclusions.	6-10
6.4.2	Methodology.	6-3	6.8	REGULATORY FACTORS	6-11
6.4.3	Results.	6-4	6.8.1	General.	6-11
6.5	FINANCIAL INCENTIVES	6-4	6.8.2	Available Financial Mechanisms	6-11
6.5.1	General.	6-4	6.8.3	Available Procedural Mechanisms	6-12
6.5.2	Methodology and Assumptions.	6-5	6.8.3.1	General.	6-12
6.5.3	Low Interest Loans	6-6	6.8.3.2	Licensing Requirements	6-12
6.5.4	Investment Tax Credits	6-6	6.8.3.3	Potential Areas for Improvement	6-13
6.5.5	Decreasing Asset Guideline Period	6-6	6.9	LEGAL CONSIDERATIONS	6-13
6.5.6	Accelerated Depreciation	6-6	6.9.1	Access to Sun and Wind	6-13
6.5.7	Results.	6-6	6.9.2	Antitrust.	6-13
6.6	MARKET PENETRATION	6-6	6.9.3	Patent Law	6-14
6.6.1	General.	6-6	6.10	SOCIOECONOMICS IMPACTS.	6-14
6.6.2	Methodology and Assumptions.	6-7	6.10.1	General	6-14
6.6.3	Results.	6-7	6.10.2	Housing	6-14
6.7	EVALUATION OF SYSTEM INTEGRATION STUDIES.	6-7	6.10.3	Traffic	6-14
6.7.1	Background	6-7	6.10.4	Community Facilities.	6-14
6.7.2	Break-even Investment.	6-8	6.10.5	Regional Economics.	6-14
6.7.3	Sensitivity.	6-8	6.11	LEGISLATIVE REQUIREMENTS.	6-15
6.7.4	Evaluation Results	6-8	6.12	UTILITY INVOLVEMENT	6-15
6.7.4.1	Solar Thermal Plants	6-9	6.12.1	General	6-15
6.7.4.2	Photovoltaic Plants.	6-9	6.12.2	Near Term Participation	6-16
6.7.4.3	Wind Energy Conversion Plants	6-9	6.12.3	Long Range Participation.	6-16
6.7.4.4	Retrofit Hybrid Plants	6-9			

SOUTHWEST

LIST OF TABLES

<u>Table</u>	<u>Description</u>	<u>Table</u>	<u>Description</u>
3.1-1	Solar Energy Costs and Values in 1977 Dollars	6.6-1	Range of the Number of Solar Electric Generating Plants in the United States
4.1-1	Land and Water Use Requirements	6.6-2	Market Forecast Questionnaire Results
4.3-1	Anticipated Construction Work Force Requirements	6.7-1	Breakeven Investment and Financial Incentive Required by the Year 2000 for Mature Generating Plants
4.4-1	Capital Investment and O&M Costs of Solar Generating Facilities	6.7-2	Cost of 1,000 MWe of Solar Electric Generation Starting Commercial Operation (1977 Dollars)
5.1-1	Utilities/Concepts Studied		
5.1-2	System Characteristics		
6.5-1	Comparison of Methods to Accelerate Depreciation to Straight Line Depreciation		

SOUTHWEST

LIST OF ILLUSTRATIONS

<u>Figure</u>	<u>Title</u>	<u>Figure</u>	<u>Title</u>
1.1-1	Southwest Region - Approximate Electric Power Service Areas of Participating Utilities	4.2-11	Concept of a Distributed Receiver Solar Thermal Electric Generating Plant
3.3-1	Effects of Fuel Escalation on Solar Break-Even Investment - Solar Thermal; 200 MWh Storage - Privately Financed Utilities	4.2-12	Concentrating Collectors for Distributed Receiver Solar Thermal Electric Generating Plant
3.3-2	Effects of Fuel Escalation on Solar Break-Even Investment - Solar Thermal; 600 MWh Storage - Privately Financed Utilities	5.1-1	Flow Diagram - Computer Models
3.3-3	Solar Break-Even Investment - Solar Thermal, 200 MWh Storage	6.3-1	Solar Radiation Direct Normal Term, Annual Average - Day Values
3.3-4	Solar Break-Even Investment - Solar Thermal, 600 MWh Storage	6.3-2	Solar Radiation, Total Horizontal, Annual Average - Day Values
3.4-1	Technical Maturity of Central Station Solar Electric Generating Plants	6.3-3	Mean Annual Wind Power Estimated at 50 Meters Above Exposed Areas
4.2-1	10.5 MWe Wind Energy Conversion Electric Generating Plant	6.5-1	Public Service Company of New Mexico - Multiplier to Revise Base Case Solar Break-Even Investment for Changes in Cost of Debt
4.2-2	Concept of a Wind Energy Conversion Electric Generating Plant (Horizontal Axis Rotor)	6.5-2	Salt River Project - Multiplier to Revise Base Case Solar Break-Even Investment for Changes in Cost of Debt
4.2-3	100 MWe Solar Thermal Central Receiver Electric Generating Plant	6.5-3	El Paso Electric Company - Multiplier to Revise Base Case Solar Break-Even Investment for Changes in Cost of Debt
4.2-4	Heliostat for Central Receiver Solar Thermal Electric Generating Plant	6.5-4	Southern California Edison Company - Multiplier to Revise Base Case - Solar Break-Even Investment for Changes in Cost of Debt
4.2-5	Receiver for Central Receiver Solar Thermal Electric Generating Plant	6.5-5	Public Service Company of Colorado - Multiplier to Revise Base Case - Solar Break-Even Investment for Changes in Cost of Debt
4.2-6	100 MWe Retrofit Hybrid Solar Thermal Electric Generating Plant	6.5-6	Arizona Public Service Company - Multiplier to Revise Base Case Solar Break-Even Investment for Changes in Cost of Debt
4.2-7	Heliostat for Central Receiver Solar Thermal Electric Generating Plant	6.5-7	Multiplier to Revise Base Case Solar Break-Even Investment for Changes in Investment Tax Credit
4.2-8	Receiver for Central Receiver Solar Thermal Electric Generating Plant		
4.2-9	Concept of a Solar Photovoltaic Electric Generating Plant		
4.2-10	Silicon Solar Cell		

SOUTHWEST

LIST OF ILLUSTRATIONS (CONT)

6.5-8	Multiplier to Revise Base Case Solar Break-Even Investment for Changes in Asset Guideline Period	6.7-11	Incentive Requirements for Year 2000, Public Service Company of Colorado - Fuel Escalation - 8.0%
6.7-1	Public Service Company of New Mexico - Solar Break-Even Investment in the Year 2000	6.7-12	Incentive Requirements for Year 2000, Arizona Public Service Company - Fuel Escalation - 4.9%
6.7-2	Salt River Project - Solar Break-Even Investment in the Year 2000	6.7-13	Comparison of Break-Even Investment and Financial Incentive Requirements - Solar Thermal, 600 MWh Energy Storage
6.7-3	El Paso Electric Company - Solar Break-Even Investment in the Year 2000	6.7-14	Comparison of Break-Even Investment and Financial Incentive Requirements - Solar Thermal, 200 MWh Energy Storage
6.7-4	Southern California Edison Company - Solar Break-Even Investment in the Year 2000	6.7-15	Comparison of Break-Even Investment and Financial Incentive Requirements - Solar Thermal, No Energy Storage
6.7-5	Public Service Company of Colorado - Solar Break-Even Investment in the Year 2000	6.7-16	Comparison of Break-Even Investment and Financial Incentive Requirements - Photovoltaic, No Energy Storage
6.7-6	Arizona Public Service Company - Solar Break-Even Investment in the Year 2000	6.7-17	Comparison of Break-Even Investment and Financial Incentive Requirements - Wind - No Energy Storage; Wind - 10 MWh Energy Storage
6.7-7	Incentive Requirements for Year 2000, Public Service Company of New Mexico - Fuel Escalation - 7.0%	6.7-18	Comparison of Break-Even Investment and Financial Incentive Requirements - Retrofit Hybrid
6.7-8	Incentive Requirements for Year 2000, Salt River Project, Fuel Escalation - 5.3%		
6.7-9	Incentive Requirements for Year 2000, El Paso Electric Company - Fuel Escalation - 7.2%		
6.7-10	Incentive Requirements for Year 2000, Southern California Edison Company - Fuel Escalation - 6.7%		

SOUTHWEST

SECTION 1

INTRODUCTION

The purpose of this project was to provide information which could be used by DOE in formulating their plans for commercialization and market penetration of central station solar electric generating plants in the southwestern region of the United States. The area of interest, shown on Figure 1.1-1, includes Arizona, California, Colorado, Nevada, New Mexico, Utah, and sections of Oklahoma and Texas. The figure also shows the service areas of the electric utilities who participated in the Southwest Project and who are located in the southwest region.

The project evaluated the potential integration of central station solar electric generating facilities into the existing electric grids of the region through the year 2000 by making use of system planning methodology which is commonly used throughout the electric utility industry. Solar technologies considered in this study were selected on the basis of potential availability, applicability to the region, and viability during the time frame of 1985-2000. The technologies included: wind energy conversion, solar thermal electric, solar photovoltaic conversion, and hybrid (solar thermal repowering) solar electric systems. (See Figures 4.2-1, 4.2-3, 4.2-9, and 4.2-6, respectively.) Each of the technologies considered, except hybrid, was paired with a compatible dedicated energy storage system to ascertain the impact of such a system upon plant performance and its applicability to a utility system. The hybrid concept utilizes a conventionally fueled steam generator as well as a solar steam generator, so it is not as dependent upon the availability of solar energy as are the other concepts.

The participants in this project included 12 electric utility companies and a state power authority in the southwestern United States as well as a major consulting engineering firm. Eleven of the electric utilities are private investor owned and one is a public utility. The state power authority functions as a wholesaler of electric power only. The total installed capacity of the participating utilities, as of January 1, 1977, was approximately 30,000 MWe. This represents about 48 percent of the installed capacity in the region. The installed capacity of the individual utilities ranges from 562 to 14,066 MWe. The study participants shared a common need to identify and plan for the use of electric generation technologies

best suited to meet the energy needs of their customers during the coming years. The diversity of the participating utilities ensures a balanced perspective for the evaluation of all aspects of solar electric generation systems throughout the southwest.

The efforts of S&W, the prime contractor, and the participating utilities on this and continuing projects are indicative of a strong electric utility industry interest in the development of solar power technology on a sound technical and economic basis. As potential future users of this technology, the utility participants in the project directed their efforts toward accomplishing a comprehensive review of the entire range of technical, economic, regulatory, and institutional factors that can influence the commercialization of solar electric generating plants.

The continuous and ongoing development of these technologies was recognized by the participants, thereby necessitating the establishment of an arbitrarily selected cutoff date for the consideration of technical information. This study uses technical information which was available as of March 1977. It is considered that the results found herein will remain broadly valid unless and until significant technological advances and/or economic developments occur.

The project had two distinct and complementary objectives. One objective was to address the technical problems that must be resolved to facilitate the market penetration of solar electric generating plants. The other objective was to address institutional means of removing existing or potential barriers to accelerated commercialization of these technologies.

This volume, the Executive Summary, contains a broad synopsis of the information found in Volumes II through IV. Wherever possible within this volume, figures and/or tables have been designed to concisely present the necessary information. Conclusions reached herein reflect an amalgamation of those conclusions reached independently in the other volumes as well as those established in perspective of the overall study.

Section 2 of this volume presents a concise summary of the overall results of this study. Section 3 presents a more

detailed analysis of the results, and presents a discussion of areas where future developmental efforts should be concentrated.

Section 4 of this volume presents an assessment of selected solar conversion systems and subsystems that are available or under development to determine how they comply with electric utility standards and practices. The prime purpose of the assessment was to provide conceptual descriptions of state-of-the-art solar electric generating plants and to use these descriptions to define the use of solar conversion technologies in the utility grid.

The methodology used for this study was to gather technical information on solar electric generating plant concepts and to evaluate this information from an electric utility viewpoint. The available information was supplemented by utility industry experience and the experience of the participants with other emerging energy technologies. Conceptual descriptions of representative solar electric generating plants were developed based on all three factors.

The technical information gathered on the selected concepts and their associated energy storage facilities focused on those systems which, in the opinion of the participants, could be considered as likely candidates for future incorporation into electric utility systems. The technical information was obtained through direct contact with various agencies and institutions that sponsor developmental work in the field of solar electric generation systems, companies that have undertaken developmental or study work, universities, and various other organizations, as well as from existing publications.

The conceptual descriptions serve to define the state-of-the-art of solar electric generating plants from the electric utility viewpoint. This definition served as a basis for identifying preliminary electric utility industry technical requirements and considerations, estimating the capital investment, and operation and maintenance (O&M) costs, and defining solar plant operation models.

Estimates of the capital investment and O&M costs for the selected concepts were used as inputs for the computer calculated electric utility system generation expansion models to determine the potential operational and economic impact and viability of solar electric generating plants.

DOE has established "cost goals", for selected components and systems, which reflect expected advances in design and production techniques necessary to bring solar technology to the point of commercial viability. In the instances where the established "cost goals" were outside the range of estimated values, the "cost goal" value was used as an additional input to the various calculations requiring such parameters.

The capital investment costs of conventional electric generating plants of the following types - nuclear, coal-fired, oil-fired, combustion turbine, and combined cycle - were also estimated. These costs were used as inputs for electric utility system generation expansion models.

Section 5 of this volume includes a discussion of the utility generation expansion plans, computer models, and economic factors which were used to perform the system integration studies which determined the applicability and the relative value of solar electric generating systems to the utility systems. The results of these studies, in terms of break-even costs, and the sensitivity of these costs to critical variable parameters are also discussed.

Section 6 of this volume discusses the institutional means of accelerating the commercialization of solar electric generating systems. Financial, legal, socioeconomic, regulatory, and institutional factors which assist or constrain the development of solar electric technologies in the Southwest are identified and actions to mitigate the effects of these constraints are evaluated. This section also includes a discussion of legislative needs to support commercialization including an evaluation of proposed state and federal legislation and ways in which the electric utility industry can participate in research, development, and demonstration (RD&D) and commercialization of solar electric generating plants.

SOUTHWEST

SECTION 2

SUMMARY

It has often been stated that the United States must, if it is to maintain its paramount position in the world, decrease its dependence upon exhaustible, increasingly expensive energy sources and turn instead to forms of energy which are renewable and/or available within its own borders. Although there are numerous energy resources which, when combined with conservation efforts, promise to satisfy the nations future energy needs, those mentioned most often for central station electric generation applications are coal, nuclear, and solar. The former two are more conventional technologies about which much is known, both positive and negative. Less is known about the potential value of central station solar electric generating plants to the electric utility industry. This study addresses the contribution that solar energy could make to actual utility systems in the southwestern United States and the potential barriers to that contribution.

The major results of the studies conducted as part of this project, as discussed in detail in Volumes II, III, and IV, indicate that:

- solar energy concepts investigated have the potential to make an important contribution to the regional generating capability by the year 2000;
- there are numerous and substantial economic and institutional barriers which must be overcome before this potential can be realized;
- solar facilities will be of greatest value to utilities having high system fuel costs (those primarily using oil and gas) and those having low fixed charge rates;
- the break-even investment for solar facilities is highly sensitive to the rate of fuel cost increases during the period in question;
- there are no overwhelming problems associated with the socioeconomic, environmental, and/or legal impacts associated with design, construction, and operation of central station solar facilities;

- wind generation and central station solar thermal generating plants are deemed to be the technologies closest to maturity; photovoltaic plants were found to be less mature;
- dedicated energy storage facilities using present technology cost more than their expected value to the utilities and, as such, should not be considered for early commercial applications except as a buffer against short term solar transients; and,
- the utilities desire that institutional arrangements used to overcome cost differentials be of a traditional nature rather than be designed specifically for this situation.

Potential user confidence in the cost, availability, and reliability of solar electric generating technologies would be enhanced through the establishment of a well planned demonstration program with large scale plants. Such a program would also help determine the merits of the various concepts which have been proposed.

In summary, the situation facing the use of solar technology for central station electric generation in the Southwest through the year 2000 is similar to that faced by other emerging energy technologies; i.e., technical viability tempered by economic and, in some cases, regulatory constraints. The cost of the financial incentives required to achieve a market penetration of 5 percent of the total installed generation capacity, an amount equal to 8,000 MW, by the year 2000 in this single region of the United States, is estimated to be approximately \$11 billion in 1976 dollars. The cost and implications of not proceeding with an ambitious solar program may well prove to be even greater. The utility industry, recognizing their responsibility to provide the public with sufficient electric power at economical cost, can and is willing to participate in programs designed to meet the needs of the nation and which are consistent with the above responsibilities.

SECTION 3

FINDINGS AND CONCLUSIONS

3.1 GENERAL

The evaluations conducted as part of this project were designed to determine the technical, economic, and social viability of central station solar electric generating facilities through the year 2000 in the area of the United States, the Southwest, which has the most abundant solar resources. Five conceptual designs representing technological variations considered achievable and useful during the study time frame were evaluated, using sophisticated computer programs, on six actual utility systems within the region. This modeling effort, which utilized accepted computer methodology, provided a realistic assessment of the value of these facilities to the utility systems on which they could be installed, and permitted practical consideration of both quantifiable and nonquantifiable aspects.

No effort was made to compare the relative technical merits of the conceptual designs studied, nor was an effort made to predict technological advancements beyond present-day state-of-the-art. Data provided by the utilities, including generation expansion plans, represented information deemed current at the specific time it was supplied and was based, to the greatest extent possible, on actual experience. Such data and plans, however, are subject to continuous change as new information becomes available. Similarly, other evaluations were based on the latest data available on actual regional and national conditions.

3.2 TECHNICAL CONCLUSIONS

All the concepts evaluated were determined to be technologically feasible during the time period of concern. The estimated average plant investment costs of the investigated conceptual designs with maximum energy storage ranged from \$1,885/kW to \$7,695/kW, in 1977 dollars as can be seen in Table 3.1-1. The differential between these estimated costs and the break-even investment value, the expected value to the utilities, is shown in Table 3.1-1 to be quite extensive in most cases. In addition, no funds have been allocated for contingencies as is normally done when estimating power plant costs. It is, therefore, obvious that significant financial incentives will have to be provided to make central station solar facilities economically competitive.

The fact that wind energy conversion was found to be the lowest cost concept was an interesting result of the study; it had been expected, as indicated in numerous technical documents, that the retrofit hybrid concept would have the lowest cost since there would be no need to purchase the balance-of-plant equipment already in place for the fossil unit. Further evaluation showed this anomaly to be caused by the extensive field piping and electrical work necessitated by the eight-module design originally selected for evaluation. It was, therefore, determined that the most economical retrofit hybrid design was one which used a single receiver tower designed especially for the specific plant application. With this alternate design, the estimated cost for retrofit hybrid was shown to be one of the lowest costs of the concepts evaluated although still higher than the wind generation concept.

Dedicated energy storage systems were selected for use with each of the generating concepts except retrofit hybrid. The systems were designed with comparable capacity and utilized conceptual designs compatible with each generating concept. Battery storage systems were found to be inefficient and to require extensive operating environment maintenance equipment. The cost of the storage systems selected for evaluation with solar thermal facilities proved to be more than the calculated value of the storage capacity. By extrapolation, it was concluded at the end of this study that energy storage should not be included in the first generation of commercial-sized plants except to serve as a buffer against short-term solar transients. This conclusion also identified the need for additional development work to improve the performance and economics of the storage systems so that the capacity replacement value of the generating concepts could be improved without incurring increased financial penalties.

