27
3-3-78
25 ap. to NTIS

GENERAL ELECTRIC

REPORT NO. AL0-3686-14
MARCH 19, 1977

CONCEPTUAL DESIGN AND SYSTEMS ANALYSIS OF PHOTOVOLTAIC SYSTEMS

FINAL REPORT

MASTER

VOLUME II
STUDY RESULTS

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.

NOTICE

This report was prepared as an account of work sponsored by the United States Government. Neither the United States nor the United States Energy Research and Development Administration, nor any of their employees, nor any of their contractors, subcontractors, or 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.

REPORT NO. ALO-3686-14
MARCH 19, 1977

CONCEPTUAL DESIGN
AND
SYSTEM ANALYSIS
OF
PHOTOVOLTAIC SYSTEMS

FINAL REPORT

VOLUME II
STUDY RESULTS

NOTICE
This report was prepared as an account of work sponsored by the United States Government. Neither the United States nor the United States Department of Energy, nor any of their employees, nor any of their contractors, subcontractors, or 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.

CUSTOMER: SANDIA LABORATORIES
ERDA CONTRACT: EY-76-C-04-3686
STUDY PERIOD: JUNE 1975 THROUGH MARCH 1977

ADVANCED ENERGY PROGRAMS

GENERAL ELECTRIC

SPACE DIVISION

Valley Forge Space Center

P. O. Box 8555 • Philadelphia, Penna. 19101

DISTRIBUTION OF THIS DOCUMENT IS UNLIMITED

THIS PAGE
WAS INTENTIONALLY
LEFT BLANK

FOREWORD

This report presents the results of a study on the Conceptual Design and System Analysis of Photovoltaic Power Systems. The program was performed under ERDA Contract EY-76-C-04-3686 for the Sandia Laboratories under the guidance of Dr. Billy Marshall.

The report consists of three volumes. Volume I contains a Study Summary of the major study results. Volume II contains the detailed results pertaining to on-site residential photovoltaic systems, central power plant photovoltaic systems, and intermediate size systems applied to commercial and public buildings. Volume III contains supporting appendix material.

The study was conducted by the Advanced Energy Programs of the General Electric Company Space Division. Mr. Aaron Kirpich served as Program Manager and prepared this report with contributions from the following individuals: R. Allred, B. Ayres, R. Biddescombe, E. Buerger, L. Davis, W. Hausz, S. Irwin, W. Kornrumpf, R. Linden, R. McCarthy, G. O'Brien, R. Pohl, N. Shepard, C. Shilas, H. Stoll, J. Triandafyllis, E. Tschupp, and R. Usher. Mr. R. Barchet, Manager, Photovoltaic Programs, and Mr. G. O'Brien provided valuable editorial comment on the content and organization of this report.

The following organizations participated in this study:

Organization	Contribution
General Electric Company	
Advanced Energy Programs - Space Division	Overall Responsibility
Corporate Research and Development	Power Conditioning - Residential System
Electric Utility Systems Engineering Department	Economic Analysis
Installation and Service Engineering Operation	Central Power Plant Electrical Systems
TEMPO - Center for Advanced Studies	Impact Assessments
*Arizona Public Service	Consultation, Utility/ Residence Interface
*Florida Power & Light	Consultation, Utility/ Residence Interface
*Pacific Gas & Electric	Consultation, Utility/ Residence Interface
*Pennsylvania Power and Light	Consultation, Utility/ Residence Interface
*Philadelphia Electric Company	Consultation, Utility/ Residence Interface
*Tredyffrin - Easttown School Districts, Tredyffrin Township, Pa.	Architectural & Engineering Data, Valley Forge Junior High School
C&D Batteries	Lead-acid battery data
Halsey & Ryder, Architects	Roof installation cost data
Sheldahl Corporation	Concentrator Data
Solarex Corporation	Solar Cell Data

*Non-funded support

TABLE OF CONTENTS

VOLUME II

PART

- A ON-SITE RESIDENCE SYSTEM
- B CENTRAL POWER PLANT SYSTEM
- C INTERMEDIATE SIZE SYSTEMS

PART A
ON-SITE RESIDENCE SYSTEM

TABLE OF CONTENTS

Section	Page
1	SUMMARY AND CONCLUSIONS 1-1
	1.1 Summary 1-1
	1.2 Conclusions 1-7
2	CONCEPTUAL DESIGN 2-1
	2.1 Introduction 2-1
	2.2 Concept No. 1 2-2
	2.3 Concept No. 2 2-7
	2.4 Concept No. 3 2-7
	2.5 Concept No. 4 2-9
	2.6 Concept No. 5 2-10
	2.7 Concept No. 6 2-10
3	PERFORMANCE ANALYSIS 3-1
	3.1 Introduction 3-1
	3.2 System Modeling Methodology 3-2
	3.2.1 Direct Charge System 3-2
	3.2.2 Parallel Maximum Power Tracker System. 3-4
	3.2.3 No Battery/Feedback System 3-5
	3.2.4 Direct Charge/Air Cooled System 3-5
	3.2.5 Photovoltaic/Thermal Total Energy System 3-6
	3.3 Subsystem Analytical Models 3-8
	3.3.1 Solar Array Electrical Model 3-8
	3.3.2 Roof Mounted Array 3-10
	3.3.3 Battery Model 3-20
	3.3.4 Electrical Load Demand. 3-22
	3.3.5 Electrically Driven Heat Pump 3-22
	3.3.6 Collector Heat Exchanger 3-25
	3.4 Sensitivity Analysis Results 3-26
	3.4.1 Approach. 3-26
	3.4.2 Number of Series Solar Cells 3-27
	3.4.3 Solar Roof Azimuth Angle 3-28
	3.4.4 Solar Roof Slope Angle 3-28
	3.4.5 System Sizing 3-30
	3.5 System Comparison Results 3-35
	3.6 References, Section 3 3-39

TABLE OF CONTENTS (Continued)

Section	Page
4	ECONOMIC ANALYSIS. 4-1
4.1	Introduction 4-1
4.2	Levelized Busbar Cost Analysis 4-1
4.2.1	Analysis Methodology 4-1
4.2.2	LBC Analysis Input Data. 4-2
4.2.3	LBC Analysis Results 4-8
4.3	Location Sensitivity 4-23
4.3.1	Regional Levelized Busbar Costs. 4-23
4.3.2	Comparison with Regional Price of Electricity 4-28
4.4	Economic Worth to Utility Systems 4-35
4.4.1	Introduction 4-35
4.4.2	Utility Evaluation Considerations. 4-36
4.4.3	Evaluation of PV Benefits 4-40
4.4.4	Economic Evaluation Results 4-40
4.4.5	PV System Cost Allocations 4-46
4.4.6	Conclusions of PV Worth Analysis 4-47
4.5	Reference Section. 4-48
5	SUBSYSTEM ANALYSIS 5-1
5.1	Introduction 5-1
5.2	Interface with Electric Utility 5-1
5.2.1	Introduction and Summary 5-1
5.2.2	Detailed Discussion 5-3
5.3	Solar Array Studies 5-7
5.4	Energy Storage. 5-12
5.5	Power Conditioning 5-19
5.5.1	Performance Considerations 5-21
5.5.2	Inverter Design 5-23
5.5.3	Shunt Regulator 5-34
5.6	Lightning Protection 5-36
5.7	Subsystem Cost Data 5-39
5.7.1	Solar Array 5-39
5.7.2	Batteries. 5-39
5.7.3	Inverters. 5-39
6	TECHNOLOGY NEEDS. 6-1
6.1	Introduction 6-1
6.2	Solar Arrays 6-1
6.3	Batteries. 6-2
6.4	System Electronics 6-3

TABLE OF CONTENTS (Continued)

Section	Page
7	RESIDENTIAL MARKET PENETRATION. 7-1
7.1	Introduction 7-1
7.2	PEPS Applied to New Construction 7-1
7.3	PEPS Applied to Retrofit Market 7-3
7.3.1	Retrofit Penetration Scenarios 7-5
7.3.2	Design Implication 7-5
7.3.3	References, Section 7 7-5
8	SPECIFICATIONS 8-1
8.1	Residence Photovoltaic System Guideline Specification 8-1
8.1.1	Scope 8-1
8.1.2	Electrical Output 8-1
8.1.3	Performance 8-1
8.1.4	Utility Interface 8-2
8.1.5	Physical Characteristics 8-2
8.1.6	Life 8-2
8.1.7	Grounding 8-2
8.1.8	Lightning. 8-3
8.1.9	Repair and Maintenance 8-3
8.2	Solar Array Guideline Specification 8-3
8.2.1	Type 8-3
8.2.2	Physical Characteristics 8-3
8.2.3	Electrical Characteristics 8-3
8.2.4	Interconnection. 8-4
8.2.5	Performance 8-4
8.2.6	Environmental Durability 8-4
8.2.7	Repair/Replacement 8-4
8.2.8	Auxiliary Devices 8-4
8.2.9	Wiring 8-4
8.3	Battery System Guideline Specification 8-4
8.3.1	Type 8-4
8.3.2	Rating. 8-5
8.3.3	Performance 8-5
8.3.4	Physical Characteristics 8-5
8.3.5	Enclosure 8-5
8.3.6	Safety 8-5

TABLE OF CONTENTS (Continued)

Section	Page
8.4 DC/AC Inverter Guideline Specification	8-5
8.4.1 Type	8-5
8.4.2 Output	8-5
8.4.3 Current Limit	8-6
8.4.4 Solar Array Power Tracking	8-6
8.4.5 Parallel Operation with Utility	8-6
8.4.6 Performance	8-6
8.4.7 Harmonic Content	8-6
8.4.8 Isolation	8-6
8.4.9 Utility Presence	8-6
8.4.10 Inverter Startup	8-7
8.4.11 Heat Removal	8-7
8.4.12 Life	8-7
8.4.13 Safety	8-7
8.5 DC/AC Inverter Guideline Specification	8-7
8.5.1 Type	8-7
8.5.2 Output	8-7
8.5.3 Current Limit	8-7
8.5.4 Control	8-7
8.5.5 Battery Status Tie-In	8-8
8.5.6 Parallel Operation with Utility	8-8
8.5.7 Performance	8-8
8.5.8 Harmonic Content	8-8
8.5.9 Isolation	8-8
8.5.10 Utility Presence	8-8
8.5.11 Startup	8-8
8.5.12 Heat Removal	8-9
8.5.13 Life	8-9
8.5.14 Safety	8-9
8.6 Battery Charge Regulator Guideline Specification	8-9
8.6.1 Type	8-9
8.6.2 Charge Profile	8-9
8.6.3 Discharge Profile	8-10
8.6.4 Solar Array Shunting Circuits	8-10
8.6.5 Controls	8-10

LIST OF ILLUSTRATIONS

Figure		Page
1-1	PV Breakeven Cost as a Function of Capacity Factors	1-1
2-1	Photovoltaic Powered Residences	2-3
2-2	Functional Block Diagram, System with Energy Storage	2-4
2-3	Diversified Load Demand Profile	2-6
2-4	Hot Water Heater Electrical Load Demand Profile	2-6
2-5	Typical Hourly Heating Demand from Building Transient Thermal Loads Program	2-7
2-6	Photovoltaic Power System Performance for a Typical Week in January for Washington, D. C. Site Location	2-8
2-7	Functional Block Diagram, System Without Energy Storage	2-9
2-8	Solar Array Cooling Methods	2-10
3-1	Simplified Functional Block Diagram of Direct Charge System Approach	3-3
3-2	Simplified Functional Block Diagram of the Parallel Maximum Power Tracker System Approach	3-4
3-3	Simplified Functional Block Diagram of the No Battery/Feedback System	3-5
3-4	Simplified Functional Block Diagram of Direct Charge/Hybrid System	3-7
3-5	Terrestrial Solar Cell I-V Characteristics	3-8
3-6	Determination of Diffuse Insolation	3-9
3-7	Solar Array Heat Transfer Mechanisms	3-11
3-8	Results of Solar Cell Temperature Prediction Model	3-14
3-9	Definition of Terms for Underside Cooling	3-15
3-10	Cell Temperature vs. Wind Speed	3-16
3-11	Hybrid Photovoltaic/Solar Thermal Flat Plate Collector	3-17
3-12	Sheet and Tube Dimensions	3-18
3-13	Absorptance-Transmittance Product for Solar Cells and Single Lexan Cover	3-20
3-14	Typical Hybrid Lead-Acid Battery Charge/Discharge Characteristics	3-21
3-15	Diversified Load Demand Profile	3-23
3-16	Hot Water Heater Electrical Load Demand Profile	3-23
3-17	Performance of 3-Ton Current Design Heat Pump in Heating Mode Without Defrosting	3-24
3-18	Determination of the Optimum Number of Series Solar Cells	3-28
3-19	Determination of the Optimum Solar Roof Azimuth Angle Orientation	3-28

LIST OF ILLUSTRATIONS (Continued)

Figure		Page
3-20	Determination of Optimum Solar Roof Slope Angle	3-29
3-21	System Performance vs. Solar Array and Battery Size	3-31
3-22	Monthly Load and PV Output for UNREG System	3-33
3-23	Monthly Load and PV Output for NOBATTERY System	3-34
4-1	Relationship of Levelized Cost to Capacity, Battery, and Maintenance Costs	4-3
4-2	Relationship of Fixed Charge Rate and Levelized Cost	4-4
4-3	Capital Cost for Nominal System.	4-7
4-4	Cost Tradeoffs for Phoenix Location	4-10
4-5	Cost Tradeoffs for Cleveland Location.	4-11
4-6	Cost Tradeoffs for Miami Location	4-12
4-7	Levelized Busbar Cost in Phoenix	4-14
4-8	Levelized Busbar Cost in Cleveland.	4-16
4-9	Levelized Busbar Cost in Miami.	4-16
4-10	Comparison of Levelized Busbar Costs	4-17
4-11	Effect of Cell Efficiency on System Capital Cost	4-19
4-12	Effect of Cell Efficiency on Levelized Cost	4-19
4-13	Effect of Investment Credit on Levelized Cost	4-21
4-14	Effect of Consumer Income Tax Bracket on Levelized Cost	4-21
4-15	Linear Fit of Temperature Corrected Calculated Annual Solar Array Energy Output	4-24
4-16	Correction of System with and Without Storage	4-25
4-17	Historic Residential Price of Electricity	4-29
4-18	Average Residential Price of Electricity in Sample Cities and Census Divisions, 1975	4-30
4-19	Photovoltaic Target Areas for \$100/m ² Solar Array Cost	4-31
4-20	Photovoltaic Target Areas for \$50/m ² Solar Array Cost.	4-32
4-21	Photovoltaic System Cost Reductions	4-33
4-22	Cities in which Residential Photovoltaic Systems are Potentially Competitive, 1985-2000	4-34
4-23	Dispatch of Generating Unit Types	4-36
4-24	Daily Variation of the Risk of Losing Load	4-37
4-25	Daily Variation of 1000 MW of Residential PEPS Capacity	4-38
4-26	Hourly Risk-Weighted Effective Capability of 1000 MW Residential PV Capacity	4-39
4-27	PV Breakeven Cost as a Function of Penetration	4-41
4-28	PV Breakeven Cost as a Function of Capacity Factor	4-42
4-29	PV Capacity Credit as a Function of Capacity Factor	4-43

LIST OF ILLUSTRATIONS (Continued)

Figure		Page
4-30	PV Breakeven Cost and Energy Displacement as a Function of Nuclear Capacity Displacement	4-43
4-31	PV Breakeven Cost as Influenced by Plant and Fuel Escalation	4-45
4-32	PV Output Profile with Storage Capacity - June, Washington, D. C. Area	4-46
4-33	PV Breakeven Cost as a Function of Storage Capacity in the Washington, D. C. Climatic Area	4-46
4-34	Allocation of Capital Costs	4-47
5-1	Solar Shingle Design	5-8
5-2	Solar Cell Shingle (Roof) Wiring Schematic	5-9
5-3	Typical Solar Cell Shingled Roof	5-11
5-4	Forced Air Cooled Solar Cell Panel	5-13
5-5	Installation of Forced Air Cooled Panels	5-15
5-6	Hybrid Photovoltaic-Thermal Collector Panel	5-17
5-7	C&D Hybrid Lead-Acid Battery Module	5-20
5-8	Typical Normalized Inverter Characteristics	5-21
5-9	Distribution of Load Power Level for Typical Residence	5-22
5-10	Residential Inverter Efficiency	5-22
5-11	Excess Residential Load	5-23
5-12	Double Bridge Inverter with Shared Transformer-Coupled Commutating Circuit, Including a Two-Level Square-Pulse-Froming Network	5-25
5-13	Suggested Construction of Output Transformer Using Standard E-Curve or Laminations Leakage Reactance Between Primary and Secondary Windings Serves as AC Output Filter	5-28
5-14	Alternative Construction of Output Transformer Having Higher Leakage Reactance	5-28
5-15	Generation of Stepped Voltage Waveform Having Adjustable Fundamental and No Third Harmonic Phase Shift Control Method	5-29
5-16	Generation of Stepped Voltage Waveform Having Adjustable Fundamental and No Third Harmonic Pulse Width Control Method	5-30
5-17	Typical Phaser Diagram and Inverter	5-32
5-18	System Block Diagram	5-33
5-19	Block Diagram of Shunt Regulator	5-35
5-20	Lightning Protection Concept	5-37
5-21	Lightning Protection	5-38
5-22	Cost of Hybrid Lead-Acid Battery System	5-40

LIST OF ILLUSTRATIONS (Continued)

Figure		Page
7-1	Potential Growth in New Residential PV Systems Based on Regional Competitive Cost Analysis.	7-2
7-2	Photovoltaic Market Penetration Scenario, New Construction Only . .	7-4
7-3	Photovoltaic Market Penetration Scenario, New Construction Plus Retrofit	7-4

LIST OF TABLES

Table		Page
1-1	Study Results Summary	1-3
2-1	Conceptual Design Characteristics for Residence Photovoltaic System .	2-1
2-2	System Characteristics, Concept No. 1	2-4
3-1	Assumed Parameters for Array Temperature Determination	3-14
3-2	Values of Collector Physical Parameters	3-20
3-3	Station Locations and Other Pertinent Information	3-27
3-4	Optimum Solar Roof Slope Angle	3-30
3-5	Annual System Output	3-32
3-6	Residential Electrical Load Demand	3-30
3-7	Comparison of Direct Charge System with No-Battery/Power Feed- back System for 84 m ² Solar Cell Area	3-36
3-8	Comparison of Other System Options for Cleveland, Ohio Site Location with 84 m ² Solar Cell Area and 48 kW-Hr Battery Capacity. .	3-37
3-9	Hybrid System Design Parameters	3-39
4-1	Economic Assumptions for Utility Ownership Economic Analysis . . .	4-2
4-2	Economic Assumptions for Consumer Ownership Economic Analysis. .	4-2
4-3	Capital Costs of Residential Photovoltaic System with Energy Storage (Concept No. 1)	4-5
4-4	Capital Costs of Residential Photovoltaic System Without Energy Storage (Concept No. 4).	4-6
4-5	Operating Costs of Residential Photovoltaic Systems With and Without Batteries	4-6
4-6	Yearly Output of Solar Photovoltaic System	4-8
4-7	Calculation of Levelized Busbar Cost (Example)	4-9
4-8	Optimum Levelized Cost (\$/kW-Hr) Systems with Energy Storage . .	4-12
4-9	Comparison of Levelized Costs (\$/kW-Hr) for Optimum and Nominal Systems with Energy Storage	4-13
4-10	Baseline No Battery Case Levelized Cost of Power Results for an 84-Square Meter Solar Cell Area	4-14
4-11	Summary of Domestic Hot Water System	4-23
4-12	Performance of System Without Energy Storage at 10 Selected Locations	4-23
4-13	Ranking of Locations by System Output.	4-26
4-14	Calculation of Levelized Cost.	4-28
4-15	Conventional Electricity Price Projections	4-29
4-16	PV Study Results	4-40

LIST OF TABLES (Continued)

Table		Page
5-1	Utility Interface Issues	5-2
5-2	Shunt Regulator Cost.	5-41
5-3	Inverter Costs.	5-42
6-1	Component Technology Status On-Site Residence P/V Systems	6-1
6-2	Uninterruptible Power System Suppliers	6-4
7-1	Fisher-Pry Takeover Times	7-3
7-2	Fisher-Pry Photovoltaic Penetration Scenarios-Key Parameters	7-3

SECTION 1

SUMMARY AND CONCLUSIONS

This volume (Part A) presents the results of the on-site residence photovoltaic power system. The scope of the study encompassed the development of conceptual designs, evaluation of their performance, determination of costs, identification of required technology developments, and an assessment of significant institutional impacts.

1.1 SUMMARY

Conceptual designs were developed around the application to single family residences located in three selected regions of the U.S. : Phoenix, Arizona; Cleveland, Ohio; and Miami, Florida. Electrical loads were based on assuming the residences were all-electric in nature. Fixed daily profiles were used for diversified loads (lighting, appliances, etc.) and domestic hot water needs which resulted in a daily demand of 35 kilowatt-hours. Variable profiles were used for heating and cooling loads which were calculated using hourly weather data. A heat pump was used for heating and cooling with resistance heating augmentation when required. The monthly averaged daily electrical heating and cooling varied from 3 kWh (in February) to 52 kWh (in August) for Phoenix with an annual demand of 7921 kWh. In Cleveland the values varied from 85 kWh (in January) to 5 kWh (in May) with an annual demand of 12096 kWh.

Solar array concepts were restricted to rooftop installations with areas limited by roof sizes consistent with houses of contemporary design. Emphasis was placed on planar solar array designs cooled by natural air convection, installed on south-oriented sloping roofs. Forced air convection and liquid cooled designs were also considered. All concepts were based on using 5.72 cm (2.25 inch) diameter silicon solar cells having an air mass one (AM 1) efficiency of 13.4 percent at a temperature of 28°C and a solar intensity of 100 milliwatts per square centimeter. A nominal design for the rooftop solar array used 32,832 round cells arranged in a redundantly connected matrix of 513 cells in series by 64 cells in parallel. The cell area was 84 square meters mounted on a roof having dimensions of 7.32 x 14.64 meters (24 x 48 feet). Using 19-cell hexagonal shingle assemblies (15.24 cm edge length) as the basic array building blocks, the packing factor within each shingle was determined to be 0.807. With allowance for non-photovoltaic shingles along the roof edges, the overall roof packing factor was determined to be 0.786.

Systems both with and without battery energy storage were studied. The design for the system with energy storage used a 96-cell, 48 kilowatt-hour lead-acid battery in parallel with the solar array. All photovoltaic power was used for the residence loads or battery charging and was furnished to the loads in the form of three-wire, 120/240 Volt, single-phase ac developed through a dc/ac inverter in parallel with the incoming utility line. This arrangement provided instantaneous backup power in the event of any photovoltaic power system interruption and to cover large peak loads. The decision to invert photovoltaic and battery power to ac was based on an investigation of dc versus ac distribution which concluded that ac would have the least impact relative to its match with the large class of ac operated devices. Although the dc/ac inversion process involves losses, these can be potentially recovered for

useful thermal purposes. Any dc regulation would incur similar losses, a likelihood in view of the large voltage swing of the photovoltaic source.

The system without energy storage also used a dc/ac inverter in parallel with the incoming utility line, but in this case solar array power in excess of demand was fed back through the incoming utility line to be used elsewhere in the utility system. For this system the inverter was controlled to extract power from the solar array at its maximum power point.

Using computer simulations and hourly weather data for the regions being studied, performance analyses determined hourly and annual energy production. This was compared with the annual demand to provide a displacement factor which describes the percentage of utility energy displaced by the photovoltaic system. For the design with energy storage, displacement factors varied from 38 percent for Cleveland to 80 percent for Phoenix. Performance sensitivity to a number of variables produced the following results: (1) the best roof tilt angle was found to be somewhat less than the latitude angle and ranged from 4° less in Cleveland (latitude 41°) to 11° less in Phoenix (latitude 33°); (2) a direct southward oriented roof was best in all cases, but $\pm 15^{\circ}$ from south did not result in significant penalties; (3) maximum power tracking of the solar array was found to result in negligible improvement over direct charge systems; (4) for direct charge systems, a value of 5.35 for the ratio of series solar cells to series battery cells was found to be the best compromise for all regions considered and was close to the optimum value in all cases; (5) frequent updating of the roof tilt angle to accommodate the changing declination angle of the sun resulted in negligible performance improvement; (6) forced air cooling of the underside of the solar array resulted in fan power requirements which just about cancelled any performance gain; (7) natural convection cooling of the top and underside of the solar array was found to yield only slight improvement over topside cooling alone and did not justify the additional ducted paneling expense involved; (8) the removal of heat from the dc/ac inverter by circulating fluid appears to be a worthwhile expense in terms of the energy savings possible; (9) photovoltaic/thermal collectors reduced the all-electric residence demand by 25 percent, for the one case studied for Cleveland, but only raised the displacement factor from 38 percent to 45 percent due mainly to decreased photovoltaic efficiency at the higher temperature operation of the solar arrays. (See Part C, Intermediate School System, for more extended analysis of combined photovoltaic/thermal systems.)

Economic analyses were performed in several stages. In the initial stage, analyses were performed in conjunction with the performance results to determine the most cost effective designs. Results were expressed in terms of levelized busbar costs (LBC) which represent annualized 1975 constant year dollars per kilowatt-hour of energy produced. These costs were found to be relatively constant over wide ranges of array and battery sizes. A "weak" optimum appeared to exist for the nominal design in all regions studied. The effect on levelized cost of too large an array or battery could be noticed indicating their poor utilization. No such optimization was found for the system without energy storage since all energy produced was assumed to be utilized either directly or as feedback to the utility.

For the system with energy storage, levelized costs were found to range from 8.5¢/kWh for Phoenix to 15¢/kWh for Cleveland based on a modular (cells bonded and interconnected to a

modular substrate) solar array cost of 50¢/peak Watt. The system without batteries yielded levelized costs of 3.5¢/kW-hr. for Phoenix to 6¢/kWh. for Cleveland. The levelized costs were based on utility ownership of the photovoltaic system using a before-tax discount factor of 15 percent, 30 year life, a corporate tax of 48 percent, and an investment credit of 10 percent.

In the second stage of economic evaluation, the results for Phoenix, Cleveland and Miami were used to develop the regional sensitivity of the levelized busbar cost. Insolation and mean temperature data from the Climatic Atlas of the U.S. were used to establish the sensitivity, considering basic solar array costs of \$50 and \$100 per square meter. Comparisons were then made with projected regional costs of electricity. At \$100/m² the best regions identified were Hawaii, Puerto Rico, and New York City. At \$50/m² many additional regions emerged including the southern tier of states and New England.

The third stage of economic evaluation determined the worth of residential PV generation in terms of competing forms of utility system generation. The residential PV systems were considered to be utility owned, contributing their output to the utility network. Analytical techniques developed by GE's Electric Utility Systems Engineering Department for the electric industry were employed. Calculations were performed for utilities located in Washington, D. C. ; Phoenix, Arizona; and Miami, Florida using projections of load and generation growth out to the year 2000. Base case calculations first determined optimum utility system configurations without PV generation using an appropriate set of economic assumptions regarding plant and fuel costs. The calculations were then repeated for an assumed photovoltaic penetration with hourly weather data used to define hour by hour generation. PV worth was determined as the difference in the present worth of the conventional generation for the two cases. The key results of these studies are summarized on Figure 1-1 which correlates the worth (breakeven cost) of the residential PV system with the capacity factor, defined as the ratio of the average annual output to the system rating, taken to be 11.25 kW. The independent evaluation of introducing PV system into three widely differing utilities produced the proportional relationship shown. Since the capacity factor is proportional to the annual energy output, Figure 1-1 provides a convenient means for estimating breakeven costs in various regions. For example, the annual energy output for the no-storage residence PV system in Cleveland was found to be 62 percent of that in Phoenix. Therefore, the estimated breakeven cost is 62 percent of the \$4,100 breakeven cost in Phoenix or \$2,540 per residence PV system.

● PLOT BASED ON FOLLOWING CONVENTIONAL PLANT ASSUMPTIONS (1975 \$'s):

GENERATION TYPE	PLANT COST, \$/KW	FUEL COST, \$/MWH
NUCLEAR	540	4.20
COAL-STEAM	490	12.50
OIL-STEAM	350	20.80
GAS TURBINE	140	27.00

Figure 1-1. PV Breakeven Cost as a Function of Capacity Factor

Additional cases considered a pessimistic set of economic assumptions with higher rates of inflation and the possibility of a nuclear power plant moratorium in 1985. Either of these scenarios resulted in an increase of about 25 percent in the PV system worth for the three regions considered. The system in Washington with storage and feedback, indicated a worth improvement over the system without storage in Washington, in spite of a reduced annual energy output. However, storage costs would have to be less than \$20/kWh with a minimum life of 30 years to gain the benefit of the worth improvement. The system in Phoenix with 24 hour storage but without feedback, indicated a significant drop in system worth. This is attributed to the utilization of the stored PV energy during night-time hours when less costly energy from the utility is available.

Although the system with feedback and no storage emerged as the most economical approach, a number of questions arise relative to its practical integration into a utility network. Does the feedback of excess array output to the utility grid impose severe technical difficulties? Should ownership of the system reside with the owner or utility? If consumer owned, how would credit for feedback be handled? What are the legal ramifications if the system is utility owned? These and other questions were addressed in an investigation undertaken with the following utility companies:

1. Arizona Public Service
2. Florida Power and Light
3. Pacific Gas and Electric
4. Pennsylvania Power and Light
5. Philadelphia Electric

Questionnaires were submitted to each utility company and discussions held in a series of followup meetings. The following represents the consensus of opinion on the major issues considered:

1. Technical Issues

There are no barriers for implementing photovoltaic feedback energy from multiple small systems into the utility networks. Depending on the amount of feedback, as established by the number and concentration of photovoltaic powered residences, varying impacts might be encountered and would involve such considerations as distribution, transformer and circuit breaker sizing. A matter of concern revolves around the question of safety to repair crews who would have to cope with "hot" lines on both sides of a particular fault. A possible solution to this problem would be to make the photovoltaic system output operationally dependent on the presence of utility power. With any loss of utility power, the output of the photovoltaic system would be interrupted automatically. Specific implementation schemes would be worked out on the basis of existing and developing control equipment. Some of the equipment is currently being considered for incorporation into utility networks for other reasons. Some minor changes in operating procedures and rules may be required, but are not of a serious or limiting nature.

2. Institutional Issues

Questions relating to ownership of the residential photovoltaic systems also are not viewed as significant barriers by the utilities. There are specific problems that can be worked out by appropriate contractual arrangements. The utilities contacted were willing and anxious to lead the way in working out these techniques rather than being confronted with solutions imposed by others (regulatory commissions, etc.). Ownership of the residential rooftop by either consumer or utility can be accommodated by the utility. If owned by the utility, it would assume responsibility for all of the associated problems of maintenance, liability, etc.

3. Economic Issues

The major issue as seen by the utilities is one of economic viability including life and maintenance characteristics, and its translation into equitable rates for consumed and supplied energy. For consumer owned PV systems it was the considered opinion that feedback would be credited only for its energy content and not for any contribution to capacity displacement. Ownership of residential PV systems by the utility would be contingent on both the physical and analytical demonstration of its economic worth. Studies for determining this worth, of the type cited earlier, would have to be carried out within the framework of each utility's operating characteristics before widespread applications would be considered. Utilities are working on analytic and demonstration programs with these objectives in mind.

Several additional institutional issues were focussed on estimating penetration rates, potential fuel savings, the reduction of fossil plant emissions due to displacement by photovoltaic generation and material availability impacts.

Assuming the introduction of residential photovoltaic power generation in 1985, and an intermediate case market penetration profile modeled according to comparable technological innovations, it is estimated that 17 percent of the homes existing in the year 2020 that were built after 1985, would be equipped with photovoltaic power systems. This penetration results in an annual fuel saving conservatively estimated to be 6×10^{14} Btu's. This corresponds to a reduction in fossil plant emissions due to eight baseload plants rated at 1000 MW (e) each. Material impacts are negligible, except possibly for lead that would be used for systems with battery energy storage.

The consideration of retrofitting homes with photovoltaic systems vastly increases the potential market. Because of the relative performance insensitivity to roof slope and azimuth angles, many homes could be successfully retrofitted with minimal building modifications or performance penalties. The shingled solar array concept developed during the study is particularly adaptable to conventional sloping roof construction.

1.2 CONCLUSIONS

The major conclusions of the study are as follows:

1. For average size all-electric houses, on-site residence photovoltaic systems with energy storage can achieve energy displacements varying from 38 to 80 percent for the range of U. S. weather conditions. Identically sized systems, without energy storage and the feedback of photovoltaic power to the utility grid can achieve displacements of 51 to 98 percent. This improvement results from the avoidance of battery inefficiency and assumes retrieval of the feedback energy on a one-for-one basis during non-sunlight hours.
2. Using a solar array cost of \$500 per peak kilowatt, the levelized busbar cost for the residential system without energy storage varies from 3.5 cents/kWH in Phoenix to 6.0 cents/kWH in Cleveland. For systems with energy storage, the levelized busbar costs are more than doubled. Comparing levelized busbar costs with projected regional prices of electricity, photovoltaic installations are potentially attractive in a number of U. S. regions as solar array costs approach \$500 per peak kilowatt. The regions include the Southwest, Florida, and New England.
3. Within the context of utility system economics, credits for capacity and energy displacements indicate that residential photovoltaic system costs are high by factors of 1.5 to 2, based on solar array costs of \$500 per peak kilowatt. Systems with energy storage are high by factors of 4 and greater. ~~depending on how much storage is used and whether or not it is specifically dedicated to a single residence.~~
4. In the view of five utility companies who were consulted, the feedback of residential photovoltaic power to the utility network is not considered to be of a serious or limiting nature. Technical problems to be solved concern the quality of the feedback and interruption of the feedback for safety reasons. These problems appear to be solvable with available technology and within reasonable cost.
5. Ownership of the rooftop residential PV system by either the utility or consumer can be accommodated by appropriate contractual arrangements. Ownership by the utility would involve agreements to provide for residence property transfer, liabilities and rights of access for service and maintenance. Consumer ownership would involve two-way metering of power flow with a probable reduced rate of compensation for feedback power. Assuming competitive PV generation, incentives to the utilities for installing residential PV systems are the low cost for use of the roof area (as opposed to using open land areas), and the ability to increase generation in small increments. With utility ownership, the incentive to the homeowner would be the utility installation and maintenance of a weatherproof roof.

SECTION 2
CONCEPTUAL DESIGN

SECTION 2

CONCEPTUAL DESIGN

2.1 INTRODUCTION

Six conceptual designs for the on-site residential photovoltaic system, having the characteristics summarized on Table 2-1, were investigated. Principal emphasis was placed on Concepts 1 and 4, comparing systems with and without energy storage. Concepts 2 and 3 represented different mechanizations of Concept 1; Concepts 5 and 6 were developed to examine the potential for improved thermal performance by using forced fluid cooling of the solar array. A number of other design variations which will be identified in the following concept descriptions were also examined. In all of the concepts, the electrical output is in the form of three wire, 120/240 Volt, 60 Hertz, ac power identical to that used in most residences.

**TABLE 2-1. CONCEPTUAL DESIGN CHARACTERISTICS FOR
RESIDENCE PHOTOVOLTAIC SYSTEM**

Concept Number	Code Name	Solar Array	Array Cooling	Energy Storage	Power Conditioning	Utility	Interface	Charge Regulation	Load Demands
1	UNREG	Shingle	Front surface natural convection	Lead-acid batteries	dc/ac Inverter	Uninterruptible backup	No feedback	Shunt Reg	All electric home
2	SUNREG	Shingle, update tilt angle							
3	TRACKER	Shingle						Part-time parallel tracker	
4	NOBATTERY	Shingle		None			Excess power feedback	None	
5	UNREGA	Hollow core panels	Back surface forced air cooling	Lead-acid batteries			No feedback	Shunt Reg	
6	UNREGH	Hybrid thermal/PV panels	Liquid coolant						

2.2 CONCEPT NO. 1. Shingled solar array, lead-acid batteries, direct charge of battery from solar array, no power feedback to utility.

Figure 2-1 depicts a shingle-type array on houses representative of northern and southern locations of the U.S. This shows that photovoltaic systems need not dictate significant changes in current architectural styles.

The solar array, described in greater detail in Section 5, consists of hexagonal shingles, and contains 19 series cells of 5.72 cm diameter each. This cell was selected on the basis of present technology although the shingle design can be easily modified to use larger circular or rectangular cells. A unique mounting scheme provides a highly redundant interconnection matrix with 513 cells in series and 64 cells in parallel.

A functional block diagram of the power system is shown in Figure 2-2. The approach, wherein AC power, synchronized with the utility backup source, is distributed to the loads, has emerged as the most favorable one of several that were considered. As discussed in Appendix A the possibility of distributing solar array/battery dc power to certain loads was also considered; however, a general survey of present appliances indicated that major load and control modifications would be necessary to render them suitable for dc operation. Even for those devices, mainly of the resistance heater type, that could operate satisfactorily on dc without significant modification, the inherent poor regulation of the battery source would result in large variations in heating. Since the heating is proportional to the square of voltage, a 30 percent voltage variation typical of batteries would result in a 60 percent variation in heating.

As shown in the block diagram (Figure 2-2), a direct charge system is used in which the solar arrays are electrically clamped to the battery terminals so that the solar array operating point is established by the voltage of the battery. The number of solar cells in series in relation to the number of battery cells in series is selected to yield the maximum generation of solar array power. A solar array with 513 cells in series, used in conjunction with a 96-cell battery system, appears optimum for all locations considered, as discussed later in Section 3. Table 2-2 lists the pertinent power system sizing information for this point design. Battery charge control is accomplished by limiting the battery charge voltage to a prescribed level. Control is exerted by partial shunting of discrete sections of the solar array current to prevent any further increase in battery voltage. A binary division of the array strings permits control to sufficiently small current increments using simple transistor switches. In addition to limiting charge voltage, excessive battery temperature would also be used to limit charge current by shunting out array sections.

Battery discharge control is only exerted when the battery has been almost depleted, as indicated by a lower discharge voltage limit. When this occurs, the transfer of power through the dc/ac inverter is interrupted completely and is not restored until the battery is fully recharged. This would occur when the upper charge voltage limit is reached.

SOUTHERN U.S. LOCATION

(a) Southern U.S. Location

NORTHERN U.S. LOCATION

(b) Northern U.S. Location

Figure 2-1. Photovoltaic Powered Residences

Figure 2-2. Functional Block Diagram, System with Energy Storage

TABLE 2-2. SYSTEM CHARACTERISTICS, CONCEPT NO. 1

Parameter	Value
Solar Array	
Cell Type	Silicon, 5.72 cm dia, 13.4% (AM1, 28°C)
Series Cells	513
Parallel Cells	64
Roof Area (M ²)	109
Total Cell Area (M ²)	84
Roof Azimuth Angle	0° (Due South)
Roof Slope Angle	Cleveland - 37° Phoenix - 22° Miami - 17°
Battery	
Type	Hybrid Lead-acid
Series Cells	96
Capacity	250 Ampere Hours (48 kW _e -hr)
Total Weight	2232. kg
Inverter	8 kW

The dc/ac inverter is a phase controlled device which operates synchronously with the utility source. It receives dc input power from the combined solar array/battery source in the range of approximately 170 to 240 Volts which corresponds to the discharge to charge voltage range of the battery. Three-wire, single phase, 240/120 Vac power is produced at the inverter output which feeds the residence loads.

The dc/ac inverter supplies power up to a tentative limit of 8 kilowatts. Any load demands which exceed this limit are supplied by the direct tie-in of the utility source. This uninterruptible feature is particularly important when considering the very high demands associated with the starting of motors and other household electrical devices (lamps, irons, etc.).

The charge status of the battery permitting, the controls of the dc/ac inverter operate to null out any supply of power by the utility source. This is accomplished by phase shift techniques. This mode of control is only effective for meeting demands up to the limit rating of the inverter; thereafter, the utility source shares in meeting larger demands.

Several features are incorporated to cover failure mode possibilities. First, a fused disconnect is used on the battery discharge leg to prevent the burn-out of shorted equipment. Second, should an upstream fault develop in the utility system, the inverter would be shut down to prevent the inadvertent feedback of power to the utility grid. For this purpose a utility presence signal is required to enable the inverter. Although the system could be arranged to operate with the loss of utility power, the shut-down approach appears to best satisfy operational considerations and is less complex. One operational example is the repair of upstream utility faults and the possible danger to the repair crew from feedback energy. Accommodation of stand-alone capability would involve means for rapidly decoupling the system from the utility in the event of a utility fault, and would also require an internal means of frequency generation.

An additional possible feature for the system, which actually applies to all of the concepts, would be to extract the dissipated energy in the dc/ac inverter due to its inefficiency and, as an example, use it for heating domestic hot water. This could be accomplished by piping fluid through a heat sink located in the inverter and then transferring the accumulated heat to the residence hot water tank. Since it does not appear that all of the hot water demand could be satisfied by this means, the basic strategy would be to provide any auxiliary heating at nighttime, either from the storage batteries, depending on their state-of-charge, or from the backup utility source. Another method, which might possibly utilize the available dissipated energy more effectively, uses two hot water tanks, with one electrically heated and always on hot standby. In this way there is always assurance of a supply of hot water if the other tank, heated by the inverter heat sink, is inoperative because of inclement weather. The economic worth of these approaches is discussed in Section 4.4.3.

Electrical power demands were based on an all-electric home, the demands providing the basis for sizing the solar array, batteries and power conditioning equipment. Three basic components of demand were identified.

The first component consists of diversified loads which include demands associated with lighting, appliances and a variety of miscellaneous equipments. A single daily profile, shown on Figure 2-3, was used for this location independent demand. The profile, applicable to an average 5-member family, represents the average of a number of profiles obtained from several utility companies. For purposes of simplifying performance analyses, the profile was assumed to remain fixed over the entire year.

The second demand component pertains to domestic hot water needs. Here, too, a fixed profile (Figure 2-4) was assumed. This component was kept separate from the diversified demand in order to facilitate later analyses.

Figure 2-3. Diversified Load Demand Profile

Figure 2-4. Hot Water Heater Electrical Load Demand Profile

The third demand component is variable and pertains to residence heating and cooling. A thermal model of the residence was prepared and heating and cooling demands were established as a function of both weather and internal energy conditions. Figure 2-5 indicates a typical demand profile on a given day in Washington, D. C. for a well-insulated house of the type common to the Northeastern USA. The electrical demand is determined from the heating demand considering the use of a heat pump.

A typical cycle of operation for the system is shown on Figure 2-6. Just before sunrise the battery state-of-charge is at its lowest point. As the sun intensity increases the solar array provides power for the load and for charging the battery. After midday, the battery reaches full charge and any excess array output is handled by the array shunt circuits. After sunset the battery provides all energy until the following morning when recharging commences. As shown for January 23, the insolation is insufficient to recharge the battery and therefore a greater depth of discharge results. If the battery state-of-charge had dropped to about 10 percent, the low discharge voltage would have interrupted the inverter. Re-enabling of the inverter would occur with attainment of full charge. This would be indicated when the charge voltage reaches a prescribed level.

Figure 2-5. Typical Hourly Heating Demand From Building
Transient Thermal Loads Program

Not indicated on Figure 2-6 are the occurrence of numerous load peaks due to motor startups and other transients which exceed the capability of the inverter. Since the inverter is specifically limited to an 8 kVA output, any larger loads are satisfied by the utility source. Because the inverter and utility sources are tied together, there is no interruption of service.

2.3 CONCEPT NO. 2. Same as Concept No. 1, except roof tilt is adjustable.

This concept was considered only to the extent of determining the performance benefit associated with periodic roof tilt adjustment due to the changing declination of the sun. As reported in Section 3, the benefit is negligible and no further attention was given to this concept.

2.4 CONCEPT NO. 3. Same as Concept No. 1, except part-time parallel maximum power tracker is introduced in charge leg of battery.

This concept was developed to compare the units of maximum power tracking of the solar array with the direct charge system of Concept No. 1. As reported in Section 3, significant benefits were not realizable; therefore, no further effort was applied to this concept. However, maximum power tracking for systems without energy storage, of the type described below for Concept No. 4, do appear attractive.

Figure 2-6. Photovoltaic Power System Performance For A Typical Week In January For Washington, D.C. Site Location

2.5 CONCEPT NO. 4. Shingled solar array, no energy storage, maximum power tracking of solar array, power feedback to utility grid.

The solar array for this concept is identical to that for Concept No. 1 except that the partial shunt circuits are removed because the batteries and the associated need for charge control are eliminated.

The functional block diagram for the system is shown on Figure 2-7. As in Concept No. 1, ac power, synchronized with the utility backup source, is distributed to the loads. By sensing the solar array current and voltage, the dc/ac inverter is controlled to receive input power at the maximum power point of the solar array. The inverter is sized to handle 13 kVA which roughly corresponds to the maximum output of the solar array. With maximum power tracking, the inverter output power not absorbed by the load is fed back to the utility grid. If the inverter output is less than the load, the utility provides the difference.

As in the case of Concept No. 1, any loss of the utility tie-in results in interruption of inverter operation. This is especially important for this concept because excess array inverter output could damage the residence loads due to over-voltage. Also, as indicated for Concept No. 1, feedback potentials might present a hazard to crews repairing the utility distribution fault. Stand-alone capability for this no energy storage system would be of limited attractiveness because of the limited hours of sunshine and sensitivity to insolation variations.

Figure 2-7. Functional Block Diagram, System Without Energy Storage

Synchronization of the inverter output with the utility is accomplished by first sensing the utility presence and sync signal. This signal properly phases the inverter output before the inverter contactor is closed. This basic implementation also applies to synchronizing the inverter of Concept No. 1.

2.6 CONCEPT NO. 5. Same as Concept No. 1, plus convection cooling of under-surface of solar array.

The purpose of this concept was to investigate the benefits of underside air cooling of the residence roof-mounted solar array. A sketch of the basic approach is shown on Figure 2-8(a). In addition to front-surface cooling by natural convection and wind, cooling may be accomplished by natural or forced convection at the solar array under surface. The concept was developed sufficiently to permit adequate analysis of the technical and cost factors.

2.7 CONCEPT NO. 6. Same as Concept No. 1, plus liquid cooling of hybrid collector, and introduction of solar heating and cooling system.

This total energy concept was developed to examine the merits of combining photovoltaic and solar heating and cooling systems. As shown on Figure 2-8(b), the basic approach was to mount solar cells on the absorber plate of a single paned solar collector. Liquid circulated through passages in the absorber plate transport the collected thermal energy for use in heating the residence. During the summertime the hot fluid may be used to operate an absorption air conditioner or may be used to drive a low-temperature Rankine engine which in turn would drive a mechanical compressor refrigeration unit.

Figure 2-8. Solar Array Cooling Methods

The basic electrical, heating and cooling demands are identical to those used for Concept No. 1. In addition to the photovoltaic system which includes batteries and power conditioning equipment, the hybrid system includes equipment for accommodating, circulating, and storing the solar produced thermal energy.

SECTION 3

PERFORMANCE ANALYSIS

SECTION 3

PERFORMANCE ANALYSIS

3.1 INTRODUCTION

Analytical models for the six different residential photovoltaic power system concepts identified in Section 2 have been developed to permit the assessment of system performance on an annual basis using hourly insolation and weather data tapes as the input. The analysis methodology in each case is similar in that the programs determine the instantaneous system operating point as a function of individual subsystem characteristics. This operating point of the system is determined for each discrete time increment (one hour) of the total time period (which may be up to one year long) by performing iterative numerical calculations until Kirchoff's Law is satisfied at each node within the system.

The subsystem characteristics are common among these system analysis programs and are discussed in Section 3.3

In all cases the input to the system analysis program is a magnetic tape which consists of 8762 records. The first record is a title which identifies the data on the tape but is not used in the system analysis program. The second record includes the following parameters:

IYEAR	- Year of the weather data (last two digits only)
NZONE	- Number of zones in the residence thermal analysis model
XLON	- Longitude of the residence location
LATIT	- Latitude of the residence location
TZN	- Time zone number for the location used in calculating the equation of time

<u>TZN</u>	<u>Time Zone</u>
5	Eastern
6	Central
7	Mountain
8	Pacific

The next 8760 records have the same parameters for each hour of the year. These parameters, in the order of appearance on the tape, are listed below:

MON	- Month of the year
DAY	- Day of the month
HR	- Hour of the day (0 - 23)
HBAR	- Horizontal measured solar insolation (Btu/hr-ft ²)
HEXT	- Extraterrestrial solar insolation (Btu/hr-ft ²)
TAMB	- Ambient dry bulb temperature (°F)
TWB	- Ambient wet bulb temperature (°F)
RH	- Relative humidity (%)
WIND	- Wind speed (miles/hour)
QL	- Hourly building heating/cooling requirement, total of all zones (Btu/hr-ft ²)
QLZ (I)	- Hourly building heating/cooling requirements for zone (I). (Btu/hr-ft ²)
QINF (I)	- Hourly building infiltration heating/cooling requirement for zone (I). (Btu/hr-ft ²)
QLAT (I)	- Hourly latent heat requirement for zone (I). (Btu/hr-ft ²)

This tape is generated by processing the appropriate weather/insolation data base tape with a program called Building Transient Thermal Loads (BTTL) which is described in Appendix B. The BTTL program rewrites the weather/insolation data and adds the calculated building heating/cooling loads as listed above.

3.2 SYSTEM MODELING METHODOLOGY

3.2.1 DIRECT CHARGE SYSTEM (Used in Concepts 1, 2, 5 and 6)

The first system model, called UNREG, utilizes a Direct Charge System (DCS) in which the battery is connected directly across the solar array bus as shown on Figure 3-1. With this system configuration, charging is at the rate determined by the load demand and the solar array capability until such time as the battery voltage limit is reached. At this predetermined voltage level the battery charge controller (BCC) limits the voltage by shunting excess current through dissipative elements.

Figure 3-1. Simplified Functional Block Diagram of Direct Charge System (DCS) Approach

For each discrete time increment (each hour) the operating point of the system is determined by performing an iterative numerical calculation until Kirchoff's Law is satisfied at the node between the solar array, battery and load. The resulting instantaneous battery charge/discharge current is used to correct the battery state-of-charge (SOC). During battery charge, an average charge efficiency factor is used to correct the SOC to account for charging inefficiencies. At each one hour time interval the program prints out the following data:

1. Month, day and hour
2. AC load demand for the diversified load + hot water heating (kW)
3. AC load demand for heating or air conditioning (kW)
4. Solar array power output (kW)
5. Accumulative ampere-hours discharged
6. Accumulative ampere-hours charged
7. Battery state-of-charge
8. Battery voltage
9. Battery power (kW)
10. Power required from the utility (kW)
11. Excess power dissipated in shunt voltage limited (kW)
12. Inverter power loss (kW)

13. Total insolation of solar array panel surface
14. Ambient temperature
15. Solar cell temperature
16. Wind speed
17. Total building heating/cooling load.

The program switches operation onto the utility when the battery voltage reaches a pre-determined low threshold value. The system continues to operate on utility power with the inverter disabled until the battery voltage reaches the shunt limit value. At this point operation is switched back onto the photovoltaic/battery system by enabling the inverter.

3.2.2 PARALLEL MAXIMUM POWER TRACKER SYSTEM (Used in Concept 3)

The Parallel Maximum Power Tracker System (PMPTS) shown in Figure 3-2 allows operation at the solar array maximum power voltage when the array is illuminated and the output capability exceeds the load demand. If the total available power at the array maximum power point is greater than what the load inverter and batteries will accept, the duty cycle of the PWM regulator automatically decreases to move the system operating voltage toward the open circuit voltage of the array until the available source power is equal to the total power demand of the load and batteries. When the load demand exceeds the power available from the solar array, the batteries discharge, clamping the dc bus voltage to the battery discharge voltage and forcing operation at a voltage considerably less than the solar array maximum power voltage.

Figure 3-2. Simplified Functional Block Diagram of the Parallel Maximum Power Tracker System (PMPTS) Approach

3.2.3 NO BATTERY/FEEDBACK SYSTEM (Used in Concept 4)

The No Battery/Feedback system shown in Figure 3-3 consists of a maximum power tracking inverter which is connected directly to the solar cell circuits. When the solar array power output capability allows the inverter output power to exceed the house load demand the excess power flows back onto the utility grid. During night time periods and when the sunlit array maximum power output is less than the load demand, power is supplied by the utility to meet the house load demand. Thus, the utility distribution system essentially becomes the storage medium for the residential photovoltaic system. When the photovoltaic power generation capacity within a given region is small compared to the utility distribution capacity, the utility grid will appear to be an "infinite" sink for power.

The performance analysis program for this configuration of power system employs an iterative calculation routine to hunt for the solar array maximum power operating point during each sunlit hour.

3.2.4 DIRECT CHARGE/AIR COOLED SYSTEM (Used in Concept 5)

The Direct Charge/Air Cooled system is identical to the Direct Charge system described in Section 3.2.1 except that the solar cell roof allows air cooling of the rear surface of the solar cell modules. The system analysis program assumes that ambient air passes through the rear side cooling channels either naturally or by an appropriately

Figure 3-3. Simplified Functional Block Diagram of the No Battery/Feedback System

sized fan. The air which exists from the top of the roof is exhausted to the atmosphere with no attempt made to utilize this heat. In the case of forced air circulation, the program attempts to find the air mass flow rate which maximizes the charge rate for each sunlit hourly calculation interval. An optimum value should exist since higher mass flow rates result in lower solar cell temperature with corresponding higher solar array power output. On the other hand higher mass flow rates require increased fan electrical power to force the air through the rear side flow channels. This fan power penalty is added to the other house load demands in the determination of the flow rate which maximize the charge rate.

The solar cell temperature calculations required for this program are described in Section 3.3.2.2.

