

3/2
10-8-81
MP
DOE/NASA/0195-1
NASA CR-165352
M206

MASTER

Dr

30a4
B7570

Photovoltaic Stand-Alone Systems:

Preliminary Engineering-Design Handbook

H. L. Macomber and John B. Ruzek
Monegon, Ltd.

Federick A. Costello
F. A. Costello, Inc.

and

Staff of Bird Engineering
Research Associates, Inc.

August 1981

Prepared for
NATIONAL AERONAUTICS AND SPACE ADMINISTRATION
Lewis Research Center
Under Contract DEN 3-195

for
U.S. DEPARTMENT OF ENERGY
Conservation and Renewable Energy
Division of Thermal Solar Energy Systems

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 to document work sponsored by the United States Government. Neither the United States nor its agent, the United States Department of Energy, nor any Federal 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.

Photovoltaic Stand-Alone Systems:

Preliminary Engineering-Design Handbook

H. L. Macomber and John B. Ruzek
Monegon, Ltd.
Gaithersburg, Maryland 951 4052

Frederick A. Costello
F. A. Costello, Inc.
Herndon, Virginia 951 4053

and

Staff of Bird Engineering
Research Associates, Inc.
Vienna, Virginia 951 4054

August 1981

Prepared for
National Aeronautics and Space Administration
Lewis Research Center
Cleveland, Ohio 44135
Under Contract DEN 3-195

for
U.S. DEPARTMENT OF ENERGY
Conservation and Renewable Energy
Division of Solar Thermal Energy Systems
Washington, D.C. 20545
Under Interagency Agreement DE-AI01-79ET20485

DISCLAIMER

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

fy

ACKNOWLEDGEMENT

This handbook was prepared by MONEGON, LTD., of Gaithersburg, Maryland under Contract DEN3-195 with the National Aeronautics and Space Administration, Lewis Research Center. John B. Ruzek served as Project Engineer with management support by Dr. Harold L. Macomber. Valuable assistance was provided by two subcontractors, Frederick A. Costello, Inc., Consulting Engineers, and Bird Engineering-Research Associates, Inc.

NOTE: Throughout this handbook, reference is made to Loss of Load Probability (LOLP) estimation procedures. According to the 1970 National Power Survey of the Federal Power Commission, these estimating procedures may be more correctly defined as Loss of Energy Probability (LOEP) procedures. This definitional difference in no way affects the accuracy or usefulness of these procedures.

CONTENTS

<u>Section</u>	<u>Title</u>	<u>Page</u>
1	INTRODUCTION	1-1
2	GUIDE TO HANDBOOK USAGE	2-1
3	TYPICAL STAND-ALONE PHOTOVOLTAIC SYSTEM CONFIGURATIONS	3-1
4	COMPONENT DESIGN AND ENGINEERING INFORMATION	4-1
4.1	Electrical Loads	4-1
4.1.1	Estimating the Load	4-1
4.1.2	Load Reduction Strategies	4-4
4.1.3	Merits and Disadvantages of Both Ac and Dc Power	4-5
4.2	Photovoltaic Arrays	4-7
4.2.1	Photovoltaic Terminology	4-7
4.2.2	Ideal Solar-Cell Current-Voltage Characteristics	4-12
4.2.3	Current-Voltage Characteristics of Arrays in the Field	4-21
4.2.4	Available Modules	4-24
4.3	Lead-Acid Storage Batteries	4-27
4.3.1	Advantages and Disadvantages of Batteries in Photovoltaic Systems	4-27
4.3.2	Battery Operation	4-28
4.3.3	Battery Current/Voltage Characteristics	4-28
4.3.4	Battery-System Design	4-32
4.3.5	Battery Life	4-33
4.3.6	Lead-Acid Storage Battery Safety	4-36
4.4	Power Handling	4-40
4.4.1	Dc Power Conditioning	4-40
4.4.2	Control Schemes	4-43
4.4.3	Electrical Wiring	4-46
4.5	Emergency Backup Systems	4-51
4.5.1	Load Analysis	4-51
4.5.2	Basic PVPS Design Margin	4-52
4.5.3	Types and Suitability of Backup Systems	4-53
4.5.4	Incorporation of Backup Into the PV System	4-56

CONTENTS (Continued)

<u>Section</u>	<u>Title</u>	<u>Page</u>
5	INFORMATION NEEDED TO START THE DESIGN PROCESS	5-1
6	PRELIMINARY SYSTEM DESIGN CONSIDERATIONS	6-1
6.1	Insolation and Siting	6-1
6.2	Operation of PV Systems Under Varying Loads	6-7
6.2.1	Array and Battery Quick-Sizing Method	6-7
6.2.2	Component Sizing	6-9
6.3	Basic Approach to Feasibility Assessment of Photovoltaic Power Systems	6-13
6.3.1	Preliminary Estimate	6-13
6.3.2	Life Cycle Cost Determination	6-15
6.4	Reliability Engineering Approach	6-18
6.4.1	Definition and Specification of PV System R & M Requirements	6-18
6.4.2	R & M Networks and Block Diagrams	6-24
6.4.3	Reliability Prediction and Feasibility Requirements	6-29
6.4.4	Failure Mode and Effects Analysis	6-30
6.5	Advantages and Disadvantages of PV Power Systems	6-34
7	SYSTEM DESIGN	7-1
7.1	Design Philosophy	7-1
7.2	System Design Procedure	7-2
7.3	Codes and Standards	7-15
7.3.1	Codes	7-15
7.3.2	Standards	7-16
7.3.3	Manuals	7-17
7.3.4	Approved Equipment Listings	7-17
7.3.5	Notes	7-18
7.3.6	Applicable Document List	7-18

CONTENTS (Continued)

<u>Section</u>	<u>Title</u>	<u>Page</u>
8	INSTALLATIONS, OPERATION AND MAINTENANCE	8-1
8.1	Introduction	8-1
8.2	Power Outages	8-1
8.3	Reliability and Maintainability	8-2
8.4	Operation and Maintenance Tradeoffs	8-3
	8.4.1 Operation and Preventive Maintenance	8-3
	8.4.2 Corrective Maintenance	8-5
8.5	System Maintenance	8-8
	8.5.1 Maintenance Concept	8-8
	8.5.2 Maintainability Design	8-9
8.6	Logistics Design	8-11
	8.6.1 Supply Support	8-11
	8.6.2 Power System Drawings	8-13
	8.6.3 Tools, Test Equipment, and Maintenance Aids	8-13
	8.6.4 Technical Manuals	8-14
	8.6.5 Training	8-15
8.7	Installation Design Considerations	8-15
	8.7.1 Physical Considerations	8-15
	8.7.2 Equipment Housing and Structure Considerations	8-16
	8.7.3 Installation Checkout and Acceptance Testing	8-16
9	SITE SAFETY	9-1
9.1	Personnel Safety Checklist	9-1
	9.1.1 Safety & Health Standards	9-1
	9.1.2 Electric Shock	9-2
	9.1.3 Toxic & Flammable Materials	9-2
	9.1.4 Fire Safety	9-2
	9.1.5 Excessive Surface Temperatures	9-3
	9.1.6 Equipment Identification Labeling	9-3
	9.1.7 Physical Barriers	9-3

CONTENTS (Continued)

<u>Section</u>	<u>Title</u>	<u>Page</u>
9.2	Facility Safety Checklist	9-4
	9.2.1 PVPS Safety Protection from Environmental Conditions	9-4
	9.2.2 PVPS Safety Protection from Man-Made Conditions	9-5
	9.2.3 PVPS Safety Protection from Component Failure	9-6
9.3	References	9-6
10	DESIGN EXAMPLES	10-1
	10.1 Remote Multiple-Load Application	10-1
	10.1.1 Northern Hemisphere Location	10-1
	10.1.2 Southern Hemisphere Location	10-2
11	INSOLATION	11-1
	11.1 Introduction	11-1
	11.2 Insolation Calculation Programs	11-5
	11.3 Statistical Insolation Computations	11-13
	11.4 Sun Angle Charts	11-15
	11.5 Row-to-Row Shading	11-15
12	PHOTOVOLTAIC SYSTEM COMPONENTS	12-1
	12.1 Solar Cell Modules	12-1
	12.2 Batteries	12-7
	12.3 Dc Regulators	12-9
	12.4 Dc Motors	12-10
13	GLOSSARY OF TERMS	13-1
	13.1 Definitions of Photovoltaic Terminology	13-1
	13.2 Conversion Factors	13-3
14	PHOTOVOLTAIC POWER SYSTEM EQUIPMENT SUPPLIERS	14-1
	14.1 Photovoltaic Cells, Modules	14-1
	14.2 Batteries	14-2
	14.3 Power Conditioning Equipment	14-3
	14.4 Direct Current Motors and Load Devices	14-5

CONTENTS (Continued)

<u>Section</u>	<u>Title</u>	<u>Page</u>
APPENDIX A	WORLDWIDE INSOLATION DATA	A-1
APPENDIX B	FAILURE RATES FOR RELIABILITY ESTIMATION	B-1
	B.1 Failure-Rate Trends	B-1
	B.2 Sources of Failure-Rate Data	B-2
	B.3 Estimated Failure Rates for Certain Items in the Typical PV System	B-3
APPENDIX C	LISTING OF SPONSORS OF CODES AND STANDARDS	C-1
	C.1 List of Codes and Standards Agencies and Their Addresses	C-1
	C.2 Listing of Codes and Standards by Agencies	C-2
REFERENCES		R-1

EXHIBITS

<u>Exhibit</u>		<u>Page</u>
2-1	Flow Chart, Photovoltaic Stand-Alone Systems Preliminary Engineering Design Handbook	2-2
3-1	Generalized Stand-Alone Direct Current Photovoltaic Power System Block Diagram	3-2
4.1-1	Load Diversity	4-3
4.1-2	Load-Reduction Strategies	4-4
4.1-3	Disadvantages of Dc and Ac	4-6
4.2-1	Terminology for Large-Scale Photovoltaic Installations	4-8
4.2-2	Series/Parallel Circuit Nomenclature	4-10
4.2-3	Module Output and Intermediate Loss Mechanisms	4-11
4.2-4	Operation of a Solar Cell	4-13
4.2-5	Equivalent Circuit of a Solar Cell	4-15
4.2-6	Typical Array Characteristics	4-16
4.2-7	Current-Voltage Characteristics of Cells in Series and Parallel	4-18
4.2-8	Protection From Open Circuit Failures	4-20
4.2-9	Array Power Loss Fraction Vs. Substring Failure Density	4-23
4.2-10	Typical Available Silicon Solar Modules	4-25
4.2-11	Nominal Array Costs (1975 Cost Levels)	4-26
4.3-1	Characteristics Summary Table: Commercially Available Batteries	4-29
4.3-2	Lead-Acid Battery Characteristic Curves	4-30
4.3-3	Lead-Acid Battery Failure Mechanisms	4-34
4.3-4	Typical Battery State of Charge (SOC) History	4-35

EXHIBITS (Continued)

<u>Exhibit</u>		<u>Page</u>
4.4-1	Self-Regulated PV System	4-42
4.4-2	I-V Curve of PV Module Exhibiting Self-Regulation	4-42
4.4-3	Voltage-Regulated PV System	4-42
4.4-4	Simplified Block Diagram For a Maximum Power Tracking Controller	4-45
4.5-1	Summary Descriptions of Backup Systems	4-55
5-1	Minimum Data Requirements to Establish Feasibility	5-2
5-2	General Checklist for Detailed Design	5-3
6.1-1	Average Monthly Insolation ($\text{kWh/m}^2\text{-day}$) and the Ratio of Standard Deviation (Sigma 1) to Average	6-3
6.1-2	Horizon Profiles for Two Candidate Sites	6-6
6.2-1	Quick Sizing Computational Procedure for Array and Storage	6-10
6.2-2	Battery Storage Requirements for 1% LOLP	6-11
6.2-3	Effect of Depth of Discharge on Battery Life on Typical Lead-Acid Motive Power Type Cell	6-12
6.3-1	Components, System Costs and Economic Parameters	6-16
6.3-2	Photovoltaic Power System Preliminary Design Life Cycle Cost Computation	6-17
6.4-1	Reliability Functions for Exponential (Random) and Gaussian (Wearout) Facilities	6-19
6.4-2	Partial Description of Requirements for Hypothetical Customer Application	6-22
6.4-3	Example Reliability Allocation for a Hypothetical System	6-23
6.4-4	Functional Reliability Block Diagram	6-25
6.4-5	Functional Oriented Reliability Block Diagram	6-25
6.4-6	Optional Module Configurations: (A) Series: (B) Series/Parallel	6-26

EXHIBITS (Continued)

<u>Exhibit</u>		<u>Page</u>
7.2-1	Loss-of-Load Probability Computational Procedure	7-3
7.2-2	Cumulative Distribution Function for the Normal Curve	7-4
7.2-3	Example of Loss-of-Load Probability Computation	7-7
7.2-4	Listing of a TI-59 Program for Calculating Loss-of-Load Probability	7-8
7.2-5	Instructions for the Operation of the TI-59 Program for Computing the Loss-of-Load Probability	7-9
7.2-6	Listing of an HP-67 Program for Calculating Loss-of-Load Probability	7-10
7.2-7	Instructions for the Use of the HP-67 Program for Calculating Loss-of-Load Probability	7-13
7.2-8	Typical Cases for the Loss-of-Load Probability	7-14
8.2-1	Causes of Power Loss in PV Systems	8-1
8.4-1	Reliability Improvement with Standby Redundancy	8-7
10.1-1	Multiple Load Application Monthly Load Summary	10-3
10.1-2	Multiple Load Application Equipment Sizing	10-4
11.1-1	Insolation Computation for a South-Facing Array	11-2
11.1-2	Insolation Computation Example: Washington, D.C.	11-3
11.1-3	Ground Reflectances for Various Surfaces	11-4
11.2-1	Instructions for Operating the TI-59 Insolation Computation Program	11-6
11.2-2	Listing of a TI-59 Insolation Computation Program	11-7
11.2-3	Instructions for Operating the HP-67 Insolation Computation Program	11-9
11.2-4	Listing of an HP-67 Insolation Computation Program	11-10
11.3-1	Generalized K_H Distribution Curves	11-14

EXHIBITS (Continued)

<u>Exhibit</u>		<u>Page</u>
11.4-1	Illustration of Solar Altitude and Azimuth Angles	11-16
11.4-2	Sun Chart for 0 ^o Latitude	11-17
11.4-3	Sun Chart for 8 ^o Latitude	11-17
11.4-4	Sun Chart for 16 ^o Latitude	11-18
11.4-5	Sun Chart for 24 ^o Latitude	11-18
11.4-6	Sun Chart for 32 ^o Latitude	11-19
11.4-7	Sun Chart for 40 ^o Latitude	11-19
11.4-8	Sun Chart for 48 ^o Latitude	11-20
11.4-9	Sun Chart for 56 ^o Latitude	11-20
11.4-10	Sun Chart for 64 ^o Latitude	11-21
11.4-11	Sample Shading Calculation	11-22
11.5-1	Minimum Row-to-Row Spacing Required for No Shading Between 0900 and 1500 Hours on Dec. 21 (June 21)	11-23
12.1-1	Comparison of Typical Specifications for Photovoltaic Modules	12-3
12.2-1	Table of Important Battery Design Characteristics	12-8
12.3-1	Dc Regulators Specification Requirements	12-9
12.4-1	Representative Data on Dc Motors	12-11
B-1	Failure Rate of an Item as a Function of Operating Time	B-1
B-2	Preliminary Failure-Rate Estimates of Selected Items	B-3

Blank

SECTION 1 INTRODUCTION

The central component of any photovoltaic power system is the solar cell. It is the transducer that directly converts the sun's radiant energy into electricity. The technology for using solar cells to produce usable electrical energy is known and proven. The orbiting satellite Vanguard I, launched in March 1958, used solar cell panels to power its radio transmitter for about six years before radiation damage caused it to fail. The space program that continued after Vanguard I not only used photovoltaic systems, but fostered an industry for producing the spacecraft solar cells and arrays.

The production of photovoltaics associated with the space program reached about 50 kW per year and then leveled off. The 1973 oil embargo provided the stimulus for the government and the industry to begin to take serious steps to accelerate the normally very slow development process in order to seek significant expansion of the initial terrestrial markets. As of 1980, the annual production of solar cells is well in excess of 4 MW per year.

In 1973 a few pioneers of the photovoltaic industry began the terrestrial photovoltaic industry by shifting from the use of reject space solar cells to cells designed specifically for terrestrial use. This industry has installed thousands of photovoltaic systems representing a cumulative power of more than 6 MW since this beginning.

Since its initiation in 1975, the U.S. Department of Energy (DOE) National Photovoltaic Program has sponsored the design and implementation of nearly 40 system applications classed as "stand-alone" systems with less than 15 kW peak in power rating. In addition, through the DOE managed Federal Photovoltaic Utilization Program (FPUP), 3,118 applications of the small stand-alone class have been funded for installation in the first two of a five-cycle program.

Outside of DOE, the Department of Defense has funded the design and installation of nearly 150 stand-alone photovoltaic systems. A few scattered applications have also been sponsored by other government agencies such as the Indian Health Service of the U.S. Department of Health, Education, and Welfare and by the U.S. Department of State, Agency for International Development.

The purpose of this handbook is to enable a system design engineer to perform the preliminary system engineering of the stand-alone Photovoltaic Power System (PVPS). This preliminary system engineering includes the determination of overall system cost-effectiveness, the initial sizing of arrays and battery systems, and the considerations which must be specifically addressed in the subsequent detailed engineering stage of the project.

The scope of this handbook is limited to flat-plate, stand-alone PVPS for locations anywhere in the U.S. and in areas of the world which are located between the latitudes of 60° South and 60° North. As a stand-alone electrical system, the PVPS will be a self-sufficient system which includes an array field, power conditioning and control; battery storage, instrumentation and dc loads. While the intent of this handbook is for low-power applications, serving loads up to 15 kW in size, the theory and sizing methods are not dependent upon the generating capacity of the system or the peak demand of the loads, but only on the desired reliability criteria chosen.

SECTION 2

GUIDE TO HANDBOOK USAGE

This handbook is intended to aid a system design engineer in determining the suitability of stand-alone photovoltaic power systems for specific applications. It will be helpful in the preliminary engineering of the system in which the initial sizing of the major components of the power system are determined.

A flow chart is presented in Exhibit 2-1 which can be used to guide the reader in the use of this handbook. The flow chart expresses the relationships between the various sections of the handbook. The first three sections of the handbook contain introductory material and will not normally be referred to in the design process.

Section 4 enables the user to estimate loads in the PVPS, to estimate array performance, develop current-voltage curves for arrays with parallel and series connections, to estimate power output as a function of time, develop the conceptual design of the array for high reliability. This section of the handbook also shows the reader typical battery operations, battery current-voltage characteristics, and the procedures of estimating system performance with a battery, as well as the safety aspects of using lead-acid batteries in a stand-alone system. This section also describes the power handling portion of the PVPS which interfaces the arrays with the end-use loads. This includes dc power conditioning, control schemes, electrical wiring, and emergency back-up systems.

Section 5 contains two lists which will be useful in the assembly of data needed in the design processes. The first list contains the minimum data requirements to establish the feasibility of a photovoltaic power system (PVPS) in the preliminary design stage. The second is a more comprehensive list for the detailed design stage of the PVPS prior to construction which follows preliminary engineering.

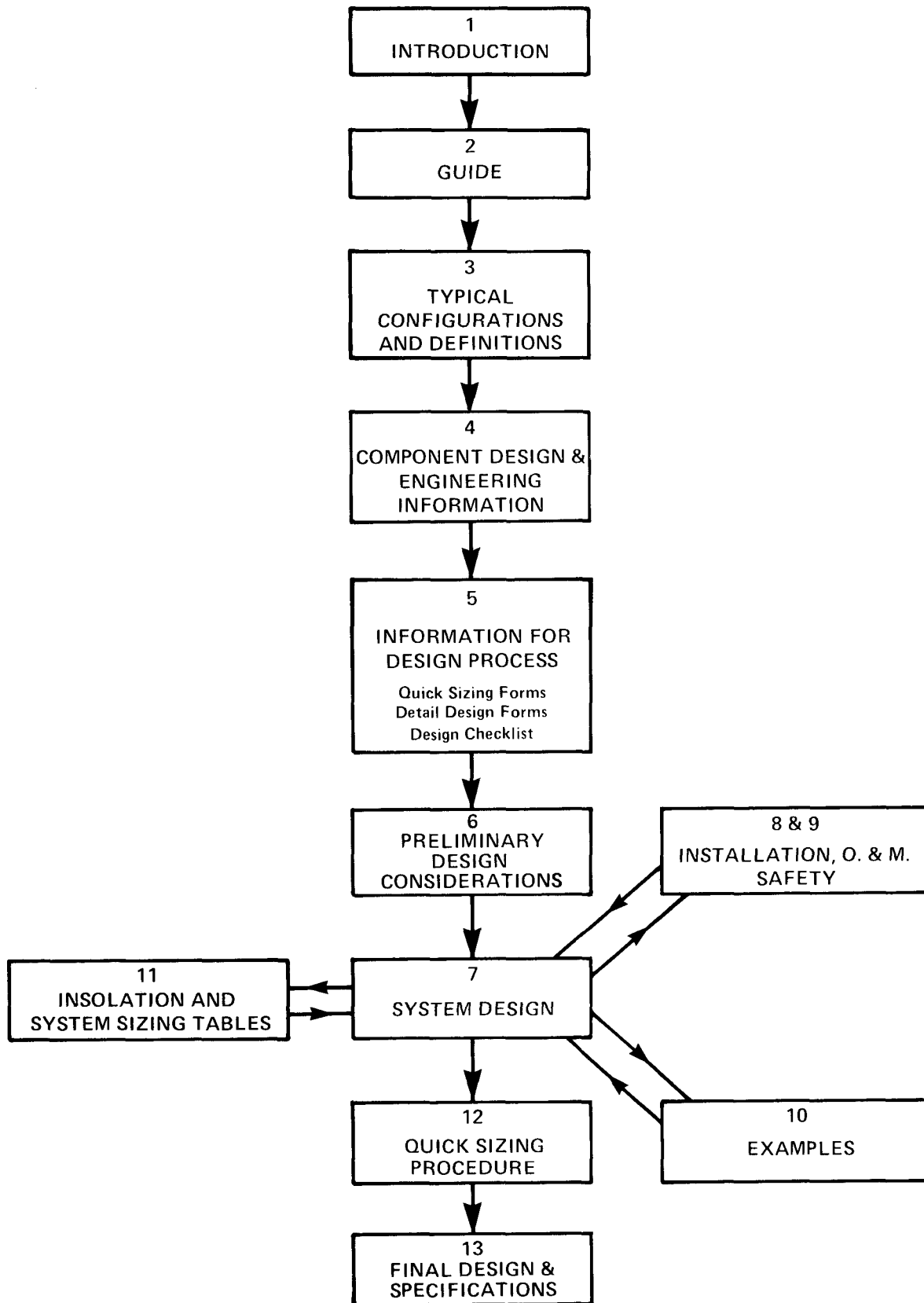


Exhibit 2-1

FLOW CHART
PHOTOVOLTAIC STAND-ALONE SYSTEMS
PRELIMINARY ENGINEERING DESIGN HANDBOOK

Section 6 presents the preliminary design considerations including insolation and siting, operation of the PVPS under varying loads, approaches to reliability engineering, the advantages and disadvantages of PV power systems, the elements of life-cycle costing and the quick-sizing of PV power systems. Section 7 presents the procedure for system design and the method for estimating the loss of load probability.

Sections 8 and 9 cover the installation, operations, maintenance and safety aspects of the PVPS. They set forth the basic design considerations which must be considered during detailed design of the system.

Section 10 presents an example of the quick-sizing procedure to determine the approximate size and cost of a photovoltaic system for any particular application. This quick-sizing is useful in evaluating photovoltaic feasibility without going through a detailed analysis.

Section 11 presents the calculational tools for the determination of the insolation on a tilted surface. Using the clearness index for a specific site (tabulated in Appendix A for a number of cities in the U.S. and throughout the world), the latitude angle of the site, the tilt angle of the site and the reflectance of the ground in front of the array, the average daily insolation for a given month can be determined.

For quick reference, Sections 12, 13, and 14 contain data on photovoltaic system components, a glossary of terms, and listings of equipment suppliers, respectively.

2-4

SECTION 3
TYPICAL STAND-ALONE
PHOTOVOLTAIC SYSTEM CONFIGURATIONS

A photovoltaic power system using today's technologies and designed for a stand-alone (non utility-grid connected) application in today's markets includes a solar array using flat plate or concentrating type collectors, and may include such electrical system components as a system controller, a lead acid battery, a voltage regulator, an instrumentation system and an on-site standby generator for emergency back-up. Exhibit 3-1 is a generalized stand-alone direct current photovoltaic power system block diagram showing the elements of the generating and load portions of the overall system.

A flat plate array or concentrator array functions as the solar collector for the photovoltaic system. At present, flat plate arrays are the principle collectors used in the installed photovoltaic power systems in the world. Some concentrator applications exist. The methodology of sizing the arrays in this handbook applies to either fixed-tilt or seasonally adjusted tilted, flat plate arrays.

The power conditioning subsystem provides the interface between the arrays and the power system's loads. The function of a power conditioning subsystem is to render the variable dc output of the array suitable to meet the power requirements of the loads. For dc systems, the power conditioning subsystem typically includes voltage regulation, energy storage, and possibly a dc/dc converter interface with the loads.

The lead-acid battery provides the energy storage for the photovoltaic system. It increases the reliability level of providing power to the loads and also improves the array efficiency by keeping the solar cell voltage within prescribed limits. The operation of the arrays is presented in Section 4.

A regulator is required when electrochemical storage is employed. The regulator controls the current and voltage inputs to the batteries to protect them from damage at either end of the charging cycle. At the beginning of the cycle,

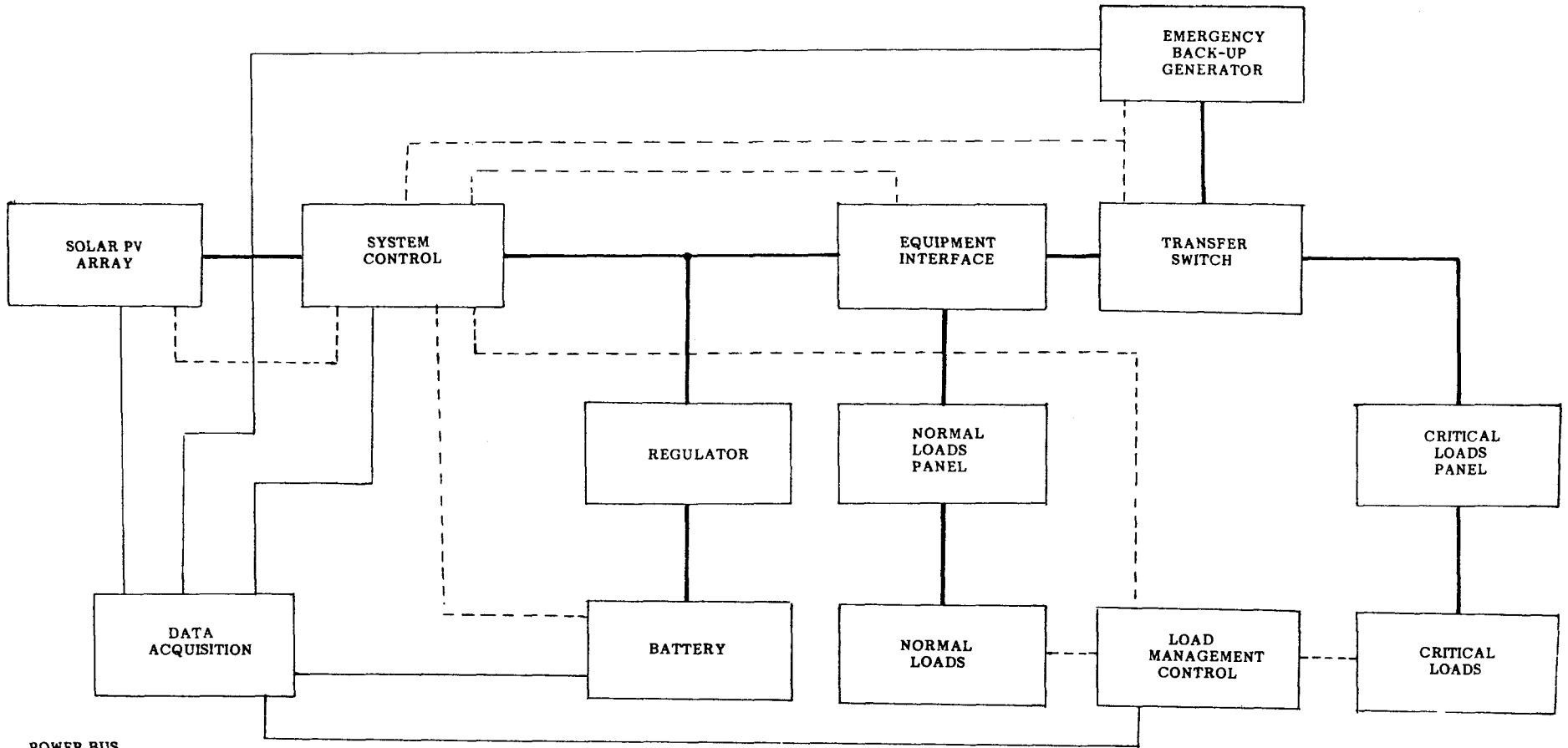
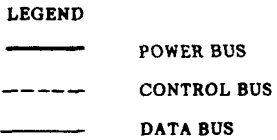


Exhibit 3-1

GENERALIZED STAND-ALONE DIRECT CURRENT PHOTOVOLTAIC POWER SYSTEM BLOCK DIAGRAM

the discharged batteries would draw a large current from an unregulated photovoltaic array which would cause overheating of the batteries and shorten their lives. At the end of the charging cycle, the voltage across an unregulated battery would be too large and further charging would generate hydrogen gas and dehydrate the batteries.

In order to provide a higher degree of reliability of electric service to the power system's loads than the combination of the photovoltaic arrays and storage batteries might be capable of in a cost effective manner, an emergency back-up generating unit may be connected into the system. When emergency back-up is incorporated, it is advantageous to be able to feed just those loads which are deemed to be of an emergency or critical nature. An automatic transfer switch may thus be incorporated to "throw" these loads over to the emergency back-up system upon the complete discharge of the storage batteries during periods of low insolation.

A load management control system may also be included in some systems to reduce the peak aggregate of the loads and thus reduce somewhat the required capacity of both the photovoltaic arrays and that of the energy storage system. It is also possible to control the loads in such a way as to reduce not only the peak diversified demand but also the system's average daily energy requirements by means of duty cyclers and load schedules which limit electricity use according to preset patterns. Such a strategy would also help reduce the size of arrays and the energy storage system.

The sections which follow present details of various components for photovoltaic power systems and tradeoff considerations in the preliminary sizing of those systems.

SECTION 4
COMPONENT DESIGN AND
ENGINEERING INFORMATION

4.1 ELECTRICAL LOADS

The size and cost of a photovoltaic system is strongly dependent upon the energy requirements of the loads which are to be served. The peak demand and energy requirements must be estimated as well as possible, to avoid unnecessarily oversizing the power system and adding to cost. This is especially apparent when the relative component costs are compared in the capital cost estimate for the life-cycle cost computation based on current-day (1980) levels. It is seen in such a comparison that the unit cost of array capacity is typically appreciably higher than for any other part of the power system. This sub-section reviews load estimations, load reduction strategies and considerations of using dc rather than ac for the distribution system and loads.

4.1.1 Estimating the Load

Individual loads are characterized by their power requirements as determined by both voltage and current ratings and duty cycle, which will determine their energy requirements. Dc loads may be made of either resistive elements, drawing constant power for given applied voltages, or may be composed of motors which are dependent upon the mechanical torque requirements of the driven loads to determine voltage and current inputs. A third category of energy transformation utilizing induction coupling applies to ac load categories and includes examples such as fluorescent lamps, power supplies with transformers, and high frequency converters such as microwave oven supplies. For systems up to 15 kW in size, the load might be comprised of a single device, e.g. a single 15 hp motor, or a multiple combination of lesser-sized motors and resistive loads.

The first aspect of the load analysis is to define energy requirements of the combination of loads to be operated by the power system. The power requirement represents the maximum demand at any one time. Since some of the equipment is operated on a cyclic basis, the average demand or the energy requirement is considerably less than would be obtained by assuming a full-time operation, and multiplying rated power requirements by 24 hours a day.

Cyclic operation of a large number of components permits the undersizing of equipment on the basis of load diversity. The odds are that if there are enough components drawing power from the system, not all components will draw current simultaneously. Large electric utilities make constant use of the low odds associated with their enormous systems in capacity sizing of generating units and distribution circuits. As an example, suppose there are four components on the line, drawing 1, 2, 3, and 5 kilowatts peak power randomly with duty cycles of 50 percent, 40 percent, 30 percent, and 20 percent, respectively. The probability that all four loads will operate simultaneously is 1.2 percent, as shown on Exhibit 4.1-1.

The 1.2 percent figure can be translated into 0.012 times 365 days, or 4 days per year that the aggregate load on the system will equal 10 kW. The probability of other load combinations are shown in the exhibit along with the expected energy demand of 72 kWh/day. The daily load factor for this system is 30% ($72 \text{ kWh} / (10 \text{ kW} \times 24 \text{ hr})$), which is equivalent to having an average 3 kW load running 24 hours/day. The full 10 kW of generating capacity must be installed to meet the peak loads unless either a load management scheme is installed or a 1.2% probability of overload is acceptable.

The probability of any other load can be estimated from the data on Exhibit 4.1-1. For example, the probability that the load will be 2 kW is equal to the probability that the 2 kW load will be on (0.40), multiplied by the probability that the three loads will be off ($0.5 \times 0.7 \times 0.8$), giving a probability of 0.112 that the load will be 2 kW. Similar computations can be executed for the other load sizes, so a curve of load size versus probability can be generated.

Exhibit 4.1-1
LOAD DIVERSITY

Load	Operating Time
1 kW	50%
2 kW	40%
3 kW	30%
4 kW	20%

Probability of simultaneous operation = $0.5 \times 0.4 \times 0.3 \times 0.2 = 0.012 = 1.2\%$

Probability of all combinations:

kW	Probability	Expected kWh/day
0	$(1-0.5) \times (1-0.4) \times (1-0.3) \times (1-0.2) = 0.168$	0
1	$0.5 \times (1-0.4) \times (1-0.3) \times (1-0.2) = 0.168$	4.0
2	$0.4 \times (1-0.5) \times (1-0.3) \times (1-0.2) = 0.112$	5.4
3	$0.3 \times (1-0.5) \times (1-0.4) \times (1-0.2) + 0.5 \times 0.4 \times (1-0.3) \times (1-0.2) = 0.184$	13.3
4	$0.5 \times 0.3 \times (1-0.4) \times (1-0.2) + 0.2 \times (1-0.5) \times (1-0.4) \times (1-0.3) = 0.114$	10.9
5	$0.3 \times 0.4 \times (1-0.5) \times (1-0.2) + 0.5 \times 0.2 \times (1-0.4) \times (1-0.3) = 0.090$	10.8
6	$0.5 \times 0.4 \times 0.3 \times (1-0.2) + 0.2 \times 0.4 \times (1-0.5) \times (1-0.3) = 0.076$	10.9
7	$0.2 \times 0.3 \times (1-0.5) \times (1-0.4) + 0.2 \times 0.4 \times 0.5 \times (1-0.3) = 0.046$	7.7
8	$0.2 \times 0.3 \times 0.5 \times (1-0.4) = 0.018$	3.5
9	$0.2 \times 0.3 \times 0.4 \times (1-0.5) = 0.012$	2.9
10	$0.2 \times 0.3 \times 0.4 \times 0.5 = 0.012$	<u>2.9</u>
Total daily load		72.0

4.1.2 Load Reduction Strategies

The foregoing discussion brings us to the logical concept of load shedding. If the probability of simultaneous operation is low, or if some functions are not critical, the peak demand can be limited by a controller that senses the total demand and supplies power to the low-priority components only when the demand on the power system is low. Reducing the peak load has an indirect effect on the reduction in energy demand, although it is difficult to estimate the energy impact without a detailed, sophisticated computer program that tracks system performance on an hourly basis.

When the energy demand of a potential photovoltaic application is analyzed, methods for reducing the requirements frequently are discovered. Exhibit 4.1-2 lists the most frequent methods of reduction. First, components can be operated cyclically. When one load is operating at peak demand, a second load can be shut off, thereby reducing peak power demand and, consequently, the sizes of the equipment such as motors. Smaller sized motors operating at higher loadings will result in higher system efficiency during off peak operation, and, therefore, lower energy consumption. The cyclic operation of the components can be either manual or automatic, although the automatic system will be more costly and will introduce another power-consuming component into the system. The automatic systems will generally be cost-effective only if the peak power under simultaneous operation is significantly greater than peak power under cyclic operation. At a ratio of approximately 3:1 (simultaneous to cyclic), the cyclic operation should be examined.

Exhibit 4.1-2

LOAD-REDUCTION STRATEGIES

Cyclic operation of components

Manual

Automatic

Diversity

Load Shedding

4.1.3 Merits and Disadvantages of Both Ac and Dc Power

For a remote stand-alone photovoltaic power system, the advantage of utilizing direct current loads is that the frequency inverter is not required, thus saving both the costs of the inverter equipment and of the added array capacity which would be required to supply the power lost from inverter inefficiency. A disadvantage of using dc is that there is very little flexibility to choose a higher distribution system voltage than that of the load in order to minimize the losses in the distribution system.

In making an assessment of whether or not to utilize an ac distribution system, the question of regulation should be considered. Although the inversion of dc to ac carries with it a nominal penalty of 12 percent inefficiency, relatively good ac output regulation can be achieved with the inverter within nominal limits of +5 percent. Regulating dc from an unregulated dc source (of which the array/battery combination is typical with a voltage range of +30 percent) also involves an inefficiency penalty of about 12 percent. Thus, power economy benefits would only result by using unregulated dc. Exhibit 4.1-3 lists some of the disadvantages of dc and ac for selected items.

Exhibit 4.1-3
DISADVANTAGES OF DC AND AC

Interaction	Waveform	
	dc	ac
Motor Drive	Brushes wear	
Universal/Induction	More expensive than ac equipment	
Lights		Fluorescent less efficient at low frequency operation
	Loss of incandescent and fluorescent reliability	
Electronics	Requires regulation	Requires regulation/rectification
PV Output		Requires inverter
Battery Charging		Requires rectification
Controls	Contact wear	Requires rectification
Multiple Voltages	Not easily accommodated	

4.2 PHOTOVOLTAIC ARRAYS

The intent of this sub-section is to (1) develop the current-voltage curve for arrays of solar cells consisting of parallel and series connections; (2) estimate the power output as a function of time, indicating the decrease that occurs due to cell failure, dirt accumulation, and maintenance routines; and (3) develop the conceptual design of the array for high reliability.

4.2.1 Photovoltaic Terminology

The terminology associated with the photovoltaic power systems, as used in this handbook, is that adopted from U.S. Department of Energy (DOE) projects. The power output from most solar cells currently in use is approximately 0.5 watts for a single cell; therefore, most systems require groups of cells to produce sufficient power. Cells are normally grouped into "modules"*, which are encapsulated with various materials to protect the cells and electrical connectors from the environment. A current typical module is two feet by two feet by two inches, with a glass cover through which the cells are exposed to the sunlight.

The modules are frequently combined into panels of, perhaps, four modules each. These panels are pre-wired and attached to a light structure for erection in the field as a unit. If the power output from a module is 30 watts, then power from a panel containing four modules is 120 watts. The panels are often attached to a field-erected structure to form an array (see Exhibit 4.2-1). Logical groups of arrays form an array subfield, which may feed a single power control system. The subarrays can be combined to form the entire array field. For small systems, the module, panel, array, subarray field, and array field may be identical, with only one module being used.

*In order to be consistent with much of the current literature which results from DOE-funded studies this Handbook uses the DOE definition of "module" viz., the smallest, independent, encapsulated unit consisting of two or more solar cells in series or parallel. It should be noted, however, that the photovoltaic industry often refers to the same item as a "panel".

SOLAR CELL – The basic photovoltaic device which generates electricity when exposed to sunlight.

MODULE – The smallest complete, environmentally protected assembly of solar cells and other components (including electrical connectors) designed to generate dc power when under unconcentrated terrestrial sunlight.

PANEL – A collection of one or more modules fastened together, factory preassembled and wired, forming a field installable unit.

ARRAY – A mechanically integrated assembly of panels together with support structure (including foundations) and other components, as required, to form a free-standing field installed unit that produces dc power.

BRANCH CIRCUIT – A group of modules or parallel modules connected in series to provide dc power at the dc voltage level of the power conditioning unit (PCU). A branch circuit may involve the interconnection of modules located in several arrays.

ARRAY SUBFIELD – A group of solar photovoltaic arrays associated by the collection of branch circuits that achieves the rated dc power level of the power conditioning unit.

ARRAY FIELD – The aggregate of all array subfields that generate power within the photovoltaic central power station.

PHOTOVOLTAIC CENTRAL POWER STATION – The array field together with auxiliary systems (power conditioning, wiring, switchyard, protection, control) and facilities required to convert terrestrial sunlight into ac electrical energy suitable for connection to an electric power grid.