It was determined that solar facilities will be of greater value to utilities having high system fuel costs (those primarily using oil and gas) and those having low fixed charge rates. Of the utilities studied, SRP, an agency of the State of Arizona, would benefit the most from the addition of solar facilities to its system, based on a comparison with an alternative expansion plan which includes conventional power generation heavily dependent upon oil fuel.

The differences between the plant investment costs and the value to the utility will have to be made up by a combination of incentives supported and funded, to a great extent, by the Federal Government. This financial support may be provided by a variety of incentive mechanisms varying from direct assistance in the form of loans and grants to indirect assistance in the form of tax abatements, special treatment by rate regulating authorities, and revisions to the regulatory framework, all of which are designed to reduce solar plant costs to the user.

Review of the construction and O&M activities associated with the selected concepts showed no insurmountable problems. There will be, however, a need to develop and refine construction and maintenance techniques associated with activities conducted at the top of tall structures; train utility employees in activities unique to solar technology; develop methods to condition and dispatch the electricity generated by wind and photovoltaic plants and/or stored in battery storage systems; and obtain sites with the required size and characteristics.

Wind generation and solar thermal generating plants were deemed to be the technologies closest to technical maturity with 1985 and 1990 being the most optimistic dates, respectively, for early commercialization of commercial scale facilities using these concepts. Photovoltaic plants with present-day state-of-the-art technology were found to be less mature with the expectation that 1994 was the earliest that such a facility would be added to a utility system. This latter concept will require a technological breakthrough to be economically competitive. There appears to be a need to advance the state-of-the-art of encapsulant design as those presently in use have a limited life and high cost. Another identified concern was the present lack of adequate photovoltaic cell efficiency and production capability. In 1977, the annual production capability in the United States was only sufficient to produce cells capable of generating 1 MW. If the photovoltaic concept is to have a major role in the use of solar energy, this capability will have to be vastly expanded in the near future.

Retrofit hybrid appears attractive economically and should also be available by the late 1980's, but the application of this concept may be limited by regulatory constraints and the availability of compatible fossil-fueled power plants.

Aside from the purely financial aspects, it appears that implementation of central station solar technology offers no overwhelming problems associated with the socioeconomic, environmental, and legal implications of designing, constructing, and operating these facilities. A program designed to construct the desired solar capacity will introduce large sums of capital into the regional economy and assist in the development of an industry which may eventually serve the entire country, as well as possibly alleviating the regional unemployment situation.

3.3 SYSTEM INTEGRATION STUDIES

The six utilities participating in the system integration study exhibited a wide range of characteristics that resulted in wide variations in the break-even investment value associated with each concept. The break-even investment cost represents the life cycle cost value of the concept studied to the respective utility system and, as such, must be subtracted from the cost of constructing and operating the facility to determine the amount of incentive required to make the facility economically attractive. It is important to recognize the interdependence of the parameters studied. Concepts having high value but high cost may be less attractive than concepts having less value but more reasonable cost. The parameter of greatest importance to the purchasing utility and the subsidizing agency is the differential amount between the value and the installed cost. Other considerations such as overall financial requirements and ability to borrow capital are also of importance.

The most significant characteristic affecting the break-even investment value was determined to be the cost of fuel replaced by solar generation. The fuel replacement value was found to be more important for solar generating units which have little capacity value, such as photovoltaic and wind, than for solar thermal units which exhibit higher capacity replacement value. There were three distinct fuel replacement cost categories in evidence. Utility systems such as ELP, which would displace nuclear capacity with solar capacity in their generation expansion plans, have fuel replacement costs of 15 mills per kWh (1985) or below. Systems such as PSC and APS, which would displace a high percentage of coal-fired capacity from their generation plans, had fuel replacement costs of 17 and 21 mills per kWh, respectively (1985). Replacing a high percentage of oil-fired capacity (mostly combustion turbines) from the generation expansion plans on systems such

as SCE and SRP, resulted in fuel replacement costs of 41 and 49 mills per kWh, respectively (1985).

Systems having high fuel replacement costs (SCE and SRP) also showed lower investment in capacity replaced because combustion turbines require a lower capital investment than other conventional units. A second factor which has a major effect on the break-even investment in solar generation is the fixed-charge rate. SRP, because it is an agency of the State of Arizona, has a fixed charge rate of 11.88 percent. This is 60 percent of the fixed charge rate used by most of the other utilities.

The break-even investment for solar facilities was found to be highly sensitive to the rate of fuel cost increases. Expected fuel cost increase rates, ranging from 4.9 to 8.0 percent per year, were estimated by utilities for the entire period under study. (The effect of inflation is included in these numbers.) All base case calculations were performed using these estimated values. Calculations were also performed for all utilities using fuel cost increase rates of 8 and 10 percent per year through the year 2020 in order to determine the potential impact of possible international political perturbations. These latter calculations indicated dramatic increases in the break-even investment for most of the utilities studied with concomitant reduction in incentive requirements. In general, increasing the fuel escalation rate to 10 percent results in a doubling of the value of solar thermal generation to privately financed utilities which displace coal- and oil-fired capacity with solar generation (Figures 3.3-1 and 3.3-2). As a result of the low SRP fixed charge rate and high fuel replacement credit, the value of solar thermal to SRP was determined to be more sensitive to fuel escalation than was the value of solar thermal to other utilities.

Solar thermal plants with dedicated storage capacity are characterized by higher capacity factors and higher fuel replacement credit than the other solar technologies. The solar thermal unit with 600 MWh of storage capability has the highest fuel credit and capacity replacement credit of all of the concepts studied. Figures 3.3-3 and 3.3-4 show the relative value of solar thermal plants with 200 and 600 MWh of storage for each of the six utilities and indicate the relative importance of capacity credit, fuel replacement credit, and O&M penalty. The shaded areas of the figures represent the O&M penalty (the additional cost of O&M associated with solar facilities)

which reduces the overall value of solar generation. The crossed area represents capitalized fuel savings or fuel replacement credit. The blank area represents capacity replacement credit, and is composed of the capital investment in conventional capacity that was displaced by solar capacity in a generation expansion plan. SRP has the highest value in the first two categories due to its lower fixed charge rate while in the third category, ELP's large capacity credit is due to its higher insolation levels and its load characteristics.

The hybrid unit considered in the system integration studies consisted of a solar generator backfitted to an oil-fired fossil fueled unit, resulting in an extension of the commercial life of the fossil unit. As a result, the unit was accorded full capacity credit as well as fuel replacement credit.

The photovoltaic plant with no storage analyzed in this study was found to be comparable in value to a solar thermal plant with no storage. The solar thermal plant exhibited a higher capacity replacement and fuel saving value due to its two axis tracking mirrors but these advantages were nearly offset by the lower O&M costs of the nontracking photovoltaic plant. The break-even investment in photovoltaic generation was found to be more sensitive to fuel escalation than was the investment in solar thermal plants.

The wind energy systems were found to have relatively low break-even values, but these results would differ for specific wind sites or wind machine designs that could produce a higher capacity factor. The capacity replacement value is very low and the fuel savings are offset to a considerable extent by O&M penalties. The small size of these units contributes to a relatively high O&M cost in dollars per kilowatt.

The annual system peak load growth rates projected by the participating utilities for this study varied from an average compound annual rate from 1985-2000 of 2.9 to 7.2 percent. Rates different from those projected will not affect the results to any great degree but several possible trends are worth noting. Lower load growth rates than those projected will tend to increase the fuel replacement value by reducing the rate at which new, efficient capacity is added. This trend would improve the value of hybrid fuel savers and photovoltaic solar units relative to solar thermal plants and increase the break-even investment of all solar capacity.

3.4 INSTITUTIONAL CONCLUSIONS

The institutional studies utilized the results developed in the technical and systems integrations studies and investigated numerous aspects which do not directly lend themselves to quantitative analyses.

It was determined that the southwest region has excellent resources to support widespread use of central station solar electric generating plants, although additional work is required to collect data on these resources. The region is experiencing widespread growth, has the best solar resources in the United States, and has sufficient available land to support a sizable market penetration of solar electric generating plants. In addition, the region has adequate labor forces and facilities to support construction and the unemployment rate is somewhat higher than the national average. The only possible regional constraint is the lack of water in certain subregions, a problem which can be ameliorated by the choice of a concept requiring little water. In summation, the region is optimally suited for the achievement of solar electric power generation demonstration/utilization goals.

The studies indicated that, during the time frame of 1985-2000, financial incentives equaling approximately 65-75 percent of the plant investment costs will be required to introduce solar electric generation into the Southwest on a commercial scale. Thus, the amount of penetration will be highly dependent on the level and duration of government subsidization. It is optimistically expected that the maximum regional penetration will be approximately 3-5 percent by the year 2000. The estimated amount of federal funds necessary to achieve this limited penetration will be more than 50 percent of the \$20 billion estimated by Congress for national use to develop all new energy technologies during the next decade, as indicated in the Federal Nonnuclear Energy Research and Development Act of 1974. It is conjectural whether this amount can and will be available for a single technology in a single region.

Solar electric generation in the Southwest is not impeded by inadequate solar resources; the region has excellent resources. Nor is it impeded by an unwillingness of utilities to participate in solar electric demonstrations and to employ solar electric plants in their systems. No unsurmountable technical or non-technical problems are apparent from this study. The major barriers identified

are precisely those experienced by any emerging technology:

- Technical readiness
- Economic viability
- User confidence, and
- Institutional road blocks.

To achieve technical readiness requires:

- For wind energy conversion electric generating plants:
 1. Site-specific determination and quantification of the wind resource.
 2. Demonstration of multi-unit (five or more) wind generating plants on several utility systems in the region.
 3. Accumulation of at least one year of favorable operational and maintenance experience.
- For retrofit hybrid solar thermal electric generating plants:
 1. Designs that minimize the number of receiver towers.
 2. Demonstration of 50 MW or larger size plants on several utility systems in the region.
 3. Accumulation of at least one year of favorable operational and maintenance experience that includes demonstration of resolution of control and interface of solar/fossil plant and load-following capability.
- For solar thermal central receiver electric generating plants:
 1. Proof of acceptable solutions for a number of engineering details of plant design.
 2. Demonstration of 100 MW or larger plants on several utility systems in the region.
 3. Accumulation of at least one year of favorable operational and maintenance experience.

SOUTHWEST

- For photovoltaic electric generating plants:

1. Verification of a long-life effective encapsulant for the cells.
2. Increase in cell efficiency and packing density to minimize cost of structural framing and foundation supports.
3. Demonstration of 100 MW or larger plants on several utility systems in the region.

To achieve economic viability requires one, or a combination of, the following:

- Mandated unavailability of certain conventional fuel options (i.e., the Fuel Use Act)
- Substantial increase in the cost of conventional fuels above the rate of general inflation.
- Some form of economic subsidy to bridge the gap between the worth of a solar electric generation plant and its investment/operational cost.

To achieve user confidence requires:

- Satisfactory operation of demonstration plants on the particular utility or similar utility system.
- Confidence in the solar equipment vendor who will be required to guarantee and service the solar equipment.
- Confidence that near-term technological gains will not render the solar plant immaturely obsolete.
- Adequate knowledge of solar resource availability over the life of the plant.
- Adequate cost/risk sharing programs.

To remove institutional roadblocks requires:

- Expeditionary licensing procedures
- Expeditionary rate-determination processes.

In order for the estimated 3-5 percent regional penetration to be achieved by the year 2000, the barriers listed above must be surmounted within the time frames shown in Figure 3.4-1. This figure indicates the earliest anticipated time for operation of the first generation of commercial size solar electric generating plants. This time schedule is: a) 1985-1988 for wind energy conversion; b) 1990-1993 for solar thermal; and c) 1994-1997 for photovoltaic plants.

Assumptions made in developing these time frames are: a) DOE program goals for operation of full-scale demonstration plants are achieved, b) at least one year of successful operation of demonstration plants has occurred, and c) licensing (or prelicensing) and construction of the first generation of utility orders meet the time frames shown. Another important assumption is that the plants be economically viable to the utility. For this to take place, the spread between the solar plant cost and their worth to the utilities (see Table 3.1-1) must be bridged.

This can be done by financial incentives, waiting for fuel escalation to increase conventional plant generation costs, and by unforeseen technical advancements that could improve solar electric generating plant economics. The time frame for fuel costs to escalate and the technology to advance to make solar economically competitive with conventional electric generating technologies is unknown but will probably not occur prior to the year 2000.

Site selection and licensing of solar electric generating plants are expected to take a minimum of 3 years for each technology if the present regulatory framework remains applicable. This is due primarily to the need to address the requirements of the National Environmental Policy Act (NEPA), including the collection of data for, and the preparation of, an environmental report for each project. Commercialization of solar electric generating plants could be accelerated by banking and prelicensing of prospective sites, resolving generic licensing issues, and combining federal and state licensing proceedings.

Utility participants indicated a preference for financial incentives such as low interest loans and certain tax devices since these mechanisms are well known to the electric utility industry and could be utilized in a more conventional manner than incentives designed specifically for a single purpose.

SOUTHWEST

Institutional arrangements which share costs and risks between the government and electric utilities were looked upon as the arrangements which could have the greatest positive impact on the commercialization of these facilities, particularly in the early stages. It was believed that the active involvement of the electric utility industry and solar equipment manufacturers with the Federal Government can best help remove uncertainties which constrain widespread use of this technology.

The support of political entities and leaders on national and regional levels will be a necessary prerequisite for the advancement of solar technology. Such support can manifest itself in the form of federal and state legislative action and/or the cooperation of rate setting authorities.

Legislative action could be taken to accelerate the commercialization process by funding continued support for research and development activities, authorizing increased funds for commercial scale demonstration plants, providing financial incentives on the state and federal levels, and revising and expediting the licensing process.

Electric utility rate setting authorities can make a positive contribution toward accelerating commercialization of solar electric generating plants by:

1. allowing a higher rate of return on invested capital associated with these plants than is allowed for conventional plants;
2. minimizing the duration from the time a utility applies for a revision of rates to reflect the inclusion of solar facilities in the rate base to the time when the regulatory authority approves said application;
3. permitting inclusion in the rate base of construction work in progress (CWIP) costs associated with solar electric generating plants; and
4. raising the level of recoverable funds which may be used for solar related RD&D activities.

Utilities can best aid in the acceleration process by actively participating in the development of solar programs. These include R&D activities; provision of demonstration plant sites and operating personnel; providing regulatory assistance; and, serving as a market for electricity generated by, and providing on-line evaluation of, these facilities.

In addition, public acceptance will play a major role in the advancement of solar electric generation. For this technology to receive widespread use, it must have the public's confidence. As a result, it is important that manufacturers, utilities, and government maintain an ongoing public relations program to keep the public aware of the costs, benefits, operating characteristics and environmental considerations of solar electric power generation. This effort should begin with the demonstration programs and continue throughout the commercialization process.

SOUTHWEST

TABLE 3.1-1

SOLAR ENERGY COSTS AND VALUES
IN 1977 DOLLARS

Concept	Storage Capacity (MWh)	Range of Plant Investment Costs ⁽¹⁾ (\$/kW)	Investment Value of This Concept to the Utility ⁽²⁾⁽⁵⁾ For 10 Percent Market Penetration					
			PSNM ⁽³⁾	SRP ⁽⁴⁾	ELP	SCE	PSC	APS
			(Values shown only where system was modeled.)					
Solar Thermal Central Receiver	0	1,470/2,240				620		
Solar Thermal Central Receiver	200	1,850/2,800	700	990	550	830	580	450
Solar Thermal Central Receiver	600	2,550/3,870		1,430	720	1,120	790	610
Photovoltaic	0	2,080/2,900		870		640		310
Photovoltaic	200	3,680/4,960						
Photovoltaic	600	5,640/7,620						
Wind Energy Conversion	0	920/1,230			20	320	260	
Wind Energy Conversion	10	1,330/1,810						
Wind Energy Conversion	30	1,610/2,160						
Retrofit Hybrid	-	1,040/1,740	730	480				

NOTES:

1. Plant investment costs shown are the range of low and high estimates established in Volume II modified to include average interest during construction (IDC) and owner's costs. All values are in 1977 dollars. No contingency funds are included.
2. Break-even investment values reflect values developed in Volume III (in 1985 dollars) revised to 1977 dollars.
3. Values for PSNM are based on 1 percent market penetration.
4. Values for SRP are based on 5 percent market penetration.
5. The difference between the investment value to the utility and the estimated investment cost is the incentive required to break even.

FIGURE 3.3-1
EFFECTS OF FUEL ESCALATION ON
SOLAR BREAK-EVEN INVESTMENT
SOLAR THERMAL-200 MWh STORAGE
PRIVATELY FINANCED UTILITIES

FIGURE 3.3-2
EFFECTS OF FUEL ESCALATION ON
SOLAR BREAK-EVEN INVESTMENT
SOLAR THERMAL-600MWh STORAGE
PRIVATELY FINANCED UTILITIES

SOUTHWEST PROJECT

LEGEND

CAPACITY REPLACEMENT CREDIT

FUEL REPLACEMENT CREDIT

OPERATION AND MAINTENANCE PENALTY

FIGURE 3.3-3
SOLAR BREAK-EVEN INVESTMENT
SOLAR THERMAL 200 MWh STORAGE

LEGEND

CAPACITY REPLACEMENT CREDIT

FUEL REPLACEMENT CREDIT

O & M PENALTY

FIGURE 3.3-4
SOLAR BREAK-EVEN INVESTMENT
SOLAR THERMAL 600 MWh STORAGE

FIGURE 3.4-1
TECHNICAL MATURITY OF CENTRAL STATION
SOLAR ELECTRIC GENERATING PLANTS

SECTION 4

THE STATE-OF-THE-ART OF
SOLAR ELECTRIC GENERATING PLANTS4.1 OBJECTIVE AND APPROACH OF THE
TECHNICAL STUDIES

The objective of the technical studies was to provide technical information on current or near-term state-of-the-art solar electric generating plant concepts and to evaluate representative plants from an electric utility viewpoint. Information was gathered on wind energy conversion, solar thermal electric, and solar photovoltaic electric generating systems, as well as associated energy storage facilities. The assessment established conceptual descriptions of solar electric generating plants and defined their possible application to the electric utility grid.

The selection of representative plants was based on the following criteria.

1. Acceptability to the utility grid
2. Projected technical feasibility
3. Environmental and social acceptability
4. Potential economic viability and commercial acceptance

It was recognized that solar energy conversion technology is presently in a dynamic state. The technical information included in the report reflected information available before March 1977, the deadline established for technical input to this study. It may be anticipated that major technology changes occurring after this date could have an impact upon the results of this study.

Conceptual plant descriptions were established based upon available technical information. They reflect an assessment of the information gathered on the state-of-the-art of solar energy conversion and energy storage equipment, utility industry background, experience of the study participants, consideration of the siting and climatological conditions typical of the Southwest, and viability of the selected concepts within the projected time frame of 1985-2000.

The solar electric generating plant ratings (100 MWe for the solar thermal and photovoltaic plants and 10.5 MWe for the wind energy conversion plant) were based on a module size which would be acceptable for integration into the generation

expansion plan of the smallest electric utility system to be modeled. Solar electric generating unit sizes are not directly comparable to traditionally - fueled unit sizes due to the variability of the solar energy sources with the resultant lower potential load factors and plant output. Energy storage concepts were selected and paired with chosen conversion technologies on the basis of compatibility of technology interfaces, viability during the selected time frame, and adaptability to potential site conditions.

The energy storage systems associated with each conceptual design were selected and sized to provide comparable energy storage capability for each concept. The potential availability of wind energy throughout the 24 hour daily cycle dictated sizing of the storage system for this concept at a capacity level capable of providing the average plant output (rated capability multiplied by capacity factor) throughout the daily cycle. This compared with the philosophy of sizing the storage system for those concepts requiring insolation at a value equivalent to the plant rated output over the selected time period.