3.2.5 PHOTOVOLTAIC/THERMAL TOTAL ENERGY SYSTEM (Used in Concept 6)

This system has a hybrid photovoltaic/solar thermal collector panel as the energy source. A simplified schematic arrangement of the system configuration is given in Figure 3-4 with the electrical portion of the system shown on the left half of the diagram and the solar thermal portion shown on the right half. The electrical portion of the system is identical to the DCS described in Section 3.2.1. The solar thermal portion of the system utilizes a single Lexan pane collector panel as the heat source. A glycol/water mixture is pumped through the collector system and transferred to the water thermal energy storage (TES) tank by means of a collector heat exchanger as shown.

During the heating season thermal energy from the collectors and/or TES can be used to supply the following load demands depending on the temperature level of the TES:

1. Supply heat directly to the air handler for direct space heating
2. Supply heat energy to the heat pump input
3. Supply heat energy to meet the domestic hot water load demand.

If the TES temperature is above 43°C , the heat energy from the TES is supplied directly to the air handler for direct space heating. Under these conditions the hot TES water is also used to meet the entire domestic hot water load demand. If the TES temperature is below 43°C but above the outside ambient temperature or above 4°C , the TES water is used to solar augment the heat pump by using an evaporator coil within the TES. Under these conditions the domestic hot water demand is supplemented by electrical heating. If the TES temperature is below 4°C or below the outside ambient temperature the heat pump operation is switched to the outside air coil and the hot water demand is satisfied by electrical heating.

During the cooling season the heat energy from the collectors is used to meet the domestic hot water load demand and to operate a Rankine engine for driving the heat pump compressor. Alternatively the heat energy may be dissipated in a water-to-air heat exchanger to achieve lower solar cell temperatures. An objective of analysis presented later is to determine which alternate is most attractive. Absorption cooling was not used as an option since it introduces additional equipment whose functions can already be served by the available heat pump.

Figure 3-4. Simplified Functional Block Diagram of Direct Charge/Hybrid System

3.3 SUBSYSTEM ANALYTICAL MODELS

3.3.1 SOLAR ARRAY ELECTRICAL MODEL

The synthesis of solar array current-voltage characteristics is based on a set of solar cell characteristics which represent the predicted performance for high grade, large volume production terrestrial cells with the following characteristics:

1. N on P
2. Phosphorus diffused, 2000Å junction depth
3. Tantalum oxide A-R coating
4. Silver collector grid
5. Czochralski Si, B-doped, 2 ohm-cm

The performance of this cell type was obtained from Solarex under a subcontract arrangement. Figure 3-5 shows these cell I-V characteristics at 100 mw/cm² with the spectral distribution as given in reference (1)*. These characteristics are represented by the following relationships:

$$I = CI_{sc} - \frac{V}{R_p} - I_o \left\{ \exp \left[K (V + IR_s) \right] - 1 \right\}$$

where:

$\bar{I}$ = Cell output current

V = Voltage across cell terminals

• Cell efficiency 13.4%
100 mw/cm², 28°C, AM1

Figure 3-5. Terrestrial Solar Cell I-V Characteristics

*See references at end of section.

I_{sc} = Illumination current (virtually equal to short-circuit current)

C = Ratio of the total insolation incident on the solar cells to the reference insolation for the basic cell characteristics (100 mw/cm²)

R_p = Shunt resistance of the cell

I_o = Reverse saturation current of the ideal diode characteristic

K = Coefficient of the exponential

R_s = Series resistance of the cell

I_{sc} , R_p , I_o , K , and R_s are represented as six-degree polynomials of temperature.

The total solar array output characteristics is calculated based on the single cell characteristic by multiplying the voltages and currents by the number of cells in series and parallel, respectively. In addition, the isolation diode voltage drop (as a function of temperature and fraction of rated forward current) and the series resistance of panel wiring are included in the array characteristic.

The value for total incident insolation (direct plus diffuse) is obtained by taking the total insolation incident on a horizontal surface (H_{TO}) as read from the insolation data base tape, and separating it into direct (H_{DIR}) and diffuse (H_{DIF}) components using a curve fit of the results of Liu and Jordan shown on Figure 3-6 taken from Reference (2).

Figure 3-6. Determination of Diffuse Insolation

The total flux incident on the tilted solar array surface (H_T) is given by: (from Reference 3)

$$H_T = H_{DIR} R_{DIR} + H_{DIF} \left(\frac{1 + \cos \beta}{2} \right) + (H_{DIR} + H_{DIF}) \left(\frac{1 - \cos \beta}{2} \right)$$

where:

R_{DIR} = Factor to correct horizontal incident direct radiation to that on the inclined array surface

β = Angle between horizontal and solar array surface

ρ = Reflectance of the surrounding ground (- 0.15)

The factor R_{DIR} is given by:

$$R_{DIR} = \frac{\cos \theta_i}{\cos \theta_j}$$

where:

θ_i is the solar incidence angle on the array and θ_j is the solar incidence angle on a horizontal surface. These are given as a function of the day of the year, time of day and surface location and orientation in accordance with the following relationship:

$$\begin{aligned} \cos \theta_i = & \sin \delta (\sin \phi \cos \beta - \cos \lambda \cos \phi \sin \beta) \\ & + \sin \lambda \sin \beta \cos \delta \sin \omega \\ & + \cos \delta \cos \omega (\cos \lambda \sin \phi \sin \beta + \cos \phi \cos \beta) \end{aligned}$$

where:

ϕ = Site latitude (north is positive)

δ = Solar declination angle

β = Angle between horizontal and solar array surface

λ = Solar array surface azimuth angle (zero is due south, west of south is positive)

ω = Hour angle (zero is solar noon)

For a horizontal surface this expression reduces to

$$\cos \theta_j = \sin \delta \sin \phi + \cos \delta \cos \omega \cos \phi$$

3.3.2 ROOF MOUNTED ARRAY

3.3.2.1 Free Convection Cooled Roof-Mounted Array

Solar cells which are mounted directly on the residence roof are principally cooled by natural convection occurring on the top surface, although the temperature is affected somewhat by the heat transfer through the roof to the attic space. The significant heat transfer mechanisms for determining the equilibrium cell temperature are illustrated on Figure 3-7 and are as follows:

1. Heat transfer through the solar array roof to the attic, Q_1 (w/m^2)
2. Heat transfer through the opposite roof (without solar cells) from the attic, Q_2 (w/m^2)
3. Heat transfer from the attic to the living space of the residence, Q_3 (w/m^2)

The simultaneous solution of expressions describing these heat transfer mechanisms yields the desired value of cell temperature. The expressions used are as follows:

Figure 3-7. Solar Array Heat Transfer Mechanisms

Equation 1 for Q1

$$Q_1 = U_1 (T_{\text{cell}} - T_{\text{attic}}) = \left[\alpha_c p + \alpha_p (1-p) \right] H_T - h_r (T_{\text{cell}} - T_{\text{sky}}) - h_o (T_{\text{cell}} - T_{\text{amb}}) - \eta_c p H_T$$

Equation 2 for Q2

$$Q_2 = U_2 (T_{\text{attic}} - T_{\text{roof}}) = \alpha_r H_R - h_r (T_{\text{roof}} - T_{\text{sky}}) - h_o (T_{\text{roof}} - T_{\text{amb}})$$

Equation 3 for Q3

$$A_3 Q_3 = A_1 Q_1 - A_2 Q_2$$

$$A_3 U_3 (T_{\text{attic}} - T_{\text{room}}) = A_1 U_1 (T_{\text{cell}} - T_{\text{attic}}) - A_2 U_2 (T_{\text{attic}} - T_{\text{roof}})$$

where:

T_{cell} = Temperature of solar array, °K

T_{attic} = Temperature of attic air, °K

T_{sky} = Temperature of sky, °K

T_{amb} = Temperature of ambient air, °K

T_{roof} = Temperature of non-solar array roof, °K

T_{room} = Temperature of living space, °K

U_1 = Heat transfer coefficient of solar array roof, W/m² °K

U_2 = Heat transfer coefficient of non-solar array roof, W/m² °K

U_3 = Heat transfer coefficient of attic floor, W/m² °K

α_c = Solar cell absorptivity

α_p = White paint absorptivity

p = Solar cell packing factor

α_r = Non-solar array roof absorptivity

H_T = Solar radiation incident on the solar array, W/m²

H_R = Solar radiation incident on the non-solar array roof, W/m²

η_c = Solar cell efficiency, adjusted to temperature T_{cell}

h_r = Radiative film coefficient, $W/m^2 \text{ } ^\circ K$

h_o = Natural convection film coefficient, $W/m^2 \text{ } ^\circ K$

A_1 = Solar array roof area, m^2

A_2 = Non-solar array roof area, m^2

A_3 = Attic floor area, m^2

The cell, attic, and non-solar array roof temperatures are the dependent variables to be determined by the solution of the equations presented. All other terms are established independently from weather data, the residence physical characteristics, and available formulations for certain terms as described below:

1. The sky temperature, T_{sky} , can be calculated according to Reference (4) by the following formula:

$$T_{sky} = 0.0552 T_{amb}^{1.5} \text{ (degrees K)}$$

2. The radiative film coefficient can be calculated by:

$$h_r = \epsilon \sigma \frac{T_{cell}^4 - T_{sky}^4}{T_{cell} - T_{sky}}$$

where:

ϵ = Emissivity of solar array (= 0.80)

σ = Stefan - Boltzmann constant

3. The film coefficient, h_o , according to Reference (5), can be calculated as follows:

$$h_o = 5.7 + 3.8 V$$

where:

V = wind speed, m/s

Using equation (1), (2), and (3), a plot of cell temperature as a function of insolation, wind speed, and ambient temperature is shown on Figure 3-8. Table 3-1 lists the assumed values of the other terms used in developing the plot. The plot indicates the dominance of wind speed in effecting the cell temperature rise above ambient. The greatest reduction in temperature occurs at low wind speeds with diminishing reductions as the wind speed increases.

Figure 3-8. Results of Solar Cell Temperature Prediction Model

Table 3-1. Assumed Parameters for Array Temperature Determination

Parameter	Value
U_1	$2.61 \text{ WM}^{-2} \text{ K}^{-1}$
U_2	$2.67 \text{ WM}^{-2} \text{ K}^{-1}$
U_3	$0.27 \text{ WM}^{-2} \text{ K}^{-1}$
α_c	0.88
α_p	0.2
p	0.808
α_r	0.9
A_1	84.0 m^2
A_2	84.0 m^2
A_3	69.8 m^2
T_{room}	$20 \text{ }^{\circ}\text{C}$

3.3.2.2 Cooling of Under-Surface of Solar Array

With forced air cooling through channel passages on the underside of the solar cells, equation (1) can be rewritten to take the additional heat removal into account.

$$\alpha H_T - h_r (T_{\text{cell}} - T_{\text{sky}}) - h_o (T_{\text{cell}} - T_{\text{amb}}) - \dot{m} C_p \Delta T = U_1 (T_{\text{cell}} - T_{\text{attic}}) \quad (\text{Eq. 4})$$

where:

$\dot{m}$ = Flowrate of forced air, kg/s

C_p = Specific heat of air, kj/kg °K

ΔT = Temperature increase of air due to cooling the solar array, °K

Equations (2) and (3) still apply. Therefore, T_{cell} may be obtained by simultaneously solving equations (4), (2) and (3).

With natural convection cooling on both the top and bottom sides of the solar array, equation (4) must be modified as follows:

$$\begin{aligned} & \alpha_c H_T - h_r \left[\frac{T_{\text{cell}, 1} + T_{\text{cell}, 2}}{2} - T_{\text{sky}} \right] \\ & - h_o \left[\frac{T_{\text{cell}, 1} + T_{\text{cell}, 2}}{2} - T_{\text{amb}} \right] \\ & - h_i \left[\frac{T_{\text{cell}, 1} + T_{\text{cell}, 2}}{2} - \frac{T_{\text{air, in}} + T_{\text{air, out}}}{2} \right] \\ & = U \left[\frac{T_{\text{cell}, 1} + T_{\text{cell}, 2}}{2} - T_{\text{attic}} \right] \end{aligned}$$

where:

$$U = \frac{1}{\frac{1}{h_1} + \frac{1}{h_{\text{in}}} + \frac{X}{K} \text{ roof}}$$

The terms of the equation are defined below on Figure 3-9.

Figure 3-9. Definition of Terms for Underside Cooling

Figure 3 10. Cell Temperature vs. Wind Speed

Using the above expressions, an analysis was performed for comparing cell temperatures with and without underside cooling according to the above sketch. The results are shown on Figure 3-10 for a specific set of conditions, considering only natural convection cooling. For this case, the average reduction in cell temperature is about 5°C .

3.3.2.3 Hybrid Solar Thermal Collector Panel

The hybrid photovoltaic/solar thermal collector is modeled as a tube and sheet type collector construction with the solar cells mounted directly to the absorber plate as shown in Figure 3-11. The modeling of this collector performance assumes instantaneous response to any thermal changes it encounters and follows the analysis method described in Reference (6).

The output from the collector model is the useful solar energy which the collector picks up during a given hour. The useful energy transferred to the fluid circulating through the collector is given by the relationship:

$$Q_u = F_R [H_R - U_L (T_{\text{IN}} - T_{\text{AMB}})]$$

Figure 3-11. Hybrid Photovoltaic/Solar Thermal Flat Plate Collector

where

Q_u = Useful energy out of the collector (kW/m^2)

F_R = An efficiency factor which allows the heat loss from the collector to be expressed in terms of fluid inlet temperature to the collector rather than average collector temperature

$H_R = \alpha \tau S K_C$ = The product of collector solar absorptance (α), net transmission (τ) of solar energy through the collector cover including the influences of reflection and absorption in the cover, and solar flux per unit area (S) on the collector, (kW/m^2). K_C (~ 0.9) reduces the product to account for photovoltaic conversion of about 10 percent.

U_L = Heat loss coefficient ($\text{kW/m}^2 \text{ } ^\circ\text{C}$) from the collector due to its temperature elevation above ambient. This includes loss through the cover by means of convection and radiation as well as conductive losses out the back and sides of the collector.

T_{IN} = Inlet fluid temperature ($^\circ\text{C}$).

T_{AMB} = Ambient air temperature ($^\circ\text{C}$)

The efficiency factor, F_R , is defined by the following expression:

$$F_R = \frac{G \cdot C_p}{U_L} \left[1 - \exp \left(\frac{-F' U_L}{G \cdot C_p} \right) \right]$$

where:

- G = Collector flow rate per unit area of collector surface (kg/hr-m²)
 C_p = Specific heat of collector fluid (kW-hr/kg-°C)
 F' = Efficiency factor which accounts for such factors as absorber plate fin efficiency, and temperature gradient through absorber tubes

The collector efficiency factor, F' , is given by

$$F' = \frac{1/U_L}{w \left\{ U_L \left[\frac{1}{D + (w - D) F} \right] + \frac{1}{C_b} + \pi D_i h_{fi} \right\}}$$

where:

- h_{fi} = Heat transfer coefficient between the fluid and the tube wall
 C_b = Conductance of bond between tube and sheet

and D_i , D , and W are as defined in Figure 3-12.

Figure 3-12. Sheet and Tube Dimensions

The function F is the standard fin efficiency for straight fins with rectangular profile as given by

$$F = \frac{\tanh \frac{m(W-D)}{2}}{\frac{m(W-D)}{2}}$$

where:

$$m = \left(\frac{U_L}{k \delta} \right)^{1/2}$$

k = Thermal conductivity of plate.

The overall heat loss coefficient, U_L , is found by adding together the top, bottom and edge loss coefficients.

$$U_L = U_t + U_b + U_e$$

The relationship defining U_t is an empirically derived expression given by:

$$U_t = \left(\frac{N}{(344/T_p) \left[(T_p - T_a) / (N + f) \right]^{0.31} + \frac{1}{h_w}} \right)^{-1} \frac{\sigma (T_p + T_a) (T_p^2 + T_a^2)}{\left[\epsilon_p + 0.0425N(1 - \epsilon_p) \right]^{-1} + \left[(2N + f - 1) / \epsilon_g \right]^{-N}}$$

where:

- N = Number of glass covers
- $f = (1.0 - 0.04h_w + 5.0 \times 10^{-4} h_w^2 (1 + 0.058N))$
- e_g = Emittance of glass (0.88)
- e_p = Emittance of plate
- T_a = Ambient temperature ($^{\circ}K$)
- T_p = Plate temperature ($^{\circ}K$)
- h_w = Wind heat transfer coefficient

The wind heat transfer coefficient is given as before by:

$$h_w = 5.7 + 3.8V$$

where:

- V = wind speed (m/s)

The collector routine solves these equations in an iterative procedure to converge on a value of the mean plate temperature with its corresponding value of useful heat collected, Q_u . The physical constants for the collector configuration considered in these analysis are listed in Table 3-2 and the calculated relationship for the $\alpha\tau$ product is shown in Figure 3-13.

TABLE 3-2. VALUES OF COLLECTOR PHYSICAL PARAMETERS

Parameter	Value
W	36 mm
D	6.16 mm
D _i	4.72 mm
U _b	0.60 w/m ² C
U _e	0.28 w/m ² C
δ	1.5 mm
k	204. w/mC
ε _g	0.90
ε _p	0.90

Figure 3-13. Absorptance - Transmittance Product for Solar Cells and Single Lexan Cover

3.3.3 BATTERY MODEL

The charge and discharge voltage of a hybrid lead acid battery has been modeled as a function of battery state-of-charge (SOC) and instantaneous charge or discharge rate. Figure 3-14 shows these characteristics as modeled based on data supplied by C&D Batteries. The bottom set of curves are discharge characteristics with discharge rates

Figure 3-14. Typical Hybrid Lead-Acid Battery Charge/Discharge Characteristics

*Charge (or discharge) rates are represented as ratio of capacity (C in Ampere-hours) to hours (H) required to either fully charge battery (from zero SOC) or fully discharge battery (from 1.00 SOC).

varying from C/50 to C/5. The top set of curves are charge characteristics at the same rates, assuming that recharge starts from the fully discharged condition.

A average ampere-hour charging efficiency of 0.952 was used in the simulations based on information supplied by C&D Batteries.

3.3.4 ELECTRICAL LOAD DEMAND

The electrical load demands for the diversified and domestic hot water loads have been synthesized from several data sources, and are representative for a family size of five for any day of the year at any location within the continental U.S. The basic characteristics of these loads are shown on Figures 3-15 and 3-16. The diversified load demand profile includes lighting and appliances (frost-free refrigerator, electric range, color TV, dishwasher, electric dryer and other miscellaneous small appliances). For a typical day, the diversified electrical load demand is relatively low in the early morning hours, has peaks at the breakfast, lunch and dinner hours, and drops off in the evening. The hot water heater electrical load demand profile has an accumulative daily energy requirement of 14.00 kW-hr and has approximately the same shape as the diversified load demand profile. The electrical load demand associated with space heating and air conditioning is obtained from the hourly heating or cooling load demand by accounting for the appropriate coefficient of performance (COP) as obtained from the heat pump model which is described in the following section.

3.3.5 ELECTRICALLY DRIVEN HEAT PUMP

The electrical power needed for a combination heat pump/resistance heating system to handle a given hourly heating load during the heating season or a cooling load during the air-conditioning season is represented by a coefficient of performance (COP). The COP and the thermal capacity of each of six heat pump systems is given as a function of the outside dry bulb temperature. Any of the heat pump systems listed below can be selected:

24,000 Btu/hr	Current Design Heat Pump System
35,000 Btu/hr	Current Design Heat Pump System
48,000 Btu/hr	Current Design Heat Pump System
24,000 Btu/hr	Projected Heat Pump System
35,000 Btu/hr	Projected Heat Pump System
48,000 Btu/hr	Projected Heat Pump System

Figure 3-15. Diversified Load Demand Profile

Figure 3-16.. Hot Water Heater Electrical Load Demand Profile

The COP's and capacities used in the subroutine for the first three heat pump systems are representative values out of the General Electric Central Air-Conditioning and Heating Product Data Guide. For the same thermal capacities as the current design heat pump systems, an assumption has been made that the projected heat pump system will need 40 percent less electrical energy resulting in COP's that are 1.67 times larger than the current design heat pump system. In the cooling mode, it has been assumed that the indoor dry bulb temperature is 25.6°C (78°F) and the indoor wet bulb temperature is 18.3°C (65°F), which corresponds to an indoor relative humidity of fifty percent. In the heating mode, the indoor dry bulb temperature is assumed to be 21.1°F (70°F). If a heat pump system cannot completely handle a specific hourly heating demand, supplementary electric resistance heating is provided. The resistance heating COP is assumed to be 0.995, based on the Product Data Guide referenced above. If a heat pump COP is less than 0.995 then only resistance heating is used. Figure 3-17 shows the COP and capacity of a 3-ton current design heat pump when operating into heating mode.

In the heating mode operation some combinations of outdoor temperature and humidity will produce frost on the heat pump evaporator coil and will lower its heating performance. When this happens, the evaporator coil must be "defrosted" periodically much like household refrigerators and freezers. The most common method of defrosting is to change the heat pump operation over to the cooling mode for a few minutes so that the evaporator coil is heated and the frost is melted. During this defrost period,

Figure 3-17. Performance of 3-Ton Current Design Heat Pump in Heating Mode Without Defrosting

additional power in the form of electric resistance heating must be used to supply the heating load and to counteract the cooling caused by the reversed operation of the heat pump. The elapsed time for defrosting is about 5% of the regular operating time. The input power and reversed output during defrosting is assumed to be the same as during regular operation. With that assumption, the total input power that the heat pump will need, including the defrosting power, is $1.1 P_{HP}$, where P_{HP} is the electric power needed by the heat pump when no defrosting is required.

Likewise, the electric resistance heater power input, when the heat pump is defrosting, is $P_{RH} + \frac{0.1 C_{HP}}{COP_{RH}}$. P_{RH} is the electric power needed by the resistance heater when the heat pump is not defrosting, C_{HP} is the heat load handled by the heat pump if it were not defrosting, and COP_{RH} is the coefficient of performance of the resistance heater.

Frost will accumulate on the heat pump outdoor coils when the temperature reaches approximately 4.4°C (40°F), but will lessen with simultaneous decrease in outdoor temperature and moisture content. It is assumed that defrosting will be necessary when both of the following temperature and humidity conditions exist:

$$-2.2^{\circ}\text{C} \leq T_{OD} \leq 3.9^{\circ}\text{C}; \frac{(1.8 T_{OD} + 72)}{100} \leq RH \leq 1.00$$

where:

RH = Relative humidity

T_{OD} = Outside dry bulb temperature, $^{\circ}\text{C}$

3.3.6 COLLECTOR HEAT EXCHANGER

A heat exchanger is used to transfer the collected heat from a glycol-water collector circulating fluid to the circuit which charges the thermal energy storage (TES) tank. This heat exchanger is modeled as a parallel-counter flow exchanger with the shell fluid mixed using the effectiveness relationships from Footnote (11). The heat transferred in the heat exchanger is defined in terms of the effectiveness (ϵ) by the following relationship:

$$Q = \epsilon C_{\min} (T_{h, \text{ in}} - T_{c, \text{ in}})$$

where:

Q = Heat transferred in heat exchanger (Btu/hr)

ϵ = Heat exchanger effectiveness

$C_{\min}$ = Minimum capacity rate where capacity rate is defined as the specific heat of one of the fluids times the mass flow rate of that fluid. (Btu/hr. $^{\circ}\text{F}$).

$T_{h, in}$ = Inlet temperature of the hot fluid (F)

$T_{c, in}$ = Inlet temperature of the cold fluid (F)

The effectiveness of this heat exchanger type is given by:

$$\epsilon = \frac{2}{\left(1 + \frac{C_{min}}{C_{max}}\right) + \left[\frac{1 + \exp(-\Gamma)}{1 - \exp(-\Gamma)}\right] \sqrt{1 + \left(\frac{C_{min}}{C_{max}}\right)^2}}$$

where:

$$\Gamma = NTU \sqrt{1 + \left(\frac{C_{min}}{C_{max}}\right)^2}$$

NTU = number of transfer units

$$= \frac{UA}{C_{min}}$$

U = Overall heat exchanger "U" factor (Btu/hr. F ft²)

A = Heat transfer area (ft²)

C_{max} = The maximum capacity rate where capacity rate is defined as the specific heat of one of the fluids times the mass flow rate of that fluid (Btu/hr -F).

The implementation of the heat exchanger model led to an iterative numerical solution to determine the actual heat transfer when the heat exchanger is coupled to the solar collector circuit.

3.4 SENSITIVITY ANALYSIS RESULTS

3.4.1 APPROACH

The performance sensitivity analyses were conducted using the basic UNREG program as described in Section 3.2.1. These analyses were repeated for three different potential site locations: (1) Cleveland, Ohio, (2) Phoenix, Arizona, and (3) Miami, Florida. The first two of these three locations were required by the contract. Weather/insolation data base tapes for these two required sites were obtained from the Aerospace Corp. Table 3-3 summarizes the pertinent data regarding these sites as well as the third site, Miami, Florida, which was added to increase the data base for the sensitivity analyses. The tape for the Miami location was obtained from the GE library. Table 3-3 gives the total yearly insolation values as obtained by integrating the data from the tapes and compares this with the average yearly insolation value as obtained from the climatic atlas.

TABLE 3-3. STATION LOCATIONS AND OTHER PERTINENT INFORMATION

Station Location	Source of Weather/ Insolation Data Base Tape	Year	Station Longitude	Station Latitude	Yearly Insolation on a Horizontal Surface				Percent Deviation of Selected Yearly Insolation from Climatic Atlas AVERAGE
					From Data Base Tape		From Climatic Atlas		
					kw-hr/m ²	Langleys	kw-hr/m ²	Langleys	
Cleveland, Ohio	Aerospace	1962	81.85°W	41.40°N	1264.2	108606.	1423.3	122275.	-11.2
Phoenix, Arizona	Aerospace	1962	112.02°W	33.43°N	2118.7	182023.	2209.3	189800.	-4.1
Miami, Florida	GE	1963	80.3°W	25.8°N	1949.6	167491.	1916.1	164615.	+1.7

For each of these three site locations the sensitivity analysis approach consisted of four major areas of investigation:

1. Determination of the optimum number of series solar cells to be used with the selected 96 cell battery,
2. Selection of the optimum solar roof azimuth angle orientation,
3. Determination of the optimum solar roof slope angle,
4. For the optimum conditions as defined above, calculation of the system performance for various combinations of solar cell area and battery capacity.

The following sections discuss the results in each of these areas of investigation. In all cases the measure of system performance is the Annual Energy Displacement Factor, which is defined as the ratio of the total annual electrical energy output of the photovoltaic system to the total annual electrical energy demand of the residence.

3.4.2 NUMBER OF SERIES SOLAR CELLS

Figure 3-18 shows the annual energy displacement factor as a function of the number of series solar cells in the array for a constant solar cell area of 84.0 m². For each site considered, the solar roof slope was set equal to the site latitude angle and the roof azimuth was due south. Each resulting curve shows the characteristic sharp drop-off as the number of series solar cells is reduced. As the number of series solar cells is reduced for a given set of insolation and temperature conditions, more and more hours of operation in the summer result in a battery charging voltage which exceeds the array maximum power voltage. On the other hand an increase in the number of series cells above the optimum causes a gradual decrease in system output due to the reduction in array current at the average battery charging voltage.

The results of this analysis for the three sites considered indicates that near optimum system performance can be achieved by the selection of a single value for the number of series solar cells. A value between 510 and 520 nearly achieves optimum system performance for all sites considered.

3.4.3 SOLAR ROOF AZIMUTH ANGLE

The sensitivity to solar roof azimuth angle orientation was investigated with the results as shown in Figure 3-19. For this analysis the number of series cells was fixed at 513 and the total solar cell area was held constant at 84.0 m^2 . The solar roof slope angle (measured from the horizontal) was set equal to the site latitude for each of the three locations. As shown in Figure 3-19, the results confirm that the optimum solar roof azimuth orientation is due south in each case, but the effect on system performance is not significant for orientations ± 15 degrees from due south. The maximum system performance penalty over this range of azimuth angle is 1.3 percent for the Cleveland site location.

3.4.4 SOLAR ROOF SLOPE ANGLE

The results of the sensitivity analysis for solar roof slope angle (measured from the horizontal) are given in Figure 3-20. For each site location the roof slope angle was varied from approximately (Latitude -30) degrees to (Latitude +15) degrees. The roof azimuth orientation was due south in all cases and the number of series cells was 513 with a total cell area of 84.0 m^2 .

Figure 3-18. Determination of the Optimum Number of Series Solar Cells

Figure 3-19. Determination of the Optimum Solar Roof Azimuth Angle Orientation

- NOMINAL CELL EFFICIENCY 13.4%
- 84.0 M² CELL AREA
- SOLAR ROOF AZIMUTH ANGLE = 0°

Figure 3-20. Determination of Optimum Solar Roof Slope Angle

An optimum slope angle results from this analysis as indicated on the figure and tabulated in Table 3-4. For both Phoenix and Miami this optimum is clearly defined at (L-11) degrees and (L-9) degrees, respectively. However, for the Cleveland site location the slope angle could be selected anywhere between L and (L-15) degrees with very little effect on annual energy displacement factor. A value of 37 degrees, or (L-4) degrees, was selected to provide near optimum performance with a high enough roof pitch to accommodate a two story house and to allow the self removal of snow.

3.4.5 SYSTEM SIZING

Figure 3-21 shows the system performance, in terms of annual energy displacement factor, as a function of total solar cell area and battery size. For each of the three site locations the number of series solar cells was fixed at 513 and the roof azimuth orientation was due south. The roof slope angle was varied from site-to-site to correspond to the optimum value determined in Section 3.4.4. The total solar cell area on the roof was varied from 63.0 to 132.3m² and the battery capacity was varied from 125 ampere-hours (24 kW-hrs) to 500 ampere-hours (96 kW-hrs).

Table 3-5 summarizes the results of these calculations in terms of the total annual system output as determined by performing a yearly system performance analysis for each solar cell area/battery capacity combinations listed. Figure 3-21 was plotted by dividing each of these numbers by the calculated annual residential electrical load demand which is listed in Table 3-6 for each of the site locations.

TABLE 3-4. OPTIMUM SOLAR ROOF SLOPE ANGLE
(Measured from Horizontal)

Site Location	Optimum Slope Roof Slope Angle (α)	
	α	Latitude - α
Cleveland	37 deg	4 deg
Phoenix	22	11
Miami	17	9

TABLE 3-6. RESIDENTIAL ELECTRICAL LOAD DEMAND

Site Location	Total Annual Electrical Demand (kW-hr)
Cleveland, Ohio	24871.
Phoenix, Ariz	20696.
Miami, Florida	21566

Figure 3-21. System Performance vs. Solar Array and Battery Size

TABLE 3-5. ANNUAL SYSTEM OUTPUT

Solar Cell Area (m ²)	Battery Capacity (A-H)	Photovoltaic/Battery System Output (kW-hrs)		
		Cleveland, Ohio	Phoenix, Arizona	Miami, Florida
63.0	125	6720	10960	10204
	250	7371	12770	11550
	375	7387	12838	11864
	500	7402	12906	11843
84.0	125	8290	12414	11854
	250	9479	16415	14856
	375	9685	16677	15300
	500	9884	16943	15849
109.3	125	9382	13323	12960
	250	10717	18591	17725
	375	11182	19345	18455
	500	11236	19479	18701
132.3	250	11360	19658	19368
	375	12065	20492	20125
	500	12192	20579	20509

Some interesting observations can be made from the results plotted in Figure 3-21. Within practical size limits, the load demand of a Cleveland residence could not be completely supplied by a photovoltaic/battery system. On the other hand a Phoenix residence with 132.3m² of solar cell area and 96 kW-hrs of battery capacity could operate on an annual basis with very little energy required from the utility.

With a nominal solar cell area of 84 m², and a 48 kilowatt-hour battery capacity, Figure 3-22 shows the monthly variations in load and PV system output for each of the site locations studied, as modeled by the program UNREG. The plots indicate that in all three cases the PV system output never exceeds the load and closely matches the load during certain months. Larger systems would have necessitated the dissipation of excess output. Thus, the nominal system appears to provide optimum performance for the cases studied.

In contrast to the results of Figure 3-22, monthly variations in load and PV system output were determined for the systems without energy storage, as modeled by the program NOBATTERY. The results are shown on Figure 3-23. In this case the PV output can exceed the load without limit since the excess is accommodated as feedback to the utility grid.

Figure 3-22. Monthly Load and PV Output for UNREG System

Figure 3-23. Monthly Load and PV Output for NOBATTERY System

3.5 SYSTEM COMPARISON RESULTS

The comparison of the UNREG system with the NOBATTERY system are summarized on Table 3-7 for each of the three site locations. In each case the no-battery system with feedback to the utility performs significantly better than the Direct Charge System with the same solar cell area. The improvement in performance is 34 percent in Clemeland and about 25 percent in the other two cities. Note that the house electrical load is the same for the two systems in each of the three site locations. The solar array output is greater for the NOBATTERY case because the inverter has been designed to hunt for and operate at the solar array maximum power point. For the UNREG cases the "excess energy" is dissipated in the shunt voltage limiter whereas on the NOBATTERY cases this excess energy is fed back to the utility. The energy which goes into battery heat dissipation is also saved in the NOBATTERY system. The significant improvement of the NOBATTERY system is the result of transferring the burden for energy storage to the utility system. Although this transfer would appear to incur economic penalties to the utility, an economic comparison of the UNREG and NOBATTERY cases, considering their integration into a utility system, indicated superiority of the UNREG approach. These results are discussed later in Section 4.4.

Table 3-8 gives the results of a comparative evaluation of five of the six basic system concepts described in Section 3.2 for the Cleveland, Ohio site location (all except UNREGA). The UNREG and NOBATTERY results are the same as in Table 3-7 for the Cleveland site. The SUNREG program provides for daily updates of the solar array slope angle from the horizontal so that the sun is normal to the array at solar noon. The resulting small improvement in performance, compared to the UNREG system with a fixed slope angle, would hardly merit the cost of the additional mechanisms required to change the slope angle.

The TRACKER system also shows a small improvement in performance compared to the UNREG System. The solar array output is higher than the UNREG case because, like the NOBATTERY System, the TRACKER System dynamically tracks the solar array maximum power operating point. However, in the TRACKER case the solar array output is slightly less than the NOBATTERY case. This is due to the fact that the TRACKER system is maximum power tracking only when the batteries are charging. During the sunrise and sunset periods of the day, when some load sharing battery discharge is required, the solar array bus voltage is clamped to the battery discharge voltage and the maximum power tracking battery charge regulator is disabled. The comparatively large power conditioning losses in the TRACKER system are a result of the additional losses in the PWM battery charge regulator. A regulator efficiency of 90 percent was used in the calculation.

The photovoltaic/thermal total energy system, represented by the UNREGH program, was evaluated for the Cleveland site location using the system design parameters given in Table 3-9. The analysis considered the option of cooling the solar cells during Summer operation rather than operating them hotter to permit Rankine engine driving of the heat pump compressor. The solar cell cooling option was favored for several reasons: (1) the relatively high cost of the Rankine equipment; (2) the low coefficient of performance possible with the Rankine engine/heat pump combination because of the limited temperature capability of the single-pane flat-plate solar collector configuration used.

TABLE 3-7. COMPARISON OF DIRECT CHARGE SYSTEM WITH NO-BATTERY/POWER FEEDBACK SYSTEM FOR 84 M² SOLAR CELL AREA.

Annual System Performance	Cleveland		Phoenix		Miami	
	UNREG with 48 kW-hr Battery	NOBATTERY	UNREG with 48 kW-hr Battery	NOBATTERY	UNREG with 48 kW-hr Battery	NOBATTERY
House Electrical Load (KW _e -hr)	24871.	24871.	20696.	20696.	21566.	21566.
System Output (KW _e -hr)	9479.	12698.	16420.	20339.	14856.	18533.
Utility Make-up (KW _e -hr)	15392.	17798.	4276.	10377.	6710.	10954.
Solar Array Output (KW _e -hr)	13208.	14595.	21972.	23378.	20010.	21302.
Power Conditioning Losses (KW _e -hr)	1417.	1897.	2453.	3039.	2220.	2769.
Excess Energy (KW _e -hr)	675.*	5625.**	781.*	10020.**	659.*	7921.**
Battery Heat Dissipation (KW _e -hr)	1637.	-----	2318.	-----	2275.	-----
Energy Displacement Factor	0.381	0.511	0.793	0.933	0.689	0.859

*Dissipated in shunt regulator

**Feedback to utility

TABLE 3-8. COMPARISON OF OTHER SYSTEM OPTIONS FOR CLEVELAND, OHIO SITE LOCATION WITH
84 m² SOLAR CELL AREA AND 48 kW-HR BATTERY CAPACITY

	System Implementation				
	Concept 1	Concept 4	Concept 2	Concept 3	Concept 6
	UNREG	NOBTRY	SUNREG	TRACKER	UNREGH
House Electrical Load (KW _e -hr)	24871.	24871.	24871.	24871.	18576.
Diversified and Domestic Hot Water Loads	12775.	12775.	12775.	12775.	12775.
Heating and Cooling Load	12096.	12096.	12096.	12096.	5801.
System Output (KW _e -hr)	9479.	12698.	9597.	9671.	8287.
Utility Make-up (KW _e -hr)	15392.	17798.	15273.	15200.	10289.
Solar Array Output (KW _e -hr)	13208.	14595.	13766.	14207.	10964.
Power Conditioning Losses (KW _e -hr)	1417.	1897.	1434.	2365.	1238.
Excess Energy (KW _e -hr)	675.	5625.	904.	526.	139.
Battery Heat Dissipation (KW _e -hr)	1637.	-----	1831.	1645.	1300.
Energy Displacement Factor	0.381	0.511	0.386	0.389	0.446

Using the solar cell cooling approach the resulting electrical load demands are reduced as shown in Table 3-8 because some of the energy demands for space heating and domestic hot water are supplied by the solar thermal portion of the system. The other performance parameters in Table 3-8 relate to the electrical portion of the system. The solar array output and system output are less than the basic UNREG system because the average operating temperature of the solar cells is higher due to the presence of the single Lexan cover on the collector panels. The overall electrical energy displacement factor is approximately 18 percent better than the basic UNREG system. An economic evaluation of the total energy UNREG approach for the single residential case considered here, is discussed in Section 4.4.3. More comprehensive treatment of combined photovoltaic/thermal collection is presented in Part C, Intermediate School System.

Analysis of the UNREG system was limited to comparing forced and natural air cooling of the solar array underside for a few representative conditions rather than performing an hour-by-hour analysis for an entire year. The results indicate that little if any benefit is derived from forced air underside cooling of the solar array. Although the solar array output improved over the system with topside natural convection cooling, the gain was absorbed by the fan power required for forced air circulation. The comparative evaluation of topside natural cooling with top plus underside natural cooling, shown earlier on Figure 3-9, indicated a cell temperature improvement of about 5°C, equivalent to a performance gain of about 2.5 percent. From an economic standpoint this would permit an additional 2.5 percent in the capital cost to achieve an identical cost to performance ratio. At a system capital cost of \$11,000 for the no-battery systems, with solar array costs at \$100/m² (see Section 4.3), the allowance for underside cooling is then \$275 or about \$3.25/m² for an array cell area of 84 m². This appears to be substantially less than that required for an underside cooled ducted panel and therefore further consideration of this approach was dropped. Free standing panels might benefit more significantly from underside cooling; however, such configurations did not appear appropriate for the on-site residence application.

Table 3-9. HYBRID SYSTEM DESIGN PARAMETERS

CHARACTERISTIC	VALUE
Total Solar Cell Area	84.0 M ²
Total Collector Panel Area	120 M ²
Thermal Energy Storage Medium	Water
Thermal Energy Storage Size	5859 kg
Collector Fluid	30% ethylene glycol/water
Collector Heat Exchanger UA	21.1 kW/°C
Collector Fluid Flow Rate	4536 kg/hr
TES Flow Rate	4536 kg/hr
Battery Size	48 kW-hr

3.6 REFERENCES, SECTION 3

1. "Interim Solar Cell Testing Procedures for Terrestrial Applications," Brandhorst, H., et al, July 1975, Lewis Research Center
2. Liu, B. Y. N. and Jordan, R. C., "The Interrelationship and Characteristic Distribution of Direct, Diffuse and Total Solar Radiation," Solar Energy, Vol IV, No. 3, July 1960, p 8
3. Duffie, J. A. and Beckman, W. A., "Solar Energy Thermal Processes," Wiley, 1974, p 54
4. Ibid, p 76
5. Ibid, p 83
6. Ibid, pp 120-177

SECTION 4
ECONOMIC ANALYSIS

SECTION 4

ECONOMIC ANALYSIS

4.1 INTRODUCTION

Economic analysis of the residence photovoltaic concept is carried out in three stages. First, levelized busbar costs (LBC) are determined which establish the annual revenue required to meet the cost of photovoltaic generation. The results are mainly used to compare the economic merits of competing technical concepts used at selected site locations (Cleveland, Phoenix, Miami). Second, the LBC results are extended to cover many regions and are then compared with regional electricity prices to determine those areas where photovoltaics may be economically viable. Lastly, the worth of photovoltaics from a utility viewpoint is determined for several selected regions in terms of both capacity and energy displacement.

4.2 LEVELIZED BUSBAR COST ANALYSIS

4.2.1 ANALYSIS METHODOLOGY

Levelized busbar costs are determined by annualizing the total system cost over the life of the system and then dividing the annualized cost by the annual energy output:

$$\text{LBC} = \frac{\text{Annualized Cost}}{\text{Annual Energy Output}}$$

The annualized cost is comprised of contributions associated with initial capital outlays, periodic battery replacement costs, and operating and maintenance (O&M) costs. Since these costs are expressed in different terms (e. g., capital outlay is given in dollars, while O&M is given in dollars per year), different factors are used to convert the costs to consistent annualized values:

$$\begin{aligned} \text{Annualized Cost} = & F_1 \times (\text{initial outlay}) \\ & + F_2 \times (\text{periodic replacement costs}) \\ & + F_3 \times (\text{annual O\&M costs}) \end{aligned}$$

The F factors may be expressed in terms of constant or current year dollars. Their determination involves assumptions regarding the capital structure involved, and applicable economic factors. Tables 4-1 and 4-2 show the assumptions used in the economic analysis for utility and consumer ownership cases. Using these data and a discounted cash flow analysis, Appendix C derives the F factors as a function of before-tax discount rate. The before-tax discount rate represents the effective cost of borrowed money due to interest on loans, return on equity, and payment of corporate taxes. Figure 4-1 shows the resulting factors plotted against the before-tax discount rate for the utility and consumer ownership cases.

TABLE 4-1. ECONOMIC ASSUMPTIONS
FOR UTILITY OWNERSHIP
ECONOMIC ANALYSIS

Capital Structure		
Debt Fraction :	50%	
Equity Fraction :	50%	
Risk Premium :	2.5% (Difference between interest on debt and return on equity)	
Before Tax Discount Rate: 5 to 15 percent		
After Tax Discount Rate: 2.6 to 7.8 percent		
Escalation Rates:		
	<u>1975-1985</u>	<u>1986-2019</u>
General Price Level	3.8	4.2
O&M Labor	4.8	4.5
Materials	3.1	3.8
Installed Capital	4.8	4.6
Insurance	4.8	4.6
Federal Tax Rate: 48%		
Other Taxes: 2 percent state and local		
Year of Capital Expenditures: 1989		
Start of Operations: 1990		
System Lifetime: 30 Years		
Depreciation Method: Sum of Years Digits		
Investment Tax Credit: 10 percent		

TABLE 4-2. ECONOMIC ASSUMPTIONS
FOR CONSUMER OWNERSHIP

Capital Structure		
Debt Fraction: 100%		
Before Tax Discount Rate		
Varied parametrically from 5 to 15 percent		
After Tax Discount Rate: 4 to 12 percent		
Escalation Rates:		
	<u>1975-1985</u>	<u>1986-2019</u>
General Price Level	3.8	4.2
O & M Labor	4.8	4.5
Materials	3.1	3.8
Installed Capital	4.8	4.6
Insurance	4.8	4.6
Tax Rate: 20 percent		
Other Taxes: 1 percent local		
Year of Capital Expenditure: 1989		
Start of Operation: 1990		
System Lifetime: 30 Years		
Depreciation: Not applicable		
Tax Credit: None		

Use of the factors provides annualized (or levelized) costs in constant 1975 dollars.* Figure 4-2 may be used to express the initial outlay levelized cost in current year dollars. This is often referred to as the Fixed Charge Rate (FCR). With these plots, levelized costs may be determined for specified before-tax discount rates or fixed charge rates. It should be noted that these relationships only hold for the assumptions listed earlier on Tables 4-1 and 4-2.

4.2.2 LBC ANALYSIS INPUT DATA

Capital costs were developed for the two major system alternatives described earlier, namely Concept No. 1 with energy storage and Concept No. 4 without energy storage. Tables 4-3 and 4-4 show the breakdown of costs identified for nominal designs of these respective cases. Figure 4-3 shows the dependence of capital costs on the unit costs of solar arrays and batteries. The unit costs are based on assuming mature technology and high rates of production. Operating costs for the nominal designs are shown on Table 4-5.

The annual system output for determining the cost per kilowatt-hour is shown on Table 4-6. Besides the output for the nominal system, (Cases 5 and 16 for the battery and no-battery systems respectively), outputs are shown for several array and battery size combinations as developed in Section 3.

Supporting data for the cost of key subsystems is presented in Section 5.7.

*Note: This is not the parameter designated as BBEC in Reference 1, Paragraph 4.5.
The calculation here is BBEC₀.

Figure 4-1. Relationship of Levelized Cost to Capital, Battery, and Maintenance Costs

Figure 4-2. Relationship of Fixed Charge Rate and Levelized Cost

TABLE 4-3. CAPITAL COSTS OF RESIDENTIAL PHOTOVOLTAIC SYSTEM WITH ENERGY STORAGE (CONCEPT NO. 1)

Item	Unit Cost	Cost for Nominal System	Cost Data Source
Solar Array Shingle	\$50 to \$200/M ² array area	\$5250 to \$21,000	Independent variable
Solar Array Installation			
Labor:			
Shingle Laydown	\$7.88/M ²	827	1974 Bldg. Cost File
Wiring, sheet metal	\$1.00/M ²	105	1974 Bldg. Cost File
Material:			
Wire, sheet metal, felt, etc.	\$0.95/M ²	100	1974 Bldg. Cost File
Credit for Conventional Roof			
Labor:			
Shingle Laydown	\$5.40/M ²	-567	1974 Bldg. Cost File
Material:			
Shingle, felt, etc.	\$2.20/M ²	-231	1974 Bldg. Cost File
Lead-acid battery, 96 cell, 250 ampere-hour	-	3700 (Recurring cost every 10 years)	C&D Batteries, Inc.
Battery Room	-		
Labor & Material	-	1425	1974 Bldg. Cost File
DC/AC Inverter, 8KVA	\$125/KVA	1000	GE-CRD
Shunt Charge Regulator	-	340	Engrg. estimate
Electrical Devices	-	300	Catalog Data
Breakers, Switches, etc.	-		
Electrical Equipment Installation	-	400	Engrg. estimate
Lightning Protection, Labor & Material	-	300	Catalog Data

Capital cost = \$7,699 (excluding solar cell shingles)

NOTES: (1) Nominal System Sizing: 84 M² active cell area
105 M² solar array area (0.8 packing factor)
250 ampere-hour battery
8 kVA dc/ac inverter

(2) Costs shown in 1975 dollars

TABLE 4-4. CAPITAL COSTS OF RESIDENTIAL PHOTOVOLTAIC SYSTEM WITHOUT ENERGY STORAGE (CONCEPT NO. 4)

Item	Unit Cost	Cost for Nominal System	Cost Data Source
Solar Array Shingle	\$50 to \$200/M ² array area	\$5250 to \$21,000	Independent variable
Solar Array Installation			
Labor:			
Shingle Laydown	\$7.88/M ²	827	1974 Bldg. Cost File
Wiring, sheet metal	\$1.00/M ²	105	1974 Bldg. Cost File
Material:			
Wire, sheet metal, felt, etc.	\$0.95/M ²	100	1974 Bldg. Cost File
Credit for Conventional Roof			
Labor:			
Shingle Laydown	\$5.40/M ²	-567	1974 Bldg. Cost File
Material:			
Shingle, felt, etc.	\$2.20/M ²	-231	1974 Bldg. Cost File
DC/AC Inverter, 13 KVA	\$125/KVA	1625	GE-CRD
Electrical Devices			
Breakers, Switches, etc.	-	150	Catalog Data
Electrical Equipment			
Installation	-	200	Engineering Estimate
Lightning Protection, Labor & Material	-	300	Catalog Data

Capital cost at Start Year: \$2509 (excluding solar cell shingles)

NOTES: (1) Nominal System Sizing: 84.0 M² active cell area
105 M² solar array area (0.8 packing factor)
13 kVA dc/ac inverter

(2) Costs shown in 1975 dollars

TABLE 4-5. OPERATING COSTS OF RESIDENTIAL PHOTOVOLTAIC SYSTEMS WITH AND WITHOUT BATTERIES

Item	Cost
Maintenance	\$50/year
Insurance (Annual Premium)	0.5 percent of capital cost

NOTE: Costs shown in 1975 dollars

Figure 4-3. Capital Cost for Nominal System

4.2.3 LBC ANALYSIS RESULTS

4.2.3.1 Systems with Energy Storage (Concept 1)

Levelized busbar costs for systems with energy storage were determined with the aid of Figure 4-1, using the cost data cited earlier and the annual output data of Table 4-6. Battery costs were based on a 10-year replacement schedule. Calculations mainly considered utility ownership using a 15 percent before-tax discount rate, although initial parametric results also considered consumer ownership.

TABLE 4-6. YEARLY OUTPUT OF SOLAR PHOTOVOLTAIC SYSTEM
(Nominal cell efficiency 13.4%)

Case	Solar Array Area (m ²)	Battery Size (Amp-Hr)	System Output in Megawatt-Hours/Year		
			Cleveland	Phoenix	Miami
1	78.8	125	6.72	11.01	10.20
2	105.0	125	8.29	12.41	11.85
3	136.5	125	9.38	13.32	12.96
4	78.8	250	7.37	12.77	11.55
5	105.0	250	9.48	16.41	14.86
6	136.5	250	10.72	18.59	17.73
7	165.4	250	11.36	19.66	19.37
8	78.8	375	7.39	12.84	11.86
9	105.0	375	9.69	16.68	15.30
10	136.5	375	11.18	19.35	18.46
11	165.4	375	12.07	20.49	20.13
12	78.8	500	7.40	12.91	11.84
13	105.0	500	9.88	16.94	15.85
14	136.5	500	11.24	19.48	18.70
15	165.4	500	12.19	20.58	20.51
16	84.0	0	12.70	20.34	18.53

The example calculation shown on Table 4-7 illustrates how levelized busbar costs are calculated using the plots of Figure 4-1. The example pertains to the system with energy storage for a site location in Phoenix.

As indicated the method produces a levelized cost of \$0.169/ kWh

Levelized cost sensitivity was analyzed for the nominal designs by varying key parameters including solar array size, solar array cost and battery capacity. Figures 4-4 thru 4-6 show the sensitivity results for the residential PV system with energy storage for locations in Phoenix, Cleveland and Miami. Both utility and consumer ownership were considered. These results are based on a nominal cell efficiency of 13.4%.

TABLE 4-7. CALCULATION OF LEVELIZED BUS BAR COST (EXAMPLE)

1. Initial Capital Cost		
105 m ² shingled solar array area @ \$200/m ²	\$21,000	
Other, excluding batteries (See Table 4-1)	<u>3,999</u>	
Total	\$24,999	
Levelized contribution from Figure 4-2(a) for 15% before tax discount, 0.0882 x 24,999		\$2,205
2. Battery Costs		
250 ampere-hour battery \$3700 per, initial plus 2 replacements @ 10 year intervals	\$11,100	
Levelized contribution from Figure 4-2(b) for 15% before tax discount, 0.0461 x 11,100		\$ 512
3. Maintenance		
Per year	\$ 50	
Levelized contribution from Figure 4-2(c) for 15% before tax discount, 1.1 x 50		\$ 55
Total Levelized Bus Bar Cost		<u>\$2,772/yr</u>
Annual Energy: 16.41 MWh for Phoenix (See Table 4-6)		
Levelized Bus Bar Cost/kWh = $\frac{2,772}{16,410}$ = \$0.169/kWh		

The presentation of the results for Phoenix on Figure 4-4 is typical of that shown for the other locations. Plot (a) shows the dependence of levelized cost on battery capacity, solar array area, and solar array cost for the case of utility ownership. Over the range of battery capacity considered (125 to 500 ampere-hours) the curves indicate minimum cost at particular battery sizes although the shallowness of the curves show relative insensitivity over a wide range of array and battery sizes.

The optimum solar array area for the system may be estimated from plot (b) which is established by plotting the minimum levelized cost for each curve of plot (a) as a function of area. As shown in plot (b) the most economic area lies between 100 to 150 square meters of array depending on unit area costs. The corresponding optimum battery capacities are shown on plot (c), also developed from plot (a). Plots (d), (e), and (f) present the same information as plots (a), (b) and (c), but consider consumer ownership.