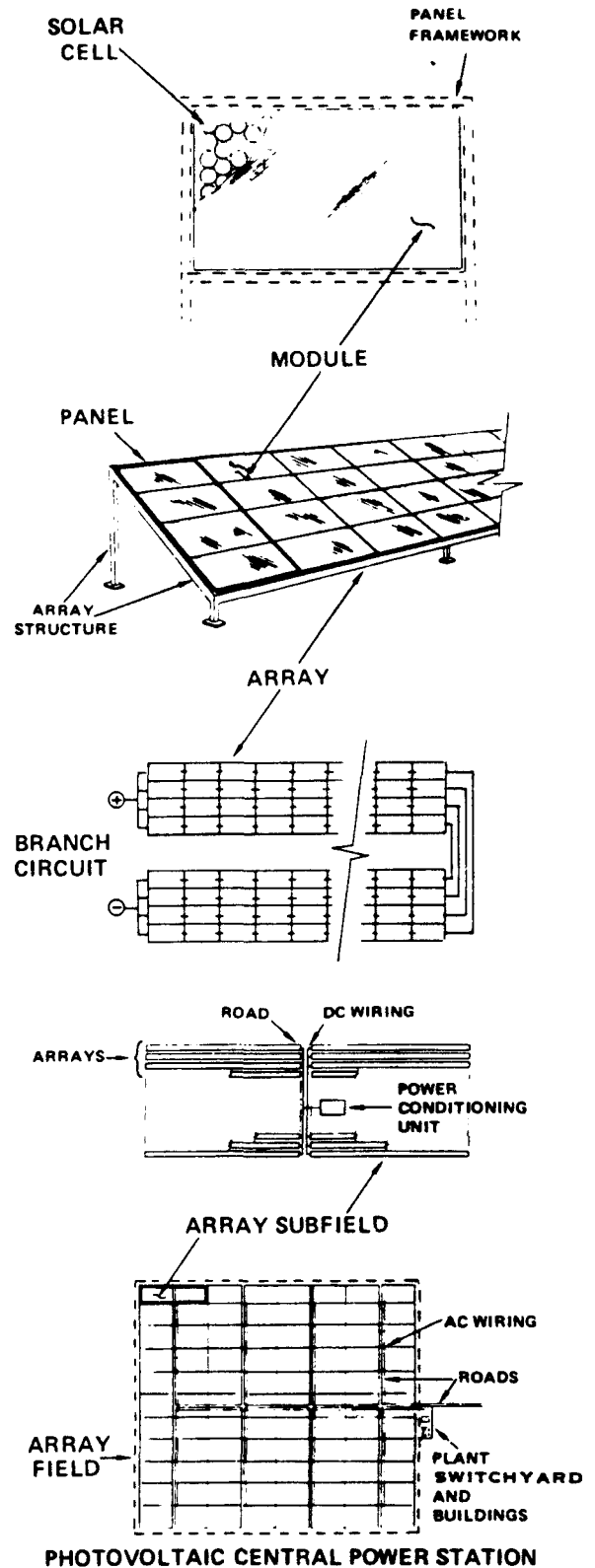


Exhibit 4.2-1

TERMINOLOGY FOR LARGE-SCALE PHOTOVOLTAIC INSTALLATIONS

(Source: Reference 4-1)

The nomenclature for the electrical circuits associated with the array is shown in Exhibit 4.2-2. Groups of cells arranged in series are called substrings; substrings arranged in parallel are called series blocks; series blocks connected in series are called branch circuits; and branch circuits are connected in parallel to form the array circuit. Blocking diodes are used to prevent the reverse flow of electricity from the load through the solar cells during times when part or all of the array is shadowed, although one blocking diode might be used for the entire array, rather than for each branch circuit as shown in Exhibit 4.2-2. Bypass diodes are frequently used to permit the current to pass through the branch circuit even when one or more of the series blocks has totally failed in the open-circuit condition.

The terminology pertaining to module output and efficiencies is presented in Exhibit 4.2-3. The overall efficiency is partitioned into efficiencies that identify each of the loss mechanisms. The ratio of the cell area to the module area is called the module packing efficiency, n_p . The cell active area is the product of the module area, the module packing efficiency and the cell nesting efficiency. The cell efficiency, n_c , is usually measured by a flash technique in which the cell temperature does not rise because the flash duration is so short. The efficiency so measured, at an insolation of 1.0 kW/m^2 and a cell temperature of 28°C , is called the bare cell efficiency. If the cell is encapsulated such as with a glass cover, the efficiency measured by this technique is called the encapsulated-cell efficiency.

The NOCT efficiency (Nominal Operating-Cell Temperature) corrects for the temperature at which a cell would operate in the field. The NOCT efficiency is measured at 1.0 kW/m^2 insolation and an outdoor-air temperature of 20°C , with a wind speed of one meter per second. The efficiency is measured at the cell temperature realized when the circuit is open, so no power is being extracted. The effect of power extraction is small, but the open-circuit temperature is used for purposes of standardization. The NOCT corrects for the losses associated with increased cell temperature.

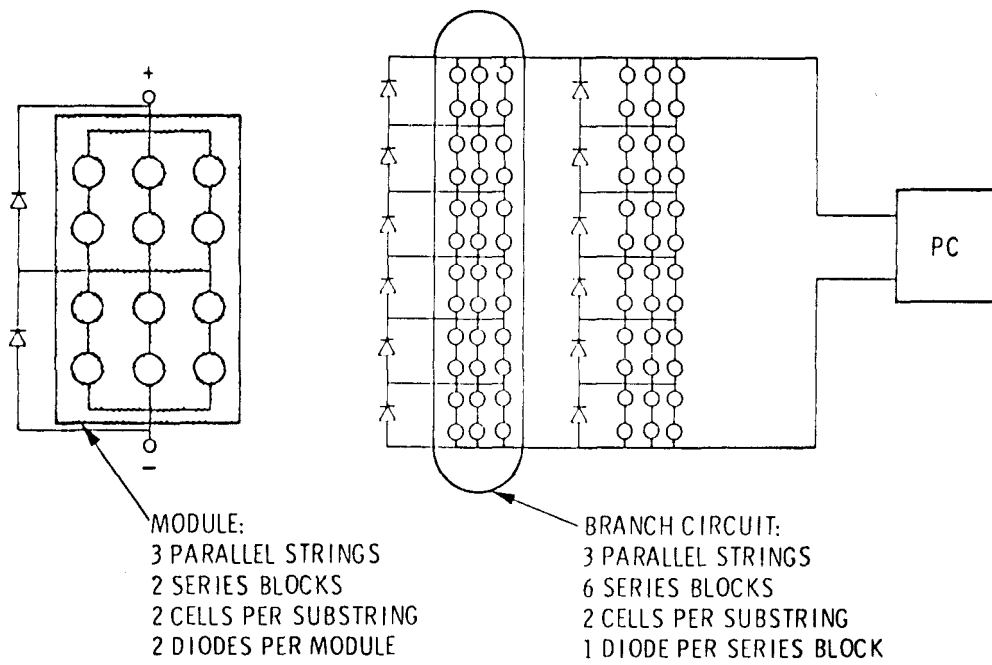


Exhibit 4.2-2

SERIES/PARALLEL CIRCUIT NOMENCLATURE

Exhibit 4.2-3

MODULE OUTPUT AND INTERMEDIATE LOSS MECHANISMS

	Definitions	Typical Values
	Overall Module Efficiency * at 1,000 W/m ² and NOCT (Nominal Operating Cell Temperature) is:	
	$n_m = n_p \times n_{NOCT} \times n_{EC} \times n_{IM}$	10%
where:	$n_p =$ Module Packing Efficiency = $n_{BR} \times n_N$	81%
	$n_{BR} = 1 - \left(\frac{\text{Module Border} + \text{Bus Area} + \text{Interconnect Area}}{\text{Module Area}} \right)$	90%
	$n_N =$ Cell Nesting Efficiency	100%
	$= \frac{\text{total cell area}}{\text{Module area} - (\text{Border area} + \text{Bus area} + \text{IC area})}$	
	$n_{NOCT} =$ Nominal Operating Cell Temperature Efficiency	90%
	$n_{EC} =$ Encapsulated Cell Efficiency at 1,000W/m ² , 28°C	13.5%
	$n_c =$ Bare Cell Efficiency (1,000W/m ² , 28°C)	15%
	$n_T =$ Optical Transmission Efficiency	95%
	$n_{MIS} =$ Electric Mismatch/Series Resistance Efficiency	95%
	$n_{IM} =$ Illumination Mismatch Efficiency	98%
	Therefore, module output is:	
	$m_O =$ Insolation x n_M	
	$=$ Insolation x $(n_{BR} \times n_N) \times (n_{NOCT}) \times (n_c \times n_T \times n_{MIS}) \times (n_{IM})$	

*(Reference 4-2, 4-3)

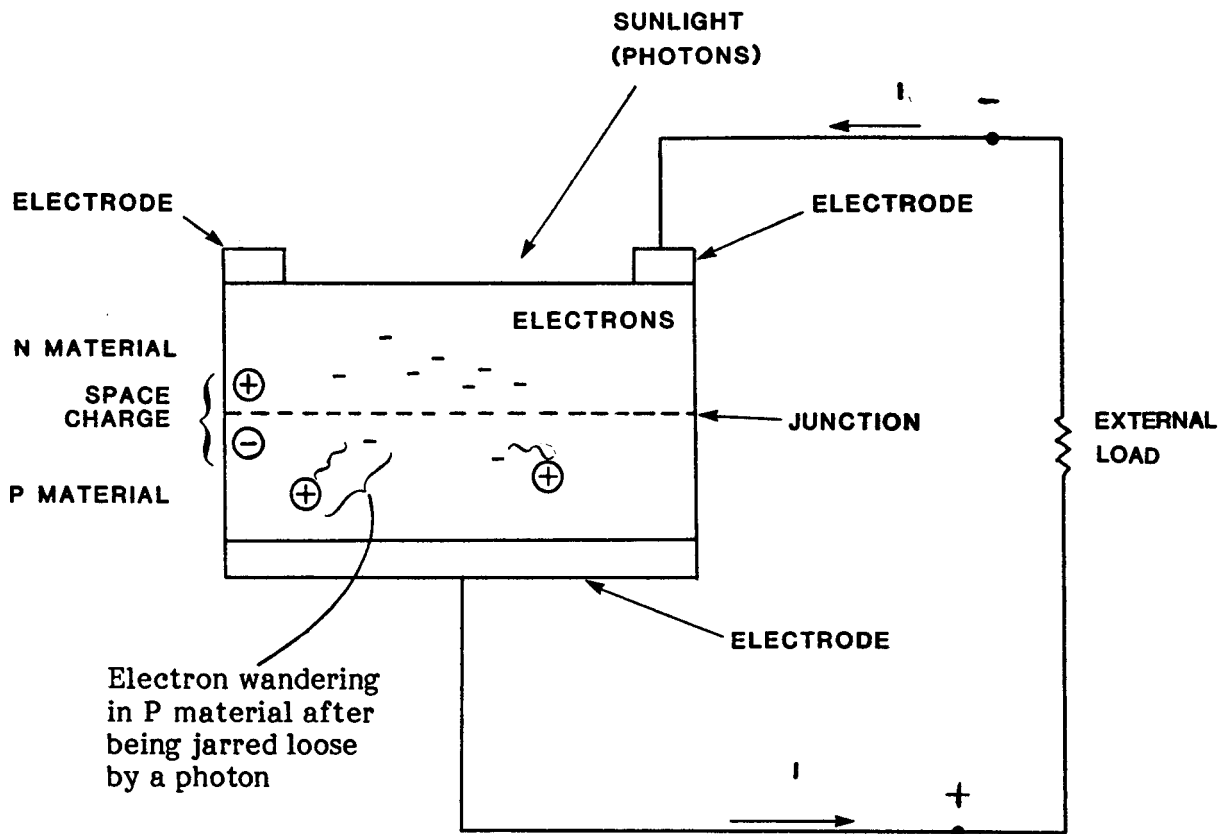
If the cells do not have identical current/voltage characteristics, there will be an additional loss, characterized by the electrical mismatch efficiency. If the cells are not all illuminated uniformly, perhaps due to partial shading by other panels, there is an additional loss which is characterized by the illumination-mismatch efficiency.

The overall panel output is the product of the insolation and the following efficiencies: module packing, encapsulated cell, NOCT and illumination mismatch. Some of these efficiencies are obtainable directly from the manufacturer. Others must be calculated, based on the techniques to be presented in this section.

4.2.2 Ideal Solar-Cell Current-Voltage Characteristics

Although the mathematical description of the processes occurring in a solar cell are quite complicated, the physical description is simple. Photons from the sunlight pass through the upper layer (the "n" material) into the thicker "p" material, where they strike the atoms, jarring electrons loose. The electrons wander throughout the "p" material until they are either recaptured by a positively charged ion (an atom that lost an electron) or until they are captured in the "n" material. The electrostatic charge near the junction between the "n" and "p" materials is such that, once in the vicinity of the junction, an electron is drawn across the junction and is held in the "n" material. As a consequence, the "n" material becomes negatively charged and the "p" material, which loses the electrons, becomes positively charged. If the electrons are gathered by the electrodes on the top surface of the cell and connected to an electrode on the bottom surface, the electrons will flow through the external connection, providing electricity through the external circuit. (Exhibit 4.2-4).

The junction in the solar cell is the same as the junction in a diode that might be used to pass electricity in one direction but not in the other. Approximately 0.4 volts is all that is required to drive the electrons from the "n" to the "p" region, across the electrostatic charge at the junction. This internal flow limits the voltage that can be attained with a solar cell. The resistance to electron flow from the "p" to the "n" material is much greater, being on the order of 50



- (a) Some are recaptured by the positive charge (hole)
 - (b) Some wander across the junction and get trapped by the space-charge barrier across the junction.
- } P region becomes +
N region becomes -

Exhibit 4.2-4

OPERATION OF A SOLAR CELL

volts. Only because the photons jar the electrons loose is there a flow in this direction under normal solar cell operation.

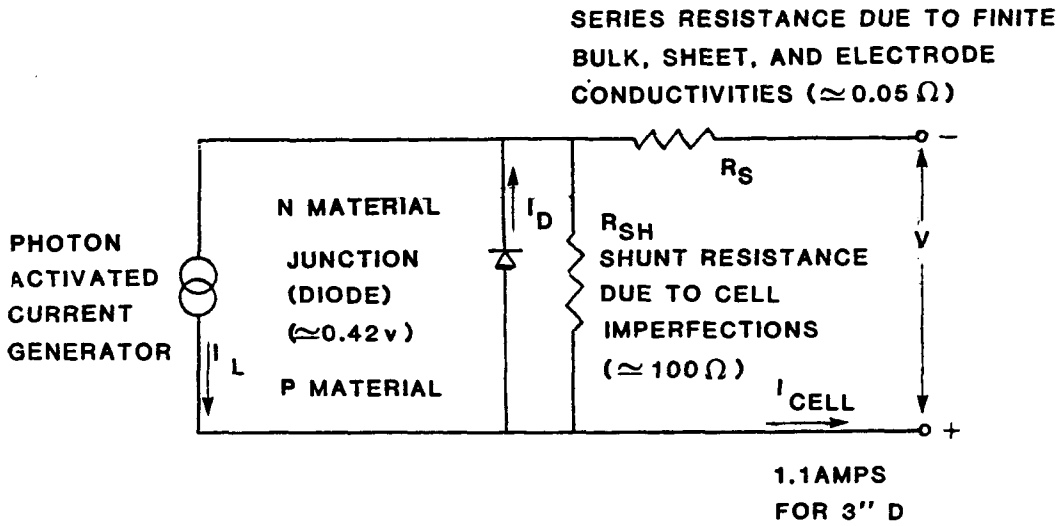
An equivalent circuit for a solar cell can be devised that incorporates its diode nature (Exhibit 4.2-5). The photon bombardment acts as a current source, driving the electrical current from the "n" to the "p" material. The diode tends to short this current directly back to the "n" material. An additional shunt resistance, characterizing primarily the losses near the edges and corners of the cell, adds to this shunting, although the shunt resistance is usually too small to be considered in most analyses. A series resistor characterizes the resistance of the cell material itself, the electrode resistance, and the constriction resistance encountered when the electrons travel along the sheet of "n" material into the small electrodes on the top surface.

The equation that describes the equivalent circuit and the corresponding current/voltage relationship consists of the following terms (Exhibit 4.2-5):

- a. the current source, called the light current, which is proportional to the illumination;
- b. the diode current, given by the Shockley equation; and
- c. the current through the shunt resistor.

With slight adjustment of the constants in the equation, excellent agreement can be obtained between the theoretical current/voltage relationship and the actual relationship. Notice that the relationship between the current and voltage is nonlinear, so the computations will be difficult and the relationships somewhat obscure.

Some insight into the importance of the various terms in the current/voltage relationship can be obtained by re-examining the typical performance curves for solar cells (Exhibit 4.2-6). The current is proportional to the illumination, whereas the open-circuit voltage changes little with illumination. Notice also that temperature has little effect on the short-circuit current, but that increasing temperatures decrease the open-circuit voltage -- an important effect when solar cells are used to charge batteries. When the voltage is zero, there is no flow of current through the diode. For small increases in the voltage, there is still



Current density output of solar cell:

$$I_{Cell}/A = \overbrace{S s}^{I_L/A} + \overbrace{K_{dev} A_o T^3 e^{-E_{GO}/KT} \left[1 - e^{-\frac{q}{kT} (V + R_s I_{Cell})} \right]}^{\text{Diode Current}} - \overbrace{\frac{V + R_s I_{Cell}}{R_{SH}}}^{\text{Shunt Current}}$$

Electronic charge ($q/K = 11600^\circ K$)

Boltzman constant

Band gap at $0^\circ K$ ($E_{GO}/K = 14000^\circ K$ for silicon)

Cell temperature ($^\circ K$)

Material constant (1.54×10^{45} carriers²/m⁶/ $^\circ K^3$ for silicon)

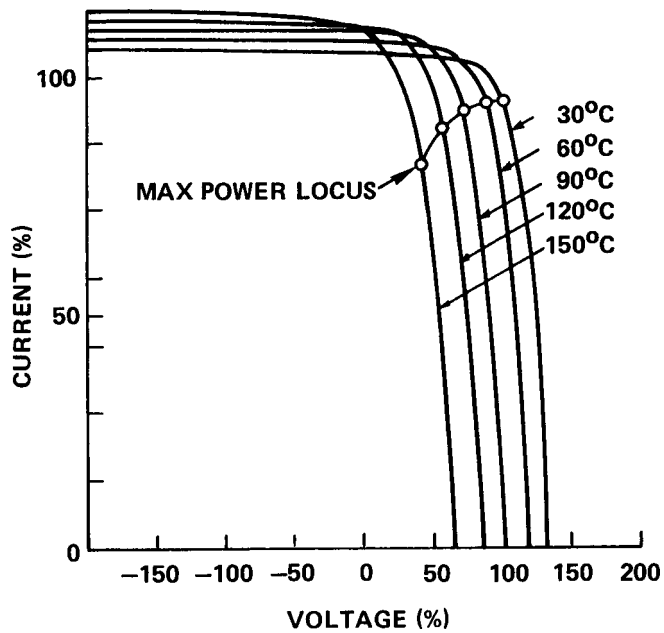
Device constant (1.55×10^{-39} Amps m⁴/carrier² for typical cells)

Current sensitivity (Amps/kW)

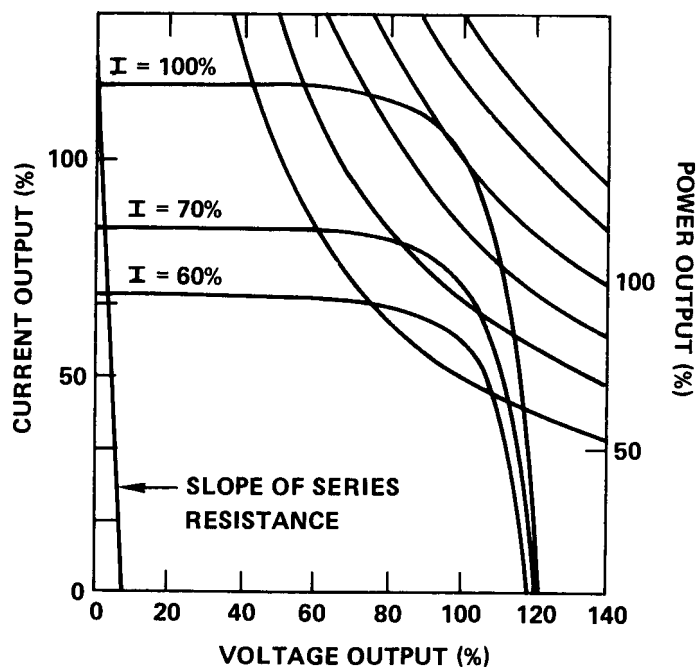
Insolation (kW/m²)

Exhibit 4.2-5

EQUIVALENT CIRCUIT OF A SOLAR CELL



OUTPUT CHARACTERISTIC VERSUS TEMPERATURE



TYPICAL I-V CURVES OF A SOLAR ARRAY AT THREE DIFFERENT ILLUMINATION LEVELS (Constant Spectral Distribution and Temperature, Illustrative Example)

Exhibit 4.2-6

TYPICAL ARRAY CHARACTERISTICS

no flow through the diode, which requires approximately 0.4 volts for significant current flow. Therefore, the slope of the I-V curve at low voltage depends only on the shunt resistance. The curve would be horizontal if the resistance were infinite.

As the cell output voltage increases, the diode current becomes important, so the output current from the cell begins to decrease rapidly. At approximately 0.55 volts, the photon-generated current is passed totally by the diode. At this near-constant-voltage condition, changes in the current have little effect on the diode and shunt current, so the current/voltage relationship is governed by the series resistance. The slope of the cell's I-V curve at zero current is equal to (the negative of) the series resistance. For best performance, the series resistance should be high, so better cells have steeper slopes at zero current.

The power output of a cell falls to zero at both zero voltage and zero current. Somewhere in between the power will be at a maximum. The maximum will occur near the knee of the curve, typically at 0.42 V and 1.1 A. The ratio of the peak power to the product of the open-circuit voltage and short-circuit current is called the fill factor.

The characteristics of the individual cells can be combined to obtain the characteristics of strings of cells connected in series or in parallel (Exhibit 4.2-7). For example, the current passing through two cells in series is the same, so the current-voltage curve of the pair of cells is constructed from that of the individual cells by adding the voltages for each current. For example, in Exhibit 4.2-7, the voltage of one cell is 0.4 when the current is 1.0 A. For two cells operating at 1.0 A, the output would be at $0.4 + 0.4 = 0.8\text{V}$. If the two cells were connected in parallel, rather than in series, the voltage across each of the cells would be the same, but the currents would add. Thus, at 0.4 V, the output current of two cells in parallel would be twice the 1.0 A, or 2.0 A. The same procedures would be used for more cells in parallel or series or for entire modules in parallel or series.

If one cell is only 15% illuminated (dotted I-V curve in Exhibit 4.2-7), it will seriously alter the performance of the pair of cells. For example, if the cells are in series and an output current of 0.4 A is to be obtained, the output voltage would be $0.49 - 25 = -24.5\text{ V}$, as read from the Exhibit. The negative implies that an external voltage source would be required to drive the current in the forward

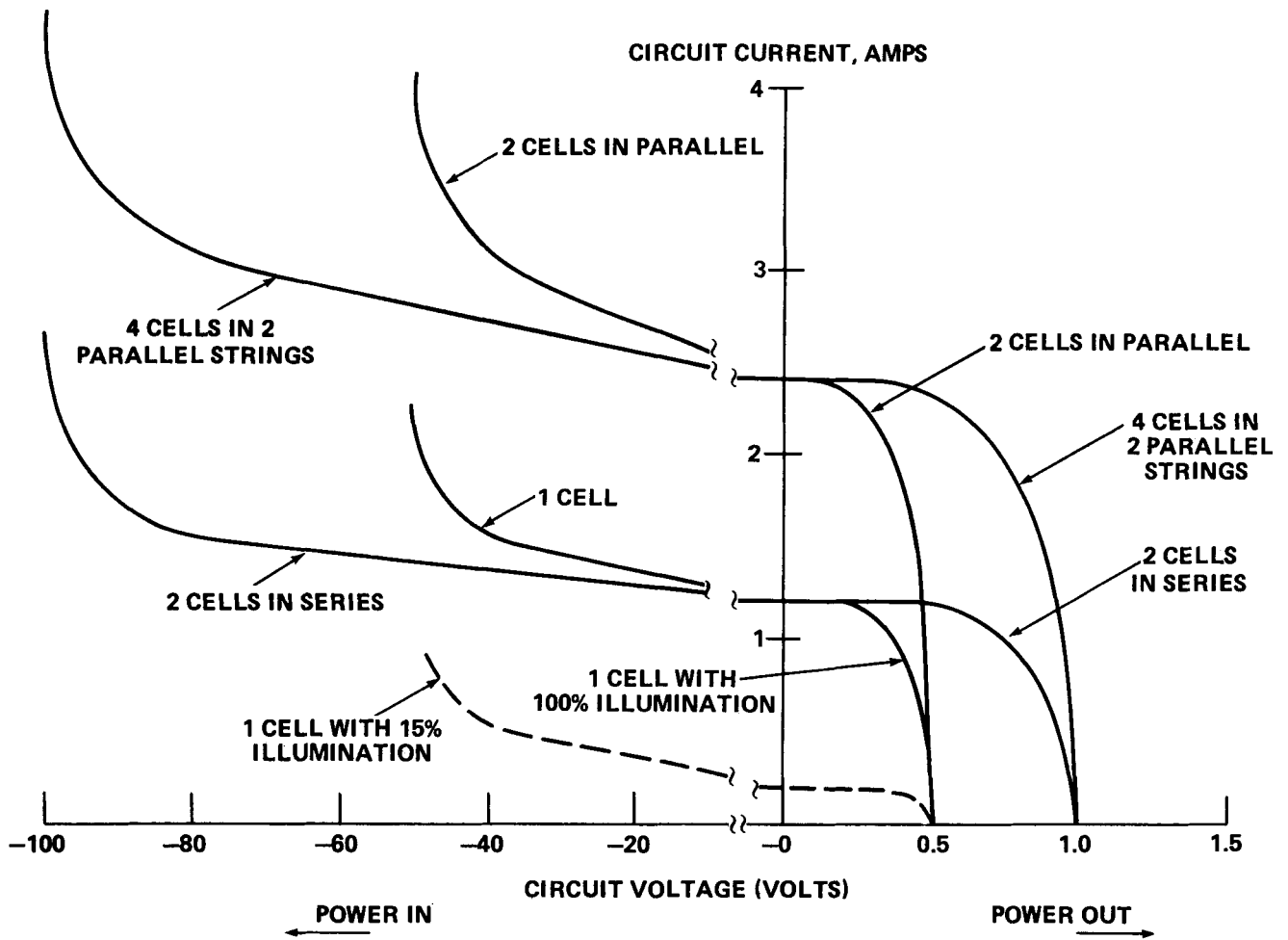


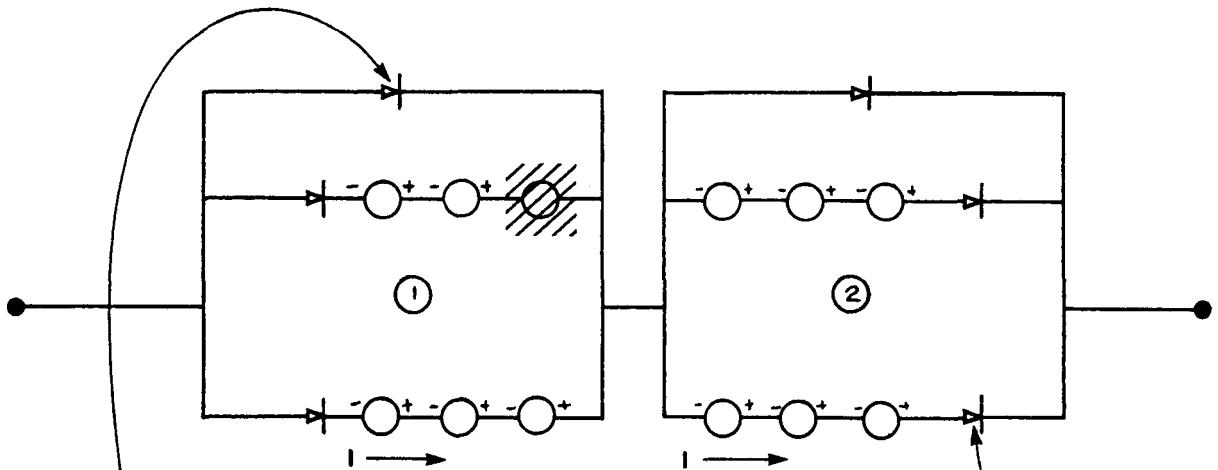
Exhibit 4.2-7

CURRENT-VOLTAGE CHARACTERISTICS
OF CELLS IN SERIES AND PARALLELS

direction. Only if the output current were decreased from 0.4 to 0.18 A would a positive voltage be obtained. The 0.18 A represents the short-circuit current of the shaded cell. The current through cells in series is limited by the current of the cell with the lowest illumination. If two cells are in parallel and one is only 15% illuminated, the output voltage would be only slightly reduced. At 0.4 V, the current would be $1.0 + 0.15 = 1.15$ A (Exhibit 4.2-7), down from the 2.0 V realized with 100% illumination on both cells. The voltage across cells in parallel is limited by the voltage of the cell with the lowest illumination, but, as was seen in Exhibit 4.2-7, this is only slightly less than the voltage of the cell with full illumination.

In the usual photovoltaic system with many cells, diodes can be used beneficially to offset the effects of broken and partially illuminated cells (Exhibit 4.2-8). Series blocks can use bypass diodes, so the branch circuit is not totally lost when the series block is shaded or has too many cell failures. The bypass diode also prevents overheating of a partially shaded cell. For example, in the shaded cell in the previous paragraph, a current of 0.4 A would result in a voltage drop of 25 V, so 10 W must be dissipated in the cell. A hot spot would develop that could further damage the cell, its encapsulation, or neighboring cells. Most systems use both blocking and bypass diodes. The optimal arrangement depends on the number of cells in series and parallel and the maintenance costs. Blocking diodes can be used to prevent a reverse current from being forced through the branch circuit either by other branch circuits or by the batteries.

The system current-voltage characteristics are determined by the interaction among the photovoltaic array, the battery and the load. The methods for determining the system voltage, as described in conjunction with Exhibit 4.2-6, apply as well for the entire array. The effects of cell failures and partial shading can be examined upon construction of the I-V curves using the series/parallel analyses just described, superimposed upon the I-V characteristics of the battery and load.



(a) Bypass diode prevents Series Block 2 from driving too much current through unfailed substring in Series Block 1 (overheats) but carries loss of entire Series Block 1 upon partial shading.

(b) Bypass diode prevents loss of array upon total shading of Series Block 1

(a) Blocking diode prevents reverse current -- but gives a constant ΔV loss (≈ 0.4 v) (Use several in parallel to minimize loss)

(b) Blocking diode required for array to prevent battery discharge through array

(c) Bypass diode can prevent overheating of shaded cell (module) under reverse bias -- if many cells in series

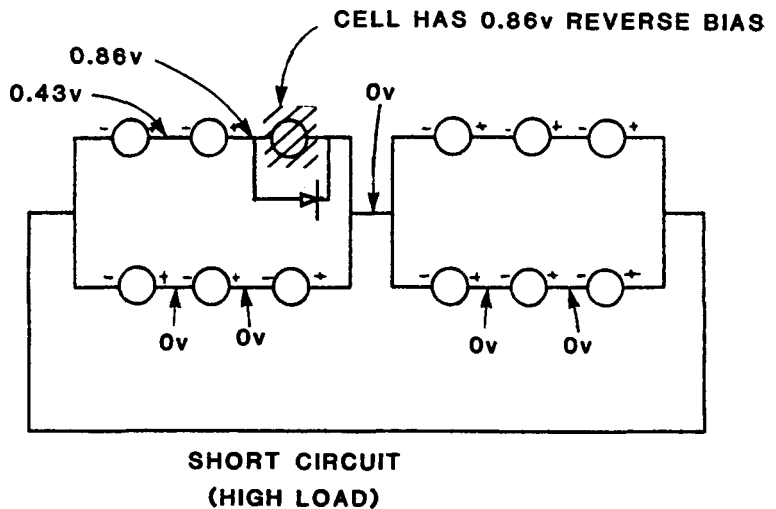


Exhibit 4.2-8

PROTECTION FROM OPEN-CIRCUIT FAILURES

4.2.3 Current-Voltage Characteristics of Arrays in the Field

The manufacturer's reported I-V curves, as considered in the previous section, must be modified for field operation by considering the effects of cell mismatch, dirt, cell failures and maintenance strategies. Cell-to-cell I-V differences result in a decrease in array output as compared to the output that would be calculated if all of the cells had the average maximum-power current/voltage combination. For N cells in series in each of P substrings, forming S series blocks and B branch circuits, the decrease in power output due to mismatch is given by the equation

$$\frac{\Delta P}{\bar{P}_{MP}} = 5.06 \left[\sigma_I^2 \left(1 - \frac{1}{N}\right) + \frac{\sigma_V^2}{N} \left(1 - \frac{1}{P}\right) + \frac{\sigma_I^2}{NP} \left(1 - \frac{1}{S}\right) + \frac{\sigma_V^2}{NPS} \left(1 - \frac{1}{B}\right) \right]$$

where σ_I is the standard deviation of the maximum-power current and σ_V is the standard deviation of the maximum-power voltage. Typically σ_I is 0.07; no typical value has been reported for σ_V . For this σ_I and for σ_V equal to zero, the power loss is only 2% for N = 10.

Dirt accumulation can be severe for arrays tilted only slightly and for arrays in areas with much air pollution. The dirt will continually accumulate on soft surfaces, such as silicon rubber, so almost all manufacturers now use glass coverplates. Frequent rains help keep the glass clean. After months of operation without cleaning, dirt caused losses of 4% in Chicago; 3% in Lexington, MA; 3% in Cambridge, MA; 1% at Mount Washington, NH; and 12% in New York City (Ref. 4-4).

The effects of failures of individual cells, primarily due to cracking, is important but difficult to compute. The computational difficulties arise from the number of combinations of failed cells. For example, if all of the cell failures occur in one substring of a series block, the effect on the entire array field is much less than if one cell fails in each branch circuit. Some cases already have been analyzed at NASA's Jet Propulsion Laboratory; typical results are presented in Exhibit 4.2-9. The probability of any given configuration of failed cells can be estimated using the binomial and multinomial distributions. Although long and

tedious, the computations are straightforward. However, the computation of the I-V curve for the system for each of these configurations is a major difficulty. There are many non-linear equations to be solved, with a different set for each combination of failures. The substring failure density is computed for N cells per substring by the formula

expression:

$$F_{SS} = 1 - P_c^N$$

where P_c is the probability of survival of one cell within the time period of interest. For example, the mean time between failures of cells is approximately 200 years, so the probability of survival for one year is

$$P_c = \exp(-t/200) = \exp(-1/200) = 0.995$$

If 20 cells were connected in series to make a substring, the failure density, F_{SS} , after one year would be 0.095.

The abscissa of Exhibit 4.2-9 would be determined by this value. If there were 8 parallel strings in each of 50 series blocks, the branch-circuit power loss fraction would be 0.29, as read from Exhibit 4.2-9. The power output for this number of cells ($20 \times 8 \times 50 = 8000$) would be approximately 4 kW when new; the power output after one year, if none of the modules were replaced, would be $0.71 \times 4 = 2.84$ kW. In addition, other curves must be used if a simple voltage regulator is used instead of a peak-power tracker. Eventually, there should be enough design charts to cover all practical possibilities.

Although Exhibit 4.2-9 seems to imply that the greater the number of series blocks, the greater the power loss, the opposite is the case. For the 8000 cells, if there were 500 series blocks, there would be only 2 cells per block, so the failure density would be only 0.01. For this failure density, the power loss fraction would be only 0.08 and the output after one year, 3.68 kW. Therefore, the more series blocks (the more cross ties between parallel substrings), the lower the power-loss fraction.

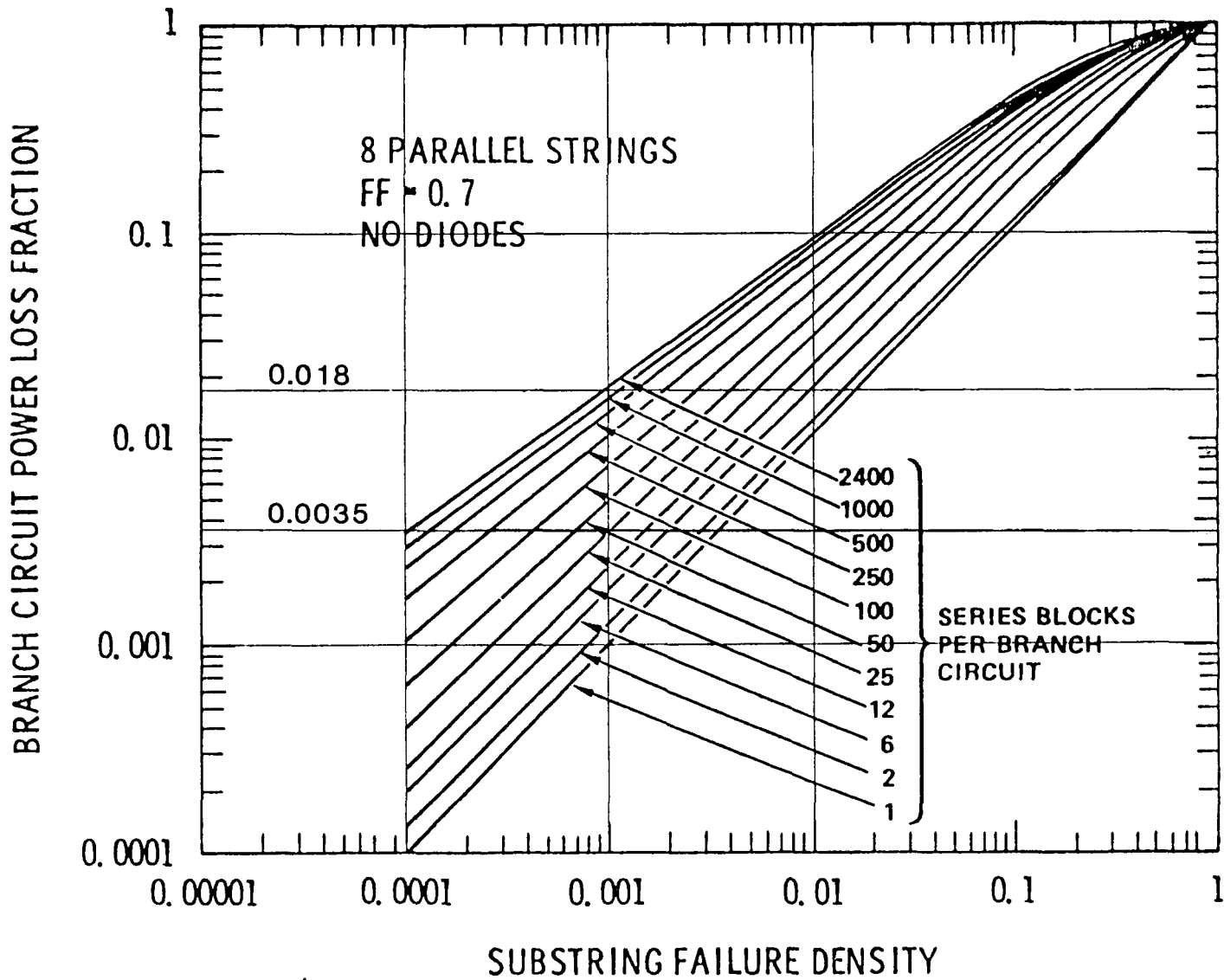


Exhibit 4.2-9

ARRAY POWER LOSS FRACTION
 VERSUS SUBSTRING FAILURE DENSITY

(Source: Reference 4-5)

Much of the loss due to cell failures can be avoided if failed modules are replaced during routine maintenance. There is a tradeoff, however, between the cost of the replacement module and oversizing the array initially to compensate for expected failures. Locating failures also presents a maintenance problem. Monitoring the output from subsections of the array can reduce the area requiring inspection. Visual inspection will frequently be sufficient to discover the broken cells; detecting the higher temperatures of broken cells can also help. (See Section 8 for additional information on maintenance).

4.2.4 Available Modules

Modules are available in almost any combination of operating voltage and current (Exhibit 4.2-10). The unit costs are relatively insensitive to module size, at least for sizes above 2' by 4' (Exhibit 4.2-11). The reliability of the larger modules can be kept sufficiently high by using enough cross ties (series blocks) within the module.

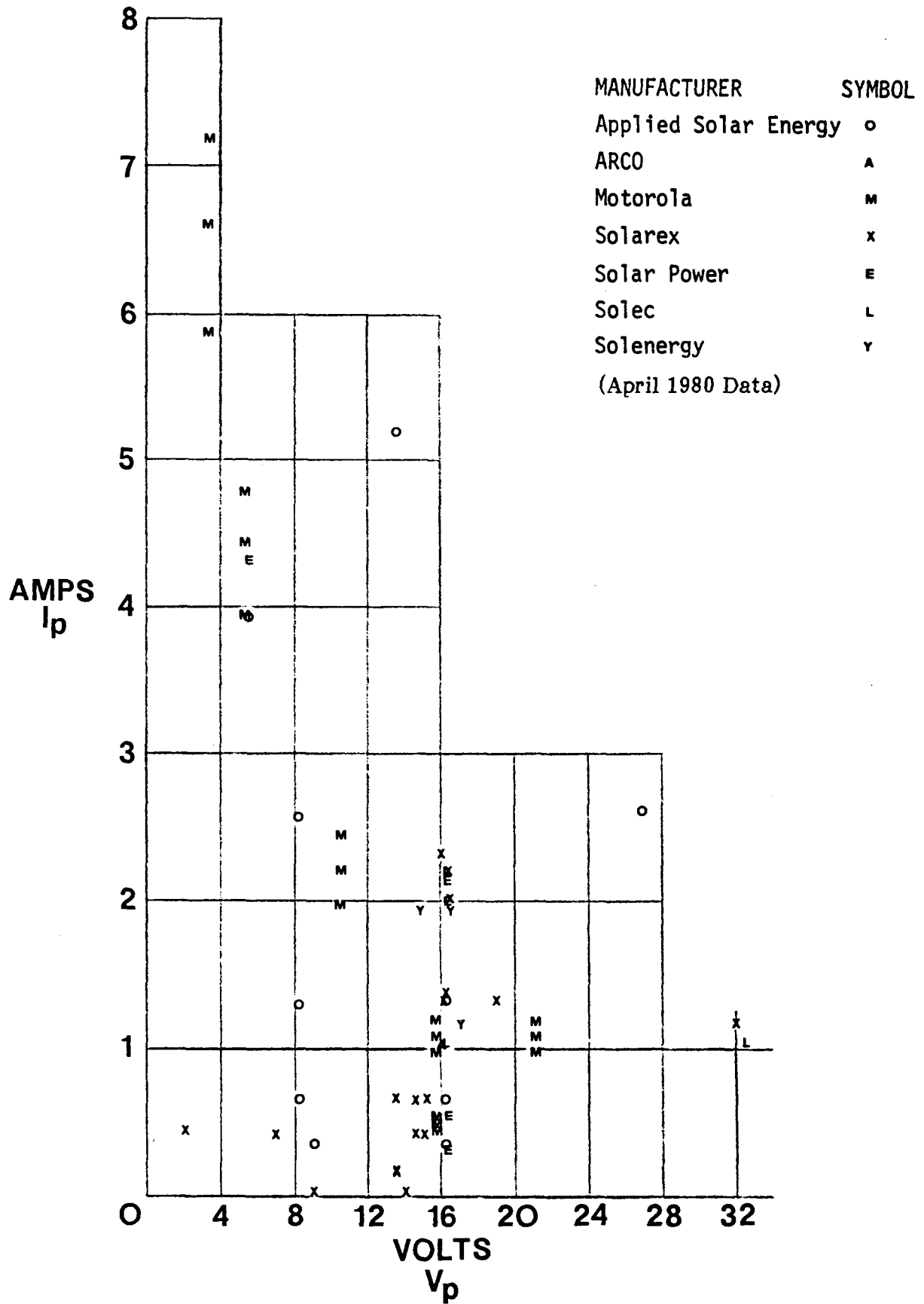


Exhibit 4.2-10

TYPICAL AVAILABLE SILICON SOLAR MODULES

ELEMENT	UNITS	COST		
		2 x 4	4 x 4	4 x 8
<u>INITIAL:</u>				
MODULE DIRECT COST	\$/m ²	60	60	60
MODULE YIELD COST	\$/m ²	0-5	0-8	0-23
• MODULE SUBTOTAL	\$/m ²	60-65	60-68	60-83
PANEL FRAME	\$/m ²	24	18	15
PANEL WIRING	\$/m ²	2-4	2-3	1-2
• PANEL SUBTOTAL	\$/m ²	26-28	20-21	16-17
PANEL INSTALLATION	\$/m ²	1	1	1
INSTALLED ARRAY STRUCT	\$/m ²	22	22	22
• ARRAY TOTAL	\$/m ²	109-116	103-112	99-123
<u>PER REPLACEMENT ACTION:</u>				
FAULT IDENTIFICATION	\$/PANEL	4	4	4
PANEL SUBSTITUTION LABOR	\$/PANEL	21	21	21
MODULE REPLACEMENT LABOR	\$/MOD	12	12	12
REPLACEMENT MODULE PARTS (INC 1% INVENTORY COST)	\$/m ²	61-66	61-69	61-84

Exhibit 4.2-11

NOMINAL ARRAY COSTS (1975 Cost Levels)

(Source: Reference 4-5)

4.3 LEAD-ACID STORAGE BATTERIES

By the end of this sub-section, the reader should be able to (1) list the various reasons batteries enhance the performance of photovoltaic systems; (2) specify reasonable requirements for the batteries used in photovoltaic systems; and (3) analyze the battery-photovoltaics interaction so the system performance can be predicted. Sample problems, illustrating this use of this sub-section, are presented in Section 7.2.