Technical information was gathered and categorized utilizing a method which divided the plants into major subsystems and then further divided the subsystems into major components. This method was chosen to facilitate an analysis of the technical problems that needed to be addressed and resolved in order to accelerate the commercialization of solar electric generating plants.

Information was gathered for three basic wind energy conversion electric generating plant configurations identified by their rotor characteristics; i.e., horizontal shaft rotors, vertical shaft rotors, and vortex generators; two basic configurations of solar thermal electric generating plants; i.e., central receiver systems and distributed receiver systems; and on solar photovoltaic electric generating plants. In all cases, long-term energy storage for deferred electric power generation was determined to be technically feasible.

In addition to solar thermal electric generating plants which utilize solar energy exclusively, hybrid configurations have also been proposed employing

conventionally fueled thermal energy sources to augment the solar energy input. The solar facilities would be added to existing conventionally fueled power plants, thereby permitting more economical utilization of the existing generating facilities and eliminating the need for long term energy storage. Short-term storage to serve as a buffer against minor solar transients may still be required.

In conjunction with solar electric generating plants, four major categories of energy storage systems which could potentially have been used were evaluated. These categories are: mechanical, thermal, chemical, and electrical. Each of the various types of energy storage systems can be used for long- or short-term energy storage.

4.2 ESTABLISHMENT OF CONCEPTUAL DESIGNS

Conceptual plant descriptions were established for five representative solar electric generating plant concepts.

4.2.1 Wind Energy Conversion Electric Generating Plant

4.2.1.1 Design

The wind energy conversion electric generating plant (Figure 4.2-1) was designed to provide approximately 10.5 MWe of power at rated wind speed with either no storage or a 10 or 30 MWh battery storage subsystem. (See Section 3.1.1, Volume II.) The conceptual plant model utilized seven wind generators and consisted of a control building, maintenance building, switchyard, and, if energy storage was provided, a battery storage building with a separate switchyard. Each wind generator was a horizontal shaft, two-bladed, constant speed unit with a 180 foot diameter rotor (Figure 4.2-2). Each of the seven wind generators in the design was rated at 1.5 MWe at a wind speed of approximately 30 mph at the rotor hub height.

In general, at peak utility system load, the wind generator units will provide their entire power output directly to the grid (individual utility operations may vary). When energy storage is provided, the wind generator power plant control system will transfer the wind generators from the grid mode to storage mode to charge the batteries during off-peak load periods. Whenever the batteries are fully charged, wind generated power will be provided to the grid.

The wind plant consists of five major subsystems. The rotor subsystem includes the blades, variable pitch controls, and

hub of each wind generator. The drive subsystem includes a fixed ratio gear box, the mechanical portion of the rotor controls, pintle orientation mechanism, and parking brake/inching drive for each wind generator. The structural subsystem includes an approximately 130 foot high, steel truss structure mounted on a concrete foundation, the pintle (turntable), protective shrouding, and the hoist associated with each wind generator. The control subsystem consists of the necessary controls to supervise and record the parameters associated with the operation of the plant. The electrical subsystem consists of the generator and controls, protective relay equipment, main step-up transformer, lightning protection equipment, station service transformer, battery storage transformer, and emergency power supplies and switchyard equipment. Where required, an advanced lead-acid battery storage subsystem is provided for 10 or 30 MWh storage. The batteries are remotely located in a protected structure for safety reasons due to hydrogen gas that may be generated when charging lead acid batteries. Each of the wind generator units are separated from each other by a minimum of 0.5 mile, and are enclosed by a 100 x 100 foot, 6 foot high chain link fence for security purposes.

4.2.1.2 Operation

Operation of each wind generator will be initiated when the wind velocity at that specific generator reaches the wind cut-in speed of approximately 11 mph, the speed necessary to generate electrical power. At this speed, the control subsystem directs the pintle orientation mechanism to align the rotor axis with the wind and generated power is fed to the utility grid. When the wind velocity during normal operation decreases below the required minimum cut-in speed, the wind generator will begin to motor and the control system will disconnect the wind generator from the grid.

4.2.2 Solar Thermal Central Receiver Electric Generating Plant

4.2.2.1 Design

The 100 MWe solar thermal central receiver electric generating plant is designed to generate 100 MWe with zero, 200 MWh, or 600 MWh of energy storage and consists of a solar portion and the balance of the plant. The solar portion consists of four heliostat fields (Figure 4.2-3), each made up of two-axis tracking heliostats that reflect solar flux to an associated receiver-boiler mounted on top of a reinforced concrete tower. The receiver accepts feedwater from the feedwater

system and utilizes the solar energy to produce steam that can be used either directly to generate electrical power or to charge the thermal energy storage subsystem. The number of heliostats and the height of the receiver towers vary, from 12,880 and 768 feet to 22,420 and 948 feet, depending on the amount of associated storage.

The nominal rating (100 MWe) of the solar thermal central receiver electric generating plant is determined at the lowest typical noontime direct insolation at 32 degrees north latitude. The turbine generator is rated at 120 MWe (gross output) in order to utilize the highest peak hourly insolation expected during the year.

The solar thermal central receiver electric generating plant consists of three major equipment subsystems (four if energy storage is provided).

The collector subsystem has three major components: the collector fields, the computer controls, and the calibration arrays. The collector fields are four approximately circular fields of heliostats with a receiver tower located 1/2 radius south of the centerline of each field. Each heliostat consists of 430 square feet of spherical surfaced mirrors (Figure 4.2-4). A computer located in the control building is provided to compute the angle tracking information for the field heliostats and to position them as required.

The receiver subsystem consists of a solar receiver tower and the receiver (steam generator) for each collector field (Figure 4.2-5). The solar receiver tower is a hollow cylinder constructed of reinforced concrete and is designed to support the receiver assembly. The receiver mounted on the top transfers the energy reflected from the heliostats to the feedwater piped within, converting the water into superheated steam. The receiver is a recirculating drum boiler with a helical superheater and spray attenuator on the outlet side.

The energy storage subsystem is a two-stage sensible heat system utilizing rock and oil in the main stage and heat transfer salt (HTS) in the second stage. The HTS is Hitec, a eutectic mixture of inorganic salts, developed by DuPont Company. Two heat exchangers in series are provided to transfer energy between the receiver and the storage subsystem.

The balance-of-plant consists primarily of the electric power generation subsystem which includes the turbine generator and

its associated accessory equipment, feedwater heaters, and associated pumps, heat rejection equipment, and electrical equipment to provide electric output to the grid. The turbine is an industrial, non-reheat intermediate admission type and is rated at 120 MWe. The condenser is a conventional industrial unit and is water cooled. Circulating water is pumped through the condenser from and to a wet/dry cooling tower. The switchyard includes a main step-up transformer to interface between the utility grid and the plant.

4.2.2.2 Operation

Normal daily operation of the solar thermal central receiver plant will commence before sunrise. Weather forecasts will be examined, heliostats exercised, and the temperature of the feedwater and steam piping and equipment loops will be raised above residual levels. When the insolation levels reach the point where boiling occurs in the steam generator, the steam is introduced to the turbine and the generator synchronized with the utility grid to dispatch the available electrical energy.

4.2.3 Retrofit Hybrid Solar Thermal Electric Generating Plant

4.2.3.1 Design

The 100 MWe retrofit hybrid solar thermal electric generating plant concept entails the addition of solar-powered steam generating equipment to an existing, operating fossil-fired electric generating plant (Figure 4.2-6), thereby extending the commercial life of the fossil plant. The plant conceptual design involves the use of an existing 100 MWe oil/gas fired steam generator to supplement a central receiver solar thermal system. The initial solar thermal central receiver system design selected for evaluation in this study was based on eight 12.5 MWe solar modules, sized to provide sufficient steam to the existing turbine generator to generate 100 MWe. Upon evaluation, it was realized that the costs of this design were excessive and a decision was made to use a single tower design similar to that described in Section 4.2.2. The information contained in this report is based on this latter design. The sizing of the unit is established by selecting the lowest typical noontime direct insolation expected at 32 degrees north latitude. Each solar module consists of a field of two axis tracking heliostats which reflect and concentrate flux on a tower-mounted receiver (steam generator). The energy in the reflected solar flux is transferred in the receiver to the

feedwater to generate steam. The existing turbine extraction cycle remains unchanged. The design does not include any provision for long-term energy storage since steam generation can be supplemented or supplanted during insolation transients or solar plant outages by the fossil-fueled steam generator.

Each solar module of the retrofit hybrid plant consists of two major equipment subsystems. The collector subsystem has three major components: the heliostats, computer controls, and associated electrical equipment and wiring. Each heliostat (Figure 4.2-7) consists of nine rectangular flat mirrors with a total reflecting area of 400 square feet, and is capable of being driven in both elevation and azimuth by a pair of direct gear drive mechanisms. The controls of the collector subsystem consist of two basic control elements: a fine tracking system and an executive control system. The electrical equipment consists of transformers and electrical switchgear to supply electrical power from the plant's auxiliary power supply to each heliostat and to each receiver tower.

The receiver, tower, and fluid transport piping and pumps constitute the receiver subsystem. The receiver (Figure 4.2-8) consists of a receiver cavity and steam generator mounted on top of the receiver tower. The reflected solar energy is utilized in the steam generator to heat incoming feedwater to generate steam. Each tower is a reinforced concrete structure designed to support the receiver and its associated platform structure. The fluid transport piping and pumps deliver the feedwater to the steam generator from the discharge of the existing feedwater heaters, and the piping conducts the steam from the receiver superheater outlet to the main steam line of the turbine generator in the fossil-fueled plant. The existing feedwater heating and treatment facilities together with augmented pumping equipment are utilized for proper feedwater flow.

4.2.3.2 Operation

As the retrofit hybrid solar thermal electric generation plant involves the use of two diverse technologies to produce steam for use in a common turbine, the requirements of and implications to both technologies must be addressed when considering the operation of the plant. The plants are capable of operating in a solar-only mode, a solar-fossil mix mode, and fossil-only mode without adversely affecting turbine generator performance. In all of the modes, the existing turbine extraction cycle remains unchanged.

Condensate from the condenser is pumped through feedwater heaters in the existing plant and is then directed to the appropriate steam generator. Steam exiting the steam generator is piped to the common main steam header, desuperheated if necessary, and admitted to the turbine. During periods when the solar generator is out of service, the fossil-fueled steam generator may be used independently to drive the turbine generator.

Solar operation of the retrofit hybrid solar thermal electric generating plant commences when the sun elevation angle is approximately 10 degrees. The fossil-fueled steam generator is used to supply steam for warming, starting, and maintaining the balance of plant. When the reflected solar energy is sufficient to generate steam in the solar steam generator, the steam is directed to the turbine and the electricity produced is supplied to the grid.

4.2.4 Solar Photovoltaic Electric Generating Plant

4.2.4.1 Design

The 100 MWe solar photovoltaic electric generating plant is designed to generate 100 MWe with zero energy storage or with a 200 or 600 MWh energy storage subsystem (Figure 4.2-9). The solar photovoltaic electric generating plant uses fixed-tilt arrays of single crystal silicon cells to generate power. Inverters are used to convert dc electrical power to ac electrical power and transformers adjust the ac electrical voltage for transmission to the utility grid.

The nominal rating of a plant is based on selecting the lowest typical noontime total insolation at 32 degrees north latitude. The two major factors which affect the performance (i.e., output) of the photovoltaic arrays are the amount of available insolation and the ambient temperature. The amount of insolation received by a nontracking surface is a function of the position of the sun. The efficiency of the photovoltaic arrays is a function of the photovoltaic cell temperature.

The solar photovoltaic electric generating plant consists of five major subsystems. The photovoltaic array subsystem (Figure 4.2-10) consists of 4 inch diameter circular photovoltaic cell modules and the electrical connections between the modules of an array. Each array consists of 264 single crystal silicon photovoltaic cell modules. The array size is 4 x 8 feet and the arrays

are arranged edge-to-edge in rows of 400 feet. Each row is capable of generating approximately 25 kW.

The array support subsystem consists of the support frames for the photovoltaic arrays and the foundations for these support frames. The power conversion and control subsystem consists of the inverters and automatic control equipment necessary to invert direct current from the photovoltaic arrays and the storage batteries to alternating current.

The power wiring and electrical equipment subsystem consists of the in-plant transmission wiring and transformers. A main step-up transformer is provided in the main switchyard to transform the voltage to the utility grid voltage.

The energy storage subsystem consists of advanced lead acid storage batteries and rectifiers (chargers). The batteries are charged by converting the previously inverted ac power back to dc. Inversion to ac allows close control of array voltage without the use of expensive switching networks.

4.2.4.2 Operation

The photovoltaic arrays generate electricity at a constant voltage and at an electric current proportional to the incident amount of total insolation. Arrays dedicated to charging the battery storage subsystem are available to provide supplemental power to the grid when storage is fully charged.

4.2.5 Solar Thermal Distributed Receiver Electric Generating Plant

4.2.5.1 Design

The solar thermal distributed receiver electric generating plant is designed to generate 100 MWe with zero, 200, or 600 MWh of energy storage (Figure 4.2-11). The solar portion of the plant utilizes a fixed-mirror solar concentrator (FMSC) system. Each FMSC (Figure 4.2-12) consists of a fixed-mirror assembly which concentrates the insolation on a tracking receiver located within the assembly. A molten heat transfer salt (HTS) is pumped through the receiver assembly where it is heated by the solar energy. After being heated, the HTS is delivered to the shell side of the steam generator to heat feedwater to superheated steam. The steam is used to drive a non-reheat turbine generator to generate electrical power. The HTS can also be used to charge the thermal energy storage subsystem.

The balance-of-plant consists of the turbine generator, feedwater heaters, pumps, condenser, wet/dry cooling tower, and electrical equipment.

The nominal rating of a solar thermal distributed receiver electric generating plant is established by selecting the lowest typical noontime direct insolation at 32 degrees north latitude. The turbine generator is rated at 120 MWe in order to utilize the highest peak hourly insolation expected during the year.

The solar thermal distributed receiver electric generating plant consists of four major equipment subsystems (five if energy storage is provided). The collector subsystem is a fixed-mirror assembly consisting of an aboveground concave-shaped concrete base supporting rows of 600 feet long, 3 inch wide mirror slats. Each row of slats is fixed to the concrete base. The receiver subsystem consists of the solar receiver and the steam generator. The solar receiver is comprised of five side-by-side stainless steel tubes which run the length of each fixed mirror assembly. An HTS is conveyed through the tubes where it is heated by the insolation reflected and concentrated by the fixed-mirror assembly. As the sun elevation angle changes, a pair of reflected beam sensors transmit a signal to move the solar receiver along a circular arc above the fixed-mirror assembly.

The steam generator is a tube and shell heat exchanger in which steam is generated from feedwater on the shell side by absorbing energy from the HTS circulating through the tubes.

The heat transport subsystem consists of the HTS, piping, pumps, valves, insulation, controls, and electric heat tracing. The HTS is Hitec, a eutectic mixture of inorganic salts, developed by DuPont Company. The HTS is pumped into the "cold" end of the receiver and exits the "hot" end where it is transported to the tube side of the steam generator where the heat is transferred to the feedwater, thereby producing superheated steam.

The energy storage subsystem is a two-stage sensible heat system utilizing rock and oil in the main stage and HTS in the second stage. The HTS utilized in the storage subsystem is Hitec, the same eutectic mixture of inorganic salts used in the heat transport subsystem. Two heat exchangers are provided in series to transfer energy between the receiver and the storage system. Actual energy storage is accomplished in the HTS and oil/rock storage tanks.

The electric power generation subsystem consists of the turbine generator and its associated accessory equipment, feedwater heaters and associated pumps, heat rejection equipment, and electrical equipment to provide plant output compatible to the electric grid and to receive emergency power from the electric grid. The turbine is an industrial non-reheat intermediate admission type and is rated to accept steam generated by the highest peak hourly insolation level expected during the year. The condenser is a conventional industrial unit and is water cooled. Circulating water is pumped through the condenser to and from a wet/dry cooling tower.

4.2.5.2 Operation

Normal daily operation of the solar thermal distributed receiver power plant commences before sunrise. Weather forecasts are examined, auxiliary power is supplied to the receiver tracking control circuit and other essential plant auxiliaries, and feedwater circulation is started. When the amount of insolation is sufficient to generate steam, the steam is introduced to the turbine and the electric output supplied to the system.

4.3 EVALUATION OF ELECTRIC UTILITY INDUSTRY TECHNICAL REQUIREMENTS

4.3.1 Methodology

Each representative solar electric generating plant concept was reviewed independently and evaluated against current industry criteria in the following categories:

1. Engineering feasibility
2. Siting and environment
3. Procurement
4. Construction
5. Operability
6. Maintenance
7. Availability

The prime objective of this study was to define the utilities' technical requirements with respect to utilizing solar electric generating plants on their systems. By describing the utility considerations applicable to power plants in general and which could potentially apply to various representative solar plants, areas that may require further development to eliminate potential technical barriers to accelerated commercial introduction were identified.

Conceptual designs utilizing the largest size energy storage capability were chosen for review so that maximum land-use, component size, and system complexity

could be evaluated. Land use and water requirements for the various concepts are given on Table 4.1-1. If reduced energy storage is provided, the impact in these and other areas should be lessened.

4.3.2 Definition of Parameters

The parameters utilized as a basis of evaluation were chosen to ensure a uniform understanding and treatment of practices generally applicable to the electric utility industry and the technical requirements and considerations necessary to evaluate electric generating plants and associated facilities.

4.3.2.1 Engineering Feasibility

An evaluation of engineering feasibility of any new power plant design requires that the following information be considered.

1. Performance
2. Cost-effectiveness and service life
3. Ability of the design to meet regulatory requirements
4. Site and equipment arrangements
5. Design standards, codes, and safety considerations
6. Constructibility

4.3.2.2 Siting and Environment

Siting of a utility's electric generating facilities involves balancing site-specific engineering and economic evaluations with environmental, socioeconomic, institutional, and political factors.

4.3.2.3 Procurement

Awareness of the requirements of the electric utility industry's procurement cycle by present and potential suppliers of solar equipment and the taking of actions to address those requirements can serve to facilitate the commercialization process by furthering utility confidence in manufacturers and equipment.

4.3.2.4 Construction

Evaluation of the constructibility of any new power plant design must consider the following parameters.

1. Site preparation requirements

2. Special erection techniques, difficulties, equipment, and facilities
3. Type, quantity, and availability of construction materials required
4. Construction schedules
5. Manpower requirements
6. Transportation requirements

4.3.2.5 Operability and Control

The operation and control of a power plant are closely related to the method by which the plant's generated power is dispatched to the utility grid. The ability of a generating plant to respond to system transients, its load-following capability, its startup and shutdown times, and the incremental costs of generation are some of the factors which must be addressed.

4.3.2.6 Maintenance

The maintenance requirements of any type of electric generating plant necessitate that reliable information on the following parameters be available.

1. Maintenance schedules
2. Estimated repairs, type, and time required
3. Personnel requirements
4. Spare parts inventory
5. Type and quantity of maintenance materials
6. Special maintenance equipment and facilities

4.3.2.7 Availability

The reliability with which electric power is delivered by a solar electric generating plant is a function of both the availability of solar energy and the availability of plant equipment. The availability of insolation or wind is site specific and will require collection of meteorological and climatological data at the site. The availability of the plant can then be determined if mechanical performance data are developed for all the plant subsystems and components.