UTILITY OWNERSHIP

- 1975 : 15
- 30 YEAR LIFE
- START YEAR 1990
- 15% BEFORE TAX DISCOUNT RATE
- 48% CORPORATE TAX
- 10% INVESTMENT CREDIT
- SYD DEPRECIATION

CONSUMER OWNERSHIP

- 1975 : 15
- 30 YEAR LIFE
- START YEAR 1990
- 10% BEFORE TAX DISCOUNT RATE
- 20% TAX BRACKET
- 0% INVESTMENT CREDIT

Figure 4-4. Cost Tradeoffs for Phoenix Location

- UTILITY OWNERSHIP
- 1975 \$/S
 - 30 YEAR LIFE
 - START YEAR 1990
 - 15% BEFORE TAX DISCOUNT RATE
 - 48% CORPORATE TAX
 - 10% INVESTMENT CREDIT
 - SYD DEPRECIATION

- CONSUMER OWNERSHIP
- 1975 \$/S
 - 10 YEAR LIFE
 - START YEAR 1990
 - 10% BEFORE TAX DISCOUNT RATE
 - 20% TAX BRACKET
 - 6% INVESTMENT CREDIT

Figure 4-5. Cost Tradeoffs for Cleveland Location

UTILITY OWNERSHIP

- 1975 $\epsilon/\$$
- 30 YEAR LIFE
- START YEAR 1990
- 15% BEFORE-TAX DISCOUNT RATE
- 48% CORPORATE TAX
- 10% INVESTMENT CREDIT
- SYD DEPRECIATION

CONSUMER OWNERSHIP

- 1975 $\epsilon/\$$
- 30 YEAR LIFE
- START YEAR 1990
- 10% BEFORE TAX DISCOUNT RATE
- 20% TAX BRACKET
- 0% INVESTMENT CREDIT

Figure 4-6. Cost Tradeoffs for Miami Location

TABLE 4-8. OPTIMUM LEVELIZED COST (\$/kWh)
SYSTEMS WITH ENERGY STORAGE

Solar Array Cost		Phoenix		Cleveland		Miami	
		Utility Owned	Consumer Owned	Utility Owned	Consumer Owned	Utility Owned	Consumer Owned
\$200/m ²	Array Area, m ²	105	120	105	105	140	130
	Battery Capacity, A-H	300	350	250	250	380	350
	Levelized Cost, \$/kWh	.169	.140	.292	.252	.183	.157
\$100/m ²	Array Area, m ²	130	120	120	120	130	120
	Battery Capacity, A-H	340	280	220	250	340	300
	Levelized Cost, \$/kWh	.110	.092	.187	.165	.124	.110
\$50/m ²	Array Area, m ²	150	120	120	110	140	140
	Battery Capacity, A-H	360	250	180	200	300	275
	Levelized Cost, \$/kWh	.079	.067	.067	.125	.086	.075

Table 4-8 lists the optimum solar array areas, battery capacities, and levelized costs derived from Figures 4-4 through 4-6 for the three locations considered. An examination of the data indicates practically the same results for utility and consumer ownership.

The data indicates array area ranging from 105 to 150 square meters and battery capacity ranging from 50 to 325 ampere-hours. As noted previously, levelized costs are relatively insensitive to size and, therefore, a clearcut optimum is not produced by the analysis. A wide range of array and battery size appears to serve almost as well as the optimum designs defined by Table 4-8. This is demonstrated on Table 4-9 which compares the performance of the optimum designs with the nominal design described earlier (105 square meter array area; 250 ampere-hours battery capacity).

TABLE 4-9. COMPARISON OF LEVELIZED COSTS (\$/kWh) FOR OPTIMUM
AND NOMINAL SYSTEMS WITH ENERGY STORAGE*

Solar Array Cost	Optimum Design	Phoenix Nominal Design	Percent Diff.	Optimum Design	Cleveland Nominal Design	Percent Diff.	Optimum Design	Miami Nominal Design	Percent Diff.
\$200/M ²	0.169	0.169	0	0.292	0.292	0	0.183	0.187	2
\$100/M ²	0.110	0.112	2	0.187	0.195	4	0.124	0.124	0
\$50/M ²	0.079	0.084	6	0.142	0.146	3	0.086	0.093	7

*Based on utility ownership and 15% before-tax discount rate.

Divergence of levelized costs from the optimum values appears greatest with the lowest solar array cost.

4.2.3.2 Systems Without Energy Storage (Concept 4)

The determination of levelized costs for systems without energy storage is summarized on Table 4-10. Because of the absence of energy storage, the tradeoffs leading to an optimum array area are not economic but technical in nature. The data of Table 4-10 are based on using the 105 square meters of array area selected for the nominal design and the cost data presented in Table 4-4.

TABLE 4-10. BASELINE NO BATTERY CASE LEVELIZED COST
OF POWER RESULTS FOR A 105 SQUARE
METER ARRAY AREA

City	Type of Ownership	Solar Cost (\$/M ²)	Levelized Cost of Power (\$/kW-Hr)
Cleveland	Utility	50	0.058
		100	0.095
		200	0.167
	Consumer	50	0.049
		100	0.078
		200	0.138
Phoenix	Utility	50	0.036
		100	0.059
		200	0.104
	Consumer	50	0.030
		100	0.049
		200	0.086
Miami	Utility	50	0.040
		100	0.065
		200	0.115
	Consumer	50	0.033
		100	0.054
		200	0.095

4.2.3.3 Comparisons With and Without Energy Storage

The comparison of levelized costs for systems with and without energy storage is summarized on Figures 4-7, 4-8, and 4-9 for each of the locations. The substantially lower costs of the systems without energy storage are attributable to battery associated needs. The influence of the battery cost itself is shown parametrically. The difference in the levelized cost between the battery and no-battery systems is not proportional to the battery cost reduction alone because of the cost of such other battery related items as the shunt charge regulator and the battery protective enclosure. Also, the inefficiency of battery energy storage tends to drive the levelized costs upward regardless of the cost of the batteries themselves. Because of these factors, even if the battery were available at no cost, the levelized cost for the system with energy storage is appreciably higher than the system without energy storage. The nominal systems were used as the basis for these plots.

Figure 4-7. Levelized Bus Bar Cost in Phoenix

An overall comparison of levelized costs for the locations considered is shown on Figure 4-10 which permits a relative assessment of cost performance.

Figure 4-8. Levelized Bus Bar Cost in Cleveland

Figure 4-9. Levelized Bus Bar Cost in Miami

Figure 4-10. Comparison of Levelized Bus Bar Costs

Calculations were also performed to determine the effect of solar cell efficiency on capital and levelized costs. The plot of Figure 4-11 shows the effect on the system capital cost for varying values of solar cell efficiency and solar array cost (this includes the costs of the solar cells, substrate, encapsulation and assembly into a module). The plot was developed from the basic no-battery system which uses 84 m² of cell area with the cells rated at 13.4 percent efficiency at the bare cell output conditions shown, resulting in a rated peak output of 11.25 kW. Capital costs for the system have been determined (Table 4-4) to be \$2,509, excluding the cost of solar array modules but including their installation and wiring and the cost of the other system components (electronics, etc.). At a solar array module cost of \$50/m², the system cost is \$690 per rated kW as shown for the nominal design point on the plot. System capital costs are appropriately adjusted for the other array costs shown. The effect of efficiency is taken into account by inversely adjusting the area to produce the identical rated peak output of 11.25 kW.

The effect on levelized cost of varying cell efficiency and array cost is shown on Figure 4-12 for the Phoenix and Cleveland locations for systems with and without batteries. Again, these plots were developed by varying area inversely with cell efficiency to maintain the system output at a fixed value. For convenience purposes, overlay plots of solar array cost, expressed in dollars per peak Watt, are also included. The combinations of solar array cost and cell efficiency that result in a desired levelized cost can be derived from the plots. For example, to achieve a levelized cost of 5 cent/kWh in Phoenix for the system

Figure 4-11. Effect of Cell Efficiency on System Capital Cost

without batteries the array cost must be about $\$30/\text{m}^2$ if cells of 5 percent efficiency are used, or about $\$90/\text{m}^2$ if cells of 15 percent efficiency are used. With peak output nominally based on an insolation of $1 \text{ kW}/\text{m}^2$, the cost for both cases is $\$0.75/\text{peak watt}$ using a packing factor of 80 percent. The intercept on the abscissa of the plots represents that portion of the levelized cost due to all items aside from the solar array. The higher intercept values for the systems with batteries is due principally to the cost of the batteries themselves. The lower intercept values of the Phoenix case compared to Cleveland is the direct result of the higher annual energy produced.

Several plots were prepared for determining adjustment in levelized costs as a function of several economic variables as described below:

1. For the case of utility ownership, levelized costs of the nominal system were previously developed assuming an investment credit of 10 percent. Figure 4-13 indicates the adjustment if different credit allowances are used. Thus, according to the plot, the modified levelized cost for a 20 percent investment credit would be 80 percent of that corresponding to a 10 percent investment credit, considering a utility owned system with energy storage. Similar plots are shown for consumer ownership for which zero investment credit was used in establishing the baseline levelized costs.
2. The effect of income tax bracket on the levelized cost is shown in Figure 4-14 for the case of consumer ownership. Reductions in levelized cost with higher tax

Figure 4-12. Effect of Cell Efficiency on Levelized Cost

Figure 4-13. Effect of Investment Credit on Levelized Cost

Figure 4-14. Effect of Consumer Income Tax Bracket on Levelized Cost

brackets result from the fact that tax savings, due to deductions of mortgage principal with a consequent reduction in the levelized cost of power.

4.2.3.4 Combined Photovoltaic/Thermal System (Concept 6)

Economic evaluation of the combined PV/thermal UNREGH system is compared below with the PV-only UNREG system. Table 3-8 shows the performance for both systems applied to a residence in Cleveland. With both systems satisfying the electrical and heating/cooling loads, the significant difference is in the amount of annual utility makeup power required:

Concept 1 (UNREG)	15,392 kWh
Concept 6 (UNREGH)	<u>10,289 kWh</u>

Difference saved by UNREGH: 5,103 kWh

Figure 4-12 indicates a levelized cost of \$0.14/kWh corresponding to a solar array cost of \$0.50 per peak Watt. Assuming the residence PV system is competitive with utility power then the annual saving in purchased power is $5103 \text{ kWh} \times \$0.14/\text{kWh} = \$714$. This annual saving may be applied to the purchase of the non-photovoltaic elements of the total energy system.

Figure 4-2(a) indicates a levelized cost to initial investment ratio of 0.0882 which corresponds to a 15 percent discount rate and a 30-year payout period. Thus, the \$714 represents an investment of \$8,095.

As indicated on Table 3-9, the total collector area is 120 m^2 and therefore the unit area capital cost may be $\$8,095 \div 120 \text{ m}^2 = \$67/\text{m}^2$ or about \$6.20/ft². This is not just the allowable collector cost but the solar thermal system cost per unit area of collector. This includes the cost of the collectors along with the numerous other items required - tankage, pumps, valves, piping, etc.

Based on projected costs of 5 to 10 dollars/ft² for solar thermal collectors alone and an equivalent amount for the remaining system elements, the analysis for the single case considered in the Cleveland location does not strongly favor the total energy approach. More comprehensive analyses of combined systems are presented in Part C, Section 4.4.

4.2.3.5 Use of Inverter Dissipated Heat

As described in Section 2.2, utilization of the dc/ac inverter dissipated heat for heating the domestic hot water might prove to be an attractive feature. Table 4-11 summarizes the data pertaining to this possibility considering that 75 percent of the inverter losses could be used for water heating. As indicated, the capital cost to produce the equivalent of the inverter dissipated heat varies from \$756 to \$1809. Thus, any investment up to these limits would be economically beneficial. It is estimated that proper heat sinking of the inverter and the inclusion of additional pumps, piping, tankage and controls to handle the dissipated heat would cost on the order of several hundred dollars. Thus, use of the dissipated heat would be a very worthwhile feature.

TABLE 4-11. SUMMARY OF DOMESTIC HOT WATER SYSTEM

	Location	Cleveland		Phoenix		Miami		Data Source
		UNREG	NOBATRY	UNREG	NOBATRY	UNREG	NOBATRY	
(1)	Power Conditioning Losses (KW -hr)	1417	1897	2453	3039	2220	2769	Table 3-7
(2)	Energy Available for Heating, $0.75 \times (1)$	1063	1423	1840	2279	1665	2077	
(3)	Levelized Cost, \$/. kW-hr (Based on \$ 50/m ²)	0.146	0.058	0.084	0.036	0.093	0.040	Tables 4-9, 4-10
(4)	Annual Cost Saving (2) $\times$ (3) \$/s/year	135	83	155	82	155	83	---
(5)	Capital Cost, \$'s (4) $\div$ 0.0882	1757	941	1757	930	1757	942	Figure 4-2(a) for 15% dis- count rate

4.3 LOCATION SENSITIVITY

4.3.1 REGIONAL LEVELIZED BUS BAR COSTS

The sensitivity of levelized cost with location was investigated by performing system computer simulations for a number of widely distributed sites. The nominal system without energy storage, containing a solar array area of 105 square meter, and a cell efficiency of 13.4%, was used as the basis for these simulations. The results are shown on Table 4-12. The ambient temperatures shown are based on annually averaging the daytime maximum values.

TABLE 4-12. PERFORMANCE OF SYSTEM WITHOUT ENERGY STORAGE AT 10 SELECTED LOCATIONS

Location	Day Time Avg. Temp, °C	Horizontal Annual Insolation, kW-hrs/M ²	Annual Output, kW-hrs/M ²	Year
Cleveland, O	13.3	1264	121	1962
Washington, D.C.	17.7	1689	169	1963
Madison, Wisc	12.7	1615	166	1961
Los Angeles, Cal	21.2	1577	150	1963
Charleston, S.C.	23.4	1744	167	1963
Nashville, Tenn	20.4	1549	145	1959
Ft. Worth, Tex	24.1	1830	173	1962
Omaha, Neb	16.5	1645	173	1963
Phoenix, Ariz	28.8	2119	194	1962
Miami, Fla	27.3	1950	176	1963

These data may be modified by adjusting the outputs for a constant ambient temperature of 28°C. A plot of the adjusted data is shown on Figure 4-15, where each output is increased (or decreased) 0.345 percent for each degree C that the annually averaged ambient temperature is below (or above) 28°C. This adjustment factor reflects the basic dependence of solar array output with temperature considering the use of silicon solar cells. A least squares polynomial data fit subroutine was used to develop the linear plot shown. As described below the linear relationship provides the basis for establishing output sensitivity at various other locations in the country.

Figure 4-15. Linear Fit of Temperature Corrected Calculated Annual Solar Array Energy Output

Insolation and averaged daytime ambient temperatures for various locations in the U.S. were extracted from the Climatic Atlas of the United States, issued by the U.S. Department of Commerce. Unadjusted photovoltaic output at a given location is determined from Figure 4-15 using the appropriate insolation value for the location. The photovoltaic output is then adjusted upward or downward according to the location temperature using the dependence factor noted earlier.

An important point to be noted is that the adjustments are made on the basis of ambient temperatures rather than the array panel temperatures on which output is directly dependent. In actuality, however, the outputs shown on Table 4-12 are based on panel temperatures. If one assumes the difference in panel and ambient temperatures to be constant, then the difference in ambient temperatures provides a direct means for establishing the adjusted panel temperature.

The resulting adjusted outputs are listed on Table 4-13 by performance rating. Discrepancies between Tables 4-12 and 4-13 for certain locations are the result of the interpolation method used and reflect the difference in insolation for specific years compared with the averaged insolation over many years provided by the Climatic Atlas.

The levelized costs shown on Table 4-13 are developed by the steps shown on Table 4-14 for the nominal system without energy storage.

Relative costs from location to location would not be substantially affected if systems with energy storage were considered. Figure 4-16 shows the cost ratio for systems with and without energy storage as a function of insolation. These plots were derived directly from data presented previously in Section 4.4.1 and indicate the cost ratio is insensitive to insolation. Thus, if one establishes the relative cost of system with and without energy storage for a particular location, the cost ratio will remain the same for other locations. As a result, location sensitivity for systems with energy storage will pretty much reflect the same relative values as those indicated for Table 4-13.

Figure 4-16. Correction of System With and Without Storage

TABLE 4-13. RANKING OF LOCATIONS BY SYSTEM OUTPUT*

Ranking By System Output	Location	Yearly Insolation (kW-Hrs/M ²)	Yearly Average Normal Daily Maximum Temp. (°C)	System Output (kW-Hrs/M ²)	System Levelized Cost, Cents/kWh	
					Array Cost:	
					\$ 100/M ²	\$ 50/M ²
1	El Paso, Texas	2275	25.1	212	5.4	3.3
2	Albuquerque, New Mexico	2173	20.6	206	5.6	3.4
3	Flagstaff, Arizona	2118	16.0	203	5.6	3.5
4	Honolulu, Hawaii	2190	28.1	202	5.6	3.5
4	Phoenix, Arizona	2209	30.0	202	5.6	3.5
5	Yuma, Arizona	2207	31.8	201	5.6	3.6
5	Las Vegas, Nevada	2160	25.9	201	5.6	3.6
6	San Juan, Puerto Rico	2173	29.5	199	5.8	3.8
7	Hilo, Hawaii	2122	23.2	198	5.8	3.8
8	Grand Junction, Colorado	1936	18.1	185	6.1	3.8
8	Reno, Nevada	1948	19.2	185	6.1	3.9
9	Midland, Texas	1978	24.6	184	6.1	3.9
10	Lander, Wyoming	1881	14.3	182	6.3	3.9
11	Amarillo, Texas	1910	22.4	179	6.3	4.0
12	Fresno, California	1910	25.4	178	6.4	4.0
12	Tampa, Florida	1923	27.6	178	6.4	4.0
12	Hatteras, North Carolina	1881	20.4	178	6.4	4.0
13	Miami, Florida	1914	28.4	176	6.4	4.0
13	Forth Worth, Texas	1889	24.7	176	6.4	4.0
14	Houston, Texas	1889	26.2	175	6.4	4.0
15	Los Angeles, California	1851	21.0	174	6.4	4.1
15	Oklahoma City, Oklahoma	1851	21.2	174	6.4	4.1
16	San Antonio, Texas	1876	26.2	174	6.5	4.1
17	Brownsville, Texas	1876	28.1	173	6.5	4.1
18	Miles City, Montana	1698	14.8	163	7.0	4.4
18	Yellowstone Nat. Park, Wyoming	1677	11.1	163	7.0	4.4
19	San Francisco, California	1698	18.6	161	7.0	4.4
19	Tallahassee, Florida	1740	26.1	161	7.0	4.4
19	Crater Lake, Oregon	1651	9.9	161	7.0	4.4
20	Jacksonville, Florida	1740	26.5	160	7.0	4.4
20	Wichita, Kansas	1698	20.2	160	7.1	4.5
20	Norfolk, Virginia	1698	20.5	160	7.1	4.5
21	Eureka, California	1650	14.2	160	7.1	4.5
21	Boise, Idaho	1677	17.3	160	7.1	4.5
21	Raleigh, North Carolina	1698	21.5	160	7.1	4.5
21	Williston, North Dakota	1647	11.4	160	7.1	4.5
21	Rapid City, South Dakota	1668	15.3	160	7.1	4.5
21	Salt Lake City, Utah	1673	17.6	160	7.1	4.5
22	Montgomery, Alabama	1698	24.4	158	7.1	4.5
22	Shreveport, Louisiana	1698	24.4	158	7.1	4.5
23	Atlanta, Georgia	1681	22.1	158	7.1	4.5
24	North Platte, Nebraska	1634	17.2	156	7.2	4.6
25	Little Rock, Arkansas	1634	22.7	154	7.5	4.6
25	Lincoln, Nebraska	1609	17.6	154	7.5	4.6

*Assumes utility ownership of PV system.

TABLE 4-13. RANKING OF LOCATIONS BY SYSTEM OUTPUT (Continued)

Ranking By System Output	Location	Yearly Insolation (kW-Hrs/M ²)	Yearly Average Normal Daily Maximum Temp. (°C)	System Output (kW-Hrs/M ²)	System Levelized Cost, Cents/kWh	
					Array Cost:	
					\$ 100/M ²	\$ 50/M ²
25	Memphis, Tennessee	1634	22.7	154	7.5	4.6
26	Bismarck, North Dakota	1566	12.1	152	7.5	4.6
27	St. Louis, Missouri	1549	14.6	150	7.6	4.8
28	Asheville, North Carolina	1571	19.6	149	7.6	4.8
28	Denver, Colorado	1558	17.8	149	7.8	4.8
29	Spokane, Washington	1532	14.2	148	7.8	4.8
30	Washington, D.C.	1915	18.8	144	7.9	4.0
30	Havre, Montana	1486	13.1	144	7.9	4.8
30	Missoula, Montana	1486	13.4	144	7.9	4.9
31	Minneapolis, Minnesota	1447	12.6	143	8.0	4.9
32	International Falls, Minnesota	1443	8.5	142	8.0	4.9
32	Charleston, South Carolina	1715	24.4	142	8.0	4.9
32	Nashville, Tennessee	1507	21.4	142	8.0	4.9
33	Fargo, North Dakota	1486	19.1	141	8.0	4.9
33	Cincinnati, Ohio	1486	19.0	141	8.0	5.0
33	Des Moines, Iowa	1465	15.6	141	8.1	5.0
34	Sault St. Marie, Michigan	1414	9.6	138	8.3	5.1
35	Buffalo, New York	1423	13.1	138	8.3	5.1
35	Columbus, Ohio	1443	17.1	138	8.3	5.1
35	Cleveland, Ohio	1423	13.1	138	8.3	5.1
35	Philadelphia, Pennsylvania	1439	17.4	138	8.3	5.1
36	New Orleans, Louisiana	1473	25.7	137	8.3	5.1
37	Green Bay, Wisconsin	1375	12.0	134	8.6	5.4
38	Caribou, Maine	1341	8.8	132	8.8	5.4
39	Boston, Massachusetts	1367	15.1	131	8.8	5.4
40	Detroit, Michigan	1358	15.4	130	8.8	5.4
41	Glacier Nt. Park, Montana	1324	11.9	129	8.9	5.5
42	Astoria, Oregon	1278	14.7	123	9.0	5.6
43	Portland, Oregon	1278	16.6	122	9.0	5.7
44	New York, New York	1265	16.7	121	9.1	5.9
45	Burlington, Vermont	1189	12.7	115	9.8	6.1
46	Pittsburgh, Pennsylvania	1189	15.8	114	10.0	6.1
47	Chicago, Illinois	1159	14.9	111	10.3	6.4
47	Seattle, Washington	1155	15.2	111	10.3	6.4
48	Shamya, Alaska	1061	5.1	106	10.8	6.5
49	Juneau, Alaska	1032	8.1	102	11.3	6.9
50	Cold Bay, Alaska	998	6.0	99	11.5	7.0
51	Anchorage, Alaska	964	6.2	95	11.9	7.3
51	Fairbanks, Alaska	951	2.9	95	11.9	7.4
51	Nome, Alaska	951	2.8	95	11.9	7.5
52	Barrow, Alaska	874	-9.3	91	12.5	7.8

TABLE 4-14. CALCULATION OF LEVELIZED COST

1. Array Cost	\$100/M ²	\$50/M ²
2. Array Area (Nominal System)	105M ²	105M ²
3. Total Array Cost ① x ②	\$10,500	\$5,250
4. Other Capital Cost (See Table 4-2)	\$ 2,509	\$2,509
5. Total Capital Cost ③ + ④	\$13,009	\$7,759
6. Levelized Cost Factor (See Figure 4-2)	0.0882	0.0882
7. Annual Cost ⑤ x ⑥	\$1,147	\$ 684
8. Levelized O&M (See Table 4-3 & Fig. 4-2)	\$ 55	\$ 55
9. Total Levelized Cost ⑦ + ⑧	\$1,202	\$ 739
10. Unit Area Levelized Cost ⑨ ÷ ②	\$11.45/M ²	\$7.04/M ²
11. Annual Output (El Paso)	212 kWh/M ²	212 kWh/M ²
12. Levelized Cost ⑩ ÷ ⑪	5.4 Cents/kWh	3.3 Cents/kWh

4.3.2 COMPARISON WITH REGIONAL PRICES OF ELECTRICITY

For identifying regions of the U.S. where photovoltaics might be economically attractive, an analysis was performed which compares the levelized bus bar cost of photovoltaic generation with the price of electricity. Since the price of electricity involves complex considerations of rate structures, the comparisons should not be construed as establishing photovoltaic competitiveness. Rather, they serve as a screening method in determining where photovoltaics might be best applied. The question of competitiveness is addressed in Section 4.5 which deals with the worth of photovoltaic generation from a utility viewpoint.

Key inputs to the analysis were the regional levelized bus bar costs of photovoltaics listed on Table 4-13 and conventional electricity price projections. The output of the analysis was twofold: A "snapshot" of the potential regional competitiveness of photovoltaics in 1985 and a "dynamic view" (1985-2000) of the possible impact of system cost reductions on the regional competitiveness of photovoltaics.

4.3.2.1 Projected Electricity Prices

As shown in Figure 4-17, the historic real price of residential electricity has followed a long-term 0.71 cost reduction curve (i.e., a reduction on price of 29% for every cumulative doubling of production). Deviations from the curve can be related to major upheavals in the economy: the "dip" in the 1920's resulted mostly from the sharp inflationary surge after World War I; the upswing in the 1930's corresponds to the Great Depression. The recent perturbations resulted from OPEC's quadrupling of oil prices.

Figure 4-17. Historic Residential Price of Electricity

In the future, new factors such as increased fuel costs, environmental protection costs, and higher than average inflation in site labor costs are likely to increase the average price of electricity. Other factors, notably growth in coal and nuclear additions, which are cheaper than oil and gas plants, increased savings from economies of scale as more use is made of larger plants and complexes, and increases in efficiency in individual plants, will tend to decrease the average price/kWh generated.

The impact of these factors is reflected in the high, baseline, and low projections shown on Figure 4-17. Table 4-15 summarizes these projections in relation to the national average price.

TABLE 4-15. CONVENTIONAL ELECTRICITY PRICE PROJECTIONS

Projection	Average Residential Price of Electricity, ¢/kWh*		
	1975	1985	2000
High	3.21	4.33	4.80
Baseline	3.21	3.33	3.14
Low	3.21	3.20	2.75

*In 1975 dollars

Electricity prices for key cities are shown on Figure 4-18. These are assumed to be representative of the regions in which the cities are located. For the purpose of the analysis presented here, projections of these regional prices for 1985 and 2000 are proportioned according to the national average projections shown previously on Table 4-15.

Figure 4-18. Average Residential Price of Electricity in Sample Cities and Census Divisions, 1975

4.3.2.2 Comparison with Photovoltaics in 1985

Using the photovoltaic levelized bus bar costs for various cities listed in Table 4-13, the comparison with electricity prices for the low or baseline projections, are shown on Figure 4-19 for a solar array cost of \$100/m². Locations in New York City; Hilo, H. I.; and San Juan, P. R. show a positive difference between electricity prices and the photovoltaic levelized bus bar cost. The "high" projection of electricity prices would add regions in the Southwest as well as Boston and Philadelphia.

For a solar array cost of \$50/m², many additional regions emerge as shown on Figure 4-20. On both maps, of course, the results obtained for cities are applied to the regions in which they are located. (A noteworthy exception is New York City which has unique characteristics).

PHOTOVOLTAIC ELECTRICITY (¢/kwh)

Figure 4-19. Photovoltaic Target Areas for \$100/m² Solar Array Cost

In order to estimate the possible reductions in photovoltaic system costs which would be attributable to experience, it was assumed that the cost of the cells themselves would follow a 70% cost reduction curve, while the cost of the rest of the system, which is comprised of more traditional components, would follow a 90% curve. Both curves apply to cumulative doublings of production. Using these learning rates, the reduction in cost with increased production is shown on Figure 4-21. The cost is expressed as the levelized system cost per square meter of solar array. The starting value of \$11.45/m² corresponds to item 10 of Table 4-14 which shows how the levelized value is determined from a basic solar array capital cost of \$100/m². Of this amount, \$10/m² is used for encapsulation and support, using the shingle design described later in Section 5.3, and \$90 is used for solar cells (for 0.8 m² assuming an 80 percent packing factor). Using Item 6 of Table 4-14, the levelized cost of the solar cells is $90 \times 0.0882 = \$7.94/\text{m}^2$ of solar array which is the starting point shown on Figure 4-21.

Figure 4-21. Photovoltaic System Cost Reductions

Relating the PV cost reduction to its competitive enhancement, Figure 4-22 describes the likely sequence in which cities become markets for photovoltaics. In estimating this sequence of potential markets, the following assumptions were used:

1. A region becomes a "market" when the price of photovoltaic generation is the same or cheaper than conventionally generated electricity.

Figure 4-22. Cities in Which Residential Photovoltaic Systems Are Potentially Competitive, 1985-2000

2. 60% of annual new construction is the upper limit on the market for photovoltaic systems (20% of the new houses have a selling price below \$20,000; these owners are unlikely to be able to afford the capital investment required for a photovoltaic system. An additional 20% of new construction is excluded for factors such as sites with excessive shading and localized weather patterns unfavorable to a solar system).
3. Growth in each region is exponential until it reaches 60% of annual new construction, where it levels off.

All calculations are based on \$100/m² array costs.

The starting point was the regions shown in Figure 4-19, as being locations where photovoltaics would be competitive in 1985. Listing exponential growth for these regions, it was estimated that by 1990, one doubling of production would have occurred, reducing the price of photovoltaic systems enough to make them competitive in seven additional regions. Detailed description of the regional growth curves, and comparison of reduced photovoltaic and conventionally generated costs in ¢/kWh are given in Appendix E.

Both this dynamic view of the potential competitiveness of photovoltaic systems in 1985-2000 and the preceding competitive "snapshot" in 1985 are based on a key cost assumption: that the electric utilities would buy excess residential electricity from the house and sell the homeowner make-up power at the same price. Such a one-to-one trade is unlikely. The exact ratio depends on the value of the excess electricity to the utility, which is a function of the utilities load patterns and generation mix. The next section analyzes the potential value of photovoltaic energy to utilities in a few selected areas.

4.4 ECONOMIC WORTH TO UTILITY SYSTEMS

4.4.1 INTRODUCTION

As contrasted with the previous section which determined levelized busbar costs as a function of design and annual energy output, this section deals with the worth of photovoltaics (PV) generation within the framework of utility system economics. Given the diurnal and seasonal variations of photovoltaic systems, an analysis was performed for determining this worth in terms of the savings associated with displaced energy and capacity. The study was conducted by General Electric's Electric Utility System Engineering Department using the methodologies embodied in EUSED's Optimized Generation Planning computer program. A description of this program is contained in Appendix D along with the detailed study results.

The analysis determined the worth of PV generation by initially characterizing a given utility system without PV generation in terms of projected load growth, planned generation growth, and a set of projected economic assumptions. Present worth calculations determined the accumulated costs of new generation equipment and associated operation and maintenance over a specified number of years. PV generation was then introduced according to an assumed penetration profile. The seasonal and daily output characteristics of the PV generation resulted in a modification to the optimum mix of new generation capability that should be used. Using the modified configuration of equipment (excluding the PV generation), present worth costs were recalculated. The difference in present worth costs was then used to determine the worth of the PV generation to the utility system.

The analysis was conducted for utilities located in Washington, D.C.; Phoenix, Arizona; and Miami, Florida. Following is a summary of the major characteristics and assumptions used:

1. Each utility system was defined in terms of its present generation capability, scheduled additions, heat rates, fuel characteristics, and load growth.
2. PV generation was characterized using the daily and seasonal performance of the residential PV systems. As described previously each residence unit contains 84 square meters of solar cells with a nominal efficiency of 13.4 percent. The magnitude of the PV contribution to the utility was determined by the number of PV residences dispersed throughout the service region. The studies mainly emphasized systems without energy storage, although cases with energy storage were analyzed for the Washington and Phoenix locations.
3. Economic assumptions were used which defined the cost of new generation plant equipment, fuel costs, and escalation rates out to the year 2000. A variety of influencing factors were evaluated including the effects of higher plant and fuel costs and the impact of a nuclear moratorium.
4. Starting in 1985, a PV penetration rate was used which incrementally introduced residential systems out to the year 2000. This resulted in a peak PV output corresponding to about 10 percent of the utility's capacity.

The following sections discuss the basic methods of analysis and present the major results. A final section considers the impact of the breakeven worth calculations on the allocation of costs within the residential PV system.

4.4.2. UTILITY EVALUATION CONSIDERATIONS

The power demands of an electric utility vary considerably, both on a daily and seasonal basis. To meet these demands reliably and economically, utilities have a mix of generating units. The role each type of unit has in serving load demand is determined by its operating and capital cost characteristics along with its reliability of service.

The costs of generating electricity are composed of two principal items: (1) the fixed capital costs associated with the initial cost of the generating unit; and (2) operating costs associated with fuel consumption and operating and maintenance costs. Base load units, such as nuclear and coal-steam units, are characterized by high capital costs and low operating costs and serve most of the electric utility base load demands. Gas turbines, on the other hand, have low capital costs and are the most economic units for peaking load demands. Figure 4-23 illustrates a typical dispatch profile of generating types.

Because PV generation tends to coincide with the daily peak demand it can potentially displace expensive gas turbine fuels although other types of displacement might yield more optimum cost results. The strategies to be considered are developed in the following discussions.

Figure 4-23. Dispatch of Generating Unit Types

Generation additions are planned to meet annual load growth and provide sufficient reserves to maintain power system reliability. Forced outages, load uncertainty, and maintenance requirements are factors considered in such planning. With sufficient penetration, PV generation can reduce a fraction of the conventional generating units that must be added each year. Evaluation of this capacity displacement requires an analysis of utility system reliability.

The effective load carrying capability (ELCC) of a generating unit is a measure of the unit's reliability contribution to serving the peak load demands of the electric utility. More formally the ELCC of a generating unit is the amount of additional system load that the unit would enable the power system to supply for the same reliability of service. The ELCC of a generating unit is always less than its nameplate rating because of forced outages, maintenance requirements and the reliability characteristics of the power system in which it is installed. Typically, gas turbines have ELCC's of 90 percent of nameplate rating and nuclear units have ELCCs of 75 percent.

An evaluation of the effective capability of the PV unit must provide for the time-dependent characteristics of photovoltaic power. As illustrated in Figure 4-24, for a typical day the utility's risk of not serving load is also time-dependent, being exponentially proportional to the daily peak load. It can be seen from this figure that for reliability considerations, the PEPS output at 4 p.m. is more valuable to the utility system than the output at noon.

Figure 4-24. Daily Variation of the Risk of Losing Load

While Figure 4-24 illustrates a typical day with a peak load occurring at 4 p.m., the actual time occurrence of the peak load is not fixed and may vary from 12 noon to 8 p.m. Consequently, probability distributions of the time of utility peak load must be used in hourly reliability evaluations.

An hourly probability distribution of PEPS output can be developed from simulated PV output data. Typical results of selected hours for a rated PEPS capacity of 1000 MW are presented in Figure 4-25. Note that for some hours in the day, e.g., the late afternoon hours, the PV output never reached the rated capacity of 1000 MW. It is more useful, for reliability considerations, to give a PV unit a rating for each hour based on the maximum output that would be expected in that hour.

Figure 4-25. Daily Variation of 1000 MW of Residential PEPS Capacity

Once the hourly statistical characteristics of the PV unit have been determined, the PV capacity can be treated as a multi-state generating unit for which conventional methods of calculating the effective load carrying capability are available. The dashed lines in Figure 4-25 represent the hourly-effective capability of the PEPS capacity. Similar analysis can be made for each hour of PEPS generation. The hourly effective capabilities are then multiplied by the hourly risk factors in Figure 4-24 to obtain a risk-weighted effective capability distribution. The results for the month of August are plotted in Figure 4-26. The net daily

Figure 4-26. Hourly Risk-Weighted Effective Capability of 100 MW Residential PV Capacity

effective capability of the PEPS capacity is the sum of the hourly effective capabilities divided by the sum of the relative risk factors. For this example, the effective capability of the PV generation is 320 MW or 32% of the rated capacity.

An approximation of this procedure can be developed by observing that the hours between 3 p.m. and 6 p.m. principally contribute to the net result. The approximation procedure evaluated the effective PV capability as a function of the average PV availability between 3 p.m. and 6 p.m. The daily effective capability using this approximation for this example is 280 MW or 28% of the rated capacity. This approximating method tends to more conservatively reflect the PV effective capability (in this case, 4% less). For the purpose of evaluating the long term impact on electric utilities, the approximate calculation provides satisfactory results (the effect of this approximation on the breakeven cost is small as shown in Appendix D).

The average effective PV capability is 30% of the rated capacity ($\pm 10\%$ depending on location and size of penetration). For example, if 1000 MW of PV generation has an effective capability of 30% (300 MW effective capability), the PV generation could displace 333 MW of gas turbines ($300/0.9$) or 400 MW of nuclear capacity ($300/0.75$). Thus, if 1000 MW of PV generation were added to the electric utility system, 333 MW of future gas turbine additions or 400 MW of nuclear capacity additions would not be required.

4.4.3 EVALUATION OF PV BENEFITS

The discussion in the previous section serves to illustrate the two principal benefits that are associated with PV penetration: (1) fuel savings credit and (2) capacity displacement credit.

Fuel savings credit results from PV displacement of conventional fossil and nuclear fuels. Capacity credit results from PEPS displacement of conventional fossil and nuclear generation plant additions. The precise evaluation of these components requires a simulation model of the electric utility industry which properly accounts for the daily and seasonal variation of electric load demands, the mix of generation and fuel types used in the industry, and the decision analysis practiced by the utility industry in evaluating alternative generation addition types.

The Optimized Generation Planning (OGP) Program (a proprietary program of the General Electric Company - Electric Utility Systems Engineering Department) was utilized in conducting these studies. This program simulates the year by year operation of an electric utility and determines the minimum cost generation additions through time.

The electric utility systems representing the three climatic areas considered in this study are Virginia Electric and Power Co. (Washington, D.C. area), Arizona Public Service (Phoenix area), and in the Miami area a three company pool consisting of Florida Power and Light, Florida Power Corp., and Tampa Electric Co. The first task of this study was to simulate the generation expansion of these systems from 1985 through year 2000 using the OGP program to determine the minimum cost generation additions. A second OGP case is run inserting PV generation at a fixed capacity penetration. The benefits of PV penetration can then be evaluated as the difference in total system costs between the two cases.

4.4.4 ECONOMIC EVALUATION RESULTS

The results of this study are summarized in Table 4-16 by climatic area. The "base case" results in each climatic area correspond to a PV capacity penetration approaching 10% of the individual utility system's generating capacity by year 2000. All costs are in current 1975 dollars.

Table 4-16. PV Study Results

	Breakeven	Cost (1)	Year 2000 Rated Capacity (MW)	Capacity Credit %	Capacity Factor
	\$/Unit (2)	\$/kW			
Washington, D.C.	2800	249	3940	26	0.16
Miami, Florida	3100	276	6050	36	0.19
Phoenix, Arizona	4070	362	1275	43	0.21

1. All costs 1975 \$
2. Unit refers to residential PV system rating of 11.25 kW

PV penetration, from 1985 to year 2000, principally displaces base load nuclear capacity additions. Fuel savings are principally associated with nuclear fuel as a result of fewer plant additions. Base load nuclear plants are characterized by high capital costs and relatively low fuel costs. Consequently, the major component of PV breakeven cost relates to investment savings credit.

PV generation cannot be classified as peaking power. Peaking applications require a very high availability of the peaking capacity so that it can be brought up to rating at any time that the load demands it. Because of the relatively low availability of their capacity rating, other additional capacity must be provided in order to maintain adequate overall system reliability. This other capacity will likely be gas turbines because of their low capital cost. They may run only in peak periods when PV capacity is not available.

By considering several different penetration levels, the influence of penetration size on the PV breakeven cost is only slightly sensitive to penetration -- decreasing approximately 3% per 1000 MW for the small range of penetrations considered in this study. However, as PV penetration increases significantly above the 10% level within an electric utility system the breakeven cost can be expected to decrease more rapidly.

Perhaps the best correlator of PV breakeven cost is the PV capacity factor. The capacity factor of a generating unit is defined as:

$$\text{Capacity Factor} = \frac{\text{Annual Energy (KWH)}}{\text{Rated Capacity (KW)} * 8760 \text{ hr}}$$

Figure 4-27. PV Breakeven Cost as a Function of Penetration

Figure 4-28 is a plot of the breakeven costs of PV units in the three climatic areas as a function of capacity factor. Included for reference purposes are some of the basic plant and fuel cost assumptions used in developing the relationship. If the breakeven costs are normalized to a common penetration level (per Figure 4-27) a nearly linear relationship between breakeven cost and PV capacity factor is evident. Since this linear relationship was developed using three widely differing climatic regions and utility systems, it is probably valid for estimating the breakeven costs in other climatic regions. For example, the annual energy produced by the residential PV system in Cleveland is 63 percent of that produced in Phoenix (see data on Table 3-7 for NOBATRY system). Therefore, assuming the proportionality of Figure 4-28, the breakeven cost in Cleveland would be 63 percent of \$4100 or approximately \$2600. The same reasoning can be applied to the considerations of different solar cell and power conditioning efficiencies. The nominal residential PV system used in this worth analysis was based on 13.4 percent solar cells and an 87 percent DC/AC inverter efficiency. Since different efficiencies would directly affect the annual energy output (proportional to capacity factor) the breakeven costs would also vary in direct proportion.

Similarly, PV capacity displacement credit (conventional capacity displaced rated PV capacity) tends to be linearly related to capacity factor as illustrated in Figure 4-29.

These studies indicate that the PV breakeven cost is optimal when nuclear capacity is displaced. By varying the amount of nuclear capacity displaced by PV generation the curve in Figure 4-30 can be constructed. The system fuel savings credited to PV generation for the various nuclear displacement strategies have also been plotted. As nuclear capacity displacement increases, fossil fuel savings diminish rapidly.

Figure 4-28. PV Breakeven Cost as a Function of Capacity Factor

Figure 4-29. PV Capacity Credit as a Function of Capacity Factor

Figure 4-30. PV Breakeven Cost and Energy Displacement as a Function of Nuclear Capacity Displacement

Note that a relatively broad maximum exists between PV breakeven cost and nuclear capacity displacement. In the vicinity of the maximum point, fossil fuel savings can increase significantly for only a slight penalty in PV breakeven cost. For example, the optimum condition for the system represented in Figure 4-30 results in a 30% nuclear capacity displacement. Nuclear fuel and some oil are saved; however, coal consumption increases slightly. By adopting a strategy that limits nuclear capacity displacement to 10%, fossil fuel savings will increase by an order of magnitude. This is accomplished with a penalty in PEPS breakeven cost of only 10 percent.

The economic assumptions characterizing the electric utility systems in this study represent current industry projections. However, future uncertainties of fuel and plant costs can have a significant impact on the worth of PV generation to electric utilities. Figure 4-31 illustrates the effect of a 25% real increase in all plant costs. PEPS breakeven costs in this economic scenario increase 30% above the base case results.

The benefits of adding system storage capacity with PV generation were studied. The advantages of adding storage capacity are principally twofold: (1) PV capacity can be made available at periods more valuable to the utility and (2) storage improves the reliability of the power system. The cost and inefficiency of storage weigh against the benefits.

Parametric storage cases were evaluated in the Washington, D.C. climatic area. A typical storage schedule is presented in Figure 4-32. In some scheme, PV energy is stored during the morning hours and discharged (at 70% efficiency) during the utility peak period between 3 p.m. and 6 p.m.

Since the natural daily PV output profile coincides with the utility load, there is little incentive to add much more than 15 kWh storage for utility peak sharing strategies.

The results of the storage evaluations are presented in Figure 4-33. At zero storage cost, 15 kWh of storage is optimal. However, as the cost of storage increases less storage capacity is economically justified. If the storage cost exceeds approximately 50 \$/kWh (1975), PV generation without storage is economically preferred.

An alternative storage strategy was evaluated in the Phoenix climatic area. In this case, 48 kWh of dedicated storage capacity was added to a residence and dispatched throughout the entire day with the objective of maximizing the independence of the PV residence from the electric utility. Neglecting the storage cost, this strategy decreased the breakeven cost by 25% from the base case result. The energy lost to the storage inefficiency is the major penalty of this scheme. The substantial cost of 48 kWh storage capacity also adds a large penalty to this approach.

Thus, from the electric utility standpoint, storage schedules designed for increasing the availability of PV during the peak demand are of more value than a 24 hour schedule dedicated to serving the residence load.

Figure 4-31. PV Breakeven Cost as Influenced by Plant and Fuel Escalation

Figure 4-32. PV Output Profile With Storage Capacity - June, Washington, D.C. Area

Figure 4-33. PV Breakeven Cost as a Function of Storage Capacity in the Washington, D.C. Climatic Area

4.4.5 PV SYSTEM COST ALLOCATIONS

Figure 4-34 provides a graphic means for determining competitive solar array cost on the basis of the above worth results. The major cost elements of the system are treated parametrically in order to show the effect of cost variables. The lower left-hand plot shows the relationship of system cost and solar array cost, both expressed in \$/kW. (For the residence, the system rating is the same as the peak PV output under standard illumination conditions at 1 kW/m^2 insolation, air-mass one, and 28°C cell temperature.) The electrical equipment cost parameters refer to the combined costs of power conditioning, cabling from the solar array and any additional switching and control components. The upper left-hand plot relates the solar cost in \$/kW to solar array cost in $\$/\text{m}^2$ with parameters of solar cell efficiency. This plot is based on using a solar cell packing factor of 80 percent. The upper right-hand plot relates solar array cost ($\$/\text{m}^2$) to solar cell cost ($\$/\text{m}^2$) with parameters of substrate and installation cost. This parameter combines the costs of cell interconnection, encapsulation and mounting to substrates, and the necessary installation to form a total solar array. This plot is also based on an 80% packing factor.

Figure 4-34. Allocation of Capital Costs

To determine the impact of the breakeven worth calculations, the plot is entered along the lower vertical axis. This is shown for a breakeven worth of $\$500/\text{kW}$ which approximates

the result obtained from Phoenix considering plant and fuel escalation (see Figure 4-31). An electrical equipment cost of \$200/kW is selected as determined for the residence no-storage system. (Table 4-4 indicates \$2,275 for electrical equipment; at a solar array rating of 11.25 kW, this corresponds to \$202/kW). Proceeding upward from this point, two solar cell efficiency cases are considered. For 15 percent cells and a \$12/m² substrate and installation cost, the required solar cell cost is about \$30/m²; for 20 percent cells, the solar cell cost is \$45/m². The \$12/m² substrate and installation cost is based on a manufacturing estimate of \$10/m² for fabrication of the shingled design described later in Section 5.3, and a net installation cost of about \$2/m², including credit for the replacement of conventional roof shingles (see Table 4-4).

An examination of Figure 4-34 reveals several important facts. First, the electrical equipment constitutes a large percentage of the system cost with the remainder to be shared by the solar cells and substrate and installation costs. Second, the sensitivity to power conditioning efficiency appears to be significant. The breakeven worth calculations were based on an inverter efficiency of 87 percent. If this were increased to 95 percent (estimated for the intermediate size systems in Part C) the breakeven worth values would increase proportionately. Consider the case for Phoenix: the baseline breakeven value would increase from \$500 to \$546/kW. Tracing through the plot for the 20 percent cell case, the solar cell cost would increase from \$45 to \$55 per m² (22% improvement).

4.4.6 CONCLUSIONS OF PV WORTH ANALYSIS

The principal results and conclusions of the economic evaluation of PV generation are listed below:

1. The PV breakeven cost is optimal when PV penetration displaces nuclear capacity additions in an electric utility system. The principal fuel saved with PV penetration is nuclear fuel as a result of fewer plant additions.
2. The PV breakeven cost is directly proportional to the annual PV capacity factor. Since the capacity factor is proportional to solar cell and power conditioning efficiencies, breakeven costs are also directly proportional to these efficiencies.
3. The capacity displacement credit is linearly related to the annual PV capacity factor.
4. Fossil fuel savings can increase significantly for only a slight penalty in breakeven cost if strategies limiting the base load type capacity displacement with PV generation are adopted.
5. Future uncertainties in plant and fuel cost escalation can increase the value of PV generation to electric utilities. A 25% real plant cost increase and of 50% real fuel cost increase can increase the PV breakeven cost by 30%.
6. The optimal storage capacity is in the vicinity of 15 kWh for each residential PV unit. However, this storage capacity is economically attractive only if the cost of storage is below 25 \$/kWh. Less storage capacity is economically justified as the cost of storage increases. Storage capacity is not economically justified with residential PV systems if the storage cost exceeds 50 \$/kWh.

7. Storage is not a prerequisite for the utilization of PV energy provided sufficient backup capacity is available to maintain overall system reliability. Gas turbines are a likely choice because of their low capital costs. They would be required to run only during the utility peak demand periods when PV capacity is not available.

4.5 REFERENCES

1. "The Cost of Energy From Utility-Owned Solar Electric Systems," Doane, J.W., et al, June 1976, Report JPL 5040-29, Jet Propulsion Laboratory.

SECTION 5
SUBSYSTEM ANALYSIS

SECTION 5

SUBSYSTEM ANALYSIS

5.1 INTRODUCTION

This section reports on various subsystem and interface analyses that were undertaken in support of developing the conceptual designs, establishing the performance of subsystems, and establishing realistic costs for use in cost sensitivity studies.

5.2 INTERFACE WITH ELECTRIC UTILITY

5.2.1 INTRODUCTION AND SUMMARY

Except for rare instances where total independence is either necessary or desired, it seems reasonable to assume that residential photovoltaic systems will mainly develop with dependence on utilities as the backup source of power. As demonstrated in the performance analysis (Section 3), systems both with and without energy storage will depend to varying degrees on utility backup power. The system without storage and the feedback of excess energy to the utility offers a possible means for improving the economic position of residential photovoltaic generation.

Investigation of this possibility, along with the consideration of other technical, institutional, and economic issues, was undertaken through discussions with five widely dispersed utility companies:

Arizona Public Service

Florida Power & Light

Pacific Gas & Electric

Pennsylvania Power and Light

Philadelphia Electric

Each of the companies was provided with a description of the residential PV concepts, and a set of technical, economic and ownership questions relating to the interface with the utility. Discussions were then held in a series of followup meetings. Each utility was represented by personnel from diverse operating divisions. Specific questions and discussion summaries are provided in Appendix F.

A summary of the issues considered is presented on Table 5-1.

TABLE 5-1. UTILITY INTERFACE ISSUES

Technical	Institutional	Economic
<ul style="list-style-type: none"> • Penetration level • Distribution Impacts • Feedback Quality • Safety, Fault Isolation • Remote Control • Metering 	<ul style="list-style-type: none"> • Ownership • Maintenance • Incentives • Combined PV/Thermal • Site Preferences • Sun Rights 	<ul style="list-style-type: none"> • Incentives • Feedback Credit

Overall conclusions are as follows:

1. Technical Issues

There are no technical barriers for implementing photovoltaic feedback energy from multiple small systems into the utility networks. There may be specific implementation schemes to be worked out on the basis of existing and developing control equipment. Some of the equipment is currently being considered for incorporation into utility networks for other reasons. Some minor changes in operating procedures and rules may be required, but are not of a serious or limiting nature.

2. Institutional Issues

Questions relating to ownership of the residential photovoltaic systems also are not viewed as significant barriers by the utilities. There are specific problems that can be worked out by appropriate contractual arrangements. The utilities contacted were willing and anxious to lead the way in working out these techniques rather than being confronted with solutions imposed by others (regulatory commissions, etc.). Ownership of the residential rooftop by either consumer or utility can be accommodated by the utility. If owned by the utility, it would assume responsibility for all of the associated problems of maintenance, liability, etc.

3. Economic Issues

The major issue as seen by the utilities is one of economic viability including life and maintenance characteristics, and its translation into equitable rates for consumed and supplied energy. The value of small dispersed systems vis a vis centrally located systems must be demonstrated. The worth of PV systems versus solar thermal and other options must be demonstrated. Utilities are working and will continue to work on analytic and demonstration programs to select the practical mix of energy sources to meet the needs of their business.

5.2.2 DETAILED DISCUSSION

The information gathered during the discussions provided a guide to the type of issues requiring further investigation and resolution with the development of practical economic PV systems. Discussion consensus on the technical issues of feedback magnitude, characteristics, control and safety indicated that no significant technical problem would hinder implementation. Economic and ownership issues also appear to be soluble, but the opinions and diversity of solutions suggested a broad spectrum of possibilities. The economic issues indicated the need for a great deal of realistic economic evaluation on the worth of PV systems, including capacity displacement in terms of operating utility characteristics.

5.2.2.1 Technical Issues

The technical issues assessed have been broadly grouped into the following: PV power level; feedback power characteristics; safety; and control.

1. Relative PV Power Level. The magnitude of PV generation from residential rooftops appears to be a question of very minor concern for new all-electric service areas. Typically such a new residential area would have 4-25 kVA residential service lines fed from a 50 kVA transformer. This size of local distribution system would easily accommodate the feedback of 13 kVA rooftop systems with normal load diversity. The concentration of solar PV homes in an area may require increased capacity tap lines. From that point back into the distribution system normal system load diversity will be able to absorb any residential PV feedback power. In older service areas, and areas using other non-electric energy sources for home heating the feedback capacity of the local residential distribution system would be smaller. PV installations in these latter areas would also be limited to a much lower density by the suitability of individual residences for a retrofit solar installation. Thus, in general it would appear that no significant impact on the capacity and sizing of distribution networks will be caused by PV installations.

2. Feedback Power Characteristics. The characteristics of PV feedback power will have to be controlled to keep harmonic and reactive power components within acceptable limits. This need is common to both the feedback power and the power used by the residential load. Specific control and commutation techniques applied to the inverter design will be required to minimize these components. The level of acceptable harmonic content will be in the order of a few percent. Reactive kVA control of the PV system output is projected to be simple and inexpensive for residential type loads.

3. Safety. The safety issue of PV feedback has been evaluated from the point of view of a utility line fault. The design concept of the residential system incorporates a utility presence signal. With failure of that signal, the PV system would shut down and the parallel utility line connection through a contactor would be opened. This arrangement meets the requirement of not having a hot line on the PV side of a fault. The detail design of a device for controlling the parallel utility contactor would have no discriminate between a utility presence and the feedback from other PV systems, and be receptive to control signals from the utility for load management purposes.