4.3.1 Advantages and Disadvantages of Batteries in Photovoltaic Systems

Batteries give photovoltaic systems the following advantages:

- Capability to provide energy for sunless periods
- Capability to meet momentary peak power demands
- A stable voltage for the system
- Capability to store energy produced by the array in excess of the instantaneous demand, thereby reducing energy loss

One recent study showed that systems without batteries deliver an average of 2.5 hours per day of rated output, whereas systems with batteries deliver 4.5 hours. Another study showed little difference in annual system output when operated at constant (battery) voltage as compared to operation at the instantaneous optimal peak-power array voltage.

Because batteries and the associated charge-rate regulator add to the number of parts in the system, certain disadvantages accrue. Batteries (1) add to the system complexity; (2) add to its cost; (3) increase the maintenance activity and maintenance cost for the system; and (4) frequently reduced the system reliability. Only in those rare circumstances for which low charge rates are acceptable can the charge controllers be omitted. Despite these disadvantages, batteries are frequently worth including in the design, so the understanding of their operation is important.

4.3.2 Battery Operation

Of the many types of batteries available (Exhibit 4.3-1), we will concentrate on lead-acid batteries, because these are the most frequently used in photovoltaic systems. The positive electrode of the lead-acid battery consists of lead oxide; the negative, lead. Both are converted to lead sulfate in the discharge process. The electrodes are immersed in sulfuric acid with an approximately 40% acid concentration.

In practice, the electrodes and sulfuric acid are enclosed in a polyethylene container. The electrodes themselves are formed by a grid made from a lead-calcium alloy. (The less expensive lead-antimony alloy is not suitable for photovoltaics because it causes a higher battery self-discharge rate than desirable). A paste of lead oxide is pressed into the grid such that the paste, when cured, forms a porous structure, thereby exposing a large surface area to the acid. Various fibrous mats separate the two electrodes. The mats are strong enough to keep the electrodes apart and to hold the pasted material in place, but are loose enough to permit the easy flow of ions from electrode to electrode. When the electrons flow through the electrodes, they are captured or released by the porous materials, but are conducted to the grid and hence to the external battery terminal.

4.3.3 Battery Current/Voltage Characteristics

The effect of various processes on the output voltage and current of lead-acid batteries are illustrated in Exhibit 4.3-2. The batteries' discharge period is shown in (a) and the charging period in (b) of the exhibit.

When the discharge period starts, the terminal voltage is high because the ions are uniformly distributed throughout the electrolyte. Shortly thereafter, the voltage has dropped considerably because the ions must migrate between the electrodes, thereby adding to the internal resistance. Since, at this time, the ions are not uniformly distributed, the process is known as polarization. At high currents, the internal resistance causes the terminal voltage to drop. At low

Characteristic	Units	LEAD-ACID (Pb/H ₂ SO ₄ /PbO ₂)										NICKEL-CADMIUM (Ni/Cd)							
		AUTOMOTIVE (SLI)		MOTIVE POWER				STATIONARY				PHOTOVOLTAIC			SEALED SINTERED PLATE		SEALED POCKET PLATE		
		Calcium	Antimony	DIESEL STARTING	Antimony	Calcium	Antimony	Calcium	Plante	SEALED	Low Rate		Medium Rate	SEALED SINTERED PLATE	SEALED POCKET PLATE	Low Rate	Medium Rate	High Rate	
											Calcium	Pure Lead							
Rated capacity = 77°F	Ah cell	33 340 ⁽¹⁾	33 340 ⁽¹⁾	57 568 ⁽²⁾	180 2175 ⁽³⁾	150 2250 ⁽³⁾	10 800 ⁽²⁾	50 2550 ⁽²⁾	10 1000 ⁽²⁾	1 40 ⁽¹⁾	50 3000 ⁽⁴⁾	26 600 ⁽⁵⁾	150 2250 ⁽³⁾	0 1 23 ⁽⁶⁾	0 8 30 ⁽⁸⁾	5 488 ⁽²⁾	9 382 ⁽²⁾	9 470 ⁽²⁾	
Nominal operating voltage	volts cell	1 98 ⁽¹⁾	1 98 ⁽¹⁾	1 98 ⁽²⁾	1 94 ⁽³⁾	1 94 ⁽²⁾	1 94 ⁽²⁾	1 94 ⁽²⁾	1 94 ⁽²⁾	1 97 ⁽¹⁾	2 05 ⁽⁴⁾	2 30 ⁽⁵⁾	1 94 ⁽²⁾	1 25 ⁽⁶⁾	1 25 ⁽⁶⁾	1 20 ⁽²⁾	1 25 ⁽²⁾	2 25 ⁽²⁾	
Nominal end of charge voltage	volts cell	2 55	2 55	2 55	2 55	2 55	2 55	2 55	2 55	2 55	2 45	2 40	2 55	1 45	1 80	1 65	1 60	1 60	
Nominal discharge cutoff voltage	volts cell	1 75 ⁽¹⁾	1 75 ⁽¹⁾	1 75 ⁽²⁾	1 76 ⁽³⁾	1 76 ⁽³⁾	1 75 ⁽²⁾	1 75 ⁽²⁾	1 75 ⁽²⁾	1 75 ⁽¹⁾	1 95 ⁽⁴⁾	1 75 ⁽⁵⁾	1 76 ⁽³⁾	1 00 ⁽⁶⁾	1 00 ⁽⁶⁾	1 00 ⁽²⁾	1 00 ⁽²⁾	1 00 ⁽²⁾	
Available capacity = 104°F	of rated	105	105	105	105	105	105	105	105	108	102	102	105	98	98	98	98	98	
Available capacity = 32°F	of rated	70	70	70	70	70	70	70	70	87	70	70	70	90	90	90	90	90	
Available capacity = 20°F	of rated	20	20	20	20	20	20	20	20	60	20	20	20	65	65	65	65	65	
Nominal energy efficiency		70 80	70 80	70 80	70 80	70 80	70 80	70 80	70 80	70 80	70 80	70 80	70 80	60 70	60 70	60 70	60 70	60 70	
Self discharge rate = 77°F	per month	1	7 50 ⁽⁸⁾	7 50 ⁽⁸⁾	7 50 ⁽⁸⁾	1	7 50 ⁽³⁾	1	3	7	1	3	1	5 ⁽⁹⁾	5 ⁽⁹⁾	5 ⁽⁹⁾	5 ⁽⁹⁾	5 ⁽⁹⁾	
Nominal cycle life ⁽¹⁰⁾	Cycles	20 50	150 250	500	1500 2000	1000 1500	250 500	100 500	250 500	100 200	350	180	1000 1500	500	500 1000	1500 2000	1500 2000	1500 2000	
Nominal calendar life ⁽¹¹⁾	Years	2 5	2 5	8	5 15	10 20	15	15 24	24 30	2 5	5 15	5 15	10 20	8	12	24	24	24	
Energy density	Wh lb	13 22 ⁽¹²⁾	13 22 ⁽¹²⁾	5 8 ⁽²⁾	8 4 11 0 ⁽³⁾	8 4 12 3 ⁽³⁾	5 10 ⁽²⁾	6 10 ⁽²⁾	4 7 ⁽²⁾	9 16 ⁽¹⁾	5 6 18 8 ⁽⁴⁾	1 7 29 ⁽⁵⁾	6 13 ⁽³⁾	7 19 ⁽⁶⁾	4 11 ⁽⁶⁾	9 11 ⁽²⁾	9 10 ⁽²⁾	6 7 ⁽²⁾	
	Wh in ³	0 8 1 6 ⁽¹⁾	0 8 1 6 ⁽¹⁾	0 3 0 5 ⁽²⁾	1 1 1 4 ⁽³⁾	0 7 1 5 ⁽³⁾	0 3 0 8 ⁽²⁾	0 4 0 8 ⁽²⁾	0 2 0 6 ⁽²⁾	0 8 1 5 ⁽¹⁾	0 4 1 4 ⁽⁴⁾	1 1 1 4 ⁽⁵⁾	0 6 1 5	0 8 2 2 ⁽⁶⁾	0 3 1 0 ⁽⁶⁾	0 4 0 5 ⁽²⁾	0 3 0 6 ⁽²⁾	0 3 0 4 ⁽²⁾	
Cost ⁽¹²⁾	\$ kWh	70 77	70	142 162	112 130	150 200	112 130	122 130	365	375	135 175	98	165 195	900 52 000	900 1100	315 1050	315 1050	315 1050	
	\$ kWh cycle	1 40 3 85	0 28 0 47	0 28 0 32	0 06 0 09	10 0 20	0 22 0 52	0 24 1 30	0 73 1 46	1 88 3 75	0 39 0 50	TBD	0 11 0 20	1 8 104	0 90 2 20	0 16 0 70	0 16 0 70	0 16 0 70	
	\$ kWh year	14 0 38 5	14 0 35 0	17 8 20 3	7 5 26 0	7 5 20	7 5 8 7	5 1 8 7	12 2 15 2	7 5 188	9 0 35 0	6 5 19 6	8 3 19 5	11 3 65 00	7 5 9 2	13 1 43 8	13 1 43 8	13 1 43 8	

(1) At the 20 hour rate
 (2) At the 8 hour rate
 (3) At the 6 hour rate
 (4) At the 500 hour rate
 (5) At the 800 hour rate
 (6) At the 5 hour rate
 (7) At the 1 hour rate
 (8) Range indicates increase in self discharge rate with age
 (9) For first 4 months after complete charge after 4 months rate reduces to 0 25 per month
 (10) To 80 percent depth of discharge
 (11) In the absence of cycle operation
 (12) 1979 dollars. Prices fluctuate with material costs. Battery costs presented in this table should be used for purposes of comparison only.

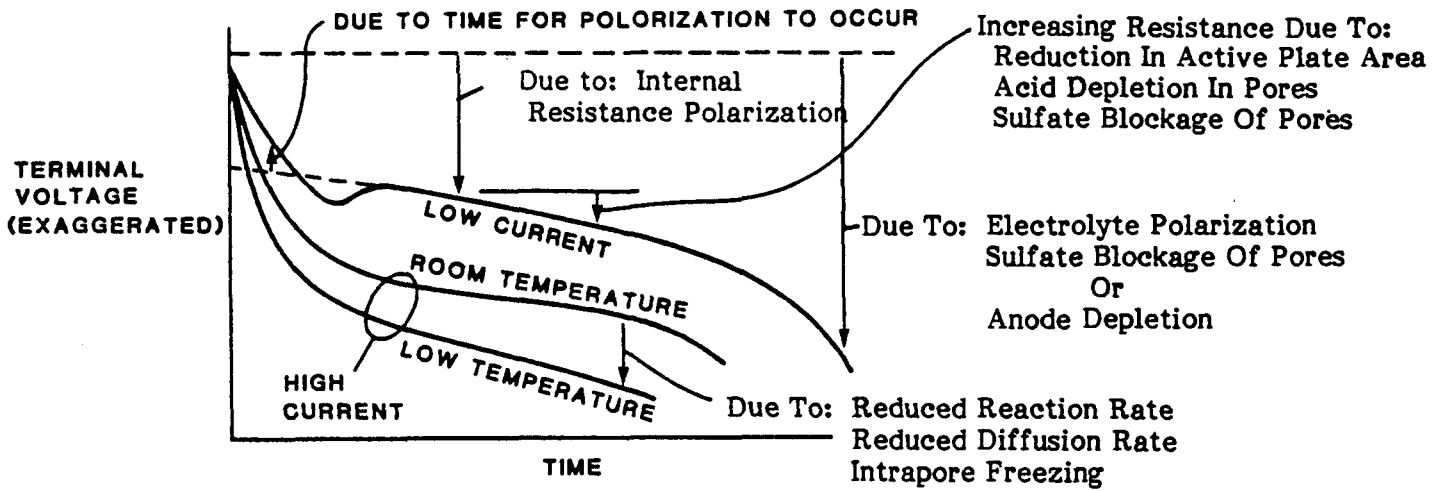
N A - Not applicable
 TBD - To be determined

Exhibit 4.3-1
 CHARACTERISTICS SUMMARY TABLE: COMMERCIALY AVAILABLE BATTERIES

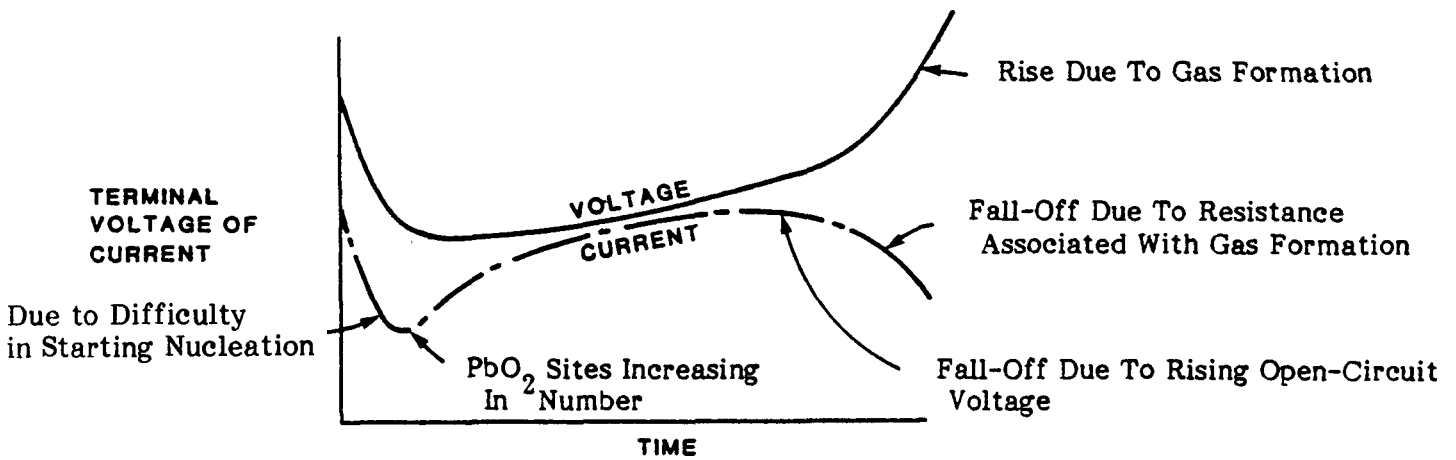
(Source: Reference 4-1)

LEAD-ACID BATTERY CHARACTERISTIC CURVES

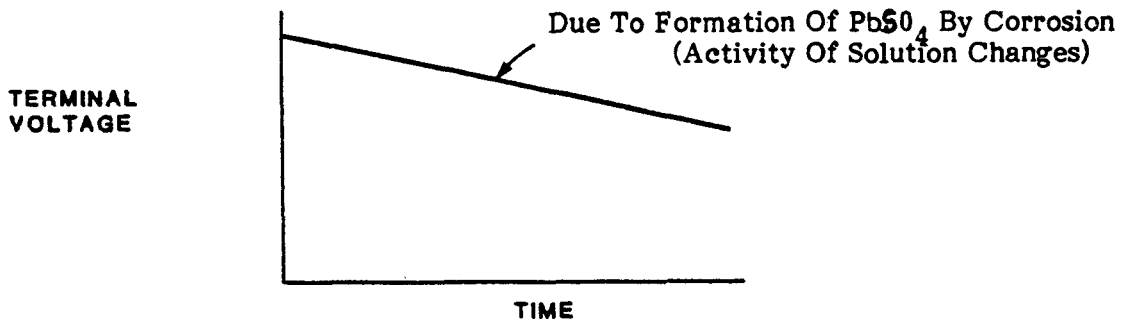
(a) DISCHARGING



(b) CHARGING



(c) REST (OPEN CIRCUIT)



temperatures, the reactivity of the cell decreases, so the terminal voltage drops further. Near the end of the discharge period, the sulfuric acid is nearly completely consumed, so its electrical resistance increases greatly. In addition, the lead with which it can react is nearly exhausted. (Most cells are designed such that the acid is depleted before the lead).

At the beginning of the charge cycle, there are few sites of lead oxide. As a result, the terminal voltage must be high to obtain nucleation and a significant charge rate. As the number of lead-oxide sites increases, the terminal voltage can decrease while the current remains constant. However, after a while, the number of sites requiring charging starts to decrease, so ions must congregate at those few sites and the effect of polarization increases. Near the end of the charge period, hydrogen forms at the anode, with the gas layer greatly increasing the internal resistance of the cell.

If left standing (Exhibit 4.3.2 (c)), the terminal voltage of the cell will decrease with time, due to the impurities in the water and the alloys in the cell, which react with the electrolyte and decrease the acid concentration.

The current and voltage during discharge can be described in terms of the state of charge of the cell (SOC, ranging from 0 to 1.0) by the equation:

$$V = V_r - \frac{I}{AH} \left[\frac{0.189}{SOC} + IR \right]$$

where the SOC is the ratio of the charge at the time of interest to the maximum charge, as measured for the 500-hour discharge rate. The symbols are defined as follows:

- V_r = rest voltage = $2.094 * [1.0 - 0.001 * (T-25. ^\circ C)]$
- V = Terminal Voltage
- I = current (Amperes)
- AH = the ampere-hour rating of the battery for the discharge rate
- IR = internal resistance of the cell
 $= 0.15 * [1.0 - 0.02 * (T-25)]$

The 0.189 factor represents the internal resistance due to polarization.

During the charging period, the current and voltage are given by

$$V = V_r + \frac{I}{AH} \left[\frac{0.189}{1.142 - SOC} + IR \right] + \underline{(SOC - 0.9) \text{Ln} \left(\frac{300 \cdot I}{AH} + 1.0 \right)}$$

The underlined term is included only if the first two terms sum to more than 2.28 volts. During the idle period (neither charging nor discharging), the state of charge decreases according to the equation (lead-calcium)

$$SOC = SOC_0 * \text{Exp} (-k \cdot t)$$

$$k = 300 * \text{Exp} (-4400/T)$$

with T in $^{\circ}\text{K}$, t in hours, and K in hours⁻¹. At room temperature, K = 0.0001.

4.3.4 Battery-System design

The design of the battery system is an iterative process: (1) the battery size is selected; (2) the system performance is computed; and (3) the life-cycle cost is computed. These three steps are repeated until the system with the minimum life-cycle cost is found.

The iterative process must be performed with the battery selection eventually being confirmed by the manufacturer. Most, if not all, battery manufacturers want to know how many ampere-hours or kWh must be stored and in what environment (temperature, charge/discharge cycles, etc.). They will then recommend a battery. Therefore, the manufacturer's recommendation must be anticipated to determine the optimal storage requirements for the system. Thus it is important to be able to compute the battery performance.

The exact computation of the battery performance would require a detailed circuit analysis using Kirchhoff's current law. Because the batteries,

power conditioning equipment and photovoltaic cells have non-linear current/voltage characteristics, solutions to the governing equations are difficult to obtain. Usually, the solution to a set of non-linear algebraic and differential equations must be computed for each instant of time.

A more common procedure is to treat the battery as a simple constant-voltage kWh or Ah storage device. The energy produced by the photovoltaic array is computed first. The load demand is determined, with the excess energy available to the battery. If the battery is fully charged, the excess is assumed to be used by the load. If the battery is not fully charged, the excess energy is absorbed by the battery, increasing the amount of energy stored therein. If the load exceeds the power output of the array, the difference is withdrawn from the battery, decreasing the energy stored therein, until the battery is fully discharged. This state-of-charge accounting can be done on an hourly, daily, weekly or monthly basis. This more common procedure is a reasonable approach to conceptual system design; however, the voltage variation of the battery is significant so final designs should be based on the more accurate method of solving the circuit equations. The foregoing equations, and those to follow, can be used in either approach. The sample problems presented in Section 7.3 will illustrate the use of the more common energy or ampere-hour accounting procedure.

4.3.5 Battery Life

Numerous factors, only some of which can be evaluated quantitatively, influence battery life (Exhibit 4.3.3). Corrosion inside the batteries is controlled by the acid concentration and the temperature. High temperatures also hasten evaporation of the water. Overcharging results in water loss, which can shorten the battery life if the water is not replenished. Low temperatures reduce the capacity by increasing the polarization loss (no equation is available to describe this effect at present). Low temperatures can also cause freezing. Charge/discharge cycles are limited by mechanical and chemical interactions. The only available data is for the same minimum state of charge during each cycle. A typical state-of-charge history for batteries in photovoltaic systems is depicted in Exhibit 4.3.4. There is no equation to predict cycle life under such variable minimum states of charge.

Exhibit 4.3-3

LEAD-ACID BATTERY FAILURE MECHANISMS

a. Chemical: $\text{Life} = \text{Life at } 25^{\circ}\text{C} * \exp[-5070 * (1/T - 1/298)]$

T = Temperature $^{\circ}\text{K}$

Corrosion of the terminals

Corrosion of the grid

Growth of large lead sulfite crystals

b. High temperature: $T = T_{\text{ambient}} + 125 * (V - V_r) * I/AH$

Hastens chemical effects

Hastens evaporation

c. Water loss: $m_l = 0.336 * \text{ampere-hours of overcharge} + \text{evaporation}$

d. Low temperature

Loss of capacity, per I-V characteristic

Freezing

specific gravity:	1.0	1.1	1.2	1.3	1.4	1.5
freezing point ($^{\circ}\text{C}$)	-0	-8	-27	-70	-36	-29

e. Mechanical: $\text{Cycle life} = 9000 * \exp[-(1. - \text{minimum state of charge})]$

Shorting by dendrite growth

Shorting by sediment at the bottom of the plates

Flaking due to vibration

Flaking due to differential expansion

Dirt

Non-uniform plate growth

f. Self discharge: $\text{SOC} = \text{Initial SOC} * \exp -300 * t * (\exp -4400/T)$, where

t = Time, hours

T = Temperature, $^{\circ}\text{R}$

Chemical reactions accelerated by Fe and Cl in the water

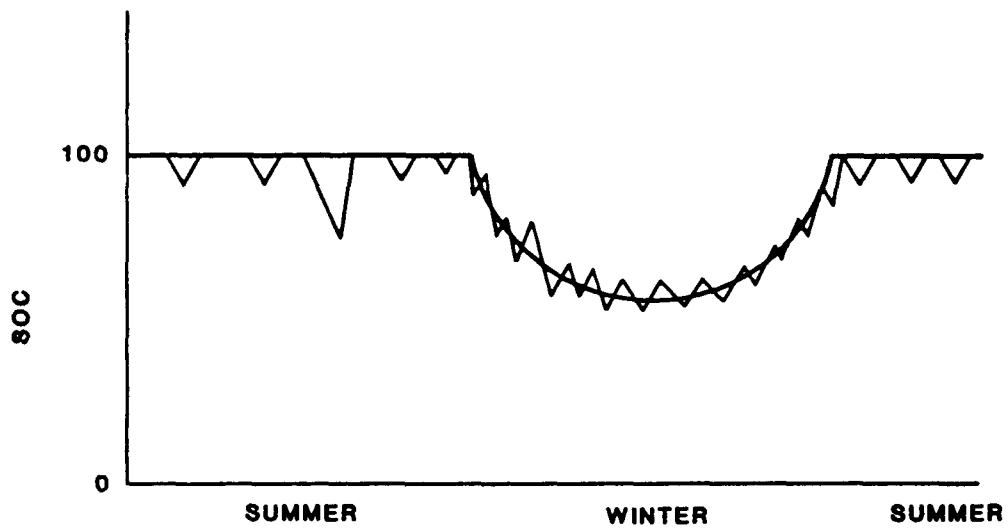


Exhibit 4.3-4

TYPICAL BATTERY STATE OF CHARGE (SOC) HISTORY

Exhibit 4.3-3 lists equations from which an estimate can be made of the life of a battery in any set of circumstances, provided certain assumptions are made concerning the effective minimum state of charge to be used in the cycle-life equation. (Note that the cycle life and the life per item (a) of the exhibit are independent. Item (a) gives the years the battery will last before corrosion prevails. The overall life is the lesser of items (a) and (e), as modified by the other life-determining factors).

The self-discharge characteristic of batteries sometimes causes failures of systems of batteries, rather than a single battery. The equation presented in Exhibit 4.3-3 is the nominal self-discharge rate. However, the rate will vary from battery to battery, depending on the particular materials used. Therefore, in a group of batteries connected in series, some batteries (cells) will be at a lower state of charge than others. On recharging, unless overcharging is used, the lower-SOC cells may not completely recharge before the voltage regulator interrupts the current. Then, while the system is idle, the more rapidly self-discharging cells will self-discharge further and may eventually become totally discharged. Testing of the batteries with an hydrometer will reveal the problem but not eliminate the cause. Overcharging eliminates the cause but depletes the water reserves and increases the maintenance.

Stratification of the electrolyte in the cells also can cause a loss of capacity. The problem occurs at SOC below 1.0 in tall batteries. Although there is no quantitative evaluation available, pumps are sometimes recommended by the manufacturer to keep the electrolyte mixed.

4.3.6 Lead-Acid Storage Battery Safety

Several important safety criteria that are applicable must be considered if lead-acid storage batteries are to be incorporated in the stand-alone system. Lead-acid batteries are of two general types:

- Lead-antimony battery, with voltage output about two volts per cell and ampere-hour (Ah) rating from 100 Ah to 1000 Ah for an 8-hour discharge rate. Charge/discharge efficiency is high (85% to 90%). During the charging cycle, an overvoltage (equalizing charge) is required for a period of time to assure that all cells in a battery bank will be recharged to the same voltage level.
- Lead-calcium battery, with output voltage and ampere-hour rating similar to those of the lead-antimony battery. Lead-calcium batteries usually require less maintenance than lead-antimony batteries and do not require an equalizing charge during recharge. Depending on the degree of discharge and cycling rate, batteries can be operated for long periods (e.g., several months) without adding water.

The following design "safety" considerations correspond to the more serious hazards experienced in the use of lead-acid batteries in uninterruptable power supplies:

(1) Danger of Hydrogen Explosion. Hydrogen which was liberated during the charging cycle can accumulate in an unvented room and may result in an explosive mixture. A flame or spark can then cause an explosion, with possible injury to personnel or damage to the charging equipment, although flame arrestors greatly reduce the probability.

Design Guideline: Provide for ventilation in the layout of the proposed battery area or "room" (NEC 480-8(a)) . Ensure that no flame-producing or spark-producing devices are installed within the battery area or room. Each vented cell must be equipped with a flame arrestor to prevent destruction of the cell due to ignition of gases (NEC 480-9(a)) . Install a "No Smoking - No Sparks" warning sign in the battery area.

(2) Danger of Electrolyte Spillage. Direct contact with the electrolyte (a mixture of sulfuric acid (H_2SO_4) and water) can cause severe injury (burns) to the skin and possibly permanent damage to the eyes. Unless properly designed to

release accumulated gas pressure, battery cells can explode scattering cell parts and electrolyte. Volumes of fresh water applied quickly and continuously may avert serious damage.

Design Guideline: Provide a fresh-water emergency shower or safety fountain within a few feet of the battery bank. Ensure sealed battery cells are equipped with pressure release vents (NEC 480-9(b)) . Ensure that proposed maintenance manuals for the battery bank include appropriate cautionary notes, e.g.: "Wear rubber apron, gloves, boots, and facemasks when handling, checking, filling, charging, or repairing a battery"; "Wear protective clothing and goggles when mixing acid and water"; "Always add acid carefully to water and stir constantly to mix well when preparing electrolyte". Specify that no sulfuric acid solutions of more than 1.400 specific gravity acid may be used inasmuch as when water is added to high specific gravity acid considerable heat and violent reaction will occur, possibly splashing the handler.

(3) Danger of Electrical Shock. If terminal voltage of the proposed battery bank is to be designed for greater than 50 volts ($V_o \geq 50V$ dc), there is danger of electrical shock during inspection/maintenance/servicing the battery bank (NEC Article 110-17(a)).

Design Guideline: Ensure that batteries are installed in groups having total voltage of not more than 250 volts on any one rack. Provide spacing (or insulation) between racks (NEC 480-6) . Provide a safety ground-disconnect circuit to allow the battery bank to "float" i.e., (+) and (-) terminals of a high-voltage string are disconnected during maintenance involving servicing, filling, or replacing a battery in a string within the battery bank. Design of the disconnect circuit must provide clearly visible visual indication of the disconnect status. The design should also provide shut-off and disconnection of dc/dc regulator chargers from both the solar array (input) side and battery (output) side during repair of the dc/dc regulator.

(4) Danger of Personnel Physical Injury. Batteries constitute a heavy, concentrated load and can easily cause painful strains or injury to a handler's back, hands, face, or feet. Also, dropped batteries may be damaged, causing injury due to electrolyte spillage as described in (2) above.

Design Guideline: Batteries should be lifted with mechanical equipment, such as hoist, crane, or lift truck. They should be moved horizontally with power trucks, conveyors, or rollers. Safety shoes and "hard hats" are recommended for handlers' protection (metallic safety hats should be avoided). The system design must include the tools and equipment required for handling individual battery replacement as a routine maintenance task. The system layout and structural design for battery racks/benches should facilitate maintenance and thus encourage the use of available handling equipment.

(5) Facility Damage. Spillage or leakage of electrolyte on benches, battery terminals, racks, floors, etc., can cause corrosion or severe damage unless promptly cleaned up with appropriate neutralizing solution (e.g., one pound of baking soda with one gallon of water). Furthermore, loss of electrolyte by leakage from a battery will lower battery capacity and can cause faults to the rack (and ground circuit).

Design Guidelines: Provide reasonably controlled temperature ambient in the battery room to prevent freezing if decrease in battery electrolyte specific gravity raises the freezing point of the battery above the local ambient temperature.

(6) Damage Due to Corrosion. Fumes and fine spray of dilute acid given off by lead-acid batteries are very corrosive, particularly to metal work and structural items constructed of iron or steel brought in close proximity to cells.

Design Guideline: If steel conduit, structural elements, fasteners, etc., are considered for use in the battery area or room, it is recommended that these items be zinc-coated and kept well painted with asphalt-based paint.

4.4 POWER HANDLING

The power handling portion of the PV power system is essentially that part of the system which interfaces the arrays with the end-use loads. It is comprised of the necessary array control system, voltage regulators, storage batteries, inverters, and distribution system (including cables, overcurrent protection devices, disconnecting means, grounding system and any load management controllers). Except for the array control system, the power handling system ordinarily consists of electrical equipment which is quite conventional in function and design. This sub-section covers those functions and design concerns of the power handling system.

4.4.1 Dc Power Conditioning

The parameters under which solar arrays operate at a given location cause the characteristic dc output voltages to vary over a considerable range throughout the year. Some of these variations are random, such as the levels of insolation during intermittent cloud cover. Insolation and ambient temperature also undergo variations of a more gradual nature due to diurnal and seasonal factors. The voltage and power output of a photovoltaic power system is more variable than that of most conventional generators and thus needs some "conditioning" and storage or back-up before it can be used for most purposes. (For those stand-alone systems having ac loads in whole or in part, an inverter would be required to convert the dc output to an alternating current waveform at a specified voltage and frequency).

Design of a stand-alone photovoltaic (PV) system which includes batteries for energy storage requires not only sizing the array power output and battery storage capacity to meet the load, but also fixing the number of battery cells placed in series relative to the number of PV cells in series in order to keep the battery voltage in the neighborhood of the array maximum-power-point voltage during operation.

In a photovoltaic (PV) system, it is desirable to extract the maximum amount of energy out of the array; a situation that would exist if the array were to be operated at the maximum power point at every instant. In a stand-alone system where the array is connected in parallel with a battery storage subsystem, the number of battery cells which are connected in series defines the nominal dc bus voltage. Although the nominal dc bus voltage may lie in the neighborhood of the array maximum-power-point voltage for some nominal combinations of insolation level and cell temperature, there will generally be a mismatch between the actual operating dc bus voltage and the maximum-power-point voltage of the array at any particular instant in time. This mismatch, which will result in an effective decrease in the efficiency of the array, depends on the state-of-charge of the battery, the battery charge or discharge current, and on the temperature and insolation level of the PV array. If a variable lossless matching network is interposed between the array and the battery, then a maximum-power-point tracking strategy can be used to constrain the array to always operate at the maximum power point.

The decision to include or not to include a maximum-power-point tracker (MPPT) will depend on the additional useful energy which could be collected by using the MPPT and on MPPT costs.

Of those dc systems containing storage, the simplest configuration of the power conditioning system is the direct connection (though a blocking diode) of the array to the storage system and then to the load. This is illustrated in Exhibit 4.4-1. This configuration finds cost-effective applications for smaller systems up to approximately 2 kWp capacity. The direct connection of the array to the battery without regulation is advisable only when the peak output current of the array is less than 5 percent of the charge capacity of the batteries in the system.

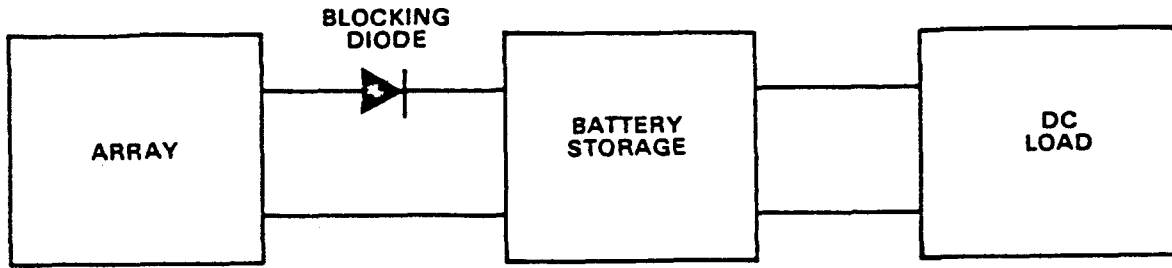


Exhibit 4.4-1
 SELF-REGULATED PV SYSTEM

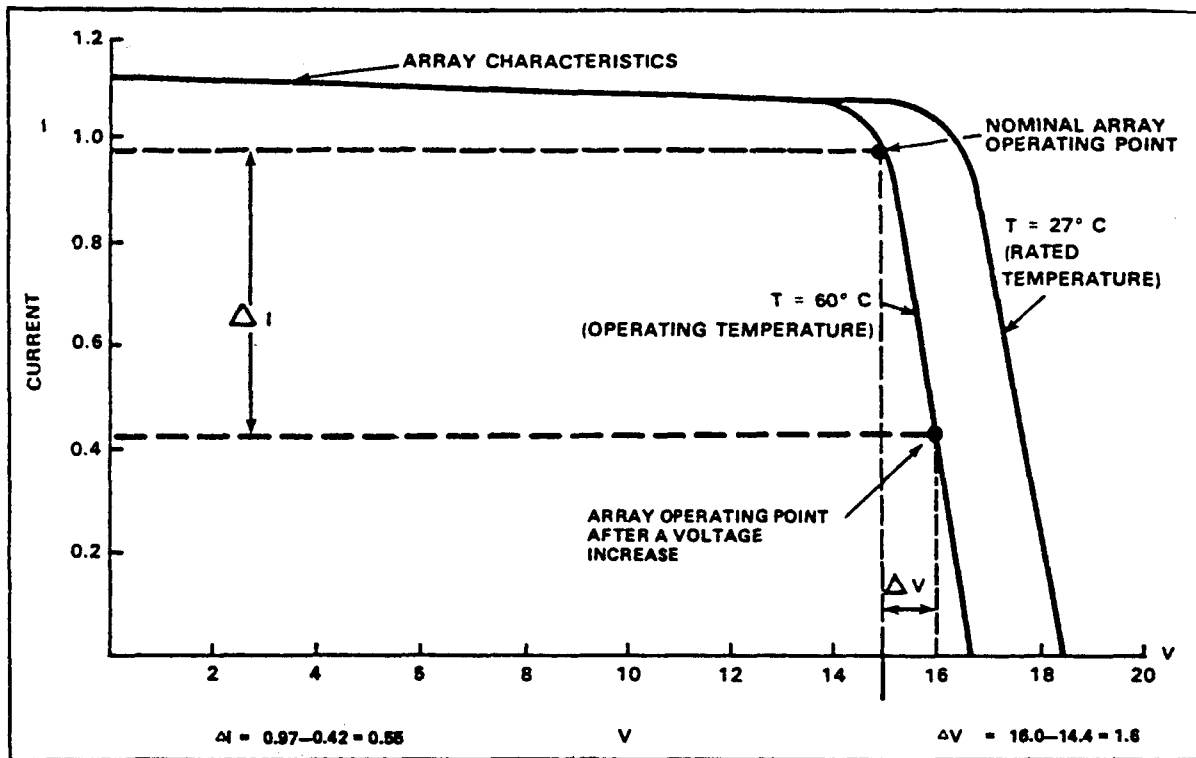


Exhibit 4.4-2
 I-V CURVE OF PV MODULE EXHIBITING SELF REGULATION
 (Source: Reference 4-6)

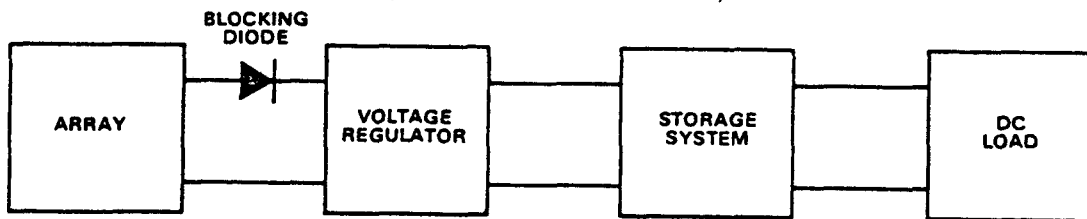


Exhibit 4.4-3
 VOLTAGE-REGULATED PV SYSTEM

The storage battery continually supplies power to the loads and is charged by the power produced by the PV array during periods of insolation. When the voltage of the battery storage system equals that of the array (less the voltage drop across the blocking diode), current flow into the storage system would stop, with the batteries being at a full state of charge.

The self-regulated PV system configuration places specific constraints on the selection of the PV array current and voltage operating conditions, resulting in the array operating at other than the maximum power point. These constraints are centered around the battery's charging voltage requirements. For a 12 V lead-acid battery, the voltage range under charge varies from 12.8 V (at 60% discharge) to 14.4 V (at full charge). To transfer the maximum power from the array to the battery, the voltage operating-point of the array should be approximately 14.4 V plus the voltage drop across the diode of approximately 0.75 V, or a level of 15.15 V, as shown on Exhibit 4.4-2. The output current of the array is 0.97 A at this operating point. For a slight increase in cell voltage above the nominal array voltage, cell current will decrease rapidly, limiting the charging current.

The voltage variations caused by changing weather conditions and degradation due to aging can be compensated by controlling the array voltage by means of a voltage regulator. A typical voltage regulator, either in parallel or series with the array, the storage system, and the load, is shown in Exhibit 4.4-3. In order to regulate the voltage with the required limits to prevent battery over-charge and outgassing, the (shunt) voltage regulator must dissipate a certain amount of power to ground. If the load can utilize all of the PV power, the shunt regulator consumes no power. Based on the output voltage, a simple design regulator "shunts" current through a regulating transistor to keep the output voltage constant.

4.4.2 Control Schemes

The output of a PV array has the same characteristics as portrayed in Exhibit 4.2-6 as a series of I-V curves, dependent upon illumination levels and temperature. The specific operating point on a particular curve is dependent upon both the characteristics of the load and the available output from the array. Possible types of loads are constant resistance, constant voltage loads (such as

batteries) and constant power loads with dynamic impedances. Fluctuations in operating points can be caused by changes in the load as well as from changes in the array's output due to dynamic variation with either insolation, temperature or wind.