4.3.3 Results of Technical Analyses

4.3.3.1 Wind Energy Conversion Electric Generating Plants

The wind energy conversion electric generating plant was predicted to have minimal technical problems associated with commercialization efforts. It was suggested that some additional work is needed in the areas of identifying the potential for cost effective application of these plants in a utility system (they are primarily used for energy displacement rather than capacity displacement due to the variability of wind energy), the need for remote operation, and minimization of maintenance. It is not expected that this concept will have major adverse environmental impacts (other than the possible aesthetic impact of numerous 200 foot tall windmills spread across the countryside), require excessive construction activities, or present major maintenance or operational problems.

4.3.3.2 Solar Thermal Central Receiver Electric Generating Plants

A number of potential areas of concern were identified for the solar thermal central receiver electric generating plant. Additional work is necessary in the following areas: analyzing the effects of thermal cycling on the performance of the receiver; improving boiler feedwater quality; improving the design and construction of the receiver towers; increasing the capability of heliostat mirrors; expanding the experience of dealing with large scale utilization of heat transfer oils and salts; and the engineering design of the energy storage subsystem-turbine interface. Identified environmental concerns are the need to have a fairly large level site and the importance of site hydrology, as the plant design is predicated on the ability of thousands of heliostat foundations to remain fixed and level despite adverse environmental conditions. In addition, the aesthetic impact of four 750 to 950 foot tall towers located on a flat plain may prove to be unfavorable.

There appear to be no insurmountable obstacles associated with the construction of solar thermal central receiver electric generating plants although it may be necessary to relocate construction manpower to meet the peak manpower requirements (Table 4.3-1 presents manpower requirements for this and other concepts). Such dislocation of personnel brings with it a number of related socioeconomic problems such as potential overtaxing of existing facilities and increasing housing costs.

The effective operation and control of such a plant will be dependent upon the development of a detailed and timely weather forecasting system to provide extensive weather data. Such a system at present does not exist. In addition, it may be necessary to provide additional training for operating personnel due to the uniqueness of this concept on the utility's system. Maintenance requirements may be complicated by the need to schedule most normal maintenance during nighttime hours and the special attention which must be given to personnel access to particular areas during unit operation.

4.3.3.3 Retrofit Hybrid Solar Thermal Electric Generating Plants

The evaluation of the engineering and economic feasibility of the 100 MWe retrofit hybrid solar thermal electric generating plant, as initially conceived for this study, resulted in the conclusion that the estimated cost of the concept was higher than the cost of the base 100 MWe central receiver solar thermal electric generating plant even though the hybrid plant did not require the purchase of power plant equipment associated with the fossil-fueled plant. It was, therefore, concluded that the number of receiver towers associated with the solar retrofit of an existing fossil-fired electric generating plant should be kept to a minimum, preferably one receiver tower specifically sized for the optimal economic operation of the solar-fossil hybrid plant at the selected site. It was also determined that the concept of supplying a single turbine simultaneously with steam from separate solar-fired and fossil-fired boilers should be further investigated to give increased assurance of its potential viability. Another identified area of concern was the need to have approximately 800 acres of relatively flat land immediately adjacent to an existing fossil-fired plant.

Construction requirements and considerations for a retrofit hybrid configuration are similar to those delineated for a solar thermal central receiver plant except for the fact that there may be some advantages to constructing such a system adjacent to an existing power plant site owing to the potential use of existing facilities.

In the areas of operability and control, it was determined that the need for accurate and timely weather data will be necessary, as it is for the central receiver plant. In addition, it will be necessary to develop control logic for the interaction of the two diverse boilers as

they both will supply steam to a common header where it will be directed to the existing turbine. The introduction of solar conversion systems to an existing station and utility system could present unique situations beyond the realm of the stations and/or the utility's previous experience. This may require additional training of personnel.

In the areas of maintenance and availability, it was expected that no major problems would be encountered other than those identified for the solar thermal electric generating plant.

4.3.3.4 Solar Photovoltaic Electric Generating Plants

A review of the solar photovoltaic electric generating plant concept resulted in the determination that there are a number of major areas requiring further study. A long life cost-effective encapsulant should be developed and demonstrated since the principal cause of cell failure appears to be due to encapsulant degradation. Furthermore, it is not clear that the required large quantities of photovoltaic cells will be available in the time frame of interest (1985-2000) as the 1977 total annual production capability of photovoltaic cells in the United States is only adequate to generate 1 MWe. Additionally, present methods available for the charging of the storage batteries from photovoltaic cells are inefficient resulting in comparatively high system losses. The need to maintain the batteries at 77 F to meet the design temperature required for a 2,000 cycle battery life is also a drawback.

In the siting and environmental areas, the 100 MWe solar photovoltaic electric generating plant requires a somewhat larger area than that required by the other concepts. The number of foundations needed to support the photovoltaic arrays and their associated cost make the foundation design a major economic consideration in site selection. Site soil conditions which permit a simplified foundation design could result in significant cost savings.

There appear to be no insurmountable obstacles associated with the construction of a solar photovoltaic electric generating plant. The number of workers required for this concept can be varied, depending upon the elapsed time chosen for the construction of the plant, which will alleviate any problems associated with inadequate labor forces. The modularity of this concept presents certain construction advantages such as the

expected improvement in construction efficiency as workmen become more familiar with installation techniques. In addition, site preparation is not as difficult for this type of plant as it is for a solar thermal plant as the alignment and aiming of the photovoltaic arrays is not as critical.

The operation of a solar photovoltaic electric generating plant would benefit from the development and utilization of a detailed weather forecasting system similar to that required for the other solar concepts. The operation of the plant and energy storage subsystem should be highly automated to minimize the number of personnel required during operation. The power output of the solar photovoltaic electric generating plant may vary continuously in accordance with insolation transients. This could cause difficulties in dispatching the plant's output. It may, therefore, be necessary to use an energy storage system to serve as a buffer to stabilize the plant output for discharge to the utility grid.

In the maintenance area, the modularity of these plants will permit damaged sections to be isolated, replaced, and repaired during normal working hours without affecting the output of the rest of the plant. The large quantity of batteries required virtually mandates the automation of all continuous maintenance and testing activities. Scheduled replacement of batteries may prove to be the major maintenance item and electric utilities may choose to sign long-term contracts with suppliers to replace the batteries on a regular schedule.

4.3.3.5 Solar Thermal Distributed Receiver Electric Generating Plants

The 100 MWe solar thermal distributed receiver electric generating plant will require additional experience with the manufacturing and installation of collector-receivers as the cost for this subsystem accounts for nearly 80 percent of the estimated plant cost. In addition to the need to reduce the cost associated with this subsystem, it must be demonstrated that a collector-receiver subsystem will be capable of generating steam at the temperatures required by conventional electric utility steam turbines. The ability to reach and sustain high temperatures should be proven as should the continued satisfactory operation of the receiver pipings' flexible and swivel joints under these conditions. The potential for fouling and corrosion of energy storage components as well as the need to develop improved heat

transfer salts are two other areas requiring additional work.

In the siting and environmental areas, the solar thermal distributed receiver electric generating base plant will have somewhat larger cooling water requirements during operation than that needed for other concepts, and the large quantities of concrete associated with the receiver foundations will, in turn, require large quantities of water during the construction phase.

There appear to be no insurmountable obstacles associated with the construction of a solar thermal distributed receiver electric generating plant although it can be expected that because of the large peak manpower requirement there may be a need to attract workers from outside the immediate area. Each of the fixed-mirror solar concentrators must be uniformly supported along its entire 600 foot length which will necessitate an extensive foundation design. In addition, there may be some difficulty with the initial alignment and control of differential settling along the 600 foot long collector-receiver rows.

It is expected that the operability and control, maintenance, and availability of distributed receiver plants will present problems and solutions similar to those encountered with the solar thermal central receiver electric generating plants as previously discussed.

4.4 CAPITAL INVESTMENT AND OPERATION AND MAINTENANCE COSTS OF SOLAR UNITS

4.4.1 Methodology and Assumptions

One of the goals of this study was to develop information on the estimated capital investment and O&M costs of solar electric generating plants to serve as a basis for modeling and incorporating solar electric plants into electric utility system generation expansion plans. The cost estimates for the solar electric generating plants were prepared using estimating practices which are normal for the electric utility industry except for those deviations indicated below.

Recognizing the dynamic nature of solar technology and the growth of associated manufacturing and service industries, it was assumed that the capital investment and O&M costs of the components and subsystems of the developing solar technologies would be reduced from present levels as a result of increased production and use. Two different methodologies were used to determine the amount of expected cost reduction. One method utilized

results of engineering evaluations of solar equipment development projections of future costs of present state-of-the-art components and subsystems. The other method utilized available DOE cost goals for the components and subsystems as input to the investment model, thereby permitting an analysis of the potential impact of these goals on the commercialization of solar electric generating plants.

IDC and owner's costs, two items which are normally part of a plant's capital investment cost, were not included in these cost estimates as they vary for each electric utility. Estimates of these costs were, however, included with the other utility-specific inputs needed for the generation expansion plans. Contingency funds, an item which is normally part of a plant's estimated capital investment cost, was neither included in these calculations nor added as a utility-specific input.

The capital investment costs, in 1977 dollars, were estimated for each of the five conceptual representative solar electric generating plants. The cost estimate for each plant included the estimated capital investment cost of the base plant with nominal 0, 2, and 6 hours of energy storage. Each capital investment cost estimate included the total direct cost of the plant, the distributable cost, the indirect cost, the spare parts cost associated with the plant, and an allowance for miscellaneous additional costs not otherwise included.

A cost breakdown structure in accordance with the Federal Energy Regulatory Commission (FERC), formerly the Federal Power Commission, accounting system, as modified for solar plants, was established and account numbers assigned for the various solar electric generating plant subsystems. Current cost of major conventional electric generating plant equipment, such as turbine generators, wet/dry cooling towers, condensers, and pumps, were obtained from equipment manufacturers. The material and labor cost for other conventional power plant components and activities such as piping, valves, wiring, motors, buildings, foundations, etc, were based on recent experience with the purchase and installation of these components in the Southwest.

The estimated cost of the components and subsystems associated with the solar portions of the plants such as heliostats, receivers, wind generators, etc, was based on an engineering evaluation of the cost of the components projected by solar

equipment developers. The engineering evaluation involved determining the cost of fabrication materials and installation labor, and the potential for cost reduction.

The DOE cost goals for the solar components and subsystems were determined from a literature search and contacts with DOE solar program personnel. In those situations where cost goals deviated significantly from the range of estimated costs, the goal values were used to establish an alternate estimated plant cost to serve as an additional factor in the utility system generating expansion plans.

4.4.2 Discussion of Capital Investment Costs

A tabulation of the estimated range of the capital investment and O&M costs of the concepts evaluated is shown in Table 4.4-1.

4.4.2.1 Wind Energy Conversion Electric Generating Plants

A review of the capital investment cost estimate for the 10.5 MWe wind energy conversion electric generating plant showed that a significant portion of a plant's total direct costs are attributable to the wind generator components, including the tower and the energy storage subsystem. As indicated above, costs were estimated based on previously published studies. There was no published indication of a specific DOE cost goal for a wind energy conversion system of the size considered in this study. However, the range of costs estimated was believed to be sufficiently optimistic so as to encompass any goals which DOE may establish in the near future.

4.4.2.2 Solar Thermal Central Receiver Electric Generating Plants

The capital investment cost estimate for the solar thermal central receiver electric generating plant indicates that the collector-receiver and energy storage subsystem contribute a significant portion of the plant's total direct cost. The estimated cost of yard work and field wiring equipment and controls are necessarily higher than would be expected for a conventional power plant due to the larger amount of land required. The boiler plant balance of plant, turbine plant, and the accessory electric equipment result in costs similar to those of conventional electric generating plants.

Due to the uncertainties associated with the developmental status of the heliostats and receivers, a range of estimated costs for these components was developed. Similar methodology was used to develop the costs for the complete energy storage subsystem (oil/rock storage tank, Hitec storage tanks, heat exchangers, preheaters, oil maintenance systems, controls, piping, valves, pumps, and maintenance equipment).

There was no current published indication of a specific DOE cost goal for a commercial solar thermal central receiver electric generating plant of the size considered in this study. Conversations with DOE staff revealed that there is a cost goal of \$7 per square foot of installed heliostats. Since the range of estimated costs for the heliostats encompasses this cost, an alternate cost estimate was not prepared.

4.4.2.3 Retrofit Hybrid Electric Generating Plants

A capital investment cost estimate was prepared for the retrofit hybrid electric generating plant utilizing a design which reflects a solar collector system similar to that of the solar thermal central receiver electric generating plant. The cost estimate for the plant design was performed by modifying the detailed breakdown of cost for the solar thermal central receiver electric generating plant by revising downward the cost estimate for the yard work, buildings, and boiler plant balance of plant accounts to reflect those components which are in existence as part of the conventional electric generating plant. The field wiring equipment and controls account was increased by adding 20 percent to account for interfacing with the existing boiler and turbine controls.

4.4.2.4 Solar Photovoltaic Electric Generating Plants

A review of the capital investment cost estimates for solar photovoltaic electric generating plants indicates that the photovoltaic arrays support structure, photovoltaic equipment, and energy storage subsystem accounts are a significant portion of the plant total direct cost. The yard work and buildings accounts reflect the extensive site area requirements. The field wiring, equipment and controls, and the inverter accounts reflect the cost of conditioning and transmitting the generated electric power. The cost of the photovoltaic array support structure is a major contributor to the overall cost of a commercial size solar photovoltaic electric generating plant. Although it is felt that the cost of the

photovoltaic support structure has been significantly underestimated in other reports due to faulty assumptions, the estimates contained herein are considered more accurate as they are based on the cost of materials and the erection techniques used in installing large quantities of galvanized steel frame structures, and these techniques are considered to be quite conventional.

Due to the uncertainties associated with the developmental status of the photovoltaic arrays and the electric storage battery systems, a range of estimates was developed for both these accounts.

The DOE national photovoltaic programs far-term cost goal is to achieve a photovoltaic flat plate module or concentrator array price of \$100 to \$300 per peak kilowatt in 1990 (1975 dollars). This cost range was not assumed as being representative of state-of-the-art photovoltaic equipment since its achievement could only result from an as-yet undefined technical breakthrough. However, a portion of the utility system modeling effort was performed utilizing a conceptual plant cost based upon the DOE cost goal and similar assumptions to those used in developing the capital costs shown in Table 4.4-1.

4.4.2.5 Solar Thermal Distributed Receiver Electric Generating Plants

The collector-receiver account contributes roughly 82 percent of the total direct cost of the solar thermal distributed receiver electric generating plant. The cost estimate for this account includes the material and installation cost of concrete bases for the collectors, foundations, mirrors, receivers, drives and controls. The participants were of the opinion that existing cost estimates for the components of this account were not realistic and, therefore, an independent effort to assess these costs was undertaken.

There was no published indication of any specific DOE cost goal for a commercial utility size solar thermal distributor receiver electric generating plant and no information concerning a realistic goal for the collector-receiver subsystem could be obtained. Therefore, an alternate cost estimate was not prepared for this concept.

4.4.3 Discussion of O&M Costs

Estimates of the expected monthly O&M costs for each of the five conceptual

solar electric generating plants were made by the six electric utilities whose systems were modeled. The results, which are also found in Table 4.4-1, are in 1977 dollars and reflect the range of values reported by the six utilities. The O&M cost estimates were prepared by identifying the manpower requirements associated with these activities and the total monthly wages, plus associated overhead costs, were then calculated by each of the utilities. The overhead costs were determined by applying percentages of the employees' wages to reflect paid absences, home office expenses, fringe benefits, and consumable materials and supplies. In so doing, the normal monthly O&M costs are recognized to be directly related to the total monthly wages for the O&M personnel.

The estimated monthly O&M costs for the wind energy conversion electric generating plant were based on the design philosophy of remote operation of the wind generator and routine inspection of equipment, calibration of instruments, and lubrication of components by a roving maintenance crew. Major maintenance activities would require the assignment of additional personnel.

The estimated total O&M costs for solar thermal central receiver electric generating plants and solar thermal distributed receiver electric generating plants assumed the permanent assignment of a complete complement of O&M personnel to each plant. These costs were based on the electric utilities experience with similar size conventional steam-electric generating plants.

The estimated total monthly O&M costs for the retrofit hybrid solar thermal electric generating plant assumed the permanent assignment of a complete complement of personnel to each retrofit hybrid plant, and were based on the O&M activities associated with both the conventional and solar portions of the plant.

The estimated total monthly O&M costs for the solar photovoltaic electric generating plant assumed the permanent assignment of a complete complement of O&M personnel to each plant, and were based on the electric utilities experience with similar electric equipment, such as switchgear, inverters, rectifiers, transformers, breakers, and storage batteries.

4.5 COST OF REPRESENTATIVE CONVENTIONAL ELECTRIC GENERATING PLANTS

4.5.1 Methodology and Assumptions

One objective of this study was to calculate the investment costs for conventional fossil and nuclear electric generating plants as a common base input for the computer-run electric utility system generation expansion plans. There are no generally applicable industry-wide cost curves for electric generating plants because the investment costs are subject to many influences that reflect variations in design and construction as the result of specific site and utility requirements. To properly address these variations, a two-component cost model for conventional electric generating plants was developed. The two components of the model are the base cost of conventional nuclear and fossil fueled electric power generating plants with chosen common design parameters and cost adders or multipliers to permit adjustment of the base cost to reflect variations in the common design parameters.

4.5.2 Results

A series of curves was developed and presented in Volume II based on historical cost data and cost estimates related to current design and construction projects. Base case parameters selected for all applicable concepts are a once-through cooling water system for condensing the steam turbine exhaust, average site preparation complexity, and present day (1977) cost. As noted earlier, cost per kilowatt of capacity is not a totally adequate indication of the comparative value of different technologies due to the variation in potential load factors associated with each technology and the inclusion and exclusion of different parameters in the various cost estimates.

The base investment cost of the various types of conventional electric generating plants considered can be adjusted to reflect variations in design and construction conditions which occur as the result of specific site and utility requirements. These adjustments are as follows.

1. A value of 0.2g ground acceleration was chosen as the common seismic design parameter for determining the base cost of the plant. Where requirements exceed this base value, factors were provided to increase the base cost of any of the conventional electric generating plants.

SOUTHWEST

2. Cost data were provided to increase the investment cost of plants having cooling methods other than the base case once-through, saltwater cooling system.
3. In situations where high sulfur content fuel is utilized and/or scrubbers are mandated by regulatory requirements, a cost increment based on using a throwaway limestone type scrubber with sludge stabilization was established.
4. The base case investment costs assume average water treatment requirements. Any proposed site having poor quality well water and/or requiring impoundment of water treatment wastes would require an added cost which was provided.
5. The investment cost of the first electric generating unit installed at any site which will eventually have multiple units is usually more than the later units since it bears the cost burden of initial site preparation and development of fuel storage, fuel handling, and main switchyard facilities. The cost increment associated with being the first unit at a site was provided.
6. The cost of designing and constructing an electric generating plant normally includes expenses associated with review and supervision of contractors, land costs, site insurance, security, etc, directly incurred by the utility owner. The cost multiplier selected by each utility to identify its "owner's cost" reflects experience with the various types of conventional electric generating plants. A range of multipliers was provided in the study although it would be up to each individual utility to select the multiplier deemed appropriate for its system.
7. IDC is the cost to a utility of borrowing capital to pay for the facility during construction activities. It was assumed that these costs could vary from 8 to 13 percent of the plant costs per year, at simple interest, depending on the financial position of the utility involved and the availability of funds in the financial marketplace. Here again, the specific value used would be dependent upon the individual utility.
8. Escalation reflects the rising cost of material and labor expected from the present day (1977) to the date when 60 percent of the assumed construction period is reached. A value of 6 percent compounded annually was chosen as the escalation rate for all cost estimates. (It should be noted that although the use of this value appears, based on recent history, to be overly optimistic, historical data over extended periods of time indicate its probable applicability.) The impact of this value would be dependent upon the length of time expected between the present day and the achievement of the escalation end-point for each specific facility.