4. Control. Control of PV feedback power by the utility will be required for several reasons. These would include: (1) the level of PV power when PV penetration becomes significant (5-10% level); (2) PV shutdown for fault repair, load management, and system integrity. Many techniques for remote load management and metering are currently being developed and tested for other reasons. Most utility personnel believed that some of these techniques will be implemented, and that PV control could be added at a nominal cost estimated at less than \$ 100 per residence.

In addition to the direct remote control of the PV systems, existing techniques for voltage regulation and directional relay control would require modification in areas of high PV penetration. The PV feedback energy would raise the voltage levels during periods of high insolation and possibly reverse the flow of energy in portions of the distribution system.

Metering of two way energy flow poses no technical problems although meters would have to be modified to accommodate separate measurement of the incoming and outgoing energy relative to differing charge and credit rates that would be applied. One of the utilities contacted is working out the arrangement of energy credit for a residential customer now who has installed his own windmill generator.

5.2.2.2 Institutional Issues

A number of institutional factors were considered which included: legal arrangements; maintenance responsibility; installation incentives; the impacts of combined PV/thermal systems; site preferences; and other miscellaneous issues.

1. Legal Arrangements. Considering utility ownership of the residential rooftop PV system, the general consensus indicated that contractual arrangements between the utility and consumer would provide the basis for implementation. Such contracts would be complicated and would have to provide long term guarantees to assure capital recovery over the life of the system. Terms of the contract would have to provide for ownership property transfer, house remodeling affecting the roof system, liabilities, and utility rights of access for maintenance and repair. Deed restrictions might be necessary. Mortgage and insurance company relationships would have to be defined. Tax assessment of the roof system at higher utility tax rates would have to be accommodated. None of these factors was considered to be of an insurmountable nature.

2. Maintenance Responsibility. With utility ownership of the rooftop PV system, the utility would assume responsibility for maintenance including periodic cleaning if required. This responsibility requires additional information to permit assessment. Demonstrated system reliability and life data is needed. Surface contamination with time and associated performance degradation must be determined. Susceptability to vandalism, storm, and wind damage must be at least statistically predictable. These various problems relating to maintenance have a potential for creating non-economic costs for PV roof systems. Full consideration of the maintenance potential would have to include examination of the tradeoffs between a fixed shingle system, and the use of more expensive plug-in modules with shop repair of malfunctioning units.

A unique problem for utilities arises with maintenance needs on customer property. There is a need to assign responsibility for damage that may have been created by customer (e.g., when cleaning debris from gutters, etc.), and to have easy access to the property for inspection, maintenance, and repair activities. This customer relationship can become quite strained on occasion, and has the potential for creating problems that utilities would rather avoid. Experience on easements and distribution maintenance activities indicate occasional difficulties for the utilities.

3. Incentives. Incentives for utility ownership of the rooftop system were identified. First and foremost, the incentive for installing PV systems will occur when they become economically competitive. Aside from this basic consideration, other incentives for installing rooftop systems include: (1) the relative cheapness for the use of the roof area, particularly in regions of high land cost; (2) the ability to increase generation capacity in small increments rather than in the large steps associated with major plant installations.

Customer incentive for the utility-owned rooftop PV system includes the provision of a free roof on his residence which is maintained and serviced by the utility company.

4. Impacts of Combined PV/Thermal Solar Systems. Some versions of a rooftop PV system envision a combined PV electric and thermal energy collection unit. Consideration of utility ownership of this system type produced negative opinions mainly along the lines that this is beyond the scope of utility business. But if such a combined system were to prove practical and desirable, utilities would and could accommodate it. Charges for thermal credits would not be practical on an energy measurement basis. Charges for the additional capital cost and maintenance requirements of the thermal portion of the system would be approached on the basis of a fixed monthly charge. With this type of system an additional incentive develops for the customer in that the additional and improved insulation provided as part of a thermal collector would tend to reduce the customer's requirement for energy.

5. Site Preferences. Arrangement of a utility owned PV system on a commercial structure such as a shopping mall rather than a residence was generally preferred by the utilities. This type of contract would be easier to work out with a customer able to recognize mutual benefits. A rental fee for the roof on a long term basis provides incentive for the property owner, and provides space and access for the utility.

Several utility representatives identified a societal issue which might prove troublesome. Since some roofs are more favorably located for insolation and sized for useful systems, there must be a selection process to decide which ones would be suitable for installations. This process in some sense implies discrimination in selecting customers for special benefits; free roof, feedback credits, rate differentials. This might prove awkward or unacceptable to the public and regulatory commissions.

7. Miscellaneous Issues. No problem is foreseen relative to customer-owned systems. It may be necessary to impose utility system integrity, control, and safety requirements as a condition of service to a customer. The growth of these types of systems are viewed as very long range, and the required controls can be implemented as needed with the growth pattern.

Several issues were raised by the utility representatives that would strongly influence their views of rooftop PV systems. These issues are common to many types of solar systems and are being actively investigated in many other solar areas. These would include the maintenance of "Sun Rights", insurance rates, underwriter approvals, building code requirements and architectural/aesthetic acceptability.

5.2.2.3 Economic Issues

Economic issues were regarded from the standpoint of utility or consumer ownership.

A precondition for utility ownership of rooftop PV systems would be the demonstration that capacity and energy credits are sufficient to meet the financial burdens imposed by the initial capital expenditure and operating expenses. In view of the present non-economic status of PV generation, efforts toward achieving economic parity must come in the form of governmental support and subsidy. Opinions were offered that demonstration units, as well as substantial analytical efforts in the context of utility economics, are necessary to identify the costs of fabricating, installing and operating PV systems.

Relative to consumer ownership, the same economic conditions will largely apply, but in relation to the utility it was universally judged that the compensation for feedback energy would be at reduced rates.

All utilities were firm in their belief that the feedback energy could receive credit for fuel displacement at some average fuel rate only. Since the available insolation is limited to several hours a day, which may not coincide with peak demand periods, no capacity credit could be provided. The utility would still have to have their full load capacity, distribution network, and service available to the customer. In general, this full service availability would probably result in increased costs for incoming energy since the investment and operation costs of the system would be spread across a smaller base of centrally supplied energy. Rate structures are complicated and constantly changing. The basis for the structures is being widely studied and significant changes are expected in the future. Reversal of high quantity rate step reductions, demand rates, service availability rates, off peak power rates and other rate factors may be expected in the future. The rate credit for PV feedback energy will be provided on an equitable basis within the framework of the rate structure and regulatory requirements existing at the time of PV installations.

Rate structures would be contingent upon ownership of the PV system. With utility ownership, no customer credit is required for feedback energy. With customer ownership, some equitable though reduced rate for feedback can be established. Another alternative might be a fixed lease type of payment for the feedback rather than credit for energy units.

Several other ownership options and therefore rate options are possible. These could include such possibilities as third party ownership with customer or utility lease arrangements. Customer ownership of a utility financed system is another possibility. The potential variations suggest the need for in-depth assessment in later studies.

5.3 SOLAR ARRAY STUDIES

Three concepts for the residence rooftop solar array which were analyzed are described briefly below:

1. Planar solar array, front surface free convection cooling - This approach is typified by the mounting of the solar cells onto the roof surface by shingling or other intermediate substrates. Front surface protection is provided by directly bonded transparent encapsulants.
2. Planar solar array, rear surface forced convection cooling - The solar cells are bonded to a hollow core substrate with cooling provided by underside free or forced convection in addition to the front surface free convection cooling.
3. Planar solar array, liquid circulation cooling - The liquid circulation is intended to collect solar thermal energy for use in residence heating systems. A front surface window promotes higher thermal collection efficiency, although some sacrifice in photovoltaic efficiency results with higher temperature operation. During summer operation, the circulating liquid can be diverted to release its thermal energy to an air cooled heat exchanger to provide reduced temperature operation.

The configurations described above have been modeled mathematically with respect to their thermal and electrical characteristics for use in computer simulations (See Section 3).

Work was also performed in developing practical designs for the above concepts. A design for the first approach is shown on Figure 5-1. The solar cell modules are in the form of shingles which can be attached like regular roof shingles. The shingle contains nineteen circular solar cells which are interconnected into a single series string and sandwiched between encapsulating transparent layers of plastic material.

The negative and positive leads of the 19-cell string terminate in redundant connections with clearance hole negative terminals on the shingle underside and threaded hole positive terminals on the topside. This is shown on the righthand sketch of Figure 5-1. The terminations are located so that the clearance holes of overlaid shingles are properly registered with the threaded holes of the under shingle. This alignment of adjacent shingles is shown on the left-hand sketch of Figure 5-1.

By progressively laying down shingle rows from the lower roof edge to the crest, and interconnecting them as described above, a series-parallel interconnection matrix is developed as shown on Figure 5-2. The roof slant length of 24 feet and horizontal length of 48 feet accommodates the 32 x 54 shingle matrix shown. Because of the redundant four terminal connections of each shingle, any single terminal failure does not result in power loss. Further, any open-circuit failure within a shingle is limited to that shingle only, because of the bypass nature of the matrix.

Figure 5-1. Solar Shingle Design

COLUMN NO.

NOTE: EACH HEX REPRESENTS SINGLE STRING OF 19 SOLAR CELLS (2 1/2 DIA.) IN SERIES.

Figure 5-2. Solar Cell Shingle (Roof) Wiring Schematic

The negative terminal of the overall array is located halfway up the roof and extends the entire roof length. Twenty-seven rows extend both above and below the negative terminal for a total of 513 series cells on either side. Both halves are joined in parallel to produce output at a nominal voltage of 240 Vdc.

The arrangement described above applies to the no-battery system which utilizes the two-wire output of the total solar array. For the system which utilizes batteries the arrangement is somewhat modified although no external differences would be evident. Figure 5-3 shows the configuration along with several features that are common to both the battery and no-battery systems. First, power from the main negative and positive terminals is transferred by flat-ribbon conductors to the crest of the roof. A detailed sketch shows a typical shingle to ribbon connection for this purpose. All such flat-ribbon conductors are brought to junction boxes located under accessible sheet metal covers along the roof crest. The sheet metal covers also house diode and shunt regulator electronics that are used for the system with batteries. These sheet metal enclosures are located to be remote and relatively inaccessible for safety reasons, although they can be serviced by qualified personnel entering upon the opposite roof surface not containing solar cells.

Mechanization of the shunt regulator for the system with batteries requires that the solar array be divided into a number of separate sections. The serrated lines on Figure 5-3 are intended to illustrate this division. No paralleling of shingles is made along the serration lines resulting in the required division. A number of partial length dotted lines are shown which indicate various tap points for implementing the partial shunt system.

The shingle approach described above can be implemented with conventional roof construction using rafters and plywood sheathing. A waterproof underlayment, such as tarpaper, would be applied to the sheathing. With the wiring arrangement as described, no penetrations to the waterproof membrane or sheathing are required since all interconnections and routing is accomplished externally.

The concern for fire hazards is often mentioned in connection with future terrestrial photovoltaic installations. As long as the back flow of current from such low impedance sources as batteries is prevented by proper isolation devices, any potential problem is relieved. Any shorted condition on the solar array will result in currents only slightly higher than the current normally delivered. Since electrical fires normally result from the large current available from utility or battery sources, the natural current limiting of solar arrays will reduce the fire hazard potential. The interconnections of the shingle design as presently conceived are essentially bare although they are protected against direct exposure by the overlapping leaf of the next shingle. They can be easily moisture proofed if this is found to be necessary.

Figure 5-3. Typical Solar Cell Shingled Roof

The concept for the second approach is shown on Figure 5-4. The solar cell modules are bonded to a sandwich substrate with longitudinal air passages built in. Figure 5-5 shows attachment details to the roofs. With forced draft air circulating through the passages it has been estimated that a 10 to 15 percent improvement in photovoltaic power output is possible, although the fan power required can be substantial, possibly on the order of 5 percent. A treatment of this tradeoff was covered earlier in Section 3. The net gain must be gauged in terms of the increased substrate and fan costs. The attractiveness of this approach increases, of course, if one considers the utilization of the air for heating purposes.

The concept for the third approach is shown on Figure 5-6. The panels provide the three basic functions of generating electricity, collecting thermal energy and providing weather protection. Although this combining of functions results in architectural and installation complications, its merit lies in the fact that about half the roof area is required compared with the case if thermal collection and photovoltaic generation were accomplished separately.

5.4 ENERGY STORAGE

Based on studies conducted during the proposal effort the decision was made that lead acid batteries be used as the energy storage device. A subcontract was negotiated with C&D Batteries division of Eltra Corporation for studying and recommending a lead-acid battery design for the residence application.

The batteries selected to perform the energy storage function in the residential power system are assembled using C&D C75-9 cells. The cells differ from cells in general use due to their "hybrid" construction. The positive plates contain the normal 6% antimony grid, but the negative plates contain a 0.07% calcium grid. The lead antimony positives provide the deep cycle characteristics required for this application, and the lead calcium negatives assure a longer useful life with reduced maintenance and simplified charge control.

The cells are insulated with C&D five fold insulation, microporous ribbed separators, perforated koroseal retainers, two glass expansion mats, and glass slyver. The cell container is high density, crosslinked, polyethylene, which is non-burning and virtually unbreakable. The cell cover is high impact molded rubber with lead bushing inserts to eliminate post corrosion and leakage. The vent caps are explosion proof ceramic flash arrestors.

To further insure a life expectancy of ten years in this battery application, the cell has been derated from its normal rating of 332 ampere hours at the 10 hour discharge rate to 225 ampere hours.

Figure 5-4. Forced Air Cooled Solar Cell Panel

Figure 5-5. Installation of Forced Air Cooled Panels

Figure 5-6. Hybrid Photovoltaic - Thermal Collector Panel

The point design residential battery will be made up of four modules, each containing 24 of the cells described above. The modules will have the dimensions and weight noted on Figure 5-7. A plastic battery tray will be used in preference to a steel tray for weight and safety considerations. Care must be exercised to minimize the danger from the 240 volt battery. The 24 cell module has been tentatively selected, but cooling and handling considerations may later dictate that a smaller module (such as 12 cells) be used. The estimated factory cost of each battery module is \$2100 at a production rate of 100 modules per year, and \$925 at a production rate of 10,000 modules per year.

The 96 cells in series will be charged at a maximum current of 50 Amperes until the battery voltage reaches 240 Volts, (2.50 Volts/cell). At this voltage the battery charge current will taper to approximately 4.5 amperes. A two hour timer will reduce the voltage limit from 240 Volts to 230 Volts, (2.40 Volts/cell), and the current will taper to less than 2 Amperes. The continuous overcharge at 230 Volts will be safe and will result in a minimal heat dissipation and minimal water additions.

The use of a relatively large battery at 240 Volts located in a residence requires special safety precautions. In addition to the danger from electric shock, there are also the dangers from sulfuric acid electrolyte, and hydrogen gas released from the cells. The following safety precautions must be strictly observed.

1. The battery room must be accessible to authorized personnel only
2. The room must be ventilated to remove hydrogen gas
3. No smoking is permitted in the battery room
4. Rubber shoes and gloves must be worn when servicing the battery
5. The battery must not be grounded
6. No tools or equipment must be placed on batteries
7. No open flames or spark producing equipment can be permitted in battery room
8. Keep flash arrestors in cells at all times
9. Always have fresh water available in case of electrolyte splash or spillage

5.5 POWER CONDITIONING

For the residential photovoltaic system, power conditioning pertains to the inversion of dc to ac in synchronism with the utility backup source, and the control of battery charging by means of the solar array shunt regulator.

This section discusses the requirements placed on the power conditioning equipment and the concepts developed for implementing these requirements relative to systems with and without batteries.

- LIGHT-WEIGHT, HIGH-STRENGTH ALUMINUM OR EQUIVALENT TRAY FOR MAXIMUM POWER-PER-POUND
- COMPLETELY SEALED TOP TO PREVENT ACCUMULATION OF FOREIGN MATERIAL AND ELECTROLYTE SPILLAGE BETWEEN CELLS
- ELECTROSTATICALLY APPLIED EPOXY COATING PROTECTS AGAINST CHIPPING, CRACKING AND ABRASION.

Figure 5-7. C&D Hybrid Lead-Acid Battery Module

5.5.1 PERFORMANCE CONSIDERATIONS

In the following discussion, emphasis is placed on the considerations for the dc/ac inverter which constitutes the major element of the power conditioning equipment.

In developing the requirements and concept for the inverter, use was made of the extensive technology developed for solid state power conditioning equipment.

Established techniques enable the design of inverters for meeting the frequency, voltage, current, and harmonic requirements for the residence. Synchronization of the output voltage and frequency with the utility line can be accomplished with very simple techniques at this time. Techniques for controlling the output current peaks are also well known. It is also possible to control the system parameters to avoid third harmonic voltages, a significant point with respect to induction motor operation.

The computer and medical power supply fields have developed techniques allowing a load to be supplied from either the utility line or a battery without interruption. The control laws and implementation for safe operation of these systems have also been extensively developed.

Figure 5-8 provides a normalized efficiency curve for a typical inverter. The inverter has two loss components - steady state commutating losses and the load related I^2R losses. At high output levels, the fixed losses are small compared to the load proportional losses resulting in a flat efficiency curve from 40 to 100% of rated load. Below 40% of rated load the constant commutating and control losses decrease the output efficiency.

The effect of inverter efficiency in relation to residential load profiles was considered for six houses located in a suburban area of Schenectady, N.Y. The houses were instrumented with recording current meters and data accumulated over a number of days.

Figure 5-8. Typical Normalized Inverter Characteristics

Only summer profiles were considered. The houses all had electric ranges and gas fired hot water heaters. None of the units had electric heat, heat pumps or central air conditioners; however, most had at least one window air conditioner. A typical load distribution profile is presented in Figure 5-9. This house used 30.4 kWh in a 24-hour period. This resulted in an average load of 1.27 kW, which is typical for this area. It can be seen that 70 percent of the daily power was used at or below the 2.5 kW level; maximum power drawn was 7 kW. This graph is typical of the average of the houses sampled.

Figure 5-9. Distribution of Load Power Level for Typical Residence

Figure 5-10. Residential Inverter Efficiency

and 4 kW combination would operate between 94% and 88% efficiency and would then need less purchased power than either of the two smaller inverters, yet retain the efficiency of the small inverter at light loads. This combination of 2 kW and 4 kW inverters appeared favorable for all of the homes studied although the daily energy consumed varied over a wide range.

For reduced complexity a single inverter approach would be preferred although the above discussion indicates there would be a sacrifice in overall performance. A design approach for improving the efficiency of the single inverter concept over a wider range of output is described in Section 5.5.2.

If the curve of Figures 5-8 is multiplied by that of Figure 5-9, an overall system efficiency can be determined. Furthermore, by allowing the full load rating of the inverter to vary, it is possible to investigate the system efficiency as a function of rating as shown on Figure 5-10. It can be seen that the effective system efficiency could be as low as 50% if a 10 kW inverter were used.

It can be inferred from Figure 5-10 that a small rating on the inverter is needed for high efficiency. However, as the inverter rating is lowered, the amount of power purchased from the utility will increase as shown in Figure 5-11. This is a plot of the excess residential load as a function of inverter rating. It is interesting to note that an inverter rated at 6 KVA would only require the user to purchase 5 percent of his power from the utility for the case considered.

Included also in the Figure 5-10 plot are the results if two inverters of different ratings are operated in parallel. The controller would operate the 2 kW rated inverter until it was overloaded up to its limit. The 4 kW would then be operated at the 2 kW level and the 2 kW unit stopped. The larger unit would then operate up to its limit at which time the 2 kW inverter operation would be restored to aid in supplying the load. The utility would supply any excess above 6 kW. The 2 kW

Figure 5-11. Excess Residential Load

producing positive torque. For motors designed with very severe cost-performance criteria in mind, the overheating may result in motor failure. Typical motors in this category are refrigerator and room air conditioning compressor motors. In general, such motors can tolerate distortions of about ten percent, but beyond that are prone to failure.

One of the effects of harmonic content is to reduce the fundamental voltage component. Since breakover torque is proportional to the fundamental voltage some motors might not be able to reach operating speeds due to the load characteristics. Typical of this condition are the initial pump down of refrigerators on hot day operation of room air conditioners.

Besides the amount of distortion, the specific harmonic content affects performance so that the higher the harmonic, the less will be the effect on motor losses. Therefore, a voltage with five percent of the third harmonic may be as bad as a voltage with 10% of the fifth or seventh harmonic. Where possible, the third harmonic should be avoided.

5.5.2 INVERTER DESIGN

It has been shown that an inverter design having a high efficiency that remains high at light loads is very important in the proposed residential photovoltaic power system. As noted, one approach is to employ a dual inverter system consisting of two separate

Another important aspect of inverters concerns their output harmonic content. Domestic appliances and loads have been optimized for operation on ac voltages. Resistive loads and universal motor loads can operate on ac which is badly distorted since they only rely on the periodic current reversals for suitable operation. However, induction motor and induction coupled loads require more controlled conditions. It is well known that induction motors cannot utilize energy not derived from the fundamental component of voltage. A line voltage with ten percent harmonic content reduces the efficiency of the motor by an equivalent amount with the energy devoted to generating heat rather than

inverters of different sizes that are switched as needed to most closely match the load. However, it is believed that better performance can be achieved by using a single inverter of a type especially adapted to maintain high efficiency at light loads.

Other features that are practically necessary in an inverter for this application are:

1. Supply 240/120 Volts output with unbalanced loading
2. Transformer isolation between the ac and dc systems
3. Operation in parallel with the ac utility
4. Voltage control, both magnitude and phase
5. Current limiting for protection
6. Near-elimination of third harmonic components

The circuit diagram of an inverter designed to meet these objectives is shown in Figure 5-12. The basic double-bridge arrangement of the eight main power thyristors and diodes permits both voltage control and third harmonic elimination by stepped-wave techniques. No arm of the bridge is required to commute more than the minimum of twice per cycle. Pulse-width modulation techniques that require multiple commutations per cycle would allow a single bridge configuration, but would have greater switching losses and, therefore, lower efficiency.

Each of the four half-bridge arms in Figure 5-12 is provided with a commutating reactor L_D having a secondary winding by means of which the commutating pulse is coupled into the main circuit. Unlike most other inverters, a single commutating circuit is sufficient for all of the main thyristors: the pulse is generated in the arm where it is needed, by firing the appropriate one of the auxiliary thyristors SA, SB, SC or SD. The commutating capacitor (or capacitors) is precharged from the auxiliary supply to some voltage that can be controlled (within limits) by the charging thyristor SR.

To turn off either of the main thyristors in arm A, for example, auxiliary thyristor SA is fired. The capacitor C discharges through the secondary windings of the reactor L_D in arm A and generates a pulse of current that first extinguishes any load current in the main thyristors; then the excess flows through the feedback diodes in inverse-parallel with those thyristors while they recover their blocking ability. During this action, the capacitor voltage reverses.

The subsequent reversal of capacitor current is blocked by the auxiliary thyristor SA, but passes through diode DR instead. In this way, the capacitor swings back to its original voltage polarity, regaining much of its charge in the process and recovering energy that would be "trapped" and lost in some other circuits. The remaining losses are made up by firing the charging thyristor SR at the appropriate time in the cycle. The incoming main thyristor in arm A is also gated on, allowing the load current to reverse at will.

Figure 5-12. Double Bridge Inverter With Shared Transformer-Coupled Commutating Circuit, Including a Two-Level, Square-Pulse-Forming Network

Use of a common commutating circuit makes it feasible to provide for two or more levels of commutating impulse. With light loads, a small low-loss pulse is sufficient, and is generated in the manner just described. For heavy loads, the extra thyristor SO in Figure 5-12 is fired in addition to one of SA-SD, placing the second commutating capacitor C' in parallel with C and thereby, producing a larger pulse. Also shown in the commutating circuit of Figure 5-12 are smaller capacitors associated with each of C and C'. These are tuned to ring at the third harmonic of the main half-sinusoid, thereby forming a nearly square current pulse which produces a longer turn-off time for a given charge, and is therefore, more efficient.

Many other commutating circuits require a separate capacitor for each main thyristor, rendering the use of multi-level pulses or pulse-forming networks prohibitively complex. Each of these capacitors must be sized to extinguish the peak value of the highest load current. Furthermore, such a large commutating pulse must be generated whenever the arms of the power circuit are required to switch, even though the turn-off action may be redundant.

Commutation in an inverter is termed redundant when the nature of the load is such that the instantaneous load current is flowing through a feedback diode at the time of switching. The associated thyristor is already non-conducting, so the action of the commutating circuit is unnecessary. However, a commutating pulse must usually be generated in order to reverse the charge on the capacitor in preparation for the next commutation.

Such superfluous and lossy energy exchange can be avoided in the circuit of Figure 5-12, since the capacitor is always charged with the same polarity at the beginning of any commutation. When the upper diode in arm A is conducting, for example, the current will naturally commute to the lower thyristor when the latter is fired, and no other action is necessary. This type of commutation is generally associated with loads having a leading power factor. At very light loads, the ac output filter capacitor can correct the power factor to be leading, so all commutations may be "redundant" and the switching losses will be very small.

The circuit of Figure 5-12 has a further efficiency improving advantage not available to most other circuits when operating from a variable dc supply voltage. The commutating pulse magnitude can be made independent of the dc supply by controlling the auxiliary supply or the charging thyristor SR. With suitable design, this circuit has no "inevitable" losses (i. e., losses that cannot be avoided, even with ideal components). Such losses are inherent in most other circuits.

The combinations of these various features can be used to advantage in designing the inverter to maintain a high efficiency at light loads with no penalty at heavy loads.

The light load losses will consist mainly of transformer losses and losses in the filter components, which can be reduced by careful design. Switching losses, which are considerable in many other circuits, will be very small at light load.

Two alternative methods of constructing the output transformer are suggested in Figures 5-13 and 5-14. The inductive reactance required for the ac output filter is incorporated in the transformer as leakage reactance between the windings. The arrangement in Figure 5-14 has less copper in the secondary windings, but the leakage reactance may be larger than desired.

Generation of a stepped voltage waveform by the double bridge connections is illustrated in Figures 5-15 and 5-16. Each of the four arms A, B, C and D commutate twice per cycle, producing square waves at different relative phase angles. The voltage difference between A and B appears across one of the transformer primary windings; the difference between C and D appears across the other, as indicated. The sum of the primary winding voltages $(A-B) + (C-D)$ is induced in the secondary windings, stepped up or down by the turns ratio.

It is desired to control the switching angles of the four arms so that the resultant secondary voltage has an adjustable fundamental component and zero third harmonic component. This control can be accomplished by either of two methods, which will be called phase shift control and pulse width control.

In phase shift control, illustrated in Figure 5-15, the phase displacement between arms A and B is maintained constant at 120° , so that the voltage A-B is a quasi-square wave of pulse width $\beta = 120^\circ$, and has no third harmonic. Similarly, the relative phase between arms C and D is also 120° , so the other primary voltage C-D has the same property. Consequently the resultant sum also has zero third harmonic. The fundamental amplitude is varied by adjusting the relative phase shift 2α between the two primary voltages (A-B) and (C-D), between $\alpha = 0^\circ$ for full output and $\alpha = 90^\circ$ for no output voltage.

The same resultant waveform can be produced by pulse width control as shown in Figure 5-16. Here, the relative phase displacement between arms A and B is adjustable, to generate a quasi-square waveform of width β across the primary windings A-B. Similarly, the voltage C-D has the same adjustable pulse width β , but is phase shifted by a constant angle $2\alpha = 60^\circ$. This angle places the third harmonics contained in the two primary windings in phase opposition, eliminating that undesired component from the resultant.

The better method of control is that which minimizes the flux linkages required of the transformer. For the particular value of resultant shown in Figures 5-15 and 5-16, it can be seen that the pulse width β in Figure 5-16 is greater than 120° , so the voltage-time product (equal to flux linkages) is greater. Therefore, in this region ($\beta > 120^\circ$), the phase shift control method is preferred. However, when a lower value of ac voltage (relative to the dc voltage) is desired, pulse width control having $\beta < 120^\circ$ will require the smaller-flux linkages and is better.

Figure 5-13. Suggested Construction of Output Transformer Using Standard E-Cores or Laminations. Leakage Reactance Between Primary and Secondary Windings Serves as ac Output Filter

Figure 5-14. Alternative Construction of Output Transformer Having Higher Leakage Reactance

Figure 5-15. Generation of Stepped Voltage Waveform Having Adjustable Fundamental and No Third Harmonic Phase Shift Control Method

Figure 5-16. Generation of Stepped Voltage Waveform Having Adjustable Fundamental and No Third Harmonic Pulse Width Control Method

When a wide range of adjustment is required, as in this application to accommodate a variable battery voltage, variable utility voltage and load regulation, then a combined control technique is necessary to achieve optimum performance. A change from phase shift control to pulse width control is made at or near $\beta = 120^\circ$, $\alpha = 30^\circ$. This will minimize the size and losses of the transformer. It also avoids simultaneous commutations, which the common commutating circuit of Figure 5-12 would have difficulty in performing. Since a short time interval between successive commutations must be allowed for the capacitors to recharge, there will be a small intermediate non-ideal control range during transfer from one mode to the other. A small amount of third harmonic output can be expected in this region, but it should be insignificant if the filter is properly designed.

The ac filter shown in Figure 5-12 includes the leakage inductance of the transformer as a series element and a shunt filter capacitor. In addition, a resonant shunt trap turned to about the fifth harmonic is required to obtain a well balanced design that meets the harmonic spectrum allowed.

For operation in parallel with the utility line, the control oscillator that generates the timing signals for firing the thyristors must be locked in frequency to the line, and at some adjustable phase angle δ . The fundamental amplitude will be controlled by the method previously described to match the line voltage. Connected and controlled in this manner, the inverter can be regarded as an ac generator in which the series reactance of the transformer corresponds with the reactance of an ac machine. The sharing of load and transfer of real and reactive power between the inverter and the utility will be controlled in the desired manner by techniques that have been developed for uninterruptible power supplies (UPS). Such techniques are well known and similar in concept to the methods used for paralleling alternators. Real power is controlled by adjusting the phase angle δ and reactive power by adjusting the amplitude of voltage generated by the inverter. The filter capacitor supplies additional reactive power to the load or utility (see the phase diagram in Figure 5-17).

5.5.2.1 Application to System With Batteries

As discussed earlier in Section 5.5.1, an 8 kVA inverter is sufficient to handle almost 100 percent of the residence power demands. This is the nominal rating selected for the system with energy storage.

In applying the inverter to this system the basic assumption was made that no power developed by the inverter would be fed back to the utility source. The control law to be implemented for satisfying this assumption is to null the utility current to zero. This can be accomplished by monitoring the difference between the inverter output current and load current and driving the inverter electronics to reduce the difference to zero.

Operating in Parallel with Utility

V = utility voltage

E = inverter generated voltage

I_i = current supplied by inverter

I_c = current supplied by filter capacitor

I_μ = current supplied by utility

I_ℓ = house load current

δ = adjustable phase lock angle

$j\omega LI_i$ = transformer reactance drop

Figure 5-17. Typical Phasor Diagram for Inverter

As noted in Section 2, the response to a loss of the utility source would be to interrupt the inverter operation. The utility condition can be monitored by inserting current transformers in the utility supply lines and comparing the phase relationship between inverter and utility. During a short circuit condition there will be no emf and therefore large real and reactive currents. During an open circuit condition the currents will have both real and reactive components reduced to zero. As shown on Figure 5-18, use of a contactor in the utility leg would permit continued operation of the inverter in the event of loss of the utility source. In this case the contactor would be opened and the inverter would operate on its own internal voltage and frequency references.

With utility presence, startup of the inverter occurs when the battery reaches full charge as indicated by the charge voltage. The inverter contactor is closed upon frequency and voltage synchronization with the utility line. Since the system is synchronized no surge currents will be generated. The inverter can then be programmed to null the utility current to zero on a controlled ramp to also minimize surge currents.

On detecting a non-emergency shutdown condition such as low battery voltage charge, the inverter is shut down by opening the inverter contactor and interrupting gating pulses to the inverter.

Figure 5-18. System Block Diagram

On detecting an emergency shutdown condition such as a short circuited output or input, the large commutating capacitor can be used to commutate whichever leg of the bridge is conducting and then interrupt any following gate pulses. The inverter contractor can then be opened as soon as possible.

In the case of a short circuit in the residential load, the main residential breaker will open, clearing the fault. This makes it unnecessary to rate the contactors for full load and overload break conditions.

5.5.2.2 Application to System Without Batteries

For this system the inverter rating is set at 13 kVA as established by the maximum solar array output of the nominal system described earlier in Section 2. The significant difference in system operation is that the maximum output derived from the solar array, in excess of the residence load, is fed back to the utility source. The control law to be implemented is to extract power from the solar array at its maximum power point. This can be determined by dithering the operating voltage about some initially arbitrary value and detecting the dynamic changes in the sensed voltage - current product (power). The proper operating point is reached when the indicated product changes are minimized or brought to zero. Alternatively, the maximum power operating point can be approximated as a function of array temperature although this method is subject to some error over wide ranges of solar intensity.

The conditions for system startup and shutdown are similar to those for the system with batteries. One important difference, however, relates to loss of utility presence. For the no battery system, inverter shutdown is important to prevent overvoltage stress to the house loads because of inability to absorb the excess power that was normally fed back to the utility. A change in control mode from maximum power tracking to output voltage regulation could of course accommodate the loss of utility. The worth of such a feature would have to be weighed in terms of expected utility outages and the cost of the additional controls.

5.5.3 SHUNT REGULATOR

The shunt regulator, used only for the system with batteries, modulates the solar array current to limit the battery charge voltage to a prescribed upper value. As discussed in Section 5.4, the basic charge control strategy is to initially limit the voltage to 2.50 Volts per cell and after two hours, reduce the limit to a 2.40 Voltage trickle limit.

As shown previously on Figure 2-2, the shunting concept consists of short-circuiting portions of the solar array to effect a reduction in output current. Figure 5-19 shows the shunt regulator consisting of five switched shunt elements and the optional addition of a single linear element. Depending on the degree of current control desired the latter element may not be necessary.

No current is shunted away from the batteries and load until the solar array voltage reaches 240 Vdc. This indicates that the storage battery has reached a fully charged state, and that current into the battery should be reduced to the level necessary to maintain battery voltage.

When the solar array output voltage attempts to exceed 240 Volts several things take place:

1. A two-hour timer is started. This timer accumulates time as long as battery voltage remains at 240 Vdc. When battery voltage drops below 211 Vdc (indicating the battery is being discharged) the timer resets.
2. The linear shunt element starts shunting current in order to regulate solar array output voltage at 240 Vdc.

The linear shunt current increases in order to regulate solar array voltage until this stage becomes saturated. The solar array voltage then begins to increase again until the count-up threshold for the switched elements is reached. The binary counter then begins to count-up at a one-Hertz rate until the solar array voltage decreases below the count-up threshold. Since the linear shunt range is greater than each switched step of the counter, it will come out of saturation and again regulate solar array voltage. The counter is then inhibited and solar array voltage is again regulated

Figure 5-19. Block Diagram-Shunt Regulator

by the linear shunt element. As excess solar array power increases, the regulator operates in this fashion to regulate solar array output voltage, up to full output if necessary.

If excess solar array power decreases, the linear shunt element will shunt less current until it is completely off. Solar array output voltage will then decrease until the count-down threshold voltage is reached. At this point the binary counter will count-down either until regulation is again obtained with the linear element or until all switched loads are removed.

The binary counter and linear shunt will add and subtract load from the system to balance out excess solar array power as long as it is present. Count-up, count-down, and linear shunt threshold voltages will be modified as required by the two-hour timer to maintain the proper battery state of charge.

The basic approach described above was favored over a full dissipative design because of high cost and the complexity of utilizing the waste heat. With the switched shunt approach, not only are the shunt switches relatively less expensive, but it is still possible to utilize the excess power by means of separately controlled loads, e.g., resistive heating elements.

5.6 LIGHTNING PROTECTION

The probability of a lightning strike on the residential solar array depends on the prevalence of lightning activity in the particular geographical region and on the nature of alternate targets in the surrounding area. In general, strike probabilities are greatly reduced in congested areas and therefore, the need for lightning protection would be lessened in such areas. Certainly, for initial demonstration projects in which the solar arrays will presumably be very expensive, the investment in lightning protection will be worthwhile. However, as the cost of solar arrays decreases, the need for protection will accordingly diminish.

The following discussion centers on the effects of lightning strikes and methods which might be employed to minimize them. Protection against lightning must include direct as well as secondary effects. Direct effects involve the termination of the lightning flash to parts of the system: burning effects at the point of attachment, carrying the high current to ground, and differences of potential with nearby conductive parts due to the inductive drop along the lightning current in nearby circuits, in the present case the cell array on the roof as well as the connection of the cell array with the conventional utility supply to the house.

Direct Effects

Attachment of a lightning stroke to the unprotected roof system is assumed to be unacceptable, so that this discussion will address the case of some protection system suitable to receive the stroke, and lead the current down to earth in a safe and controlled manner.

The National Fire Protection Association has published a Code for Lightning Protection (NFPA 78-1975) which provides specific guidance on the design of air terminals ("lightning rods") to be installed on the roof of a building, and on the arrangement of downconductors going from the air terminals to ground. One of the requirements of such a system is to bond nearby metallic masses in order to eliminate the risk of "side flash". In the present case, however, the presumed extreme sensitivity of the solar cells to overvoltages raises the question of whether or not it could be possible to make the array system part of the path to ground for the lightning current.

Side flash is the phenomenon caused by the very high differences of potential developed during the rising portion of the lightning current, between the down conductors carrying the lightning current to ground, and adjacent but not connected metallic parts (which may be connected by a separate ground connection to earth), as their ground connection does not carry any lightning current. With reference to Figure 5-20, the voltage appearing across the A-B gap is $L \, di/dt$, where typically L is $0.25 \, \mu\text{H}$ per foot of conductor, and di/dt can reach $100 \, \text{kA}/\text{microsecond}$; thus a difference of potential of $0.25 \, 10^{-6} \times 10^5 / 10^{-6} = 25 \, \text{kV}/\text{foot}$ can be established along the down conductors.

Figure 5-20. Lightning Protection Concept

This shows the need for separating the air terminal and down conductor system from the roof array or the need to establish a bond between them, requiring the roof array to become part of the current path.

Another consideration is the so-called "Cone of Protection" afforded by the system of air terminals, which states that metallic objects included in a 1:1 cone having a lightning terminal at the apex are substantially (but not positively) immune to attachment of a lightning stroke. Therefore, in the case of the roof array, a system of air terminals can be provided to form a combination of cones including all the array. The system likely to provide the most effective protection is shown on Figure 5-21. Cables of sufficient mass to survive the burning associated with attachment of a stroke will not produce significant shadow; their sizing and height above the roof is more a matter of economics and aesthetics.

Figure 5-21. Lightning Protection

Note that on Figure 5-21, the size of the array has been reduced to provide sufficient clearance at the edges of the array to avoid side flash. An alternative may be to conduct the current through tall air terminals that are physically separated from the residence.

Indirect Effects

Induced voltages in the array, due to the fast changes of magnetic field around the lightning down conductors, will be affected by the coupling of the array to this field. Two approaches can reduce the severity of the problem: (1) the layout of the array may be designed with minimum area current loops; (2) suitable overvoltage protection can be incorporated at strategic points of the array. Actual magnitudes and available energy of the transient overvoltages induced in the array will be greatly affected by the type of coupling between the lightning current and the cell array.

Overvoltages entering the house through the utility service line can also occur. Standard methods are available for coping with this problem.

5.7 SUBSYSTEM COST DATA

The following cost data for the major subsystems was used in determining the capital expenditures for the nominal system presented in Section 3.

5.7.1 SOLAR ARRAY

No cost data was solicited from vendors for solar array assemblies since their cost was treated as an independent variable. The cost range of \$50 to \$200 per square meter was considered to be the range at which photovoltaic power becomes competitive with other forms of generation. In the cost analyses of Section 3, solar array costs were considered to include all panel material and assembly costs, not just the cost of the cells themselves. Thus, a stated cost of \$100/square meter of cell area includes not only a square meter of solar cells, but all encapsulating, interconnection and substrate materials and their assembly into a panel.

5.7.2 BATTERIES

The estimated cost of batteries was furnished by C&D Batteries and is shown on Figure 5-22. For the nominal system size of 250 ampere-hours (48 KW-hr) and a production rate 10,000 modules per year, the plot indicates a cost of \$3700/battery, the cost used in the economic analysis.

5.7.3 INVERTERS

An estimate of inverter cost was based on the concept described in Section 5.5. Table 5-1 shows a breakdown of cost versus the number of inverters produced. Based on this data a cost of \$125/kVA was used for the economic analysis which corresponds to a production between 10k and 100k units.

Figure 5-22. Cost of Hybrid Lead-Acid Battery System

TABLE 5-1. INVERTER COSTS

			Number of Inverters			
			1K	10K	100K	1000K
<u>Active Devices</u>						
14	SCRs	C234E	79.52	76.30	73.64	70.00
10	Diodes	IN3693	34.00	30.60	27.60	24.00
<u>Capacitors</u>						
5	40 μ fd AC	45F175	28.05	27.50	26.75	25.00
2	6 μ fd	28F1048FC	8.08	7.80	7.50	7.20
1	100 μ F	28F	14.15	14.00	13.83	13.70
<u>Transformers</u>						
14	Aladdin Pulse	306196	25.90	22.40	19.60	16.00
4	Commutating	Custom	13.00	10.00	7.00	6.50
2	20 μ hy	Custom Air Core	1.20	1.00	.70	.60
1	400 μ hy	Custom Air Core	3.60	2.90	2.10	1.90
1	6.8my	Stancore C2687	4.18	4.16	4.16	4.16
1	Output 8kVA	Distribution	240.00	230.00	210.00	200.00
<u>Controls</u>						
1	Control Logic		200.00	100.00	75.00	50.00
3	Contactors and Fuses		120.00	110.00	100.00	100.00
Labor			200.00	150.00	75.00	50.00
Total 6kVA Inverter			971.68	786.66	642.9	569.96
\$ /kVA			161.95	131.11	107.15	94.99

TABLE 5-2. SHUNT REGULATOR COST

Shunt Transistors		
1/2 Array	-	\$80.00
1/4 Array	-	40.00
1/8 Array	-	5.00
1/4 Array	-	5.00
1/32 Array	-	5.00
Linear	-	5.00
Transistor Cost	-	\$140.00
Shunt Transistor Drives	-	\$75.00
Logic, Control, Power Supply	-	\$85.00
Array Diode	-	\$20.00
Circuit Breaker Drive, Bat. Overtemp	-	\$20.00
Total		\$340.00

SECTION 6
TECHNOLOGY DEVELOPMENT

SECTION 6

TECHNOLOGY NEEDS

6.1 INTRODUCTION

An assessment of the residence photovoltaic systems described herein indicates that, except for solar arrays, the various elements can be designed and produced using available technology. Table 6-1 summarizes the technology status of the major elements and identifies necessary development efforts.

Table 6-1. Component Technology Status, On-Site Residence P/V System

Component	Technology Base	Development Needs
Solar Arrays		
Cells	Space Program Spin-Off	Cost Reduction
Mounting/Interconnection	Construction, Electrical Industries,	Environmental Ruggedness
Lightning Protection	Varistor Technology	Integration into Solar Arrays
Batteries (lead acid)	Broad-Based Industry: Commercial Industrial Automotive	Cost Reduction
DC/AC Inversion	Solid-State Power Supplies, Micro-circuitry	Solar Array Max. Power Tracking; Cost Reduction

6.2 SOLAR ARRAYS

As a result of the considerable background derived from the space program, the essential characteristics of solar arrays are well established. The major obstacle to their widespread terrestrial utilization results from their present high cost. In recognition of this fact the major effort in ERDA's photovoltaic program is devoted to developing inexpensive solar cell production methods. In addition, sizable efforts are underway for developing automated assembly techniques and for perfecting long-life encapsulants for environmental protection. Thus, the technology needs for solar arrays appear to be adequately identified.

One additional possible area of technology development for terrestrial solar arrays concerns lightning protection. This would apply for locations where strike probabilities are sufficiently high to justify the expense of protection. Conventional air terminals (lightning rods) and down conductors provide protection against direct lightning strokes, and strategically located arrestors protect against surges induced in the incoming power lines to the residence. In this latter case, the arrestors prevent damage by limiting induced voltages

to safe levels. A similar form of protection can be provided for the exposed solar array circuits which may be susceptible to voltage induction arising from electric and magnetic field changes associated with lightning phenomena.

The use of metal oxide varistors (MOV's), connected across groups of solar cells may provide an appropriate means for limiting the level of induced voltages. These devices are voltage dependent, symmetrical resistors which perform similarly to back-to-back zener diodes in circuit protective functions. When exposed to high energy transients, the varistor impedance changes from high to low values, clamping the transient to safe voltage levels.

The increase of current with peak voltage is given by the empirical expression:

$$I = KV^\alpha$$

where:

I = Current through the varistor

V = Peak voltage in the clamping region

K = Device constant

Alpha is the slope of the current-voltage characteristic of the device. The larger the value of alpha, the better the clamping action.

Under transient step voltage conditions, varistors initially exhibit capacitance characteristics which enhance their attractiveness for protection against secondary lightning effects. The capacitance varies directly with the area of the varistor and inversely with its thickness. The thickness also determines the voltage rating and the energy rating (which is also area dependent). This combination of characteristics is compatible with its integration into solar array assemblies. Its ability to be formed into any shape suggests that it can be built into the substrate of the solar cell modules. With respect to the shingle concept described earlier, the varistor would consist of an area of metal oxide material molded into the shingle encapsulant layers and joined electrically to the terminals of the 19-cell string. The area and thickness would determine the capacitive and dissipative characteristics of the device.

6.3 BATTERIES

Lead-acid battery technology is well established and served as the basis for defining the energy storage subsystem of the conceptual design. As noted previously, the batteries constitute a major element of cost, comparable in impact with the solar cells once their cost goals are achieved. Since the cost of lead-acid batteries is largely associated with the basic materials, principally lead, it is not anticipated that drastic reductions in cost will be forthcoming. Thus, technology needs for energy storage systems should be directed toward alternative approaches as exemplified by sodium-sulfur batteries and similar developments.

6.4 SYSTEM ELECTRONICS

The DC/AC inverter for the residence photovoltaic system falls into the category of equipment known as uninterruptible power supplies (UPS). The maturity of the UPS technology is indicated by the listing of suppliers shown on Table 6-2.

No specific piece of equipment on Table 6-2 exactly fits the requirements specified for the residence inverter. However, some could be modified and adapted with little difficulty. The principal development item would pertain to providing maximum power tracking of the solar array. Available techniques and devices would be utilized in providing this capability. In this light, no long term technology needs are identified for the required inversion function. Rather, the design and production is a matter of adapting available technology.

The technology needs for the battery charger electronics (shunt regulator, controls) fall into a similar category - design and production can be accomplished with available technology.

TABLE 6-2. UNINTERRUPTIBLE POWER SYSTEM SUPPLIERS

Suppliers	Capacity				Component Types									Systems					
	Power		Energy		Rectifier	Battery	Inverter	Power Board	DC-DC Converter	Component Power Supply	Switch Types			Design	Construct	Install	Turnkey	Maintenance	Training
	Min	Max	Min	Max							Static	Electro-mechanical	Manual						
	VA	VA	Watt-hrs	Watt-hrs															
CML MACARR	5 + 1	5 + 7	5 + 1	5 + 7	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•
Cyberex	2 + 3	1 + 6	2 + 1	1 + 6	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•
Deltec	5 + 2	2 + 4			•	•	•	•	•	•	•	•	•	•	•	•	•	•	•
ESB, Inc.	1 + 3	1 + 6			•	•	•	•	•	•	•	•	•	•	•	•	•	•	•
Elgar	5 + 2	2 + 4	5 + 1	5 + 4	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•
Exide Lightguard	5 + 2	5 + 3	5 + 2	5 + 3	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•
ICS	5 + 2	5 + 4	1 + 2	1 + 5	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•
Lorain	5 + 2				•	•	•	•	•	•	•	•	•	•	•	•	•	•	•
Mideastern	2 + 2	1 + 4	5 + 1	2 + 3															
NIFE	1 + 1	2 + 5	1 + 4	2 + 5	•	•	•				•	•	•	•	•	•	•	•	•
Nova	5 + 1	5 + 3	1 + 1	5 + 3		•	•		•	•	•	•	•	•	•	•	•	•	•
Power Syst. & Cont.	5 + 3	1 + 6	1 + 2	1 + 7	•	•	•		•	•	•	•	•	•	•	•	•	•	•
Ratelco	2 + 2	1 + 4			•		•	•	•	•	•	•	•	•	•	•	•	•	•
Sawyer Ind.	2 + 2	1 + 3																	
Sola		1 + 5																	
Solidstate Controls	2 + 2	2 + 5			•	•	•				•	•	•	•	•	•	•	•	•
Static Power	5 + 4	1 + 6*			•	•	•		•	•	•	•	•	•	•	•	•	•	•
Teledyne Inct	5 + 3	5 + 7			•	•	•	•	•	•	•	•	•	•	•	•	•	•	•
Terado	1 + 1	2 + 3	1 + 1†	5 + 0	•	•	•	•			•	•	•	•	•	•	•	•	•
Topaz	5 + 2	5 + 4	1 + 2	2 + 5	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•
Westinghouse	1 + 3	5 + 6	1 + 3	1 + 6	•	•	•				•	•	•	•	•	•	•	•	•
Wilmore	2 + 2		5 + 1		•	•	•				•	•	•	•	•	•	•	•	•

† Watt-seconds

• Multiples of 300 kVa

Notation: 5 + 4 = 50,000; 1 + 6 = 1,000,000

SECTION 7

RESIDENTIAL MARKET PENETRATION

SECTION 7

RESIDENTIAL MARKET PENETRATION

7.1 INTRODUCTION

This section summarizes an analysis on the potential penetration of residential photovoltaic systems. Detailed discussion and supporting data are contained in Appendix E.

Single family residences represent an important potential market for photovoltaic electric power systems (PEPS). Such residences constitute by far the largest category of dwelling types, accounting for more than 65 percent of the total residential housing in inventory in 1970⁽¹⁾*. They are projected to comprise approximately 62 percent of the housing market⁽²⁾ by 1990.

Single family dwellings are also anticipated to maintain their dominant share of residential energy consumption. In 1970, single-unit detached dwellings accounted for approximately 75 percent of residential energy demand. Project Independence projections show the share as 74 percent of residential consumption in 1990⁽³⁾.

The implications of PEPS applied to new construction and retrofitted to existing homes are covered in the following sections.

7.2 PEPS APPLIED TO NEW CONSTRUCTION

New single-family construction is assumed to be the first market for photovoltaic systems. A photovoltaic roof, all electric equipment (the baseline house design is assumed to be an all-electric residence) and extra insulation, coupled with other features intended to reduce the total energy load the solar system must meet, can specifically be designed into a new house. Therefore, the system is likely to be cheaper and more attractive to the new home builder than to the owner of an existing residence.

As was discussed in Section 6, the attractiveness of residential photovoltaic systems will vary from region to region, depending on the cost of photovoltaic versus conventional generation. As was discussed in Section 4, an analysis of the potential competitiveness of photovoltaic systems was performed, based on \$100/m² array costs. In 1985, photovoltaic systems are potentially competitive with central station electricity in 4 regions: Hilo, Hawaii; Honolulu, Oahu; San Juan, Puerto Rico; and New York City. If photovoltaic systems were to penetrate the new housing market in these areas at an annual growth rate of 15%, by 1990 enough production experience would have been accumulated to reduce the cost of photovoltaic systems by approximately 25%. This assumes a 0.70 experience curve on the solar cell itself and a 0.90 slope in the remainder of the system. This cost reduction would make photovoltaic systems potentially competitive in seven additional regions. Similar costs reductions occur in 1993, 1994-1/2, 1996, 1997-1/2 and 2000 and with them, the expansion of the photovoltaic market. The penetration curve, resulting from this analysis, is presented in Figure 7-1.

*See Section 7.4 for references.

Figure 7-1. Potential Growth in New Residential PV Systems Based on Regional Competitive Cost Analyses

In a separate analysis, the penetration of photovoltaic was projected using the Fisher-Pry methodology⁽⁴⁾ which has, as its key parameters, estimates of the segment of the total market a new technology can penetrate (called the "domain"); and estimates of the time required to reach from 10% to 90% of the domain (called the "takeover time"). Some guidance on selection of appropriate takeover time is provided by case studies compiled by Fisher and Pry (see Table 7-1). The assumptions selected for projecting photovoltaic generation are given in Table 7-2. The results are plotted in Figure 7-2.

As can be seen by comparing the curves in Figures 7-1 and 7-3, the Fisher-Pry penetration results are lower in 2000 than the estimates resulting from the regional competitive-price analyses. The Fisher-Pry estimates range from approximately 400,000 to 75,000 installed systems in 2000. The estimate resulting from the regional cost analysis is over 3 million.

This curve overstates the growth in photovoltaic systems. As was mentioned in Section 4, the analysis of cost comparisons between conventional and photovoltaic generation assumed that the utilities would accept photovoltaic electricity not used by the house at the same price they would charge the house for additional electricity in excess of its photovoltaic generation. Such a one-to-one trade is unlikely. Thus, an upward bias is incorporated in the regional-competitive curve. The degree of bias depends on the actual credit the utilities would give for photovoltaic electricity supplied to the grid. Analysis of the value of this electricity to the utility is complex; such analyses were conducted for selected utilities and are reported on elsewhere in the report.