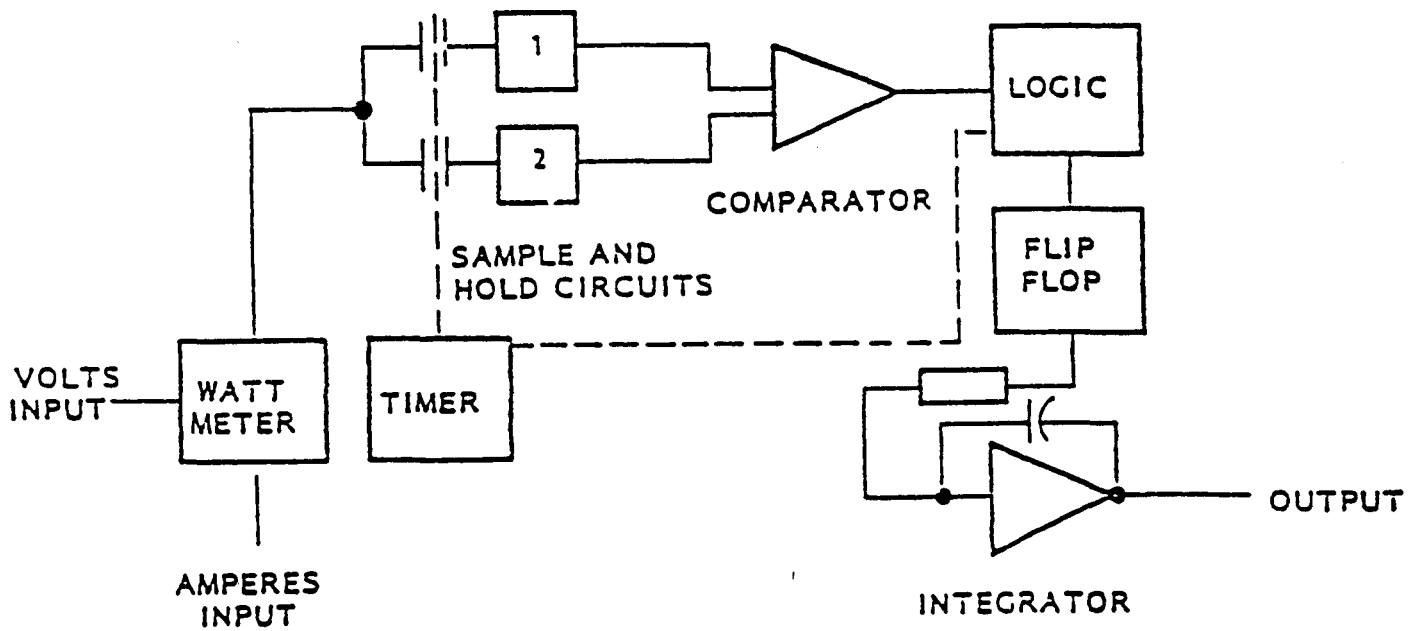
The voltage and current output of the array can be manipulated so that maximum energy can be extracted from the system. Maximum power tracking allows the greatest precision in operating near the maximum power point of the photovoltaic I-V characteristics as shown in Exhibit 4.2-6 by using a feedback method to determine operating points. The control accomplishes the change of operating point voltage with respect to the required load voltage by driving a dc/dc converter. The converter provides the interface between the array and the loads as shown in Exhibit 3-1. A simplified block diagram is shown in Exhibit 4.4-4 for a tracking controller. The basic elements include:

- A wattmeter circuit that continuously measures the power level and provides a signal output proportional to actual power.
- Two sample and hold circuits, controlled by a timer, that alternately sample the wattmeter signal output and hold it for comparison with the next sample.
- A flip-flop circuit that changes state whenever a new sample is smaller than the preceding one, but remains in the same state if a new sample is larger than the preceding one, thus representing an increase in power level.
- An integrator circuit that provides a constantly changing output whose direction of change is increasing for one state of the flip-flop and decreasing for the other state of the flip-flop.

The decision of whether to use maximum power tracking or not can be best answered by performing a system simulation on an hourly basis with the control system modeled in detail. The performance of the system both with and without maximum power tracking can be measured and used as a gauge in determining the cost-effectiveness of the control system and the required dc/dc converter.

Exhibit 4.4-4

SIMPLIFIED BLOCK DIAGRAM FOR
A MAXIMUM POWER TRACKING CONTROLLER



The various control functions which a power conditioning system can incorporate include:

- Configuration Control
- System autostart/shutdown
- Battery state of charge estimation (if applicable)
- Maximum power point tracking (if applicable)
- Selection of emergency back-up source
- System operation summary displays
- Data recording interface
- Load management
- Failure reporting/automatic recovery

4.4.3 Electrical Wiring

The electrical systems which require wiring in the field and which must be addressed consist of intra- and inter-array wiring, wiring to the power conditioning system, control and instrumentation wiring, and distribution wiring to the loads. A wiring installation for a power system must consider the following factors:

- Safety and reliability
- Avoidance of excessive voltage drop
- Avoidance of excessive copper (power) loss
- Flexibility in changing locations of equipment
- Provision for supplying increased loads
- Provision for economical maintenance

The interconnection and cabling (I & C) design criteria for a photovoltaic power system are similar to those for dc power systems. The design load and the photovoltaic array design configuration must be completed before attempting I & C design.

Proper wiring design involves the cost-effective selection of cabling to:

- Intraconnect panels of the PVPS array
- Interconnect the PVPS array to the load
- Provide integrated grounding of the arrays and a lightning protection system (NFPS 78-1975)
- Comply with national/local electrical installation codes
- Satisfy environmental requirements

Tables 250-94, 250-95, and 310-16 through 310-19 of the National Electrical Code (NEC) provide the requirements for cable sizing. Table 310-13, of the NEC provides the insulation requirements based on the cable's environment. Normally, more than one cable type will satisfy the load and environmental requirements. For such a case, the least expensive cable should be selected.

To ensure satisfactory operation of electrical devices, full voltage should be applied. Under load, the voltage drop from the source should be minimized. Good practice is to limit the voltage drop from the service entrance to any motor to 5%. In electric heating equipment, the voltage drop should generally not exceed 2%.

Power Loss

The power loss in a distribution system depends upon the resistance of the wires and the square of the individual currents which each carries. Feeders sized by the NEC will not always be the most economical size, especially if loads such as motors are operated at or near full load any considerable part of the time. In many cases, it may be more economical to increase the conductor size to reduce copper losses.

Flexibility of Wiring Systems

In industrial power systems, the changing of locations of loads such as motors is a more or less common occurrence throughout the life of the facility and

suitable designs should be incorporated to meet these changing conditions. Flexibility is usually accomplished by using busways which will accommodate plug-in devices, wireways and raceways where a large number of feeders and motor branch circuits are carried. Where motor sizes may increase, some oversizing of raceways is prudent.

Provisions for Expansion and Maintenance

Spare capacity for future load growth can be installed initially at less cost than if provided after construction is completed. The provision for providing capacity for increased loads must be made with respect to physical constraints as well as electrical capacity limitations. For example, conduits embedded in a concrete slab imply a permanent job and future demands must be considered in the early stages of the layout. Maintenance must likewise be considered by providing enough access for working clearances in front of equipment line-ups such as switchgear and for the complete removal of the same.

Economics of Wiring Design

There are many considerations in selecting a conductor for a particular wiring installation. Some of these are mechanical strength, current carrying capacity, reasonable voltage drop and insulation. With increasing costs of electrical energy, it is more apparent that the cost of annual losses often may dictate a higher initial investment in larger copper. This is especially true for both PVPS and for any circuits which operate at high capacity factor such as main feeders and where conductor and raceway investment is heavy.

Annual costs of different alternative systems should be compared to select the most economical. These costs are made up of the annual fixed charges of the investment and the cost of copper losses. By using the resistance of a circular mil-foot of commercial copper wire (a wire 1 foot long and having a cross sectional area of 1 cmil) at 10.7 ohms, the power loss in a circuit at 20°C is:

$$P = \frac{10.7 \times I^2 \times L \times n}{\text{cmils}}$$

Where:

- P = the power lost in the conductors in watts
 I = the current in amperes in the conductor
 L = length of the conductor in feet
 cmils = the area of the conductor in circular mils
 n = 2 for a 2 wire circuit (dc or single phase)
 or n = 3 for a 3-wire 3-phase circuit (assuming balanced currents)

The cost of the energy lost due to the power losses should be based upon the number of hours of operation each year and the cost of replacement energy at the PV site. By reducing the information to a table, the total annual costs of various sized conductors may be readily determined and the minimum annual cost scheme chosen.

Array Wiring

Array wiring costs tend to increase greatly as module size is reduced. Wiring costs are inversely proportional to branch circuit voltage level, the optimum (minimum) for residential applications being between 100 V dc and 300 V dc. Electrical terminations are the principal cost drivers for array branch circuit wiring, although a modular quick-connect wiring system can be significantly less expensive than junction box wiring systems, particularly when the branch circuit wiring is exposed to weather. However, until such time as a modular quick-connect system is developed and code-approved, the junction-box system should be used. The conductor construction for use at 600V or less shall comply with section 310-13 of the NEC. Conductors must be selected depending upon their installation (wet, dry) and the resistance of the outer covering to moisture and ultraviolet light.

Wiring Methods

Numerous wiring methods are authorized by the NEC, with most of them being used to a greater or lesser extent in commercial and industrial buildings. For procedures in planning power distribution systems, the reader is referred to several of the IEEE recommended practices (See Appendix C).

Sources for Additional Design Data

An analysis of the several factors to be considered in selecting wiring and cabling for photovoltaic purposes is contained in Reference 4-7. These factors, corresponding to chapter headings in the volume are electrical, structural, safety, durability/reliability, and installation. A glossary of terms used within the volume is included for reference.

4.5 EMERGENCY BACKUP SYSTEMS

The need for backup to a stand-alone photovoltaic power system is determined by the definition of "criticality" of the load to be serviced by the proposed PVPS. The choice of a particular type of backup suitable for the application is influenced primarily by the size of the critical load (in kWh/day) relative to total load to be serviced by the PVPS; by the design margin of the basic PVPS relative to predicted insolation at the proposed site; and by the owner's plan for operation and maintenance of the installed system.

Thus, all of these factors must be considered early in the preliminary phase of design to produce an integrated PVPS which will satisfy the load demand.

4.5.1 Load Analysis

It is necessary to identify, subdivide, and quantitatively describe the characteristics of the total load into those which are classified as emergency, essential, or convenience loads. If none of the load elements are considered as an emergency (or critical) load, a backup system should not be required. However, if any part of the load is critical, then there is the need for sufficient backup to cover only that portion of the critical load. Provision can be made in the PVPS design to unload (disconnect) non-critical elements of the load to delay (or possibly avoid) power loss to the critical load. Emergency, essential and convenience loads are defined as follows:

(1) Emergency Loads -- continuous power is required and loss of such power would have severe and lasting impact. The emergency load category is further subdivided into (a) those loads which are essential for safety to life or whose interruption would produce serious hazards to industrial processes and (b) those loads which are critical whose interruption would lead to economic hardship. Critical loads cannot tolerate power loss in excess of a specified period of power outage. Emergency loads are normally supplied by two separate sources with automatic switching upon loss of one supply.

(2) Essential Loads -- Power normally supplied by two sources with either manual or delayed automatic switching. Power loss would have disruptive impact but would not be classified as critical.

(3) Non-essential or Convenience Loads -- power loss would have little impact on daily operations or routine -- and would, at most, cause some inconvenience.

Not all applications will have all three load categories, and the number and duration of power outages that can be accepted will vary for each category.

4.5.2 Basic PVPS Design Margin

At this time, there is insufficient data to accurately estimate the frequency and duration of power losses (outages) due to the various "failure modes" which can jeopardize the operational success of a well designed photovoltaic power system. The major causes of power failure will be due primarily to the inadequacy of the design to cope with the variability of nature and to the limitation of hardware reliability.

Choice of basic PVPS design margins adequate to cope with all possible combinations of extreme weather conditions could not be cost-effective. For example, the insolation in many parts of the country is not known to within perhaps 30%. Some of these variables include the following:

(1) Extremes in Weather Conditions. In the design process, an allowance is made for the maximum number of low-insolation days. However, the design margin will not be based on the worst possible condition, but the worst experienced over the past ten to twenty years. There is always a possibility that there will be less sunlight than considered in the design. Similarly, the design margin considers the recent cold weather history for the site. Cold weather, even if it does not cause battery failure, will cause a loss in battery capacity. This loss in capacity can result in deeper discharge of the batteries, with an attendant shortening of the battery life, or a loss in the capability to store and later supply the needed energy. Again, cold weather is considered in the design, but

nature may provide colder weather than anticipated. In some locations, the PVPS may be subjected to unpredictable extremes of other conditions (lightning, hail, tornadoes, etc.) which cannot be completely designed against.

- (2) Changes in Load Demands. An "apparent" deficiency in design margin is often traced either to changes in the load (loads added after completion of system design), or to underestimating the load as defined in the original system specification.
- (3) Optical Degradation. Optical degradation of the outer surface of the solar array is caused by "dirt" accumulation. Arrays covered with silicon rubber have experienced a 30-percent loss of power in 15 months in some circumstances. Cleaning restores much of this loss, although some ultraviolet degradation persists. Although an allowance is made in the design, loss of transmission through the optical coating could cause significant power losses and ultimately loss of rated power required by the load. (As a consequence of the high losses with silicone, most modules now have cover material made of glass).
- (4) Component Failure. Failure rates of components integrated into the PVPS design can be estimated on the basis of historical data, plus test data accumulated by vendors and certified test facilities. The PVPS design is configured (as described in subsection 6.4) to provide an adequate design margin to protect (at a specified risk) against power loss due to component failure for a given period (e.g., 30 days, 90 days, 6 months, etc.), consistent with specified operating and maintenance provisions.

4.5.3 Types and Suitability of Backup Systems

Several backup systems might be suitable for the applications envisioned for the proposed stand-alone system. In many cases, the loss of power will not be critical, and backup will not be required. However, as discussed above, those loads which are judged to be critical are sensitive primarily to downtime (i.e., time that will elapse before the power can be restored). Maintaining some

inventory of spares will help keep the elapsed time to a minimum, and standardizing replacement components (e.g., modularity of the array) will reduce the cost of replacement spares.

Manual backups are a viable, low-cost alternative for inhabited PVPS installations. For example, village water can be hand pumped on an emergency basis, although provision must be made in the initial design for hand pumping by positive-displacement pumps (centrifugal pumps cannot be manually operated). For larger pumping operations or large-power operations, an engine can be justified for the backup system. Since the engine will be used only on occasion, it may prove troublesome to start; therefore, it should be started regularly (e.g., once a week).

Low power radio communications equipment (transceivers) and other low power devices can be powered by primary batteries or pedal-powered generators in emergencies. However, primary batteries (e. g., zinc-air batteries), once discharged, must be manually replaced when depleted, so the operating costs (replacement costs) would be high.

Battery backups may be more practical, if standby rechargeable batteries are used. For example, lead-acid batteries could be maintained in fully charged state by the solar array, although the backup battery should not be connected to the main battery bank. However, if the solar-recharged battery cannot recover from an emergency condition, it may be necessary to recharge the backup batteries by a fixed engine/generator (or by a portable engine/generator carried by the maintenance team). The engine/generator may be considered an essential backup for those unpredicted periods of extremely low insolation for many days.

The advantages and disadvantages of various combinations just described are summarized in Exhibit 4.5-1. Life cycle cost of alternative backup types should be performed, taking into account the maintenance support cost as well as the initial cost. For example, a low-power engine/generator may be low in initial cost, but the cost of maintenance support might make the life cycle cost higher than a solar (or wind) recharged battery. Moreover, the engine/generator requires periodic transport of fuel (gasoline or diesel oil) to the site, which may be a physical problem for remote installations.

SUMMARY DESCRIPTION OF BACKUP SYSTEMS

Type of System	Application Suitability	Advantages	Disadvantages
<p>1. Manual (e.g., Hand pumps, manual hoists, hand or pedal driven generators, etc.)</p>	<p>Suitable for low-power loads. Applicable primarily to local (inhabited) sites; can be used in remote (unattended) sites with adequate monitoring (alarm) and response by off-site personnel. Very low initial cost (\$200 - \$500).</p>	<p>Simple to operate; highly reliable; minimum maintenance.</p>	<p>Requires operating manhours for duration of power outage.</p>
<p>2. Primary Battery (e.g., Non-rechargeable zinc-carbon batteries.)</p>	<p>Suitable for very low power loads. Applicable primarily to remote sites for emergency lighting (signal beacons), communication, instrumentation, etc. Relatively low initial cost (\$200 - \$500 per KW).</p>	<p>Highly reliable; no maintenance (except for battery replacement).</p>	<p>Requires immediate replacement of battery with new battery.</p>
<p>3. Gasoline Engine/Generator</p>	<p>Suitable for medium power load ($P < 5KW$) for long periods of power outage. Readily applicable to local (inhabited) sites; adaptable to remote sites with provision for off-site control. Relatively low initial cost (\$200 - \$500 per KW).</p>	<p>Highly reliable (local); moderately reliable (remote). Durable (many years) under long periods of operation. Light weight (2-man portability).</p>	<p>Requires weekly preventive maintenance and operability "run-up" test under load, to verify equipment availability. Requires transport and storage of fuel (gasoline) at site. In remote application, may experience carburetion failure in "start" mode, requiring off-site maintenance team.</p>
<p>4. Diesel Engine/Generator</p>	<p>Suitable for full critical power load ($5KW < P < 15KW$) of the PVPS. Readily applicable to local (inhabited) sites; adaptable to remote sites equipped with automatic switchover provisions. Relatively low initial cost (\$300 - \$600 per KW).</p>	<p>Highly reliable under local control; moderately reliable (higher than gasoline engine) under remote control. Durable (many years) under long periods of operation.</p>	<p>Requires weekly preventive maintenance and operability "run-up" test under load, to verify equipment availability. Requires transport and storage of diesel fuel at the site. In remote application, may fail to start in extremely cold weather, requiring off-site maintenance team.</p>
<p>5. Rechargeable Secondary Battery (e.g., lead-calcium battery): (A) - solar recharged (B) - wind recharged (C) - fossil recharged (D) - portable charger</p>	<p>Suitable for full capacity of critical load. Readily applicable to local sites; adaptable to remote sites equipped with automatic switching and charge regulation. High initial cost (\$150 - \$500 per KWH), depending on required capacity: (A) - High initial cost of additional solar modules (\$20,000 - \$40,000 per KW). (B) - Moderate cost of wind generator (\$2,000 - \$5,000 per KW). (C) - Relatively low cost of gasoline or diesel engine/generator (as in 3 and 4 above). (D) - Low cost of portable gasoline engine/generator charger (\$500 - \$1,000).</p>	<p>Backup battery bank is reliable. Recharging either solar array or wind charger highly reliable. Gasoline/diesel engine reliable under conditions described in 3 and 4 above. Portable charger is reliable.</p>	<p>Battery life limited (5 - 10 years). Engine generators require relatively high maintenance (see 3 and 4 above). Solar or wind recharge capability depends on weather conditions.</p>

As indicated in the exhibit, suitability of a given backup system for critical loads depends on size of the critical load in kWh allowable duration of power outage, whether the application is local (i.e., inhabited) or remote (i. e., unattended), and accessibility of the site for off-site maintenance support.

4.5.4 Incorporation of Backup Into the PV System

Once the type of backup has been selected, the backup system must be integrated into the basic photovoltaic power supply. Means of switchover from PV to backup (and visa versa when the emergency is over) may be manual or automatic, depending on whether the system is designed for local or remote operation. Manual operation involves a simple alarm system and a control panel to provide status information (instrumentation), and switching controls to make the timely switch over from PV array to backup system. On the other hand, remote sites must relay this status information by telemetry to the off-site receiver (control) station which alerts the maintenance team when the system is not performing properly. Switchover to the backup system can be accomplished either by transporting the maintenance team to the site, or by including a control channel in the telemetry link by which the backup system can be "commanded" to come on line. A remote actuator will be required for this type of backup, although the actuator can be a simple electrical relay or solid-state switch. Automatic switchover (without telemetry command) is also possible, although the electronic circuitry for the sensing and controlling functions will be more complex and somewhat more failure-prone than the telemetry control method.

A reliability/maintenance/cost tradeoff analysis should be performed to support a design decision between employing on-site manual switching with on-site personnel, or transported off-site personnel, semi-automatic switching via telemetry monitoring and control, or fully automatic on-site sensing and switching.

SECTION 5

INFORMATION NEEDED TO START THE DESIGN PROCESS

This section presents the system design engineer with two lists which will guide him in assembling data needed in the design process. The first list presents the minimum data required to perform design computations. The second is a checklist for the entire design process, including tradeoffs, site investigations, and design pitfalls. The reader is expected to use this section as a quick reference to ensure that he has gathered the requisite data.

Little data is needed to perform the design computations for the preliminary stage covered by this handbook. In essence, the daily loads and daily solar radiation are almost sufficient (Exhibit 5-1). Other factors are needed to compute the economics of the system and to compare the photovoltaic life-cycle cost to costs of the competing systems. If each item of Exhibit 5-1 is obtained, then all of the computations required in the various sections of this handbook can be completed. If the data requirements of Exhibit 5-1 are compared to the data requirements of Exhibit 5-2, some appreciation can be obtained of the scope of this handbook. The handbook covers preliminary design approaches only in order to evaluate total photovoltaic systems. The detailed design required to actually construct a system, must address the many questions raised in Exhibit 5-2.

Exhibit 5-1
Minimum Data Requirements
to Establish Feasibility

Technical requirements

Daily energy to be supplied by the system, on the average for each month

Peak power demands

Future power and energy requirements

Reliability criteria for photovoltaic power system

Estimated output of the system when insolation is 1 kW/sq. meter

Siting requirements such as fences, grading, markers, site preparation, similar weather (world insolation data are listed in Appendix A)

Current costs of photovoltaic system components

PV modules

Batteries

Power conditioning system

Structures and supports

Electrical distribution system

Costs of alternate power systems:

Utility-supplied electricity, including connection costs, demand costs, and energy costs or engine-generator set costs

Fuel costs, including the cost of resupplying

Battery recharge costs

Cost of transportation to the site for repairs to whichever system is adopted (depending on distance to nearest repair station)

Exhibit 5-2

General Checklist for Detailed Design

Site

1. Check array location for foundation and structural support.
2. Check site for locations of underground or overhead cables and utilities and any other obstructions which could cause shading problems.
3. Check installation route and shipping route.
4. Check foundation requirements for battery housing.
5. For existing load centers, check power/energy requirements.
 - a. Check equipment on line
 - b. Check life-styles as they influence use of equipment
 - c. Measure total power/energy consumption for sample days

Criteria

1. Power and energy requirements
2. Reliability requirements for power system operation
3. Allowable load separation for startup purposes.
4. Required voltage regulation.
5. Maintenance strategy/frequency of site inspections
6. Instrumentation and monitoring system requirements for initial checkout and maintenance, and operation.

System

1. Determine optimal array tilt, including the possibility of tracking and occasional reorientation.
2. Determine the optimal array size, storage size, etc., on the basis of life-cycle cost but meeting the requirements of performance, reliability, and safety.
3. Determine the effect of degradation of the array, power conditioning components, batteries, cables, connectors, etc., on the long-term system performance and the initial design requirements.
4. Determine array output as a function of time of day, month, and year; include in the effects of temperature, dust accumulation, partial system failure (outages), state of battery charge, load demand, etc., using a detailed simulation.

Exhibit 5-2 Continued
General Checklist for Detailed Design

5. Determine the optimal system voltage, including the effects of partial shading, reliability of the array, module failure, safety, component efficiencies, cable costs, component costs, availability of components.
6. Define the auxiliary power system: total, partial, etc., connection to the load, interface with the array and power conditioning subsystem.
7. Determine optimal arrangement of diodes in the array, including isolation diodes and shunt diodes.
8. Allocate the voltage losses, such as the diode losses, cable losses, battery losses, etc., justifying on the basis of cost.
9. Examine the load and power-system I-V characteristics so potential mismatches (average or instantaneous) can be identified. List and rectify potential mismatches (e.g., define a control system to provide matching).
10. Determine the temperature control requirements and how the batteries, voltage regulators and power converters will meet them.
11. Determine how the maintenance personnel will identify a failed module component.
12. Define the test points for startup and monitoring of system performance.
13. Determine optimal cleaning cycle, if any.
14. Determine how protection against vandalism will be provided.
15. Determine the requirements for spare parts.

Array

1. Obtain from the manufacturers the I-V characteristics of the modules as combined functions of temperature and illumination. Include the range of I-V characteristics.
2. Determine if modules should be matched within a series string to maximize the array output, considering the cost savings possible but also the difficulty in replacement matching.
3. Provide test points within the array.
4. Provide indications to identify failed modules or connections.
5. Segment the array for maintenance safety and performance during maintenance.

Exhibit 5-2 Continued
General Checklist for Detailed Design

6. Determine the least-cost structure, allowing for expansion and contraction due to temperature and humidity. Include aluminum, steel, wood, concrete, and any other native materials. Include foundation design. Include deflection analysis. Protect against corrosion.
7. Estimate the cost of the structure so the optimal cell packing density can be determined.
8. Design the array to withstand the environment: dust, wind, sand, temperature cycling, hail, rain, humidity cycling, installation and maintenance loads, normal and abnormal voltages, lightning, earthquakes, ice, freezing rain, settlement, ground uplift, combinations of loads and their probability of occurrence.
9. Review for design compliance with the national codes and standards, such as BOCA, UBC, SBC, ANSI, NEC, NEMA, and their local variations.
10. Obtain the data on soil borings as required for the foundation work.
11. Decide on custom-designing a structure or purchasing a structure from manufacturer.
12. Determine if shading is prevented.
13. Protect the array and cables from falling objects.
14. Design to protect the maintenance personnel from high voltages and temperatures.
15. Provide sufficient redundancy to meet the reliability requirements, such as dual leads, alternate circuit paths, etc.

Power Conditioning System

1. Develop the voltage/cost/reliability data for the components in the systems.
2. Define the input/output voltages and currents, including auxiliary power requirements, for a complete range of loads for use in the system design.
3. Examine the system for potential instabilities at high loads and other combinations of battery/array/load supply and demand conditions.
4. Define the environmental requirements for the equipment.

Exhibit 5-2 Continued
General Checklist for Detailed Design

5. Protect the equipment from weather: rain, dust, wind, humidity, temperature, earthquake, lightning, sand, installation and maintenance loads, shipping loads, normal and abnormal voltages and currents, settlement, ground uplift.
6. Specify compliance to the applicable national standards and codes: ANSI, IEEE, NEC, NEMA and their local variations.

Energy Storage System

1. Determine if battery use can be minimized by storing the end product (such as pumped water) rather than electricity.
2. Select the battery type: pure lead, lead-calcium, sealed, SLI, silver-zinc, iron-redox, nickel-cadmium (pocket plate). Consider cost, availability, depth of discharge, reliability, life (cycles, years), capacity vs temperature.
3. Obtain the I-V characteristics of the batteries as a combined function of temperature and state of charge for use in the system simulation.
4. Obtain the life estimates for the batteries as a function of temperature and number of cycles.
5. Determine the optimal voltage of the battery array in terms of the entire system.
6. Estimate the frequency of, and provide for the failure of, one battery in the entire storage system.
7. Determine how rapidly the batteries will self-discharge.
8. Estimate the battery reliability and maintenance requirements and costs.
9. Determine the number of spare batteries needed.
10. Estimate the cost of the batteries in place for use in the systems design.
11. Layout the batteries to minimize the potential faults.
12. Determine the need for and method of dispersing hydrogen generated in the battery housing.

Exhibit 5-2 Continued
General Checklist for Detailed Design

13. Design the housing for the following loads: weight, wind, maintenance, earthquake, lightning, hail, deflection, thermal and humidity cycling, ground uplift, dust, sand and combinations thereof.
14. Design to the applicable standards and codes: ANSI, IEEE, NEC, NEMA, OSHA and their local variations.

Emergency Power System

1. Provide a power source as required during the times when the photovoltaics need repair or routine maintenance.
2. Determine if the emergency (backup) power system need be automatically activated.
3. Establish a procedure and cost for maintaining the emergency system in a state of readiness.
4. Estimate the reliability of the emergency power system. Provide a second emergency generating unit if needed to obtain the desired reliability
5. Design the emergency power system to the national standards and codes: BOC, UBC, SBC, ANSI, NEC, IEEE, NEMA, OSHA and their local variations.
6. Design the housing for the following loads: weight, wind, maintenance, earthquake, lightning, hail, deflection, thermal and humidity cycling, ground uplift, dust, sand and combinations thereof.
7. Estimate the installed, operating and maintaining costs for use in the system design.
8. Determine the efficiency of the system versus load for use in the system simulation.
9. Determine the spare-parts requirements.
10. Determine the availability and cost of competent repair services.

5-8

SECTION 6
PRELIMINARY SYSTEM DESIGN CONSIDERATIONS

6.1 INSOLATION AND SITING

A generally open, sunlit area will be required for the array. The first step is to identify such an area. The area can be considered open if the angular elevation of neighboring trees, buildings, etc., within an azimuth angle $\pm 60^\circ$ degrees of South (northern hemisphere) or North (southern hemisphere) satisfies the relationship:*

$$\text{elevation angle (above horizon)} \leq 56^\circ - \left| \text{Latitude angle} \right|$$

The next step is to determine if the area is large enough. The clearness index, \bar{K}_H , for the site should be estimated from Appendix A, based on the closest city that also has similar weather. Values of \bar{K}_H should be read for the four winter months. For each of these months, the corresponding solar radiation (called insolation in the U.S.) should be read from Exhibit 6.1-1. (Linear interpolation is permissible between values of \bar{K}_H for any one month.). The area of the clearing required for the array is given by the equation:

$$\text{Area (sq. meters)} = \frac{\text{Load (in kWh/day)} * [\cos(t) + \sin(t)/\tan(66.5 - |L|)]}{\eta * \text{solar radiation (in kWh/m}^2 \text{ - day)}}$$

where, as in the first equation, the magnitude of the latitude angle L is used. The array tilt angle is given by t; it is usually equal to the absolute value of the latitude angle. The system efficiency, η , typically is composed of 14 percent for the array, 80 percent for the battery, and 90 percent for the power conditioner, giving $\eta = 0.14 * 0.80 * 0.90 = 10$ percent. The solar radiation to be used on the equation is the minimum for the four winter months.

*The sun-angle charts of Section 11.4 can be used to estimate how much the horizon obstructs the sun. The charts must be used at latitudes above 56° because there may be no sunlight in December.

Example: Suppose two candidate sites for a 12 kWh/day load are in a remote area near Washington, D.C. Suppose a surveyor's transit had been used, looking within 60° of South, to determine the skyline (horizon) to be shown in Exhibit 6.1-2 for the two sites. Both have 110 m^2 available. Which site is most suitable?

From Appendix A, we find that Washington, D.C. is at a latitude of 38.95 degrees. For the space to be considered "open", the skyline must be lower than

$$56 - 38.95 = 17.05$$

Site A (Exhibit 6.1-2) is not suitable; Site B is.

The values of the clearness index are first obtained from Appendix A, and the average daily insolation on an array tilted at the latitude angle is obtained from Exhibit 6.1-1 by interpolation for the winter months. For November, for example:

a. Interpolation between 30 degrees and 45 degrees latitude:

$$\text{at } \bar{K}_H = 0.3: \quad 2.180 + (1.636 - 2.180) * (38.95 - 30) / (45 - 30) = 1.855$$

$$\text{at } \bar{K}_H = 0.5: \quad 4.011 + (3.328 - 4.011) * (38.95 - 30) / (45 - 30) = 3.603$$

b. Interpolation between \bar{K}_H 's:

$$\text{at } \bar{K}_H = 0.421: \quad 1.855 + (3.603 - 1.855) (0.421 - 0.3) / (0.5 - 0.3) = 2.912 \text{ kWh/m}^2 \text{ day}$$

Similarly, for December, interpolation gives 2.32 kWh/m^2 day, so the land area required is ($\eta = 10\%$):

$$A = 12 * R / (2.32 \eta) = 103 \text{ square meters of land}$$

Where $R = \cos t + \sin t / \tan (66.5 - L) = 1.983$. The required area is 103 square meters and 110 square meters are available, so Site B is a good candidate.

Exhibit 6.1-1

AVERAGE MONTHLY INSOLATION (KWH/M²-DAY) AND THE RATIO (SIGMA 1) OF STANDARD DEVIATION TO AVERAGE

$$K_H = 0.3$$

KH = .3		Tilt = Latitude					Tilt = Latitude + 10°				
		0°	15°	30°	45°	60°	0°	15°	30°	45°	60°
JAN	MEAN *	2.989	2.592	2.073	1.504	0.895	3.067	2.633	2.097	1.531	0.928
	SIGMA 1	0.692	0.748	0.852	1.036	1.328	0.716	0.778	0.891	1.079	1.355
FEB	MEAN	3.092	2.800	2.360	1.842	1.307	3.130	2.801	2.342	1.826	1.310
	SIGMA 1	0.692	0.731	0.808	0.948	1.182	0.706	0.751	0.837	0.985	1.217
MAR	MEAN	3.130	2.995	2.681	2.248	1.772	3.111	2.936	2.597	2.159	1.701
	SIGMA 1	0.692	0.709	0.757	0.848	1.007	0.693	0.716	0.770	0.870	1.038
APR	MEAN	3.040	3.073	2.910	2.589	2.177	2.965	2.955	2.757	2.418	2.008
	SIGMA 1	0.692	0.689	0.710	0.761	0.852	0.680	0.682	0.709	0.766	0.866
MAY	MEAN	2.875	3.044	3.018	2.817	2.504	2.758	2.883	2.815	2.583	2.256
	SIGMA 1	0.692	0.673	0.677	0.703	0.754	0.668	0.655	0.664	0.696	0.753
JUN	MEAN	2.761	2.996	3.042	2.910	2.664	2.626	2.816	2.816	2.647	2.379
	SIGMA 1	0.692	0.665	0.661	0.677	0.712	0.662	0.642	0.643	0.665	0.705
JUL	MEAN	2.793	3.003	3.023	2.866	2.595	2.665	2.831	2.806	2.614	2.325
	SIGMA 1	0.692	0.668	0.667	0.686	0.726	0.665	0.647	0.651	0.676	0.722
AUG	MEAN	2.935	3.039	2.949	2.691	2.328	2.838	2.899	2.770	2.487	2.119
	SIGMA 1	0.692	0.680	0.692	0.729	0.798	0.674	0.668	0.685	0.728	0.804
SEP	MEAN	3.066	3.014	2.775	2.396	1.950	3.019	2.926	2.657	2.268	1.832
	SIGMA 1	0.692	0.699	0.733	0.803	0.926	0.687	0.699	0.739	0.816	0.949
OCT	MEAN	3.091	2.873	2.493	2.018	1.520	3.103	2.847	2.446	1.971	1.492
	SIGMA 1	0.692	0.721	0.783	0.899	1.098	0.700	0.734	0.805	0.930	1.133
NOV	MEAN	3.017	2.665	2.180	1.636	1.067	3.079	2.690	2.188	1.646	1.090
	SIGMA 1	0.692	0.741	0.833	0.998	1.265	0.712	0.767	0.868	1.039	1.297
DEC	MEAN	2.945	2.524	1.989	1.411	0.773	3.034	2.575	2.023	1.446	0.809
	SIGMA 1	0.692	0.753	0.864	1.060	1.369	0.718	0.786	0.906	1.105	1.392

*Note: In all cases the MEAN is (I) and SIGMA 1 is (R)

For southern latitudes, the values listed for July pertain to January, August to February, etc. Otherwise, the tables are equally valued for northern and southern latitudes.

Exhibit 6.1-1 (Continued)

AVERAGE MONTHLY INSOLATION (KWH/M²-DAY) AND THE RATIO (SIGMA 1) OF STANDARD DEVIATION TO AVERAGE

$$K_H = 0.5$$

KH = .5		Tilt = Latitude					Tilt = Latitude + 10°				
		0°	15°	30°	45°	60°	0°	15°	30°	45°	60°
JAN	MEAN *	4.955	4.489	3.861	3.126	2.150	5.182	4.663	4.005	3.255	2.256
	SIGMA 1	0.413	0.453	0.517	0.608	0.718	0.430	0.473	0.538	0.627	0.726
FEB	MEAN	5.126	4.787	4.268	3.642	2.930	5.248	4.863	4.319	3.688	2.986
	SIGMA 1	0.413	0.441	0.491	0.568	0.667	0.424	0.455	0.508	0.585	0.680
MAR	MEAN	5.188	5.033	4.674	4.176	3.625	5.161	4.962	4.574	4.070	3.537
	SIGMA 1	0.413	0.426	0.459	0.515	0.595	0.414	0.431	0.468	0.527	0.609
APR	MEAN	5.039	5.079	4.895	4.529	4.057	4.863	4.855	4.631	4.245	3.776
	SIGMA 1	0.413	0.411	0.426	0.462	0.517	0.404	0.405	0.425	0.465	0.525
MAY	MEAN	4.766	4.962	4.937	4.711	4.356	4.480	4.627	4.554	4.294	3.923
	SIGMA 1	0.413	0.398	0.401	0.421	0.457	0.395	0.384	0.392	0.416	0.457
JUN	MEAN	4.578	4.850	4.907	4.762	4.487	4.242	4.465	4.471	4.284	3.984
	SIGMA 1	0.413	0.392	0.389	0.402	0.428	0.390	0.373	0.375	0.392	0.423
JUL	MEAN	4.630	4.874	4.901	4.727	4.422	4.313	4.508	4.485	4.272	3.946
	SIGMA 1	0.413	0.394	0.393	0.409	0.438	0.392	0.377	0.381	0.400	0.435
AUG	MEAN	4.865	4.987	4.887	4.594	4.181	4.632	4.705	4.561	4.241	3.822
	SIGMA 1	0.413	0.404	0.413	0.440	0.485	0.399	0.394	0.407	0.439	0.489
SEP	MEAN	5.082	5.023	4.750	4.317	3.804	4.981	4.877	4.570	4.125	3.624
	SIGMA 1	0.413	0.418	0.443	0.488	0.556	0.409	0.418	0.447	0.496	0.568
OCT	MEAN	5.124	4.872	4.432	3.874	3.265	5.176	4.881	4.415	3.855	3.263
	SIGMA 1	0.413	0.434	0.476	0.543	0.634	0.419	0.444	0.489	0.559	0.648
NOV	MEAN	5.002	4.590	4.011	3.328	2.490	5.184	4.724	4.117	3.425	2.581
	SIGMA 1	0.413	0.448	0.506	0.591	0.697	0.428	0.465	0.526	0.610	0.707
DEC	MEAN	4.883	4.387	3.735	2.971	1.891	5.135	4.585	3.899	3.116	1.999
	SIGMA 1	0.413	0.456	0.524	0.619	0.731	0.432	0.477	0.546	0.637	0.738

*Note: In all cases the MEAN is (I) and SIGMA 1 is (R)

For southern latitudes, the values listed for July pertain to January, August to February, etc. Otherwise, the tables are equally valued for northern and southern latitudes.

Exhibit 6.1-1 (Continued)

AVERAGE MONTHLY INSOLATION (KWH/M²-DAY) AND THE RATIO (SIGMA 1) OF STANDARD DEVIATION TO AVERAGE

$$K_H = 0.7$$

KH = .7		Tilt = Latitude					Tilt = Latitude +10				
		0°	15°	30°	45°	60°	0°	15°	30°	45°	60°
JAN	MEAN *	6.952	6.529	5.928	5.146	3.816	7.387	6.902	6.254	5.430	4.027
	SIGMA 1	0.178	0.196	0.224	0.257	0.292	0.186	0.205	0.232	0.263	0.294
FEB	MEAN	7.193	6.890	6.418	5.817	5.028	7.434	7.086	6.585	5.970	5.170
	SIGMA 1	0.178	0.191	0.213	0.243	0.277	0.183	0.197	0.220	0.249	0.280
MAR	MEAN	7.280	7.145	6.834	6.399	5.910	7.246	7.075	6.740	6.300	5.826
	SIGMA 1	0.178	0.184	0.199	0.223	0.253	0.178	0.186	0.203	0.228	0.258
APR	MEAN	7.071	7.108	6.952	6.638	6.230	6.762	6.759	6.572	6.241	5.835
	SIGMA 1	0.178	0.176	0.184	0.200	0.224	0.173	0.174	0.184	0.202	0.227
MAY	MEAN	6.687	6.863	6.847	6.659	6.358	6.174	6.309	6.255	6.039	5.726
	SIGMA 1	0.178	0.170	0.172	0.182	0.198	0.168	0.163	0.167	0.179	0.198
JUN	MEAN	6.423	6.665	6.723	6.607	6.380	5.819	6.020	6.037	5.887	5.639
	SIGMA 1	0.178	0.167	0.165	0.172	0.185	0.166	0.157	0.158	0.167	0.182
JUL	MEAN	6.496	6.714	6.745	6.603	6.348	5.926	6.103	6.094	5.920	5.648
	SIGMA 1	0.178	0.168	0.168	0.175	0.190	0.167	0.159	0.161	0.171	0.188
AUG	MEAN	6.827	6.936	6.855	6.606	6.252	6.411	6.481	6.364	6.093	5.734
	SIGMA 1	0.178	0.173	0.178	0.190	0.210	0.171	0.168	0.175	0.190	0.212
SEP	MEAN	7.131	7.081	6.847	6.472	6.024	6.961	6.874	6.612	6.227	5.789
	SIGMA 1	0.178	0.180	0.192	0.212	0.239	0.176	0.180	0.194	0.215	0.243
OCT	MEAN	7.190	6.968	6.578	6.071	5.476	7.303	7.042	6.628	6.115	5.528
	SIGMA 1	0.178	0.188	0.207	0.234	0.266	0.181	0.192	0.212	0.240	0.271
NOV	MEAN	7.018	6.647	6.105	5.410	4.359	7.371	6.947	6.366	5.644	4.552
	SIGMA 1	0.178	0.194	0.219	0.251	0.286	0.185	0.202	0.227	0.258	0.289
DEC	MEAN	6.851	6.400	5.766	4.929	3.386	7.332	6.813	6.126	5.238	3.595
	SIGMA 1	0.178	0.198	0.226	0.261	0.295	0.187	0.207	0.235	0.267	0.297

*Note: In all cases the MEAN is (I) and SIGMA 1 is (R)

For southern latitudes, the values listed for July pertain to January, August to February, etc. Otherwise, the tables are equally valued for northern and southern latitudes.

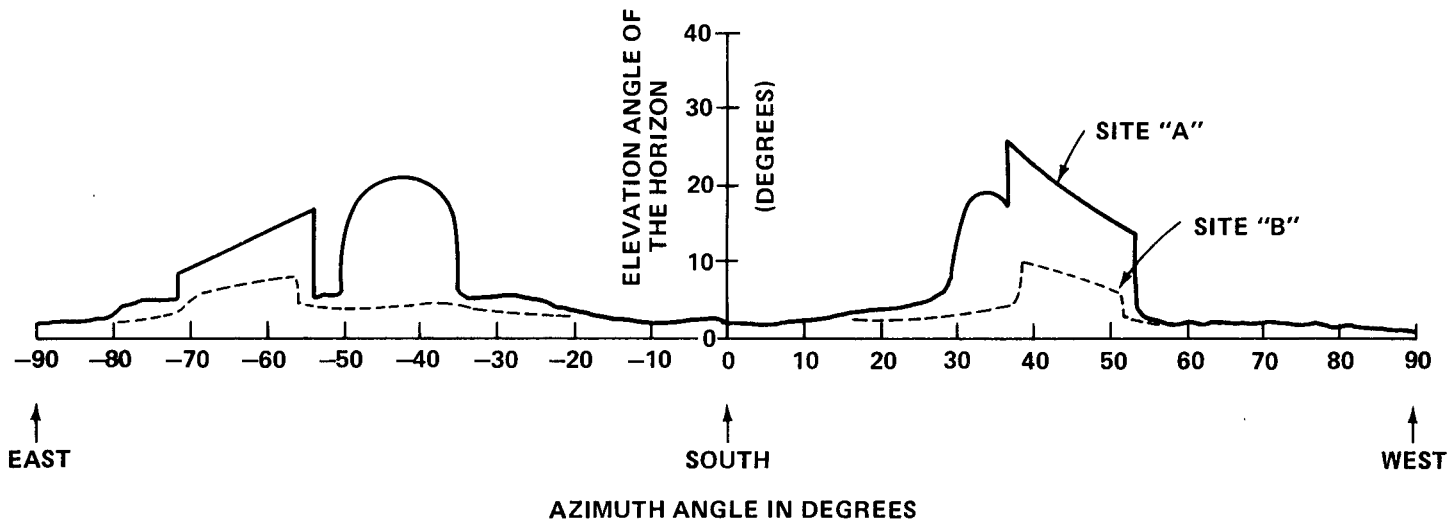


Exhibit 6.1-2

HORIZON PROFILES FOR TWO CANDIDATE SITES

6.2 PRELIMINARY ASSESSMENT OF PHOTOVOLTAIC SYSTEM DESIGN

An initial estimate can be made of the array-area and storage-capacity requirements to supply a particular load at a given site, for a required level of reliability, using a quick-sizing system approach. Once the capacity of the system is determined, the major components are sized. The gross system cost can be computed on the basis of the array and battery costs, and the process can be repeated by varying the array tilt angles, array areas and battery capacity until the minimum cost is determined. After the detailed engineering design phase is completed, a final cost estimate should also include the costs of site grading, array structures, buildings, power conditioning equipment, instrumentation, distribution wiring and any emergency (back-up) generator system.