SOUTHWEST

TABLE 4.1-1

LAND AND WATER USE REQUIREMENTS

<u>Concept</u>	<u>Associated Energy Storage (MWh)</u>	<u>Land Requirements (acres)</u>	<u>Water⁽¹⁾ Requirements (acre-ft per year)</u>
Wind ⁽²⁾	0	785	(3)
Wind ⁽²⁾	10	785	(3)
Wind ⁽²⁾	30	785	1.6
Solar Thermal Central Receiver	0	598	(3)
Solar Thermal Central Receiver	200	742	(3)
Solar Thermal Central Receiver	600	1,032	130
Photovoltaic	0	1,010	(3)
Photovoltaic	200	1,370	(3)
Photovoltaic	600	1,980	7
Solar Thermal Distributed Receiver	0	440	(3)
Solar Thermal Distributed Receiver	200	550	(3)
Solar Thermal Distributed Receiver	600	827	130
Retrofit Hybrid	-	620	5 ⁽⁴⁾

NOTES:

1. Water requirements reflect the use of 90/10 dry/wet cooling towers and the storage and reuse of water for maintenance activities.
2. Wind generating plant parameters are based on 10.5 MWe nominal rating. All others are based on 100 MWe nominal ratings.
3. Not calculated.
4. Additional water beyond that presently required for fossil facility.

FIGURE 4.2-1
10.5-MWe WIND ENERGY CONVERSION
ELECTRIC GENERATING PLANT

FIGURE 4.2 - 2
CONCEPT OF A
WIND ENERGY CONVERSION
ELECTRIC GENERATING PLANT
(HORIZONTAL AXIS ROTOR)

FIGURE 4.2-3
100-MWe SOLAR THERMAL
CENTRAL RECEIVER
ELECTRIC GENERATING PLANT

SOUTHWEST PROJECT

FIGURE 4.2-4
HELIOSTAT FOR CENTRAL
RECEIVER SOLAR THERMAL
ELECTRIC GENERATING PLANT

EXTERNAL
CONFIGURATION

INTERNAL
CONFIGURATION

FIGURE 4.2-5
RECEIVER FOR CENTRAL
RECEIVER SOLAR THERMAL
ELECTRIC GENERATING PLANT

FIGURE 4.2-6

100-MWe RETROFIT HYBRID
SOLAR THERMAL ELECTRIC
GENERATING PLANT

SOUTHWEST PROJECT

FIGURE 4.2-7
HELIOSTAT FOR CENTRAL
RECEIVER SOLAR THERMAL
ELECTRIC GENERATING PLANT

EXTERNAL
CONFIGURATION

FRONT
ELEVATION

FIGURE 4.2-8
RECEIVER FOR CENTRAL
RECEIVER SOLAR THERMAL
ELECTRIC GENERATING PLANT

Sandia Labs Concept

FIGURE 4.2-9
CONCEPT OF A
SOLAR PHOTOVOLTAIC
ELECTRIC GENERATING PLANT

SOUTHWEST PROJECT

CELL DESIGN

CELL

(FIBERGLASS PANEL BACKING;
SILICONE RUBBER ENCAPSULATION,
HEX PATTERN)

ARRAY

FIGURE 4.2-10
SILICON SOLAR CELL

FIGURE 4.2-II
CONCEPT OF A
DISTRIBUTED RECEIVER
SOLAR THERMAL
ELECTRIC GENERATING PLANT

SOUTHWEST PROJECT

FIGURE 4.2-12
CONCENTRATING COLLECTORS FOR
DISTRIBUTED RECEIVER SOLAR THERMAL
ELECTRIC GENERATING PLANT

SOUTHWEST

TABLE 4.3-1

ANTICIPATED CONSTRUCTION WORK FORCE REQUIREMENTS

<u>Concept</u>	<u>Associated Storage (MWh)</u>	<u>Construction Period (Months)</u>	<u>Peak Construction Work Force Requirements</u>	<u>Duration at Peak (Months)</u>
Wind ⁽¹⁾	30	26	125	12
Solar Thermal Central Receiver	600	42	2,500	21
Retrofit Hybrid	-	36	1,000	24
Photovoltaic ⁽²⁾	600	42	2,100	24
Photovoltaic ⁽²⁾	600	48	1,500	36
Photovoltaic ⁽²⁾	600	80	900	68
Solar Thermal Dis- tributed Receiver	600	48	1,600	30

NOTES:

1. Wind generation parameters based on nominal rating of 10.5 MWe. All other parameters based on nominal rating of 100 MWe.
2. Construction period of photovoltaic plants may be varied as desired with resultant variations in peak construction work force.

SOUTHWEST

TABLE 4.4-1

CAPITAL INVESTMENT AND O&M COSTS OF
SOLAR GENERATING FACILITIES
(1977 DOLLARS)

<u>Concept</u>	<u>Storage Capacity (MWh)</u>	<u>Capital Cost Estimate (\$/kW) (1)</u>	<u>Monthly O&M Costs (\$)</u>
Wind Energy Conversion(2)	0	856/1,153	29,000/ 45,000
Wind Energy Conversion(2)	10	1,225/1,667	30,000/ 45,000
Wind Energy Conversion(2)	30	1,463/1,964	30,000/ 45,000
Solar Thermal Central Receiver	0	1,376/2,094	184,000/248,000
Solar Thermal Central Receiver	200	1,719/2,596	193,000/258,000
Solar Thermal Central Receiver	600	2,355/3,576	207,000/272,000
Retrofit Hybrid	-	969/1,629	196,000/265,000(3)
Photovoltaic	0	1,942/2,714	64,000/ 87,000
Photovoltaic	200	3,413/4,607	74,000/100,000
Photovoltaic	600	5,214/7,035	89,000/118,000
Solar Thermal Distributed Receiver	0	3,207/4,376	165,000/222,000
Solar Thermal Distributed Receiver	200	4,366/5,926	170,000/227,000
Solar Thermal Distributed Receiver	600	6,531/8,856	174,000/229,000

NOTES:

1. Figures represent the range of estimated costs and do not include IDC, owner's costs, and contingency funding as is indicated in Section 4.4-1.
2. O&M costs associated with wind energy conversion are for a plant nominal rating of 10.5 MWe. All other O&M costs are based on plants with nominal rating of 100 MWe.
3. Costs shown reflect operation and maintenance (material and personnel) of the combined existing fossil and add-on solar plant.

SECTION 5

SYSTEM INTEGRATION STUDIES

5.1 INTRODUCTION

5.1.1 Purpose

The purpose of the system integration studies conducted as part of this project was to establish the investment that utilities could afford to make in solar thermal, photovoltaic, and wind energy systems and to assess the sensitivity of the break-even cost to changes in critical parameters including fuel escalation rates, fixed charge rates, reliability criteria, land, growth rate, cloud cover, wind calms, number of sites, load shape, and energy storage. The results were used as input to the institutional studies discussed in Section 6.

5.1.2 Methodology and Assumptions

The performance of these studies entailed the establishment of long range system generation expansion plans including only traditional technologies for six representative utilities in the Southwest, and then developing and utilizing computer models to analyze the implications of including solar power plants in the planned generation mix. A variety of economic analyses were then performed and the developed information was utilized in combination with established characteristics of the utilities involved to develop expansion plans which include solar generation for each specific utility system. Finally, these latter expansion plans were analyzed. The addition of solar technology to utility systems was not done in an optimal manner, and is intended to show relative values only. The utilities analyzed in this portion of the study and the concepts evaluated for each are shown in Table 5.1-1.

The base case expansion plans which were supplied by the utilities were the actual plans when the data for this project were developed. It must, however, be emphasized that "actual" system expansion plans are constantly changing as new information becomes available and the plans included here reflect the conditions in existence only at a single specific point in time.

By including specific systems in the analyses, certain practical aspects of the problems of integrating solar generation into utility expansion plans are identified that would otherwise be missed in a hypothetical study. These aspects include the impact of regulatory

restrictions and the desire to vary the types of generation to limit the risks associated with dependence on a single primary fuel.

Once the base case expansion plans were established, it was necessary to determine the elements of expense over the study period on a consistent basis for all six utilities. Comparisons could then be made between the base case plans and plans including solar generation and between various utilities. These expense elements include fixed charges on investment, fuel costs, and O&M expenses.

The most complex part of this analysis is the fuel dispatch simulation which is used to determine the fuel cost component of annual expense. For this purpose, a proprietary computer program PROMOD III, developed and owned by Energy Management Associates (EMA) of Atlanta, Georgia, was used. Each utility supplied detailed data on load shape, load forecast, unit heat rates, fuel costs, O&M costs, forced outage rates, maintenance schedules, etc, as input to PROMOD III. The annual O&M cost of conventional generation was estimated to be approximately 1 percent of the capital investment cost. The annual fuel costs were taken directly from PROMOD III fuel cost simulations; then a utility leveled fixed charge rate was used to develop a capital recovery factor which was in turn used to indicate the present worth of the annual fuel charges.

Evaluation of solar generating units is more complicated than analysis of conventional units because of hourly and seasonal variations in solar generating capacity due to predictable variations in solar insolation and less predictable changes in weather conditions. However, this disadvantage can be partially offset by the reasonable assumption that solar generation can be dispatched without consideration of the heat rate and fuel cost characteristics of other units on the system since solar units should always be in operation when environmental conditions permit. This assumption allows the problem to be segregated into two independent phases, one being the problem of determining the hour-by-hour solar generation and adjusting the load to be supplied by the remaining units, and the second being the application of standard dispatch procedures to allocate the remaining load to conventional generation.

Three computer programs were developed to perform the analysis required in Phase 1 and PROMOD was used for Phase 2.

The PROMOD III program performs the conventional unit dispatch using a probabilistic dispatch technique which is known as the Booth-Baleriaux simulation. Basically the units are loaded according to weekly load duration curves, which take into account the probability that units will be forced out of service, an action which has the effect of increasing loading on units with higher incremental cost of generation. Planned maintenance is also considered in the evaluations.

Two programs, Weather Tape Processor (WTP) and Run-of-the-Sun-Power- Availability-Model (ROSPAM), convert hourly weather data, insolation levels, and solar plant characteristics into hour-by-hour energy available for supplying electric power to the grid or for storage. This calculation is performed for a day considered typical for each given month.

WTP edits Aerospace Corporation weather tapes for a given location to extract hourly data on temperature, wind speed, direct and total insolation, etc, and converts this information to ROSPAM input. ROSPAM models three solar generator types - solar thermal, photovoltaic, and wind energy systems - in accordance with the specific conceptual details delineated in Section 3.2. Direct insolation data were used for solar thermal plants and total insolation data were used for photovoltaic plants. In addition to these programs, a Load Adjustment Model (LAM) was developed by EMA for this project. This model performs two basic functions. It uses power availability curves, supplied by ROSPAM, and system hourly load data for a typical week to dispatch storage associated with the solar generation, and it develops a new hourly load curve by computing the expected solar generation and subtracting it from the conventional hourly load curve. The flow of information from one program to the next is illustrated on Figure 5.1-1.

The output of LAM is converted to a weekly curve which is provided to PROMOD III where a probabilistic fuel cost simulation determines the loading on conventional units and the reliability of the system. The reliability of the system with solar generation was compared with the reliability of the system without solar generation and the result was a less reliable system. It was then possible to reduce the amount of conventional generating capacity in the base case plan until the resulting system reliability matched the base case value. To

accomplish the reduction in generation, only capacity installed after 1985 was considered for replacement. Of this capacity, hydroelectric and geothermal were generally exempted, leaving nuclear, coal, and oil-fired capacity to be replaced by new solar generation. For four utilities, only coal and oil-fired capacity was replaced by solar. The conventional units were derated proportionately to achieve the target level of reliability, and the investment in conventional capacity removed in this manner was defined as replacement value of the added solar capacity.

Once the conventional units were derated, PROMOD III was used to dispatch the conventional generation to supply the adjusted load curve. The resulting system generation and fuel expense was then subtracted from the generation and fuel cost of the base case to produce solar generator MWh and fuel savings.

The methodology utilized for the economic analyses used in the system integration studies is either consistent with or extracted directly from the publication, Cost of Energy Utility Owned Solar Electric Systems - A Required Revenue Methodology for ERDA/EPRI Evaluations, prepared by Jet Propulsion Laboratory.

Two approaches were used to compare solar technologies with conventional generation. One was based on a 15 year (1985-2000) expansion plan including the effects of the plan for a 20-year period beyond the plans termination point. The other was based on a 1 year analysis for the year 2000 with fuel and O&M costs levelized over 20 years. Although it may be argued that the life cycle of a solar plant may exceed 20 years, it should be remembered that technological advances may cause early obsolescence of first generation facilities, and that the present worth of fuel savings beyond the 20-year time frame is of little real economic value in these studies.

Levelized fixed charge rates were used to compute the annual cost of investment by multiplying the investment by the fixed charge rate. Fixed charges on the investment are directly comparable to other annual expenses such as fuel costs and can be "capitalized" by dividing the annual cost by the levelized fixed charge rate to produce an equivalent investment that would generate annual fixed charges equal to the annual expense.

Fuel escalation is the variable to which the value of solar generation is most

sensitive. Each participating utility specified an expected 1985 fuel cost and an expected escalation rate for each fuel type in the base case expansion plans. Fuel escalation rates varied from 4-8 percent as shown in Table 5.1-2. In the sensitivity studies, the effect of varying fuel escalation rates over a range of 6-10 percent was investigated for each utility in order to demonstrate the effect of fuel escalation on the break-even investment in solar generation.

5.1.3 Discussion of Results

The results of the utility system integration studies were a determination of the break-even investment cost between solar thermal, photovoltaic, and wind energy systems on one hand and conventional generating capacity on the other hand, and the sensitivity of these values to fuel escalation, accelerated depreciation, investment tax credit, and cost of debt. In-depth discussions of the results of these studies and the impact on the institutional aspects of this project can be found in Section 6.

SOUTHWEST

TABLE 5.1-1

UTILITIES/CONCEPTS STUDIED

<u>Concept</u>	<u>Storage Capacity (MWh)</u>	<u>Utility</u>					
		<u>PSNM</u>	<u>SRP</u>	<u>ELP</u>	<u>SCE</u>	<u>PSC</u>	<u>APS</u>
Solar Thermal Central Receiver	0				X		
Solar Thermal Central Receiver	200	X	X	X	X	X	X
Solar Thermal Central Receiver	600		X	X	X	X	X
Photovoltaic	0		X		X		X
Wind Energy Conversion	0			X	X	X	
Wind Energy Conversion	10				X		
Retrofit Hybrid	-	X	X		X		

SOUTHWEST

TABLE 5.1-2
SYSTEM CHARACTERISTICS

<u>Utility</u>	<u>Replacement Fuel Value, mills/kWh</u>		<u>Escalation⁽¹⁾ (Percent)</u>	<u>Levelized Fixed Charge Rate (Percent)</u>
	<u>1985</u>	<u>2000</u>		
PSNM	18	68	7.0	14.61
SRP	49	106	5.3	11.88
ELP	10	27	7.2	19.62
SCE	41	108	6.7	19.62
PSC	17	53	8.0	19.62
APS	21	43	4.9	19.62

NOTE:

1. Values include effects of 6 percent general inflation.

SOURCE:
SOUTHEAST REPORT

FIGURE 5.1-1
FLOW DIAGRAM
COMPUTER MODELS

SECTION 6

INSTITUTIONAL STUDIES

6.1 GENERAL

The institutional studies conducted as part of this project identified potential means of accelerating the commercialization of solar electric generation systems. Financial, legal, socioeconomic, regulatory, and institutional constraints which have potential for inhibiting the development of solar electric technologies in the Southwest were identified and actions to mitigate the effect of these constraints were evaluated.

Specific issues addressed were the use of financial incentives to remove economic obstacles to marketplace acceptance including a review of specific incentives with respect to their acceptability to the utility industry; an evaluation of the capability of the most acceptable incentives to reduce the cost of solar electric technologies to the utilities to a level comparable with conventional electric power plant technologies; a discussion of socioeconomic impacts for each solar technology for varying levels of market penetration; governmental and regulatory factors that may impede commercialization; the development of licensing schedules for each solar technology and methods by which the licensing process can be streamlined; legal issues such as patent law, solar and wind rights, and anti-trust issues; institutional arrangements for sharing costs and risks; legislative needs to support and accelerate commercialization; and ways in which the electric utility industry can participate in RD&D and commercialization of solar electric generating plants.

Commercialization of a new product or technology has been defined as a process by which the new product or technology progresses from the conceptual stage to a status of marketplace acceptance. Commercialization is a complex process with ultimate success depending upon three major factors:

1. technical feasibility
2. existence of a market for the product
3. acceptable return on investment for developers, manufacturers, and users

For the private sector to participate in this process, risks involved in bringing a new product or technology to market must be acceptable.

6.2 COMMERCIALIZATION PROCESS

The commercialization process can be divided into four distinct phases.

1. The R&D phase includes the activities which bring a concept through identification and elimination of technological uncertainties.
2. The demonstration phase, which focuses on testing systems that approach commercial scale size in a "real world" operating environment, includes an evaluation of technical, economic, environmental, legal, and other factors.
3. The introduction into the marketplace phase which includes procurement and establishment of production facilities and all the other activities necessary to generate, support, and subsequently develop the expected market.
4. The commercial deployment phase which occurs when usage becomes widespread.

As each of the first three phases requires financial support and usually offers no immediate return, the expenditures involved are considered investments toward developing the potential for a new product to obtain market acceptance.

Accelerated commercialization - usually a joint government and private sector process - can be defined as planned action to increase the rate, level, and breadth of both acceptance and use of a new type of product, system, or process. The general objective of such actions is to maximize the market share of the new technology in a cost-effective manner while minimizing any negative impacts. Federal Government involvement to accelerate the commercialization of an energy technology can arise when:

1. the capital requirements, risks, or urgency of the effort are more than the private sector can or is willing to support;

SOUTHWEST

2. barriers to commercialization due to governmental policies and regulations exist; and
3. the anticipated benefits to the nation, e.g., reduced dependence on imported oil and creation of a favorable balance of payments, warrant government action.

Some of the ways in which government can intercede and accelerate commercialization of new energy technologies include:

1. sponsoring and funding RD&D programs
2. cost and risk sharing
3. providing financial incentives
4. removing barriers inhibiting private industry
5. developing approaches which minimize legal and regulatory constraints

These approaches and others are discussed and analyzed in greater detail below.

6.3 SOUTHWEST REGION

6.3.1 Population

The Southwest study region encompasses approximately 2,000,000 square kilometers (766,000 square miles), half of which is owned by the Federal Government. In 1976, there were approximately 30 million people located in the region. Over the last 15 years, the population has increased at more than double the rate of the rest of the nation. Growth in the region is expected to continue, and the population is expected to reach approximately 40 million people by the year 2000. This represents a 49 percent increase over the 1970 population, a rate which, while slowed from the current pace, is still considerably higher than the projected growth of 36 percent for the remainder of the country. Based on past and present growth patterns, the majority of this population increase in the Southwest is expected to occur mainly in the metropolitan and urban areas due to limitations in water availability and the high percentage of land owned by the Federal Government.