TABLE 7-1. FISHER-PRY TAKEOVER TIMES

Substitution	ΔT (years)
Synthetic/Natural Rubber	58
Synthetic/Natural Fibers	58
Plastic/Natural Leather	57
Margarine/Butter	56
Electric Arc/Open Hearth Specialty Steels	47
Water Based/Oil-Based Paint Remover	43
Open Hearth/Bessemer Steel	42
Sulfate/Tree-Tapped Turpentine	42
Plastic/Hardwood Residence Floors	25
Plastic/Other - Pleasure Boat Hulls	20
Organic/Inorganic Insecticides	19
Synthetic/Natural Tire Fibers	17.50
Plastic/Metal - Cars	16
BOF/Open Hearth - Steels	10.50
Detergent/Natural Soap (U.S.)	8.75
Detergent/Natural Soap (Japan)	8.25

Table 7-2. FISHER-PRY PHOTOVOLTAIC PENETRATION SCENARIOS-KEY PARAMETERS

	Domain	Years From 10 to 90 Percent Market Share
"Rapid" Growth	60% of Annual New Construction	10
"Intermediate" Growth	60% of Annual New Construction	15
"Slow" Growth	60% of Annual New Construction	20

The Fisher-Fry penetration projections, on the other hand, may be biased in a downward direction. They are based on historical studies of the growth of new technologies. The case of solar energy systems may be quite different from these past experiences. Government R&D, consumer and utility awareness of the need to conserve fossil fuels, the uncertainties surrounding nuclear power, as well as the positive environmental benefits of solar energy may contribute to more rapid acceptance than the experience documented by Fisher and Pry. If this is the case, the results from this analysis understate the actual sales of photovoltaic systems.

7.3 PEPS APPLIED TO THE RETROFIT MARKET

Although new construction is considered the first market for photovoltaic systems, the retrofit market is a much larger market, especially before 2000.

Figure 7-2. Photovoltaic Market Penetration Scenarios, New Construction Only

Figure 7-3. Photovoltaic Market Penetration Scenario, New Construction Plus Retrofit

Several impacts of PEPS applied to new construction were analyzed for the Fisher-Pry penetration cases and are discussed in the Appendix E. Given the number of systems these scenarios project, the impacts of photovoltaics, which are a direct function of the penetration, are small before 2000, although they increase thereafter.

7.3.1 RETROFIT PENETRATION SCENARIOS

Results of three retrofit penetration projections, based on the Fisher-Pry methodology, are graphically presented in Figure 7-3. As depicted, the additions increase the total number of PEPS units in 2000 by a factor of 13. In order to achieve such penetration, it was assumed that 20 percent of the total existing single-family housing stock would be an available market each year for PEPS retrofits. This percent corresponds to the share of the inventory in 1985 which is of an age to need major systems replacements. Roofs and oil and gas furnaces - selected as exemplar home systems - are replaced approximately every 20 years. Thus, homeowners of residences that are 20 years old (± 5 years) and 40 years old (± 5 years) would be likely to be making decisions about investing in new home systems. In 1985, it is estimated that 20 percent of the inventory will fall into this category. As in the case of new construction, 60% of this segment are assumed to be candidates for photovoltaics.

As indicated in Figure 7-3, two retrofit cases were projected: one assuming that retrofit penetration lags behind new construction by five years; and a second assuming they penetrate concurrently. The former case is likely if the cost of retrofitting PEPS is significantly greater than the cost of a new system. The second case would occur if the differential is small. The differential between the two projections represents the "value" of reducing the costs of retrofit.

7.3.2 DESIGN IMPLICATIONS

Capturing a share of the retrofit market creates special criteria for evaluating system characteristics. Designs which are easy to install on existing structures would reduce the cost and therefore increase the attractiveness of the system. The shingle design described elsewhere in this report appears particularly suitable for retrofit installations on pitched roofs. Special purpose PEPS systems, sized to handle specific energy loads rather than providing for all needs, might also be very appealing to homeowners who would be willing to make smaller investments.

7.4 REFERENCES, SECTION 7

1. U.S. Bureau of the Census, U.S. Census of Housing; 1970, Vol I
2. Federal Energy Agency, Project Independence: Residential and Commercial Energy Use Patterns 1970-1990, Vol I, Washington, D.C., November 1974, p. 54
3. Ibid, pp. 34-44
4. John C. Fisher and Robert H. Pry, "A Simple Substitution Model of Technological Change", in Marvin J. Cetron and Christine A. Ralph, Industrial Applications of Technological Forecasting, New York, Wiley, 1971, pp. 290-307.

SECTION 8
SPECIFICATIONS

SECTION 8

SPECIFICATIONS

8.1 RESIDENCE PHOTOVOLTAIC SYSTEM GUIDELINE SPECIFICATION

8.1.1 SCOPE

The residence photovoltaic (PV) system shall consist of a roof-mounted solar array, the optional use of batteries for meeting the residence loads during low or zero insolation periods, a means for converting the dc power of the PV/battery combination to conventional ac output, and all necessary controls and wiring for physical and electrical integration into the residence. The PV system shall be tied in parallel with a utility line which shall serve as a backup source for electrical energy.

8.1.2 ELECTRICAL OUTPUT

The electrical output of the PV system shall be in the form of single phase, 60 Hertz, three-wire ac at 240/120 Volts. The output shall be in proper synchronism and phase with the backup utility source.

8.1.2.1 With Energy Storage

If the PV system includes battery energy storage, the maximum output from the dc/ac inverter shall be limited to a rating above which only 5 percent of the residence energy demands are supplied. In this case, the output shall be devoted to meeting the residence loads with no feedback of the PV generated power back to the utility source. Night-time charging of the PV system batteries from the utility source is optional.

8.1.2.2 Without Energy Storage

If the PV system does not include battery energy storage, the maximum output shall be sufficient to handle the peak output of the solar array. In this case the excess output, over that required by the residence loads, shall be fed back to the utility source.

8.1.3 PERFORMANCE

The PV system shall provide a portion of the residence electrical energy needs consistent with the amount of solar array area installed, the efficiency of the solar cells used, and the insolation characteristics of the residence location. A guideline to system performance is provided by Table 4-12, and Figure 4-13 showing system output (annual KW-hrs. per square meter of active solar cell area) for different locations within the U.S. These data pertain to systems without energy storage with full credit taken for power feedback to the utility source. The values shown take power conditioning losses into account.

Systems with energy storage perform about 80 percent as well as systems without energy storage. Thus, the data of Table 4-12 and Figure 4-13 should be reduced by 20 percent to estimate the performance for systems with energy storage.

A nominal cell efficiency of 13.4 percent was used in developing the performance data. Performance at other cell efficiencies can be determined by adjusting the data of Table 4-12 and Figure 4-13 by the ratio of the new cell efficiency to the reference cell efficiency (13.4%).

8.1.4 UTILITY INTERFACE

The PV system shall operate synchronously in parallel with a utility source. The PV system shall be designed so that the utility power factor is not degraded below 0.5. The harmonic content of the PV system shall not result in any injurious effects to normal household electrical appliances. In the event of a utility power outage, operation of the PV system shall be interrupted and not re-enabled until utility power has been fully restored. This is to assure that utility repair crews are not endangered by photovoltaic feedback power. Energy independence from the utility source is permissible as long as positive means exist for disconnecting the utility in the event of a utility outage.

8.1.5 PHYSICAL CHARACTERISTICS

The components of the PV system shall be integrated into the residence structure as follows:

1. The solar array shall be installed on a southward sloping roof tilted about ten degrees less than the latitude angle. The roof surface shall be located to avoid any shadowing by external objects.
2. Batteries (if used) shall be located in a ventilated enclosure with access to authorized personnel only.
3. Power conditioning and other equipment shall be located in a sheltered area with sufficient ventilation to assure adequate means of heat dissipation. Enclosures shall be provided as a safeguard against accidents.

8.1.6 LIFE

The PV system shall be designed for a life goal of 30 years.

8.1.7 GROUNDING

Standard practices for equipment grounding shall be adhered to. Equipment grounding shall be sized to handle the entire time-current duty permitted by overcurrent protective devices without thermal or mechanical overstress. Grounding paths shall be installed as close to the point of power application as possible. All enclosures shall be properly grounded and interconnected to avoid side flashover due to lightning strikes.

8.1.8 LIGHTNING

Protection against the primary and secondary effects of lightning shall be provided to the extent that lightning strike probabilities and economics deem this to be necessary. Lightning protective devices shall be installed in a manner avoiding any shadowing on the solar array.

8.1.9 REPAIR AND MAINTENANCE

The PV system shall be installed with full consideration given to the needs for accessibility, repair and maintenance. Means shall be provided to permit periodic cleansing of the solar array surface. To the extent practicable, access shall be provided to the various interconnections for checkout and repair.

8.2 SOLAR ARRAY GUIDELINE SPECIFICATION

8.2.1 TYPE

The solar arrays shall be used for residence power generation and shall be of the planar non-concentrating type to be attached to residence roofing structures. Solar cells of proven design, performance and durability shall be utilized.

8.2.2 PHYSICAL CHARACTERISTICS

The solar arrays shall be of modular construction for ease of manufacture, test, transportability, handling and installation. The solar array modular assemblies shall have physical characteristics that result in convenient simple methods of attachment and at the same time, provide close packing for efficient utilization of the roof mounting area. The installation of the solar array assemblies shall result in a weatherproof surface that provides a roofing function resistant to leakage and air infiltration by driving rains and wind. The solar array assemblies shall be designed for attachment to sloping roofs of conventional design. Depending on the surface material, attachment shall be made with such devices as nails, screws or clips.

8.2.3 ELECTRICAL CHARACTERISTICS

The solar arrays shall produce power at a nominal voltage of 240 Vdc. The solar array modular assemblies shall be electrically configured so that joining in series of a number of assemblies results in the desired 240 Vdc output. The buildup of voltage shall be achievable over a nominal roof length of about 25 feet, preferably in the roof slant direction. The buildup of current shall be accomplished by adding voltage strings of module assemblies in the horizontal direction, preferably in increments of about 2 feet.

8.2.4 INTERCONNECTION

The solar array module assemblies shall be electrically interconnected by means of standard connector, crimping or terminal screw devices. The interconnection shall be designed to permit module removal for repair or replacement. The interconnection shall be located or protected to minimize contact deterioration and corrosion due to weather exposure. The interconnections for building up solar array voltage and current shall be accomplished to provide a highly redundant series-parallel matrix which minimizes the loss of total solar array output resulting from the open-circuit failure of any single module assembly.

8.2.5 PERFORMANCE

At an air-mass-one (AM1) intensity of 100 MW/cm^2 and a solar cell temperature of 28°C , the solar array shall produce an output of 100 Watts/m^2 of gross area at its maximum power voltage-current point.

8.2.6 ENVIRONMENTAL DURABILITY

The solar arrays shall have a life of 30 years operating in a terrestrial weather environment. The design shall withstand the extremes due to temperature, wind, radiation, wetness and pollution.

8.2.7 REPAIR/REPLACEMENT

The solar array design shall permit the replacement of defective module assemblies with minimal disturbance to other surrounding modules.

8.2.8 AUXILIARY DEVICES

Array associated devices such as isolation diodes, shunting switches and the like shall be located in close proximity to the solar array, preferably on the roofing surface with appropriate weather protection enclosures.

8.2.9 WIRING

All wiring within the solar array and to the auxiliary solar array devices shall be accomplished on the exterior of the residence structural shell for the purpose of reducing the number of penetrations required and to provide access for servicing.

8.3 BATTERY SYSTEM GUIDELINE SPECIFICATION

8.3.1 TYPE

The battery system shall provide energy storage for meeting residence loads at night and during periods of low insolation. The system shall be of the lead-acid type and shall be capable of continuous charge-discharge cycling operation.

8.3.2 RATING

The battery system shall consist of 96 lead-acid cells in series and shall operate between limits of 240 Vdc (maximum charge voltage) and 172 Vdc (minimum discharge voltage). The nominal capacity shall be 250 ampere-hours at an 8-hour discharge rate.

8.3.3 PERFORMANCE

The battery system shall have a 10-year life with a capability of 1500 charge-discharge cycles with the rated capacity removed during each discharge. The maximum charge rate shall be 65 amperes (c/3.8 rate) and the maximum discharge rate shall be 55 amperes (c/4.5 rate). These characteristics shall apply for a nominal temperature range of 55 to 95°F.

8.3.4 PHYSICAL CHARACTERISTICS

For ease of handling the battery system shall consist of several battery assemblies connected in series. Nominally, each assembly shall consist of 24 series connected cells packaged into a single container. Nominal dimensions shall be 18 x 26 x 32 inches; nominal weight shall be 1230 pounds. Four such assemblies are required per battery system.

8.3.5 ENCLOSURE

The batteries shall be located in a separate enclosure either separate or attached to the residence. The enclosure shall be sufficiently ventilated to prevent the dangerous buildup of gaseous emissions (mainly hydrogen) from the battery cells, and shall be designed to prevent any entry of the emission into the residence. The enclosure shall be secured against entry by other than qualified servicing personnel.

8.3.6 SAFETY

Features shall be included in the battery design to assure safe operation and to permit direct means for monitoring such characteristics as temperature and electrolyte level.

8.4 DC/AC INVERTER GUIDELINE SPECIFICATION. (For system without batteries)

8.4.1 TYPE

The inverter shall receive dc power from a photovoltaic solar array and supply ac power to typical residential electrical loads in parallel with a utility source. The inverter shall employ solid-state techniques in converting the dc to ac.

8.4.2 OUTPUT

The inverter shall be rated at the maximum solar array output and shall supply its output in the form of single phase, 60 Hertz, three-wire (two lines and ground) ac at 240/120

Volts and 120 Volts from either hot line to the neutral grounded third line. The outputs to the 120 Volt line to ground circuits, may be completely unbalanced.

8.4.3 CURRENT LIMIT

The inverter shall be designed to limit the output of each 120 Volt leg to one-half of the total rated output.

8.4.4 SOLAR ARRAY POWER TRACKING

The inverter shall operate to extract the maximum power from the solar array source. This shall be accomplished by sensing the solar array voltage and current and adjusting the inverter impedance characteristics to maximize the voltage-current product. Maximum power voltage may vary from 200 to 240 Volts; current may vary up to 75 amperes.

8.4.5 PARALLEL OPERATION WITH UTILITY

The inverter shall operate in parallel with a utility source. Any output produced by the inverter that is not absorbed by the residence loads shall be feedback to the utility source. The inverter shall operate in synchronism with the utility source. The inverter shall be designed so that the utility power factor is not degraded below 0.5.

8.4.6 PERFORMANCE

The inverter shall have an efficiency of greater than 88 percent for the range from 25 to 100 percent of the rated output. The inverter efficiency may be less than 50 percent for loads less than 10 percent of rating.

8.4.7 HARMONIC CONTENT

Third and fifth harmonic components shall not each constitute more than 15 percent of the output harmonic content. The fundamental component of frequency shall not be less than 95 Volts for each line to ground circuit.

8.4.8 ISOLATION

Transformer isolation shall be provided between dc and ac circuits of the inverter.

8.4.9 UTILITY PRESENCE

The inverter shall be operative only upon condition of utility presence. Should an open or short-circuit fault develop in the utility source, operation of the inverter shall be interrupted immediately. A fail-safe means shall be provided for assuring that this criterion is satisfied.

8.4.10 INVERTER STARTUP

A contactor shall be provided at the inverter output which shall be closed upon condition of: (1) utility presence; (2) synchronization of the inverter circuitry with the utility source.

8.4.11 HEAT REMOVAL

The inverter shall be equipped with a water-cooled heat sink for removing the internally generated heat. To enhance the usefulness of this heat for such purposes as heating water for domestic purposes, the heat dissipation devices (SCR's, etc.) shall be designed to operate at elevated temperatures consistent with life requirements.

8.4.12 LIFE

The inverter shall be designed for a life of 30 years.

8.4.13 SAFETY

The equipment shall be designed to meet standard safety requirements considering its use in a residence. Enclosures shall be provided against the possibility of shock; adequate provision shall be made for properly grounding the unit. The unit shall be located in a protected area with access to servicing personnel.

8.5 DC/AC INVERTER GUIDELINE SPECIFICATION. (For system with batteries)

8.5.1 TYPE

The inverter shall receive dc power from a photovoltaic/battery source and supply ac power to typical residential electrical loads in parallel with a utility source. The inverter shall employ solid-state techniques in converting the dc to ac.

8.5.2 OUTPUT

The inverter shall be rated at a level below which 95 percent of the energy demands are supplied (roughly 8 kVA for residences). The inverter shall supply its output in the form of single phase, 60 Hertz, three-wire (two lines and ground) ac at 240/120 Volts. The outputs to the 120 Volt line to ground circuits, may be completely unbalanced.

8.5.3 CURRENT LIMIT

The inverter shall be designed to limit the output of each 120 Volt leg to one-half the total rated output.

8.5.4 CONTROL

The inverter shall operate to meet the residential loads up to the limit of its rating. With current limiting imposed at this level, higher demands shall be satisfied by the utility source. Below the rating limit, control shall be exerted by adjusting the inverter output to null out any power from the utility.

8.5.5 BATTERY STATUS TIE-IN

The inverter shall be either fully enabled or disabled in response to a battery status signal (see Battery Charge Regulator Specification).

8.5.6 PARALLEL OPERATION WITH UTILITY

The inverter shall operate in parallel with a utility source. No output produced by the inverter shall be fed back to the utility source. The inverter shall operate in synchronism with the utility source. The inverter shall be designed so that the utility power factor is not degraded below 0.5.

8.5.7 PERFORMANCE

The inverter shall have an efficiency of greater than 88 percent for the range from 25 to 100 percent of the rated output. The inverter efficiency may be less than 50 percent for loads less than 10 percent of rating.

8.5.8 HARMONIC CONTENT

Third and fifth harmonic components shall not each constitute more than 15 percent of the output harmonic content. The fundamental component of frequency shall not be less than 95 Volts for each line-to-ground circuit.

8.5.9 ISOLATION

Transformer isolation shall be provided between the dc and ac circuits of the inverter.

8.5.10 UTILITY PRESENCE

Inverter requirements differ depending on whether or not operation is desired during the period of a utility outage:

Option 1. Operation not required. For this case, the inverter shall be operative only upon condition of utility presence. A contactor located at the inverter output shall be opened in response to a utility fault. A fail-safe means shall be provided for assuring that no feedback from the inverter to the fault location can occur.

Option 2. Operation required. For this case, uninterrupted operation shall be contingent on isolating the utility fault by means of a contactor in the utility leg. Again, a fail-safe means shall be provided for assuring no feedback to the utility line. This option requires free-run inverter capability for generating the 60 Hertz output.

8.5.11 STARTUP

For Option 1 above, a contactor shall be provided at the inverter output which shall be

closed upon condition of: (1) utility presence; (2) synchronization of the inverter circuitry with the utility source.

For Option 2 above, contactors in both the inverter and utility legs shall be employed and properly sequenced to accommodate several possible operating modes: (1) inverter startup with utility presence; (2) inverter startup without utility presence; (3) inverter operative and to be resynchronized to restored utility source; (4) inverter inoperative and utility restored during inoperative interval.

8.5.12 HEAT REMOVAL

The inverter shall be equipped with a water cooled heat sink for removing the internally generated heat. To enhance the usefulness of this heat for such purposes as heating water for domestic purposes, the heat dissipation devices (SCR's, etc.) shall be designed to operate at elevated temperatures consistent with life requirements.

8.5.13 LIFE

The inverter shall be designed for a life of 30 years.

8.5.14 SAFETY

The equipment shall be designed to meet standard safety requirements considering its use in a residence. Enclosures shall be provided against the possibility of shock; adequate provision shall be made for properly grounding the unit. The unit shall be located in a protected area with access to servicing personnel.

8.6 BATTERY CHARGE REGULATOR (BCR) GUIDELINE SPECIFICATION

8.6.1 TYPE

The BCR shall consist of: (1) solar array shunting circuits for modulating the solar array output, over that supplied to the DC/AC inverter, in accordance with a prescribed charging profile; (2) associated control circuits.

8.6.2 CHARGE PROFILE

The battery charge profile shall be controlled in relation to the voltage measured at the battery terminals. No limit shall be placed on the charging current provided by the solar array until a charge voltage of 240 volts is reached. At this level, the solar array current to the battery shall be modulated so that the voltage is maintained but not exceeded. This limit shall be maintained for two hours from the time the 240 volt level is reached and then reduced to a 230 volt trickle charge level. Should the two hour upper limit period be interrupted by a discharge which is less than 210 volts, a new two hour period shall be initiated.

The charge profile shall include an override trickle current limit at the C/100 rate if the battery temperature reaches 150 degrees F. The override shall be removed when the temperature drops to 110 degrees F.

8.6.3 DISCHARGE PROFILE

The battery shall be limited to a minimum discharge voltage of 172 volts. At this level the BCR shall turn off the DC/AC inverter so that all solar array power is devoted to battery recharge. The inverter shall be re-enabled when the full charge level of 240 volts is reached.

8.6.4 SOLAR ARRAY SHUNTING CIRCUITS

Solar array output modulation for charge control shall be achieved by sectionalizing the solar array and shorting out a certain number of sections to meet a particular output requirement. Transistor switches, either fully on or off, shall be utilized for shorting out the array sections which shall be sized according to binary proportions. The number of binary divisions shall be sufficient to effect current control within 3 percent of peak solar array current.

8.6.5 CONTROLS

The BCR controls shall include the necessary logic and sequencing for meeting the charge, discharge and temperature requirements outlined in the previous paragraphs.

PART B

CENTRAL POWER PLANT SYSTEM

PAGES i to ii
WERE INTENTIONALLY
LEFT BLANK

TABLE OF CONTENTS - PART B

<u>Section</u>		<u>Page</u>
1	SUMMARY AND CONCLUSIONS	B-1
1.1	Summary	B-1
1.2	Conclusions	B-6
2	CONCEPTUAL DESIGN	B-7
2.1	Introduction and Summary Descriptions	B-7
2.1.1	Overall Plant	B-8
2.1.2	Solar Azimuth Tracker	B-8
2.1.3	Low-Ratio Concentrator	B-9
2.1.4	Fixed Panel Array	B-9
2.1.5	Comparison of Concepts	B-10
2.2	Concept No. 1 - Solar Azimuth Tracker	B-11
2.2.1	Pontoon Concentrator	B-12
2.2.2	Pond	B-15
2.2.2.1	Pond Array	B-16
2.2.2.2	Sun Tracking System	B-17
2.2.2.3	Central Hub	B-18
2.2.2.4	Electrical Layout	B-20
2.2.3	Array Sector	B-21
2.2.4	Overall Array Layout	B-23
2.3	Concept No. 2 - Low-Ratio Concentrator	B-25
2.3.1	Basic Concentrator Geometry	B-25
2.3.2	Panel Designs	B-26
2.3.3	Array Sector	B-28
2.3.4	Array Field	B-28
2.4	Concept No. 3 - Fixed Panel Array	B-28
2.5	Plant Electrical Systems	B-31
2.5.1	Overall Plant Function	B-32
2.5.2	DC-AC Converter Station	B-32
2.5.3	Transformer Station	B-34
2.5.4	Switching Station	B-34
2.5.5	Plant Controls	B-35
3	PERFORMANCE ANALYSIS	B-37
3.1	Introduction	B-37
3.2	Analytical Models	B-37
3.2.1	System Model	B-37
3.2.2	Solar Azimuth Tracker	B-38
3.2.3	Low-Ratio Concentrator	B-45
3.2.4	Fixed Panel Array	B-48
3.3	Performance Analysis Results	B-48

TABLE OF CONTENTS - PART B (Cont'd)

<u>Section</u>	<u>Page</u>
4	ECONOMIC ANALYSIS B-53
4.1	Introduction B-53
4.2	Methodology B-53
4.3	Economic Analysis Input Data B-53
4.4	Economic Analysis Results B-54
4.4.1	Levelized Busbar Energy Cost B-54
4.4.2	Economic Impact on Utility Systems B-61
5	TECHNOLOGY NEEDS B-69
5.1	Introduction B-69
5.2	Array System Technology Needs B-69
5.2.1	Solar Cells B-69
5.2.2	Materials B-70
5.2.3	Pontoon Hermetic Sealing B-71
5.3	Plant Electrical Equipment B-71
6	BARRIERS B-73
6.1	Introduction B-73
6.2	Water Requirements B-73
6.3	Land Requirements B-74
6.4	Ecological Impacts B-75
6.5	Utility Load Patterns B-76
6.6	Capital Requirements B-78
6.7	Materials Requirements B-80

LIST OF ILLUSTRATIONS

<u>Figure</u>		<u>Page</u>
1-1	Comparison of Levelized Costs.	B-4
2-1	Solar Azimuth Tracker	B-9
2-2	Low-Ratio Concentrator	B-10
2-3	Pontoon Concentrator	B-13
2-4	Pontoon Cross Sectional View	B-13
2-5	Fluid Cooling of Solar Cells	B-14
2-6	Pontoon Electrical Circuit	B-15
2-7	Pond Layout	B-17
2-8	Hub Configuration	B-18
2-9	Pond Electrical Circuit	B-19
2-10	Pond Array Wiring Arrangement	B-20
2-11	Pond Lightning Protection	B-21
2-12	40-Pond Array Sector	B-22
2-13	10-Pond Circuit	B-23
2-14	Solar Azimuth Tracker Plant Layout	B-24
2-15	Concentrator/Solar Vector Geometry	B-25
2-16	Low-Ratio Concentrator Solar Array	B-27
2-17	Cross-Section, Low-Ratio Concentrator.	B-27
2-18	Low-Ratio Concentrator Array Sector Layout.	B-28
2-19	Low-Ratio Concentrator Plant Layout	B-29
2-20	Central Plant One-Line Diagram	B-33
3-1	System Model	B-37
3-2	Pontoon Collector Optical Losses	B-39
3-3	Pontoon Optical Characteristics	B-40
3-4	Concentrator Solar Cell Characteristics.	B-41
3-5	Concentrator Temperature Model	B-42
3-6	Power Conditioning Losses	B-43
3-7	Performance Analysis Printouts for 40-Pond Sector	B-44
3-8	Low-Ratio Concentrator Geometry	B-45
3-9	Low-Ratio Concentrator Temperature Dependence	B-48
3-10	Comparison of Monthly Output	B-51
3-11	Output Duration Curve.	B-51
4-1	Levelized Cost Determination	B-57
4-2	Levelized Busbar Energy Cost, Solar Azimuth Tracker	B-59
4-3	Levelized Busbar Energy Cost, Low-Ratio Concentrator	B-59
4-4	Levelized Busbar Energy Cost, Fixed Panel Array	B-60
4-5	Comparison of Levelized Busbar Energy Costs	B-60
4-6	Break-Even Costs for Central Power Plant Concepts	B-65
4-7	Solar Azimuth Tracker, Effect of Break-Even Costs	B-66
4-8	Fixed Panel Array, Effect of Break-Even Costs	B-67

LIST OF ILLUSTRATIONS (Cont)

<u>Figure</u>		<u>Page</u>
6-1	Utility Sales of Electricity to Residential, Commercial and Industrial Customers	B-77
6-2	Projected Demand for Copper	B-81
6-3	Projected Demand for Aluminum	B-82
6-4	Projected Demand for Concrete	B-82
6-5	Projected Demand for Glass.	B-83
6-6	Projected Photovoltaic Demand for Lexan	B-84
6-7	Projected Demand for Single Crystal Silicon for Photovoltaic Cells	B-84

LIST OF TABLES - PART B

<u>Table</u>		<u>Page</u>
1-1	Summary of Concepts	B-2
1-2	Central Power Plant Capital Costs	B-3
2-1	Comparison of Concepts	B-10
2-2	Pontoon Collector Characteristics	B-12
2-3	Pond System Characteristics	B-16
2-4	Fixed Panel Solar Array Characteristics	B-30
3-1	Array Sector Annual Output for Three Concepts	B-50
4-1	Central Power Plant Capital Costs	B-55
4-2	Annual O&M and Insurance Costs	B-56
4-3	Economic Analysis Assumptions	B-56
4-4	Example Calculation of Levelized Busbar Energy Cost	B-57
4-5	Central Power Plant Worth Analysis Results (Phoenix Location) . .	B-62

SECTION 1

SUMMARY AND CONCLUSIONS

SECTION 1

SUMMARY AND CONCLUSIONS

This volume (Part B) presents the results on the photovoltaic central power plant study. The study encompassed the development of conceptual designs, evaluation of their performance, determination of costs, identification of technology requirements, and an assessment of significant institutional and environmental impacts. For comparison purposes three power plant versions were evaluated: a 25 to 1 concentration ratio solar azimuth tracking system which utilizes pond-floated collectors; a 3.2 to 1 concentration ratio system requiring seasonal tilt adjustment; and a fixed array system consisting of east-west rows of southward tilted panels. The systems were evaluated for a site location in Phoenix, Arizona. A summary of the study is presented below followed by the major study conclusions.

1.1 SUMMARY

This portion of the overall study dealt with the conceptual design and evaluation of photovoltaic central power plants. Such plants, deployed over large land areas, would contribute directly to the bulk energy of utility grid systems. The analysis of such systems was carried out for a site location in the Phoenix, Arizona region.

Conceptual designs were developed without using dedicated plant energy storage. Through a combination of anticipatory data and management of the utility's generation and remote storage units, it was assumed that the time-varying nature of the photovoltaic plant output could be properly handled by the utility system without the smoothing provided by energy storage. Avoidance of dedicated energy storage was heavily influenced by the poor economic results obtained for the residence case (see appropriate sections of Part A) and by significant technical complexities uncovered during preliminary conceptual investigations. For these reasons it appeared more logical to consider energy storage from a broader utility system viewpoint where its use could be more economically justified as an element operating together with many generation sources.

To identify the dominant characteristics affecting photovoltaic plant performance and cost, three radically different conceptual designs were developed. This permitted the comparison of key factors and aided in determining where emphasis should be placed in future technological developments.

The first concept employs high-ratio (25 to 1) parabolic cylinder concentrators in the form of pontoons floated on a pond of water. A large quantity of uniformly aligned pontoons joined side by side form a circular array about 150 meters in diameter. The entire array is rotated on the pond surface about a central fixed hub slip ring assembly to track the azimuthal position of the sun, thereby concentrating the sun's rays along the focal line of each pontoon parabolic reflector. Solar cells mounted along the focal line convert the concentrated rays into electrical dc. The overall plant consists of a multiplicity of ponds, together with DC/AC converter, transformer and switching stations.

The second concept consists of low-ratio (3.2 to 1) concentrators whose tilt positions are adjusted semiannually to optimize the collection of solar energy. The concentrators, consisting of semiparabolic cylindrical reflectors with solar cells mounted on the axial plane, are arranged in east-west rows.

The third concept uses flat solar cell panels tilted 22 degrees above horizontal in a southward facing direction. The panels are also arranged in east-west rows with a row-to-row pitch distance of about 1.7 times the panel width to minimize morning and evening shadowing.

Analytical models were prepared for each concept which established the predicted behavior under varying illumination and environmental conditions. Performance analyses were conducted using hourly weather data for the Phoenix region for the year 1962. On the basis of unit area performance, the systems were relatively scaled to produce an equivalent annual output. Using nominal cell efficiencies, Table 1-1 summarizes the significant sizing parameters for each concept, corresponding to an output of 2.83×10^6 MWh.

TABLE 1-1. SUMMARY OF CONCEPTS

Concept	1	2	3
Description	Solar Azimuth Tracker	Low-Ratio Concentrator	Fixed Panel Array
Nominal Cell	11.8%	13.4%	13.4%
Cell Area	1.0 km^2	7.3 km^2	10.1 km^2
Collector Area	25.0 km^2	32.6 km^2	12.9 km^2
Land Area	50.0 km^2	39.3 km^2	24 km^2
Annual Performance	2.83×10^6 MWh	2.83×10^6 MWh	2.83×10^6 MWh
Plant Rating	1500 MW	1500 MW	1500 MW

Based on this tabulated data, and design definitions developed for each concept, capital costs were determined. Table 1-2 summarizes this information and indicates the relative contributions of the major subsystems.

Using a set of economic assumptions, and hypothesizing 30-year life for the systems, levelized busbar energy costs (LBEC) were determined. These were analyzed considering variations in solar cell efficiency, solar cell cost, substrate and reflector costs and discount rates. Figure 1-1 compares the LBEC for the three concepts against solar cell cost expressed in \$/peak kW, using 12.5 and 25 percent efficient solar cells. Although 25 percent cells are probably not attainable, their use here illustrates the relative effect of higher efficiencies on the several concepts considered. Included for comparative purposes are results for the no-battery residence case.

TABLE 1-2. CENTRAL POWER PLANT CAPITAL COSTS

	(In millions of dollars)		
	Concept No. 1 Solar Azimuth Tracker	Concept No. 2 Low-Ratio Concentrator	Concept No 3 Fixed Panel Array
Array System			
Land (at \$500/hectare)	\$ 2.5	\$ 2.0	\$ 1.2
Site Preparation and Development	116.1	18.5	12.4
Solar Cells (at \$50/m ²)	50.0	365.0	505.0
Solar Collectors	852.9	789.3	306.6
Misc. (Support, Array Cabling, etc.)	133.4	347.5	231.7
Subtotal	1154.9	1522.3	1056.4
Electrical Plant System			
Converter Stations (50) Bldg and Equip.	105.6	105.6	105.6
Transformer Stations (5) Bldg and Equip.	15.0	15.0	15.0
Switching Station (1) Bldg and Equip.	6.5	6.5	6.5
Plant Control Center Bldg and Equip.	2.5	2.5	2.5
Underground Cabling and Conduit	11.3	11.3	11.3
Towers and Fixtures, Switching Station	1.0	1.0	1.0
Yardwork	0.8	0.8	0.8
Subtotal	<u>142.7</u>	<u>142.7</u>	<u>142.7</u>
Total (Major Components, Labor and Material)	1297.6	1665.0	1199.6

Figure 1-1. Comparison of Levelized Costs

As an adjunct to LBEC determinations, several independent analyses were undertaken to establish the worth of photovoltaic central power plants from a utility viewpoint. Starting in 1985, it was assumed that photovoltaic systems were gradually introduced into an Arizona utility to displace about five percent of the peak capacity by the year 2000. Using projections of load and generation growth and a nominal escalation scenario, break-even capital costs were determined to be \$380/kW of PV plant output for the fixed panel array and \$420/kW for the solar azimuth tracker (1975 dollars). With a more pessimistic set of economic assumptions (higher inflation) the worth improved to \$490/kW and \$540/kW respectively. Translating the worth into terms of hardware costs, the following conclusions emerged, assuming the use of 15 percent efficient cells: for the solar azimuth tracker (Concept 1), collector and associated installation costs must be reduced to a value of \$25/m² with an allowable cell cost up to \$200/m² (\$1330/kW_{pk}); for the flat panel array concept the cells must cost \$35/m² (or \$233/kW_{pk}) for an assumed panel/installation cost of \$25/m²; no such analysis was performed for the low ratio concentrator approach because of its poor showing on the levelized busbar energy cost analysis.

An assessment was made of the key impacts and barriers confronting the implementation of photovoltaic central power plants. These are summarized below:

Penetration Rate. By the year 2000, it is estimated that the sunbelt region of the U.S. will have a generating capacity of 520,000 MW, of which 265,000 MW will represent new capacity installed from the year 1985. Considering the lags inherent in introducing new technologies,

it is estimated that photovoltaics could fill five percent of the new market or about 2.5 percent of the total capacity. This translates roughly into 20 plants of the pond-floated type described in this report, occupying a total land area of 1000 square kilometers.

Water Requirements. For pond-floated plants located in the southwest where evaporation rates are high, it is believed that the use of monomolecular films or floating particulates could reduce makeup water requirements to acceptable levels. It is also possible that the use of industrial waste water or brackish water could relieve any burden on fresh water supplies. Further study is needed to resolve this issue, preferably in the context of specified site locations and conditions.

Land Requirements. The land requirements for photovoltaic plants are substantial. As mentioned earlier, projected total land requirements for photovoltaic plants in 2000 are approximately 1000 km².

One possibility for reducing the impact of the land and water requirements is to give serious consideration to the use of existing structures and bodies of water. Spent coal strip mines and open-pit copper mines exist in Arizona. Such areas are large and poor quality water is usually available on-site. As another alternative, the flat alluvial plain of the Colorado River could be used along with water from the irrigation return flow of the Imperial Valley or the Wellion-Mohawk Irrigation District. The flow would provide enough water for seven photovoltaic plants. Such possibilities offer ways of rehabilitating stripped mine lands as well as creating economic use of waste water.

Environmental Aspects. The plant design must consider the possible impact of environmental effects. Accumulation of wind-blown sediment might have to be removed periodically. In the case of the pond-floated concept, the several foot pond depth should minimize the frequency for such maintenance. The ponds themselves may attract birds and other wildlife. Surface films used for evaporation control would alleviate this problem. High-voltage electrified grids used presently for cow fences and on building facades could also be employed for this purpose. The high coverage of the pond surface may promote anaerobic conditions. Some degree of water circulation and treatment would avoid this problem along with discouraging infestation by insects.

1.2 CONCLUSIONS

1. Assuming the achievement of national cost goals for solar cells (\$500/peak kW), the 30-year levelized busbar energy cost of photovoltaic central power plants located in the Phoenix region falls in the range of \$.03/kWh to \$.05/kWh. The LBEC of high-ratio (25 to 1) concentration systems is fairly independent of solar cell cost, but almost directly dependent on solar cell efficiency, while for flat-plate arrays the LBEC is more closely proportional to cell costs. Because of the insensitivity to cell costs, concentration systems offer a more economic near-term approach for implementing photovoltaic systems. Of the three solar array concepts evaluated, low-ratio (3.2 to 1) concentrators are least cost-effective.

2. To achieve economic parity with conventional generation, concentrator systems should strive toward collector costs of \$25/m² including the costs of site preparation, installation, and sun-tracking. For concentration ratios of 25:1 and greater, cell costs up to \$200/m² appear acceptable. For fixed panel solar arrays, solar cell costs of \$200 to \$250 per peak kW appear to be the appropriate cost range, providing the combined panel and installation costs do not exceed \$25/m².
3. Analysis indicated the feasibility of photovoltaic integration without specifically dedicated energy storage. A combination of long-term and short-term anticipatory determinations of plant output should permit satisfactory utility system operation while avoiding the extreme expense of energy storage, although further studies on this aspect of generation control are required.
4. The land requirements for concentrator systems are about twice that for flat-plate systems. Although land costs are trivial in relation to the other plant costs, use of the large areas required will have an impact on the local ecology. Resistance to their use is likely from public interest groups. The use of existing or discarded industrial lands may minimize such objections. In conjunction with the water floated concentrator concept, methods for minimizing the rate of evaporation will be required. A combination of evaporation control (e.g., use of monomolecular films), the use of low quality brackish or saline water, or siting plants near coastal regions or areas of water abundance would relieve any burden on fresh water supplies.
5. Photovoltaic plants will require large capital investments. However, in contrast with other forms of generation, e.g., nuclear plants, the modular nature of photovoltaic plants will permit immediate startup as each section is completed. Thus, the construction period for the total plant has an equivalence of half that amount in terms of useful plant output and the ability of the plant to produce income.
6. A rough estimate indicates that by the year 2000, the sunbelt region of the U.S. will have a generating capacity of about 520,000 MW. Assuming a 50 percent capacity factor, this is equivalent to delivering 2.28×10^9 MWh of electrical energy. Photovoltaic plants could potentially fill 2.5 percent of this capacity. Twenty plants of the pond floated type, each producing an annual output of 2.83×10^6 MWh, would be required (total land area equal to 1000 km²). Considering the ERDA goal of emplacing 30,000 MW of photovoltaic capacity by the year 2000, no significant material problems were uncovered.
7. Technology needs have been identified for higher than normal efficiency solar cells, low-cost concentrators and reliable long-life materials. The needs for the plant electrical equipment will be satisfied by the normal evolution of device development, particularly with regard to their use in emerging high voltage dc-transmission systems. Specific developments will be required to adapt these devices and their controls to the characteristics of photovoltaic systems. Although the development of concentrators is considered to fall within the scope of available technology, significant efforts are required to perfect designs which can be mass produced at low cost.

SECTION 2

CONCEPTUAL DESIGN

SECTION 2

CONCEPTUAL DESIGN

2.1 INTRODUCTION AND SUMMARY DESCRIPTIONS

Conceptual designs provide the basis for estimating system performance and cost. In view of the lack of any real precedents or guiding philosophy on the design of large area photovoltaic systems, it was decided to give attention to several design approaches rather than concentrating all effort on a single approach. This, it was felt, would provide a better overall perspective and would result in several benchmarks against which various ideas and results could be evaluated. To provide breadth to the final study results, three somewhat different solar array concepts were developed:

1. A 25:1 geometric concentration ratio approach utilizing pond-mounted parabolic troughs
2. A 3.2:1 low ratio concentrator approach requiring seasonal tilt angle adjustments
3. A fixed array approach using east-west rows of tilted panels.

These concepts represented different implementations for the solar array field of the overall plant. In other respects, mainly regarding converter and transformer equipment, a single approach was utilized. Some of the basic assumptions and ground rules used in developing the overall plant concept are noted below:

1. The photovoltaic power plant is assumed to be located in the southwestern region of the U.S. Specifically, weather data for Phoenix, Arizona for the year 1962 were used as the basis for performance calculations.
2. Solar array performance is based on silicon solar cells. As described later, point designs were based on using particular cell characteristics, although the results were extended to include varying cell efficiencies.
3. No energy storage is included in the power plant. It appeared more reasonable to consider storage in a non-dedicated sense as an aspect of the overall utility system with each storage element considered as an electrical link that could provide energy to or accept energy from a variety of sources. The behavior of such elements involves a complex interplay with the utility system's generation units and load demands. On this basis, storage cannot be properly evaluated as operating exclusively with photovoltaic generators. For these reasons, development of the photovoltaic central power plant concepts proceeded without considering the use of energy storage.
4. Plant output requirements were assumed to be about 10,000 MWh daily. This number only served as a rough guideline in developing the concepts. Once the plant characteristics were defined, the plant could be scaled up or down to meet a specific

rating. This was the approach taken in defining the concepts described in the following section. An arbitrary size for each concept was first established, then performance output for that size was determined, and finally the plant sizes were adjusted so that all concepts produced the same annual energy output. Cost comparisons were then made on an equivalent energy basis.

Following is a summary description of the overall plant followed by brief descriptions of each of the solar array field concepts.

2.1.1 OVERALL PLANT

The overall plant, nominally rated at 1500 MW consists of 50 solar array sectors. The photovoltaic output of each sector is fed to a DC/AC converter station centrally located within the sector. Converter station ratings (30 MW) have been selected which optimize the combined cost of solar array cabling and converter equipment sizing.

The outputs of ten converter stations are fed through underground cabling at 69 kilovolts to a transformer gathering station. Five such stations are required for the overall plant. The power at these stations is transformed to 345 kilovolts, for delivery to a switching station, and thence to the interface with the utility system grid.

It is clear that the plant as described is modular in nature allowing its size to be increased or decreased as needed. The overall plant has been nominally laid out in rectilinear fashion. Many deviations from this pattern are of course possible to suit particular topographical features.

2.1.2 SOLAR AXIMUTH TRACKER

The principle behind this concept is illustrated in Figure 2-1. Parabolic trough collectors in the form of pontoons are joined side by side and floated on a pond to form a large circular array. The entire array is rotated about a fixed central hub so that the vertical plane through the pontoon parabola axis follows the azimuth of the sun. In this position the sun's rays are concentrated along the parabola focal line. Solar cells mounted along the focal line receive the solar energy at a geometric concentration ratio of 25 to 1. The floating array contains 1064 1 x 11.8 meter pontoon collectors and fits within a 152 meter diameter pond. The electrical output is fed through a slip ring at the hub and thence through underground cables. Rotation of the pond is achieved by water jet pumps mounted at the periphery of the array which produce a thrust of 12 newtons (2.7 lbs). Each pond nominally produces an output of 0.75 MW. A cluster of forty ponds forms one of the solar array sectors described for the overall plant. The forty-pond cluster is interconnected into four parallel strings, each with ten ponds in series. The resulting input to the converter station occurs nominally at 13 kilovolts. A 40-pond sector occupies a land area of 0.96 square kilometers.

Figure 2-1. Solar Azimuth Tracker

2.1.3 LOW-RATIO CONCENTRATOR

This concept uses a 3.2 to 1 low ratio concentrator whose basic geometry is illustrated in Figure 2-2. Radiant energy striking a cylindrical semi-parabolic surface is reflected onto solar cells mounted on the focal plane web formed between the apex and the focal line of the parabolic cylinder. As long as the direction of incoming light is within the limits shown, the reflected light will strike the solar cell surface. Beyond these limits, any reflected rays will strike the focal plane above the focal line. For the geometry shown, with the aperture opening horizontal, all direct solar energy is captured for the half-year from September 21 to March 21. For the period from March 21 to September 21, direct energy collection is optimized by tilting the aperture opening 37 degrees upward from horizontal in the northward direction. The collector also captures all diffuse energy within the sector of the sky between the aperture and focal planes.

The solar array field sector feeding one converter station consists of 91,168 collector panels having a total collector area of 0.651 square kilometers. The sector occupies a land area of 0.763 square kilometers.

2.1.4 FIXED PANEL ARRAY

This concept consists of east-west rows of flat solar cell panels tilted at 22 degrees above horizontal in a southward direction. A row-to-row pitch distance of 1.7 times the panel

Figure 2-2. Low-Ratio Concentrator

width is used. The total panel area for each solar array field sector serving one converter station is 0.26 square kilometers; the sector occupies a land area of 0.48 square kilometers.

2.1.5 COMPARISON OF CONCEPTS

A summary comparison of the three concepts, each employing fifty solar array sectors, is shown on Table 2-1.

TABLE 2-1. COMPARISON OF CONCEPTS

Concept	1	2	3
Description	Solar Azimuth Tracker	Low-Ratio Concentrator	Fixed Panel Array
Nominal Coll	11.8%	13.4%	13.4%
Cell Area	1.0 km ²	7.3 km ²	10.1 km ²
Collector Area	25.0 km ²	32.6 km ²	12.9 km ²
Land Area	50.0 km ²	39.3 km ²	24 km ²
Annual Performance	2.83 x 10 ⁶ MWh	2.83 x 10 ⁶ MWh	2.83 x 10 ⁶ MWh
Plant Rating	1500 MW	1500 MW	1500 MW

Detailed descriptions of each concept are presented in the following sections together with other plant systems common to all three concepts.

2.2 CONCEPT NO. 1 - SOLAR AZIMUTH TRACKER

As summarized previously, the solar azimuth tracking concept employs a circular array of pond-mounted solar collectors. The basic advantages of this approach are enumerated below:

Uniform Mounting Surface. The pond water level provides a uniform mounting surface for deployment of the solar collectors. This reduces the extent of site preparation that would otherwise be required for hard-mounted solar collectors.

Low Friction Bearing. The water is virtually frictionless in terms of the rotational torques required.

Cooling. The water can be used for solar cell cooling purposes either by conductive coupling, heat pipes, or circulation through fluid passages.

Tracking Mechanisms. A single tracking mechanism can serve the total number of pontoon collectors contained in one pond, thereby reducing costs considerably.

Elimination of Flexing Cables and Rotating Joints. Fixed electrical and mechanical connections are made between all pontoons eliminating the complexity and wearout associated with flexing and rotating joints.

Reduced Wind Load. The aperture of each pontoon collector always remains in a horizontal position resulting in an exposed height above the water surface of no more than 25 cm. The consequent reduction in wind loading greatly relieves structural requirements.

Lightning Protection. Because of the azimuth tracking characteristic, lightning protection poles and overhead wires can be located on the rotating array to always avoid the casting of shadows across the collector apertures.

The basic disadvantages are as follows:

Water Requirements. Water makeup is required to offset evaporation losses. This concern is site dependent and may be potentially relieved with the use of evaporation retardants (mono-molecular films or floating particulates) and the use of more abundant supplies of untreated or brackish water.

Performance Penalty. A penalty in output results with the fact that the solar collectors are constrained to a horizontal position. Other studies for azimuth tracker systems indicate optimum collector tilt angles at about 50 degrees above horizontal. It is judged that the sacrifice in performance is justified by a greater than compensating cost reduction which results with the horizontal low-profile pond approach.

2.2.1 PONTOON CONCENTRATOR

A summary of the pontoon characteristics is presented on Table 2-2.

TABLE 2-2. PONTOON COLLECTOR CHARACTERISTICS

Gross Dimensions	1.1m wide x 11.9 m
Aperture Width	1.0 m
Aperture Length	11.8 m
Concentration Ratio	25 to 1
Collector Focal Length	.25 m
Solar Cells	2 x 10 cm, 11.8% efficiency (1kW/m ² insolation, 28°C, AMI)
Number of Cells	2 rows, 116 series cells each
Overall Weight	1100 kg

As shown on Figures 2-3 and 2-4, the pontoon collector consists of a 1.1 x 11.9 meter concrete parabolic trough with a reflective inner surface. Concrete was selected because of its low cost and stability. A curved Lexan cover seals the collector against the entry of dirt and moisture. A double row of series connected solar cells is mounted along the focal line by means of a fin structure supported along the groove of an electrically insulating rail located at the bottom of the trough. A longitudinal rail attached to the underside of the Lexan cover centrally locates the fin assembly at its proper focal position. Upon attachment to the concrete hull the Lexan cover is sprung slightly to maintain a downward force on the fin assembly. The fin is free to move with respect to the bottom and top rails to permit thermal expansion and is also notched periodically to allow differential expansion due to the temperature gradient from the top to the bottom of the fin.

Heat rejection from the solar cells is achieved by combined radiation and convection from the fin surface. The attractiveness of this approach lies in the fact that the cell-fin assembly is well insulated electrically from the pontoon hull permitting the use of large voltage buildups. Preliminary analysis has not resolved whether the heat can be effectively rejected by this means. Alternative arrangements might employ fluid loop or heat pipe cooling along the focal line as indicated on Figure 2-5. A 0.6 mm polypropylene layer between the cell/fin assembly and fluid pipe provides the necessary electrical insulation. A combination of clamping and the use of a heat sink compound (e.g., silicone grease) insures that adequate thermal conduction is achieved. The fluid loop cooling has the additional advantage of providing potentially useful thermal heat.

Electrically the pontoons are interconnected by short cables between end-to-end pontoons. Many pontoons are wired in series to develop the desired high voltage output.

Figure 2-3. Pontoon Concentrator

Figure 2-4. Pontoon Cross Sectional View

Figure 2-5. Fluid Cooling of Solar Cells

The pontoons are structurally interconnected by lugs built into the hull. The two-hole lugs provide a rigid interconnection between side by side pontoons forming a raft configuration which is insensitive to roll motions. Possibly every fourth pontoon in a lateral direction would be joined with a single pin to permit some degree of structural flexibility.

The lugs are extended beyond the sides of the pontoon to provide a space of about 0.3 meter between adjacent pontoons. Planks spanned across the lugs provide a walkway for servicing and maintenance.

The solar cell layout in each pontoon consists of two rows of 116 series solar cells mounted on each leg of the Y at the top of the fin. The cells are electrically insulated from the fin by anodizing its surface. This is sufficient since the fin itself is well insulated from ground.

Besides providing structural support and rejecting heat, the fin serves as a bypass conducting path for certain shading conditions due to the end partitions. The upper sketch on Figure 2-6 shows the geometry of this effect. Depending on the sun elevation angle, a number of the solar cells near the partition will be shaded. This is indicated on the lower sketch where, for example, an elevation angle of 30 degrees will shade the first eight series connected cells. To permit operation under this condition, bypass diodes are introduced to divert the current through the fin. As shown, five such diodes are sufficient to overcome the blocking effect while reasonably minimizing the loss of power.

Figure 2-6. Pontoon Electrical Circuit

Analysis for locating the bypass diodes established the fact that all rays crossing the horizontal lip of the end partition converge at a single point along the focal line as shown on the upper sketch. On one side of the single point all cells are shaded, while on the other side all cells are uniformly illuminated. The location of the cutoff point from the partition is simply defined by $(2f + h) \cot \alpha$ where f is the focal length of the parabolic collector and h is the height of the horizontal partition lip above the focal line. The actual curvature of the partition described on Figures 2-3 and 2-4 tends to smear the sharpness of the cutoff point so that some light is actually received on the cells ahead of the point calculated by the above formula.

A bypass diode is also introduced at the negative terminal for completely bypassing the pontoon string in the event of an open circuit failure within the pontoon.

2.2.2 POND

A summary of the pond system characteristics is presented on Table 2-3.

TABLE 2-3. POND SYSTEM CHARACTERISTICS

Pond Diameter/Area	152 meters/18,150 m ²
Collector Aperture Area	12,550 m ²
Packing Factor	69%
Number of pontoons	1064 (28 series by 38 parallel)
Array Mass	2.3 x 10 ⁶ kilograms
Array Inertia	6.5 x 10 ⁹ kg-m ² (array-only) 1.4 x 10 ¹⁰ kg-m ² (including rotating mass of water)
Maximum Torque	880 Newton-meters (11.7 Newton thrust at rim)
Azimuth Tracking Accuracy	± 1/4 degree
Hub Load with 160 KPH Wind	110,000 Newtons
Nominal Output Voltage	1300 Volts
Nominal Peak Current	575 Amperes
Pond Water Makeup	8 liters/minute

2.2.2.1 Pond Array

The size and arrangement of the pond array is determined by the quantity of pontoons required to develop a nominal peak output of 0.75 MW, selected as the basic energy-developing module size.

In the course of identifying the system concept during this design study, a number of electrical configurations were considered resulting in various mechanical arrangements. The layout shown on Figure 2-7 was the most attractive of those considered.

The pond array consists of 1064 pontoon collectors arranged within a 152 meter pond. The 38 pontoon circuits shown are electrically paralleled with their outputs routed through nine additional pond arrays in series to a hub slip ring, and then underground to a DC/AC converter station.