6.2.1 Array and Battery Quick-Sizing Method

An estimate of the array-area and storage-capacity requirements by use of a monthly output computation is shown in Exhibit 6.2-1. Implicit in the computation is an assumption concerning the loss-of-load probability (LOLP). The LOLP was assumed to be 1 percent in the development of Exhibit 6.2-2, which is used in the monthly computation of Exhibit 6.2-1. After studying Section 7 of this handbook, adjustments may be made for other LOLP's. The monthly computations proceed as follows:

1. The clearness factor, \bar{K}_H , is obtained for the location of interest for each month from Appendix A. The values are entered in Column 1 of Exhibit 6.2-1.
2. A tilt angle is selected for the array at either latitude or latitude plus 10 degrees.
3. The average monthly insolation, \bar{I} , on the tilted array is obtained from Exhibit 6.1-1 by interpolation and entered in Column 2.
4. The ratio, R , of the standard deviation of the insolation to the average is obtained from Exhibit 6.1-1 by interpolation and entered in Column 3.

5. The standard deviation (S), is computed for each month from the formula $S = R \cdot \bar{I}$, S being entered in Column 4.
6. The kWh/day load is entered in Column 5.
7. The array performance factor, η_a , is obtained from the manufacturer, expressed in daily output per unit of array per kWh/day-m² of insolation.
8. Estimate the system efficiency, η . It will be approximately equal to the product of the array performance parameter, the battery efficiency and the power-conditioner efficiency. In Exhibit 6.2-1, = 8 percent.
9. Determine the optimal design by trial and error, selecting various values of M* for entry into Exhibit 6.2-1. A reasonable starting value is 0.33. For each selected value of M, compute the array area required for each month, according to the formula

$$\text{Area (m}^2\text{)} = \text{Load} / \left[\eta * (\bar{I} - M * S) \right]$$

In the example of Exhibit 6.2-1, the values of the area are presented in Column 6 for M = 0.33.

10. For the value of M and the ratio R, the storage requirement, C, is read from Exhibit 6.2-2. This capacity is given in days of load. For example, if the load is 20 kWh and the storage capacity C is six days, then the required storage capacity is 120 kWh. The value of C is entered for each month in Column 7. The storage capacity is expressed in the same units as the load in Column 8.

*As indicated in the theory described in Section 7 of this handbook, $M = (\bar{I} - I_D) / S$ where \bar{I} is the average monthly insolation; S, the standard deviation of the insolation; and I_D , the value of the insolation at which the average daily electrical demand is exactly met by the solar system.

11. The month requiring the largest value of array area and storage capacity will determine the equipment size. At first, several values of M should be selected to determine which gives the lowest life-cycle cost. (The value 0.33 is a reasonable starting point.) If the maximum area and maximum storage do not occur in the same month, the maximum array area should be selected according to the foregoing procedures. However, M must be computed from the equation, $M = (\bar{I} - \text{Load}/\eta A)/S$. The storage capacity C is then obtained from Exhibit 6.2-2 for this M and the monthly R . The month with the maximum product ($C * \text{Load}$) determines the battery size.

6.2.2 Component Sizing

Once the operating sizes of the array and the storage system have been computed, all the components of the PV system can be sized. The necessary array size has been computed to meet the required reliability criterion, but must be adjusted to allow for degradation with time. Assuming a 10% loss of array performance over its life due to aging, the 12 kW nominal array size must be divided by 0.9, giving a 13.33 kW required capacity at the time of installation.

The necessary battery size to be installed is the equivalent cell capacity to provide a 20-year system life divided by the allowable percent depth of discharge for the battery. A medium rate lead-acid battery is assumed with a 1000 cycle life or a 10 year calendar life. The maximum number of cycles a 9.2 day (184 kWh) battery would be subjected to over a 10 year life would be about 500. Referring to Exhibit 6.2-3 it can be seen that even at the higher mean battery temperatures, an apparent life of 500 cycles would be possible with a maximum depth of discharge of 95%. Thus, the required installed capacity of the battery will be 105% ($100\%/0.95$) of its end-of-life operating capacity, or 193 kWh in the case of the 184 kWh battery.

EXHIBIT 6.2-1
 QUICK SIZING COMPUTATIONAL PROCEDURE
 FOR ARRAY AND STORAGE⁽¹⁾

Units	Clearness Factor ⁽²⁾	Average Insolation ⁽³⁾	R	Standard Deviation ⁽³⁾	Monthly Load	Array Area ⁽⁴⁾	Storage Requirement ⁽⁵⁾	
	K_H	I		S			C	kWh
Month/Col.	1	kWh/m ² day	—	kWh/m ² day	kWh/day	m ²	Days	kWh
	1	2	3	4	5	6	7	8
January	0.417	2.72	0.73	2.00	20	122	8.1	162
February	0.447	3.41	0.63	2.15	20	93	6.7	134
March	0.460	3.99	0.55	2.19	20	77	5.7	114
April	0.480	4.48	0.48	2.15	20	66	4.8	96
May	0.496	4.76	0.42	2.00	20	61	4.2	84
June	0.521	5.01	0.37	1.85	20	57	3.6	72
July	0.509	4.88	0.39	1.90	20	59	3.8	76
August	0.499	4.70	0.43	2.02	20	62	4.3	86
September	0.494	4.43	0.48	2.13	20	67	4.7	94
October	0.480	3.91	0.55	2.15	20	78	5.7	114
November	0.421	2.91	0.70	2.05	20	112	7.7	154
December	0.383	2.32	0.81	1.89	20	148	9.2	184

Notes:

- (1) Based upon Washington, D.C. location, Latitude = 38.95°, Tilt = 38.95°.
- (2) From Appendix A Insolation Tables.
- (3) Average monthly insolation from Exhibit 6.1-1.
- (4) Array area = Load/($\eta(I - M \cdot S)$): $\eta = 0.08$.
- (5) Based upon $M = (\bar{I} - I_D)/S = 0.33$. Col. 7 entry read from Exhibit 6.2-2 Col. 8 = Col. 5 * Col. 7.

Exhibit 6.2-2

BATTERY STORAGE REQUIREMENTS FOR 1% LOLP

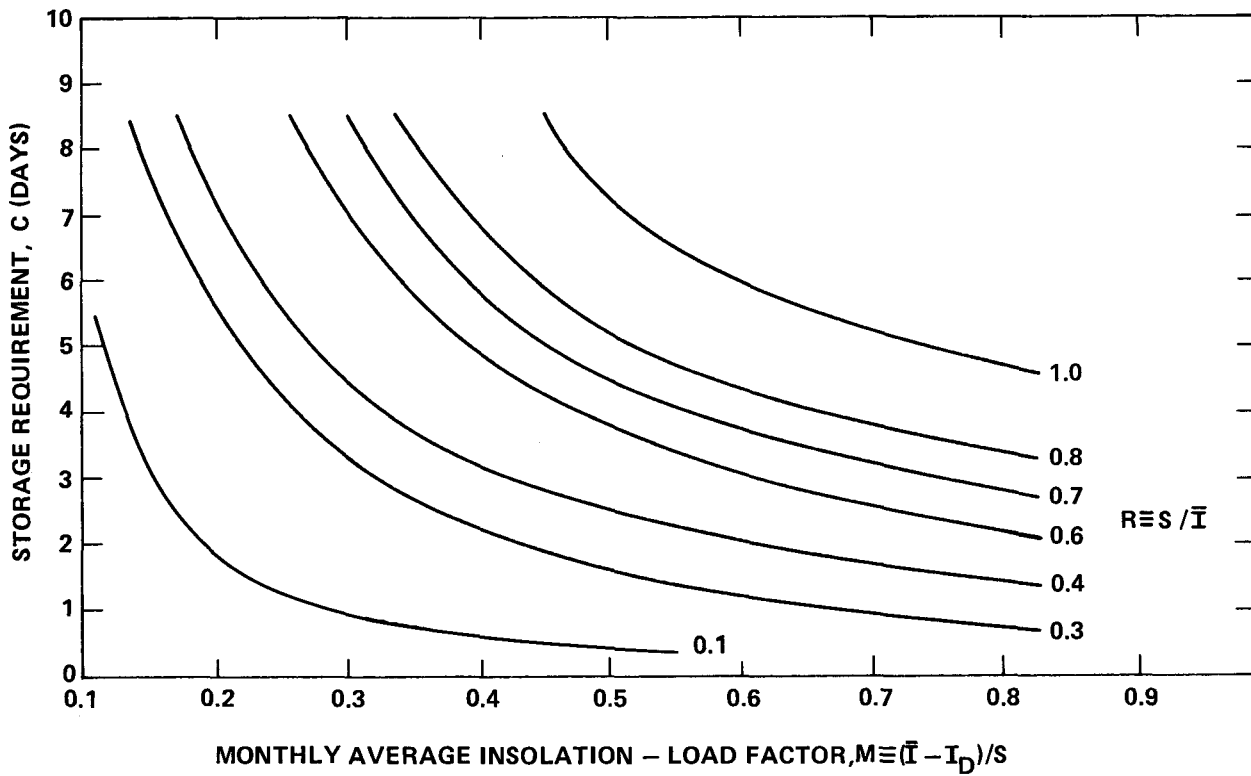
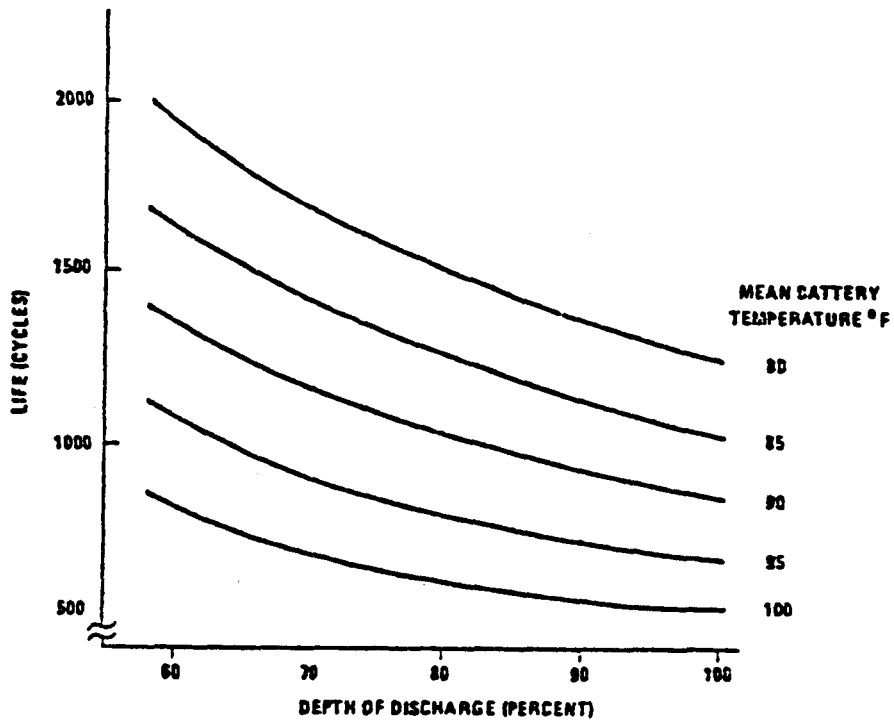


Exhibit 6.2-3

EFFECT OF DEPTH OF DISCHARGE ON BATTERY LIFE
ON TYPICAL LEAD-ACID MOTIVE POWER TYPE CELL (Reference 6-1)



6.3 BASIC APPROACH TO FEASIBILITY ASSESSMENT OF PHOTVOLTAIC POWER SYSTEMS

6.3.1 Preliminary Estimate

The preliminary estimate of cost effectiveness is the first step in determining whether or not to use a photovoltaic power system when there is an alternative power source. This section provides the methods for evaluating the life cycle costs of a system once the capital and operating costs and system performance factors are known. For a photovoltaic system, the cost of the arrays and the cost of the battery system are the two most important cost elements on which the initial capital and recurring operating costs are based.

The basic approach in making economic comparisons between a photovoltaic power system and a conventional power system is to determine the life cycle costs for each alternative. The life cycle cost procedure includes all initial capital costs and the expenditures for the entire life of each alternative including all replacements, maintenance, fuel and operating costs. Photovoltaic systems typically will require a large initial investment, but the operating cost expenditures are negligible when compared to a fuel-consuming engine-generator. Engines require a relatively modest initial expenditure, but also require continuing (escalating) expenses for fuel. For any power system alternatives which differ so in the time sequence of expenditures, the amount of back-up capacity, the cost and escalation rate of consumables and the amount of energy supplied (load factor) are all important factors in determining the break-even cost between alternatives.

In its simplest form, the life-cycle cost is the amount of money needed on hand today in order to finance the project over its entire lifetime, assuming a known rate of inflation and a given discount or cost of money interest rate. This amount is called the net present value of the project life-cycle cost. It can be written as:

$$\text{Life-cycle cost} = \text{Initial cost} + \text{Total Present Worth of Annual Costs}$$

The total present worth of the annual cost streams throughout the life of the project must include all maintenance costs, all battery replacement costs (for a PV system), all operating costs and all fuel costs for those alternatives using engine generator sets.

The present values for the recurrent costs of operations, maintenance, and back-up energy can be formulated to account for both escalation and discounting and expressed in terms of the year of first operation. The expression for the present value of recurrent costs is:

$$X_{pv} = \begin{cases} X_o \cdot \left(\frac{1 + g_o}{k - g_o} \right) \left[1 - \left(\frac{1 + g_o}{1 + k} \right)^N \right], & \text{if } k \neq g_o \\ X_o \cdot N, & \text{if } k = g_o \end{cases}$$

where

- X_{pv} = (operation + maintenance, or fuel cost) present value
- X_o = Operation + maintenance, or fuel cost in first year
- g_o = The escalation rate for operations, maintenance, or fuel cost
- k = The cost of money interest rate (discount rate)
- N = System life in years

For those recurring replacement costs for equipment such as batteries which have component lives shorter than the system life, the present value of the replacement costs is:

$$R_{pv} = X_1 (1-S) \sum_{i=1}^n \left(\frac{1 + g_1}{1 + k} \right)^{\frac{N_i}{n+1}}$$

where

- X_1 = The replacement cost of the equipment in the first year of operation
- S = Per unit salvage value of replaced equipment
- N = The system life in years
- n = The number of component replacements over N years
- g_1 = The inflation rate for equipment replacements
- k = The cost of money interest rate

The economic analysis should be conducted assuming appropriate system lifetimes for the power system components and the application. For our purpose, a system life of 20 years is assumed. This restriction does not mean, however, that the original solar equipment must be designed to last that long or that components which have longer lifetimes should be discarded in 20 years. It is not intended that the economic analysis should constrain the optimal design. The 20-year standard might be met, for instance, by replacing all the batteries at the end of 10 years or by replacing them at 5, 10, and again at 15 years if the cycling and design depth of discharge result in five year battery lives.

6.3.2 Life Cycle Cost Determination

The system components, cost and economic parameters for the system sized in Section 6.2 are presented in Exhibit 6.3-1. The hardware costs are based upon 1980 nominal levels and do not represent industry projections for the future. The indirect costs are expressed as a percentage of the material costs. Installation costs are very dependent upon the location and remoteness of the construction site and are likely to vary from the nominal value of 30% of the hardware costs. Engineering costs are likely to be higher on initial first of a kind projects than on subsequent follow-on jobs.

The inflation rates presented in Exhibit 6.3-1 for use in comparisons were chosen to be typical but may not reflect recent changing economic conditions. The absolute magnitudes of the inflation rates are not really crucial to a comparative engineering economy analysis. The important requirements are uniform assumptions and the relative rates of price change.

Exhibit 6.3-2 presents a form for the computation of the life cycle cost of the system. The costs of components and the factors for determining the present worth of annual recurring operations and maintenance cost as well as the replacement costs for batteries are based upon Exhibit 6.3-1. The evaluated life-cycle cost for the determination of feasibility is shown on Line 13 of the exhibit. This value can be compared with the costs of other alternatives and then refined by testing the sensitivity to different levels of reliability as discussed in Section 7.

Exhibit 6.3-1

COMPONENTS, SYSTEM COSTS
AND ECONOMIC PARAMETERS

<u>Components</u>	<u>Quantity</u>
PV Array: 12 kW ÷ 0.9 degradation factor	13.33 kW
Battery: 184 kWh ÷ 0.95 for depth of discharge	193 kWh
Array Life, N	20 yrs.
Battery Life	10 yrs.
<u>Hardware</u>	
PV Array Cost	\$ 10/W _p
Battery Cost	\$ 150/kWh
Salvage Value of Battery, S	0.10
<u>Indirect Costs</u>	
Engineering/Total Hardware Costs	0.10
Installation/Total Hardware Costs	0.30+*
Management/Total Hardware Costs	0.06
<u>Economic Parameters</u>	
Discount Rate, k	0.12
General Inflation Rate	0.08
Inflation Rate for O&M, g _o	0.09
Inflation Rate for Battery Replacements, g ₁	0.08
<u>Annual Recurring Costs</u>	
Array O&M (% of First Costs)	0.01
Battery O&M (% of First Costs)	0.01
<u>Present Value Factors</u>	
$X_{pv}/X_o = (1.09/0.03) [1 - (1.09/1.12)^{20}] =$	15.22
$R_{pv}/[X_1 (1-S)] = (1.08/1.12)^{10} =$	0.695

*These costs are very dependent upon location of site.

Exhibit 6.3-2

PHOTOVOLTAIC POWER SYSTEM PRELIMINARY
DESIGN LIFE CYCLE COST COMPUTATION

	<u>Quantity</u>
<u>Component Size</u>	
1. PV Array: nominal size degradation factor	13.33 kW
2. Battery size: nominal size depth of discharge	193 kWh
<u>Component Costs</u>	
3. PV Array	\$133,330
4. Battery	28,950
5. Power Conditioning System at \$1 per watt	<u>15,000</u>
6. Total Components	177,280
7. Engineering	17,730
8. Installation	53,180
9. Project Management	<u>10,640</u>
10. Total First Costs	258,830
<u>Annual Costs</u>	
11. Maintenance = $0.01 \times \text{Line 3} + 0.01 \times \text{Line 4}$ (from Exhibit 6.3-1)	1,623
<u>Replacements Present Value</u>	
12. Battery = $0.695 \times 0.9 \times \text{Line 4}$	18,108
<u>Total Life Cycle Cost</u>	
Line 10 + Line 12 + $15.22 \times \text{Line 11}$	<u>\$301,640</u>

6.4 RELIABILITY ENGINEERING APPROACH

Beginning in the early conceptual and feasibility analysis phase of PV system design, the system design engineer is confronted with many tradeoff decisions involving the alternative choice of PV array configurations, equipment/component types, physical plant (site) layout, etc. These tradeoffs are conducted primarily to optimize system performance with respect to life-cycle cost. In the design of stand-alone PV power plants, system reliability and maintainability (R&M) become key integral factors in these performance/cost tradeoff analyses.

This section discusses the more important R & M engineering and analytical technologies used in these analyses. Maintainability and maintenance aspects of system design are discussed in Section 8.

6.4.1 Definition and Specification of PV System R & M Requirements

Reliability and maintainability requirements for stand-alone PV power systems can be expressed in quantitative terms amenable to specification as design requirements, estimation in the design phase, measurement in the development/testing phase, and evaluation during operational use phases of the system life cycle. Definitions and terms are consistent with those used throughout the DOD/NASA industry (Refs. 6-2, 6-3).

Reliability

Reliability is generally defined as the probability that an item (PV system, equipment, module, etc.) will perform its specified function (within specified limits of performance) without failure for a specified period of time (or number of cycles) when operated under specified conditions. Reliability characteristic curves (reliability functions for an item are illustrated in Exhibit 6.4-1) for two basic types of failure modes common in PV power systems:

(1) Exponential Case -- failure modes which occur at random points in time (e.g., failure attributed to quality defects in PV cell manufacture, cell failures due to hail damage, etc.), which are independent of prior experience. The reliability function follows exponential (Poisson) law, given as:

$$R(t) = e^{-t/\text{MTBF}} = e^{-\lambda t}$$

Where: $R(t)$ = reliability of the item for
a given period of time, t

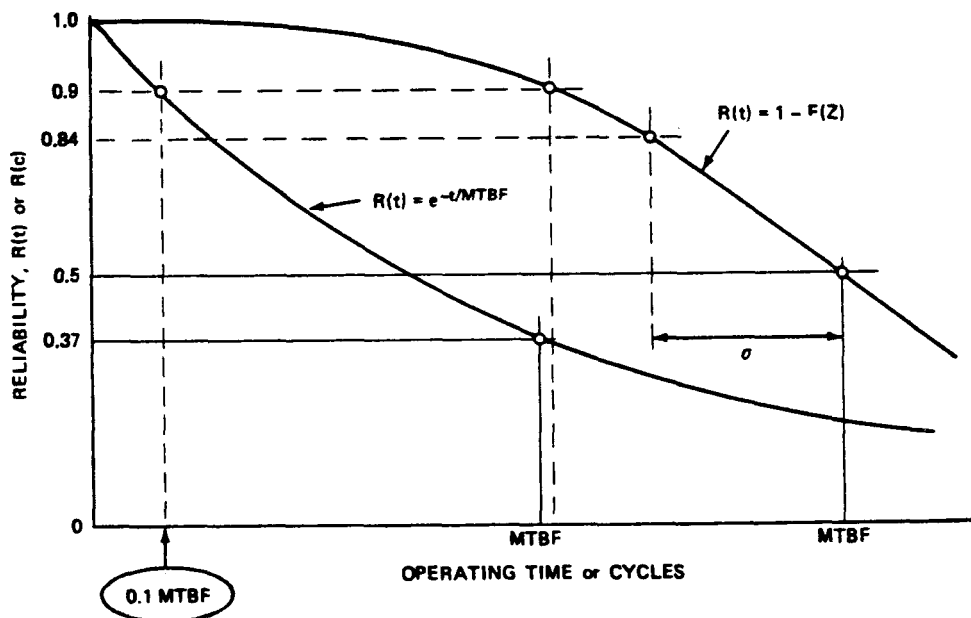
t = calendar time in units of hours,
days, months, etc., as applicable

MTBF = mean time between failures for the item

λ = item failure rate, in failures per unit of
time; $\lambda = 1/\text{MTBF}$

Exhibit 6.4-1

RELIABILITY FUNCTIONS FOR EXPONENTIAL
(RANDOM) AND GAUSSIAN (WEAROUT) FACILITIES



(2) Gaussian Case --failure modes which occur at predictable points in time, attributed to performance degradation or "wear-out" after an extended period or number of cycles of use (e.g., PV cells and batteries). The reliability function is given by:

$$R(t) = 1 - F(Z_t), \text{ for time-dependent failure modes}$$

$$R(c) = 1 - F(Z_c), \text{ for cycle-dependent failure modes}$$

where: $F(Z) =$ area under the cumulative normal distribution curve (see typical statistics textbook, e.g. Ref. 6-4).

$$Z = (x - \mu) / \sigma$$

$x =$ time (t) or cycles (c) at which reliability is to be estimated or specified

$\mu =$ mean time between failures (MTBF) or mean cycles between failures (MCBF) for the reliability function at $R \approx 0.50$

$\sigma =$ standard deviation in hours (or cycles) between 50th percentile MTBF (or MCBF) and 84th percentile on the reliability function

Maintainability (MTTR) and Downtime (MDT)

Maintainability is generally defined in terms of the mean time to repair (MTTR) an item after a failure has occurred. Repair time includes the active time required to: trace and localize the failure; perform the necessary disassembly, corrective repair, and reassembly of the item, and; "check out" (verify) the repair action.

Repair time does not include travel time (time required for the technician to arrive at the site following the indication of a failure) or logistic delay time (time involved in getting the necessary replacement parts). These time elements, along with active repair time, account for the average downtime (MDT) for the repair action.

Availability (A)

Availability of an item is generally defined as the probability that at any point in time the item will be in a satisfactory state of operation (i.e., either

operating or ready to operate when demanded) in accordance with specified performance requirements under the specified use conditions. System availability can be defined for its design (inherent) availability, A_I , and for its operating (operational) availability (A_O):

$$A_I = \frac{MTBF}{MTBF + MTTR} = \left(1 + \frac{MTTR}{MTBF}\right)^{-1}$$

$$A_O = \frac{MTBF}{MTBF + MDT} = \left(1 + \frac{MDT}{MTBF}\right)^{-1}$$

Specification of R&M Requirements

A stand-alone PV power system for particular application may be required to deliver a specified level of dc power without interruption for long periods with only periodic (e.g., weekly or monthly) scheduled maintenance/inspection. The system "operational" requirements should be stated by (or made known to the potential customer) in a formal system specification. The system specification serves two purposes: (1) it provides the contract basis for delivery and acceptance of the installed PV power system; and (2) it provides the basis for translating the system operational requirements into reliability and maintainability parameters allocable to lower-level subsystem/equipment as quantitative design R&M requirements. This section deals with the latter.

Assume, for example, the key system requirements for a particular customer's application might be summarized as illustrated in Exhibit 6.4-2. Since the customer has indicated the proposed PV installation is to be 30 miles NE of Billings, Montana, the solar parameter (e.g., average daily insolation, percent of clear days, etc.) can be computed for the intended site. The system designer must now translate this customer's system requirements into design requirements in quantitative terms (values of performance, reliability, and maintainability characteristics) allocated to the major subsystem. These design requirements are identified and quantitatively allocated to the subsystems in the system design

specification. The allocated requirements are appropriately up-dated following each design trade-off iteration during preliminary design phase(e.g., trade-off solar-array, battery-bank, and estimated cycle cost within constraints of a backup generator, load criticality, and available insolation). The following two paragraphs illustrate the reliability and maintainability design requirements which might be included in a proposed system specification. The values shown in these paragraphs are based on the customer's stated operational requirements in Exhibit 6.4-2.

Exhibit 6.4-2
 PARTIAL DESCRIPTION OF REQUIREMENTS
 FOR HYPOTHETICAL CUSTOMER APPLICATION

Voltage:	200V \pm 20V DC
Load Demand:	Continuous, with 1 to 10 kW; Average = 50 kWh per day
Load Critically:	
Load I Critical Level	10 kWh/day (with less than 1% risk of power loss between scheduled maintenance visits)
Load II Essential Load:	40 kWh/day (with less than 10% risk of power loss)
Site/Location:	Remote; 30 miles NE of Billings, Montana; latitude approximately 35 ^o N; altitude 3,500 ft; rolling terrain
Operation:	Unattended
Planned Inspection/ Maintenance:	30-day intervals
Maintainability:	Not to exceed 2-hour active repair time, on the average (excluding travel and logistic delay time)
Spares Provisioning:	Initial spares to provide 90 percent of first-year repairs; to be stocked at the PVPS site
Monitoring:	Telemetry (wire or radial) of key parameter status to off-site customer office (30 miles)

Reliability Design Requirements

1. System Reliability -- System design shall provide continuous dc power to the specified loads for uninterrupted service (excluding 30 seconds start-up of back-up unit, if necessary) during thirty (30) days of unattended operation between scheduled monthly preventive maintenance visits.

Load I (Critical Load) R = 0.99 for specified load, P_o
= 10 kWh/day

Load II (Essential Load) R = 0.90 for $P_o = 40$ kWh/day

2. Subsystem Reliability—The following subsystem/equipment design requirements shown in Exhibit 6.4-3 are preliminary design allocations to satisfy system requirements specified in (1) above. Values shown in the table are subject to revision as the result of design trade-off iterations in the design verification phase. Subsystem R-values are keyed to the functional block diagram shown in Exhibit 6.4-4 and reliability modeling procedures discussed in Paragraph 6.4.2, following.

Exhibit 6.4-3

EXAMPLE RELIABILITY ALLOCATION FOR A HYPOTHETICAL SYSTEM

System/Equipment	Allocated R Value
I* Insolation, $\bar{I}_{\min} = 3.4$; $P(I \geq \bar{I}_{\min}) =$	0.50
A Solar Array	0.95
B Array Terminal Box	0.99
C DC/DC Regulator	0.98
D Battery Bank and Terminal Box	0.95
E Generator, Primary Back-Up	0.85
F Generator, Critical Load Back-Up	0.90
G Main Power Switching Panel	0.99
H Critical Power Switching Panel	0.99
J Maintaining & Telemetry Equipment	0.995
K Distribution Panel	0.995
System Reliability (Load I and II)	0.90
(Load I only)	0.99

*For 35°N latitude (Billings, Montana), the value of minimum solar insolation (I_{\min}) during January is $\bar{I}_{\min} = \bar{K}_T \bar{R} E = 3.4$ kWh/m²-day, where $\bar{K}_T = 0.44$, $\bar{R} = 1.54$ for 50° tilt, and $E = 18.1$ kWh/m²-day. Thus the value of $P(I \geq \bar{I}_{\min}) = 0.50$ assuming $\bar{K}_T \approx \tilde{K}_T$.

6.4.2 R&M Networks and Block Diagrams

A reliability block diagram is prepared as a series-parallel network comprising the major components to be used in the proposed PV power system. The block diagram assumes failure-independence (i.e., no interactions) between the blocks. If interactions (failure dependencies) are known to exist between components, these components are combined and identified in the block diagram to account for the interactions. Reliability estimating models (math models) are then developed for each component and path in the network and for the overall PVPS system level. Procedures are illustrated in the following steps:

(1) Prepare a top-level "function-oriented" reliability block diagram based on the preliminary design functional block diagram for the system. Exhibit 6.4-5 shows the functional-oriented reliability block diagram based on the hypothetical system depicted in Exhibit 6.4-4. At the system level, reliability is given as follows for normal operation (with backup), and including solar insolation $R_I^* = P(I)$.

- Load II Performance

$$R_S (II) = \left[1 - (1-R_E)(1-R_I^* R_A R_B R_C R_D) \right] R_G R_K R_J$$

- Load I Performance

$$R_S (I) = \left[1 - R_F(1-R_E)(1-R_I^* R_A R_B R_C R_D) \right] R_G R_K R_J$$

(2) Expand the individual blocks in the "functional" reliability diagram into "equipment/circuit" oriented reliability block diagrams to show series and parallel status and major components in each path in the block.

Develop reliability math models for each block in the system. For example, Block A in Exhibit 6.4-6 is the solar array. The solar array may be configured as simple series "strings" of PV cells, or as a series/parallel network, as illustrated.

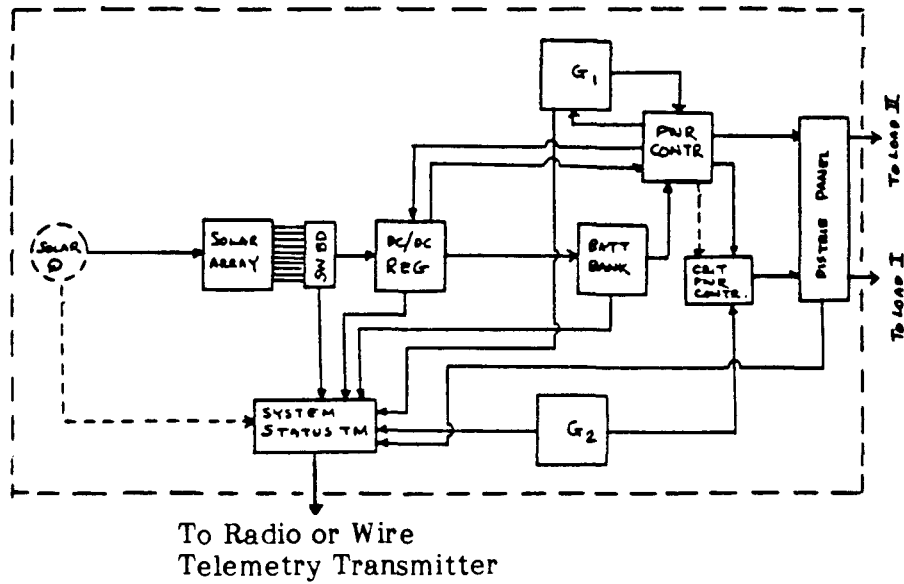


Exhibit 6.4-4 FUNCTIONAL RELIABILITY BLOCK DIAGRAM

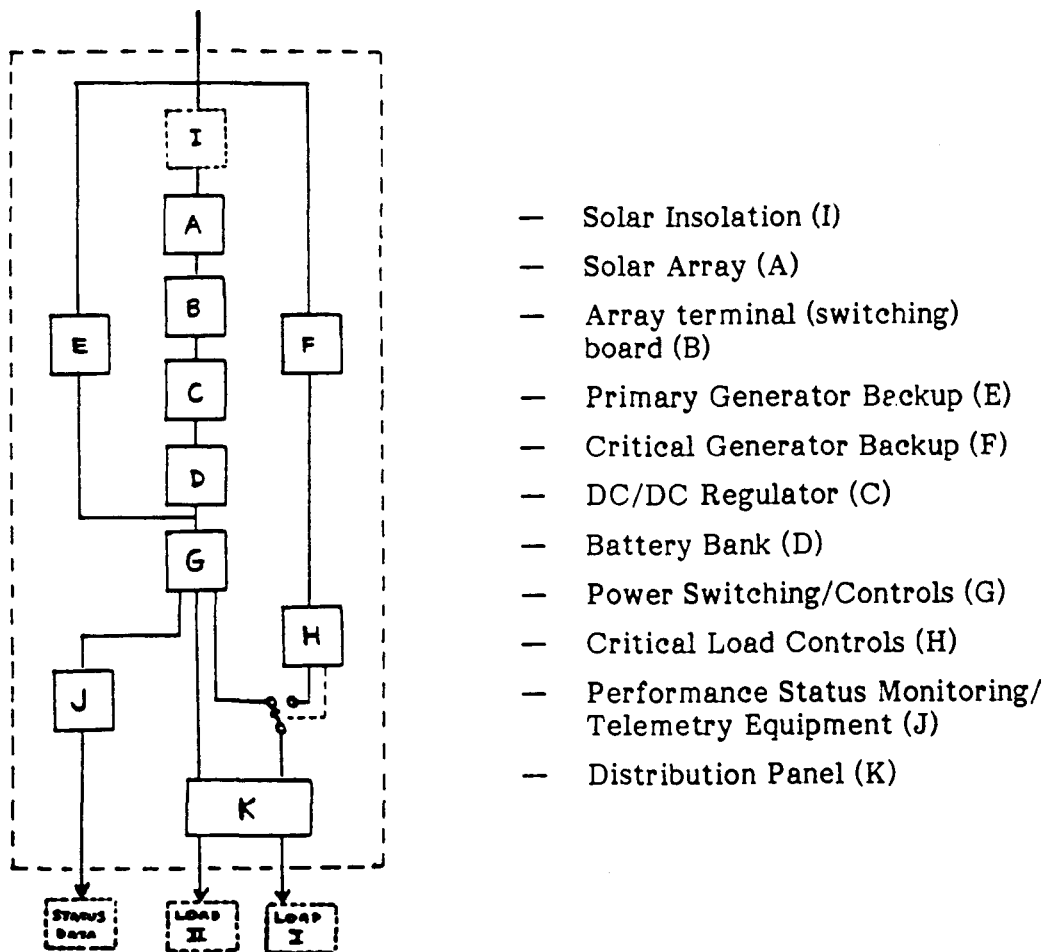


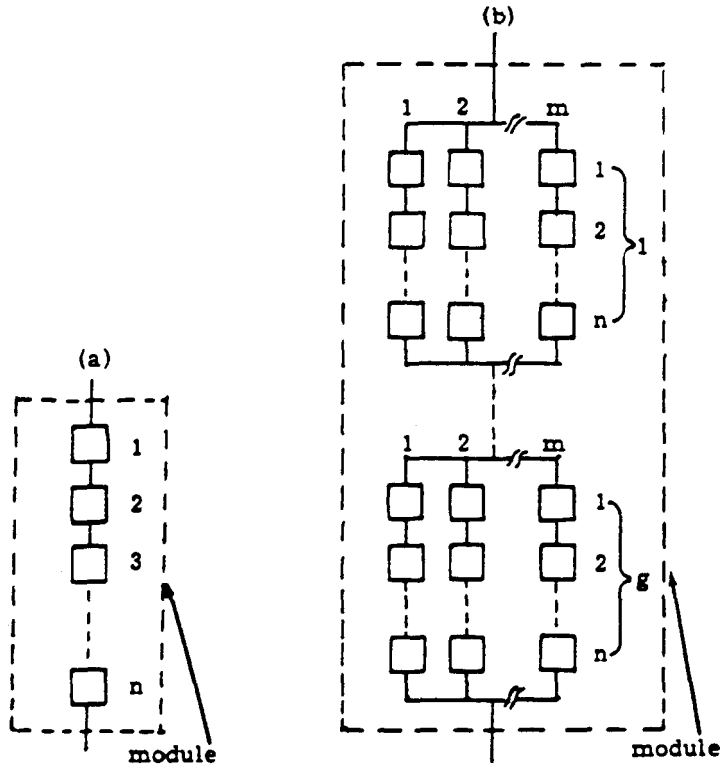
Exhibit 6.4-5

FUNCTION ORIENTED RELIABILITY BLOCK DIAGRAM

Exhibit 6.4-6

OPTIONAL MODULE CONFIGURATIONS:

(A) SERIES: (B) SERIES/PARALLEL



The choice of one configuration over another will depend on the size of array (in peak watts and voltage), cost of cross-connections vs additional series strings, ease of maintenance, reliability requirement in unattended installation, etc. Generally, configuration (b) provides higher "system" reliability for a given PV cell population in the array. Reliability models for the two configurations are given as follows:

(a)

Series Case

$$R_A = R_i^n \sum_{x=0}^r \binom{n}{x} \left(\frac{\bar{R}_i}{R_i} \right)^x$$

where: R_i = reliability of individual PV "string" in the operative redundant configuration

$$\bar{R}_i = (1 - R_i)$$

n = number of PV strings in the array

r = number of allowable string failures

and $\binom{n}{x}$ is the binomial coefficient $\frac{n!}{x!(n-x)!}$ (For complete tables of values see, National Bureau of Standards, "Tables of Binomial Probability Distribution", GPO 1949, Applied Mathematics Series 6.)

For illustration, assume the first design iteration (preliminary design) has sized the array with 64 parallel strings, each composed of 14 modules in series. Each module is configured with 36 cells in series to deliver rated array power output of 15 kWp at 200 V dc (under standard insolation, $I = 1000 \text{ W/m}^2$).

Assume that module failure rate for a 30-day unattended operation is

$\lambda_m = 780 \times 10^{-6}$ module failures/month and reliability for $R_m = e^{-780 \times 10^{-6} \times 30} = 0.9992$ for a 30 day period.

Reliability for a series string of 14 modules for a 30-day period is given by

$$R_S = (R_M)^{14} = (0.9992)^{14} = 0.989$$

Array reliability for a 30-day period can then be estimated for $r = 0, 1,$ or 2 string failures using the binomial expression above:

$$R_A (r = 0) = R_i^n = (0.989)^{64} \approx 0.493$$

$$R_A (r = 1) = 0.493 \left[1 + 64 \left(\frac{0.011}{0.989} \right) \right] = 0.844$$

$$R_A (r = 2) = 0.493 \left[1 + 64 \left(\frac{0.011}{0.989} \right) + \frac{63 \times 64}{2} \left(\frac{0.011}{0.989} \right)^2 \right] = 0.967$$

This indicates the simple series configuration (a) would require the addition of two redundant strings to satisfy the allocated reliability requirement, $R_A \geq 0.95$. This is verified here to illustrate use of Poisson approximation of the binomial expansion. Techniques for graphical solution of parallel redundant reliability estimation can be found in Ref. 6-4.

$$R(30 \text{ days}) = \sum_{x=0}^r \frac{e^{-m\lambda_m t n} (m\lambda_m t n)^x}{x!}$$

where m = number of modules in string, e.g., $m = 14$
 λ_m = module failure rate, e.g., $\lambda_m = 26 \times 10^{-6}$ failures/day
 t = unattended system operating time between scheduled preventive maintenance visits, e.g., $t = 30$ days
 n = number of strings in the array, e.g., $n = 64 + 2$ redundant strings = 66 strings

$$\text{then } m\lambda_m t n = 14 \times 26 \times 10^{-6} \times 30 \times 66 = 0.72$$

$$R(30 \text{ days}) = \sum_{x=0}^{r=2} \frac{(0.49)(0.72)^x}{x!}, \text{ for } r = 2, n = 66 \text{ (2nd iteration)}$$

$$= 0.49 + 0.35 + 0.13$$

$$\approx 0.97$$

However, only one redundant string would be required using the cross-connection configuration discussed in (b), following.

(b) Cross-Connected (Series Parallel Modules)

Assume the circuit configuration is to consist of cross connections to produce two blocks each of 64 substrings (of three series modules) in series with two blocks of 64 substrings (of four series modules).

As in (a) above, module failure rate for 30 days = 778×10^{-6} failures per month, and module reliability = $e^{-778 \times 10^{-6}} = 0.99922$.

$$\text{Substring (3 module) reliability, } R_{SS_3} = (0.99922)^3 = 0.99767$$

$$\text{Substring (4 module) reliability, } R_{SS_4} = (0.99922)^4 = 0.99689$$

$$\begin{aligned}
 R_A &= \left\{ (R_{SS_3})^{64} \left[1 + 64 \frac{(1 - R_{SS_3})}{R_{SS_3}} \right] \right\}^2 \times \left\{ (R_{SS_4})^{64} \left[1 + 64 \frac{(1 - R_{SS_4})}{R_{SS_4}} \right] \right\}^2 \\
 &= \left\{ (0.8613) \left[1 + 64 \frac{(0.00233)}{(0.99767)} \right] \right\}^2 \left\{ (0.8193) \left[1 + 64 \frac{(0.00311)}{(0.99689)} \right] \right\}^2 \\
 &= (0.9900)^2 (0.9829)^2 \\
 &= (0.947)
 \end{aligned}$$

Trade-off analysis of configurations (a) and (b) should consider the cost of interconnection required to save one string vs the cost of that string.