6.3.2 Solar Resources

Within the continental United States, the southwest region offers the greatest potential for solar technologies, particularly solar electric power generation. This is due to the abundance

of solar resources in the region. Figures 6.3-1 and 6.3-2 present the direct normal and total horizontal solar radiation, while Figure 6.3-3 shows available wind power for the region. Direct normal insolation is most appropriate in determining the potential power generated from tracking solar collection systems such as solar thermal systems. Approximate values of daily, direct, normal insolation vary within the region from less than 5 kWh per square meter in northwest California to greater than 7.5 kWh per square meter in southern portions of Arizona and California. This latter area has the highest direct normal insolation in the United States.

Total horizontal insolation is most appropriate for solar collection systems with little or no concentration capability, such as nontracking photovoltaic arrays. Horizontal insolation values vary within the southwest region from approximately 4.5 kWh per square meter in northwest California to over 6 kWh per square meter in southern Arizona and California. The highest horizontal insolation values in the United States are found in this region of Arizona and California.

Wind energy conversion is a result of solar energy affecting atmospheric patterns and the effects of local topography. There are numerous general areas in the Southwest where potential sites exist for wind generating facilities. Areas such as mountain tops and ridges are considered most desirable.

6.3.3 Utilities

There are approximately 230 electric utilities in the southwest region. As previously indicated, 12 electric utilities and one state power authority within the region participated in this study. Although the number of participating utilities is relatively small, the installed capacity of these utilities represents about 48 percent of the total installed capacity in the region. Based on the projected electrical load growth of the participating utilities, an annual growth rate of 4.2 percent was calculated for the period 1977 to 2000. Thus, the electrical demand by the year 2000 will be approximately two and one-half times the current demand.

Utilities within the region can be classified into four major categories.

1. Investor-owned utilities which constitute 11 percent of the total utilities in the region and

- who own 67 percent of the installed capacity.
2. Municipal electric utilities which account for 44 percent of the utilities in the region and which have 18 percent of the total installed capacity.
 3. Rural electric cooperatives which represent 31 percent of the total number of utilities and account for 1 percent of the region's electric generating capacity.
 4. Federal, state, and district systems which represent 14 percent of the total regional capacity and 13 percent of the utility systems.
 2. reliability of the new technology
 3. excessive cost increases of components and subsystems
 4. excessive O&M costs
 5. changes in regulatory requirements as related to the specific technology
 6. technology changes which may make the considered technology become rapidly obsolete.
 7. initial and continued acceptance by the general public.

The primary fuels for electric power generation in the Southwest are gas and oil, which are used to generate 67 percent of the electric power within the region. Coal provides 20 percent of the electric power generation; nuclear supplies 3 percent; and hydroelectric pumped storage and diesel power represent less than 1 percent of the total electric power generation.

Twenty-two utilities in the Southwest form an organization called Western Energy Supply and Transmission Associates (WEST) which participates in the planning of electric power plants and transmission facilities for the associates. In addition, the southwest region is, for the most part, included within the Western System's Coordinating Council (WSCC), a planning and reliability organization which extends over the western third of the United States and into Canada.

6.4 INSTITUTIONAL ARRANGEMENTS

6.4.1 General

Various institutional arrangements which have the potential for accelerating the commercialization of central station solar electric generating plants in the Southwest were evaluated from the utility perspective. The term "institutional arrangement" was defined, for the purposes of this study, as a relationship in which cost and risks are shared among participants.

The risks involved with the introduction of a new energy technology are numerous and include:

1. rate considerations affecting the ability of utilities to incorporate capital intensive technologies into their rate base

These risks ultimately relate to financial exposure. If the risks are perceived to be high, then the commercialization process will slow down. The goal of identifying effective institutional arrangements is to encourage the development of a self-sustaining solar electric market and the integration of solar electric power generation into electric utility systems by sharing the costs and risks among users, manufacturers, and the Federal Government.

Institutional arrangements are dynamic in that they vary with time through the commercialization process. For example, the government may assume the majority of the costs and risks during R&D and the early commercialization stage while the manufacturers and utilities may assume increasing levels of cost and risk in the later stages of commercialization.

6.4.2 Methodology

Ten examples of precedent institutional arrangements were chosen and evaluated by the project participants for possible applicability to the solar electric generating situation. All of these arrangements were initiated and established in the past by government and/or industry and all are examples of various institutional arrangements used or proposed for use to promote rapid development to commercialization of energy technologies. The arrangements are classified into three categories: joint utility industry/government, utility industry alone, and government alone.

Considerations or criteria that were used to evaluate the institutional arrangements which have the potential for stimulating the commercialization of solar electric generating plants are delineated below. Available experience suggests that the ultimate success of any institutional arrangement for any new technology can be related to the:

1. ease and cost of financing;
2. degree of utility industry cost and risk sharing;
3. degree of centralized management control;
4. potential for effective reduction of uncertainties;
5. financial resources of the utility; and
6. strength of utility-vendor interface.

6.4.3 Results

Review of the institutional arrangement categories identified above resulted in the identification of joint utility industry/government institutional arrangements as those which hold the most promise for the accelerated commercialization of solar technologies. The principal measure of success for an institutional arrangement is its ability to shift risks and benefits of a technology to the private sector at a time deemed appropriate by the participants. This ability is necessary for a technology to achieve widespread commercial success. Joint utility industry/government arrangements are best suited for the transition from substantial government involvement to a self-sustaining market.

Planned involvement of the private sector via a consortia of electric utilities, the government, and possibly equipment producers, with all parties sharing risks and costs is seen as the most promising type of arrangement for the near term. Federal funding is expected to decrease as uncertainties are reduced through demonstration programs. Arrangements incorporating the positive aspects of the Power Reactor Development Program and the Federal Nonnuclear Corporation could provide the proper balance of risk-and-cost sharing as well as maintaining strong private sector participation.

Utility industry institutional arrangements are less likely to have a significant impact on the acceleration of the commercialization process, particularly in the early stages. Electric utilities, either alone or in conjunction with equipment producers, are not expected to have, or be allowed to expend, the necessary resources to play major roles in the commercialization of solar electric generation technologies as long as the risks remain unacceptably high. Many utilities face regulatory constraints that limit the amount of

funding that they can dedicate to high risk ventures.

Power pools or utility associations can and do play a role in RD&D. This role can be expanded into the commercialization of solar electric generating plants with government assistance. Pooling arrangements, like consortia, provide a wide base over which to spread costs and risks but may, due to geographical limitations and a large number of participants, be less effective than a smaller group of utilities in conducting successful projects.

Institutional arrangements involving only the Federal Government are considered less likely to have a significant impact on the commercialization of solar electric generating technologies than those arrangements involving utility industry participation. The eventual success of R&D and commercialization programs is enhanced by the breadth of the spectrum of knowledgeable input to the program and the diversity of entities benefiting therefrom. Programs directed toward the use of solar technology for central station generation feeding utility transmission systems would, by necessity, require input from those entities having maximum experience with such stations and systems; i.e., the utilities themselves. The commercial success of the concept is, therefore, dependent on those entities who would, by definition, be excluded from a government-only institutional arrangement.

6.5 FINANCIAL INCENTIVES

6.5.1 General

The wide penetration of solar electric generating technologies must overcome some formidable obstacles, many of which are common to almost any new technology. These barriers include: high initial cost compared to existing technologies; high cost of investment capital; and uncertainties associated with (a) material and labor costs, (b) cost savings associated with economics of scale production, and (c) O&M costs. In addition, uncertainties associated with competing technologies such as fuel costs for coal, oil, and nuclear energy further complicate the decision making process.

To surmount these barriers and accelerate the commercialization process to maturity, the developing technology needs assistance in the form of financial incentives. These incentives are needed to spur utility investment in solar electric generating plants during the risky early stages of the effort to carve out a profitable position within the broad field

of energy production and distribution. The long-term benefits of accelerating the commercialization process should justify substantial financial support during these early phases.

Precedents exist for government involvement in developing energy technologies. Substantial incentives for nuclear, hydroelectric, coal, oil, and gas industries have been and in some instances continue to be provided.

6.5.2 Methodology and Assumptions

In principle, incentives to the utility industry can be classified into five major categories. Category I includes direct funding from outside sources, primarily the Federal Government. Category II includes government supported loans. Category III includes use of accounting devices which assist in the internal generation of funds. Category IV includes incentives designed to establish price parity between solar generated energy and energy produced by conventional methods. Category V includes incentives which indirectly provide tax or cost advantages.

Twenty-four specific financial incentives were selected for evaluation among the five categories.

Each of the financial incentives was reviewed and evaluated by the study participants and then rated high, medium, or low. This established a numerical basis for selecting those incentives which have the maximum probability of accelerating commercialization. Criteria used for this evaluation included:

1. cost competitiveness
2. cost overrun sharing
3. investment cost sharing
4. compatibility with generally accepted accounting principles
5. paper work burdens
6. effect on rate of commercialization
7. acceptability by public agencies

Applying these criteria to the aforementioned incentives resulted in six of the incentives receiving a uniformly high rating. These were:

1. low interest loans
2. investment tax credits

3. changes in asset guideline period
4. grants for RD&D
5. accelerated depreciation
6. treatment of solar electric generating plants as pollution reducing or energy conserving devices

All of these high ranking incentives, save one; i.e., treatment of the solar electric generating plants as pollution reducing or energy conserving devices, are well known methods which are or have been used in the electric utility industry. As a result, these incentives should be acceptable to both the electric utility industry and government, and, either singularly or in combination, should be able to provide the economic stimulus needed to accelerate the commercialization process.

The utility participants in the project emphasized the need for incentives to decrease capital requirements early in the life of the plant. Another characteristic considered important was having the incentive compatible with existing accounting and regulatory procedures.

The incentive dealing with grants for RD&D does not directly apply to the commercialization of solar electric generating plants. This incentive is more of a prerequisite for commercialization. Treatment of solar electric generating plants as a pollution reducing or energy conserving device can be considered as an unconventional regulatory incentive with potential for incorporating conventional financial incentives. This incentive, however unorthodox in concept, is innovative in that it addresses both regulatory and economic issues.

The remaining incentives (low interest loans, investment tax credits, changes in asset guideline period, and accelerated depreciation) are considered to be conventional incentives and lend themselves to a quantitative evaluation. These incentives hold the most promise as mechanisms to significantly reduce capital requirements and thereby accelerate commercialization in that they presently exist, are well known within private and governmental sectors, and do not change electric utility/government relationships.

6.5.3 Low Interest Loans

Since the effect of low interest loans on the break-even investment cost varies among electric utilities, a figure is presented for each of the utilities studied. Figures 6.5-1 through 6.5-6 show

the effectiveness of reducing the cost of debt to each of the utilities. Low interest loans are considered to be a replacement for the "debt" portion of private utility capitalization that is necessary for such projects. All of the utilities, except one, show an increase in the break-even cost by 15-30 percent for a low interest loan resulting in a cost of debt equal to 2 percent. The one exception to this was SRP which showed the break-even investment increasing by a factor of approximately 95 percent for a 2 percent cost of debt. This increase can be explained by recognizing that the fixed charge rate is comprised of four basic components: 1) cost of money; 2) depreciation; 3) federal and state income taxes; and, 4) property taxes, insurance, etc. Since SRP is an agency of the State of Arizona, monies are raised by government revenue bonds at a lower cost than encountered by investor owned utilities. Since government entities are exempted from most taxes, the cost of debt becomes the primary component of the fixed charge rate. As a result, reducing the cost of debt has a more pronounced effect on the break-even investment for this utility.

6.5.4 Investment Tax Credits

The effectiveness of investment tax credit is shown on Figure 6.5-7. The system integration studies incorporated a 4 percent investment tax credit for a majority of the utilities studied and, as a result, this is the base case from which the effectiveness of this incentive is reviewed. The figure presents, as a multiplier, the effectiveness of increasing percentages of investment tax credit.

6.5.5 Decreasing Asset Guideline Period

The effectiveness of decreasing the asset guideline period (useful life of the facility for tax purposes) is presented in Figure 6.5-8. The system integration studies used a useful life of 23 years in the base case. The figure shows that decreasing the useful life to 5 years has the effect of increasing the break-even investment cost by approximately 20 percent.

6.5.6 Accelerated Depreciation

Accelerated depreciation defers taxes from the early years to the later years of the useful life of an asset. This is done by increasing the total amount of depreciation deductible for tax purposes in the earlier years. The normal means of depreciation is known as the straight-line method. Two alternate methods, the sum of

the years' digits and double-declining balance, were suggested as examples of accelerated depreciation methods. The effectiveness of these depreciation tools is shown on Table 6.5-1. The system integration studies' break-even investment evaluations for the various solar electric generating technologies incorporate accelerated depreciation in the form of the double-declining balance method, the most effective form of accelerated depreciation of the two methods presented.

6.5.7 Results

In some cases, a particular incentive may be able to make up the difference between the estimated conceptual plant cost and the solar break-even investment cost. For most utilities, however, the simultaneous use of more than one of these incentives will be required to overcome the cost differential as break-even investment costs associated with solar technology are considerably lower than the expected plant costs.

6.6 MARKET PENETRATION

6.6.1 General

Numerous studies have been undertaken to project the potential market for solar energy in the United States. A summary of the most frequently referenced market penetration studies can be found in the DOE publication, Solar Energy - A Status Report dated June 1978. The penetration results of these studies vary from a high of approximately 25 percent to a low of 0.1 percent of the United States' total energy needs being met by solar technologies by the year 2000. It should be noted that the above market forecasts include dispersed as well as central station solar technologies and address the national situation rather than that associated with a single specific area.

6.6.2 Methodology and Assumptions

Two methods have been used to estimate the potential market for central solar electric generating stations in the Southwest through the year 2000. First - the approximate range of market penetration has been estimated based upon projections from electric utilities within the region. Second - the results of the detailed system integration studies performed for six electric utilities were used to determine the range of financial incentives required to reach a specified market penetration.

Assuming a 25 percent capacity factor (no energy storage) for solar thermal and photovoltaic plants and a 40 percent

capacity factor for wind energy conversion plants, the projected number of plants of each type is shown in Table 6.6-1. These limits represent an estimation of the number of solar electric generating plants expected in the United States based on the most optimistic and pessimistic projections contained in the studies summarized by DOE.

A market forecast questionnaire was used to estimate the market for solar electric generating technologies through the year 2000 as perceived by the electric utilities participating in the institutional studies based on specific assumptions. The questionnaire solicited information regarding the anticipated achievable installed capacity of solar thermal, wind energy, photovoltaic, and hybrid solar thermal plants during the 1986 to 1990, 1991 to 1995, and 1996 to 2000 time frames.

Assumptions made in the analyses include:

1. the life cycle cost of the solar electric generating plants will be approximately equal to conventional technologies;
2. the plants will have an acceptable level of reliability and be technically feasible;
3. the plants under consideration will have a commercially feasible size; and
4. the existing pattern of energy consumption and production will continue through the study period.

6.6.3 Results

The results of the market forecast questionnaire are presented in Table 6.6-2. It was estimated that up to 5,500 MWe of solar electric generation could be installed in the southwest region by the year 2000. The nominal amount of solar electric generation, as a percent of new capacity to be added after 1985, is expected to be on the order of 7.5 percent by the year 2000, and it is estimated that on the order of 3.5 percent of the total installed capacity will be attributed to solar electric generation by that date.

The primary factors considered important in determining if a solar electric generating plant would be added to a utility system are economics, proven plant reliability and availability, projected traditional fuel availability and cost, and regulatory and legal delays anticipated with other technologies. Some

limited financial risk can be accepted, particularly if the potential gain will offset an expected rise in fuel cost and reduce the risk of conventional fuel shortages. The risk of not being able to provide service could not be accepted by the utilities.

Both solar thermal electric and wind energy conversion systems were perceived to be in the early stages of demonstration in 1977, with the most advanced technology being wind energy conversion. Commercial introduction of wind systems in the 1986-1990 time frame and solar thermal electric systems in the 1991-1995 time frame seems likely. Photovoltaics were perceived to still be in an active phase of R&D.

6.7 EVALUATION OF SYSTEM INTEGRATION STUDIES

6.7.1 Background

Systems integration studies were performed to establish the investment that specific utilities could justify to incorporate solar electric, photovoltaic, and wind energy conversion systems into their grid. One of the most important determinations resulting from the system integration work, which served as input to the institutional studies, was the break-even investment cost. This parameter, when subtracted from plant cost, gives the financial incentive required to stimulate widespread use of solar electric generating plants (Table 6.7-1). The basic assumption to this calculation is that the cost of installing new capacity and new technologies must be competitive with the cost of installing conventional electric generating facilities. As a result, financial incentives will be required to make up the difference between the value of the solar electric generating plant to the utility and the total plant cost. Figures 6.7-1 through 6.7-6 show the solar break-even investment value in the year 2000 at varying levels of market penetration. This value (in \$/kW in 1977 and 1985 dollars) is presented for various solar electric generating technologies at different levels of energy storage for each utility studied. Due to differences in solar resource utilized, unit size, and plant availability, wind energy conversion plant break-even values should not be directly compared against solar thermal and photovoltaic break-even values.

6.7.2 Break-even Investment

The break-even investment value is comprised of three basic components.

1. Capacity replacement credit

2. Fuel replacement credit
3. O&M penalty

System characteristics vary among the electric utilities investigated, and as a result, a separate figure showing break-even investment was provided for each utility.

The value of solar electric generating plants varies from one utility to another by as much as 2 or 3 to 1 for a particular technology and energy storage level. This is due to differences in the cost of financing, system load characteristics, type of generation displaced, system fuel costs, and other variables. The break-even investment generally increases as the length of storage increases; however, this increase is not as great as the increase in the plant cost associated with the higher levels of energy storage. Thus, use of energy storage requires greater incentives than similar plants without storage.

6.7.3 Sensitivity

The most significant factor in the break-even investment is the cost of fuel being replaced. Utilities with high fuel replacement costs (those replacing oil) have the highest break-even investment cost. As a result, the incentive required, per kilowatt, is less for these utilities than for utilities where coal and nuclear are the fuels being displaced.

Sensitivity analyses measuring the effects of fuel escalation show a significant increase in the break-even investment of solar electric generating plants as the fuel escalation rate increases. Again, this is especially pronounced for those utilities with high fuel replacement values. Lowering the fixed charge rate of a utility by implementing financial incentives such as low interest loans likewise increases the break-even value. Variation of insolation and wind power levels show less effect on the break-even investment value. The systems integration study results show the highest break-even investment value to be associated with solar electric generating plants within the SRP system. This is attributed to the low fixed charge rate and the high fuel replacement value attendant with this governmental entity.

6.7.4 Evaluation Results

Financial incentive requirements for solar electric generating plants starting commercial operation in the year 2000 are determined by subtracting the break-even investment cost in the year 2000 from the

expected early commercial plant cost. Figures 6.7-7 through 6.7-12 show these requirements for solar electric generating plants at different levels of energy storage for each utility. Incentive requirements in \$/kW can be read in 1977 and 1985 dollars, using the appropriate scale. It is shown that the incentive requirements do not increase by an appreciable margin as the market penetration increases. The figures also show that for the utility studied, the amount of incentive required increases with higher levels of energy storage.

Figures 6.7-13 through 6.7-18 present bar charts for each technology and level of energy storage studied for a market penetration level of 5 percent by the year 2000. For each utility, the break-even investment value is compared to the range of mature plant costs. The weighted average escalation for fuels replaced for each utility is noted to the left of the bar graph. Incentive requirements are determined by subtracting the break-even investment from the average mature plant costs. The approximate range of incentive required can also be determined by comparing the break-even investment to the high and low mature plant costs.