The pond profile indicates that a depth of 0.5 meter is more than sufficient to accommodate the pontoons which will sink below the water level about 15 cm. Depending on the terrain on which the ponds are erected, it may be necessary to use a water barrier, such as 0.5 mm polyvinyl chloride plastic sheeting overlaid with a protective layer of sand, to minimize seepage losses. Brackish water would be suitable as the basic pond fluid. A pond water makeup of 20 liters per minute is estimated as the averaged annual requirement in the Phoenix region including credit for accumulated rainfall. Use of monomolecular films or floating particulates could significantly reduce the makeup rate. The distributed pontoons over the pond surface would tend to stabilize the film against wind shearing action.

Figure 2-7. Pond Layout

Access to the pond array for servicing and maintenance is provided by a main walkway to the hub and by smaller secondary walkways between the pontoon rows. Rails for supporting a maintenance cart that would span across several pontoon rows could also be incorporated.

2.2.2.2. Sun Tracking System

Sun tracking is accomplished by water thrusters located near the periphery of the array which receive on-off signals from an angular positioning control located at the hub. The array tracks the sun during the day within $\pm 1/4$ degree and continues its rotation through the night to be in the proper position the following morning. An analysis of the tracking requirements and the strategy for meeting these requirements is discussed in Appendix G. Basically, the control logic will involve: (1) programmed inputs defining the sun's azimuth in terms of angular position, velocity and acceleration; (2) means for comparing the programmed inputs with the actual motion parameters; (3) actuation of the water thrusters in response to measured errors.

The maximum angular acceleration of the pond array occurs at noon on June 21 and is calculated to be 6.28×10^{-8} radians per sec.². The inertia of the array, including the rotating mass of water, is estimated to be about 1.4×10^{10} kg-m². To provide the necessary torque, the water thrusters located at a radius of 75 meters must only provide a thrust of 12 Newtons (2.7 lbf), including allowance for water and bearing friction. Other torque requirements arising from wind and interaction with the earth's magnetic field were found to be negligible.

2.2.2.3 Central Hub

In considering the design for the solar array drive and tracking system, it was determined that the mechanization must be such that it could be continuously rotated through 360° . This decision dictated that slip rings be used for bringing the dc energy off the array as well as taking AC auxiliary power onto the platform. With this constraint in mind, the center pier has been designed to provide a stable pivotal structure about which the array may be rotated, a bearing to permit this rotation, the necessary slip rings for electrical power transmission across the rotating axis and a protective housing. The design concept to accomplish these functions is depicted in Figure 2-8.

Figure 2-8. Hub Configuration

The concrete base for the hub assembly would be designed to withstand the overturning torque developed by the force of a 160 km/hr (100 mph) wind on the pontoons. The exact size of the pier will depend upon the nature of the soil at the installation site but for conceptual design purposes, it was assumed to be down 3.5m (12 ft) below the bottom of the pond and have a base diameter of 25m (8 ft).

A large pair of primary bearings - approximately 108 cm (42 in.) in diameter - is used to radially position the array and permit rotation about the center axis. As shown, the inner races of these bearings are fitted to a sleeve which can slide vertically on a mating cylinder that is fixed atop the concrete pier. Keying between these two elements prevents relative rotation of the two members. This feature is necessary to accommodate possible variations in water level caused by excessive evaporation or heavy rainfall.

The requirement for 360° rotation of the array dictates some complexity in the transmission of electrical energy across the pivotal joint. The high dc current is taken from the array by large, state-of-the-art slip rings 28 cm (11 in.) in diameter. A spiral of cable within the hub allows for changes in pond water level. These cables are taken out through a center well in the pier to buried polyvinyl chloride ducts radiating from the pond's center. AC power required on the array is taken across the rotating interface by a small, three-ring assembly. A shaft encoder is integrated into the hub structure to provide feedback information for the positioning control system. Communication between the control units for the individual ponds and the central computerized command system is effected by means of a multiplexed signal transmitted over a coaxial cable. A coaxial rotary joint is utilized at the juncture.

An environmental housing of plastic, such as polycarbonate, protects the hub assembly from the elements. It also maintains a desirable separation distance between any personnel present and the high voltage dc circuits in this area. Atop the housing is mounted an arrester rod which is grounded to the base of the pier to minimize the possibility of damage from lightning strikes.

Figure 2-9. Pond Electrical Circuit

2.2.2.4 Electrical Layout

As described later in Section 2.2.3, ten ponds are wired in series, five above a center ground point and five below. The electrical circuit for a single pond array is shown on Figure 2-9 for ponds operating above ground potential. Negative operating ponds are similar except for the interchange of the diode and fuse elements.

Thirty-eight pontoon circuits of 28 pontoons each are used in the pond array. The negative and positive terminals of these circuits are joined together and routed through the hub slip ring. Each pontoon circuit is protected by 1 to 7 isolation diodes on its end farthest from ground potential (the number of diodes depends on the pond operating voltage with respect to ground), and by a fuse on its end closest to ground potential. These devices serve to prevent damage in case of a fault to ground at some point along the pontoon circuit. The diodes prevent the back-flow of current from the remaining 37 pontoon circuits through the faulted circuit. The fuse provides interruption of large forward currents being dissipated to the ground fault. A large forward in-rush is possible because of the bypass diodes built into each pontoon circuit described earlier in Section 2.2.1. Thus, a fault to ground somewhere along the 28-pontoon circuit results in a high current which harmlessly bypasses the solar cells until it is interrupted by the fuse. Because the cells are mounted on a fin structure which also serves as the bypass conductor, any fault to ground would most likely involve a breakdown of insulation between the fin structure and ground, avoiding any high current path through the cells themselves.

Figure 2-10. Pond Array Wiring Arrangement

The physical layout of the string circuits is shown on Figure 2-10. This layout represents one of several possible arrangements for achieving the matrix of paralleled pontoon strings within the circular array boundary. Further refinements could strive for improved packing density and shortened cable runs, while at the same time maintaining an ordered layout for ease of maintenance and servicing.

A concept for the lightning shield network is shown on Figure 2-11. Posts, 2.7 meters high, are erected along every fourth pontoon row and overhead shield wires strung to create a tent zone of protection. Because of the azimuth tracking rotation, neither the posts nor overhead wires cast shadows on the pontoon collectors. The wires are cabled through the slip ring to the hub pier ground electrode. By extending the posts into the pond water, an additional path of conduction is provided. Appendix H discusses lightning considerations for this application.

Figure 2-11. Pond Lightning Protection

2.2.3 ARRAY SECTOR

An array sector consists of the cluster of ponds feeding a single DC/AC converter station.

A nominal layout of the pond cluster is shown on Figure 2-12. The cluster consists of four strings of ten series ponds each feeding their output to a centrally located DC/AC converter station. Interconnecting the ponds in series so that the interconnected loop returns to its starting point achieves economy in the amount of cabling required and minimizes voltage

drop. The central location of the DC/AC converter station equalizes the lengths of loop cabling for each 10-pond string. The particular layout shown provides high utilization of the land area because of the close packing of the pond circles. A distance of about 11 meters between pond edges has been included for road access and to provide sufficient earth mass for the pond banks. A straight central road is provided for direct access to the converter station.

Figure 2-12. 40-Pond Array Sector

The circuit for a single ten-pond series string is shown on Figure 2-13. The midpoint of the string is tied to earth ground with five ponds above ground and five below ground. A bare cable underground network ties the grounding points of all ponds together. With each pond rated nominally at 1300 Vdc, the overall string operates at ± 6500 Vdc. The most extreme ponds operate nominally from 5200 to 6500 Volts above or below ground. Thus, a fault to ground within these extreme ponds requires that the 28-pontoon circuit protective diodes withstand inverse voltages of these magnitudes. Diodes are commercially available with PIV ratings of 1000 Volts. Thus, about seven series diodes would be required for adequate protection on the extreme ponds. Lesser quantities are required for the ponds closer to ground potential.

Figure 2-13. 10-Pond Circuit

2.2.4 OVERALL ARRAY LAYOUT

The layout of array sectors (40-pond clusters) forming the overall power plant, is shown on Figure 2-14. Each ten-sector group delivers its output to a step-up transformer station located along a 240-meter wide zone in which the 345 kV transmission powers are located for carrying the power to a 345 kV switching station, which is the interface with the utility grid.

Figure 2-14. Solar Azimuth Tracker Plant Layout

2.3 CONCEPT NO. 2 - LOW-RATIO CONCENTRATOR

2.3.1 BASIC CONCENTRATOR GEOMETRY

As explained previously in Section 2.1 and Figure 2-2, the low-ratio concentrator selected for the concept uses a semiparabolic cylindrical reflector. The reflected rays impinge on the focal plane surface between the parabola apex and focal lines. The distribution of light reaching the solar cell surface will be non-uniform because of the non-focussing optical characteristics. By paralleling solar cells, the effects of non-uniform illumination are minimized. Each cell within the paralleled group operates at the same voltage with its current contribution essentially in proportion to the illumination it receives. Compartmenting of the low-ratio concentrator, described later in Paragraph 2.3.2, is specifically used to delineate the paralleled groups. The compartments are then wired in series for voltage buildup.

The projection of the solar vector onto the concentrator cross-sectional plane (vertical/south plane for the concentrator axis oriented in an east-west direction) varies widely over the period of one year and therefore the concentrator must be adjusted several times during the year to most effectively gather the solar energy.

Figure 2-15 provides a graphic means for determining this projection of the solar vector for any season and time of day. From this information the best tilt of the non-focussing concentrator can be estimated.

Figure 2-15. Concentrator/Solar Vector Geometry

The projection is simply determined by drawing a line from the hour point for a particular date to the origin of the plot. An example of the projected vector is shown for 8 A. M. on December 21. The slope of the date lines is determined by the latitude. At the equator, for example, the entire plot would be rotated until the date lines were vertical. The particular slope shown pertains to the 33 degree latitude at Phoenix.

Examination of the plot reveals that all projected vectors from September 21 through March 21 fall within the acceptance angle for the aperture opening of the concentrator positioned horizontally. This single position suffices therefore for this entire six-month period. The axis of the concentrator is tilted slightly higher than the March 21 date line to assure that the incoming energy is never sharply focussed at the focal point.

Beyond March 21, the date lines reveal that the sun rises in the northern hemisphere with an increasing range of projected angles over the period of a single day. To both accommodate the increased range and its bias toward the northern hemisphere the concentrator may be tilted in several steps as shown. Projection of the concentrator axis (extension of the web line) shows the time of day at which satisfactory acceptance angles are achieved. At the intermediate position, for example, satisfactory acceptance angles are reached after 8 A. M. on April 21. The highest tilt is required to reach this condition at 8 A. M. on June 21.

From the above, it may be concluded that winter operation can be accomplished with no tilt adjustment, while summer operation may involve several adjustments. For the purpose of analyzing this collector concept in Phoenix, the aperture plane was tilted upward 37 degrees once on March 21 and reset at the horizontal position on September 21.

2.3.2 PANEL DESIGNS

Incorporation of the low-ratio concentrator into a panel configuration is shown on Figures 2-16 and 2-17. Each panel contains 16 compartments, each consisting of a semiparabolic reflector, a group of paralleled solar cells mounted on the focal plane segment, and mirrored end partitions which reflect the solar energy entering at low elevation angles during the morning and evening hours. The optical path results in all incoming energy (within the acceptance angle limits) ultimately reaching the solar cell surface. This arrangement duplicates the output from compartment to compartment allowing them to be wired in series.

The compartment has an aperture opening area of 0.4 m^2 (25 x 160 cm) and a cell area of 0.1 m^2 . The 16 compartments are wired in series as shown with the terminal leads located near the panel hinge point for ease of cable interconnection with the next adjacent panel. A bypass diode between the output leads allows all current to be bypassed in the event of an open circuit failure.

Figure 2-16. Low-Ratio Concentrator Solar Array

Figure 2-17. Cross-Section, Low-Ratio Concentrator

As indicated on the cross-sectional view, air passages are designed into the panel for natural convection cooling of the front and rear solar cell surfaces.

A ganged tilt mechanism allows many panels to be manually tilted at one time. The tilt is adjusted several times yearly.

2.3.3 ARRAY SECTOR

The layout of the array sector feeding the DC/AC converter station is shown on Figure 2-18. Forty-four panel strings are used, each containing 2072 series panels. Each string is protected with series isolation diodes at the positive and negative terminals.

2.3.4 ARRAY FIELD

The array field for Concept No. 2, shown on Figure 2-19, is similar to the layout shown earlier for Concept No. 1. The smaller array sector area reduces the overall plant area to 39.3 km².

2.4 CONCEPT NO. 3 - FIXED PANEL ARRAY

This concept was considered on a cursory basis for comparison with Concept Nos. 1 and 2. The system is based on the results obtained for the residence system without energy storage (See Section 3 of Part A).

Figure 2-18. Low-Ratio Concentrator Array Sector Layout

Figure 2-19. Low-Ratio Concentrator Plant Layout

The array consists of east-west rows of flat solar cell panels tilted southward 22 degrees above horizontal, the optimum value determined for the residence located in the Phoenix region. The total panel area is scaled upward from the residence roof area to produce the same annual energy output as the other two concepts. Land area is determined by assuming that the rows are spaced at a pitch distance of 1.7 times the panel width, or, in effect, the land area occupied by the solar array is 1.7 times the panel area. Ten percent additional land area is allocated for roads, transmission tower zones and other service needs. In other respects the plant layout is identical with the other concepts and uses the same number of converter and transformer stations.

In scaling the system from the residence results, the annual residence output was first adjusted upward to remove the effect of the 87 percent residence inverter efficiency and then downward by 3 percent to account for inverter and transformer losses. An upward adjustment of 4.5 percent was also included to account for the lower temperature operation of panel mounted solar cells with back surface natural convection cooling. The scaling calculations are summarized below:

$$\begin{aligned}
\text{Residence Annual Output} &= 20339 \text{ kWh} \\
\text{Adjusted Residence Output} &= \frac{20339 \times .97 \times 1.045}{.87} \\
&= 23700 \text{ kWh} \\
\text{Power Plant Annual Output} &= 2.83 \times 10^6 \text{ MWh} \\
&\quad (\text{See Section 3.2 for determination of Concept No. 1 performance}) \\
\text{Scaling Factor} &= \frac{2.83 \times 10^9 \text{ kWh}}{2.370 \times 10^4 \text{ kWh}} = 1.2 \times 10^5 \\
\text{Residence Solar Cell Area} &= 84 \text{ m}^2 \\
\text{Power Plant Solar Cell Area} &= 1.2 \times 10^5 \times 84 \text{ m}^2 \\
&= 10.1 \text{ km}^2
\end{aligned}$$

Using the factors enumerated above, the physical characteristics for Concept No. 3 are summarized on Table 2-4.

TABLE 2-4. FIXED PANEL SOLAR ARRAY CHARACTERISTICS

- Considered for Comparative Purposes with Concepts 1 & 2 Using Residence Results for Phoenix
- East-West Rows Tilted at 22°
- Row Spacing: $1.7 \times$ Panel Width
- Overall Panel Area: $12.9 \times 10^6 \text{ m}^2$
- Overall Cell Area: $10.1 \times 10^6 \text{ m}^2$
(Packing Factor = 78%)
- Land Area: 24 km^2
- Performance: Same as Concept No. 1 Using 13.4% Efficient Cell (100 mw/cm^2 , 28°C AM1)

2.5 PLANT ELECTRICAL SYSTEMS

The plant electrical systems have the function of converting the photovoltaic output from dc to ac at acceptable voltage and frequency conditions and then inserting the ac power into the electric bulk power grid through trunk transmission lines. The plant is designed to operate at the peak power point of the solar array. As solar array temperature and illumination conditions vary, the converter station characteristics are adjusted so that power is drawn from the array at the maximum power voltage and current. Operation at off-peak conditions may be optionally exercised as dictated by plant load/dispatch requirements.

The approach for providing these functions is to centrally locate a DC/AC converter station within each array sector, gather and channel the outputs of a number of such converter stations through distributed transformer stations, and then deliver high voltage power to the utility grid through an interfacing switching station.

The sizing of the converter and transformer stations was arrived at through a practical balance of performance, equipment availability, design constraints, and overall costs. In developing the plant electrical arrangement, a number of design variations were considered. Starting with a single pond array, it would have been possible to allocate a single DC/AC converter for its use. This would certainly increase the modular character of the plant, and might be more appropriate for a plant having a substation level of output power. However, considering the power magnitude of a central power plant, it is more economical to apply larger array segments to a single converter station, recognizing that larger array areas involve increased costs in cabling the dc array power to the converter station. The 40-pond array sector described previously has appropriately optimized the combination of cabling and converter station costs.

A key factor in establishing the array sector/converter station configuration has been to consider the use of fairly high solar array operating voltages. Both cabling and converter station costs diminish in inverse proportion to the voltage level and therefore high voltage operation is extremely desirable. The upper limit on voltage is imposed by the practical design characteristics of the solar array. The nominal 13 kilovolt level (± 6.5 kV about ground potential) selected appears to be achievable without severe design penalties for the pontoon array concept as defined. Since less attention was given to this question for the other array system concepts considered, some modification in voltage level might be in order.

The following summary descriptions of the plant electrical systems for the solar azimuth tracker concept are given in a logical progression of the overall plant function, the converter station, transformer station, switching station, and plant control. Appendix I presents a more detailed breakdown of the numerous subsystems required, along with drawings defining the physical and electrical characteristics. This electrical plant description applies to all three array system concepts.

2.5.1 OVERALL PLANT FUNCTION

As shown on Figure 2-20, the dc electrical output of each solar array sector is brought to a converter station centrally located in the sector. Using solid-state, bridge-connected valves, direct current is converted to three phase alternating current at 69 kilovolts (kV) and 60 Hz for forwarding to the transformer station by underground cable. At the transformer station the output of ten converter stations (two groups of five) is gathered, connected, and transformed from 69 kV to 345 kV, suitable for long distance transmission to the utility grid.

The output of each transformer station (5 total) is carried by overhead power line "double-circuit" transmission towers to a centrally located 345 kV switching station. The switching station gathers the total plant output and provides coordinated power switching and circuit protection. The output terminals of the 345 kV switching station serve as the interface with the utility system. A utility transmission line carries the plant electrical energy to the connection/insertion point of the electric utility bulk power grid, similar to that of other large power generating plants on the utility system.

2.5.2 DC-AC CONVERTER STATION

The converter station accepts direct current electric energy generated by the 40-pond solar array. The power is delivered to the converter station by four 600 Ampere parallel-connected circuits, each comprised of ten pond-arrays connected in series. (Thus, the maximum direct current to the converter is 2400 Amperes).

The DC-AC converter consists of a "line-commutated" inverter employing solid state thyristor-type valves in a twelve pulse configuration. Specifically, two series six-pulse bridges are connected to Y and Δ secondaries of a 3-phase transformer. Variations in solar cell temperature and incident light intensity cause attendant variations of input voltage and current to the dc-ac converter. These variations must be accommodated by the converter, while optimizing power output and providing an acceptable ac output voltage and frequency. DC input voltage range has been defined as 13 kV to 15 kV, and peak power output is 30 Mw. A current range of 240 to 2400 Amperes is accommodated by the converter. The lower limit is established by the converter valve (thyristor) characteristics. The addition of a 1/10th size valve and reactor assembly could reduce this limit significantly although higher costs would be involved.

The converter station valve assembly feeds alternating current to the converter transformer which steps the voltage up to 69 kV at 60 Hz.

The converter transformer is equipped with a "Load Tap Changer" (LTC) which modifies the effective transformer turns ratio and operates during loaded conditions. The LTC functions to accommodate changes in solar array output voltage and assures that the converter operates at its optimum "firing angle".

Figure 2-20. Central Plant One-Line Diagram

DC circuit breakers are included to disconnect the inverter from the solar array in the event that the converter is disabled temporarily by an ac system fault. The dc circuit breakers also provide protection for the converter in the event of faults in the dc bus or valves.

DC smoothing reactors minimize ripple currents and maintain electromagnetic radiation from the solar array circuits within acceptable limits.

Filters connected to the ac bus absorb current harmonics generated in the converter. The ac wave shape is thereby kept within acceptable harmonic content limits for the utility grid and associated plant equipment. The ac harmonic filter equipment also serves as a power factor correction device since it consists of shunt capacitors (as well as resistor and inductive reactor components). Each harmonic filter counterbalances the inherent lagging power factor characteristic of the converter valve and transformer equipment.

The converter station output, at 69 kV and a maximum current of 450 Amperes is transmitted by underground cable to the transformer station.

The converter station, once commissioned, operates automatically. All switching, startup and shutdown are directed and monitored by a small computer system in conjunction with other converter and station control equipment. Converter control equipment automatically adjusts the power output to the maximum power point of the solar array.

2.5.3 TRANSFORMER STATION

The transformer station gathers the power output of 10 converter stations, connects these circuits into a reliable switching arrangement, and transforms the ac power from 69 kV up to 345 kV. This is done by physically and electrically arranging and connecting standard electrical equipment into the desired configuration. The electrical configuration provides reliability by a "breaker and a half" scheme 69 kV switchyard. A single contingency outage can be sustained in the 69 kV switchyard without loss of power output capability. Two transformers each accommodating the output of five converter stations operate independently of each other. If one transformer fails, the input of its associated (5) converter stations can be switched by the 69 kV bus connecting breakers to route the power through the remaining transformer. This contingency switching, however, will limit the transformer station output to approximately 170 MW peak, and 130 MW continuous station output. Transformer station operation is automatic.

2.5.4 SWITCHING STATION

The switching station provides centralized 345 kV circuit connection and switching facilities for optimum reliability of plant power output. The "breaker and a half" scheme employed can sustain any single contingency 345 kV switchyard fault without reduction in plant output capability.

2.5.5 PLANT CONTROLS

Control of the principal power plant functions will be exercised from a centrally located control center. The nature of these functions is discussed below:

1. Solar Azimuth Tracking. As described earlier in Section 2.2.2.2, the azimuthal position of the pond arrays will be determined by data transmitted from a centrally located computer which establishes the required dynamic characteristics of the pond arrays as a function of time. Comparing the position of each pond array provides the error signal for actuating the controls located at each pond.
2. Solar Array Maximum Power Point Tracking. Operating the solar array at its proper voltage and current conditions to produce maximum output will be contingent upon instructions derived from a central control. Certain modes of plant operation may require the production of maximum possible power. In this case automatic controls located at each converter station will adjust converter operation to the maximum power solar array voltage and current conditions. In other modes of operation less than peak power production may be required as dictated by particular load/dispatch requirements. In this case central control signals would direct the converter to receive solar array power at higher voltages, resulting in reduced current.
3. Anticipatory Power Production. The integration of the photovoltaic plant into the overall utility generation system will require that load dispatchers have a reasonable knowledge of how the plant is expected to perform as a function of time. This would permit the proper planning and scheduling of other generation units. Since plant performance is so dependent on weather conditions, weather prediction will play a key role in this planning function. Long-term predictions would serve for such purposes as planned outages. Regional weather data would probably suffice for this purpose. Short-term effects, as might be caused by passing clouds, would require a somewhat different response in terms of how an impending power shortage from the photovoltaic plant would be handled. As presently visualized, illumination sensors deployed in outlying circumferential zones would anticipate impending outages, in sufficient time to allow proper compensating steps to be taken. Because of the large plant size it is difficult to imagine that inclement weather could abruptly interrupt plant operation. Under very severe conditions, it would more reasonably take from 15 to 30 minutes before plant output was totally disrupted. This probable gradualness in power output, combined with the anticipatory sensing should provide sufficient time for making the necessary system adjustments.
4. Miscellaneous Controls & Instrumentation. A variety of other plant controls and instrumentation will be required. These pertain to such items as reconfiguring circuit breakers for bypassing units under repair, monitoring the status of various units, controlling water pumps, providing communications, and the like.

SECTION 3
PERFORMANCE ANALYSIS

SECTION 3

PERFORMANCE ANALYSIS

3.1 INTRODUCTION

The analysis of the three conceptual designs described in Section 2 follows the methods used for the residence photovoltaic systems treated in Part A. Hourly weather data serve as the input to analytical models representing the system elements, to produce system performance in terms of instantaneous status or as integrated output over specified time periods.

3.2 ANALYTICAL MODELS

3.2.1 SYSTEM MODEL

A single overall system model is used in conjunction with analyzing each of the solar array concepts. The model block diagram is shown in Figure 3-1 indicating the use of a maximum power tracking DC/AC converter and step-up transformer in conjunction with the solar array. No energy storage is used and therefore the solar array output flows directly into the utility grid.

The maximum power point of the solar array varies dynamically with illumination intensity and solar array temperature. The analysis program for this arrangement employs a set of

Figure 3-1. System Model

solar cell data which establishes the maximum power point in terms of voltage and current for the illumination and temperature conditions defined for each hour.

3.2.2 SOLAR AZIMUTH TRACKER

The pontoon collector of the solar azimuth tracker concept is only sensitive to the direct component of solar flux. Because of the high concentration ratio used, diffuse sky radiation contributes negligibly to the electrical output. Since the collector aperture is always maintained horizontally, the direct component of the solar flux on a horizontal surface represents the energy reaching the collector. The output from one 2 x 10 cm solar cell in the pontoon collector is defined by the following expression:

$$P_C = H_{DIR} \times A_C \times K_T \times K_R \times K_D \times K_S \times h_C \quad (1)$$

where,

P_C = 2 x 10 cm solar cell output, Watts

H_{DIR} = direct component of solar flux on a horizontal surface, Watts/m². H_{DIR} is obtained by separating it from the total insolation incident on a horizontal surface (H_{TO}) as read from the hourly weather data, using a curve fit of the results of Liu and Jordan (See Section 3.3.1, Part A).

A_C = portion of pontoon collector aperture area devoted to one cell. Each aperture half of 0.5 meters serves one row of cells. The aperture area (A_C) for one 10-cm cell is therefore .05 m².

K_T = pontoon cover transmittance. Using Lexan as the cover window material, Figure 3-2a provides the transmittance characteristic. For the pontoon with its horizontal cover window, the incidence angle θ is determined by the day, hour and location as follows:

$$\cos \theta = \sin \delta \sin \phi + \cos \delta \cos \omega \cos \phi \quad (2)$$

where,

δ = Solar declination

ϕ = Site latitude (north positive)

ω = Hour angle (zero is solar noon)

K_R = parabolic surface reflectance. A value of 0.92 is selected as representative of high quality surfaces.

Figure 3-2. Pontoon Collector Optical Losses

K_D = dispersion loss factor. This factor expresses the percentage of the reflected energy which reaches the solar cells at the focal line as a function of the incidence angle. Figure 3-2b shows this dependence for the selected design characteristics of the pontoon collector and is based on the analytical considerations presented in Appendix J.

K_S = shading loss factor. As explained under paragraph 2.2.1, a number of cells in the pontoon circuit are progressively shaded by the end partition as the incidence angle increases. Although the shading will result in a stepwise change in output as incremental groups of cells are shaded, the smoothed curve of Figure 3-2c is used for performance calculation purposes. The combined effect of K_T , K_R , K_D and K_S is shown on Figure 3-3. Also shown is the combined effect for a split parabola configuration. As explained in Appendix J, its poorer performance at the larger incidence angles is due to increased dispersion losses. Its consideration was ruled out for this reason.

η_c = solar cell efficiency. Data from the Sandia Corporation for high concentration ratio solar cells provided the basis for determining efficiency. These data are summarized on Figure 3-4 showing cell output (kW/m^2) and cell voltage at the maximum power point as a function of energy flux reaching the solar cells and solar cell temperature. In using this plot, the energy flux reaching the solar cells is obtained from equation (1), excluding the solar cell efficiency term.

Figure 3-3. Pontoon Optical Characteristics

Figure 3-4. Concentrator Solar Cell Characteristics

The determination of solar cell temperature is based on a heat balance calculation involving the removal of heat developed at the solar cells. Preliminary analysis has been carried out considering several heat removal methods. Figure 3-5 shows the analytical results in terms of cell temperature versus flux reaching the cells for several cases: (1) use of a heat pipe located along the focal line which transfers the heat to the pond water; (2) the direct transfer of heat through the pontoon walls using the split parabola pontoon configuration; (3) passive removal of heat by rejection from the fin surface support structure.

Case 1 with the heat pipe was used for the system performance analysis. A pond sink temperature of 38°C was used which represents a rough estimate of the annual average pond temperature. More sophisticated analysis in connection with a companion study (EPRI Photovoltaic Mission Analysis) indicates that substantially lower pond temperatures may be expected. Thus, the performance results described later are conservatively low.

Case 2 using the split parabola pontoon configuration, yields lower solar cell temperatures. However, its high dispersion loss precluded the use of this concept.

Case 3 which rejects heat passively from the support fin surface, was not as thoroughly analyzed because of difficulties in establishing the various thermal interactions involved. As indicated on Figure 3-5, its temperature is anticipated to be higher than the other two cases. Its main advantage lies in its ease of physical integration with avoidance of fluid interfaces and its ability to provide excellent electrical insulation. For these reasons, a more detailed thermal analysis would be warranted.

Figure 3-5. Concentrator Temperature Model

Using the cell output resulting from the above analytical models, the overall plant output is established by proper scaling, according to the series-parallel matrix of solar cells, i.e., using 116 series by 2 parallel cells in each pontoon, 28 series by 38 parallel pontoons in each pond, and so on.

The solar array output is modified downward to take account of power conditioning and cabling losses. Figure 3-6 shows efficiency plots for the converter and transformer stations which represent the estimated performance characteristics for the equipment described earlier in Section 2.5.

A straight two percent loss is assumed for cabling. This represents a conservative assumption in that the cabling was sized for this loss at the peak current output. The loss, of course, reduces in proportion to the square of the current ratio.

A parasitic loss of 8 MW is used for operating plant auxiliaries (7 MW) and for water make-up pumping (1 MW). These losses pertain to the overall plant size comprised of 2000 ponds.

Computer assisted calculations of the above analytical models are carried out on an hour by hour basis using weather tape data supplied by the Aerospace Corporation for the Phoenix region for the year 1962. Typical hour by hour printouts of results are shown in Figure 3-7 for winter and summer days.

Figure 3-6. Power Conditioning Losses

MON	DAY	HR	SOLAR ARRAY POWER (MW)	SOLAR ARRAY VOLTAGE (KV)	SOLAR CELL TEMP. (C)	SYSTEM OUTPUT (MW)	FLUX ON HORIZ. (KW/M**2)	FLUX ON CELLS (KW/M**2)
2	1	0	0.	0.	46.667	0.	0.	0.
2	1	1	0.	0.	46.667	0.	0.	0.
2	1	2	0.	0.	46.667	0.	0.	0.
2	1	3	0.	0.	46.667	0.	0.	0.
2	1	4	0.	0.	46.667	0.	0.	0.
2	1	5	0.	0.	46.667	0.	0.	0.
2	1	6	0.	0.	46.667	0.	0.	0.
2	1	7	0.	0.	46.667	0.	0.100	0.000
2	1	8	0.525	12.975	47.518	0.427	0.353	0.235
2	1	9	6.647	14.682	57.433	6.435	0.282	2.973
2	1	10	14.566	14.574	70.216	14.304	0.453	6.668
2	1	11	20.168	14.062	83.431	19.624	0.373	9.636
2	1	12	23.182	13.592	84.325	22.792	0.536	11.252
2	1	13	23.301	13.895	84.478	22.909	0.535	11.316
2	1	14	20.591	14.037	81.021	20.241	0.571	9.862
2	1	15	15.545	14.481	71.983	15.270	0.457	7.180
2	1	16	7.934	14.667	59.443	7.758	0.285	3.544
2	1	17	0.859	13.646	48.652	0.759	0.359	0.385
2	1	18	0.	0.	46.667	0.	0.000	0.000
2	1	19	0.	0.	46.667	0.	0.	0.
2	1	20	0.	0.	46.667	0.	0.	0.
2	1	21	0.	0.	46.667	0.	0.	0.
2	1	22	0.	0.	46.667	0.	0.	0.
2	1	23	0.	0.	46.667	0.	0.	0.
2	2	0	0.	0.	46.667	0.	0.	0.
2	2	1	0.	0.	46.667	0.	0.	0.
2	2	2	0.	0.	46.667	0.	0.	0.
2	2	3	0.	0.	46.667	0.	0.	0.
2	2	4	0.	0.	46.667	0.	0.	0.
2	2	5	0.	0.	46.667	0.	0.	0.
2	2	6	0.	0.	46.667	0.	0.	0.
2	2	7	0.	0.	46.667	0.	0.000	0.000
2	2	8	0.526	12.936	47.520	0.429	0.361	0.236
2	2	9	6.297	14.689	56.871	6.140	0.285	2.918
2	2	10	14.434	14.592	70.555	14.223	0.448	6.625
2	2	11	19.938	14.033	80.017	19.595	0.544	9.510
2	2	12	22.956	13.994	84.035	22.569	0.629	11.130
2	2	13	22.187	13.891	84.332	22.797	0.630	11.254
2	2	14	20.511	14.041	80.919	20.162	0.567	9.819
2	2	15	15.363	14.498	71.632	15.039	0.449	7.085
2	2	16	7.646	14.669	59.032	7.573	0.272	3.416
2	2	17	0.831	13.603	48.616	0.731	0.355	0.373
2	2	18	0.	0.	46.667	0.	0.000	0.000
2	2	19	0.	0.	46.667	0.	0.	0.
2	2	20	0.	0.	46.667	0.	0.	0.
2	2	21	0.	0.	46.667	0.	0.	0.
2	2	22	0.	0.	46.667	0.	0.	0.
2	2	23	0.	0.	46.667	0.	0.	0.
2	3	0	0.	0.	46.667	0.	0.	0.
2	3	1	0.	0.	46.667	0.	0.	0.
2	3	2	0.	0.	46.667	0.	0.	0.
2	3	3	0.	0.	46.667	0.	0.	0.
2	3	4	0.	0.	46.667	0.	0.	0.
2	3	5	0.	0.	46.667	0.	0.	0.

WINTER DAY

MON	DAY	HR	SOLAR ARRAY POWER (MW)	SOLAR ARRAY VOLTAGE (KV)	SOLAR CELL TEMP. (C)	SYSTEM OUTPUT (MW)	FLUX ON HORIZ. (KW/M**2)	FLUX ON CELLS (KW/M**2)
7	1	0	0.	0.	46.667	0.	0.	0.
7	1	1	0.	0.	46.667	0.	0.	0.
7	1	2	0.	0.	46.667	0.	0.	0.
7	1	3	0.	0.	46.667	0.	0.	0.
7	1	4	0.	0.	46.667	0.	0.	0.
7	1	5	0.	0.	46.667	0.	0.	0.
7	1	6	0.292	11.514	47.140	0.197	0.331	0.181
7	1	7	5.251	14.714	55.194	5.111	0.208	2.357
7	1	8	14.844	14.548	70.709	14.574	0.425	6.501
7	1	9	22.624	13.923	83.619	22.242	0.567	10.150
7	1	10	27.451	13.533	90.413	27.186	0.713	12.766
7	1	11	35.817	13.832	95.396	35.360	0.796	15.584
7	1	12	32.504	13.197	97.682	31.957	0.817	16.718
7	1	13	32.732	13.178	98.056	32.186	0.814	16.847
7	1	14	31.275	13.295	95.773	30.769	0.819	16.935
7	1	15	27.954	13.559	90.853	27.485	0.722	13.565
7	1	16	21.751	13.371	82.535	21.382	0.569	10.448
7	1	17	13.622	14.546	68.851	13.571	0.334	6.381
7	1	18	6.235	14.593	56.772	6.175	0.208	2.731
7	1	19	0.469	12.523	47.427	0.372	0.267	0.286
7	1	20	0.	0.	46.667	0.	0.	0.
7	1	21	0.	0.	46.667	0.	0.	0.
7	1	22	0.	0.	46.667	0.	0.	0.
7	1	23	0.	0.	46.667	0.	0.	0.
7	2	0	0.	0.	46.667	0.	0.	0.
7	2	1	0.	0.	46.667	0.	0.	0.
7	2	2	0.	0.	46.667	0.	0.	0.
7	2	3	0.	0.	46.667	0.	0.	0.
7	2	4	0.	0.	46.667	0.	0.	0.
7	2	5	0.	0.	46.667	0.	0.	0.
7	2	6	0.	0.	46.672	0.	0.000	0.000
7	2	7	3.050	14.765	53.655	3.551	0.167	2.657
7	2	8	10.827	14.656	63.737	10.605	0.304	4.882
7	2	9	21.265	13.999	81.377	20.935	0.567	10.292
7	2	10	27.955	13.538	90.333	27.133	0.712	12.759
7	2	11	35.824	14.658	95.653	35.429	0.801	15.596
7	2	12	25.512	13.757	87.344	25.074	0.607	12.811
7	2	13	25.404	13.765	87.210	24.978	0.601	12.844
7	2	14	17.582	14.294	75.849	17.258	0.416	8.214
7	2	15	17.856	14.265	76.241	17.577	0.435	8.415
7	2	16	21.704	13.973	82.472	21.366	0.569	10.442
7	2	17	15.560	14.523	71.179	14.831	0.437	6.917
7	2	18	2.703	14.804	61.133	2.609	0.117	2.034
7	2	19	0.216	13.974	47.021	0.112	0.021	0.007
7	2	20	0.	0.	46.667	0.	0.	0.
7	2	21	0.	0.	46.667	0.	0.	0.
7	2	22	0.	0.	46.667	0.	0.	0.
7	2	23	0.	0.	46.667	0.	0.	0.
7	3	0	0.	0.	46.667	0.	0.	0.
7	3	1	0.	0.	46.667	0.	0.	0.
7	3	2	0.	0.	46.667	0.	0.	0.
7	3	3	0.	0.	46.667	0.	0.	0.
7	3	4	0.	0.	46.667	0.	0.	0.
7	3	5	0.	0.	46.667	0.	0.	0.

SUMMER DAY

Figure 3-7. Performance Analysis Printouts for 40-Pond Sector

3.2.3 LOW-RATIO CONCENTRATOR

Analysis of the low-ratio concentrator follows a pattern similar to that of the solar azimuth tracker with modifications introduced to reflect different concentrator characteristics. The defining equation is given by:

$$P_C = H_T \times A_C \times K_T \times K_R \times h_C \quad (1)$$

where the terms are similar to those used for the azimuth tracker approach except as noted below.

P_C is the output (watts) from one panel compartment containing a cell area of 1000 cm^2 . (Recall from Section 2.3.2 that each panel contains 16 series compartments each containing an aperture area of 4000 cm^2 and a cell area of 1000 cm^2).

H_T is the total radiation, within the acceptance angle limits, incident on the concentrator aperture and is given by the following equation (See Figure 3-8 as an aid in defining the terms):

Figure 3-8. Low-Ratio Concentrator Geometry

$$H_T = H_{DIR} R_{DIR} \left[\text{within limits: } \beta < \alpha < (\alpha_o + \beta) \right] + H_{DIF} \frac{1 - \cos \alpha_o}{2} \quad (2)$$

where,

H_{DIR} = direct component of solar flux on a horizontal surface as defined previously in Section 3.2.2

R_{DIR} = factor to correct H_{DIR} to that crossing the aperture opening

H_{DIF} = diffuse component of solar flux on a horizontal surface (See Section 3.3.1, Part A)

α_o = concentrator acceptance angle

α = sun elevation in vertical-south plane

β = angle between horizontal and plane of aperture opening of the concentrator.

The factor R_{DIR} is given by:

$$R_{DIR} = \frac{\cos \theta_i}{\cos \theta_j}$$

where θ_i is the angle of incidence on the aperture plane and θ_j is the angle of incidence on a horizontal surface. These terms have been previously defined as functions of the hour, day and location as described in Section 3.3.1 of Part A.

The limits applied to H_{DIR} R_{DIR} are defined by the aperture plane tilt angle (β) and the concentrator acceptance angle (α_o). As long as the sun elevation angle (α) in the vertical-south plane is within these limits, there is a contribution by direct solar energy. Outside these limits the contribution is zero. The angle α is given by:

$$\tan \alpha = \frac{\cos \delta \cos \omega \cos \phi + \sin \delta \sin \phi}{\cos \delta \cos \omega \sin \phi - \sin \delta \cos \phi}$$

where δ , ω and ϕ are declination, hour and latitude angles respectively.

In calculating H_{DIR} R_{DIR} , the following limits were used:

Period	Acceptance Angle, α_0	Aperture Opening Tilt
Sept. 21 to March 21	64°	0°
March 21 to Sept 21	64°	37° northward tilt

The contribution of diffuse energy is determined by modifying the entire skydome contribution H_{DIF} by $\frac{1 - \cos \alpha_0}{2}$ which represents the contribution within the concentrator acceptance angle.

Returning to the remaining terms of equation (1):

A_C is the effective aperture area. The compartment aperture area is 4000 cm^2 ($25 \times 160 \text{ cm}$). The solar cells are mounted with a packing efficiency of 89 percent, and therefore only 89 percent of the energy passing the aperture opening reaches the solar cells. Thus, the effective aperture area is 3560 cm^2 . The projected area on the aperture plane (See Figure 2-2) is 3200 cm^2 .

K_T is the compartment cover transmittance. For a Lexan cover window, Figure 3-2a applies.

K_R is the parabolic surface reflectance. As in the pontoon case, a value of 0.92 is used.

η_C is the solar cell efficiency. The Solarex Corporation V-I data described in Section 3.3.1 of Volume II provides the basis for determining η_C as a function of solar flux and cell temperature. Solar cell output is expressed in terms of power and voltage at the maximum power operating point. The flux is not uniformly distributed over the solar cells in one compartment. However, since the cells in a single compartment are electrically paralleled, the output is dependent on the integrated flux rather than the flux distribution. In calculating the solar cell output, several minor effects have been ignored: (1) temperature variations resulting from the non-uniform flux distribution; (2) additional reflection losses on the compartment and partitions occurring mainly during morning and evening hours.

The dependence of cell temperature with the average flux reaching the cells is shown in Figure 3-9.

The remaining steps for calculating system performance are similar to those described for the solar azimuth tracker. The compartment output is scaled upward by the matrix of series-parallel compartments, and losses for power conditioning and cabling are taken into account.

Figure 3-9. Low-Ratio Concentrator Temperature Dependence

3.2.4 FIXED PANEL ARRAY

Performance analysis of this concept is based on using the results for the Phoenix residence (See Section 3.3 of Volume II). Adjustments are made for differences in solar array temperature and power conditioning losses, and the array area is then scaled upward to produce an annual energy output equivalent to that of the azimuth tracker system.

The east-west rows of tilted panels used in this concept will experience some self-shading during the morning and evening hours. At a row-to-row pitch distance of 1.7 times the panel width analysis indicates that the losses are negligible.

3.3 PERFORMANCE ANALYSIS RESULTS

Computer simulation results for the three solar array concepts are summarized on Table 3-1. As shown, the annual output of 2.83×10^6 KWH is identical for the three systems although

the monthly contributions vary slightly because of differences in the optical and thermal characteristics. Figure 3-10 graphically compares these monthly outputs on a normalized basis. The falloff of the azimuth tracker system in the winter months is attributable to the higher average value of the incidence angle and correspondingly higher transmission and optical dispersion losses. In addition to energy output results, Table 3-1 includes monthly values of maximum power, the voltage at maximum power, and the operating voltage range. These parameters were used to define the operating characteristics for the DC/AC converter equipment.

The output-duration curves of Figure 3-11 indicate the relative generation of power for the three concepts as a function of accumulated hours. As shown, the fixed panel array produces power for a larger number of hours, although the other two systems indicate higher generation levels for the shorter number of hours. Since the systems have been sized to produce the same annual energy, the average power generation is the same in all cases. These curves are useful for establishing the rating of the power conditioning equipment. Although the three concepts have estimated peak outputs ranging from 1600 to 1750 MW, the curves indicate that a power conditioning limit of 1500 MW would result in a negligible loss of output. This was the basis for rating all concepts at 1500 MW.

TABLE 3-1. ARRAY SECTOR ANNUAL OUTPUT FOR THREE CONCEPTS

Month	1. Solar Azimuth Tracker					2. Low-Ratio Concentrator			3. Fixed Panel Array		
	Energy		Min. Power, MW	Max. Power Voltage, kV	Voltage Range, kV	Energy		Max. Power, MW	Energy		Max. Power, MW
	MWh	Normalized				MWh	Normalized		MWh	Normalized	
J	2712	0.0458	23.74	13.86		4262	0.0721	27.46	4213	0.0713	26.50
F	3117	0.0526	29.03	13.47		4370	0.074	34.40	4131	0.0699	30.76
M	4963	0.0838	32.80	13.17		5634	0.0954	32.50	5452	0.0923	32.00
A	6338	0.1070	32.79	13.17		5495	0.0950	24.46	5682	0.0962	26.28
M	7394	0.1250	34.00	13.08	10.5	6120	0.1016	27.70	6084	0.1030	26.42
J	3600	0.1113	33.84	13.09	10	4323	0.0715	23.66	3292	0.0896	22.81
J	7180	0.1212	33.81	13.09	14.8	5250	0.0889	24.46	5376	0.0944	24.44
A	6691	0.1113	31.39	13.29		5471	0.0926	22.31	5445	0.0922	23.21
S	1713	0.0795	30.40	13.36		4201	0.0711	25.52	1549	0.0770	25.18
O	4530	0.0764	27.97	13.36		5748	0.0973	28.10	4960	0.0840	24.86
N	2845	0.0480	22.90	13.31		4163	0.0705	25.21	3952	0.0668	23.16
D	2257	0.0381	18.59	14.20		3636	0.0613	23.17	3737	0.0633	22.74
Total, MWh/year	59252	1.0000				59073	1.0000		59073	1.0000	
50 Sector Output, MWh/year	2962600					2953660			2953660		
Cabling Loss, %	-59252					-59072			-59072		
Parasitic Loss (7 MW x 8760 hrs)	-61320					-61320			-61320		
Pumping Loss (1 MW x 8760 hrs)	-8760					-			-		
Net Plant Output, MWh/yr	2833268					2833268			2833268		

*These sector outputs (X 50) represent peak plant generation:

Concept 1 - 1700 MW

Concept 2 - 1720 MW

Concept 3 - 1600 MW

Figure 3-10. Comparison of Monthly Output

Figure 3-11. Output Duration Curve

SECTION 4

ECONOMIC ANALYSIS

SECTION 4

ECONOMIC ANALYSIS

4.1 INTRODUCTION

Economic analysis of the central power plant concepts is considered from two points of view. First, using a discounted cash flow analysis, levelized busbar energy cost (\$/kWh) is determined on the basis of system performance, capital costs, operating and maintenance costs, and a set of economic and financing assumptions appropriate for a utility-owned enterprise. The levelized busbar energy cost (LBEC) results permit a direct comparison with conventional busbar costs. Second, considering the inclusion of the photovoltaic plant as a generating unit in a utility system, the generated output is evaluated in terms of its worth to the utility. This latter analysis establishes the worth independently of the photovoltaic plant capital costs. Rather, it establishes the capital cost goal at which photovoltaic systems become economically attractive.

4.2 METHODOLOGY

The basic methodology for determining LBECs has been previously described in Section 4.2 of Part A. Essentially, the following steps are involved:

1. Initial cash outlays (capital costs) are determined.
2. Annual revenue requirements (sales) are established for covering all expenses including taxes, interest on debt (bonds), return on equity (stock), sinking fund for retiring the debt, and other items such as operating and maintenance costs, and insurance.
3. The present value of all future costs is computed and then levelized over the system lifetime. Using the annual energy output of the plant, levelized cost per kWh is determined.

The worth of photovoltaic generation to utility systems is determined by computer analysis utilizing operations research techniques developed by GE's Electric Utility Systems Engineering Department. Using projected load and generation growth for a particular region (the region served by the Arizona Public Service Utility was used in this study), present worth calculations are developed without considering the use of photovoltaic generation. Then, the present worth calculations are repeated considering a particular photovoltaic penetration scenario. Comparing the two sets of calculations the break-even capital cost of the photovoltaic system is determined. Appendix D contains the descriptive narrative and detailed data associated with these calculations.

4.3 ECONOMIC ANALYSIS INPUT DATA

The cost and economic factors used in the economic analysis are described below.

The summary of capital costs for the three system concepts is shown on Table 4-1. The following assumptions were used in developing the capital costs:

1. Solar cell efficiencies were taken to be 11.8% for the solar azimuth tracker and 13.4% for the low-ratio concentrator and fixed panel array concepts. These efficiencies pertain to bare cell output at 1 kW/m² illumination, 28°C, and AM1 conditions. The point designs described in Section 2 reflect the use of these efficiencies.
2. Unassembled solar cells were assumed to cost \$50/m². (As shown in later sensitivity results, both cell cost and efficiency are varied parametrically.)
3. The capital costs of the other major components, labor and material were derived from numerous sources. The plant electrical equipment costs were based on a plant rating of 1500 MW. Appendix K contains the detailed cost breakdowns and supporting data.
4. Shipping costs were assumed to constitute five percent of the major component, labor and material (MLM) costs. This was charged against all items except the concrete hulls of the solar azimuth tracker pontoon assemblies. The hulls were assumed to be manufactured on-site in a plant set up especially for this purpose.
5. Design costs were assumed to be 0.5 percent of the MLM costs. This low value was justified on the basis of the highly repetitive nature of the plant equipment.
6. Project management costs were assumed to be five percent of the MLM costs.

Operating and maintenance (O&M) costs and insurance costs for the three concepts are summarized in Table 4-2. Supporting data for the O&M costs are also contained in Appendix K.

The economic assumptions used in developing LBECs are enumerated in Table 4-3. To determine the LBEC per kilowatt-hour, an annual plant output of 2.83×10^6 MWh is used as established by the performance analyses for all three concepts.

4.4 ECONOMIC ANALYSIS RESULTS

4.4.1 LEVELIZED BUSBAR ENERGY COST

As shown in Figure 4-1, different conversion factors are used to determine the LBECs associated with initial capital expenditures, and operation and maintenance expenditures. Using a discounted cash flow analysis, Appendix C develops these conversion factors as a function of the before-tax discount rate. The example calculation shown on Table 4-4 illustrates how the combined LBEC is determined for Concept No. 1.

TABLE 4-1. CENTRAL POWER PLANT CAPITAL COSTS (IN MILLIONS OF DOLLARS)

Cost Element	Concept No. 1 Solar Azimuth Tracker	Concept No. 2 Low-Ratio Concentrator	Concept No. 3 Fixed Panel Array
Array System			
Land @ \$500/hectare	\$ 2.5	\$ 2.0	\$ 1.2
Site Preparation & Development	116.1	18.5	12.4
Solar Cells @\$50/m ²	50.0	365.0	505.0
Solar Collectors	852.9	789.3	306.6
Misc. (Support, Array Cabling, etc.)	133.4	347.5	231.7
Subtotal	1154.9	1522.3	1056.4
Plant Electrical Equipment			
Converter Stations			
Bldg. & Eqpt. (50)	105.6	105.6	105.6
Transformer Stations			
Bldg. & Eqpt. (5)	15.0	15.0	15.0
Switching Station			
Bldg. & Eqpt. (1)	6.5	6.5	6.5
Plant Control Center			
Bldg. & Eqpt.	2.5	2.5	2.5
Underground Cabling & Conduit	11.3	11.3	11.3
Towers & Fixtures, Switching Station	1.0	1.0	1.0
Yardwork	0.8	0.8	0.8
Subtotal	<u>142.7</u>	<u>142.7</u>	<u>142.7</u>
Total (Major Components, Labor & Material)	1297.6	1665.0	1199.6
Shipping	24.9	57.8	30.8
Design (0.5% MLM)	6.5	8.3	6.0
Project Management (5% MLM)	<u>65.0</u>	<u>83.0</u>	<u>60.0</u>
Total Capital Cost	\$1394.0M	\$1814.1M	\$1296.4M

TABLE 4-2. ANNUAL O&M AND INSURANCE COSTS

	Solar Azimuth Tracker	Low-Ratio Concentrator	Fixed Panel Array
Operation			
Array System	\$ 0.18M	\$ 0.48M	\$ 0.44M
Electrical Equipment	0.44	0.44	
Maintenance			
Array System	1.72	6.92	3.14
Electrical Equipment	0.34	0.34	0.34
Insurance (0.5% Capital Cost)	6.97	9.07	6.48
Total	\$ 9.65M	\$17.25M	\$10.40

TABLE 4-3. ECONOMIC ANALYSIS ASSUMPTIONS

Capital Structure

Debt Fraction: 50 %

Equity Fraction: 50 %

Risk Premium: 2.5 % (Difference Between Interest on Debt and Return on Equity)

Before-Tax Discount Rate

Varied Parametrically From 5 to 15 Percent

After-Tax Discount Rate: 2.6 to 7.8 Percent

Escalation Rates:

	<u>1975-1985</u>	<u>1986-2019</u>
General Price Level	3.8	4.2
O&M Labor	4.8	4.5
Materials	3.1	3.8
Installed Capital	4.8	4.6
Insurance	4.8	4.6

Federal Tax Rate: 48%

Other Taxes: 2% State and Local

Year of Capital Expenditure: 1989

Start of Operation: 1990

System Lifetime: 30 Years

Depreciation Method: Sum of Years Digits

Investment Tax Credit: 10 Percent

TABLE 4-4. EXAMPLE CALCULATION OF LEVELIZED BUSBAR ENERGY COST

1. Initial Capital Costs

From Table 4-1, Concept No. 1 \$1394.0M

Levelized contribution for 15% discount rate,
from Figure 4-1 (a), \$1394.0M x 0.0882 \$123.0M

2. Operation, Maintenance & Insurance

From Table 4-2, Concept No. 1 \$9.65M

Levelized Contribution from Figure 4-2 (b),
\$9.65M x 1.1 = \$ 10.6M

Total Levelized Cost \$133.6M

Annual Energy: 2.83×10^6 MWh

$$\text{Levelized Cost/kWh} = \frac{133.6\text{M}}{2.83 \times 10^9 \text{ kWh}} = \$0.047/\text{kWh}$$

Figure 4-1. Levelized Cost Determination

Using the method of the above example, LBECs were developed for variations in solar cell efficiency, solar cell cost, concentrator or mounting substrate cost, and discount rate.