In this example, configuration (b) would be recommended from a maintenance/safety standpoint. PV substrings can be grounded at cross-connections during maintenance to limit exposure of voltage less than 50 volts consistent with Article 110-17 of the National Electrical Code (NEC).

6.4.3 Reliability Prediction and Feasibility Estimation

Feasibility of the allocated reliability and maintainability requirements defined in 6.4.1 are evaluated by using the math models developed in 6.4.2 based on equipment and component failure rates presented in Appendix B. These failure rates are based on field experience over the past few years and are subject to revision with changes in the state of the art.

For example, failure rates reported on photovoltaic cells may range from 0.005×10^{-6} to 0.5×10^{-6} (failures per hour) due to variation in application stresses, environmental conditions (temperature, relative humidity, etc.), basic design, materials, and processes used in PV manufacture, and also the scarcity of PV cell failure data itself.

In jointly estimating reliability and maintainability (scheduled periodic maintenance) for the stand-alone PV system, power loss must be considered due to accumulation of "dust" on the surface of PV modules. Dust includes sand, pollen, and other air-borne particles, peculiar to the local atmosphere at the proposed site. Design discussions will involve trade-offs, primarily among cost of frequency of array "cleaning" (preventive maintenance), cost of glass outer covers for the modules, and cost of additional PV strings to make up the power loss during the desired length of unattended operating period.

Field data collected from several existing sites indicates dust accumulation rate and corresponding array power loss ranging from 1% to 38% over a one-year period without cleaning (see Appendix B). Variation in dust accumulation can be attributed to differences in the materials used in module outer surface (e.g., glass, silicone rubber, hard-coated silicone rubber), array tilt angle, and local atmospheric/pollution/weather conditions (e.g., city, suburban, rural, mountainous, desert, etc.).

6.4.4 Failure Mode and Effects Analysis

The PV power system designer should perform failure mode and effects analyses (FMEA) for his intended design (and subsequent engineering changes) to identify and evaluate any potential critical failure modes which could jeopardize personnel safety or equipment reliability during installation, operation, or maintenance of the proposed PV power system. These analyses are also useful for identifying potential maintainability problems (excessive maintenance burden in terms of maintenance manhours, equipment downtime rate); logistic support problems (excessive requirements for spares and replacement parts); and inadequacy of specified quality controls (in component production and system installation in terms of process controls, special inspections, test procedures, etc.).

Results of the FMEA should provide design guidance in choosing between several alternatives for the correction or circumvention of the identified critical failure modes -- e.g., choice between use of parts derating, feedback stabilization, circuit redundancy, location of test points for performance monitoring and failure indication (for on-line maintenance), etc.

Procedures for failure mode and effect analysis (and "fault-tree" analysis) are published in the literature,¹ describing the following basic steps:

(1) Develop the Equipment Functional/Reliability Block Diagram

Extend the reliability block diagram and mathematical models described in 6.4.2 down to the lowest replaceable item (e.g., unit, circuit, component, or part) in each functional path or "network" in the proposed design configuration.

(2) Identify Critical Failure Modes.

Identify and determine the specific failure modes within replaceable items which could render each functional path hazardous (or unsafe) to operating/maintenance personnel, unreliable (inoperable or excessively degraded performance) in equipment operation, or nonconformance to other "desired" specified system performance parameter requirements (e.g., performance tolerance limits, downtime rates, maintenance skills, etc.).

¹For example, two sources are: Military Standard 2070 (AS), "Procedures for Performing a Failure Mode Effects and Criticality Analysis for Aeronautical Equipment"; Reliability Guides (Vol. 4), NAVORD OD 44622, pp. 7-4 through 7-21, "Failure Mode and Effects Analysis by Prediction".

(3) Estimate Failure Rate for Identified Critical Failure Modes.

Determine failure rate for each identified critical failure mode by subdividing the failure rates applied in 6.4.3, allocated according to the relative frequency with which the critical failure modes occur within the estimated overall failure rate.

For example, estimated failure rates for a particular type of DC relay may be 5×10^{-6} failures per operating hour in all failure modes. Assume that life test data reveal 50 percent of the failures were due to open mode, 20 percent were due to short mode, and 30 percent were due to degraded performance (high resistance contact, chattering contacts, etc.). If "short" mode is critical in terms of safety or reliability in the proposed application, the failure rate for the critical failure mode is:

$$\begin{aligned}\lambda_c &= 5 \times 10^{-6} (0.20) \\ &= 1 \times 10^{-6} \text{ critical "short" failures per operating hour}\end{aligned}$$

In the absence of experience data (operating history or life-test data) for particular items used in the proposed PVPS design, failure-rate estimates for generic part types can be obtained from MIL-HDBK-217.² Life-test failure-mode data for certain part types can be obtained from GIDEP reports.³ However, a "worst-case" analysis may be justified if data are meager, by allocating the total failure rate to the critical failure mode.

^{2, 3}See Appendix B-2

(4) Assess Safety/Reliability Design Adequacy.

Apply estimated failure rates of identified critical failure modes in the reliability modes evolved in (1) above, and compute functional path and system-level reliability (inoperable) failure rate and safety (hazardous or unsafe) failure rate. Transform these critical failure rates to reliability and safety probability estimates (or in terms of mean time between critical failures (MTBCF)). Compare these values with the specified PV power system requirements for safety and reliability (or downtime rate).

(5) Evaluate Design Changes.

If results of FMEA indicate nonconformance to specified (or desired) requirements in (4) above, rank the identified problem areas according to their relative impact and evaluate alternative design changes for circumvention of or minimizing the undesired failure modes.

(6) Evaluate Other Hazards to System Safety/Reliability.

Other critical failure modes may be induced by human/equipment interface problems (not due to component failure) resulting in equipment operation or maintenance in modes not intended by design. Although these failure modes usually cannot be quantified in terms of failure rate, they nevertheless can be identified qualitatively as potential threats requiring placement of cautionary labels and protective measures at appropriate points in the installed system.

For example, to evaluate the safety aspect of human/equipment interface design, consider the following: electrical grounds for external metal parts, panels, controls, etc.; safety covers and notations with interlocks in the high-voltage devices; connectors and plugs designed so as not to expose high-voltage "hot" pins; local safety switch at base of solar-tracking arrays; discharging devices for high voltage PV circuits during cleaning or maintenance of solar array; barriers between adjacent test points on terminals to prevent accidental shortage by slippage of test probe; installation of fuses and circuit-breakers at ground or low-voltage end of PV strings; protection from moving parts or high-temperature parts; protection from sharp edges of components and maintenance access openings; identification of points for lifting or hoisting batteries, solar panels, etc., during installation or removal.

6.5 ADVANTAGES AND DISADVANTAGES OF PV POWER SYSTEM

Current solar technology and cost suggest that adequately designed PV power systems (PVPS) are well suited for high-reliability/low maintainability requirement applications at remote locations. Typical examples of such applications have included remote weather stations, communications relay stations, navigational buoys and agricultural water-pumping systems. Other power sources are used with varying degrees of success, with or without battery storage and rechargeable on-site battery storage. Generally, the advantages of PV power systems over other systems are their simplicity (fewer moving parts), relative ease of maintenance, high (equipment) reliability, and unattended operation. However, the major disadvantages of PV power systems (by their nature) are their dependence on adequate solar insolation, relative large size of installation area required for the solar array, and the need for dc/ac inversion equipment for ac loads.

SECTION 7 SYSTEMS DESIGN

7.1 DESIGN PHILOSOPHY

The foregoing sections of this handbook give the ingredients for an analysis of the annual energy output from a photovoltaic system. However, the systems being considered are stand-alone systems; therefore, the design must be based on the photovoltaics supplying all of the electrical power. The average power output from the system must thus be equal to the average power consumption of the load. The question to be answered is: what is the probability that the solar system will not meet the momentary load requirement? This section presents the loss-of-load probability (LOLP) computational procedure to answer this question.

If the LOLP is too high to be acceptable, either the array and/or the storage size can be increased or an emergency power system can be provided as a backup to the photovoltaics. In the latter case, the LOLP computation will indicate how often the emergency system will be used. It can then be determined, for example, how much fuel must be stored at the site to power the emergency system and how frequently it must be replenished.

The procedure, which is intended to provide the basis for developing first cut designs for cost-effective stand-alone PV power systems, involves the following steps:

1. Determination of the load (see Section 4.1)
2. Computation of the insolation (see Section 11)
3. Selection of the array and storage-system size
4. Computation of the LOLP
5. Computation of the life-cycle costs

The last three elements are considered in this section of the handbook.

7.2 SYSTEM DESIGN PROCEDURE

The system design procedure is iterative. The array and storage sizes must be selected, with the help of the quick-sizing method of Section 6, and the system performance must be computed. The performance computation is then incorporated into a life-cycle cost analysis. If the technical performance or life-cycle cost are unacceptable, then a new set of array and storage sizes must be selected.

The computational process has been systematized in Exhibit 7.2-1. The average insolation is determined via the procedures of Section 11, based on the data in Appendix A and Exhibit 6.1-1. If Exhibit 6.1-1 does not include the tilt angles of interest, then the computational procedure of Section 11.3 can be used. The standard deviation of the insolation — a measure of its variability — is presented in Exhibit 6.1-1, as required in Step 2 of Exhibit 7.2-1. The insolation required to meet the load, I_D , can be estimated from the load requirements. With the load measured in kWh per day, and system efficiency in kWh/m² output per kWh/m² of insolation,

$$I_D = \frac{[\text{kWh/day of load}]}{((\text{kWh/m}^2 \text{ output per kWh/m}^2 \text{ of insolation}) * (\text{the area of the array in square meters}))}$$

The value of I_D is required in Step 3 of Exhibit 7.2-1.

The storage size is expressed in days of storage over which the load could be met in the complete absence of sunlight. If the load were 2 kWh per day and the storage size were 12 kWh, C , the storage capacity as required in Step 4 of Exhibit 7.2-1, would be $12/2 = 6$ days. The remaining computations are self-explanatory.

An outline of the procedure is presented herein to enable the reader to understand its applicability. The equation for Step 9 is based on having the storage system initially fully charged, to capacity C . Over $N-1$ days, the storage would be depleted gradually, so the required average insolation to meet the load up to

Exhibit 7.2-1

LOSS-OF-LOAD PROBABILITY COMPUTATIONAL PROCEDURE

1. Obtain the average insolation, \bar{I} , from Exhibit 6.1-1.
2. Obtain the standard deviation, s , of the insolation from Exhibit 6.1-1.
3. Select an insolation value, I_D , at which the load will be exactly met (I_D should be less than \bar{I}):

$$I_D = \text{Load}/(\eta A)$$

where A is the array area and the units of η should give I_D in kWh/day-m².

4. Select the storage capacity, C, in days of load.
5. Set $N=C+1$ and $SUM = 0.0$
6. Compute $Z_1 = (\bar{I} - I_D)/s$
7. If Z_1 is less than 2, read from Exhibit 7.2-2 the value of Y.
If Z_1 is greater than 2, compute

$$Y = \exp(-0.5 * Z_1^2) / (\sqrt{2 * \pi} * Z_1)$$

8. Compute the probability of failing in one day, $F_1 = Y$
9. Compute $Z_{N-1} = \left[\bar{I} - I_D + C * I_D / (N-1) \right] * \sqrt{N-1} / s$
10. If Z_{N-1} is less than 2, read from Exhibit 7.2-2 the value of Y.

If Z_{N-1} is greater than 2, compute

$$Y = \exp(-0.5 * Z_{N-1}^2) / (\sqrt{2 * \pi} * Z_{N-1})$$

11. Compute the probability of surviving up to day N-1: $F_{N-1} = 0.5 - Y$
12. Compute $Z' = Z_{N-1} + I_D / (\sqrt{N-1} * s)$
13. If Z' is less than 2, read from Exhibit 7.2-2 the value of Y.

If Z' is greater than 2, compute

$$Y = \exp \left[-0.5 * (Z')^2 \right] / (\sqrt{2 * \pi} * Z')$$

14. Compute the probability of surviving corresponding to Z' : $F' = 0.5 - Y$
15. Compute $SUM = SUM + (F' - F_{N-1})$
16. If N is greater than N*, where $N^*=10*(C+1) I_D / (\bar{I} - I_D)$, go to Step 18.
17. Set $N = N + 1$ and return to Step 9.

18. Compute the probability of failure:

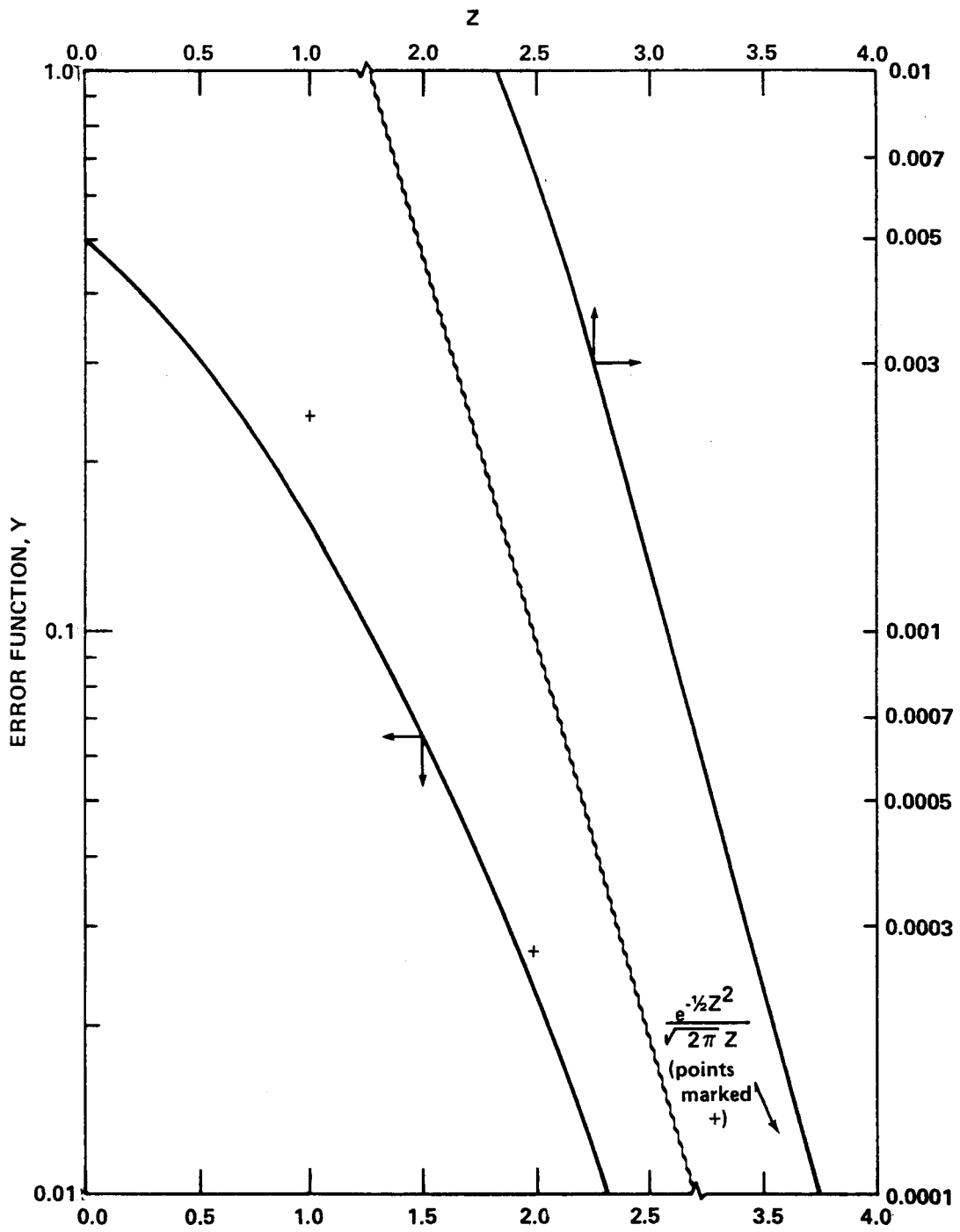
$$LOLP = F_1 * \left[SUM + \exp(-C * K_1) * \left[1 - \exp(-K_1) \right] * \exp(-K_2^2) / B \right]$$

$$K_1 = I_D * K / S$$

$$K = (\bar{I} - I_D) / s = Z_1$$

$$K_2 = K * (N^*/20)^{0.5}$$

$$B = K^2 * \left(K_2 + \sqrt{K_2^2 + 4 / \pi} \right)$$



DAILY AVERAGE INSOLATION—LOAD FACTOR $Z_1 = (\bar{I} - I_D)/S$

Exhibit 7.2-2

CUMULATIVE DISTRIBUTION FUNCTION
FOR THE NORMAL CURVE

day N-1 is $I_D - C \cdot I_D / (N-1)$. The function Z_{N-1} is the number of standard deviations the required average insolation is from the average, \bar{I} . The probability distribution function is not exactly normal (Gaussian), but closely approximates the normal after ten days. Therefore, the insolation on the tilted surface, which has been assumed as averaged over N days, is a normal distribution. This assumption is consistent with the law of large numbers in probability theory. The (cumulative) distribution function for the normal curve is called the error function. There is no simple expression for the error function, nor do hand-held calculators have the error function pre-programmed. Therefore, Exhibit 7.2-2 must be used. However, for Z greater than 2.0, the exponential function, Y, of Step 10, is a close approximation. The crossed points of Exhibit 7.2-2 show the comparison.

The LOLP computation for any one day, N, involves three factors: (1) Z_1 , which is related to the probability that the load will be lost in a single day; (2) Z_{N-1} , which corresponds to losing the load when the insolation is nearly zero on the following day; and (3) Z' , which corresponds to the losing the load when the insolation is relatively high on the following day. These three factors are combined in Step 15, although, for speed of computation, multiplication of the sum by the constant factor F_1 is deferred until after the summing is completed (Step 18).

The total LOLP must be computed by summing the probabilities for the individual days. Typically, several hundred days are required to provide an adequate estimate. When the number of the day is large, the summation can be approximated by an integral, as given in Step 18. Therefore, the summation computation need be executed only up to 10 times N^* , with the integral giving the value of the remaining terms in the summation. Consequently, the probability of failure (LOLP) of Step 18 includes all the days, up to N equal to infinity.

The procedure gives an approximate evaluation of the exact expression:

$$LOLP = \sum_{N=C+1}^{\infty} \int_{I_{N-1}/I}^{(N/N-1)I_N/I} F_1 \left(\frac{N \cdot I_N}{\bar{I}} - (N-1)x \right) F'_{N-1}(x) dx$$

where: $I_N = (1-C/N) \cdot I_D$

An example of the computational procedure is presented in Exhibit 7.2-3. The example is for a latitude of 45 degrees, a tilt of the array at 45 degrees, and a K_H of 0.5. Starting points for both the array size and battery capacity are chosen. A value of the insolation, I_D , required to meet the load, is selected (2.3 kWh/day-m²) based on the average daily kWh load, and an assumed array area with a known efficiency. Eight days storage capacity is used. Computations for only the first day are presented in detail; however, the computations were carried out to completion with a LOLP computed of 0.0016, or approximately six days loss of load over a ten year period. This relatively high level of reliability approaches the reliability criteria of bulk, interconnected utility grids that are generally designed for a one day loss of load per ten year period.

The computations were performed on a Texas Instruments TI-59 electronic calculator using the program listed in Exhibit 7.2-4. Instructions for the operation of the program are presented in Exhibit 7.2-5. Running time on this calculator was approximately 0.1 minute per day, or 0.1*N minutes. The corresponding Hewlett Packard HP-67 calculator program is presented in Exhibits 7.2-6 and 7.2-7.

With the aid of the calculator programs, the LOLP may be obtained for many variations in the design parameters. Exhibit 7.2-8 was prepared to show some of the results of a parametric variation study of LOLPs for a range of array sizes. (I_D) and storage capacities (C) that might be tried. Note that the units of insolation are immaterial, although, I, S, and I_D must all be expressed in the same units. The area of the array in square meters is determined from the expression for I_D and is expressed as:

$$\text{Area (m}^2\text{)} = (\text{kWh/day of load}) / (\text{system efficiency} * I_D)$$

Where I_D is expressed in kWh/day-m².

Exhibit 7.2-3

EXAMPLE OF LOSS-OF-LOAD PROBABILITY COMPUTATION

1. For Latitude = 45° , $\bar{K}_H = 0.5$, $\bar{I} = 2.971 \text{ kWh/day-m}^2$ (Exhibit 6.1-1)
2. For Latitude = 45° , $\bar{K}_H = 0.5$, $(\text{Sigma } 1) * \bar{I} = 1.839 \text{ kWh/day-m}^2$ (Exhibit 6.1-1)
3. Select $I_D = 2.3 \text{ kWh/day-m}^2$
4. Select $C = 8$ days
5. $N = 9$, $\text{SUM} = 0.0$
6. $Z_1 = (2.971 - 2.3)/1.839 = 0.3649$
7. Read $Y = 0.36$
8. $F_1 = 0.36$
9. $Z_{N-1} = Z_8 = (2.971 - 2.3 + 8 * 2.3/8) * \sqrt{8/1.839} = 4.569$
10. Compute: $Y = \text{EXP}(-0.5 * 4.569^2)/(\sqrt{2\pi} * 4.569) = 0.000\ 002\ 55$
11. $F_8 = 0.499\ 997\ 45$
12. $Z' = 4.569 + 2.3/\sqrt{8} * 1.839 = 5.012$
13. Compute: $Y = \text{EXP}(-0.5 * 5.012^2)/(\sqrt{2\pi} * 5.012) = 0.000\ 000\ 28$
14. $F' = 0.499\ 999\ 72$
15. $\text{SUM} = 0 + 0.499\ 999\ 72 - 0.499\ 997\ 45 = 0.000\ 002\ 27$
16. $N < N^* = 10 * 9 * 2.3 / (2.971 - 2.3) = 308.4$
17. $N = 9 + 1 = 10$
etc.
18. $K = (2.971 - 2.3)/1.839 = 0.3649$
 $K_1 = 2.3 * K / 1.839 = 0.4563$
 $K_2 = K * \sqrt{308.4/20} = 1.433$
 $B = (0.3649^2) * (1.433 + \sqrt{1.433^2 + 4/\pi}) = .4336$
 $\text{LOLP}^* = (0.36) [0.00159 + 0.00282]$
 $= 0.0016$

*Variations may occur in the value of LOLP due to different readings off the exhibit.

Exhibit 7.2-5

INSTRUCTIONS FOR THE OPERATION
OF THE TI-59 PROGRAM FOR
COMPUTING THE LOSS-OF-LOAD PROBABILITY

1. Depress B to ready the calculator for input.
2. Enter the average insolation on the tilted surface, I. (Stored in 00)
Depress R/S.
Enter the standard deviation of the insolation on the tilted surface, S.
(Stored in 01)
Depress R/S.
Enter the insolation required to exactly meet the load, I_D . (Stored in 02)
Depress R/S.
Enter the number of days of storage capacity, C. (Stored in 03)
Strike R/S.
3. The calculator prints the number of days that must be summed, then proceeds with the computations. If the LOLP is predicted to be high, the calculator will print HIGH RISK. The prediction method is approximate only, being based on the estimated maximum value of Z_{N-1} . If this value is less than 2, the risk is likely to be high. After printing HIGH RISK, the calculator proceeds with the computations.

If Z is greater than 2.0, the calculator uses the approximate formulas. If Z is less than 2.0, it will ask for the user to input the value of the probability, with the words INPUT PROB. The value of Z is displayed. After the probability is read from Exhibit 7.2-2 and entered, the user should strike R/S. The calculator will print the probability and continue with the computations.
4. The calculator will flash the probability (LOLP) up to the day being calculated, as the computations proceed.
5. If an error should occur, the calculator will stop at the point of the error, because SET FLAG 8 is incorporated in the program.
6. At the end of the computation, the calculator will print the LOLP, stop, and display the LOLP, storing the value in 05.

Exhibit 7.2-6

LISTING OF AN HP-67 PROGRAM FOR
CALCULATION OF LOSS OF LOAD PROBABILITY

Step Number	Key- strokes	Key Code	Step Number	Key- strokes	Key Code
001	f LBA A	31 25	029	1	01
002	RCL O	34 00	030	--	51
003	RCL 2	34 02	031	STO 6	34 06
004	--	51	032	÷	89
005	RCL 1	34 01	033	1	01
006	÷	81	034	--	51
007	STO 8	33 08	035	RCL 2	34 02
008	R/S	84	036	X	71
009	STO 9	33 09	037	RCL 0	34 00
010	0	00	038		
011	STO 5	33 05	038	+	61
012	RCL 3	34 03	039	RCL 6	34 06
013	1	01	040	f√X	31 54
014	+	61	041	X	71
015	STO 4	33 04	042	RCL 1	34 01
016	RCL 2	34 02	043	-	81
017	X	71	044	f GSB 1	31 22 01
018	RCL 0	34 00	045	STO + 5	33 61 05
019	RCL 2	34 02	046	RCL 2	34 02
020	--	51	047	RCL 4	34 04
021	÷	81	048	1	01
022	1	01	049	--	51
023	0	00	050	f√X	31 54
024	X	71	051	RCL 1	34 01
025	STO 7	33 07	052	X	71
026	f LBL B	31 25	053	÷	81
027	RCL 3	34 03	054	RCL 6	34 06
028	RCL 4	34 04	055	+	61

Exhibit 7.2-6 (Continued)

LISTING OF AN HP-67 PROGRAM FOR
CALCULATION OF LOSS OF LOAD PROBABILITY

Step Number	Key-strokes	Key Code		Step Number	Key-strokes	Key Code	
056	f GSB 1	31	22	01	083	f LBL 2	31 25 02
057	STO-5	33	51	05	084	h RTN	35 22
058	RCL 7		34	07	085	f LBL 3	31 25 03
059	RCL 4		34	04	086	h x \geq y	35 52
060	g x>y		32	81	087	R/S	84
061	GTO C		22	13	088	GTO 2	22 02
062	1			01	089	f LBL C	31 25 13
063	STO + 4	33	61	04	090	RCL 7	34 07
064	RCL 5		34	05	091	2	02
065	h PAUSE		35	72	092	0	00
066	GTO B		22	12	093	÷	81
067	f LBL 1	31	25	01	094	f \sqrt{x}	31 54
068	2			02	095	RCL 8	34 08
069	h x \geq y		35	52	096	X	71
070	g x \leq y		32	71	097	STO A	33 11
071	GTO 3		22	03	098	RCL 8	34 08
072	STO 6		33	06	099	RCL 2	34 02
073	g x ²		32	54	100	X	71
074	CHS			41	101	RCL 1	34 01
075	g e ^x		32	52	102	÷	81
076	RLC 6		34	06	103	STO B	33 12
077	÷			81	104	CHS	42
078	h π		35	73	105	g e ^x	32 52
079	2			02	106	CHS	42
080	X			71	107	1	01
081	f \sqrt{x}		31	54	108	+	61
082	÷			81	109	RCL B	34 12

Exhibit 7.2-6 (Continued)

LISTING OF AN HP-67 PROGRAM FOR
CALCULATION OF LOSS OF LOAD PROBABILITY

Step Number	Key- strokes		Key Code	Step Number	Key- strokes		Key Code
110	RCL 3	34	03	123	RCL A	34	11
111	X		71	124	$g x^2$	32	54
112	CHS		42	125	+		61
113	$g e^x$	32	52	126	$f\sqrt{x}$	31	54
114	X		71	127	RCL A	34	11
115	RCL A	34	11	128	+		61
116	$g x^2$	32	54	129	RCL 8	34	08
117	CHS		42	130	$g x^2$	32	54
118	$g x^e$	32	52	131	X		71
119	X		71	132	+		81
120	4		04	133	RCL 5	34	05
121	$h\pi$	35	73	134	+		61
122	÷		81	135	RCL 9	34	09
				136	X		71
				137	h RTN	35	22

Exhibit 7.2-7

INSTRUCTIONS FOR USE OF THE HP-67 PROGRAM
FOR CALCULATING LOSS-OF-LOAD PROBABILITY

1. Key the input data into the following registers:

I	REG 0	(Value from Exhibit 10.1-1)
S	REG 1	"
I _D	REG 2	(Value dependent upon application)
C	REG	"

2. Depress R/S. The program will calculate Z_1 and stop with Z_1 in the X-register. Input the value of Y_1 corresponding to Z_1 from the graph in Exhibit 7.2-2. Press R/S to re-start the program. If the program encounters a value of Z less than 2, it will stop with 2.00 in the X-Register. Press h x y to display the value of Z. Input the Y value from Exhibit 7.2-2 into the X-register. Press R/S to re-start the program. (Note: Values of Z less than 2 may indicate a high loss of load probability).
3. The program will pause and display the contents of register 5 (the running sum of Y) after each day.
4. The program will halt with the loss of load probability displayed in the X-register.

Exhibit 7.2-8

TYPICAL CASES FOR THE LOSS-OF-LOAD PROBABILITY

S/\bar{I}	I_D/\bar{I}	Storage Capacity, C (days)									
		<u>2</u>	<u>4</u>	<u>6</u>	<u>8</u>	<u>10</u>	<u>12</u>	<u>14</u>	<u>16</u>	<u>18</u>	<u>20</u>
1.0	0.5	1.2-1	4.5-2	1.8-2	7.1-3	3.2-3	1.2-3	5.2-4	2.2-4	9.6-5	4.2-5
1.0	0.4	6.8-2	2.6-2	1.0-2	4.2-3	1.8-3	7.7-4	3.4-4	1.5-4	6.8-5	3.1-5
0.8	0.5	5.3-2	1.2-2	2.9-3	7.4-4	2.0-4	5.3-5	1.4-5	4.1-6	1.2-6	3.1-7
0.8	0.4	3.0-2	6.8-3	1.7-3	4.6-4	1.3-4	3.7-5	4.1-2	3.2-6	9.8-7	2.9-7
0.7	0.8	4.1-2	1.4-2	2.5-2	1.4-2	4.2-3	1.4-3	4.5-4	1.5-4		
0.7	0.7	1.4-1	3.0-2	6.5-3	1.4-3	3.3-4	7.8-5	1.9-5	4.8-6	1.0-6	2.7-7
0.7	0.6	5.6-2	9.5-3	1.6-3	3.0-4	5.8-5	1.2-5	2.4-6	4.3-7	9.5-8	2.0-8
0.6	0.8										
0.6	0.7	6.5-2	7.8-3	1.0-3	1.3-4	1.9-5	3.0-6	4.0-7	6.6-8	1.1-8	1.8-9
0.6	0.6	2.2-2	2.0-3	2.0-4	2.1-5	2.5-6	2.5-7	3.2-8	4.0-9		
0.4	0.9	3.7-1	4.8-2	6.6-3	9.5-4	1.4-4	2.4-5	3.3-6	5.8-7	1.0-7	1.8-8
0.4	0.85	7.0-2	4.0-3	2.6-4	1.9-5	1.2-6	1.1-7	9.1-9			
0.3	0.9	4.7-2	1.4-3	1.4-3	4.7-5	1.6-6	7.3-8	3.4-9			
0.3	0.85	3.9-3	3.0-5	2.6-7	3.2-9						
0.3	0.8	4.8-4	1.1-6	3.8-9							
0.3	0.7	1.7-5	6.6-7								

Notes:

1. Read LOLP entries such as 7.2-3 as $7.2 * 10^{-3} = 0.0072 = 0.72\%$
2. The vertical lines in the table separate those cases for which the LOLP ≥ 0.01 to the left from those for which LOLP < 0.01
3. Based on the curve fit (All Z)

$$Y = \text{Exp}(-Z^2/2) * (1 + 0.083 * Z) / (\sqrt{2\pi} * Z + 2)$$
4. The results depend only on S/\bar{I} , I_D/\bar{I} and C

When evaluating several designs which involve different array sizes, and different battery capacities, but which have a constant LOLP level, the methods of life cycle cost determination discussed in Sections 6.3 and 6.4.2 should be used again to determine the optimum design which has minimum life cycle costs. Other evaluations might be performed holding the array size constant and varying storage capacity and reliability levels. The life-cycle cost differentials can then be used to evaluate the worth of any improvement in power system reliability.

7.3 CODES AND STANDARDS

The PV power system should conform to all of the appropriate regulations in the building industry. Nationally recognized regulations known as codes are the laws which have been developed to protect the health, safety, and welfare of the general public. Standards, manuals, and approved equipment listings have been developed to support these codes. The following subsections will discuss the codes, standards, and related documentation applicable to photovoltaic power systems, and requirements the designer should include in the overall PVPS design.

7.3.1 Codes

As of the writing of this handbook, there are no existing applicable electrical or building code categories into which photovoltaic modules, panels, arrays, or support equipment can be conveniently placed. Until specific codes governing PVPS components are developed, code officials will rely on existing code categories which can be interpreted as applying to photovoltaic systems. The lack of nationally recognized codes governing photovoltaics will most likely cause problems for both designers and installers in areas where building code officials are resistant to innovative products. The only areas regarding photovoltaic systems which are addressed in the codes relate to the use of storage batteries and their special wiring/interconnections procedures. These areas are covered in the National Electric Code (NEC).

The NEC is one code which is almost universally accepted throughout the country and has been recognized by all major model codes to insure the safety of persons and property using electricity. It is expected that compliance with the NEC will be an outstanding requirement for the design, installation, operation, and maintenance of PV power systems. The NEC should be fully reviewed during the system design phase.

An example of how the NEC applies directly to the installation of PV power systems is as follows: The NEC (Article 110-17(a)) requires that live parts operating at 50 volts or more shall be guarded against accidental contact during installation. This code places special requirements on the installation of photovoltaic panels, since daylight will cause these panels to become active electric generators. These types of general electrical codes can be applied to photovoltaics for wiring sizes, current ratings, grounding requirements, ground fault requirements, lightning protection, insulation of live electrical parts, and power conditioning equipment.

7.3.2 Standards

Standards are written to support the codes and provide ways through which the code requirements can be satisfied. There are four generic types of standards: (1) specifications, (2) test methods, (3) classifications, and (4) recommended practices.

The system design engineer should be aware that standards pertaining directly to photovoltaic power systems do not exist. The Solar Energy Research Institute (SERI) is developing documentation on performance criteria and test methods for photovoltaic systems. These documents should be available in the near future. Until such standards are available, existing general standards can be interpreted to include PV power systems.

The Federal Occupational Safety and Health Act (OSHA) of 1970 authorizes the issuance of National Health and Safety Standards for work places. This includes PV power system construction sites, and it is the responsibility of the contractor or builder to insure the health and safety of his employees. The designer of the PV power system should also be aware of OSHA requirements, for these requirements can affect system installation costs considerably.

7.3.3 Manuals

Accepted practice manuals are used in industry to interpret codes and standards, as well as to allow the installer to realize the intent or purpose for specific design decisions represented on system design drawings. Accepted practice manuals are written by the building industry to describe proven procedures or techniques which are most often used, and they change rapidly as a new technology develops.

As with codes and standards, accepted practice manuals written specifically for photovoltaic power systems do not exist due to the limited use of PV power system in industry. It is advisable, therefore, that manufacturers of the PV power system's components develop their own installation, maintenance, and operation manuals which shall comply with all existing codes and standards.

The building industry has been using components which display similarities to components utilized in PV power systems. For example, there are manuals of accepted practice for the installation of wiring systems that directly relate to wiring practices utilized in PV power systems.

7.3.4 Approved Equipment Listings

One way to accelerate code approval is for PV power system components to be tested (or listed) by a qualified testing laboratory, such as Underwriters Laboratories, Inc. (UL). Codes like the NEC generally allow the installation of equipment bearing the label of such a nationally recognized testing facility. Most code officials feel that there is little question as to the risk involved in allowing a new and innovative piece of equipment bearing laboratory approval labels to be installed in a construction site under their jurisdiction. If unlisted components must be used, the designer should be prepared to obtain a variance to the code. This process can be very time-consuming and costly.

7.3.5 Notes

Most local jurisdictions have adopted nationally recognized codes and standards and are enforcing them at the local level.

Any local building official has the authority to allow or disallow any product or process if he feels that compliance with established codes and standards is not met.

It may be found that, in some instances, the planned installation of a PV power system is inhibited by local officials who are not well versed or willing to make affirmative decisions about this new technology. With this fact in mind, it is important to have a good working knowledge of photovoltaics. The system design engineer should also have the ability to convey the necessary concepts about this technology to the local code officials.

7.3.6 Applicable Document List

Engineers, manufacturers and installers of photovoltaic power systems should be aware of all documentation applicable for designing, manufacturing and installing of PV power systems. Appendix C contains a listing of appropriate codes and standards and the addresses of the sponsoring agencies.

SECTION 8
INSTALLATION, OPERATION AND MAINTENANCE

8.1 INTRODUCTION

PV power systems are inherently capable of unattended operation, require only a minimum of scheduled maintenance, and only rarely require unscheduled corrective maintenance. The accessibility of the PV system site to operations and maintenance personnel and the reliability, maintainability, and availability of the power provided to the load have significant impact upon the PV system design. This section sets forth the basic operation and maintenance design considerations and tradeoffs to be considered during detailed design.

8.2 POWER OUTAGES

The principal operational requirement is the number and duration of power outages that the load can tolerate. Exhibit 8.2-1 lists the primary causes of power losses.

Exhibit 8.2-1 Causes of Power Loss in PV Systems

Natural Causes:	Consecutive cloudy days Environmental effects: Cold weather on batteries Lightning
System Design:	Less insolation than expected More load than designed for Scheduled maintenance shutdown
Equipment Malfunctions:	Array fault, or open circuit Optical degradation Electrical/electronic failure in power Conditioning and distribution equipment Batteries

8.3 RELIABILITY AND MAINTAINABILITY

Since power outages, with the exception of scheduled maintenance shutdown periods, are expected to occur randomly, the preferred method of establishing operational performance requirements on power outages is to use a statistical approach. The following parameters are recommended:

Reliability -- the probability of operating "x" days without loss of power

Maintainability -- the probability that system power will be restored within "y" hours

For example, emergency loads may be required continuously. While it is impractical to build a system that can assure no outages, a requirement of a 0.99 probability of no outages in a month could be specified. Such a stiff requirement would require consideration of back-up, non-solar systems sized to handle the critical load during natural-caused outages, an auxiliary power unit to handle the load during scheduled maintenance, significant over-capacity of the energy storage coupled with load-shedding (shut-off of convenience and even essential loads) to account for less insolation than anticipated, and a redundant fail-safe design. A 0.01 probability of outages in a month can be interpreted that, on the average, a power outage will occur once every 100 months (or every 8.3 years). However, that outage can occur at any time during the 100-month period.

For essential loads, a more realistic requirement may be a 0.10 probability of an outage in a month; that is, an outage, on the average, once every 10 months.

The second parameter of operational interest is the down time following a power outage. Components of down time are:

- Delay time in reporting power outage occurrence
- Time for operation or maintenance personnel to arrive at site
- Time to restore power, either by bringing a back-up source on line, or repairing malfunction at the site
- In the case of malfunction, time to acquire spare or repair parts and materials required to effect repair

There is generally little difference in the down time limits following a power outage among the load categories. With critical power losses being very infrequent, down time requirements are based on essential loads. For example, a down time requirement for essential loads for sites in the proximity of qualified maintenance personnel would be stated as a 95% probability that system power would be restored within 4 hours. For a remote site, the time requirement would have to be extended to permit notification and travel time.

8.4 OPERATION AND MAINTENANCE TRADEOFFS

Operation and maintenance procedures to be implemented at each site will have a significant impact on the system design. These procedures must be included in the system design tradeoff analyses involving array sizing, battery capacity, redundant features, the degree of automatic controls, and automatic monitoring and telemetry. Major operation and maintenance factors to be considered in the design tradeoff analyses are discussed in the following paragraphs.

8.4.1 Operation and Preventive Maintenance

Stand-alone PV power systems do not require an on-duty operator under normal conditions of system utilization. The routine functions of an "operator" consist of inspection and preventive maintenance. Typical tasks include:

(1) Inspection Tasks:

- Site physical security -- fencing intact, breach of security alarm test
- Array shading -- by debris, vegetation
- Array cleanliness -- dust, bird droppings
- Cabling -- damage by elements or rodents
- Grounding paths -- loose connections, corrosion
- Battery terminals -- corrosion

- Batteries -- electrolyte leakage and corrosion of support structure
- Control equipment -- cleanliness; accumulation of dirt, bird nests, rodent damage
- Fuel/oil/water -- at or above specified storage levels for backup systems

(2) Preventive Maintenance Tasks:

- Clean array surface
- Clean battery terminals and tighten connections
- Check and refill electrolytic solution
- Read and record all metered points
- Perform operability tests to assure that all automatic switching and monitoring is functional and that standby backup and emergency generator units will start and operate
- Lubrication
- Restock stored fuel
- Record all discrepancies observed by inspection and in performing preventive maintenance

In general, the PV systems should require inspection and preventive maintenance only on a scheduled periodic basis (e.g., 30 days, 60 days, 90 days, 6 months, etc.), consistent with known system degradation rate due to dust accumulation, etc. However, backup systems of the engine/generator type should be started and run for at least one hour on a weekly basis.

Site visits by operational and preventive maintenance personnel are primarily for the purpose of fault detection, exercise of switching/controls, exercise of backup systems, and observation of abnormal deterioration conditions. All of these functions (except abnormal deterioration detection) can be performed automatically and the results monitored remotely via telemetry -- either by radio or land line. Thus the tradeoff over the life of the installation is the cost of automation and remote monitoring versus the cost of having a human perform site visits (note: as a safety precaution, site operation and preventive maintenance

should be performed by a two-man team). Included in the human costs are the costs of training, transportation, site access maintenance, and the method of communication with repair facilities.

8.4.2 Corrective Maintenance

Maintenance is divided into preventive and corrective categories to permit separation of skill levels and training in the design tradeoff analyses. Whereas preventive maintenance of the entire site can be performed by one trained individual, corrective maintenance involves several different skills, including electrical, electronics, engine mechanics, and at times, construction training. Corrective maintenance also requires spare parts, test equipment, and documentation.

PV systems can be designed to permit scheduling of corrective maintenance by designing in a tolerance to faults -- that is, a design which is not sensitive to individual faults, thus permitting accumulation of faults between scheduled corrective maintenance site visits. The other end of the design spectrum is a system without fault tolerance -- corrected prior to reconnecting the load.

Establishing the design to corrective maintenance tradeoff requires consideration of the following:

- Frequency of site visits.
- Delay time when a system drops the load until unscheduled corrective maintenance can be performed, assuming full availability of personnel, test equipment, and spare parts.

Both the frequency of power outages and the maximum downtime requirement when an outage occurs are affected by corrective maintenance tradeoffs. If the maximum downtime limits are less than the delay time required to travel to the site, then only two alternatives are available:

- (1) To design a system that is fault tolerant and capable of repair without dropping the load; i. e., mechanisms must be built in for isolating the fault and de-energizing the faulty item while leaving the remainder of the system operational.