In addition to the utility fuel escalation assumptions noted to the left of the bar graphs, higher fuel escalation rates of 8 and 10 percent were used to calculate the break-even investment value for each utility at these higher rates. These break-even investment values are presented on the bar graph with the fuel escalation level noted.

6.7.4.1 Solar Thermal Plants

For solar thermal plants with 600 MWh of energy storage, the incentive requirements are lowest for the utilities with high fuel replacement values, such as SCE and SRP. For both, incentives required represent more than half the average early commercial plant costs. The other utilities would require even heavier government participation if solar thermal were to be economically competitive with traditional generation technologies on their respective systems. The effect of increasing the fuel escalation rate to 10 percent dramatically reduces the size of the incentive that would be required for most utilities.

Similar results are found for the solar thermal plant with 200 MWh of energy storage. Incentive requirements are less, however, due to lower early commercial plant costs. It, therefore, becomes apparent that as the amount of storage capacity is reduced, the amount of

incentive required is also reduced. Incentive requirements for SCE and SRP are very small and zero, respectively, when 10 percent fuel escalation is assumed.

6.7.4.2 Photovoltaic Plants

Information on photovoltaic plants with no energy storage was developed using the range of early commercial plant costs estimated in this study and the DOE "cost goals." The plant cost associated with the "cost goal" is lower than the estimated early commercial plant cost for the state-of-the-art photovoltaic equipment, since its achievement can result only from an as yet unrealized technical breakthrough. This technical breakthrough must come in the form of significantly higher cell efficiencies which would allow greater plant generation capability with only minor increases in the balance of plant costs.

For photovoltaic plants with no energy storage, the financial incentive required to make up the difference between the average early commercial plant cost and the break-even investment ranges between 50 and 80 percent of the plant cost. As in the solar thermal case, the smallest incentive is required for the utilities with the highest replacement fuel cost. With an assumed fuel escalation of 10 percent, the break-even investment value to SRP of photovoltaic exceeds the average mature plant cost. For SCE, this higher escalation rate results in the break-even investment value approaching the DOE cost goal.

6.7.4.3 Wind Energy Conversion Plants

For wind energy conversion plants, the break-even investment for SCE was found to be less than the average mature plant cost. Again, the break-even investment value decreases only slightly with decreased energy storage, while the mature plant cost is appreciably less. The resulting incentive requirements are less and energy storage cannot be justified.

6.7.4.4 Retrofit Hybrid Plants

For the two utilities studied, the break-even investment ranged from 30 to 60 percent of the average mature plant cost. For SRP, a fuel escalation rate of 10 percent yields a break-even investment that exceeds plant cost. For PSNM, the 10 percent fuel escalation rate results in a break-even investment that approaches the average mature plant cost.

6.7.4.5. Discussion

In order to estimate the value to the electric utility industry and the cost of financial incentives necessary to support different levels of market penetration for solar electric generating plants in the southwest, it is necessary to recognize there are an infinite number of market penetration scenarios that can be made by assuming different levels of market penetration, solar electric generating plant mixes, and ranges of plant costs and break-even values. Two market penetration examples were considered in this study: 1,000 MWe of solar electric generating plants starting commercial operation in the year 2000; and a market penetration of 5 percent, which is equivalent to the installation of 8,000 MWe of solar electric generating plant capacity in the Southwest by the year 2000.

Table 6.7-1 gives the range of break-even investment, financial incentive, and average early commercial plant cost for each solar electric generating plant in the year 2000. The financial incentive requirements shown are calculated by subtracting the break-even investment value from the average early commercial plant cost. Two conditions, both considered representative within the Southwest, are presented. The top number in each column represents the break-even investment value for a utility with a high fuel replacement value (on the order of 100 mills/kWh in the year 2000). The numbers in parentheses represent the break-even investment value for a utility with moderate fuel replacement value (on the order of 50 mills/kWh in the year 2000). For utilities with extremely low break-even investment values, financial incentives will be required to offset essentially the entire plant costs.

Table 6.7-2 gives the cost of 1,000 MWe solar electric generation starting commercial operation in the year 2000. The mix of generation for the various technologies, 40 percent wind, 40 percent solar thermal, 10 percent photovoltaic, and 10 percent retrofit hybrid emphasizes wind energy conversion and central receiver solar thermal due to their lower plant and financial incentive costs. Although the retrofit hybrid plant has lower plant and incentive costs than the solar thermal plant with no energy storage, it was given a smaller percentage of the total capacity as only those utilities with high fuel replacement values, existing generation compatible to retrofit, and sufficient available adjacent land area will be likely to install retrofit hybrid units. These

conditions were assumed to limit the use of the retrofit hybrid concept.

Results presented in Table 6.7-2 are for the same assumed mix of generation for both the high and moderate fuel replacement value utilities. For this example, the total cost to the utilities, in 1977 dollars, is approximately \$1.5 billion. For the high fuel replacement value case, the cost or value to the utilities is 35 percent of the plant costs, thus the incentive required is 65 percent; for the moderate fuel replacement case, 76 percent of the plant costs would require offset by incentives.

For a similar mix of solar electric generating technologies, total incentive costs were estimated for a market penetration of 5 percent, which represents a total of approximately 8,000 MWe of solar electric generating capacity by the year 2000 in the southwest region. The total cost required to achieve this penetration is on the order of \$15 billion (1977 dollars). Of this total cost, approximately \$4 billion represents the value of the solar electric generating plants to the utilities and approximately \$11 billion represents the amount which must be offset by incentives. These figures can be doubled to obtain a rough estimation of the value to the utilities and the cost to the government for a 10 percent market penetration in the Southwest.

Table 6.7-2 gives the range of the required financial incentive costs for 1,000 MWe solar electric generation by plant type for the period 1985 to 2000. The range of financial incentives, in 1977 dollars, shows the difference between the high value and low value to be 2:1 or less. The highest potential incentive cost is \$2.99 billion for the installation of 1,000 MWe of photovoltaic generating capacity. The lowest potential incentive cost is \$770 million for the installation of 1,000 MWe of solar thermal hybrid.

6.7.4.6 Conclusions

Two market penetration examples have been discussed. For both scenarios, the higher break-even investment values, associated with utilities having high fuel replacement costs, were used. With this assumption, incentive costs are a smaller percentage of the total plant costs than for the case where the fuel replacement costs are moderate or low. For the example of 5 percent market penetration within the region by the year 2000, the financial incentive required would be approximately \$11 billion in 1977 dollars.

A recent study, An Analysis of Federal Incentives Used to Stimulate Energy Production, prepared by Battelle Pacific Northwest Laboratories and dated March 1978, serves as a reference for the financial incentives estimated for solar electric generating plants. The Battelle study estimates that, since 1918, the total cost of incentives to stimulate nuclear, hydroelectric, coal, oil, and gas energy production in the entire country has been between \$124 and \$134 billion (1976 dollars). As an additional benchmark for comparison of the cost of incentives estimated for a market penetration of 5 percent, Congress has estimated the federal investment in the entire country in the next decade to support the Federal Nonnuclear Energy Research and Development Act of 1974 to be \$20 billion or more.

Utilities with high fuel replacement costs as a result of the displacement of oil-fired capacity would receive the greatest value from solar electric generating plants. The financial incentives required for these utilities would, in turn, be the lowest. Utilities which have lower fixed charge rates are expected to receive greater values from solar electric generating plants than utilities having higher rates. SRP has the highest break-even investment value of all the utilities studied. The lower fixed charge rate, as well as the planned addition of oil-fired capacity and the high fuel replacement costs associated with the system, resulted in SRP receiving the most value from solar electric generation.

Utilities with low fuel replacement costs resulting from the displacement of hydroelectric or nuclear capacity by solar electric generating plants would have low break-even values. For this condition, financial incentive costs would approach the total plant costs.

Early commercial plant cost estimates for a photovoltaic central station generating plant, using state-of-the-art equipment, indicate that the incentives required would be so large as to make the concept comparably uneconomical through the year 2000.

The use of energy storage systems using present-day technology for anything other than a buffer against short term solar transients is also shown to be unjustified. The increase in the break-even investment value resulting from the higher capacity factors made possible by the storage system are more than offset by higher plant costs. As a result, plants with long-term (greater than 15 minutes) energy storage capabilities should not be

considered for inclusion in the first generation of central station solar electric generating plants.

6.8 REGULATORY FACTORS

6.8.1 General

The economics of electric utility operations have generally been rigidly regulated by a variety of regulatory authorities whose major concerns are the reasonableness of rates for electricity sales to the public and the fairness of the financial return allowed to the utilities' investors.

In most cases, the rates which a regulatory agency permits a utility to charge are based on receiving a "fair" financial return on the funds which the utility has invested, an amount known as a rate base. This is referred to as the "rate of return" concept. One area requiring careful assessment in any proceeding to establish utility rates is the proper scope of the rate base. Items of investment to be included in the rate base must normally meet the dual criteria of being "reasonable" and "used and useful." Expenditures which the regulatory agency believes are unreasonable are not allowed in the rate base computation; nor will expenditures for plants which are not used or useful; i.e., in service and generating electricity, be allowed.

6.8.2 Available Financial Mechanisms

As a matter of policy, utility rate-setting authorities can take certain steps to enhance the attractiveness of solar-electric generating plants to utility investors. One possible way is to allow a higher rate of return on investments associated with these facilities than would normally be allowed on nonsolar facilities. However, the use of this mechanism would probably evoke much litigation from proponents of other technologies.

A second area where ratesetting authorities can contribute to the advancement of solar technologies is the treatment of CWIP costs. This is the cost of activities associated with the design and construction of power generation facilities and, as such, is not normally included in the utility rate base until the facility is declared in commercial operation. Although utilities desire that CWIP associated with all technologies be included in the rate base, regulatory agencies desiring to selectively enhance the attractiveness of certain technologies may choose to permit the inclusion of CWIP

associated with the preferred technology in the rate base as a method of making utility investment in solar more attractive.

A third opportunity for enhancement can be found in the area of regulatory lag. Regulatory lag is the delay between the time a utility applies for a revision of rates to reflect changes in the rate base and the time when the regulating authority approves the application. Commitments by regulatory agencies to reduce regulatory lag when solar electric generating facilities are involved would serve to enhance the attractiveness of this concept.

A fourth area where regulatory authority assistance is possible is the regulation of the amount of recoverable R&D funds that a utility may expend. Raising the permissible level of such expenditures for R&D activities associated with solar generating facilities can provide an increased source of funds, thereby accelerating the commercialization process.

It is concluded that regardless of the apparent attractiveness of a facility which uses renewable resources, utilities are unlikely or unable to accept the risks associated with the financial and regulatory uncertainties delineated above without recognition of these risks by regulatory authorities. There are, however, definite steps available which rate regulators can take to promote the commercialization of solar electric generating facilities.

6.8.3 Available Procedural Mechanisms

6.8.3.1 General

The expenditure of time and effort and the potential for delays associated with the licensing process have become major considerations which utilities must take into account when selecting the type of facility to be added to their system. Successful efforts to streamline the licensing process for solar electric generating facilities could serve to materially enhance their attractiveness to utilities.

Since the passage of NEPA, federal agencies have been required to review the environmental impact of facilities for which they issue permits and authorizations. Many states, as a result of increased environmental awareness, have enacted legislation similar to NEPA which requires an environmental assessment of state actions, including the issuance of permits. Additionally, local authorities

often require approvals in the form of building permits and zoning variances prior to construction.

6.8.3.2 Licensing Requirements

The types of licenses required will vary depending upon the solar technology employed. Licensing schedules for each of the five concepts studied were developed. As all of the concepts require a variety of licenses and permits from a multitude of governmental bodies and agencies, it was concluded that, based on optimistic projections, approximately 36 months would be required to acquire the necessary permission to build any of the conceptual designs. This time period extends from the decision to begin gathering data for the required environmental report through the issuance of the necessary licenses.

Solar thermal hybrid plants may prove to be among the most difficult facilities to license. One potential problem results from the fact that solar hybrid facilities will incorporate existing fossil fuel facilities. It is anticipated that the hybrid units will be of the 100 MWe size range, a size which most utilities seldom, if ever, build today. If the 100 MWe facilities to be refitted have been retired, such plants may have to be relicensed. Additionally, plans to extend the life of existing facilities which burn fuels other than coal may require further licensing actions. It can be anticipated that older fossil plants may not meet today's Clean Air Act standards and that the installation of flue-gas desulfurization systems and precipitators might make retrofitting of a solar electric facility to an older fossil-fueled facility prohibitively costly.

Central station solar electric generating facilities require large tracts of land. Many such tracts in the Southwest are held by the Federal Government - land which, even after the exclusion of national parks and Indian reservations, could include suitable sites for these facilities. Mechanisms exist which permit acquisition and/or access to these lands but they all entail extensive regulatory and governmental review which, in turn, involves time, money, and effort. The requisite activities associated with utilizing this land can, however, be conducted in parallel with other licensing activities and are not expected to materially extend the overall licensing schedule.

It should be noted that substantial state-owned lands also exist in the Southwest. Acquisition and use of such lands for the siting of solar electric generating plants

would require approval by the appropriate state authorities.

As mentioned, licensing delays invariably translate into greater facility costs which may dissuade a utility from choosing a particular technology. It is therefore desirable that licensing solar electric facilities be facilitated to the greatest extent possible.

6.8.3.3 Potential Areas for Improvement

One of the most important steps in any central station project is the selection of the site. The site selection process must embody a documented methodology which incorporates engineering, economic, environmental, socioeconomic, institutional, and political considerations. In order to have the licensing process proceed in a timely manner, the site selection process must be able to withstand public and regulatory scrutiny. Improving the site selection process and the site banking concept provides an opportunity to accelerate the overall licensing process and significantly shorten the time required to license solar electric generating plants. This, in turn, can reduce the overall time required to bring the plants into operation. It should be noted that in 5 years, there have not been any sites preapproved in states having legislation which permits such action. Further enhancement of the site banking concept could be achieved if the requisite legislation were passed to ensure that sites selected for solar facilities, once approved and banked, would be excluded from the imposition of new criteria and from the need to consider alternative locations.

A major drawback in the current power plant licensing process is the potential for relitigation of the same issue in different licensing proceedings. Legislation intended to facilitate the licensing of solar generating facilities should, therefore, endeavor to ensure that the applicable licensing agencies consider and resolve generic issues in nonduplicative proceedings and that the consideration of issues in one proceeding precludes their consideration in proceedings conducted by other regulatory entities.

The one-stop licensing process vests in a single agency within each level of government the authority to issue all permits and approvals associated with an energy facility. This avoids the necessity of having to deal with a variety of agencies in order to obtain requisite comments and approvals and allows for a coordinated review of a facility. The

passage of federal and/or state legislation vesting authority to issue all of the requisite permits for solar facilities to a single agency and establishing strict schedules for such actions would greatly enhance the licensability of this concept.

The shared jurisdiction associated with licensing power plants can result in different and sometimes inconsistent results from licensing reviews conducted by federal and state regulatory agencies. To avoid such a situation, a logical extension of the one-stop philosophy is the amalgamation of both proceedings into a single joint effort. Precedent for such an arrangement already exists, although the experience to date with such proceedings has not been encouraging. The passage of legislation on both the federal and state levels specifically permitting and calling for such proceedings and delegating the total responsibility for certain aspects of the proceedings to specific entities would be desirable and would further enhance the licensability of the solar alternative.

6.9 LEGAL CONSIDERATIONS

6.9.1 Access to Sun and Wind

The right of unimpeded access to sun and wind is fundamental to any solar generating technology. United States law does not generally recognize the existence of such a right. However, the lack of this right may not be as critical for central facilities as it is for dispersed facilities due to the physical nature of central station facilities. It is, by their nature, virtually mandated that they be located in undeveloped areas where it is unlikely that they will be surrounded by substantial building development. Ways to minimize the possibility of future outside interference include the use of zoning laws and easements.

6.9.2 Antitrust

The large capital requirements associated with major manufacturing activities can be expected to limit the number of firms entering the market for central station facilities. This situation may create an atmosphere of limited competition. Another area of potential antitrust concern would be the acquisition of solar component manufacturing concerns by companies which have major activities in other power generation technologies. There have been demands from certain groups that companies involved in more than one facet of the energy industry be forced to vertically divest themselves of certain energy related activities.

Whatever the results of such demands, it was concluded that these potential problems would not constitute a major obstacle to commercialization.

The Federal Government may well require some assurance that financial incentives provided to utilities for solar generating facilities will not be used for anti-competitive purposes. The government may also wish to guarantee access to the benefits of solar generated electricity by smaller utilities and electric generating cooperatives. These factors also should not materially affect commercialization as precedent exists in other technologies for such requirements and they have not materially impeded the commercialization of those technologies.

6.9.3 Patent Law

Patent law should not materially affect the commercialization of central station solar facilities as a significant portion of the research involved will be funded by the government or by the utilities themselves through EPRI. It can be expected that the sponsor would specify, by contract, that any discovery or invention arising out of funded work would become the property of the sponsor or could be used or assigned, possibly at a fee, by that entity.

6.10 SOCIOECONOMIC IMPACTS

6.10.1 General

Socioeconomic factors that can affect the deployment of central solar electric generating facilities are predominantly related to their construction and operation. Benefits to the region in the form of jobs in construction, operations, and support positions, and income from work and support salaries should be substantial. In addition, taxes from the plants constructed by private utilities will provide a new source of revenue to site communities and to the region as a whole.

It should be noted that the socioeconomic impacts of the construction and operation of a solar facility are similar in nature, and in many cases in scope, to those socioeconomic impacts resulting from similar phases of other major industrial projects and/or power generation facilities utilizing other technologies.

Table 4.3-1 identifies anticipated work force requirements for each solar technology. Only minor socioeconomic impacts should result within a region if the facilities are sited within 1 1/2 hours commuting distance of major labor

markets. If construction and operation work force requirements cannot be satisfied locally, workers will migrate from outside the region given sufficient inducement. If the number of migrating workers is more than the regional infrastructure can assimilate, adverse social impacts may occur. When sites for photovoltaic and solar thermal units are located beyond commuting distances, workers are more likely to relocate nearer to the site. This is due to the greater length of the construction schedule for these solar electric generating concepts, especially when constructed with high levels of energy storage. The 12-month schedule for wind energy systems base plant construction is short enough that most workers may prefer temporary quarters near the site during the workweek, returning to their families on weekends.

6.10.2 Housing

Local and regional housing resources may be inadequate if significant numbers of relocating workers are expected during construction and operation of the solar facility. The rise in demand for housing may cause home purchase prices and rental costs to rise, perhaps beyond the level affordable by local residents if prior measures are not taken to mitigate the impact on the housing market.

6.10.3 Traffic

In most cases, transportation impacts associated with the commuting work force and delivery of construction materials and equipment can be anticipated. However, where good transportation facilities exist with adequate capacity and direct access to the site, traffic impacts would be expected to be minimal. Specific data are required to determine impacts on road conditions, traffic volumes, roadway capacities, and local traffic patterns within the site vicinity.

6.10.4 Community Facilities

Demand on such community facilities as schools, health and recreation facilities, water supplies, solid waste and sewage treatment, police and fire protection, and other municipal services may exceed existing capacity if the relocating work force is significantly large. The degree to which a community infrastructure can absorb the increased population will determine the amount of adverse impact caused by the potential overcrowding and overuse of facilities and services.

6.10.5 Regional Economics

Regional economic factors which are affected by construction and operation of solar electric generating facilities are employment, payroll, and taxes.