In considering solar cell efficiency, the costs of area dependent items were varied in inverse proportion, to maintain the plant annual output at 2.83×10^6 MWh. For example, the array system cost of \$1154.9M for Concept No. 1 shown on Table 4-1 refers to a basic cell efficiency of 11.8 percent. If a 15 percent cell is used, the costs (proportional to area) reduce in inverse proportion:

$$\begin{aligned}\text{New cost} &= \frac{11.8}{15} \times 1154.9\text{M} \\ &= \$908.5\text{M}\end{aligned}$$

Other area dependent costs varied in this fashion include those associated with project management, and shipping. In the case of shipping, only that portion associated with the array system was varied.

Non-area dependent items, including the plant electrical equipment and its associated shipping charges, and design costs, were held constant regardless of cell efficiency.

The results of LBEC calculations using a 15 percent before-tax discount rate are shown in Figures 4-2, 4-3 and 4-4. Only variations in solar cell efficiency and solar cell cost, expressed in dollars per square meter (\$/m²) or dollars per peak kilowatt (\$/pk. kW), were considered. The conversion from \$/m² to \$/pk. kW is arbitrarily based on rating peak output under standard conditions (1 kW/m² insolation, 28°C cell temperature, AM1 spectrum) assuming the use of bare cells. Thus, a ten percent efficient solar cell which produces 100 Watts/m² under standard conditions, and costs \$50/m², has a peak rating of \$500/pk. kW.

For ease of interpretation the results of Figures 4-2, 4-3 and 4-4 are cross-plotted to show the relative effects of cell efficiency and cost. The right-hand plots indicate the small impact of cell cost for the azimuth tracker concept and increasing impacts for the other two concepts.

A comparison of the three concepts is shown on Figure 4-5 considering the use of solar cells with 12.5 and 25 percent efficiencies. These results are derived from the previous plots. Also included are the results of the residence application (Phoenix location, no energy storage) using a shingled solar array approach. Several important conclusions may be derived from these plots:

1. Using current cell technology (which yields high production cells of about 12.5 percent efficiency), the residence application is most cost effective for cell costs of \$500/pk. kW or less. This fact is mainly attributable to the low substrate cost of the shingle approach, estimated to be \$10/m² for the residence plot shown.
2. Above solar cell costs of \$500/pk kW, the azimuth tracker is most cost effective for the 12.5 percent cell case.

Figure 4-2. Levelized Busbar Energy Cost, Solar Azimuth Tracker

Figure 4-3. Levelized Busbar Energy Cost, Low-Ratio Concentrator

Figure 4-4. Levelized Busbar Energy Cost, Fixed Panel Array

Figure 4-5. Comparison of Levelized Busbar Energy Costs

3. At higher cell efficiencies, as represented by the 25 percent cell case, the cell cost for the residence and fixed panel concepts must be extremely low (less than \$200/pk kW) to be more cost effective than the azimuth tracker concept.
4. As expected, the azimuth tracker system is insensitive to cell costs. Thus, over a cell cost range from zero to \$1500/pk kW, the levelized cost only varies about 15 percent.
5. The disappointing results for the low-ratio concentrator are due to the high costs aside from solar cells. Its lower slope on the plot indicates that the low-ratio concentrator is effective to some extent but not enough to overcome the high cost of the other array system elements.
6. The high slope for the fixed panel and residence concepts indicates the direct need to drive cell costs downward if these concepts are to be made economically attractive. The higher slope of the residence system is due to the greater inefficiency of the residence DC/AC converter equipment.

4.4.2 ECONOMIC IMPACT ON UTILITY SYSTEMS

As contrasted with the previous section which developed photovoltaic plant cost as a function of design and performance, this section deals with the worth of photovoltaics (PV) generation within the framework of utility system economics. Given the diurnal and seasonal variations of photovoltaic systems, an analysis was performed for determining this worth in terms of the savings associated with displaced capital equipment (gas turbines, steam plants, etc.) and fuel. The study was conducted by General Electric's Electric Utility System Engineering Department using the methodologies embodied in EUSED's Optimized Generation Planning (OGP) computer program. A description of this program and its application are contained in Appendix D.

The analysis determined the worth of PV generation by initially characterizing a given utility system without PV generation in terms of projected load growth, planned generation growth, and a set of economic scenario assumptions. Present worth calculations determined the accumulated costs of new generation equipment over a specified number of years. PV generation was then introduced according to an assumed penetration profile. The seasonal and daily output characteristics of the PV generation resulted in a modification to the optimum mix of new generation capability that should be used. Using the modified configuration of equipment (excluding the PV generation), present worth costs were recalculated. The difference in present worth costs was then used to determine the worth of the PV generation to the utility system.

The analysis was conducted for the region served by the Arizona Public Service Company. Following is a summary of the major characteristics and assumptions used (these are presented in greater detail in Appendix D):

1. The utility system is defined in terms of its present generation capability, scheduled additions, heat rates, and fuel characteristics.

2. PV generation is characterized using the daily and seasonal performance of the solar azimuth tracker and fixed panel concepts. For ease of utilization by the OGP program this information is presented in terms of the monthly average of power output during daily 3-hour increments.
3. Economic assumptions are used which define the cost of new generation plant equipment, fuel costs, and escalation rates out to the year 2000. In performing the analyses, the effect of both normal and high escalation scenarios were evaluated.
4. A PV penetration rate is used which incrementally establishes the number of power plant sectors introduced out to the year 2000. At the time the peak PV output is about 10 percent of the utility system peak demand.

The results of the analysis are shown on Table 4-5. Case 1 is based on the performance characteristics of the solar azimuth tracker system (Concept 1) using a quantity of 40-pond sectors to displace conventional generation. The penetration of 824 MW displaces 4.4 percent of the conventional generation capacity with an energy displacement of 3.1 percent.

TABLE 4-5. CENTRAL POWER PLANT WORTH ANALYSIS RESULTS
(PHOENIX LOCATION)

Case	Break-Even Cost (1975 \$)		Rated Capacity in Year 2000, MW	Capacity Credit %	Capacity Factor
	\$/Sector	\$/kW			
1. Concept 1: Solar Azimuth Tracker	12.6 M	420	824	60.5	0.215
2. Concept 3: Fixed Panel Array	11.4 M	380	1213	45.2	0.215

- Notes and Definitions:
1. Sector rating; 30 MW
 2. Capacity Credit = $\frac{\text{Displaced Capacity}}{\text{Plant Rating}}$
 3. Capacity Factor = $\frac{\text{Annual Energy}}{8760 \times \text{Plant Rating}}$
 4. Phoenix Utility System Characteristics in 2000,
Capacity: 11,250 MW
Energy: 49,800 GWh/year

Case 2 pertains to the fixed panel array (Concept 3) and is based on adjustment of the residence results obtained from Phoenix, shown on Table 4-16 of Part A. The adjustment procedure assumes identical output characteristics and capacity displacement with the breakeven costs modified to reflect differences in efficiency and the method of rating:

1. From Table 4-16 (Part A) for Phoenix:

$$\text{Displaced Capacity} = 1275 \times 0.43 = 548.25 \text{ MW}$$

$$\begin{aligned}\text{Worth of PV generation} &= 1275 \times 10^3 \text{ kW} \times \$362/\text{kW} \\ &= \$461,500,000\end{aligned}$$

2. To determine the power plant array rating which produces an equivalent plant output, the residence array capacity is adjusted downward by 13 percent to remove the effect of the residence inverter efficiency and then upward by 3 percent to account for the power plant inverter and transformer losses. A downward adjustment of 4.5 percent is also included to account for lower temperature operation:

$$\begin{aligned}\text{Array rating} &= \frac{1275 \times 0.87}{0.97 \times 1.045} \\ &= 1094.3 \text{ MW}_a\end{aligned}$$

3. The plant capacity is determined by multiplying the above result by the ratio of plant rating to array rating. The array rating for Concept 3 is given by:

$$\begin{aligned}\text{Plant Array Rating} &= \frac{\text{Residence Array Rating}}{\text{Residence Solar Cell Area}} \times \text{Plant Solar Cell Area} \\ &= \frac{11.25 \text{ kW}}{84 \text{ m}^2} \times 10.1 \text{ km}^2 \\ &= 1353 \text{ MW}_a\end{aligned}$$

Then,

$$\begin{aligned}\text{Plant Capacity} &= 1094.3 \times \frac{1500}{1353} \\ &= 1213 \text{ MW}\end{aligned}$$

4. Capacity credit and breakeven costs are determined from Step 1 results:

$$\begin{aligned}\text{Capacity Credit} &= \frac{548.25}{1213} \\ &= 0.452 \\ \text{Break-even Cost} &= \frac{461,550,000}{1213 \times 10^3} \\ &= \$380/\text{kW} \\ &= \$11.4\text{M}/\text{Sector} \\ &\quad (30 \text{ MW rating})\end{aligned}$$

5. The capacity factor is determined from the annual energy output for a particular plant rating (see Table 2-1):

$$\begin{aligned}\text{Capacity factor} &= \frac{2.83 \times 10^6 \text{ MWh}}{8760 \times 1500 \text{ MW}} \\ &= 0.215\end{aligned}$$

As derived from Table 4-5, the Case 2 penetration of 1213 MW displaces 4.9 percent of the conventional capacity and 4.6 percent of the annual energy.

The results for the residential analysis (Part A, Figure 4-31) established the proportionality of breakeven cost with capacity factor. Figure 4-6 shows a similar correlation for the central power plant cases. The effects of higher plant and fuel costs are also included. Since the fixed panel array performance results were based on scaling the results of the residential system, the corresponding plots on Figure 4-6 are identical to those developed for the residential system shown in Part A, Figure 4-31. Although different DC/AC conversion efficiencies were used, this difference is reflected in a higher capacity factor and correspondingly higher breakeven cost with no effect on the proportionality of the plot.

For a given capacity factor, the plots indicate a higher breakeven cost for the solar azimuth tracker system of about 10.5 percent. Another way of stating this is that for equivalent energy output, the solar azimuth tracker system displaces a larger amount of conventional capacity as shown on Table 4-5 by comparing capacity credit for the two cases (60.5% versus 45.2%). This is believed to be due to the higher midday and summer peak outputs of the azimuth tracker with the consequent displacement occurring at times of greater risk. Thus, for a summer peaking utility (the case in Phoenix), the effective capacity and cost credit are greater.

Figures 4-7 and 4-8 provide graphic means for determining the combinations of system element costs that would satisfy a particular breakeven cost constraint. These nomograms were developed along lines similar to those for the residence systems described in Part A, Section 4.4. Tracing through these nomographs reveals the difference in cost sensitivity to key variables for the two concepts. The lower right-hand quadrant of each nomogram repeats the information presented on Figure 4-6.

Using a site location in Phoenix (0.215 capacity factor) and the high escalation scenario noted earlier, the break-even cost for the solar azimuth tracker system (Figure 4-7) is \$540/kW. The heavy lines represent the nominal cost and solar cell efficiency values for the point design costs summarized earlier on Table 4-1 using a plant rating of 1500 MW. Using a solar cell cost of \$50/m² entered along the right horizontal axis and tracing through counter-clockwise to each nominal cost value and 11.8 percent cell efficiency, results in a system cost of \$870/kW, about 1.6 times larger than the break-even cost. Several strategies may be used to narrow the gap. First, a cell efficiency of 20 percent totally eliminates the difference, although the reliable and consistent achievement of such efficiencies has yet to be demonstrated. Reducing the collector and installation cost item from \$44/m² to about \$30/m² also achieves the desired objective. This too is probably difficult to achieve in terms of present knowledge and experience. However, this item does not involve the complex technological efforts required for cell efficiency

Figure 4-6. Break-Even Costs for Central Power Plant Concepts

improvements, but rather the application of production shortcuts and cost-saving methods. It seems clear that efforts in both of these areas are required. Cost reductions in the electrical equipment area would also yield benefits, of course; however, the estimates for electrical equipment presented in this study were based on current technology and large reductions are not envisioned. The basic cost of solar cells is also important, and in fact, the basic premise underlying this economic analysis is that future solar cell costs will fall in the range of \$50/m² to \$100/m². In this regard, the nomogram (Figure 4-7) shows that the equipment costs are relatively insensitive to solar cell costs. This is due, of course, to the fact that the solar azimuth tracker uses a 25 to 1 concentration ratio with the cells only accounting for about five percent of the total costs. Thus, doubling cell costs only has the effect of increasing system costs by another five percent.

Figure 4-7. Solar Azimuth Tracker, Effect of Break-Even Costs

Figure 4-8. Fixed Panel Array, Effect of Break-Even Costs

Except for the greater significance of solar cell costs, a similar story emerges for the case of the fixed panel array shown on Figure 4-8. For the identical location in Phoenix and the higher escalation scenario, the break-even cost is \$ 490/kW, about 10 percent lower than the solar azimuth tracker. Starting with the solar cell cost of \$50/m² and tracing through to each nominal cost value and a cell efficiency of 13.4 percent, results in a system cost of \$770/kW, about 1.60 times larger than the break-even cost. Increasing solar cell efficiency and reducing the panel and installation costs results in similar system cost reductions noted for the solar azimuth tracker concept. For this concept, system costs are much more sensitive to solar cell costs. Doubling solar cell costs has the effect of increasing the system cost by 42 percent.

Normalizing the systems to the use of 15 percent efficient solar cells costing \$500/kW_{pk} results in overall costs that are too high over break-even costs by factors of 1.66 and 2.3 for the solar azimuth and fixed panel concepts respectively, considering a nominal escalation scenario. The higher escalation scenario reduces these factors to 1.30 and 1.75 respectively.

SECTION 5

TECHNOLOGY NEEDS

SECTION 5

TECHNOLOGY NEEDS

5.1 INTRODUCTION

Implementation of the photovoltaic power plant will require the evolution of low-cost solar cells, development of effective mounting and encapsulation materials, development of optical collection and tracking systems, and the adaptation of current and on-going power conditioning technology to fit the peculiar needs of photovoltaic generation. Except for breakthroughs needed to achieve low-cost solar cells, implementation can be achieved with available technology. Many of the plant design characteristics must be analyzed and optimized but these are considered to fall within the category of straightforward engineering design and practice. In the case of the solar azimuth tracker concept, major efforts are needed to define the best optical design for the pontoon collector and to perfect the most practical mechanical design. The overall pond and array configurations must be reviewed and evaluated with respect to numerous factors -- overall pond size, physical and electrical arrangement of pontoons, servicing needs, detailed dynamic analysis, environmental effects, and water supply and treatment needs, to name a few. These characteristics would be defined through successive stages of analysis, design, breadboard tests and prototype demonstrations, but are not basically limited by technology barriers.

A similar assessment of the plant electrical equipment indicates that few areas requiring specific development are foreseen.

The following sections discuss the areas of technology development which have been identified. This assessment has been principally carried out for the solar azimuth tracker concept which was considered to be most demanding in terms of technology needs.

5.2 ARRAY SYSTEM TECHNOLOGY NEEDS

5.2.1 SOLAR CELLS

The development of low-cost solar cells represents one of the dominant needs for achieving economic photovoltaic power generation. Major efforts are of course being devoted by ERDA toward this objective. An equally important objective should be directed toward achieving higher efficiency. This is particularly true for concentrator systems in which efficiency gains are reflected as cost savings in concentrators, mounting needs, site preparation and land area. In fact, the economic results reported herein indicate that, for concentrator systems, greater savings are realizable from efficiency gains than from solar cell cost reductions. A corollary result indicates that for comparable overall plant levelized busbar energy costs, expressed in \$/kWH, much higher solar cell costs can be tolerated for concentrating systems than for non-concentrating systems. Thus, concentrating systems provide a better opportunity for the realization of economic goals, without the need for extremely low cell costs. For these reasons technology efforts should be directed toward the development of higher cell efficiencies for use in concentrating systems. Such cells must of course be capable of operating at the elevated temperatures resulting from the concentrating effect.

5.2.2 MATERIALS

An underlying condition for the economic attractiveness of photovoltaic generation relates to long-life requirements. A 30-year life was assumed in the economic analysis for determining levelized costs. A key factor in achieving such durability lies in selecting stable materials that can withstand the extremes of weather conditions. The basic design of the pontoon collector recognizes this need by its minimum use of organic materials and the hermetic enclosure of the less durable elements. Following is an identification of those elements of the design which may be more susceptible to long-term degradation:

1. Pontoon Covers - A clear plastic window has been tentatively selected to cover and enclose the entire collector. Its durability against weather extremes and ultraviolet radiation may be questionable. Glass would serve as an excellent substitute, although its fabrication into a curved sheet (approximately 1 x 12 meters) might not be possible with present manufacturing techniques. A technology need relates to establishing the feasibility of such fabrication.
2. Pontoon Hull - High-density concrete has been selected as the hull material because of its low cost and stability. Because of variability in its composition and porosity it is certain that exterior sealants will be required against the entry of water. A variety of bituminous and silicone materials may be used for this purpose. A thorough investigation of prior practice, possibly followed by a materials development program, should be addressed to this question. An important aspect of such an investigation would be to investigate the effects of the widely varying organic and saline quality of the pond water.
3. Solar Cell Mounting - The electrical isolation of the fin structure on which the solar cells are mounted avoids the necessity for high voltage insulation between the cells and the fin structure itself. Anodization of the fin surface provides a stable means of insulation for the small voltage differences involved. However, organic bonds for thermally coupling the cells to the fin structure may be subject to long-term degradation, particularly under the high temperature conditions of concentration. A variety of materials have been developed for space applications, e.g., GE RTV 566 or DC 93500, which may be suitable. An attractive alternative, eliminating organic materials at this critical interface, would be to metalize the anodized fin surface and then join the cells directly by soldering. Proper attention to mismatched expansion coefficients would of course be necessary to prevent cell fracturing. Cell interconnections are also intimately involved in developing a workable system, regardless of whether organic or metalized bonds are used. The entire question of cell mounting, interconnection, and accommodation of effective heat removal represents a significant technology development need.
4. Reflector Surface - A number of materials may be considered for the reflector which lines the inner surface of the pontoon collector. As presently visualized the reflective film would be adhesively applied to the pontoon hull concrete casting. The life characteristics of such films are not well established and periodic

replacement may be required. By removing the cover window and fin structure assembly, it should not be too difficult to overlay a new reflective film on the original one. Two technology needs are identified: (1) investigation and development of durable highly reflective materials; (2) development of methods for reflective surface refurbishment.

5. Miscellaneous Elements - Several additional items made of organic materials may be subject to long-term degradation. In most cases these can be easily replaced as part of normal maintenance procedures. The insulation of pontoon interconnecting cables may degrade over a number of years as a result of continued weather exposure. O-ring seals between the cover window and pontoon hull may embrittle with time permitting the entry of dirt and moisture. If active cooling of the solar cells is used, the insulation layer (polypropylene is suggested) may break down in time. Because of the mechanical configuration proposed for the pontoon, these items can be easily replaced without having to replace the entire pontoon. Technology needs for these items are identified as a potential means for reducing maintenance.

5.2.3 PONTOON HERMETIC SEALING

For performance and electrical reasons it is desirable to seal the pontoon against the entry of moisture and dirt. Because of pressure changes that would result with temperature changes it does not appear practical that an absolute sealing system could be achieved. Instead, a means must be provided which would allow the pontoon to "breathe" to reach equilibrium with the external ambient pressure. A porous plug would be effective in preventing the entry of dust but would not exclude moisture. Dessicants may be employed for this purpose and could be situated near the concentrator focal line so that the concentrated solar energy would drive off any moisture that might have been captured in the previous cooling down period. A technology effort is required to analyze such possibilities and develop working solutions.

5.3 PLANT ELECTRICAL EQUIPMENT

Technology needs for the plant electrical equipment are minimal. The techniques utilized in the inverters for the photovoltaic power system are common to those used in the transmission of power by direct current and, as such, will evolve independently of the requirements of solar energy. A certain amount of such natural evolution has been assumed, particularly in the area of the thyristor valve itself. The DC breakers required for the photovoltaic system are very similar to those under development for power transmission (see ERDA Contract E(49-18)-2065). Some evolution in the application of minicomputers for on-line control of the station is assumed but the technology is expected to develop independently of the photovoltaic field.

SECTION 6

BARRIERS

SECTION 6

BARRIERS

6.1 INTRODUCTION

Successful introduction of photovoltaic central station power plants will depend not only on arriving at creative solutions to technological problems -- and therefore reducing costs to be competitive with other forms of power generation -- but also on anticipating and overcoming other, non-technical barriers. An assessment of such barriers was conducted, and its results are the subject of this section.

The solar azimuth tracker concept, described in detail in an earlier section, is used to assess potential barriers. The plant features solar cells mounted on floating pontoons and is sized to produce 2.83×10^6 MWh/year in the Phoenix, Arizona region. Annual resources required for implementation are based on assuming that twenty pond-floated plants are installed by the year 2000. The basis for this implementation scenario is described in Appendix L. Land, water and ecological impacts are evaluated for the Phoenix region. For this purpose, four of the plants are assumed to be located within the boundaries of Arizona.

Potential barriers considered in the study were:

1. Water requirements
2. Land requirements
3. Ecological impacts
4. Utility load patterns
5. Capital requirements
6. Material requirements

Detailed discussion of these barriers is presented in the following sections.

6.2 WATER REQUIREMENTS

Without means for impeding the high evaporative losses common to the south-west the baseline plant (2.83×10^6 MWh annual output) would consume makeup water at the rate of 40 cubic meters per minute. Meeting this rate with fresh water would impose major difficulties. Concerning the use of relatively high quality water, the situation in Arizona is typical. Mr. Wes Steiner, Arizona Water Commissioner, indicated in a telephone interview, that his Phase 3 State Water Plan could allow for as much as 239 billion gallons per year for total energy use in the state. Water usage associated with four baseline plants would consume 22 billion gallons per year or about nine percent of the water allocated to energy use. Ways of reducing this rate and of using alternative sources of low quality water are discussed below.

Alternative sources may include the use of deep saline water known to exist in northeast Arizona, or seawater pumped in from coastal regions. Either of these methods would have to face the problem of the buildup in time of Total Dissolved Salts (TDS). At some TDS value the salt crust buildup would necessitate that the ponds be flushed occasionally. A potential answer to this problem may be in using the photovoltaic collector waste heat for desalting purposes. In this scheme, besides producing electrical power, the photovoltaic plant would yield fresh water and concentrated brine. In this way the ponds would be flushed continuously preventing the TDS buildup. The flushing would also tend to minimize fouling arising from stagnant water conditions (see later discussion).

The use of existing structures, bodies of waters, and reuse of waste water provide other alternatives. For example, large coal strip mines occur in northern Arizona and enormous open-pit copper mines exist in southern Arizona. Besides providing low quality water, the spent mines and pits could be used to satisfy part of the land requirement. Another alternative could be to use the flat alluvial plain of the Colorado River to satisfy the land requirement and then utilize the high TSD irrigation return flow from the Imperial Valley or the Wellton-Mohawk Irrigation District. A third alternative could be to utilize parts of the existing reservoirs in Arizona. Although few in number, they do represent some of the largest man-made reservoirs in the world (e.g., Lake Mead with a surface area of 158,000 acres). Consideration could also be given to use of existing power generation facilities. Flotation of photovoltaic pontoons on hydro reservoirs would reduce both water and land requirements significantly.

Locating the plants in regions with plentiful water supplies, e.g., Florida, or along coastal regions with access to seawater would relieve many of the concerns associated with inland desert regions. Other barrier questions would certainly emerge, such as effects on the local ecology, but nevertheless, such locations would provide advantages of water availability and enhanced plant performance by virtue of reduced water temperatures.

The evaporation rate may be reduced by monomolecular films or by floating pellets which reduce the evaporation area. On the basis of information provided by users of monomolecular films, it is estimated that reductions in evaporation of 25 to 40 percent could be achieved. Experience with monomolecular films indicates that winds tend to disrupt the film continuity. The pontoon layout on the ponds serves as a stabilizing matrix which should minimize the wind-shearing effect.

At this stage in the development of the pond concept, firm conclusions cannot be drawn concerning the water supply question. Rather, the analysis to date brings attention to those factors which must be considered in greater detail in connection with specific implementations.

6.3 LAND REQUIREMENTS

The land required for the site of the baseline photovoltaic power plant is 50 km^2 . This is five times the acreage required for a comparable coal-fuel generating plant and 15 times the land occupied by a nuclear installation.* The four photovoltaic plants projected to be on-line in Arizona in 2000 would occupy 200 km^2 .

In the southwest, as elsewhere, utilities have experienced delays and outright prohibition in siting power plants. Much of the difficulty with conventional generation is a concern for emissions: air pollution, thermal discharge, and the effects of normal radiation. None of these would be emitted by photovoltaic plants. However, the size of the site itself might create opposition. Contact with the southwestern area representative of the Sierra Club is illustrative. The representative indicated the Club would strive "at all costs" to protect the environment in the Arizona Sonoran Desert, which is one possible site for the photovoltaic plants. Although the photovoltaic ponds do not need to be contiguous, the area they occupy would be fenced off and therefore inaccessible to those who consider the Sonoran Desert part of their national heritage.

6.4 ECOLOGICAL IMPACTS

In recent years, public objections to the environmental effects of new technologies have acted as constraints to their development. Atmospheric noise pollution weighed heavily in the decision to cancel the U.S. supersonic transport. Current delays on nuclear power plant sitings have as one cause a public debate about the environmental effects of irradiated wastes. If environmental problems are anticipated, ways may be found to mitigate their effects before they cause implementation of the new technology to be called into question. In the case of photovoltaic central power stations, no pollution problems are immediately apparent. However, the systems require large tracts of land, consume greater quantities of water than conventional generation and also differ in appearance from traditional plants. The following discussion describes aspects of the interaction between a photovoltaic plant and the environment with emphasis on the issues which could develop into public concerns.

The desert ecology in the area of the large plants may be disrupted beyond homeostatic recovery levels. The area, in effect, will be cleared to make way for the array ponds with the majority of the plant and animal life removed. As a consequence, a totally new environment will result.

Experience in Arizona has shown that perennial ponds become heavily used by birds. Accompanying birds are the problems of bird droppings. These droppings will create maintenance problems with the transparent covers on the pontoons although high voltage pulsing techniques used in cow fences could be effective in minimizing maintenance by discouraging the presence of birds. Droppings are rich in nitrogen species. High solar radiation, warm water, and a plant nutrient (nitrogen) will quickly create an eutrophic state within the ponds. Blooms of Cyanophyta (filamentous blue-green algae) could occur. Since reaeration rates within the ponds will be minimal, organic phycological loading can be expected with resultant anerobic conditions occurring in the tank. Evaporation suppression studies at the University of Arizona using lined ponds and plastic covers have shown that the ponds become anaerobic if greater than 50 percent of the surface area is covered.

*Reference: Council on Environmental Quality, Energy, and the Environment - Electric Power, U.S. Government Printing Office, Washington, DC, August 1973.

Pontoon configuration in the photovoltaic ponds will cover as much as 70 percent of the surface area. These anaerobic conditions are usually accompanied by odor problems. Some degree of water recirculation and treatment may be necessary to achieve acceptable water conditions.

Perennial ponds in Arizona are also usually infected with midge flies, sand flies, mosquitos, etc., since stagnant water is a favorite breeding area. To control the flies and the algal problems, pesticides and herbicides will be required. The presence of these organics then becomes a problem for any reuse of the waste water. Again, recirculation of the pond water would tend to reduce such concerns.

In cases where water for photovoltaic ponds is brought into the plant site, the resulting evaporation may result in a modified microclimate. One problem of altering the microclimate in an area is the possibility that exotic or non-indigenous species will be introduced. For example, certain birds may proliferate with resulting overprey on the surrounding desert reptiles and rodents. Or, these birds could prefer to dig their nests in the large Sahuaro cactus and thereby cause degradation of this local flora. Homeostasis in the desert environment is very brittle and additions of new microclimates could present environmental problems.

6.5 UTILITY LOAD PATTERNS

A current trend toward increased "peak" demands for electricity in the winter may reduce the value to the utilities of photovoltaic systems, at least as peaking units. As a solar-fueled form of generation, photovoltaic plants produce their maximum output in the summer. A key consideration in determining the value of this output is its coincidence with peak demands for power. The higher the correlation with peak demands, the greater the substitution that is possible for conventional peaking units (e.g., gas turbines which although relatively low in capital costs have high fuel costs).

As described in a previous section of the report, conditions at Arizona Public Service (APS) favor the use of photovoltaic systems. The seasonal peaks are coincidental enough with photovoltaic output to result in a significant capacity credit (credit for conventional equipment replaced). APS anticipates even sharper summer peaks in the future as a result of the projected increase in cooling.

APS is far from the only summer peaking utility. In fact, as shown in Figure 6-1, total utility sales for the U.S. show higher peaks in the summer months than in the winter. For the southern half of the country, the summer loads greatly exceed the winter peak. As far north as New York and Chicago, large urban-area utilities experience highest peaks in the summer because of large air-conditioning loads. (The utilities serving smaller cities and rural areas in the north are usually winter peaking to supply winter lighting needs as well as some electric space heating). The peak to valley ratios for utilities is much greater than the pattern shown in Figure 6-1.

Figure 6-1. Utility Sales of Electricity to Residential, Commercial, and Industrial Customers

However, winter peaking, caused by increased electric heating loads, may become prevalent in many utilities that are now summer peaking. Forty-nine percent of the single-family residences constructed in 1974 were electrically heated, as compared to twenty-five percent five years earlier. The penetration is greatest in the south (67% in 1974). However, shortages of oil and prohibitions on new gas hookups may greatly increase the trend elsewhere. A shift to on-site energy systems, such as solar heating, can also accelerate the trend, since the supplemental heating source is generally assumed to be electricity. Winter peaking as mentioned above, is less favorable to the use of photovoltaic systems, which produce maximum output in the summer.

Several factors, however, also need to be considered before reaching any conclusions on the importance of peaking to photovoltaic systems. One is whether load patterns will be as important in determining system selection on the future as they have been in the past. Storage, peak pricing, and other load management techniques can significantly affect the existence and significance of changes in loads. Likewise, there is uncertainty about the availability and cost of conventional systems and fuels. Delays in the siting of nuclear and coal plants raises the possibility of shortfalls in the future supply of electricity. Concurrently, they raise questions about the supply and price of oil, which utilities may have to turn to for base-load generation (gas turbines are already being used as base-load units by some northeastern utilities). If conventional options are unavailable or increasingly

expensive, the match between photovoltaic output and peak system loads may be far less important than the speed with which manufacturers can bring photovoltaic plants on-line, assuming of course that the accompanying price tag is within "reason". This last factor, the cost of photovoltaic plants, is also uncertain. Peaking patterns can be meaningless, for example, if photovoltaic costs are low enough to be competitive with base-load nuclear and coal plants.

The uncertainty in all three of the factors mentioned - the use of load management techniques, the cost and availability of conventional forms of generation, and the cost of photovoltaic systems themselves, make uncertain the importance of peaking patterns as a barrier to the implementation of photovoltaic systems.

6.6 CAPITAL REQUIREMENTS

In recent years, utilities have experienced difficulty in raising financial capital for conventional facilities. Photovoltaic systems, as many new technologies and advanced generation facilities, entail a greater initial capital investment and greater risk than conventional options. Should utilities experience continuing difficulty in raising financial capital for conventional facilities, utility management is likely to become even more conservative with respect to investments in new capital-intensive technologies.

There are good reasons for questioning the utilities ability to raise the amounts of capital they require in the next 10 years. Current estimates range from \$250 billion to \$336 billion required to construct facilities from now to 1985¹. These estimates assume annual growth in electricity sales of between 5.7 and 6.9%. Even for the capital-intensive utility industry, the amounts are large and imply that the industry will have to attract an increasing share of the nation's total fixed business investment (TFBI). The utility share was between 5 and 10% in the 1960s; it would have to increase to between 12 and 16% over the next decade.² This growing utility share is not a new phenomenon, of course, and is a reflection of continued growth of electric consumption at a rate higher than the average growth of the rest of the economy.

However, to command an increasing share of total fixed business investment, electric utilities must continue to exhibit above-average earnings performance (as measured by growth and stability) and financial strength. Recent utility earning performance has been

¹FEA/Federal Reserve Board Task Force, Financing Project Independence, November 1974; FPC, Technical Advisory Committee on Finance, The Financial Outlook for the Electric Power Industry, December 1974; and J. Hass, et. al., Financing the Energy Industry, Cambridge: Ballinger Publishing Co., 1974 prepared as part of the Ford Energy Policy Project.

²Based on GNP growth of 4% per year; assumes that TFBIs share of GNP level off at 10.4% (the average 1966-74 share) or increases to 11.1% (an extrapolation of the upward trend of recent years). In the former case, the cumulative TFBI from 1974 through 1985 amounts to 2.2 trillion (measured in 1974 prices). The latter assumption yields a cumulative TFBI of 2.4 trillion.

sub-par relative to the performance of industrial companies and to the performance of utilities during most of the post World War II period. Following a decade of average annual sales growth of 7.5%, utilities have experienced virtually no growth for two years.³ Given the high fixed costs of utilities, and the assumption commonly held prior to 1973 that growth would continue indefinitely at the historic 7% rate, two years of no growth had a serious adverse impact on utility earnings.

Thus, one plausible scenario for the future shows the utilities experiencing increasing difficulty in attracting equity capital at a reasonable price. They would find that increased debt-to-equity ratio reduced their bond rating and requires higher interest. They would be unable to fund a large part of their needs from retained earnings, which would hamper their ability to purchase conventional power plants, as recent cancellations and deferments indicate. Since advanced energy forms such as PEPS and other solar energy systems are capital intensive with low fuel and operating costs, the likely tendency would be to favor conventional sources whose costs are apportioned over the life time of the system.

Another view points to hopeful signs for future utility profits. Most observers now anticipate a near-term rebound to a longer term growth of between 5 and 6 percent per year. The resumption of significant growth should have a significant and positive impact on utility earnings. In addition, reduction in the "regulatory lag" will improve earnings. Many utilities point to significant lags between (1) costs they incur from general inflation, and higher fuel prices in particular, and (2) corresponding approval for electric sales. Utility profits have suffered from the resulting squeeze. Utilities are making new progress in convincing utility commissions to streamline rate proceedings, allow automatic pass-through of higher fuel costs, grant interim rate increases and incorporate anticipated future costs into current rates. These measures, and other such measures, combined with the eventual control of inflation, should reduce the depressing effects of the "regulatory lag" on earnings. Thus, a second plausible scenario shows the utilities in a better financial position than the first portrait described above.

There are, of course, several policy tools the government can utilize to influence the utilities reaction to the capital investment required for photovoltaic systems, regardless of which of the two above scenarios become reality. Increased investment credits, specific investment credits for projects conserving fossil fuels, and government ownership and leaseback of photovoltaic systems (as a la New York State Power Authority) are three such options. At present, the extent of government intervention is uncertain.

The government is not the only factor that can significantly affect utility management's assessment of the financial aspects of photovoltaic systems. As mentioned above, the availability of nuclear generation is uncertain; delays in siting of coal plants raise similar questions about its contribution to electric supply. Increased reliance on oil has high potential and economic costs. Faced with such alternatives, the utilities with or without government incentives may find photovoltaic systems very attractive in spite of their

³1,703 million MWh in 1973, against 1,750 million MWh for 1975.

capital intensiveness. Thus, given all the possibilities and uncertainties, the significance of the capital required for the solar systems is unclear.

6.7 MATERIALS REQUIREMENTS

Materials requirements are not anticipated to present barriers for PEPS implementation, although significant growth in at least on supplying industry (silicon cell manufacturing) is implied. The baseline design requires the following materials for a 2.8 million MWh/year plant in Arizona: (Approximate quantities of each are given; precise estimates require a detailed design analysis).

<u>Material</u>	<u>Quantity (Tons)</u>
Aluminum	149
Silicon Photovoltaic Cells	500
Copper	4,500
Optical Covers	
• Plastic Option	30,000
• Glass Option	200,000
Concrete	4,400,000

The materials requirements would approximately double for plants producing comparable output, but located in the northeast.

To identify potential material shortage barriers, a study was conducted of the projected demand and supply conditions for the materials listed above in the absence of any photovoltaic implementation. Annual photovoltaic materials requirements were then compared with expected supplies to determine whether shortages might occur. All estimates are based on the implementation rates described in Appendix I. These estimates were used to generate the annual photovoltaic materials requirements plotted in the various figures given below.

As can be seen in Figure 6-2, copper requirements for photovoltaic plants are small compared with total demand for copper. Thus, these requirements are not likely to affect the supply and demand situation in the industry. However, anticipated conditions in the industry will affect the implementation of photovoltaic plants. Demand for copper is projected to increase, as shown in the figure. As indicated, a major user is the electric utility industry. At current prices, the United States does not have a sufficient domestic supply to maintain its current share of the world market through 2000. Foreign supplies are similarly insufficient. Three reactions to this situation are anticipated. First, the price of copper will be bid up. As a result, some users will switch to aluminum. Second,

¹Mineral Facts and Problems, Bureau of Mines Bulletin 650, U.S. Department of Interior, Washington, D. C., 1970.

Figure 6-2. Projected Demand for Copper

mines will be developed which yield lower grade ore than is currently economical to export. Third, new supplies will be sought and developed. If copper prices should escalate dramatically, or if the supply should be interrupted, photovoltaic system manufacturers would have the option of substituting aluminum for copper.

Aluminum

No supply problems are anticipated with aluminum. Although much of the bauxite used in producing aluminum is imported, there are large reserves and no shortage is anticipated for 2000. In fact, it is expected to serve as a substitute for copper in many uses. As indicated in Figure 6-3, the photovoltaic demand is a very small percent of total aluminum consumption.

Concrete

The baseline plant will require 4.4 million tons of concrete, which is greater than the tonnage for all other materials combined. However, as a portion of total concrete demand, the total annual requirements for photovoltaics are small. (See Figure 6-4). No problems are anticipated in the supply of concrete.

Millions of Tons

Figure 6-3. Projected Demand for Aluminum

Figure 6-4. Projected Demand for Concrete

Glass

Glass is a common construction material made from readily available inputs (by sand). The photovoltaic requirements for glass are plotted in Figure 6-5. (The estimates assume that all optical covers are made of glass). The requirements are small compared to total projected demand, although to provide enough glass for several photovoltaic plants in a year will require additional facilities. One photovoltaic plant requires the output of approximately eight float glass lines.

Figure 6-5. Projected Demand for Glass

Lexan

Optical quality plastics, such as Lexan, may be used instead of glass for pontoon covers. The current production capability for Lexan consists of one 14-machine facility. It is estimated that at least 3.5 machines would be required to produce enough output for one photovoltaic power plant. Thus, by the year 2000 production capacity appears adequate to meet the construction rate of 2 plants per year¹. (See Figure 6-6).

¹Estimates based on the following assumptions: (1) that the sheets of Lexan would be one meter wide, 11.8 meters long and 0.1 cm (40 mils) thick; (2) that one photovoltaic plant (covered collector area = 25 km²) would need a run of 60 x 10⁶ pounds, which would require 30,000 hours of machine operation; and (3) that a machine would be operated 3 shifts, 7 days a week for a total of 8,460 hours/year, with no down time for repairs or maintenance.

Figure 6-6. Projected Photovoltaic Demand for Lexan

Figure 6-7. Projected Demand for Single Crystal Silicon for Photovoltaic Cells

Single Crystal Silicon Production for Photovoltaic Cells

The photovoltaic solar cell industry is currently in its infancy and does not have the production capacity required to produce the quantities required for photovoltaic implementation. A many-fold increase in production facilities would be required, as depicted in Figure 6-7, which focuses on the demand for single crystal silicon suitable for use in photovoltaic solar cells. Should existing manufacturers hesitate to invest in expanded facilities, crystal production and cell fabrication, the government may need to offer special incentives (tax credits, guaranteed markets, etc.) to ensure adequate supplies.

PART C

INTERMEDIATE-SIZE SYSTEMS

PAGES i to ii
WERE INTENTIONALLY
LEFT BLANK

TABLE OF CONTENTS – PART C

Section		Page
1	SUMMARY AND CONCLUSIONS	C-1
	1.1 Summary	C-1
	1.2 Conclusions	C-4
2	CONCEPTUAL DESIGN	C-7
	2.1 Introduction	C-7
	2.2 Solar Array	C-8
	2.2.1 Low-Ratio Concentrator (Seashell)	C-8
	2.2.2 Roof-Integrated Collector Configurations	C-13
	2.3 Heating and Cooling System	C-15
	2.4 Electrical System	C-15
	2.4.1 Converter System	C-16
	2.4.2 Converter Equipment	C-18
3	PERFORMANCE ANALYSIS	C-23
	3.1 Introduction	C-23
	3.2 Analytical Models	C-23
	3.2.1 System Model	C-23
	3.2.2 Low-Ratio Concentrators	C-24
	3.2.3 Integrated Roof Flat-Plate Configurations	C-24
	3.2.4 Thermal Heating and Cooling System	C-33
	3.2.4.1 Solar Thermal Collectors	C-33
	3.2.4.2 Thermal Energy Storage	C-33
	3.2.4.3 Building Heating and Cooling Loads	C-33
	3.3 Performance Analysis Results	C-34
	3.3.1 Low-Ratio Concentrator System	C-34
	3.3.1.1 Parametric Analysis Results	C-34
	3.3.1.2 System Performance in Washington and Phoenix	C-37
	3.3.2 Integrated Roof Systems	C-42
	3.3.2.1 Slope Optimization Results	C-43
	3.3.2.2 System Performance Results	C-44
4	ECONOMIC ANALYSIS	C-51
	4.1 Introduction	C-51
	4.2 Methodology	C-51
	4.3 Economic Analysis Assumptions and Input Data	C-51
	4.4 Economic Analysis Results	C-52
5	MARKET POTENTIAL FOR INTERMEDIATE-SIZE SYSTEMS PUBLIC BUILDINGS	C-59

LIST OF ILLUSTRATIONS — PART C

Figure		Page
1-1	Summary of Seashell and Integrated Roof Configurations	C-2
1-2	Comparison of Levelized Busbar Energy Costs for Phoenix Location	C-4
2-1	Valley Forge Junior High School, Valley Forge, Pa.	C-7
2-2	Low-Ratio Concentration Collector	C-9
2-3	Roof-Erected Solar Array	C-10
2-4	School Solar Array Layout	C-11
2-5	Plumbing and Electrical Wiring Layout Low Concentrator (Photovoltaic) Commercial Site	C-12
2-6	Block Diagram, School Total Energy System	C-15
2-7	Converter Control Block Diagram	C-17
2-8	Electrical System One-Line Diagram	C-19
2-9	Electrical Equipment Physical Layout	C-20
3-1	System Model	C-23
3-2	Definition of Terms for Sawtooth Array Analysis	C-26
3-3	Definition of Angles for Seashell and CPC Collectors	C-35
3-4	Seashell Tilt Angle Performance in Phoenix (1962)	C-36
3-5	Seashell Collector Performance in Phoenix (1962)	C-37
3-6	CPC Tilt Angle Performance in Phoenix (1962)	C-38
3-7	CPC Collector Performance in Phoenix (1962).	C-39
3-8	Seashell and CPC area Relationships	C-40
3-9	Cost/Performance Comparison of Seashell and CPC Concentrators	C-41
3-10	Seashell Performance in Washington (1962)	C-41
3-11	Seashell Performance in Phoenix (1962)	C-42
3-12	Sawtooth Analysis Results	C-43
3-13	Monthly Performance in Washington, DC (1964)	C-48
3-14	Monthly Performance in Phoenix, Ariz. (1962)	C-49
3-15	Monthly Performance in Miami, Fla. (1963)	C-50
4-1	Levelized Cost Determination	C-55
4-2	Comparison of Levelized Busbar Energy Costs for Washington, D.C. Site Location	C-57
4-3	Comparison of Levelized Busbar Energy Costs for Phoenix Location	C-57
4-4	Comparison of Levelized Busbar Energy Costs for Miami Location	C-58
5-1	Penetration of Photovoltaic Systems in Commercial New Construction	C-59
5-2	Projected Composition New "Commercial Construction 1985-2000" (Floorspace)	C-60
5-3	Use of Roof Space on New Building with P.O Installation	C-61

LIST OF TABLES -- PART C

Table		Page
2-1	Summary of Seashell and Integrated Roof Configurations	C-14
3-1	Expressions for Energy Reaching Solar Panels of Sawtooth Concentrations	C-32
3-2	Optimum Combination of Panel and Reflector Tilt Angles	C-43
3-3	Performance Summary in Washington, DC (1964)	C-45
3-4	Performance Summary in Phoenix, Ariz. (1962)	C-46
3-5	Performance Summary in Miami, Fla. (1963)	C-47
4-1	Capital Costs	C-53
4-2	Annual O&M and Insurance Costs	C-54
4-3	Economic Assumption Analysis	C-54
4-4	Calculation of Levelized Busbar Energy Cost	C-56

SECTION 1

SUMMARY AND CONCLUSIONS

SECTION 1

SUMMARY AND CONCLUSIONS

This volume (Part C) presents the study results on intermediate-size photovoltaic systems applied to public buildings. A junior high school located in Valley Forge, Pa. provided the basis for solar array layouts and load estimates. The study encompassed the development of conceptual designs, performance evaluation, and the determination of costs. The systems were evaluated for site locations in Washington D. C., Phoenix and Miami. A summary of the study is presented below followed by the major study conclusions.

1.1 SUMMARY

Rooftop photovoltaic conceptual designs were developed for large area single story buildings. The junior high school selected for this study has a roof area of about 10,000 square meters. Two basic solar array approaches, each having a panel or aperture area of approximately 3000 square meters, were evaluated. The first used adjustable tilt low-ratio concentrators (3.2 to 1) mounted on a steel grid erected over the normal roof surface. The second approach considered several variations of flat-panel roof-integrated designs.

A summary of seven design variations investigated is shown on Figure 1-1. Cases 1 and 2 refer to the low-ratio concentrator approach, with and without solar thermal collection (through fluid circulation) for partially meeting the school's heating and cooling loads. Cases 3 to 7 refer to roof-integrated designs from the simple PV-only flat-panel approach (Case 3) to the double paned combined PV/thermal approach with sawtooth reflector augmentation (Case 7).

Considerable analysis preceded the selection of the key parameters defining these designs. Two concepts for low-ratio concentrators were analyzed and compared. The first design consisted of a semi-parabolic reflector similar to Concept No. 2 described for the central power plant (See Part B, Section 2.1.3); the second design consisted of a compound parabolic concentrator (CPC). For both designs, the annual energy reaching the solar cells was determined as a function of the concentration ratio. Using solar cell costs of \$50 and \$100 per square meter and estimates of reflector costs, the concepts were compared in terms of their relative cost to performance ratios. The optimum ratios for both designs were found to be quite similar. On this basis, it was concluded that more detailed analysis of a single selected point design for determining photovoltaic and thermal performance would be representative of this class of low-ratio concentrators. Such analyses were performed using the semi-parabolic design with a concentration ratio of 3.2 to 1. Performance was analyzed for site locations in Washington D. C. and Phoenix.

Preliminary analyses were also performed for determining the optimum panel and reflector slopes of the sawtooth roof integrated designs. Analytical expressions were developed for determining the contributions of beam and diffuse insolation reaching the solar panels both directly and by reflection. The maximum annual energy reaching the solar cells served as the basis for selecting the best combination of solar cell panel and reflector slopes. These analyses were separately performed for site locations in Washington, Phoenix and Miami.

		Description	Panel Area, m ²	Cell Area, m ²	Panel Slope, Degrees			Reflector Area, m ²			Number Cover Windows
					Washington	Phoenix	Miami	Washington	Phoenix	Miami	
1		Seashell, PV - Only	3226	806	0° - Sept 21 to March 21 30° - March 21 to Sept 21			3700	3700	3700	1
2		Seashell, PV/Thermal	3226	806	Same			3700	3700	3700	1
3		Planar Array, PV - Only	2853	2282	30	27	20	-	-	-	0
4		Planar Array, PV/Thermal	3226	2282	30	27	20	-	-	-	1
5		Sawtooth, PV - Only	2853	2282	30	27	20	3075	2580	1753	0
6		Sawtooth, PV/Thermal, 1 Cover	2853	2282	30	27	20	3075	2580	1753	0
7		Sawtooth, PV/Thermal, 2 Cover	3226	2282	30	27	20	3075	2580	1753	2

Figure 1-1. Summary of Seashell and Integrated Roof Configurations

Once the optimum slope combinations were established, more detailed analyses determined the photovoltaic and thermal performance.

Performance was analyzed without considering the use of on-site electrical energy storage. Through a direct tie-in with the school's utility line and with DC/AC conversion to the proper voltage and frequency conditions, the photovoltaic output was arranged to either supply the school's electrical load or fed back through the 4.16 kV, 3 phase incoming utility line. A DC/AC conversion efficiency of 95 percent was used. For the different solar array designs considered, the peak PV output ranged from about 200 to 500 kW.

For those designs with combined PV/thermal solar collectors, the thermal energy of the circulating fluid was accumulated in a thermal storage tank, to be withdrawn upon demand for building heating and cooling. An analysis of the building heating and cooling loads was performed for each of the regions considered. This determined the extent to which the collected solar thermal energy could be utilized. Because of the magnitude of the building thermal loads, almost all of the collected solar energy was useful with a minimal excess amount having to be discarded. An absorption chiller was used for meeting the school's air conditioning loads.

Capital costs for the various design concepts were obtained from a number of sources. Solar cell costs and efficiencies were treated parametrically. Panel and substrate costs were based on estimates developed for the residential and central power plant studies. For the combined PV/thermal designs, the costs of the combined collectors, piping, and thermal system equipment (tankage, pumps, etc.) were obtained from the direct experience of General Electric in the design and installation of solar heating and cooling systems. Construction and roofing installation costs were obtained from the architectural firm of Halsey and Ryder. This firm was responsible for the integration of solar panels on the recently completed New Jersey Environmental Center. Where specific photovoltaic designs served as roofing membranes, they were credited with the savings in normal roof design and construction. Where additional structures or roofing features were needed, the added costs were charged against the design concept.

Levelized busbar energy costs (LBEC) were developed using the methods outlined for the residential and central power plant systems. Assuming utility ownership of the system, the LBECs were calculated using a 15 percent before tax discount rate, 30-year life, and an appropriate set of escalation factors. The economic methodology used resulted in a fixed charge rate of 12.7 percent in current year dollars, equivalent to 8.83 percent in 1975 dollars for the economic factors used.

Using the annual energy for each of the designs studied, the results of the LBEC calculations are summarized on Figure 1-2 for a site location in Phoenix. In terms of economic performance, this figure shows the relative ranking of the various concepts analyzed. For the other locations studied, the relative rankings are identical. These results clearly identify the PV-only roof-integrated designs as being most cost effective.

For the combined PV/thermal designs, the LBECs have included a credit for the thermal energy supplied to the school. This credit is based on deducting \$4.93/MM Btu of thermal

Figure 1-2. Comparison of Levelized Busbar Energy Costs
for Phoenix Location

energy supplied by the solar collection system (1975 dollars). This corresponds to a fuel oil cost of \$2.96/MM Btu and a burner efficiency of 60 percent.

Projections were made on the construction of new commercial buildings for the period from 1985 to 2000. These projections indicate that about 3000 km² of roof area would be available for photovoltaic installations during this period. Assuming that 30 percent of this area could be used for solar panels (the area packing factor used for the school), this represents a potential photovoltaic generation of 100 GW. Thus, from the standpoint of area availability, commercial buildings represent a significant market for the application of photovoltaic systems.

1.2 CONCLUSIONS

1. The planar photovoltaic-only design yields the best economic results. Using this design, the levelized busbar energy costs are comparable to those obtained for the residence study.
2. Augmenting the output of planar solar arrays with sawtooth mounted reflectors improves the output about 16 percent. However, because of added costs, the overall benefit is small. Whether or not to use reflectors must be weighed in terms of the building architectural and structural characteristics.

3. Adjustable tilt low-ratio concentrators were found to be unattractive, mainly because of their inability to serve as roofing elements, and the added expense of a steel grid for mounting the concentrators.
4. Based on current fuel prices and nominal escalation rates, analysis of combined PV/thermal systems for partially meeting building heating and cooling loads did not prove to be economically attractive. From this analysis it is concluded that the improved photovoltaic performance of PV-only systems, together with their inherently lower cost, results in greater economic worth.
5. Projections of commercial and public building construction out to the year 2000 indicate substantial roof areas with the potential for accommodating up to 100 GW of photovoltaic generation.

SECTION 2

CONCEPTUAL DESIGN

SECTION 2

CONCEPTUAL DESIGN

2.1 INTRODUCTION

Within the context of this study, intermediate-size photovoltaic systems cover the range between residential and central power plant applications and include such examples as commercial buildings, public buildings, and small communities.

In considering intermediate-size systems, variations of the solar array concepts developed for the residential and central power plant systems were used. These include seasonally adjusted low-ratio concentration approaches as well as several fixed roof-integrated configurations. Systems combining the thermal collection of solar energy along with PV generation are emphasized. Appropriate comparisons are made with systems which only generate photovoltaic power.

A junior high school located in Valley Forge, Pa., served as the basis for carrying out the conceptual and analytical studies. The roof dimensions and features were used to determine the area of solar collectors that could practically be accommodated. The building thermal characteristics were modeled and introduced into analytical procedures for determining the performance of the combined thermal/photovoltaic system. The school accommodates 1200 students and is a single story structure with a roof area of 10,000 square meters. A pictorial view of the school is shown on Figure 2-1. Performance was evaluated for site locations in Washington, D.C. (1964); Phoenix, Arizona (1962); and Miami, Florida (1963).