This alternative will have the practical effect of eliminating downtime periods, thus increasing the probability of operating between scheduled corrective maintenance visits to nearly unity.

If this alternative is chosen, an additional trade off should be performed--whether to design the system:

(a) With sufficient redundancy to permit deferral of maintenance until the next scheduled corrective maintenance visit; or

(b) With only sufficient redundancy to ensure system operation until a repair crew can be dispatched to the site to accomplish the corrective maintenance. This case must include: the cost of more detailed fault detection and telemetry to tell the crew prior to dispatch what has failed; the cost of maintaining a ready repair crew; and the additional transportation and personnel-related costs of an expected larger number of unscheduled site trips rather than a predefined number of scheduled site trips. (Note: Since failures occur randomly, there is always a finite probability of having power outages between scheduled visits. This probability is a function of the fault-tolerance margin designed into the system).

(2) To design a system without fault tolerance, and to provide trained repair personnel capable of immediate reaction at or near the site, this alternative also requires adequate logistic (spare parts) support at the site. In this alternative, the system design needs only to meet the reliability requirement.

Exhibit 8.4-1 illustrates the design tradeoff advantages of initiating repair as soon as a fault occurs versus having redundant hardware to maintain a high probability of no power outage between scheduled corrective maintenance periods. The reliability functions shown in the figure are plotted as a function of system operating time (t_o) "normalized" to individual equipment MTBF (i.e., $t' = t_o/MTBF$). The figure depicts the case of standby redundancy; that is, the redundant element does not operate until the "ON" element has failed, the failure is sensed, and the standby element is activated. The apparent advantages of the type of redundancy can be significantly reduced if similar design consideration is not given to the failure-sensing and switching circuitry which should also be redundant, or if not, its reliability should exceed that of the sensed element by at least 10-to-1.

For small, simple systems, the most promising tradeoff against too much additional equipment is to combine scheduled corrective maintenance with the periodic inspection and preventive maintenance site visits plus an infrequent unscheduled corrective maintenance.

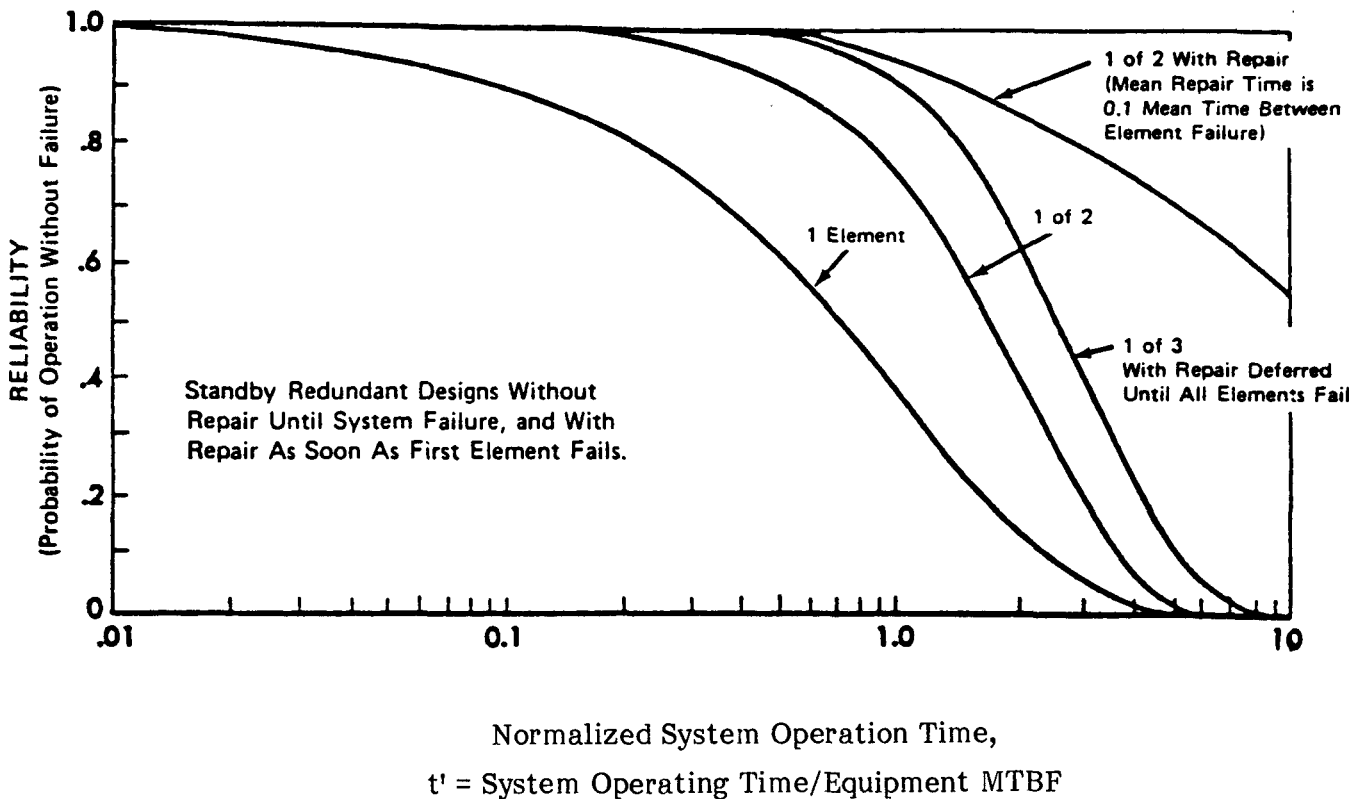


Exhibit 8.4-1
RELIABILITY IMPROVEMENT WITH STANDBY REDUNDANCY

8.5 SYSTEM MAINTENANCE

Section 8.4 identified the major tradeoffs associated with the scheduling of maintenance and identified a major component of downtime as the time from fault occurrence until arrival of the maintenance team at the site. This discussion covers the design for hands-on maintenance once the team arrives at the site.

8.5.1 Maintenance Concept

Maintenance planning begins with establishment of the concept to be followed; this should be done prior to detailed equipment design or site layout. Decisions required in establishing the maintenance concept include:

- (1) Personnel Skill Level — based on experience and training provisions. If skilled personnel are to be used, fault isolation can be accomplished using portable test equipment and technician interpretation of results; repair then can be accomplished at lower levels of complexity, such as part replacement on an electronic assembly instead of removal and replacement of the assembly.
- (2) Level of Repair. The level of on-site repair can vary from removal and replacement of whole equipments or array panels to the replacement of parts or modules. In the case of fossil-fueled backup engine generators, this can vary from complete replacement and remote repair to on-site overhaul. The level of repair selected for the site is a function of skill of personnel, ease of handling and transporting replacement parts, and test equipment required for fault isolation. The level of repair (e. g., remove and replace level) and the built-in means for fault isolation must be compatible, whether the fault-isolation procedures consist of accessible test points or built-in automatic fault localization.
- (3) On-Line Repair. This term means preventive or corrective maintenance at the site without load interruption. If the critical or essential loads cannot

be "down" during scheduled maintenance periods, then the design must be such that portions of the system can be removed from on-line status while the remainder carry the load, or auxiliary power-generating units must be brought to the site to provide a power source while the PV system is undergoing maintenance.

(4) Faulty Item Disposition. The level of remove-and-replace is influenced by whether the replaced faulty item should be discarded or returned to a centralized repair facility (such as the original vendor) for more detailed troubleshooting, repair, retest, and return to stock. This in turn affects the cost of stocking site spares, whether stored at the site or at the corrective maintenance facility.

The result of the maintenance concept is to provide design requirements on the location of fault isolation test points, the amount of automatic fault isolation to be built in, and the mechanical fasteners and electrical connections for ease of removal and replacement.

8.5.2 Maintainability Design

Maintainability, expressed as the mean time to repair (MTTR) a fault in the system, given a properly trained personnel, authorized test equipment and documentation, and the required replacement parts, is a quantitative parameter often specified to drive the physical and mechanical design of the system. Generally, MTTR should be in the range of 1.5 to 3 hours for a typical PV system. Design considerations for achieving MRRT include:

(1) Fault Isolation. This term was covered under "Maintenance Concept", in 8.5.1 above. If fault isolation is automatic, then the time required is negligible. If fault isolation is manual (i. e., using test points and portable test equipment), it may require up to 15% of the specified MRRT.

(2) Accessibility. The physical layout and packaging design for the system must assure that the equipment is accessible for each planned maintenance task and that sufficient space exists for the task to be accomplished safely. (safety involves first the safety of the maintenance personnel, and second the protection of the equipment against damage in the repair process). Accessibility involves ease

of opening or unfastening covers and doors, not locating replaceable items under other items or beyond arms reach, and providing handles or places to grip items for removal. Where solar arrays are elevated or battery storage is on elevated racks, means must be provided for accessibility by built-in catwalks, ladders, and places to setup and lay tools, or by defined portable devices such as ladders.

(3) Weight of Replacement Items. The size and weight of replacement items must be compatible with accessibility at the site and transportability to and from the site. In general, the maximum weight of a replaceable item to be handled by one person without mechanical lifting devices is 40 pounds. If the replacement area is elevated and requires ladders or various walkways, the replacement item should also be equipped with a means for carrying it with one hand (the other being used to maintain safe balance). Where two people are used or mechanical lifting and handling devices can be taken to or left at the site, the size and weight of replacement items may be increased.

(4) Maintenance Safety. The means of access to site equipment for maintenance must comply with OSHA requirements for physical safety of maintenance personnel. This includes built-in steps, walkways, and ladders. The equipment design must provide protection against inadvertent electrical, thermal, or chemical contact with maintenance personnel. Where on-line maintenance is contemplated, positive means for assuring electrical disconnections are required. System grounding must not be compromised during maintenance.

(5) Standardization. Standardization of parts, wire, connectors, sizes of nuts and bolts, and modules is an essential discipline for ease in maintenance. It reduces training, tools, and spare item inventories.

(6) Replacement Availability Warrants. Parts, modules, and assemblies used in the PV design should carry with them a replacement availability warranty which warrants that during the 20-year life of the system, replacements will be available for purchase which provide workable and consistent (not necessarily identical) form (having the same connections and attachment points), fit (capable

of fitting in the same space), and function (performs the same function and is compatible with the other items in the system). Where such warranty is not available, the design should be sufficiently simple and spacious to permit substitutes or local fabrication of replacements.

(7) Test and Checkout. Maintenance actions are not complete until the repaired system has been tested and the effectiveness of the repair has been verified. This may be accomplished automatically by built-in fault-sensing circuitry, or it may require special provisions such as a light source to verify that a replaced circuit breaker will trip on overload.

(8) Maintenance Data. An often neglected part of maintenance is documentation of the maintenance action so the owner and designer may feed back this experience into either new designs or upgrading of the existing system.

8.6 LOGISTICS DESIGN

The system design engineer is responsible for planning logistic elements for the operating life of the PV system, as described in the following paragraphs.

8.6.1 Supply Support

This logistic element has a potentially greater impact on reliability and maintenance than does the basic equipment design or maintenance transit and repair times. The lack of a spare part defeats designed-in redundancy, contributing to more power outages; once power outage occurs, the lack of a spare can keep the system down until one is obtained. The supply support planning cycle requires the following steps:

(1) Prepare a site spares list. This is a list of all items designated for removal and replacement at the site; it includes:

- Identification in an unambiguous manner and in sufficient detail to permit reordering by the identification.
- Source where replacements can be obtained.
- Statement as to whether the item should be scrapped or returned for off-site repair.

- The importance of the item to power outage for critical loads and essential loads. The importance is assessed for two levels: Major, failure of the item will cause the system to drop load: Minor, failure of the item will not cause the system to drop load although it may induce some degradation.
- The expected number of removals of the item at the site during a 12-month period.

(2) Determine recommended quantity of initial spares to be purchased and delivered with the system. The simplest method¹ is to consider each part individually on the list of Step (1), planning to provide an x% probability of having the required spares on hand throughout a one-year period or a spares procurement or repair cycle if that exceeds one year. The following tabulation provides a guide for typical x-values:

<u>Failure Impact</u>	<u>Load</u>		
	<u>Critical</u>	<u>Essential</u>	<u>Convenience</u>
Major	0.999	0.99	0.90
Minor	0.99	0.95	0.90
Other	0.90	0.90	0.90

Following is the basic formula for determining the quantity of spares:

$$\text{Prob} = \sum_{x=0}^{x=?} \frac{e^{-m} m^x}{x!}$$

Where: m = number of expected failures in 1 year, and
 x = number of spares

Examples: GOAL is Prob = 0.99 for essential load and major failure impact

(1) $m = 0.5$ failures in 1 year

Prob = 0.9856 with $x = 2$ spares
 Prob = 0.9982 with $x = 3$ spares

To exceed goal (Prob = 0.99) retain 3 spares

(2) $m = 1.5$ failures in 1 year

Prob = 0.9814 with $x = 4$ spares
 Prob = 0.9955 with $x = 5$ spares

To exceed goal (Prob = 0.99) retain 5 spares

¹More sophisticated cost optimization and system-protection level models can be developed for determining spares sets, but are beyond the scope of this handbook.

(3) Prepare a list of consumables. This would include distilled water for batteries, array face washing compound, terminal grease, paint, fuel and lubricants for backup systems, etc. The list must clearly identify the consumable product and the estimated quantity required at each preventive maintenance period.

(4) Prepare list of common and bulk items. This is a list of screws, nuts, bolts, washers, spacers, gasket material, fasteners, and other items commonly used in maintaining the equipment; include items which can be locally purchased or fabricated at local hardware-equivalent outlets and need not be provided with the system.

(5) Prepare list of off-site repair parts. This is an optional step, depending on where and by whom off-site repair will be performed. If it is to be accomplished by facilities not specializing in the specific site equipment, a complete list of repair parts containing the same information supplied in Step (1) should be prepared.

8.6.2 Power System Drawings

At least two complete sets of equipment drawings, site structural drawings, and site installation drawings should be delivered to the PV system owner, one for permanent records and the other for use in corrective maintenance that requires more knowledge than is available in the operation and maintenance manuals. These drawings may be in contractor format, with completeness and legibility the overriding criteria.

8.6.3 Tools, Test Equipment, and Maintenance Aids

Planning for this element of logistics involves preparing a list of all the tools, test equipment, and maintenance aids, such as step ladders, array covers, etc., that are required for site inspection, preventive maintenance, and on-site corrective maintenance. The list should show which items are required for inspection and preventive maintenance and which are for corrective maintenance. Special tools, test equipment, and maintenance aids are those not readily available

over the counter locally; these should be clearly identified and provided to the owner as part of the system equipment included with the system.

8.6.4 Technical Manuals

At least three manuals are required and should be prepared under cognizance of the system design engineer by personnel capable of writing clearly for the level of education and background of the user, and the user's language if necessary:

(1) Operation Manual. This manual provides an overview of what the system is, how it works (theory of operation), and how the major equipment groups, including backup systems, are interrelated to provide the power output. The manual must define the system-to-load interface and should discuss the impact on system performance of changing the load after installation. The Operation Manual must define the duties and responsibilities of the operator (inspection and preventive maintenance), and the duties of corrective maintenance personnel. It must also include safety warnings, notices, and emergency treatment for accidents such as chemical burns.

(2) Inspection and Preventive Maintenance Manual. This manual must contain a procedure for each inspection and preventive maintenance task, detailing step-by-step the action to be taken and observation made. The procedure must also tell the operator what to do when anomalies are detected. The manual must present the schedule for each task (weekly, monthly, or semi-annually), and repeat safety information.

(3) Corrective Maintenance Manual. This manual must contain the information needed to accomplish corrective maintenance to the level established by the maintenance concept. It must cover fault detection, fault isolation, remove-and-replace instructions, and -- most important -- verification testing to ensure that the repair was effective. Again, safety information must be included.

All three manuals may have individual sections covering different equipment in the design, such as solar array, batteries, and backup systems. This is acceptable provided introductory material puts each in perspective with respect to the total system.

8.6.5 Training

This logistic element ties all the preceding elements together into the total logistic support package. The planning for training consists of:

- (1) Preparation of instructors' guide for teaching courses for both operators and corrective maintenance personnel.
- (2) Determining the length of courses and the percent of hands-on training versus classroom discussions.
- (3) Providing an initial training course concurrent with site installation.

The operation and maintenance manuals discussed under 8.6.4 provide the basic course text material for the students.

8.7 INSTALLATION DESIGN CONSIDERATIONS

This discussion is written from the operation and maintenance point of view, addressing those concerns most often leading to excessive maintenance problems.

8.7.1 Physical Considerations

The following physical considerations in site layout should be adequately addressed:

- Local ground cover and vegetation growth that could arise and cause unplanned array shading.
- Location of buildings and security fences that act as snow fences and actually contribute to snowdrifts in the vicinity of arrays.
- Location of buildings and security fences that act as snow fences may provide bird perches and thus contribute to fouling of the array face.
- Personnel safety, to protect personnel from accidentally coming in contact with high voltage, thermally hot arrays, or dangerous chemicals.

8.7.2 Equipment Housing and Structure Considerations

The equipment housing and structure should be designed to prevent the following problems:

- Array edges being used as bird perches, thus inducing extreme fouling of the array face.
- Rough edges, grooves, or protusions that will catch, hold, and permit build-up of airborne debris on the array faces.
- Junction boxes and cable runs which allow entry of rodents which in turn might gnaw on insulation.
- Cable insulation and coverings which provide rodent food.
- Protective structures and buildings that provide sites for bird nests and their droppings on electronic equipment.

8.7.3 Installation Checkout and Acceptance Testing

The system design engineer and owner must agree on the means of determining structural and physical compliance with drawings and specification and for performance acceptance tests of the system. Conformance to structural and physical requirements can be determined by the owner or his representative. Conformance to performance requirements requires the development of detailed test procedures and acceptable tolerances of measured parameters; these test procedures must be documented prior to the start of site installation.

SECTION 9 SITE SAFETY

The personnel safety design requirements for both the general public and installation, maintenance, and operating personnel, and the site safety design requirements for the facility while in operation and undergoing maintenance, shall be in accordance with applicable local codes and nationally-recognized standards. Lead-acid storage battery safety is covered separately in Section 4.3.6.

The design safety checklists, described in the following paragraphs, are divided into two areas: (1) personnel and (2) facility. These should be treated with equal importance. Portions of these will be repeated. Various items within these checklists are not covered under any local or nationally recognized codes or standards, but should be considered to increase the overall safety of the PVPS facility and personnel.

9.1 PERSONNEL SAFETY CHECKLIST

9.1.1 Safety & Health Standards

The PV modules, arrays, wiring, power distribution, power conditioning, batteries, and structures (PVPS) shall comply with the Occupational Safety & Health Administration (OSHA) Standards. OSHA standards apply primarily to the on-site construction and installation procedures of the above equipments. The manufacturers of these equipments must adhere to the OSHA standards in their design of these equipments.

Electrical materials, equipments, and their installation shall be in accordance with applicable local and nationally recognized codes and standards. Such codes shall include, but not be limited to, the National Electric Code (NFPA 70-1981), American National Standards Institute (ANSI nos. A. 58.11-1972 and Z 97.1-1975), Building Official & Code Administrators International (BOCA), and others: i. e., NEMA and UL. Electrical components shall be listed and/or approved by a nationally recognized testing laboratory. (See Appendix B for a listing of codes and standards).

9.1.2 Electric Shock

The PVPS equipments and structures described in Section 9.1.1 shall be designed to prevent shock hazard during installation, normal operation, and during maintenance procedures. The life-safety hazards, which could occur as a result of a failure of any of the above equipment, shall not be greater than those imposed by conventional electrical systems. The above equipments shall be grounded in accordance with the National Electrical Code (NEC) Sections 250-72 and 250-92. These equipments shall also be designed to comply with all existing OSHA standards for installation, operation, and maintenance protection of the workers. These equipments should also be isolated from casual contact, as well as being adequately insulated, to reduce the possibility of electrical shock as a result of system anomalies.

9.1.3 Toxic & Flammable Materials

The materials used in the PVPS, as described in Section 9.1.1, shall not expose the installing, operating, or maintenance personnel to hazards related to toxicity or flammability. The PV system shall be designed to utilize materials which in the presence of fire do not endanger the installing, operating, or maintenance personnel with excessive levels of smoke or toxic fumes in accordance with nationally recognized codes such as NFPA 251-1972, ASTM E119, ASTM E84, and UL 263.

9.1.4 Fire Safety

The design, installation, operation, and maintenance of the PVPS shall provide a level of fire safety that is consistent with applicable codes and standards including, but not limited to, NFPA 256-1976 and the NEC (NFPA 70-1981). Some factors which shall be considered in assessing potential fire hazard are: potential heat, rate of heat release, smoke generation, firestopping, and ease of ignition.

The protection against auto-ignition of combustible solids used in the PVPS, especially in the PV modules, should be addressed. Combustible solids, such

as plastics, shall not be exposed to elevated temperatures which may cause ignition. Exposure of these materials over an extended period of time may result in the materials reaching, and possibly surpassing, their auto-ignition temperatures.

The PVPS site shall have on-hand emergency fire extinguishing apparatus in accordance with all local fire protection ordinances.

9.1.5 Excessive Surface Temperatures

The PVPS shall not create a hazard to installation, operation, or maintenance personnel due to excessive exterior surface temperatures. Any component that is located in areas normally subjected to personnel or general public traffic, and which is maintained at elevated temperatures in excess of 140° F or 60° C, shall be isolated from casual contact with proper clearances or passageways. Any surface where isolation is impossible shall be identified with appropriate warnings.

9.1.6 Equipment Identification Labeling

All PVPS components should be identified as to: their function; their voltage, current, power, and temperature warnings; corrosive or toxic properties; and procedures for handling accidental contact and natural or man-made occurrences (flooding, structural damage, foreign objects); and a list of authorities and their telephone numbers to contact if such occurrences should take place.

9.1.7 Physical Barriers

The PVPS shall be totally enclosed by a seven-foot (minimum) barbed-wire-top security fence approximately 30 feet from any part of the array. This barrier shall be erected before construction begins, and shall remain in place throughout the PVPS life cycle and until the PVPS is totally dismantled. Warning signs shall be displayed in plain view of the general public stating the danger of active high voltage within the fenced area (in the language of the area).

Local codes should be investigated for the appropriate distance a PVPS shall be from any residential or commercial building and from public roads.

9.2 FACILITY SAFETY CHECKLIST

9.2.1 PVPS Safety Protection from Environmental Conditions

The PVPS safety requirements shall include protection from the possibility of power interruption, transients, and electrical faults caused by natural environmental conditions. The meteorological/environmental factors should be investigated for the particular site location. Historical meteorological information is available from the National Weather Service on a national or local level, such as:

- Average wind speed
- Annual rainfall and flooding data
- Average snow loads
- Annual number of days with hail
- Annual number of days with glaze (freezing rain)
- Annual number of thunderstorm days
- Seismic data

Some or all of these areas may affect the design and safety aspects of the PVPS.

Most of these areas are covered in the design consideration sections from a structural loads aspect in other works (Refs 4-5, 9-1). Due to the uniqueness of a PVPS, these areas must also be investigated from a safety aspect. The following are examples of questions that should be answered before site construction in order to increase the reliability and overall safety of the proposed PVPS site, and which may effect the system design itself:

- Is there a history of flooding or high snow accumulation in the proposed PVPS site location? If so, what are the effects of frequent flooding or high snow accumulation on the system and personnel (including the general public)? Has the design been modified to allow sufficient ground clearances for both array and battery-storage areas?

- Is the vegetation growth rate in the proposed PVPS site location high enough to become overgrown and create a shading condition if left unattended? Has the array design been modified to allow sufficient ground clearance to compensate for this potential problem?
- Is there a history of seismic activity in the proposed site location? If so, are the system's components adequately sized to withstand frequent seismic forces and remain safe?
- Is the annual number of thunderstorm days for the proposed site location high? Has the frequency of lightning strokes to earth in the proposed site location caused an unusual amount of damage to existing structures in the past? Are the array module covers plastic, which could increase the electrostatic potential between ground and air, and could induce the lightning hazard in areas of high lightning incidence? If so, then lightning protection should definitely be a design consideration (Ref. 9-2). The NFPA Lightning Protection Code should be consulted for lightning protection procedures.

9.2.2 PVPS Safety Protection from Man-Made Conditions

The PVPS site design safety should include provisions for the protection from the possibility of power interruptions, transients, and electrical faulting created by man-made conditions.

The security fence described in Section 9.1.7 will protect the PVPS site from invasion of casual unauthorized personnel, but the temptation of vandalism is always present. Projectiles thrown or shot from any type of firearms at the photovoltaic arrays can cause enormous damage to the system.

Accidental penetration of the PVPS site by means of motorized vehicles (automobiles, tractors, etc.) is also possible. Although the site shall be isolated from public roads, as described in Section 9.1.7, an out-of-control vehicle can penetrate the security fence. A bunker-type knoll surrounding the fenced-in site can serve as both a way to hide the site from plain view and a way to create a double barrier.

9.2.3 PVPS Safety Protection from Component Failure

To prevent damage to the system from component failures, the system should be designed to eliminate excessive temperatures and reverse biasing which may occur as a result of shading or cell cracking. Examples of devices which automatically detect and isolate component failures are: high-speed fault-detection devices, fuses, circuit breakers (with adequate interrupting capacity), etc. These should be included in the detailed system design. These devices will also prevent system damage due to operator or maintenance personnel errors. This protection system should include automatic system shutdown circuitry, automatic system failure alarm, and/or telemetric failure alert system.

9.3 REFERENCES

An extensive list of codes and standards referenced in the section is presented in Appendix C and covers all aspects of the PVPS design, installation, operation, and maintenance.

SECTION 10
DESIGN EXAMPLES

10.1 REMOTE MULTIPLE-LOAD APPLICATION

10.1.1 Northern Hemisphere Location

A typical load profile for a remote village is presented in Exhibit 10.1-1, derived from data supplied by the NASA-Lewis Research Center on the Papago Indian Village of Schuchuli, Arizona (Reference 10-1). The actual installation allowed for load shedding and for tilting the collector four times per year (3.5° tilt in summer, 26° in spring and fall, and 48° in winter). To permit the direct use of the tables and charts presented in this report, a fixed array tilted at the latitude angle of 32.11° will be considered. The methods of Section 11 could be used to compute the insolation at other tilt angles; the standard deviation of the insolation could be similarly calculated or could be estimated from Exhibit 6.1-1, based on having the same sigma ratio for any tilt. The load-shedding capability will also be ignored, although this would reduce the energy-storage requirements.

The design computations are presented in Exhibit 10.1-2 in the format of the quick-sizing procedure of Section 6.2.1. The K_H values were obtained from NASA; the values are in reasonable agreement with the data of Tucson as reported by the National Weather Service (last column). The first computation of the collector area and storage capacity, for a one percent loss-of-load probability, is based on $M = 0.33$. Values of C were read from Exhibit 6.2-2. The array area required to meet the load is 45 square meters, as dictated by the August load. The storage capacity is 51 kWh, as determined by the August load. The collector area required for a one percent LOLP can be re-computed based on the storage capacity of 51 kWh. This capacity is converted to days of load (C') and the revised value of M ($= M'$) is read from the battery storage chart (Exhibit 6.2-2). The collector area is computed from the formula in Note 3 of Exhibit 10.1-2. The required collector area is again 45 square meters, as determined by the August requirement.

For the parameters chosen, the array size is 3.6 kW at 1.0 kW/m^2 of insolation. This figure compares favorably with the 3.5 kW actually installed. The 51 kWh battery capacity, however, represents the nominal capacity. Thus, when a depth of discharge of 50 percent and a round trip charging efficiency of 85 percent is assumed, the actual battery capacity would be 120 kWh. The difference between the installed 285 kWh battery and the calculated capacity can be attributed to the difference in LOLP calculated in the design example and that for the installed system.

10.1.2 Southern Hemisphere Location

The requirements for the Papago Indian Village can be applied in the Southern hemisphere as well. If we assume that the installation is at 32.11° South latitude and the tilt is again 32.11° , all of the computations would be the same, although a +6 percent correction to the insolation should be made due to the seasonal variation in the earth-sun distance (Section 11). If the K_H profile were the same, except with the January value for the Northern hemisphere being used in July in the Southern hemisphere and all other months shifted also by six months, the month-by-month computation would be identical. The only difference in Exhibit 10.1-2 would be the labeling in the "MONTH" column entry for July being used for the January entry in the Southern hemisphere.

Exhibit 10.1-1
 MULTIPLE LOAD APPLICATION
 MONTHLY LOAD SUMMARY

Device	<u>Load Ah/day</u>						Total
	Water Pumps 2 hp	Refrigerators 1/8 hp	Clothes Washer 1/4 hp	Sewing Machine 1/8 hp	Fluorescent Lights 20 W	Instruments	
Quantity	1	15	1	1	44	1 lot	
<u>Month</u>							
January	34.9	15.2	31.1	2.4	44.8	13.0	141.4
February	34.9	17.8	31.1	2.4	38.8	12.7	137.7
March	49.1	21.1	31.1	2.4	26.8	13.9	144.4
April	49.1	26.5	31.1	2.4	17.7	14.2	141.0
May	70.4	31.7	31.1	2.4	17.3	15.5	168.4
June	70.4	37.8	31.1	2.4	11.5	15.5	168.7
July	70.4	42.2	31.1	2.4	11.5	13.9	171.5
August	70.4	41.8	31.1	2.4	17.3	13.9	176.9
September	49.1	37.8	31.1	2.4	20.6	13.9	154.9
October	49.1	28.3	31.1	2.4	32.6	13.9	157.4
November	34.9	20.4	31.1	2.4	38.8	13.5	141.1
December	34.9	16.1	31.1	2.4	44.8	13.0	142.3

Exhibit 10.1-2

MULTIPLE LOAD APPLICATION EQUIPMENT SIZING

LOLP = 1 percent
 Latitude = 32.11°N
 Tilt = 32.11°N

10-4

Month	Cleaness Factor K_H	Average Insolation	Standard Deviation R	Load (kWh/day)	Array Area $A^{(2)}$ m^2	Revised Values Based on $Q = 51 \text{ kWh}$					
		$I^{(1)}$				S	Storage Requirement				
		$\frac{\text{kWh}}{\text{Day-m}^2}$				$\frac{\text{kWh}}{\text{Day-m}^2}$	C	Q	C'	M'	A'
		-				Days	kWh	Days	-	m^2	
January	0.667	5.48	0.278	17.0	43	2.6	44	3.0	0.29	42	0.633
February	0.667	5.98	0.264	16.5	38	2.4	40	3.1	0.28	37	0.665
March	0.737	7.17	0.153	17.3	32	1.1	19	2.9	0.23	31	0.692
April	0.758	7.51	0.115	16.9	29	1.1	19	3.0	0.17	29	0.744
May	0.768	7.47	0.095	20.2	35	1.0	20	2.5	0.16	34	0.765
June	0.711	6.81	0.154	20.2	39	1.3	26	2.5	0.21	38	0.755
July	0.647	6.24	0.229	20.6	45	2.3	47	2.5	0.25	44	0.658
August	0.651	6.34	0.238	21.2	45	2.4	51	2.4	0.33	45	0.657
September	0.720	7.00	0.169	18.6	35	1.6	30	2.7	0.21	34	0.680
October	0.681	6.30	0.237	18.9	41	2.1	40	2.7	0.29	40	0.671
November	0.690	5.90	0.238	16.9	39	2.1	36	3.0	0.28	38	0.637
December	0.690	5.55	0.246	17.1	42	2.2	38	3.0	0.28	41	0.612
					For 1% LOLP: Installed:	3.6 kW 3.5 kW	51 kWh 121 kWh ⁽⁴⁾				3.6kW

Notes:

- $\rho_g = 0.05$
- $\eta = 0.08$
- $A = \frac{\text{Load}}{[\eta(I - MS)]}$
 $M = (I - \text{Load}/A\eta)/S = (0.33 \text{ assumed starting value})$
- 2,380Ah battery rating chosen to operate with $50\% \leq \text{SOC} \leq 100\%$, so 1,190Ah provided at 120 volts
- K_H per SOLMET for Tucson, Arizona.

SECTION 11 INSOLATION

11.1 INTRODUCTION

The purpose of this section is to present the calculational tools for determination of the insolation on a tilted surface. The quantity that is required for system sizing is the average daily insolation for a given month on the tilted array surface. Four numbers are needed to perform the calculation of average daily insolation. These are: the clearness index or \overline{K}_H ; the latitude angle of the site; the tilt angle of the array; and the reflectance of the ground in front of the array. The clearness index is the ratio of the average monthly horizontal insolation to the extraterrestrial horizontal insolation. \overline{K}_H varies from month to month with the lowest values usually occurring in the winter.

In Appendix A, monthly values of \overline{K}_H are tabulated for a number of cities in the United States and throughout the world. The locations listed are grouped according to country. If there is no listing for a proposed site, then the closest listing should be used as long as the general weather conditions are similar. (Note that the values of \overline{K}_H in Appendix A must be divided by 1000 before they are input to the insolation calculation programs described in the following sections).

The equations that form the basis for the insolation calculation programs are presented in Exhibit 11.1-1. A sample calculation is given in Exhibit 11.1-2. A table listing the reflectances of various types of ground covers is presented in Exhibit 11.1-3.

INSOLATION COMPUTATION FOR A SOUTH-FACING ARRAY

- A. Select Latitude (L), Day of Year (Day) Ground Reflectance (ρ) and Array Tilt (ϕ) (0° for Horizontal)

- B. Obtain the monthly average clearness index, \bar{K}_H , from Appendix A.

- C. Compute the Solar Hour Angle at Sunset

$$\cos \theta_{SS} = -\tan L \tan \delta$$

$$L = \text{Latitude}$$

$$\sin \delta = \sin(\text{declination angle}) = \sin(23.45) \sin\left(\frac{284 + \text{day}}{365} \times 360^\circ\right)$$

- D. Compute the Solar Hour Angle at Sunset for the Tilted Surface

$$\cos \theta_{TS} = -\tan(L - \phi) \tan \delta$$

- E. Determine which Sunset Occurs First

$$\theta = \min(\theta_{TS}, \theta_{SS})$$

- F. Compute the Extraterrestrial Irradiance on a Plate Held Normal to the Sun's Rays

$$S_O = 1.356 \left(1 + 0.0167 \cos\left(\frac{\text{Day}}{365} * 360\right)\right)^2 \text{ kW/m}^2$$

- G. Compute the Extraterrestrial Insolation on a Horizontal Surface

$$S_{OH} = S_O \frac{24}{\pi} \left(\cos L \cos \delta \sin \theta_{SS} + \frac{\pi \theta_{SS}}{180} \sin L \sin \delta\right) \frac{\text{kWh}}{\text{m}^2\text{-Day}}$$

- H. Compute the Horizontal Insolation

$$S_H = \bar{K}_H * S_{OH}$$

- I. Compute the Diffuse-Insolation Factor (Ref. 11-1)

($K_D = S_D/S_H$) for the monthly average insolation:

$$K_D = \left\{ 0.230 + \frac{\theta_{SS}}{165} - \left[0.095 + \frac{\theta_{SS}}{220} \right] * \cos \left[114.6 * (\bar{K}_H - 0.9) \right] \right\}$$

- J. Compute the daily-direct radiation factor

$$R_D = \frac{\cos(L - \phi)}{\cos L} * \left\{ \frac{\sin \theta - \frac{\pi}{180} \theta \cos \theta_{TS}}{\sin \theta_{SS} - \frac{\pi}{180} \theta_{SS} \cos \theta_{SS}} \right\}$$

- K. Compute the average daily insolation on the tilted surface

$$I_T = S_H \left\{ (1 - K_D) R_D + \frac{1}{2} (1 + \cos \phi) K_D + \frac{1}{2} (1 - \cos \phi) \rho \right\}$$

where ρ = ground reflectance (See exhibit 11.1-3)

Exhibit 11.1-2

INSOLATION COMPUTATION EXAMPLE: WASHINGTON, D.C.

A. Let: $L = 38.95^\circ$, Day = 15 (Jan), $\phi = 55^\circ$

B. Find from Appendix A: $\bar{K}_H = 0.417$

C. Compute: $\sin \delta = \sin(23.45) * \sin\left(\frac{284 + 15}{365} * 360\right) = -0.36094$

$$\delta = -21.16^\circ$$

$$\cos \theta_{SS} = -(\tan 38.95) (\tan (-21.16)) = 0.31286$$

$$\theta_{SS} = 71.77^\circ$$

D. Compute: $\cos \theta_{TS} = -\tan(38.95 - 55) \tan(-21.16) = -0.11134$

$$\theta_{TS} = 96.39^\circ$$

E. Set: $\theta = \min(71.77, 96.39) = 71.77^\circ$

F. Compute: $S_O = 1.356 * \left(1 + 0.0167 * \cos\left(\frac{15}{365} * 360\right)\right)^2 = 1.400 \text{ kW/m}^2$

G. Compute: $S_{OH} = 1.400 * \frac{24}{\pi} * \left[\cos(38.95) \cos(-21.16) \sin(71.77) + \left(\frac{\pi * 71.77}{180}\right) \sin(38.95) \sin(-21.16) \right]$

so $S_{OH} = 4.328 \text{ kWh/m}^2 - \text{day}$

H. Compute: $S = 0.417 * 4.328 = 1.805 \text{ kWh/m}^2 - \text{day}$

I. Compute: $K_D = \left\{ 0.230 + \frac{71.77}{165} - \left[0.095 + \frac{71.77}{220} \right] * \cos \left[114.6 * (0.417 - 0.9) \right] \right\} = 0.426$

J. Compute: $R_D = \frac{\cos(38.45 - 55)}{\cos(38.95)} *$

$$\frac{\sin(71.77) - (\pi * 71.77 / 180) * \cos(96.39)}{\sin(71.77) - (\pi * 71.77 / 180) * \cos(71.77)}$$

$$= 2.416$$

K. For $\rho = 0$:

$$I_T = 1.805 * \left\{ (1 - 0.426) * 2.413 + \frac{1}{2} (1 + \cos 55) * 0.426 + \frac{1}{2} (1 - \cos 55) * 0 \right\}$$

so $I_T = 3.106 \text{ kWh/M}^2 - \text{day}$

Exhibit 11.1-3
GROUND REFLECTANCES FOR VARIOUS SURFACES

Ocean	0.05
Bituminous concrete	0.07
Wheat field	0.07
Dark soil	0.08
Green field	0.12 to 0.25
Grass, dry	0.20
Crushed rock surface	0.20
Concrete, old	0.24
Concrete, light colored	0.30
Paved asphalt	0.18
Concrete, new	0.32
Snow, fresh	0.87
Snow, old	0.50

References: (11-2, 11-3)

11.2 INSOLATION CALCULATION PROGRAMS

Programs for calculating the average daily insolation on a tilted array surface have been developed for the TI-59 and HP-67 programmable calculators. The programs are based on the equations of Exhibit 11.1-1. They will enable the effects of K_H , tilt angle and other variables on the performance of the PV system to be analyzed.

Instructions for using the TI-59 program are given in Exhibit 11.2-1. A listing of the program is presented in Exhibit 11.2-2. The instructions for use of the HP-67 program are in Exhibit 11.2-3 with the program listing given in Exhibit 11.2-4.

Exhibit 11.2-1
 INSTRUCTIONS FOR OPERATING THE
 TI-59 INSOLATION-COMPUTATION PROGRAM

1. Enter the following values in the respective storage locations:

Value	Storage Location
Latitude degrees	00
Tilt, degrees	02
Ground reflectance, decimal	13

2. Depress C to start the entry of the monthly \bar{K}_H 's. The calculator displays the month number for which the \bar{K}_H is to be entered (1.0 for January).
3. Enter the \bar{K}_H for the month indicated. Depress R/S. The calculator will display the next month number for which \bar{K}_H is to be entered. Repeat this step until all twelve values are entered.
4. Depress A to obtain the output. Typical output for the case of $\bar{K}_H = 0.5$ for each month is presented below. The average monthly insolation is printed for each month and for the year, in kWh/day- m^2 , for the tilted surface.

Latitude	20°
Tilt	30°
Ground ref.	0.050
<u>Month</u>	<u>I_T (kWh/day-m^2)</u>
Jan	4.595
Feb	4.798
Mar	4.910
April	4.832
May	4.646
June	4.512
July	4.544
Aug	4.703
Sept	4.837
Oct	4.821
Nov	4.657
Dec	4.517
Average	4.698

EXHIBIT 11.2-2 (Continued)

LISTING OF A TI-59 INSULATION COMPUTATION PROGRAM

301	99	PRT	351	28	28
302	43	RCL	352	55	=
303	13	13	353	01	1
304	99	PRT	354	02	2
305	98	ADV	355	95	=
306	01	1	356	99	PRT
307	06	6	357	86	STP
308	42	STD	358	08	08
309	15	15	359	91	R/S
310	03	3	360	00	0
311	01	1	361	22	INV
312	42	STD	362	44	SUM
313	30	30	363	02	02
314	76	LBL	364	43	RCL
315	16	R*	365	10	10
316	43	RCL	366	34	FX
317	15	15	367	61	GTD
318	75	-	368	11	R
319	01	1	369	76	LBL
320	06	6	370	13	C
321	95	=	371	01	1
322	65	x	372	06	6
323	03	3	373	42	STD
324	00	0	374	15	15
325	85	+	375	76	LBL
326	01	1	376	18	C*
327	05	5	377	43	RCL
328	95	=	378	15	15
329	42	STD	379	75	-
330	01	01	380	01	1
331	73	RC*	381	05	5
332	15	15	382	95	=
333	42	STD	383	91	R/S
334	03	03	384	72	ST*
335	12	B	385	15	15
336	44	SUM	386	01	1
337	28	28	387	44	SUM
338	01	1	388	15	15
339	44	SUM	389	61	GTD
340	15	15	390	18	C*
341	44	SUM	391	00	0
342	30	30	392	00	0
343	43	RCL			
344	15	15			
345	32	X:T			
346	02	2			
347	07	7			
348	77	GE			
349	16	R*			
350	43	RCL			

Exhibit 11.2-3

INSTRUCTION FOR OPERATING THE
HP-67 INSOLATION-COMPUTATION PROGRAM

1. Load the following quantities into the storage registers indicated below:

<u>Value</u>	<u>Register</u>
S_H	0
Day (Jan 1=1)	1
Latitude, L	2
Tilt Angle,	3
Reflectance	4

2. Depress A to initiate the program. In approximately 45 seconds, the value of S_T , the average monthly insolation on the tilted surface will be displayed in the x-register. The units of S_H are kWh/day-m².
3. To calculate I_T for a different month, the value of \bar{K}_H and the value of DAY corresponding to the middle of the month must be stored in Registers 0 and 1 respectively. Alternatively, the variation of S_T with tilt angle or ground reflectance can be studied by changing these variables with the remaining ones fixed.