A substantial number of jobs will be created during the construction and operation of solar facilities. A construction work force of 2,500 is expected to generate approximately 1,500 secondary jobs and involve approximately 9,600 people, either directly or indirectly. An operating work force of 84 will generate 114 secondary jobs and involve approximately 500 people. Even in the latter case, the result will be the introduction of almost \$3 million (1977 dollars) annually into the local economy.

Construction and operation of a solar facility will provide tax revenues to the municipal, county, and state jurisdictions through payroll tax deductions and, if owned by a private utility, by real estate taxes imposed on the facility. (In certain cases, payments in lieu of taxes are made by public agencies to the local jurisdiction.) Often the taxes accrued to the town from the facility can be substantial enough to provide for improved services and new capital expenditures. It should be noted, however, that dispersed settlement of the work force can impact adjacent municipalities not receiving real estate tax benefits.

Employment statistics for the Southwest indicate that establishment of a solar plant construction program along with the high number of construction workers required for each plant could prove quite beneficial to the region. Unemployment in the states in the region (except Colorado and Utah) was consistently higher between 1973 and 1976 than was experienced by the country as a whole. The number of primary and secondary jobs created by the construction of solar electric generating facilities should help to lower the level of unemployment to rates more consistent with the country as a whole.

The existing regional construction work force should be sufficient to handle the installation of the number of plants required to achieve a cumulative generating capacity of 1,000 MWe or that required to achieve a 5 percent market penetration level with some relocation required within the region. Achievement of higher penetration levels could be accomplished but only with some potential adverse socioeconomic impact.

Of major concern to a relocating work force is the availability of housing for

workers and their families. While there may be housing shortages on a local level, the number of units required for workers is well within the number of units being authorized and constructed in the region during the time frame under consideration.

Planning by utilities and coordination with communities around the sites could prevent undesirable impacts to housing, transportation facilities, and other services and should be a priority activity in overall construction planning.

6.11 LEGISLATIVE REQUIREMENTS

Legislative action required to support the commercialization of solar electric generating facilities falls into two categories: legislation to enhance the financial attractiveness of demonstration, pilot, and commercial facilities; and legislation designed to remove or lessen regulatory barriers to construction of such facilities or activities associated therewith. Numerous legislative mechanisms whose specified purpose is the advancement of the utilization of renewable energy sources already exist on the federal and state level. The principal example of federal legislation in this area is the Federal Nonnuclear Energy Research and Development Act of 1974 (42 USC 5901 et seq) which directs that "...the nation undertake a research, development, and demonstration program in nonnuclear energy technologies with a total federal investment which may reach or exceed \$20 billion over the next decade." Various statutes exist in a number of states, including Arizona, California, and Colorado, which have similar goals.

It may be shown with the passage of time that these and similar mechanisms are sufficient to accelerate the commercialization process. It appears at present, however, that these mechanisms neither provide sufficient financial support nor adequately address the need to shorten and remove uncertainties from the licensing process. Legislation which specifically addresses these problems by allocating additional funds, revising tax regulations, establishing simplified licensing procedures, and recognizing the need to treat solar technologies in an untraditional regulatory manner will serve to enhance and accelerate the commercialization effort.

6.12 UTILITY INVOLVEMENT

6.12.1 General

Utilities have a major interest in the future role of solar electric power

generation and therefore should continue to participate, both through EPRI and individually, in reviewing research and development programs and overall strategies mapped by DOE. In particular, inputs from utilities are essential for defining their technical and system requirements which can serve as guidance to present and prospective producers of solar energy conversion components and subsystems.

Emphasis should be placed on utility operation and maintenance requirements since some of the solar hardware producers may not be fully familiar with such specific utility requirements which can have a great bearing on the penetration of solar electric generating plants.

6.12.2 Near Term Participation

The impetus created by the Southwest Project should not be lost when the project is completed. Rather, the continued potential of the study participants to assist in the commercialization of solar electric power generation in the southwest should be recognized and a formal structure established for its continuance. An example of such a formal structure would be the creation of a regional solar electric advisory panel that would advise DOE, possibly through the Western Solar Utilization Network, regarding goals and objectives, funding needs, technical requirements, and market strategies.

It is further recommended that utilities participate in system integration studies aimed at updating and expanding the studies incorporated in this report. Periodic assessments of solar electric technologies within actual electric utility systems will enable more reliable projections of expected market penetration by each technology and would increase utility confidence in those projections.

Utilities can also participate by assisting in the gathering and analysis of solar radiation and climatological data for the southwest region. The establishment of a comprehensive long-term data bank for the region can be of great benefit because it will more accurately assess the magnitude of the solar resources and will facilitate the design of solar electric generating plants and associated energy storage facilities.

6.12.3 Long Range Participation

The involvement of the utilities in the demonstration programs should be very active. In addition to providing sites

SOUTHWEST

and coordinating and managing the construction of pilot and demonstration facilities, the utilities can provide operators and enable "on-line" operation, testing, and maintenance of such plants. Utility planners can assist designers in determining scale-up requirements, ultimate plant capacities, size of components and subsystems, and acceptable personnel requirements. In addition, utility staffs can provide input to performance specifications, ensure that the management of activities associated with pilot and demonstration central

stations is conducted in accordance with normal utility practices, and ensure that performance evaluations are conducted in a manner consistent with utility practices.

The eventual transition from a substantially subsidized technology to a sound and commercially competitive industry may well be dependent upon the utilities' ability to assist the market selection process by furthering those technologies which prove to have the most promising long-term potential.

SOUTHWEST

TABLE 6.5-1

COMPARISON OF METHODS TO ACCELERATE DEPRECIATION TO
STRAIGHT LINE DEPRECIATION

Straight Line Depreciation				Accelerated Depreciation							
				Sum of the Years' Digits				Double Declining Balance			
Year	Amount Depre- ciated	%	Cumu- lative %	Ratio	Amount Depre- ciated	%	Cumu- lative %	Ratio	Amount Depre- ciated	%	Cumu- lative %
1	\$200	20	20	5/15	\$300	33	33	2/5 (1,000)	\$400	40	40
2	200	20	40	4/15	270	27	60	2/5 (600)	240	24	64
3	200	20	60	3/15	200	20	80	2/5 (360)	144	14.4	78.4
4	200	20	80	2/15	130	13	93	2/5 (216)	86	8.6	87
5	200	20	100	1/15	7	7	100	remainder	130	13	100

NOTES:

Cost of Asset - \$1,000

Life of Asset - 5 years

SOUTHWEST

TABLE 6.6-1

RANGE OF THE NUMBER OF SOLAR ELECTRIC GENERATING PLANTS
IN THE UNITED STATES

<u>Year</u>	<u>Solar Thermal</u>	<u>Photovoltaic</u>	<u>Wind</u>
1985	0-1	0-8	0-230
2000	0-510	0-2,730	230-13,860

SOUTHWEST

TABLE 6.6-2

MARKET FORECAST QUESTIONNAIRE RESULTS

Generating capacity as of January 1977 of the utilities participating in the market forecast	- 25,060 MWe
Percent of the total generating capacity in the southwest region	- 40 percent
Estimated capacity of the participating utilities for the year	
1985	- 34,000 MWe
1990	- 42,000 MWe
1995	- 51,000 MWe
2000	- 63,000 MWe
Equivalent Annual Growth Rate	- 4.2 percent

Cumulative Solar Electric Generating Capacity by Technology - MWe	<u>Time Frame</u>		
	<u>1986-1990</u>	<u>1991-1995</u>	<u>1996-2000</u>
Solar Thermal	-	200	560
Wind Energy	80	200	310
Photovoltaic	-	150	400
Hybrid Solar Thermal	270	610	920
Total Solar	350	1,160	2,190
Estimated cumulative new capacity to be added after 1985	8,000	16,990	29,050
Amount of solar as a percentage of new capacity to be added after 1985	4.3% (in 1990)	6.8% (in 1995)	7.5% (in 2000)
Total Market Penetration	0.8% (in 1990)	2.2% (in 1995)	3.5% (in 2000)

SOUTHWEST

TABLE 6.7-1

BREAK-EVEN INVESTMENT AND
FINANCIAL INCENTIVE REQUIRED BY THE YEAR 2000
FOR MATURE GENERATING PLANTS

<u>Technology</u>	Break-even Investment \$/kW (1977 dollars)	Financial Incentive \$/kW (1977 dollars)	Average Mature Plant Cost ⁽¹⁾ \$/kW (1977 dollars)
Solar Thermal ⁽²⁾ No Storage	690 ⁽³⁾ (480)	1,170 (1,380)	1,860
Photovoltaic No Storage	700 (500)	1,790 (1,990)	2,490
Wind No Storage	330 (230)	740 (840)	1,070
Retrofit Hybrid ⁽⁴⁾	630 (440)	760 (950)	1,390

NOTES:

1. The values shown are the costs developed in Volume II, Technical Studies, adjusted to include owner's costs and IDC.
2. Break-even investment value for solar thermal with no energy storage was not calculated but is estimated herein.
3. Typical values for utilities with high fuel replacement values (on the order of 100 mills/kWh in the year 2000 and oil/coal capacity displaced). Values in parentheses represent moderate fuel replacement values (on the order of 50 mills/kWh in the year 2000 and coal/oil capacity displaced). Fuel escalation rate assumed to be equivalent to the inflation rate.
4. Value shown herein is for a solar unit retrofitted to an existing oil-fired unit, thereby extending the useful life of the plant. For this reason, the hybrid unit is assigned full capacity replacement credit.

SOUTHWEST

TABLE 6.7-2

COST OF 1,000 MWe OF SOLAR ELECTRIC GENERATION STARTING COMMERCIAL OPERATION
(1977 DOLLARS)

Technology	Generation Mix, Percent of Total MWe	MWe Solar Generation	No. of Plants	High Fuel Replace- ment Values & Oil/ Coal Capacity Displaced		Moderate Fuel Re- placement Cost & Coal/Oil Capacity Displaced		Total Cost \$x10 ⁶
				Value to Utilities \$x10 ⁶	Incentive Required \$x10 ⁶	Value to Utilities \$x10 ⁶	Incentive Required \$x10 ⁶	
Wind	40	400	38	132	296	92	336	428
Solar Thermal	40	400	4	276	468	192	552	744
Photovoltaic	10	100	1	70	179	50	199	249
Retrofit Hybrid	10	100	1	63	76	44	195	139
Total	100	1000	-	541	1,019	378	1,182	1,560
Percent of total cost				35	65	24	76	

Assumptions:

1. Cost to utilities is based on break-even investment values and assumptions listed in Table 3.1-1
2. Solar plants are assumed to have no energy storage
3. Plant costs are taken to be the average mature plant costs presented in Table 3.1-1 in 1977 dollars

NOTES

1. DATA REPRESENTS THE AVERAGE FOR THE YEARS 1945 THROUGH 1975
2. CONVERSION FACTORS
 $1 \text{ KWH/M}^2 \text{ DAY} = 3.599 \text{ M JOULES/M}^2 \text{ DAY}$
 $= 316.95 \text{ BTU/FT}^2 \text{ DAY}$
 $= 85.98 \text{ LANGLEYS/DAY}$

0 200 400 600

SCALE - MILES

SOURCE: WATT ENG. LTD.

CONVERSION
CHART

1 ann cy/day
kWh/ft² day
MJ/m² day
kWh/m² day

FIGURE 6.3-1
SOLAR RADIATION
DIRECT NORMAL TERM
ANNUAL AVERAGE-DAY VALUES

SOUTHWEST PROJECT

NOTE

OVER MOUNTAINOUS REGIONS (SHADED AREAS),
THE ESTIMATES ARE THE LOWER LIMITS EXPECTED
FOR EXPOSED MOUNTAIN TOPS AND RIDGES.
DATA REPRESENTS WATTS/SQ. METER

FIGURE 6.3-3
MEAN ANNUAL WIND POWER
ESTIMATED AT 50m ABOVE
EXPOSED AREAS

SOURCE: BATTELLE PACIFIC NORTHWEST LABORATORIES

SOUTHWEST PROJECT

FIGURE 6.5-1
PUBLIC SERVICE COMPANY OF NEW MEXICO
MULTIPLIER TO REVISE BASE CASE
SOLAR BREAK-EVEN INVESTMENT
FOR CHANGES IN COST OF DEBT

FIGURE 6.5-2
SALT RIVER PROJECT
MULTIPLIER TO REVISE BASE CASE
SOLAR BREAK-EVEN INVESTMENT
FOR CHANGES IN COST OF DEBT

SOUTHWEST PROJECT

FIGURE 6.5-3
EL PASO ELECTRIC COMPANY
MULTIPLIER TO REVISE BASE CASE
SOLAR BREAK-EVEN INVESTMENT
FOR CHANGES IN COST OF DEBT

SOUTHWEST PROJECT

FIGURE 6.5-4
SOUTHERN CALIFORNIA EDISON COMPANY
MULTIPLIER TO REVISE BASE CASE
SOLAR BREAK-EVEN INVESTMENT
FOR CHANGES IN COST OF DEBT

FIGURE 6.5-5
PUBLIC SERVICE COMPANY OF COLORADO
MULTIPLIER TO REVISE BASE CASE
SOLAR BREAK-EVEN INVESTMENT
FOR CHANGES IN COST OF DEBT

SOUTHWEST PROJECT

FIGURE 6.5-6
ARIZONA PUBLIC SERVICE COMPANY
MULTIPLIER TO REVISE BASE CASE
SOLAR BREAK-EVEN INVESTMENT
FOR CHANGES IN COST OF DEBT

SOUTHWEST PROJECT

FIGURE 6.5-7
MULTIPLIER TO REVISE BASE CASE
SOLAR BREAK-EVEN INVESTMENT
FOR CHANGES IN
INVESTMENT TAX CREDIT

SOUTHWEST PROJECT

FIGURE 6.5-8
MULTIPLIER TO REVISE BASE CASE
SOLAR BREAK-EVEN INVESTMENT FOR
CHANGES IN ASSET GUIDELINE PERIOD

FIGURE 6.7-1
PUBLIC SERVICE COMPANY OF NEW MEXICO
SOLAR BREAK-EVEN INVESTMENT
IN THE YEAR 2000

FIGURE 6.7-2
SALT RIVER PROJECT
SOLAR BREAK-EVEN INVESTMENT
IN THE YEAR 2000

NOTE:
 DIRECT ECONOMIC COMPARISON IN \$/kW
 CANNOT BE MADE BETWEEN WIND AND
 OTHER TECHNOLOGIES DUE TO DIFFERENCES
 IN PLANT SIZING CRITERIA AND
 OPERATING CHARACTERISTICS.

FIGURE 6.7-3
 EL PASO ELECTRIC COMPANY
 SOLAR BREAK-EVEN INVESTMENT
 IN THE YEAR 2000

NOTE:
 DIRECT ECONOMIC COMPARISON IN \$/kW
 CANNOT BE MADE BETWEEN WIND AND
 OTHER TECHNOLOGIES DUE TO DIFFERENCES
 IN PLANT SIZING CRITERIA AND
 OPERATING CHARACTERISTICS.

FIGURE 6.7-4
 SOUTHERN CALIFORNIA EDISON COMPANY
 SOLAR BREAK-EVEN INVESTMENT
 IN THE YEAR 2000

NOTE:
 DIRECT ECONOMIC COMPARISON IN \$/kW
 CANNOT BE MADE BETWEEN WIND AND
 OTHER TECHNOLOGIES DUE TO DIFFERENCES
 IN PLANT SIZING CRITERIA AND
 OPERATING CHARACTERISTICS.

FIGURE 6.7-5
 PUBLIC SERVICE COMPANY OF COLORADO
 SOLAR BREAK-EVEN INVESTMENT
 IN THE YEAR 2000

SOUTHWEST PROJECT

FIGURE 6.7-6
ARIZONA PUBLIC SERVICE COMPANY
SOLAR BREAK-EVEN INVESTMENT
IN THE YEAR 2000

FIGURE 6.7-7
INCENTIVE REQUIREMENTS FOR
YEAR 2000

PUBLIC SERVICE COMPANY OF
NEW MEXICO

FUEL ESCALATION - 7.0%

SOUTHWEST PROJECT

FIGURE 6.7-8
INCENTIVE REQUIREMENTS FOR
YEAR 2000
SALT RIVER PROJECT
FUEL ESCALATION - 5.3%

FIGURE 6.7-9
 INCENTIVE REQUIREMENTS FOR
 YEAR 2000
 EL PASO ELECTRIC COMPANY
 FUEL ESCALATION - 7.2 %

SOUTHWEST PROJECT

FIGURE 6.7-10
INCENTIVE REQUIREMENTS FOR
YEAR 2000

SOUTHERN CALIFORNIA
EDISON COMPANY

FUEL ESCALATION-6.7%

SOUTHWEST PROJECT

FIGURE 6.7-11
INCENTIVE REQUIREMENTS FOR
YEAR 2000
PUBLIC SERVICE COMPANY
OF COLORADO
FUEL ESCALATION - 8.0%

SOUTHWEST PROJECT

FIGURE 6.7-12

INCENTIVE REQUIREMENTS FOR
YEAR 2000

ARIZONA PUBLIC SERVICE COMPANY
FUEL ESCALATION - 4.9 %

FIGURE 6.7-13
COMPARISON OF BREAK-
EVEN INVESTMENT AND
FINANCIAL INCENTIVE
REQUIREMENTS
SOLAR THERMAL,
600MWh ENERGY STORAGE

**FIGURE 6.7-14
COMPARISON OF BREAK-
EVEN INVESTMENT AND
FINANCIAL INCENTIVE
REQUIREMENTS
SOLAR THERMAL,
200MWh ENERGY STORAGE**

SOLAR THERMAL WITH
NO ENERGY STORAGE
5% MARKET PENETRATION
BY THE YEAR 2000.

FIGURE 6.7-15
COMPARISON OF BREAK-
EVEN INVESTMENT AND
FINANCIAL INCENTIVE
REQUIREMENTS
SOLAR THERMAL,
NO ENERGY STORAGE

PHOTOVOLTAIC WITH NO
ENERGY STORAGE
5% MARKET PENETRATION
BY THE YEAR 2000.

- RANGE OF MATURE PLANT COSTS
- 10%
7%
BREAK-EVEN INVESTMENT WITH WEIGHTED AVERAGE OF ESCALATION FOR FUELS REPLACED NOTED TO LEFT.
- 8%
10%
INCREMENTAL INCREASE TO BREAK-EVEN INVESTMENT BASED ON ASSUMED FUEL ESCALATION OF 8% AND 10%
- DOE COST GOAL BASED ON A FLAT-PLATE MODULE OR CONCENTRATOR ARRAY PRICE OF \$200 PER PEAK KILOWATT IN 1990 (1975 DOLLARS) - SEE SUBSECTION 5.2.5 IN THE TECHNICAL STUDIES VOLUME FOR MORE INFORMATION.

FIGURE 6.7-16
COMPARISON OF BREAK-
EVEN INVESTMENT AND
FINANCIAL INCENTIVE
REQUIREMENTS
PHOTOVOLTAIC,
NO ENERGY STORAGE

FIGURE 6.7-17
COMPARISON OF BREAK-EVEN INVESTMENT AND FINANCIAL INCENTIVE REQUIREMENTS
WIND-10MWh ENERGY STORAGE
WIND - NO ENERGY STORAGE
SOUTHWEST PROJECT

**RETROFIT HYBRID
5% MARKET PENETRATION *
BY THE YEAR 2000**

* MARKET PENETRATION FOR PSNM IS 1%.

**FIGURE 6.7-18
COMPARISON OF BREAK-EVEN INVESTMENT AND FINANCIAL INCENTIVE REQUIREMENTS
RETROFIT HYBRID**

SOUTHWEST PROJECT