Figure 2-1. Valley Forge Junior High School, Valley Forge, Pa.

In developing the photovoltaic system concept for this building it was assumed that no electrical energy storage (batteries) was used. To accommodate this constraint, the power produced by the solar array is first converted to ac at proper voltage and frequency and fed directly to the incoming utility line to the school. The power is then either used by the school or fed back to the utility grid depending on the relative photovoltaic generation and school demand levels. In this arrangement the rooftop system serves as a utility power generation substation rather than being specifically dedicated to the school's needs.

Descriptions of the major subsystems are provided in the following paragraphs.

2.2 SOLAR ARRAY

Solar array configurations considered for the roof of the school included the low-ratio concentrator and roof-integrated designs described below.

2.2.1 LOW-RATIO CONCENTRATOR (SEASHELL)

The "seashell" configuration consists of a seasonally adjusted parabolic cylinder concentrator similar to that described for Concept No. 2 of the Central Power Plant studies (See Part B, Paragraph 2.3). Two design variations of the "seashell" configuration are considered in subsequent analyses: Configuration 1 only produces photovoltaic output; Configuration 2 produces both photovoltaic output and collects thermal energy.

The nominal design for either configuration uses a concentration ratio of 3.2 to 1. As shown in Figure 2-2, the basic element in this design consists of a bay formed by a semi-parabolic reflector, and reflecting partitions, a solar cell surface between the focal line and apex of the parabola, and a transparent window enclosing the collector aperture. As described under the central power plant version, all incoming rays within the acceptance angle limits will intersect the solar cell surface. In the winter months (September 21 through March 21) all direct rays are within the acceptance angle limits with the aperture plane positioned horizontally. From March 21 through September 21, it is necessary to tilt the aperture plane upward in a north facing direction to achieve better overall collection.

For the nominal 3.2 to 1 effective concentration ratio, each bay has aperture dimensions of 25 X 80 cm (2000 cm²) and a cell area of 500 cm². Since the cells are mounted with a packing efficiency of 90 percent, then only this percentage of the incoming energy reaches the cells. Twelve bays arranged in a 2 X 6 matrix form a panel assembly having overall dimensions of 0.62 X 4.85 meters.

In the design incorporating solar thermal collection (Configuration 2), cooling fluid is circulated through tubes mounted on the rear side of the solar cell mounting surface. Insulation surrounds these tubes to minimize thermal losses. The collected thermal energy is used for building heating and cooling. The objective of obtaining relatively high temperature circulating fluid for more effective heating and cooling was basic in considering concentration for the solar array. The low-ratio approach adopted for this design represents a compromise toward meeting the high temperature objective while at the same time avoiding the complexity

Figure 2-2. Low-Ratio Concentration Collector

of a higher performance tracking system. Only seasonal adjustments are needed to optimize solar collection.

Figure 2-3 illustrates the manner in which the 12-bay panels are supported and hinged on a steel grid erected on the roof of the building. A connecting tierod is used to gang a number of panels together for making tilt adjustments. Figure 2-3 also indicates the panel circuit diagram in which the cells in a single bay are wired in parallel and bays connected in series. A bypass diode between the negative and positive terminals permits continued operation in the event of an open-circuit failure.

The layout of the panels on the building roof is shown as shown on Figure 2-4. Since the building roof lines are not oriented in direct north-south and east-west directions, the panels are skewed with respect to the steel mounting gridwork, which is most easily erected according to the rectilinear layout of the building columns. The skewing results in an east-west alignment of the panels.

Both the need for the steel mounting grid and the accommodation of skewed mounting represent typical penalties likely to be encountered in retrofit installations. Ventilators, skylights and various other types of roof-mounted equipment represent additional obstacles which interfere with orderly roof installations. The layout of Figure 2-4 has assumed that such obstacles could be relocated or that the steel grid could be made sufficiently high to provide sufficient clearance. The presence of large trees along the southern perimeter of the building

Figure 2-3. Roof-Erected Solar Array

presented an additional problem that was handled by simply not installing collectors in that region of the roof. Also, an elevated ceiling for the school's main auditorium had to be taken into account in developing a practical layout for the solar array. Considering all of these factors, a layout was developed consisting of 12 strings of 1344 bays (112 panels per string with each panel containing 12 bays). The nominal array electrical characteristics are 540 Volts and 400 Amperes peak.

The overall electrical and piping layout for the combined photovoltaic/thermal solar array is shown on Figure 2-5. The electrical lines are routed to the existing transformer room while piping lines are routed to the existing boiler room and underground thermal storage tank.

The system without the collection of solar thermal energy (Configuration 1) accomplishes cooling of the solar cells by nature air convection. Air-flow passages are appropriately designed into the panel assembly to provide cooling on both the front and rear of the solar cell mounting surface. The physical implementation of this approach is similar to that described for Concept No. 2 of the central power plant study (See Part B, Paragraph 2.3.2).

SOLAR ARRAY DESCRIPTION:

- 3.6:1 CONCENTRATOR ADJUSTED SEVERAL TIMES YEARLY
- BAY APERTURE: 25 X 80 CM
- BAY CELL AREA: 500 CM² (PARALLELED CELLS)
- STRING: 1344 SERIES BAYS
- OVERALL ARRAY
 - 12 STRINGS
 - 540 VOLTS NOMINAL
 - 400 AMPS PEAK
 - 3226 M² APERTURE
 - 806 M² SOLAR CELLS

Figure 2-4. School Solar Array Layout

Figure 2-5. Plumbing and Electrical Wiring Layout Low Concentrator (Photovoltaic) Commercial Site

2.2.2 ROOF-INTEGRATED COLLECTOR CONFIGURATIONS

Where low-ratio concentrators are potentially cheaper than flatplate collectors because they use fewer solar cells per unit of collected solar energy, they cannot suitably serve as weatherproof roofing surfaces because of their seasonal adjustment.

Considering that fixed flat-plate systems are inherently simpler than adjustable systems and may also serve as roofing enclosures, several configurations were evaluated and compared with the low-ratio concentrator approach. Table 2-1 lists the characteristics of five roof-integrated designs that were investigated along with seashell configurations described earlier:

Configuration 3 uses solar cell shingles identical to those described for the residential system (see Part A, Paragraph 5.3). The shingles are mounted on the planar surface of a trussed rafter roof structure.

Configuration 4 is also built on a single plane roof surface, but uses combined PV/thermal panels mounted onto a skylight frame.

Configuration 5 uses solar cell shingles on the southward facing slopes of a sawtooth roof profile with reflective surfaces on the northward facing slopes.

Configuration 6 is similar to Configuration 5 with combined PV/thermal panels used in place of shingles.

Configuration 7 is similar to Configuration 6 with a double window to improve the thermal collection efficiency.

To permit meaningful comparisons of the integrated roof configurations with the low-ratio concentrator approach, the characteristics of the junior high school were utilized including the thermal properties and building dimensions. In considering the cost of the roof integrated designs, it was assumed they were incorporated into the original construction rather than being retrofitted. In all cases a solar cell area of 2282 m² was used. For the combined PV/thermal systems, the corresponding panel area was 3226 m², identical to the aperture area of the low-ratio concentrator described in Section 2.2.1. The panel tilt angles and reflector areas were determined from optimization studies described later in Paragraph 3.3.2.1.

Detailed layout studies for incorporating the integrated roof designs into the school structure were not carried out. Rather it was simply assumed that the new building having a 10,000 m² roof area (same as the existing school) could be appropriately designed to incorporate the solar panel area of 3226 m². The structural features of these configurations were developed in sufficient detail to permit reasonable cost estimates to be developed. The structural configurations and the estimation of related costs were prepared with the assistance of the architectural firm of Halsey and Ryder of Basking Ridge, N.J. This firm was responsible for the architectural and design integration of a solar heating and cooling system applied to the Environmental Education Center being erected by the State of New Jersey.

TABLE 2-1. SUMMARY OF SEASHELL AND INTEGRATED ROOF CONFIGURATIONS

		Description	Panel Area, m ²	Cell Area, m ²	Panel Slope, Degrees			Reflector Area, m ²			Number Cover Windows
					Washington	Phoenix	Miami	Washington	Phoenix	Miami	
1		Seashell, PV - Only	3225	806	0° - Sept 21 to March 21 30° - March 21 to Sept 21			3700	3700	3700	1
2		Seashell, PV/Thermal	3225	806	Same			3700	3700	3700	1
3		Planar Array, PV - Only	2853	2282	30	27	20	-	-	-	0
4		Planar Array, PV/Thermal	3226	2282	30	27	20	-	-	-	1
5		Sawtooth, PV - Only	2853	2282	30	27	20	3075	2580	1753	0
6		Sawtooth, PV/Thermal, 1 Cover	2853	2282	30	27	20	3075	2580	1753	0
7		Sawtooth, PV/Thermal, 2 Cover	3226	2282	30	27	20	3075	2580	1753	2

2.3 HEATING AND COOLING SYSTEM

A simplified schematic for the combined PV/thermal system is shown on Figure 2-6. The DC/AC inverter conditions the photovoltaic dc output to three phase ac at 4160 volts for a direct tie-in with the incoming utility line (see Paragraph 2.4 for more detailed discussion). The thermal energy from the solar array is transferred to a primary ethylene glycol/water fluid loop and thence through a heat exchanger to be either stored in the thermal storage tank or to be used directly through an absorption chiller or through heating coils located in the school's air ducting system. Although a significant amount of equipment (expansion tanks, valving, air traps, etc.) has not been defined on the schematic, the basic arrangement is typical of concepts being employed for solar heating and cooling systems.

2.4 ELECTRICAL SYSTEM

The electrical system consists of the required control, conversion, and conditioning equipment necessary to adapt and maximize the power output of the solar array to the proper utility system voltage and frequency conditions. The design of the electrical system is based on available equipment and technology. Specific design work would be required to write definitive equipment specifications, particularly regarding the master control that senses and determines the maximum power output point of the solar array.

Figure 2-6. Block Diagram, School Total Energy System

2.4.1 CONVERTER SYSTEM

The converter system consists of power conditioning units which automatically convert the solar array dc in the range of 380 to 544 Volts at a current of 45 to 450 Amperes to 3 phase, 60 Hz ac at 4160 Volts. The convertor system uses a line-commutated inverter which extracts direct current from the solar array at its maximum power point.

Power from the photovoltaic system is inserted at a point ahead of the school's 4.16 kV main circuit breaker. This injection point permits independence between the school's existing service and the converter system. Power produced by the solar array and converter system flows either to the school load or, in the case of a surplus, into the utility system.

The basic concept for the converter system is shown on the block diagram of Figure 2-7. Under normal operation the control objective is to extract power from the solar array at its maximum power operating point. The steps for accomplishing this are to independently derive the array current that would correspond to maximum power and then, through a feedback comparison with the actual current, drive a thyristor valve assembly so that the proper level of impedance is presented to the solar array.

The sensing of the maximum power point may be accomplished in several ways. One method is to slightly dither the impedance imposed on the solar array and then, through voltage and current sensing and microprocessor circuitry, dynamically calculate the power produced over the dithering range. The detection of a maximum value of power within this range indicates that the average operating point has been properly selected. Another method is to determine the best operating voltage as a function of array temperature. This latter case is based on the fact that the maximum power voltage of solar arrays is almost directly a function of temperature with a small effect due to current. Either of these methods could be employed for deriving the maximum power current signal. As shown on the lower half of the block diagram, (Figure 2-7), this signal is compared with a current feedback signal. The resulting error is used to drive the thyristor valve assembly through appropriate amplifier and signal conditioning circuitry.

An additional control feedback loop, shown on the upper half of the block diagram, is required as a protective feature for operation of the thyristor valves. To prevent their malfunction it is necessary that the extinction angle γ , which relates the ac phase difference of zero crossing current and voltage, be greater than some minimum value, nominally specified as 16 degrees. The extinction angle is affected by the output voltage and, therefore, steps are needed to counteract the influence of any sudden change due to abrupt load modifications. As shown on the diagram, this is handled by measuring the actual extinction angle, comparing it with the reference value, and then driving the thyristor valves to limit the lower value of the extinction angle. In this mode of operation the extinction angle feedback loop overrides normal maximum power point tracking until other compensating steps can be taken for modifying the output voltage.

The output voltage modification is accomplished using an induction voltage regulator inserted between the ac system and converter transformer. It nominally holds the extinction angle between limits of 18 and 22 degrees and, as shown, maintains these limits by means

Figure 2-7. Converter Control Block Diagram

of a deadband controller. The induction voltage regulator is an electromechanical device and is inherently slow-acting. Thus, it cannot handle short-term transients associated with load surges. In this case the extinction angle feedback loop reacts to protect the thyristors. With long-term load changes the induction voltage regulator is adjusted to provide operation within the proper extinction angle limits, allowing full recovery of maximum power point operation.

The techniques described above have been proven in direct current power transmission and are directly applicable to photovoltaic power conditioning. The inherent current limit characteristics of solar arrays are well matched to these line-commutation methods.

Automatic operation of the converter system proceeds as follows: When insolation and temperature are such that available solar array current is at least 10% of maximum, an automatic start sequence is initiated. The dc breaker is closed, the ac breaker is closed, and the converter control is activated. The induction voltage regulator seeks a position such that the control angle of the inverter is within proper limits. Array current is adjusted to provide operation at the maximum power point as the insolation and/or temperature vary. Should available current drop below the minimum operating value, the converter is automatically shut down. The dc breaker opens, the ac breaker opens and firing pulses from the control system are interrupted.

Interruption of the utility system voltage will result in loss of commutation in the inverter and a consequent loss of power output. Such disturbances will actuate an automatic restart sequence in which the dc breaker is opened, the control pulses stopped, the dc breaker reclosed and control pulses resumed. Should resynchronization be unsuccessful as a result of a continued utility outage, the system is locked out with appropriate annunciation indicating a fault condition.

2.4.2 CONVERTER EQUIPMENT

The converter equipment is defined on Figure 2-8. The solar array output flows through a dc breaker and dc smoothing reactor en route to the converter bridge. The dc power circuit loop is grounded at a single point. A current transformer in this ground connection detects ground faults anywhere in the dc loop. The bridge, converter transformer, induction voltage regulator, ac filter, ac breaker disconnect switch and surge arresters complete the inverter circuit. A control cabinet houses all control system circuits. The equipment is located near the school's transformer room as shown on Figure 2-9. The arrangement fits within the available space and permits access for servicing.

A master control, located in the control cabinet, accepts manual start and stop commands (by maintenance personnel), and provides automatic control sequences for dc and ac breakers and the dc ground fault detection scheme.

The valves in this power conditioner consists of a single thyristor. No current balancing or voltage grading are necessary. However, resistance-capacitance networks are required across each cell to handle current commutation transients. The thyristors are air insulated and air-cooled by fans mounted in the bridge cubicle. The fans are automatically

Figure 2-8. Electrical System One-Line Diagram

energized with startup of the converter. The gates of the thyristors are coupled to the control system by pulse transformers which provide necessary impedance matching and insulation.

Surge arresters are located at the solar array, the converter bridge and the ac interconnection point. The solar array surge arrester is connected at the solar array positive terminal to protect it from lightning-induced surges. This arrester also protects the voltage divider, the dc circuit breaker, and the dc smoothing reactor. The arrester connected to the bridge positive terminal protects the valve assembly from surges which may inadvertently reach the bridge from outside sources. The three arresters connected to the 4160-volt ac output terminals protect the switch, circuit breaker voltage regulator, harmonic filter and transformer.

The smoothing reactor is connected between the solar array and the converter to absorb the harmonic components of converter voltage. Ripple components of the direct current are controlled and rate of change of direct current during system disturbance is controlled. The 3 millihenry iron core reactor is mounted in a metal cubicle which also houses the valve structure.

The converter transformer is similar to a distribution transformer except that its secondary voltage is 455 volts, as determined by the maximum requirements of the solar array. It is planned that the three phase transformer will have delta connected primary and secondary windings. Its rating is 225 kVA OA, permitting overload during the peak output period of the daily cycle.

The induction voltage regulator is quite similar to standard three phase distribution circuit voltage regulators. The main difference is the extended adjustment range of -40 percent. The rating will accommodate the peak array power output at anticipated voltage conditions. The induction voltage regulator is a contactless, continuously adjustable device and is essentially maintenance-free.

In addition to the above major items of equipment, a variety of standard devices is required including dc and ac breakers, filters, instrumentation, cabling, and protective features.

SECTION 3

PERFORMANCE ANALYSIS

SECTION 3

PERFORMANCE ANALYSIS

3.1 INTRODUCTION

The electrical output analysis of the school photovoltaic system in large part follows the methods developed for the residential and central power plant concepts. Specific differences are noted in the paragraphs below. The thermal performance for the combined photovoltaic/thermal system is analyzed using techniques similar to those described for the combined residence system (See Part A, paragraph 3.3.2.3). In both the electrical and thermal analyses, hourly weather data serve as the input to analytical models representing the system elements. System performance is defined in terms of instantaneous electrical and thermal outputs, or as integrated energy quantities over specified time periods.

3.2 ANALYTICAL MODELS

3.2.1 SYSTEM MODEL

The model block diagram for the photovoltaic system is shown on Figure 3-1 indicating the use of a maximum power tracking DC/AC converter and step-up transformer in conjunction with the solar array. No energy storage is used, and therefore, the solar array output flows directly into the utility grid.

Figure 3-1. System Model

The maximum power point of the solar array varies dynamically with illumination intensity and solar array temperature. The analysis program for this arrangement employs a set of solar cell data which establishes the maximum power point in terms of voltage and current for the illumination and temperature conditions defined for each hour.

3.2.2 LOW-RATIO CONCENTRATORS

The defining equation for the output of one panel compartment (bay) is given by:

$$P_C = H_T \times A_C \times K_T \times K_R \times \eta_c$$

The terms of this equation are identical to those defined in the central station study (Part B, Paragraph 3.2.3) with several modifications as noted below:

1. P_C is the output from one panel compartment containing a cell of 500 cm² rather than the 1000 cm² area used in the central power version of the low-ratio concentrator.
2. Similarly, the effective aperture area A_C is 1800 cm² rather than 3600 cm².
3. The solar cell efficiency term η_c is determined as a function of insolation and temperature as previously described. For the photovoltaic-only case, cell temperature is based on the plot of Figure 3-9 of Part B. For the combined photovoltaic/thermal system case, the cell temperature is established by the characteristics of the fluid loop thermal system as explained in Paragraph 3.2.4.

To determine the overall array output, the bay output is scaled upward by the matrix of series-parallel bay elements, in this case being 1344 bays in series by 12 strings in parallel.

For determining the output at the 4160 Volt ac bus, a 5 percent allowance is included for converter and cabling losses.

3.2.3 INTEGRATED ROOF FLAT-PLATE CONFIGURATIONS

The analysis of the integrated roof configurations described earlier is based on the approach developed for the residential studies (See Part A, Paragraph 3.3). The method extends the capability of the residential analysis by considering the general case of a sawtooth configuration, including the effects of shadowing by the adjacent sawtooth and reflection from the northward facing slopes. The analysis is generalized in that with certain simplifying assumptions, the method yields results for such cases as single plane solar arrays or sawtooth configurations without reflector augmentation. The development of the methodology is presented in the following paragraphs.

Four sources of radiation reach the solar panels of the sawtooth configuration:

1. Direct Beam Radiation, E_{DB}
2. Reflected Beam Radiation, E_{RB}
3. Direct Diffuse Radiation, E_{DD}
4. Reflected Diffuse Radiation, E_{RD}

The geometry and the definition of terms associated with these sources are shown on Figure 3-2.

1. Direct Beam Radiation, E_{DB} (Watts/m²)

Three expressions for E_{DB} are applicable, depending on the value of the angle α as shown on the sketch below:

- a. For $\gamma \geq \alpha \geq 0$, shadows are cast by adjacent panel:

Designating ℓ as the panel width and ℓ' as the unshaded portion, geometrical considerations result in,

DEFINITION OF TERMS:

- $\vec{s}$ SOLAR BEAM UNIT VECTOR
- $\vec{p}$ PANEL NORMAL UNIT VECTOR
- $\vec{r}$ REFLECTOR NORMAL UNIT VECTOR
- ρ REFLECTIVITY OF REFLECTOR SURFACE
- β SOLAR PANEL TILT ANGLE
- γ REFLECTOR TILT ANGLE
- α SOLAR ELEVATION ANGLE PROJECTED ONTO VERTICAL-SOUTH PLANE
- H_B BEAM INSOLATION, WATTS/ m^2 , ONTO SURFACE NORMAL TO SOLAR BEAM VECTOR
- H_D TOTAL SKY DIFFUSE RADIATION, WATTS/ m^2 , ONTO HORIZONTAL SURFACE
- $\cdot$ SIGNIFIES VECTOR DOT PRODUCT

Figure 3-2. Definition of Terms for Sawtooth Array Analysis

$$\frac{\ell'}{\ell} = \frac{\sin \alpha}{\sin \gamma} \cdot \frac{\sin (\beta + \gamma)}{\sin (\beta + \alpha)}$$

The beam radiation, E_{DB}' reaching the unshaded portion is given by $H_B \bar{S} * \bar{p}$. For purposes of simplification it is assumed that the unshaded radiation is uniformly distributed over the entire panel so that

$$E_{DB} = E_{DB}' \cdot \frac{\ell'}{\ell}$$

Substituting the previous expressions for E_{DB} and $\frac{\ell'}{\ell}$ gives,

$$E_{DB} = H_B \bar{S} * \bar{p} \left[\frac{\sin \alpha}{\sin \gamma} \cdot \frac{\sin (\beta + \gamma)}{\sin (\beta + \alpha)} \right] \quad (1a)$$

b. For $(\pi - \beta) \geq \alpha \geq \gamma$, direct beam radiation occurs without shadowing and,

$$E_{DB} = H_B \bar{S} * \bar{p} \quad (1b)$$

c. For $\alpha \geq (\pi - \beta)$, no direct beam radiation reaches the solar panels and therefore,

$$E_{DB} = 0 \quad (1c)$$

Equations (1a), (1b), and (1c) define the direct beam radiation for the different ranges of α . Specific terms in these equations are evaluated below:

H_B , the normal beam insolation, is obtained from

$$H_B = \frac{H_{DIR}}{\cos \theta_j}$$

where H_{DIR} and θ_j equal the beam radiation and incidence angle respectively on a horizontal surface. As developed previously in Paragraph 3.3.1 of Part A, H_{DIR} is separated from total horizontal radiation measurements using the methods of Liu and Jordan, and θ_j is geometrically determined from

$$\cos \theta_j = \sin \delta \sin \phi + \cos \delta \cos \omega \cos \phi$$

where δ , ϕ , and ω are the declination, latitude and hour angles respectively.

$\bar{S} * \bar{p}$ is equal to the $\cos \theta_i$ where θ_i is the solar incidence angle on the solar panel.

This is given by:

$$\begin{aligned}\cos \theta_i = & \sin \delta (\sin \phi \cos \beta - \cos \lambda \cos \phi \sin \beta) \\ & + \sin \lambda \sin \beta \cos \delta \sin \omega \\ & + \cos \delta \cos \omega (\cos \lambda \sin \phi \sin \beta + \cos \phi \cos \beta)\end{aligned}$$

where λ is the solar panel azimuth angle and the other terms are as previously defined.

The determination of α , the projection of the sun elevation in the vertical-south plane, is obtained from the following expression:

$$\tan \alpha = \frac{\cos \delta \cos \omega \cos \phi + \sin \delta \sin \phi}{\cos \delta \cos \omega \sin \phi - \sin \delta \cos \phi}$$

2. Reflected Beam Radiation. E_{RB} (Watts/m²)

Four expressions for E_{RB} apply, depending on the value of angle α .

a. For $\gamma \geq \alpha \geq 0$, no reflection occurs and therefore,

$$E_{RB} = 0 \quad (2a)$$

b. For $2\gamma \geq \alpha \geq 0$, all radiation falling on the reflector surface is reflected onto a portion of the solar panel depending on the value of α itself as shown below:

When $\alpha = 2\gamma$, all reflected rays are distributed over the entire solar panel. However, when $\alpha < 2\gamma$ only a segment of the solar panel receives the reflected rays. In the limit, when $\alpha = \gamma$ no reflected rays reach the solar panel. The energy leaving the reflector per unit area of reflector surface, E_{RB}' , is given by,

$$E_{RB}' = H_B \rho \bar{S} * \bar{r}$$

$\bar{S} * \bar{r}$ is calculated identically to $\bar{S} * \bar{p}$ except that angle γ is substituted for angle β . The area of the solar panel and reflector surfaces are related geometrically by angles β and γ so that the radiation per unit area of solar panel, E_{RB} , is given by,

$$E_{RB} = H_B \rho \frac{\sin \beta}{\sin \gamma} \bar{S} * \bar{r} \quad (2b)$$

- c. For $(2\gamma + \beta) \geq \alpha \geq 2\gamma$, the situation is similar to that described in (b) above but in a reverse fashion - reflected rays which reach the solar panel are uniformly distributed over the panel but are associated with a limited segment of the reflector. This is shown on the sketch below:

When $\alpha > 2\gamma$ only a segment of the reflected rays reach the solar panel as shown on the right-hand sketch. In the limit, when $\alpha = \beta + 2\gamma$, the segment shrinks to zero. The geometrical relationships result in the following expression for the radiation per unit of solar panel area:

$$E_{RB} = H_B \rho \frac{\sin (2\gamma - \alpha + \beta)}{\sin (\alpha - \gamma)} \bar{S} * \bar{r} \quad (2c)$$

- d. For $\alpha \geq (2\gamma + \beta)$, no reflected radiation reaches the solar panel and therefore,

$$E_{RB} = 0 \quad (2d)$$

3. Direct Diffuse Radiation, E_{DD}

Two contributions to E_{DD} are associated with different sectors of the skydome.

- a. For the sky sector contained between the solar panel and reflector planes.

$$E_{DD} = H_D \left[\frac{1 + \cos (\beta + \gamma)}{2} \right] \quad (3a)$$

This expression is based on formulations developed by Duffie and Beckman (reference 3, Paragraph 3.6, Part A) where $(\beta + \gamma)$ represents the equivalent panel tilt above a horizontal surface.

- b. For the sector between the horizon and the reflector tilt angle γ :

The contribution of this sector may be determined by first assuming the panel is free-standing without shading effects from adjacent rows. By the previous formulation, the direct diffuse contribution (no ground reflection) to the panel tilted at angle β is given by $1/2 H_D (1 + \cos \beta)$. Thus, the contribution by the sector is the difference between this expression and that given by equation (3a). Now, reintroducing the adjacent rows, from the above sketch it is seen that shading varies from zero (for sky elements at angle γ), to total shading for sky elements along the horizon. This variation in shading can be appropriately taken into account by averaging between these extremes, or in effect halving the γ sector contribution. The resulting expression is therefore,

$$E_{DD} = H_D \times 1/2 \left[\frac{1 + \cos \beta}{2} - \frac{1 + \cos (\beta + \gamma)}{2} \right] \quad (3b)$$

4. Reflected Diffuse Radiation. E_{RD}

Two contributions to E_{RD} are associated with different sectors of the skydome.

- a. For the sector between γ and 2γ .

Radiation striking the reflector within this sector as represented by ray (a) appears to originate from a' as viewed from the solar panel. Thus, energy from this sector may be evaluated as the difference between that due to sectors S_1 and S_2 . Since only half of the energy in the sector between γ and 2γ reaches the solar panel (for reasons similar to those described in 3b above), the expression for the diffuse contribution is:

$$E_{RD1} = \frac{1}{2} H_D \rho \left[\frac{1 + \cos \beta}{2} - \frac{1 + \cos (\beta + \gamma)}{2} \right] \quad (4a)$$

b. For the sector between 2γ and $(2\gamma + \beta)$.

In this case the ray b appears to originate from b' as viewed from the solar panel. Thus, the diffuse energy appears to originate from the difference between sectors S_1 and S_2 . Again the contribution must be halved to account for the variation from zero to full intensity within the sector. Thus, the expression for this contribution is given by:

$$E_{RD2} = \rho \frac{H_D}{2} \left[\frac{1 - \cos \beta}{2} \right] \quad (4b)$$

A summary of the expressions developed above is shown on Table 3-1.

TABLE 3-1. EXPRESSIONS FOR ENERGY REACHING SOLAR PANELS OF SAWTOOTH CONFIGURATION

		Direct		Reflected	
		Expression	Limits	Expression	Limits
Beam	1a	$H_B \bar{S}^* \bar{p} \left[\frac{\sin \alpha}{\sin \gamma} \cdot \frac{\sin (\beta + \gamma)}{\sin (\beta + \alpha)} \right]$	$\gamma > \alpha > 0$	2a	0 $\gamma > \alpha > 0$
	1b	$H_B \bar{S}^* \bar{p}$	$(\pi - \beta) > \alpha > \gamma$	2b	$H_B \bar{S}^* \bar{r} \rho \frac{\sin \beta}{\sin \gamma}$ $2\gamma > \alpha > \gamma$
	1c	0	$\alpha > (\pi - \beta)$	2c	$H_B \bar{S}^* \bar{r} \frac{\sin (2\gamma - \alpha + \beta)}{\sin (\alpha - \gamma)}$ $(2\gamma + \beta) \alpha > 2\gamma$
Diffuse	3a	$H_D \left[\frac{1 + \cos (\beta + \gamma)}{2} \right]$	$(\pi - \beta) > \sec > \alpha$	4a	$\frac{H_D}{4} \rho [\cos \beta - \cos (\beta + \gamma)]$ $2\gamma > \sec > \gamma$
		$\frac{H_D}{4} [\cos \beta - \cos (\beta + \gamma)]$	$\gamma > \sec > 0$	4b	$\frac{H_D}{2} \rho \left[\frac{1 - \cos \beta}{2} \right]$ $(2\gamma + \beta) > \sec > 2\gamma$

3.2.4 THERMAL HEATING AND COOLING SYSTEM

In contrast with the photovoltaic output, which is independent of the school electrical load because of power feedback capability to the utility, the solar thermal output depends on the heating and cooling loads as well as the energy status of the thermal storage system. All of these elements enter into the hour-by-hour determination of temperatures and energy usage.

The analysis of the thermal heating and cooling system for the school is similar to that used for the hybrid residence system described earlier in several paragraphs in Section 3 of Part A. The basic method calculates the energy balance conditions existing between the solar collectors, heat exchange equipment, thermal storage, and the building heating and cooling loads. The hour-by-hour energy balance conditions are computer-calculated using subroutines which define the behavior of the system elements. The subroutine analytical models used in the residence analysis have been adjusted to reflect the characteristics of the school.

As noted the analysis determines the thermal energy provided as useful output on an hour-by-hour basis and also establishes the hourly temperature variations at key system locations. In particular the variation in the absorber temperature serves as the input for determining the photovoltaic performance for the combined system.

The characteristics of the principal elements are discussed in the following paragraphs.

3.2.4.1 Solar Thermal Collectors

Analysis of the thermal collection capability is similar to that used for the flat-plate combined collectors of the residence application. For the low-ratio concentrator designs, equation coefficients are adjusted to take account of the higher flux density reaching the absorber plate and the smaller reradiation areas.

3.2.4.2 Thermal Energy Storage

A 162 cubic meter (42,700 gallon) thermal storage tank was selected for analyzing the system performance. Sizing of this tank is based on using 50 kg of the water storage medium for each square meter of collector area. This falls within the limits generally considered for solar heating and cooling systems.

3.2.4.3 Building Heating and Cooling Loads

The building load analysis for the Valley Forge Junior High School was performed using GE's Building Load Evaluation Program (BLEP). The program, a simplified version of the Building Transient Thermal Analysis program described in Volume III, Appendix B, treats a building as a single temperature zone and neglects capacitance in the building structure. The latter feature overestimates short term thermal transient effects but, in the long term, integrated load requirements are accurate.

The physical dimensions, orientation, thermal conductance characteristics, window areas, and transmission characteristics of each building wall, roof, and floor area are described for program input. Daily schedules of ventilation requirements, occupancy, lighting, and electrical appliance use are also determined. Hourly weather data define the weather environment in the form of dry and wet bulb temperature, wind speed, and solar radiation intensity. On an hourly basis, the program calculates the conduction heat loss (or gain), the heat loss (or gain) due to ventilation and infiltration, the solar heat gain through the building windows, and the internal heat gain. The algebraic sum of the individual losses and gains is the net load.

In using the load program, the building characteristics, ventilation, occupancy schedule, etc., were derived from building drawings and discussion with school operations personnel. Although the school is used intermittently during the summer, the same use schedule for the school year was simulated during the summer to provide relatively equivalent loads. In calculating the cooling load the use of an absorption chiller was assumed having a coefficient of performance of 0.6. It was further assumed that a minimum temperature of 82°C was required to operate the chiller.

3.3 PERFORMANCE ANALYSIS RESULTS

3.3.1 LOW-RATIO CONCENTRATOR SYSTEM

Analyses of the low-ratio concentrator system were performed for Washington, D. C. and Phoenix considering both the combined PV/thermal and PV-only approaches. In addition, a parametric study of low-ratio concentrators was performed which considered variations in concentration ratio and tilt angle adjustments. Both the "seashell" design described earlier in Paragraph 2.2.1, and a compound parabolic collector (CPC) design were analyzed. The results of this parametric analysis are first presented, followed by the system analysis results for Washington and Phoenix.

3.3.1.1 Parametric Analysis Results

Study of the "seashell" concentrator was carried out parametrically varying both the concentrator acceptance angle and the aperture plane tilt angle. Figure 3-3 provides the definition of these angles for both the "seashell" and CPC designs. Phoenix weather data for the year 1962 served as the hourly input data for determining the energy reaching the collector solar cells. Both transmission and reflection losses were taken into account. Results of the analysis are shown on Figure 3-4 for different acceptance angles and aperture plane tilt angles. For each tilt angle the analysis produces a monthly profile of received energy. From the tilt angle profiles developed for a particular acceptance angle it is possible to select the one that yields the highest value of received energy for each month. The plots of Figure 3-5 indicate these optimum tilt angles and the corresponding energy for particular months. In interpreting these results it is important to realize that they apply for a system which is adjusted monthly. Less periodic adjustment would decrease the total level of received energy which could be deducted by referring back to Figure 3-4. For purposes of relative evaluation the monthly adjustment case is assumed, closely approximating the maximum possible performance.

Figure 3-3. Definition of Angles for Seashell and CPC Collectors

A similar analysis was performed using a compound parabolic collector (CPC) in place of the "seashell" configuration. Again, both the acceptance angle and aperture plane tilt were varied. The results are shown on Figures 3-6 and 3-7.

The "seashell" and CPC designs were compared on the basis of cost-to-performance ratios developed for each approach. Costs were estimated by determining the solar cell area and reflector area as a function of acceptance angle for each square meter of aperture area as defined for each design. Figure 3-8 shows these areas as a function of acceptance angle for both designs. A 50 percent truncation was assumed for the CPC case. Using these data, costs were determined assuming solar cells costs of \$50/m² and \$100/m² with an additional \$15/m² allocated for cell mounting, substrate and miscellaneous items. Reflector surface costs were assumed to be \$6.50/m². Cost-to-performance ratios were then determined using the performance data cited earlier in Figures 3-5 and 3-7.

A comparison of the cost/performance ratios is shown on Figure 3-9 indicating fairly similar performance for both designs. Regardless of the solar cell cost, the optimum designs for both approaches produce practically equivalent cost to performance ratios. From these results it may be concluded that study of the "seashell" design defined in some detail for the school application (see Paragraph 2.2.1) should be pretty representative of the best performance that can be achieved with periodically adjusted low-ratio concentration devices.

Figure 3-4. Seashell Tilt Angle Performance in Phoenix (1962)

Figure 3-5. Seashell Collector Performance in Phoenix (1962)

3.3.1.2 System Performance in Washington and Phoenix

Where the results of the previous paragraph were parametric in nature and demonstrated the basic performance similarity of the seashell and CPC concentrators, the results presented below provide overall comparisons for Washington and Phoenix in terms of the electrical and thermal energy delivered. The seashell concept described in Paragraph 2.2.1 provided the basis for the performance calculations, carried out for both the combined PV/thermal and PV-only systems.

Although the plots of Figure 3-5 indicate the desirability of monthly tilt angle adjustments, for practical operational reasons it was assumed that such adjustments were made twice a year at the time of equinox. For both Washington and Phoenix, a zero tilt angle was used for the period September 21 to March 21, and a 30 degree tilt angle from March 21 to

Figure 3-6. CPC Tilt Angle Performance in Phoenix (1962)

Figure 3-7. CPC Collector Performance in Phoenix (1962)

September 21. As estimated from Figure 3-4 for the 60 degree acceptance angle case, this represents a penalty of about 15 percent in the annual energy collected.

Figures 3-10 and 3-11 summarize the seashell simulation results for Washington and Phoenix considering both the combined PV/thermal and PV-only systems. Besides the photovoltaic and thermal energy performance results, both figures also show annual variations in maximum array power.

For the Washington, D. C. case the photovoltaic-only system produces an annual electrical energy output of 216 MWh while the combined system produces 170 MWh. The 46 MWh difference results from the higher average temperature operation of the combined system which also provides a useful thermal output of 593 MWh. The total thermal output was

Figure 3-8. Seashell and CPC Area Relationships

actually slightly higher than the 593 MWh value. However, credit could not be taken for the difference since it occurred at times when the thermal storage tank was at its limit of capacity (100° C was taken to be the upper limit for storing energy). Under such conditions the additional thermal output had to be discarded. The integrated insolation reaching the collector apertures was determined to be 2745 MWh. On this basis the energy collection efficiency is 7.9 percent for the photovoltaic-only case and 27.8 percent for the combined photovoltaic/thermal system. The electrical output efficiency for the latter case is 6.2 percent. The solar thermal system provides 45 percent of the thermal requirements. The higher summertime performance is evident from the plot, consistent with the higher levels of average insolation.

For the Phoenix case the PV-only system produces an annual electrical energy output of 315 MWh while the combined system produces 266 MWh and a thermal output of 1077 MWh. For the integrated insolation of 4499 MWh reaching the collector apertures, the energy

Figure 3-9. Cost/Performance Comparison of Seashell and CPC Concentrators

Figure 3-10. Seashell Performance in Washington (1962)

Figure 3-11. Seashell Performance in Phoenix (1962)

collection efficiency is 7.0 percent for the PV-only case and 29.9 percent for the combined case. The electrical output efficiency for the latter case is 5.9 percent. The solar thermal system provides 54 percent of the thermal requirements.

The above analyses assumed year-round school attendance. Thus, the summertime thermal output could be utilized for building cooling. Were summer sessions not held, the overall performance would suffer since the collected thermal energy would have to be discarded. By assuming uninterrupted attendance the results are more indicative for buildings with year-round occupancy.

3.3.2 INTEGRATED ROOF SYSTEMS

Analysis of the planar and sawtooth integrated roof designs first considered the optimization of surface slopes using the annual energy reaching the solar cells as the comparison criterion. Once optimum slopes were established for each of the regions studied (Washington, D. C., Phoenix, Miami) more comprehensive analyses were conducted for determining photovoltaic and thermal outputs. The slope optimization results are first presented below, followed by the system performance results.

3.3.2.1 Slope Optimization Results

Using the methods formulated in Paragraph 3.2.3, studies were performed for determining the best combination of panel and reflector angles for the sawtooth configuration. The results of these studies are plotted on Figure 3-12. In developing these plots, a solar panel slope was first selected which produced the highest annual energy without considering reflector augmentation. For Washington, Phoenix and Miami, these angles were respectively 30, 27 and 20 degrees as shown on the plots, about 5 to 10 degrees less than the latitude angles for these locations. Then the effect of varying panel spacing (or reflector tilt angle) was studied to determine the value yielding the highest reflector augmentation. The best combinations are summarized on Table 3-2.

TABLE 3-2. OPTIMUM COMBINATION OF PANEL AND REFLECTOR TILT ANGLES

	Washington	Phoenix	Miami
Solar Cell Panel	30°	27°	20°
Reflector Panel	33°	36°	40°

To verify that the solar panel tilt angles were indeed optimum, cases at other angles were also analyzed. As shown on Figure 3-12, these all resulted in lower values of incident energy providing assurance that the combinations listed were near optimum.

Figure 3-12. Sawtooth Analysis Results

3.3.2.2 System Performance Results

Annual performance summaries for the various concepts analyzed are shown on Tables 3-3, 3-4 and 3-5 for Washington, Phoenix, and Miami including the results for the low-ratio concentrator concepts. Monthly performance profiles for these regions are also presented on Figures 3-13, 14, and 15. Thermal performance is shown on the upper plots of the figures in relation to the building heating and cooling demands. As noted previously the characteristics of the Valley Forge Junior High School served as the model for this analysis.

TABLE 3-3. PERFORMANCE SUMMARY IN WASHINGTON, DC (1964)

	System Configuration (See Table 2-1)						
	1. Seashell PV-Only	2. Seashell PV/Thermal	3. Planar PV-Only	4. Planar PV/Thermal	5. Sawtooth PV-Only	6. Sawtooth PV/ Thermal	7. Sawtooth PV/ Thermal
PV Output	213.6*	170.4	451.4	294.3	519.5	324.6	260.4
Thermal Demand for Heating	—	585.7	—	585.7	—	585.7	585.7
PV Thermal Supply for Heating	—	278.6	—	299.4	—	298.3	371.8
Thermal Demand for Cooling	—	750.5	—	750.5	—	750.5	750.5
PV Thermal Supply for Cooling	—	314.6	—	260.7	—	305.0	445.9
Total PV Thermal Supply	—	593.2	—	560.1	—	603.3	817.7

*All values in megawatt-hours

TABLE 3-4. PERFORMANCE SUMMARY IN PHOENIX, ARIZ. (1962)

	System Configuration (See Table 2-1)						
	1. Seashell PV-Only	2. Seashell PV/Thermal	3. Planar PV-Only	4. Planar PV/Thermal	5. Sawtooth PV-Only	6. Sawtooth PV/ Thermal	7. Sawtooth PV/ Thermal
PV Output	315.1*	266.5	619.3	395.7	712.6	455.4	377.9
Thermal Demand for Heating	—	—	—	—	—	—	—
PV Thermal Supply for Heating	—	—	—	—	—	—	—
Thermal Demand for Cooling	—	1983.4	—	1983.4	—	1983.4	1983.4
PV Thermal Supply for Cooling	—	1077.0	—	983.8	—	1132.1	1249.6
Total PV Thermal Supply	—	1077.0	—	983.8	—	1132.1	1249.6

*All values in megawatt-hours

TABLE 3-5. PERFORMANCE SUMMARY IN MIAMI, FLA. (1963)

	System Configuration (See Table 2-1)						
	1. Seashell PV-Only	2. Seashell PV/Thermal	3. Planar PV-Only	4. Planar PV/Thermal	5. Sawtooth PV-Only	6. Sawtooth PV/ Thermal	7. Sawtooth PV/ Thermal
PV Output			565.0	337.7	637.6	394.7	329.6
Thermal Demand for Heating			—	—	—	—	—
PV Thermal Supply for Heating			—	—	—	—	—
Thermal Demand for Cooling			—	2067.0	—	2067.0	2067.0
PV Thermal Supply for Cooling			—	560.1	—	613.9	897.1
Total PV Thermal Supply			—	560.1	—	613.9	897.1

All values in megawatt-hours

Figure 3-13. Monthly Performance in Washington, DC (1964)

Figure 3-14. Monthly Performance in Phoenix, Ariz. (1962)

Figure 3-15. Monthly Performance in Miami, Fla. (1963)

SECTION 4

ECONOMIC ANALYSIS

SECTION 4

ECONOMIC ANALYSIS

4.1 INTRODUCTION

Economic analysis of the intermediate school system is similar to that performed for the residential and central power plant concepts. This involves the determination of capital and O&M costs from which 30-year levelized busbar energy costs (LBECs) are derived. The combined PV/thermal systems introduce the additional aspect of fuel savings arising from the thermal energy supplied for the school's heating and cooling needs.

4.2 METHODOLOGY

LBECs are determined using the methods outlined in Paragraph 4.2 of Part A. The LBEC determinations for the photovoltaic-only and the combined PV/thermal systems assume utility ownership and appropriately reflect utility financial practices. The following steps are involved in the analysis:

1. Initial cash outlays (capital costs) are determined.
2. Annual revenue requirements (sales) are established for covering all expenses including taxes, interest on debt (bonds), return on equity (stock), sinking fund for retiring debt, and other items such as operating and maintenance costs, and insurance.
3. The present value of all future costs is computed and then levelized over the system lifetime. Using the annual energy output of the plant, levelized cost per kWh is determined. In the case of the combined PV/thermal systems, a levelized revenue is developed for the thermal energy supplied to the building and the credit applied toward reducing the overall levelized cost.

4.3 ECONOMIC ANALYSIS ASSUMPTIONS AND INPUT DATA

The following assumptions were used in performing the economic analysis:

1. The utility owns the PV installation. In the case of the combined PV/thermal systems, this includes all thermal system equipment up to the interface with the school's conventional heating and cooling system. The absorption chiller is assumed to be part of the school's conventional equipment.
2. No fee is charged against the utility for the use of the building roof. In practice, the incentive to the school might be in the form of a fee or reduced electric rates. The issue of compensation for the school was not considered here since the principal objective was the relative economic performance of the various systems considered.

3. Capital costs were developed from numerous sources and are detailed in Appendix K, Volume III. The summary of capital costs for the seven alternate configurations is shown on Table 4-1 which assumed the use of 13.4 percent efficient solar cells costing 100 \$/m². In this summary, shipping, design, and project management costs were each assumed to be 5 percent of the major component, labor, and material costs excluding the solar cell costs. No contingency allowance was included because of the conceptual rather than detailed nature of the designs.
4. Annual operation and maintenance (O&M) and insurance costs for the PV-only and combined PV/thermal systems are summarized on Table 4-2. Detailed breakdowns are contained in Appendix K, Volume III.
5. Economic analysis assumptions are identical to those for the central power plant study and for convenience are relisted on Table 4-3.
6. Credit for the thermal energy supplied by the combined PV/thermal system is based on the cost of fuel oil providing an equivalent amount of heat. The fuel savings are accounted for by computing a levelized cost for the purchase of fuel alone and then deducting this value from the total system levelized cost. Fuel costs in 1975 are assumed to be \$2.96/MM Btu and are based on actual charges to the Valley Forge school. Fuel price escalation is assumed to be 6 percent (1975-1985) and 4.2 percent (1986-2019). A burner efficiency of 60 percent is also assumed. Since the assumed fuel price escalation is equal to the general price level escalation rate from 1986 on, the levelized fuel savings are equal to the present savings times the ratio of the 1975 to 1985 escalation rates compounded to 1985:

$$\begin{aligned}\text{Levelized Fuel Savings} &= \text{Present Savings} \times \left[\frac{1.06}{1.038} \right]^{10} \\ &= \text{PS} \times 1.233\end{aligned}$$

4.4 ECONOMIC ANALYSIS RESULTS

Figure 4-1, repeated from the central power plant section, provides the conversion factors for determining the LBECs. The example calculation shown on Table 4-4 illustrates the determination of LBECs for Configuration 2. Using this method of calculation, results for the various configurations are plotted for each region (Washington, Phoenix, and Miami) on Figures 4-2, 4-3, and 4-4 as a function of solar cell cost. The plots are based on using solar cells of 13.4 percent efficiency. Different efficiencies affect the LBECs inversely as shown by the abscissa multiplier. For example, for the abscissa value equal to \$.10/kWh, the LBEC for a 15 percent cell is reckoned as follows:

$$\text{LBEC} \times \frac{15}{13.4} = \$.10/\text{kWh}$$

$$\text{LBEC} = \frac{13.4}{15} \times .10 = \$.089/\text{kWh}$$

TABLE 4-1. CAPITAL COSTS
(In Thousands of Dollars)

Cost Element	Seashell		Integrated Roof				
	1 PV-Only	2 PV/Thermal	3 Planar PV-Only (Shingles)	4 Planar PV/Thermal 1 Cover	5 Sawtooth PV-Only (Shingles)	6 Sawtooth PV/Thermal 1 Cover	7 Sawtooth PV/Thermal 2 Covers
Solar Cells (@ \$100/M ²	80.6	80.6	228.2	228.2	228.2	228.2	228.2
Collectors	88.6	122.0	51.4	161.3	51.4	161.3	193.6
Delta Roof Cost*	112.2	112.2	-27.1	179.5	160.4	120.7	120.7
Cabling	3.5	3.5	3.5	3.5	3.5	3.5	3.5
Thermal Loops	—	133.4	—	133.4	—	133.4	133.4
DC/AC Conversion	25.2	21.3	49.5	31.7	57.0	36.4	30.2
Total (Major Components Labor and Material)	310.1	473.0	305.3	737.6	500.5	683.3	709.6
Shipping, Design, Project Mgmt (15% MLM Without Cells)	34.1	58.9	11.6	76.4	40.8	68.3	72.2
Total Capital Cost	344.5	531.4	316.9	814.0	540.8	751.6	781.1

*Delta roof cost pertains to added roof construction required to accommodate solar collectors (See Appendix K, Volume II).

TABLE 4-2. ANNUAL O&M AND INSURANCE COSTS
(In Thousands of Dollars)

	Configuration						
	1	2	3	4	5	6	7
Operation	1.2	1.2	.7	.7	.7	.7	.7
Maintenance							
Array	7.1	7.4	1.0	1.0	1.0	1.0	1.0
Electrical Equipment	.3	.3	.3	.3	.3	.3	.3
Thermal Equipment	—	1.3	—	1.3	—	1.3	1.3
Insurance (0.5% Capital Cost)	1.7	2.7	1.6	4.1	2.7	3.8	3.9
Total	10.3	12.9	3.6	7.4	4.7	7.1	7.2

TABLE 4-3. ECONOMIC ASSUMPTION ANALYSIS

Capital Structure		
Debt Fraction:	50 %	
Equity Fraction:	50 %	
Risk Premium:	2.5 % (Difference Between Interest on Debt and Return on Equity)	
Before-Tax Discount Rate		
Varied Parametrically From 5 to 15 Percent		
After-Tax Discount Rate: 2.6 to 7.8 Percent		
Escalation Rates:		
	<u>1975-1985</u>	<u>1986-2019</u>
General Price Level	3.8	4.2
O&M Labor	4.8	4.5
Materials	3.1	3.8
Installed Capital	4.8	4.6
Insurance	4.8	4.6
Federal Tax Rate: 48%		
Other Taxes: 2% State and Local		
Year of Capital Expenditure: 1989		
Start of Operation: 1990		
System Lifetime: 30 Years		
Depreciation Method: Sum of Years Digits		
Investment Tax Credit: 10 Percent

Figure 4-1. Levelized Cost Determination

This method of adjustment is based on assuming a fixed solar cell area as defined for each configuration.

TABLE 4-4. CALCULATION OF LEVELIZED BUSBAR ENERGY COST
(Example for Configuration 4 in Washington, D.C.)

1. Capital Cost

From Table 4-1, Total Capital Cost for Configuration 4 for Cells @ \$100/m² \$814.0 K

Levelized Contribution from Figure 4-1(a) for 15% before tax discount,

$$.0882 \times 814.0 \text{ K} = \$71.8 \text{ K}$$

2. O&M Insurance

From Table 4-2 7.4 K

Levelized Contribution from Figure 4-1(b) for 15% Before Tax Discount,

$$1.1 \times 7.4 = 8.1$$

3. Fuel Savings Credit

PV Thermal Supply, from Table 3-3,
560.1 MWh (1.91 x 10⁹ Btu)

$$\text{Annual Fuel Savings} = \frac{1.91 \times 10^9 \text{ Btu}}{0.6 \text{ (eff)}} \times \frac{\$2.96}{\text{MM Btu}} = 9.4 \text{ K}$$

Levelized Fuel Savings Credit, from Sec. 4.3(g)

$$9.4 \times 1.233 = \underline{-11.6}$$

Total Levelized Cost 68.3 K

4. Annual PV Output (from Table 3-3) = 294.3 kWh

$$5. \text{ Levelized Busbar Energy Cost} = \frac{68.3 \text{ K}}{294.3 \text{ kWh}} = \$0.232/\text{kWh}$$

Figure 4-2. Comparison of Levelized Busbar Energy Costs for Washington, D.C. Site Location

Figure 4-3. Comparison of Levelized Busbar Energy Costs for Phoenix Location

Figure 4-4. Comparison of Levelized Busbar Energy Costs for Miami Location

SECTION 5

MARKET POTENTIAL FOR INTERMEDIATE-SIZE SYSTEMS
PUBLIC BUILDINGS

SECTION 5

MARKET POTENTIAL FOR INTERMEDIATE-SIZE SYSTEMS PUBLIC BUILDINGS

An analysis was performed which provides projections of new construction for public and commercial buildings. From these projections, estimates of roof areas of potential use with photovoltaic systems are determined.

Commercial floor space is projected to double between 1970 and 1990, as shown in Figure 5-1. More than 80% of this floor space is in low-rise office buildings, one-story stores, one-story schools, low-rise motels, warehouses and auditoriums (See Figure 5-2). Therefore, the ratio of roof space to floor space is high — approximately 75%. This surface area, on which photovoltaic cells could be mounted, is presently unused for commercial purposes. Figure 5-3 shows one scenario for the use of this roof space on new buildings for photovoltaic generation. The scenario is based on the Fisher-Pry market penetration methodology described in Appendix E. The scenario results in the potential for 100,000 km² of installed photovoltaic array by 2000. Retrofitting existing buildings would increase the photovoltaic roof coverage significantly.

Figure 5-1. Penetration of Photovoltaic Systems in Commercial New Construction

Figure 5-2. Projected Composition New "Commercial Construction 1985-2000" (Floorspace)

Figure 5-3. Use of Roof Space on New Building With PV Installation