4. Example:

For $K_H = 0.5$, $L = 20$, DAY = 15 (January)
Tilt = 20, and $\rho = 0.05$, the calculated
value of $I_T = \underline{4.595}$.

4. The following quantities are also calculated and stored by the program:

<u>Quantity</u> *	<u>Register</u>
δ	5
θ_{ss}	6
θ_{sr}	7
θ	8
S_{OH}	9
K_D	A
R_D	B

* See Exhibit 11.1-1 for a definition of these quantities

Exhibit 11.2-4

LISTING OF AN HP-67 INSOLATION COMPUTATION PROGRAM

11-11

Step Number	Key-strokes	Key Code	Step Number	Key-strokes	Key Code	Step Number	Key-strokes	Key Code
001	f LBL A	32	028	X	71	055	f cos	31
002	RCL 1	34	029	CHS	42	056	.	83
003	2		030	g cos ⁻¹	32	057	0	00
004	8		031	STO 6	33	058	1	01
005	4		032	RCL 2	34	059	6	06
006	+		033	RCL 3	34	060	7	07
007	3		034	-	51	061	X	71
008	6		035	f TAN	31	062	1	01
009	5		036	RCL 5	34	063	+	61
010	÷		037	f TAN	31	064	g x ²	32
011	3		038	X	71	065	1	01
012	6		039	CHS	42	066	.	83
013	0		040	g cos ⁻¹	32	067	3	03
014	X		041	STO 7	33	068	5	05
015	f sin	31	042	RCL 6	34	069	6	06
016	2		043	g x<y	32	070	X	71
017	3		044	h x>y	35	071	RCL 5	34
018	.		045	STO 8	33	072	f sin	31
019	4		046	RCL 1	34	073	RCL 2	34
020	5		047	3	03	074	f sin	31
021	f sin	31	048	6	06	075	X	71
022	X		049	0	00	076	RCL 6	34
023	g sin ⁻¹	32	050	X	71	077	X	71
024	STO 5	33	051	3	03	078	hπ	35
025	f TAN	31	052	6	06	079	X	71
026	RCL 2	34	053	5	05	080	1	01
027	f TAN	31	054	÷	81	081	8	08

Exhibit 11.2-4 (Continued)

LISTING OF AN HP-67 INSULATION COMPUTATION PROGRAM

11-11

Step Number	Key-strokes	Key Code	Step Number	Key-strokes	Key Code	Step Number	Key-strokes	Key Code
082	0	00	109	X	71	136	RCL 8	34 08
083	÷	81	110	f cos	31 65	137	X	71
084	RCL 6	34 06	111	RCL 6	34 06	138	hπ	32 73
085	f sin	31 62	112	2	02 02	139	x	71
086	RCL 5	34 05	113	2	02 02	140	1	01
087	f cos	31 63	114	0	00 00	141	8	08
088	X	71 71	115	÷	81 81	142	0	00
089	RCL 2	34 02	116	.	83 83	143	÷	81
090	f cos	31 63	117	0	00 00	144	CHS	42
091	X	71 71	118	9	09 09	145	RCL 8	34 08
092	+	61 61	119	5	05 05	146	f sin	31 62
093	X	71 71	120	+	61 61	147	+	61
094	2	02 02	121	X	71 71	148	RCL 6	34 06
095	4	04 04	122	CHS	42 42	149	f cos	31 63
096	X	71 71	123	RCL 6	34 06	150	RCL 6	34 06
097	hπ	35 73	124	1	01 01	151	X	71
098	÷	81 81	125	6	06 06	152	hπ	32 73
099	STO 9	33 09	126	5	05 05	153	X	71
100	RCL 0	34 00	127	÷	81 81	154	1	01
101	.	83 83	128	+	61 61	155	8	08
102	9	09 09	129	.	83 83	156	0	00
103	-	51 51	130	2	02 02	157	-	81
104	1	01 01	131	3	03 03	158	CHS	42
105	1	01 01	132	+	61 61	159	RCL 6	34 06
106	4	04 04	133	STO A	33 11	160	f sin	31 62
107	.	83 83	134	RCL 7	34 07	161	+	61
108	6	06 06	135	f cos	31 63	162	÷	81

Exhibit 11.2-4 (Continued)

LISTING OF AN HP-67 INSOLATION COMPUTATION PROGRAM

Step Number	Key-strokes	Key Code	Step Number	Key-strokes	Key Code
163	RCL 2	34 02	190	+	61
164	RCL 3	34 03	191	2	02
165	--	51 192	192	÷	81
166	f cos	31 63	193	RCL 4	34 04
167	X	71 194	194	X	71
168	RCL 2	34 02	195	+	61
169	f cos	31 63	196	RCL 9	34 09
170	÷	81 197	197	X	71
171	STO B	33 12	198	RCL O	34 00
172	RCL A	34 11	199	X	71
173	CHS	42 200	200	h RTN	32 22
174	1	01 201	201	R/S	84
175	+	61			
176	X	71			
177	RCL 3	34 03			
178	f cos	31 63	224	R/S	84
179	1	01			
180	+	61			
181	2	02			
182	÷	81			
183	RCL A	34 11			
184	X	71			
185	+	61			
186	RCL 3	34 03			
187	f cos	31 63			
188	CHS	42			
189	1	01			

11.3 STATISTICAL INSOLATION COMPUTATIONS

The tilted surface insolation computation using monthly averages directly, as was done in Exhibit 11.1-1 disagrees with the monthly averages computed by averaging day-by-day tilted surface insolations by as much as 30%; therefore, results of the monthly method will not agree exactly with Section 6 for which the data were generated by a day-by-day method. More accurate day-by-day data can be generated by using the following method.

The insolation for each month and for each K_H ranging from 0.0 to 1.0 must be computed. The procedure is identical to that presented in Exhibit 11.1-1, with one exception: the expression for K_D must be modified. The day-by-day expression for K_D is:

$$\begin{aligned}
 K_D &= 0.99 && \text{if } K_H \text{ is less than } 0.1557 \\
 K_D &= 1.188 - K_H * (2.272 - K_H * [9.473 - K_H * (21.856 - 14.648 * K_H)]) && \text{if } K_H \text{ is between } 0.1557 \text{ and } 0.761 \\
 K_D &= 0.2255 && \text{if } K_H \text{ is greater than } 0.761
 \end{aligned}$$

The frequency with which each K_H is encountered can be determined from Exhibit 11.3-1, which gives the (cumulative) distribution, M , for each K_H as a function of the monthly average K_H . The average and standard deviation are computed from the formulas:

$$\begin{aligned}
 \text{Average insolation} &= \sum_{i=1} (M_{i+1} - M_i) (I_{T,i+1} + I_{T,i})/2 \\
 \text{Standard deviation} &= \sqrt{\sum_{i=1} (M_{i+1} - M_i) \left[(I_{T,i+1} + I_{T,i})/2 - \text{Average insolation} \right]^2}
 \end{aligned}$$

This procedure is tedious and is best performed on a computer, rather than a hand-held calculator. The latter would probably require several days of computation, whereas the former requires approximately one hour on a micro computer.

Exhibit 11.3-1
GENERALIZED K_H DISTRIBUTION COVERAGE, F (K_H)

K_H	Average K_H				
	.3	.4	.5	.6	.7
.04	.073	.015	.001	.000	.000
.08	.162	.070	.023	.008	.000
.12	.245	.129	.045	.021	.007
.16	.299	.190	.082	.039	.007
.20	.395	.249	.121	.053	.007
.24	.496	.298	.160	.076	.007
.28	.513	.346	.194	.101	.013
.32	.579	.379	.234	.126	.013
.36	.628	.438	.277	.152	.027
.40	.687	.493	.323	.191	.034
.44	.748	.545	.358	.235	.047
.48	.793	.601	.400	.269	.054
.52	.824	.654	.460	.310	.081
.56	.861	.719	.509	.360	.128
.60	.904	.760	.614	.410	.161
.64	.936	.827	.703	.467	.228
.68	.953	.888	.792	.538	.295
.72	.967	.931	.873	.648	.517
.76	.979	.967	.945	.758	.678
.80	.986	.981	.980	.884	.859
.84	.993	.997	.993	.945	.940
.88	.995	.999	1.000	.985	.980
.92	.998	.999		.996	1.000
.96	.998	1.000		.999	
1.00	1.000			1.000	

11.4 SUN ANGLE CHARTS

In this section, charts are presented to predict the amount and duration of array shading caused by objects located in front of and to the side of the array. The determination of array shading is an important part of site selection in view of the sensitivity of array output to shadowing. This sensitivity is due to series connection of cells and of modules and can be minimized but never eliminated. Thus, it is imperative that shading be kept to a minimum especially during the hours of 0900 to 1500 solar time.

From the point of view of an observer standing on earth, the position of the sun in the sky can be specified by two angles, the altitude angle and the azimuth angle. The altitude angle is the elevation of the sun above the horizon. The azimuth angle is the angle between true south (or north in the southern hemisphere) and the projection of the sun's rays onto the horizontal surface. Exhibit 11.4-1 illustrates these angles. To estimate shading, the skyline must be plotted on the sun chart closest to the site latitude. The sun charts are presented in Exhibits 11.4-2 through 11.4-10 for latitude angles from 0 to 64 degrees in 8 degree increments. The altitude and azimuth angles of objects on the horizon can be measured directly or estimated based on the known locations and elevations of objects relative to the array site. For close objects or an extended array, the measurements should be referenced to several locations along the array. An example calculation is presented in Exhibit 11.4-11.

11.5 ROW TO ROW SHADING

For PV arrays arranged in multiple rows of PV modules, the largest source of shading in the winter is likely to be the adjacent row. Sufficient spacing between rows must be provided to keep the shading to a minimum. This is most important for stand-alone systems, since the months of maximum shading (winter months) are also usually the months of lowest insolation.

In Exhibit 11.5-1 a graph is presented showing the minimum spacing between rows as a function of latitude angle for no row-to-row shading between the hours of 0900 to 1500 solar time for December 21 (June 21). It is seen that the land areas taken up by the array at the higher latitudes is excessive. The technique used to overcome this is to locate the array on a slope or to artificially create a slope by raising the rear rows. This is depicted in the exhibit.

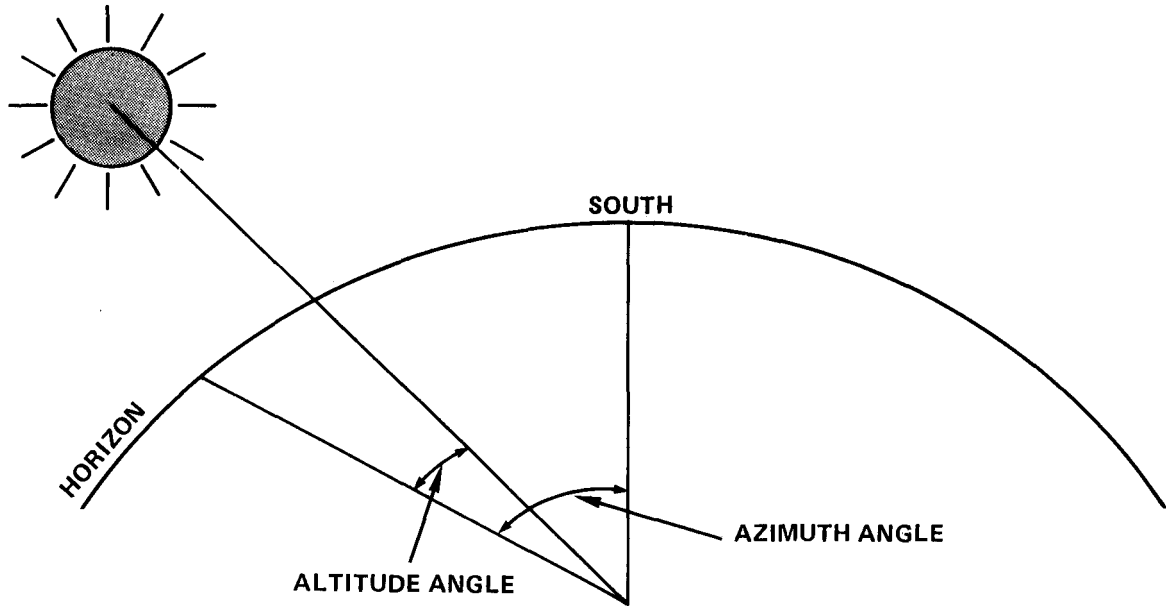
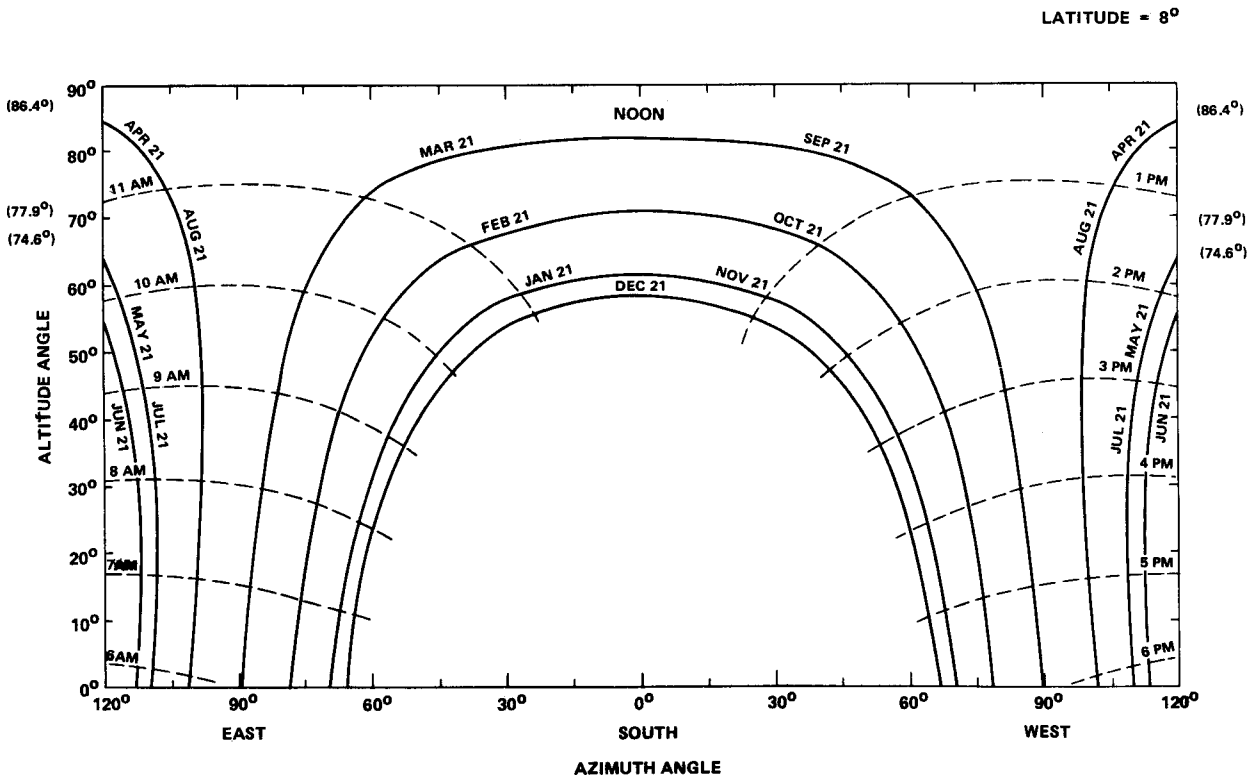
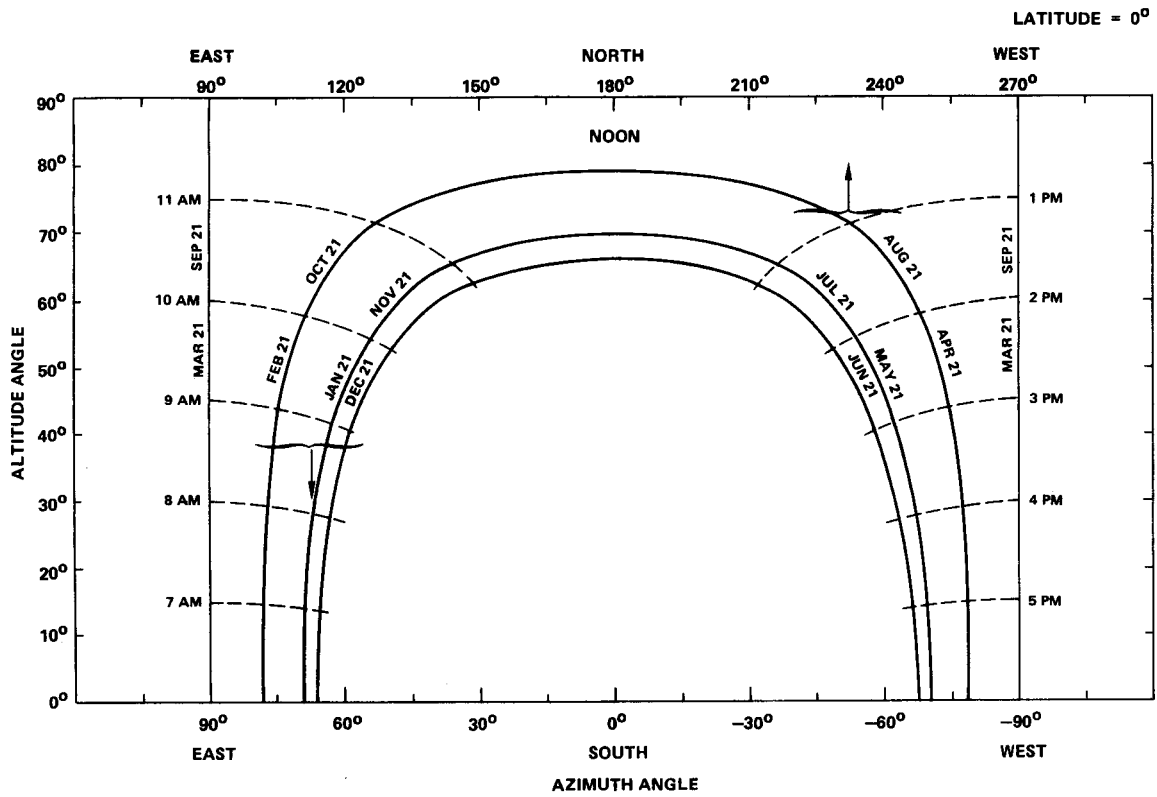


Exhibit 11.4-1

ILLUSTRATION OF SOLAR ALTITUDE AND AZIMUTH ANGLES

SUN CHART FOR 0° LATITUDE

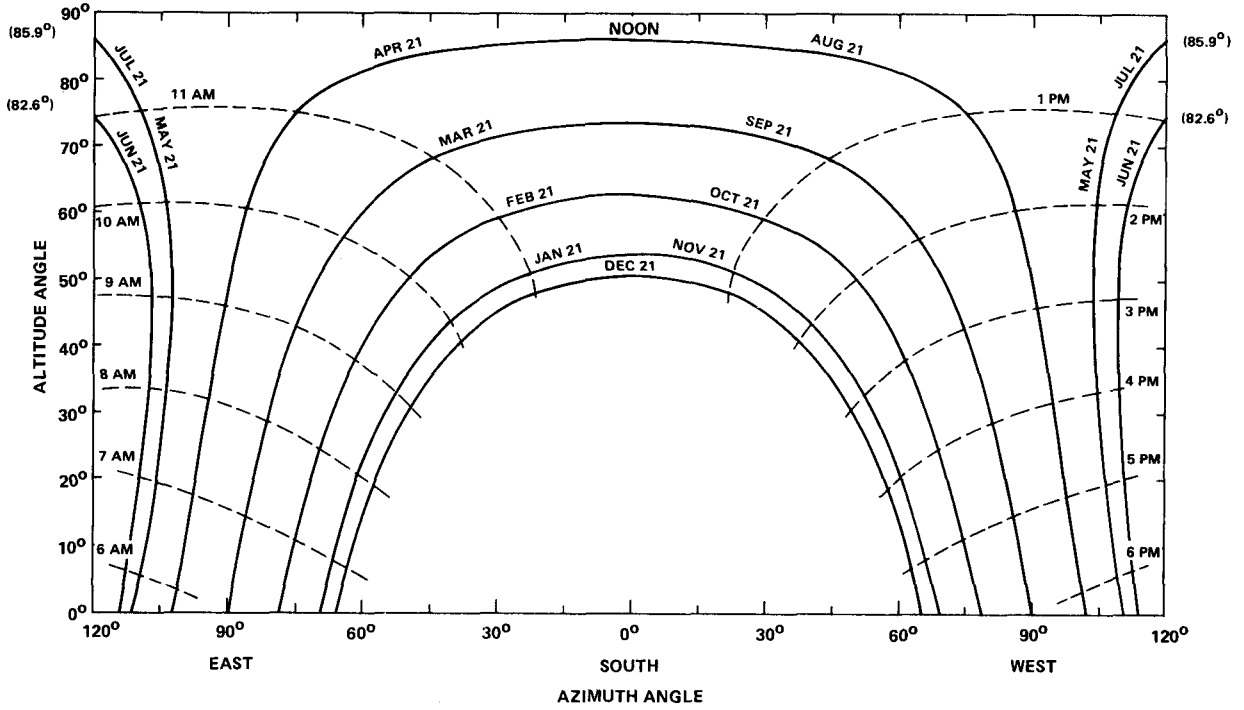


SUN CHART FOR 8° LATITUDE

Exhibit 11.4-4

SUN CHART FOR 16° LATITUDE

LATITUDE = 16°



LATITUDE = 24°

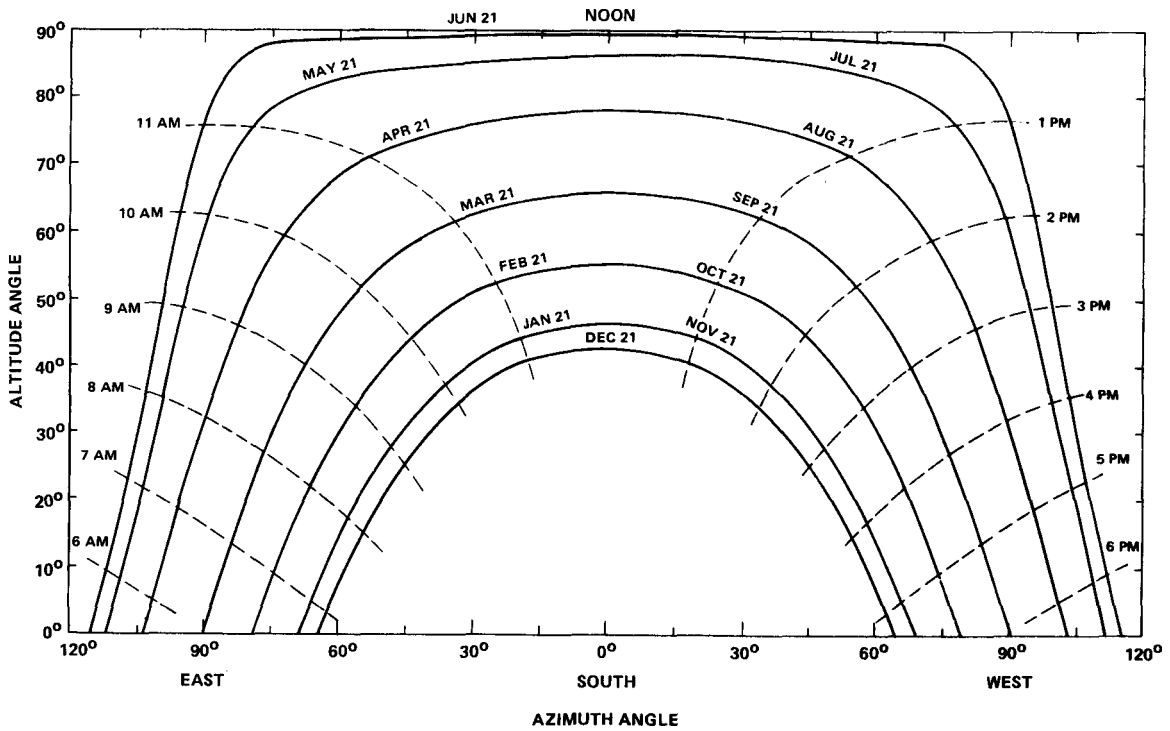
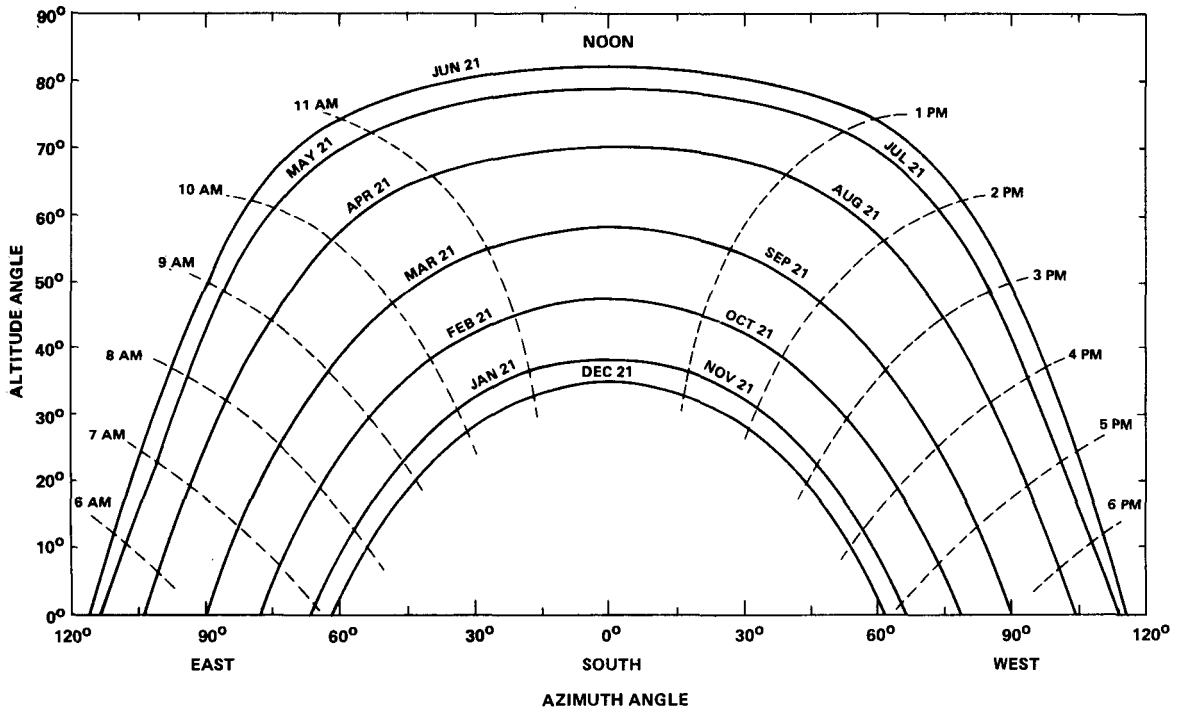


Exhibit 11.4-5

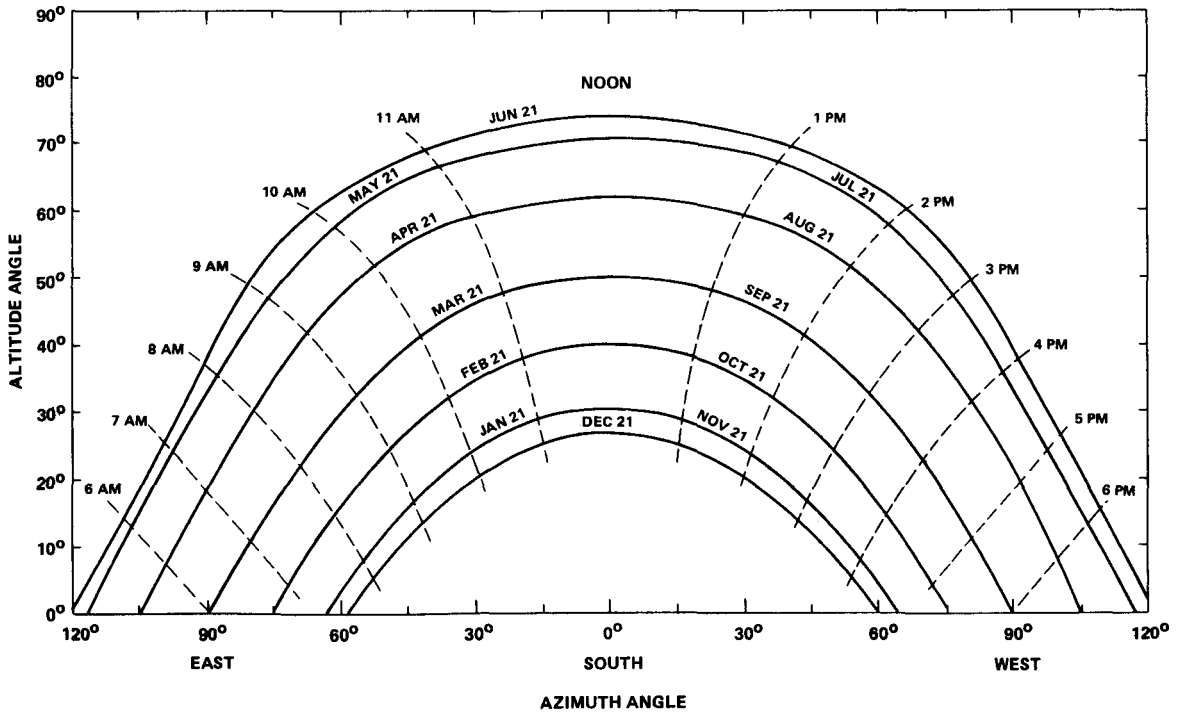
SUN CHART FOR 24° LATITUDE

SUN CHART FOR 32° LATITUDE

LATITUDE = 32°



LATITUDE = 40°

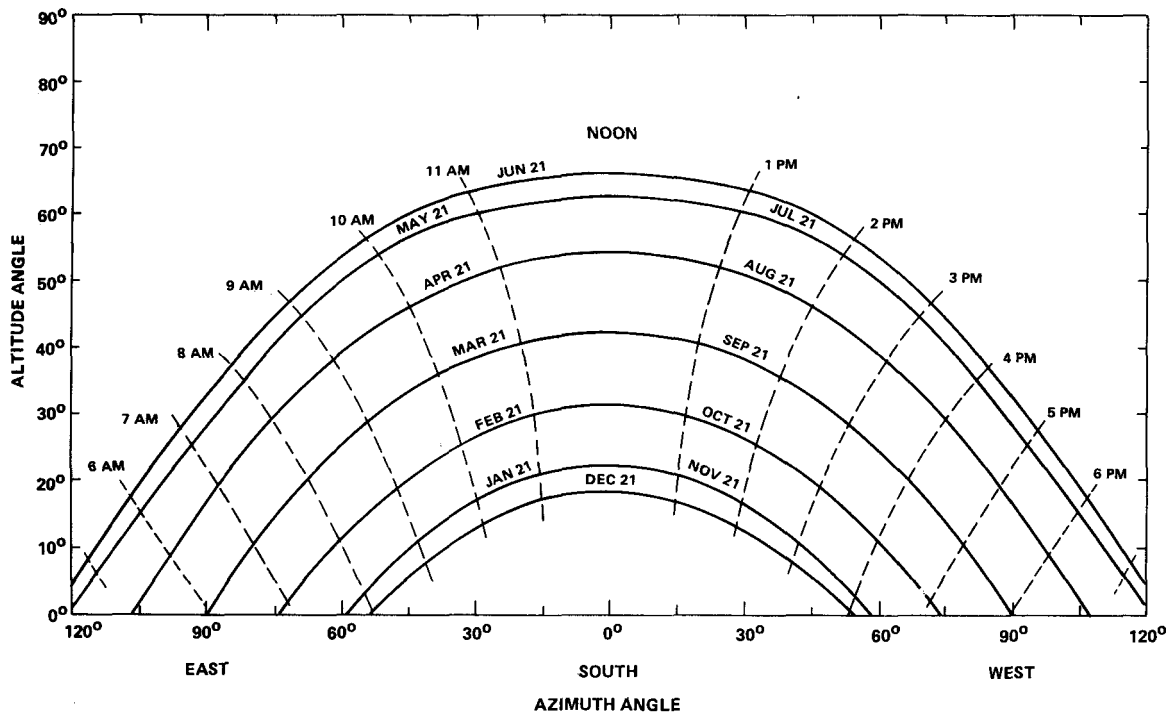


SUN CHART FOR 40° LATITUDE

Exhibit 11.4-8

SUN CHART FOR 48° LATITUDE

LATITUDE = 48°



LATITUDE = 56°

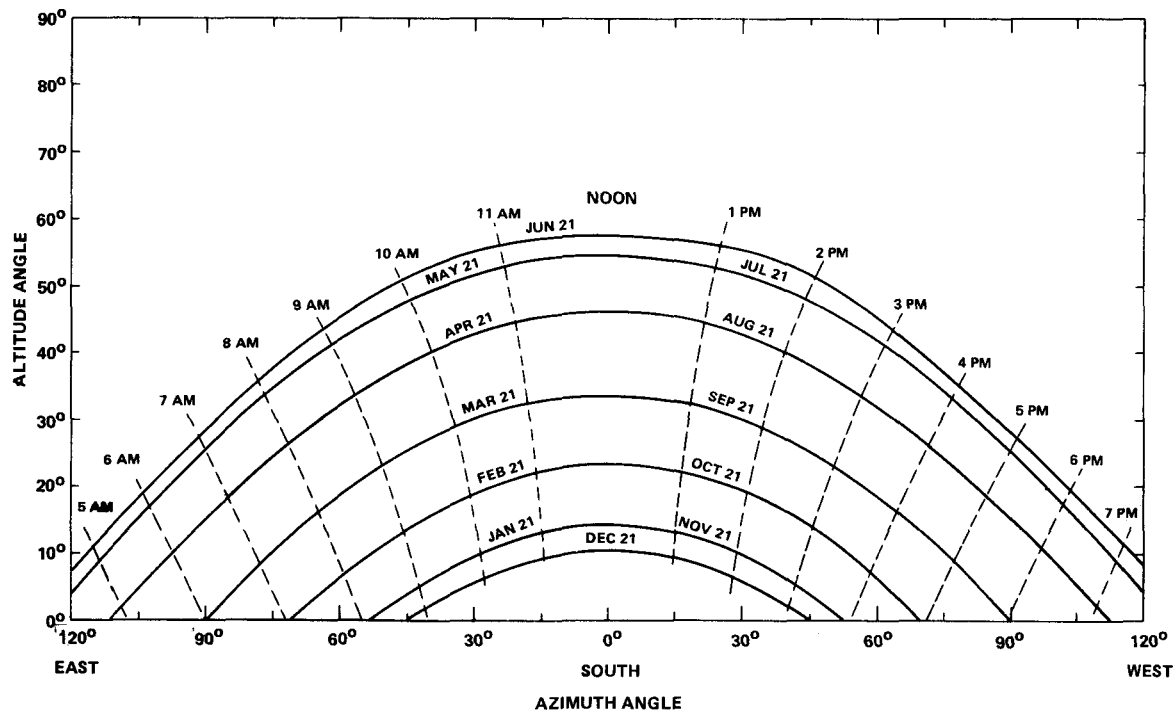


Exhibit 11.4-9

SUN CHART FOR 56° LATITUDE

LATITUDE = 64°

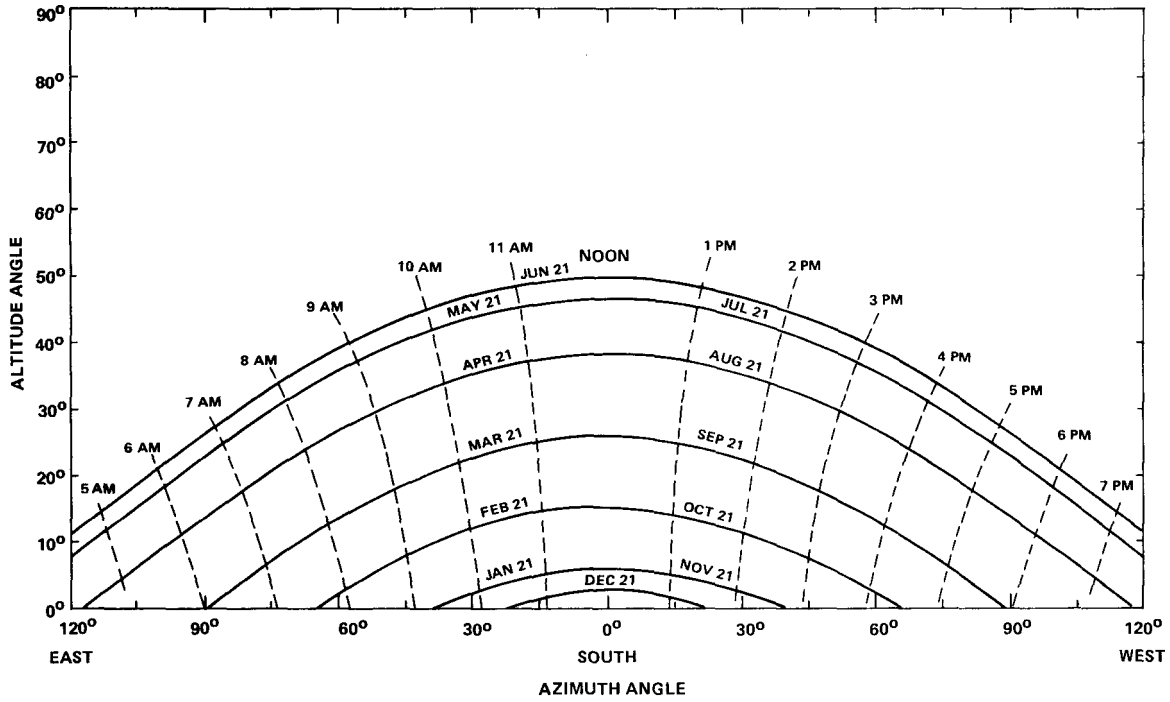
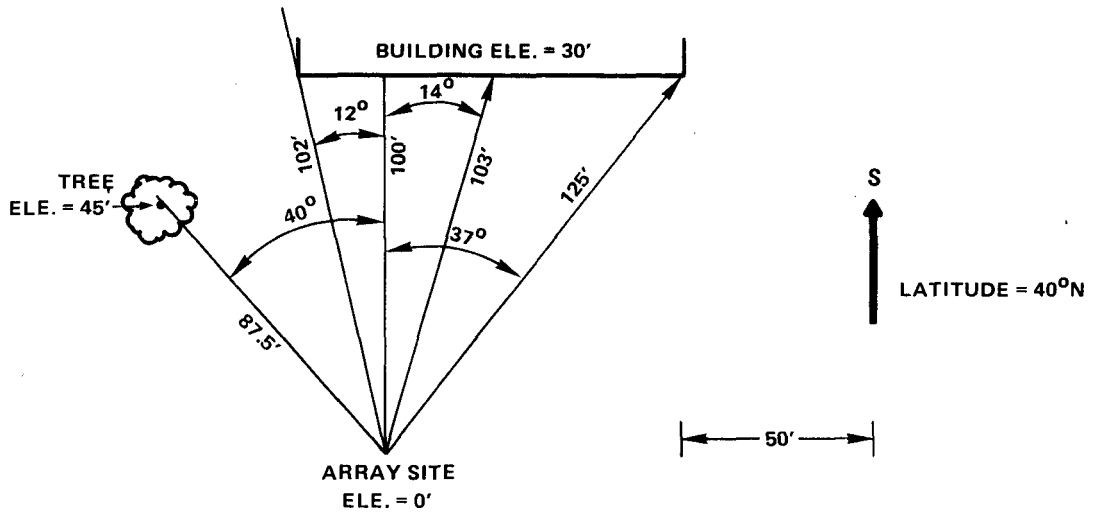


Exhibit 11.4-10

SUN CHART FOR 64° LATITUDE

Exhibit 11.4-11
 SAMPLE SHADING CALCULATION



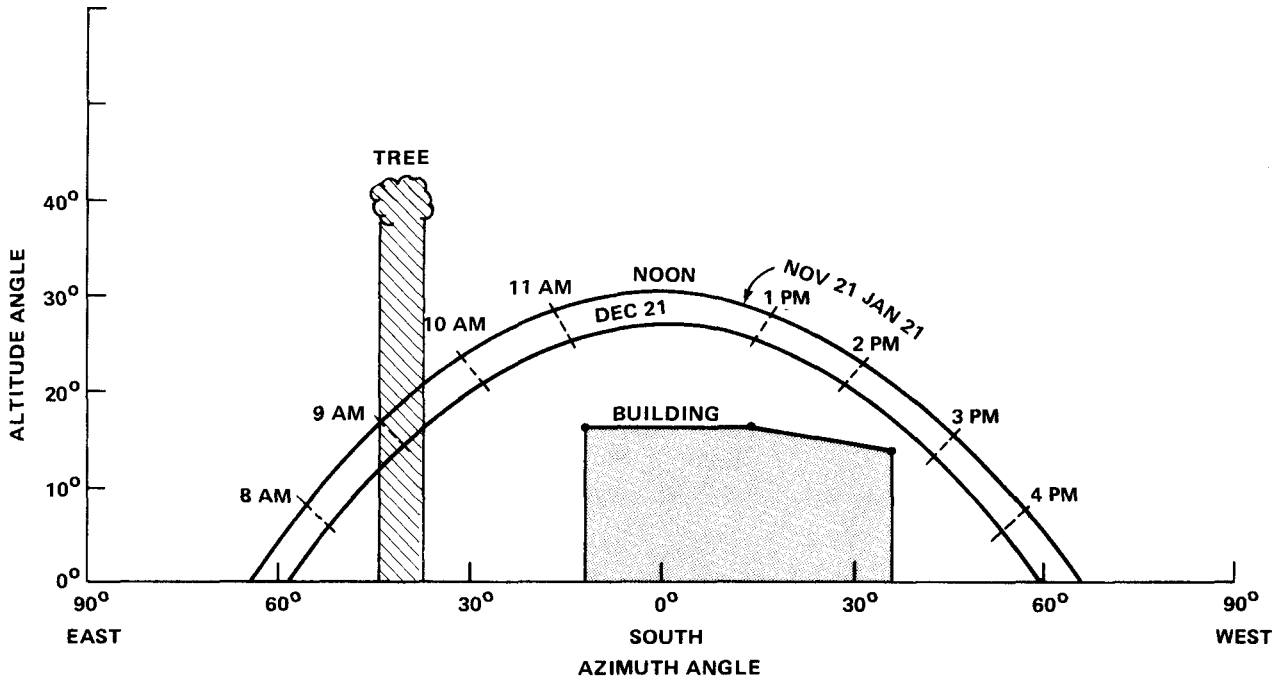
AZIMUTH OF TREE = 40° E
 ALTITUDE OF TREE = $\tan^{-1}\left(\frac{45}{87.5}\right) = \underline{\underline{43.5^\circ}}$

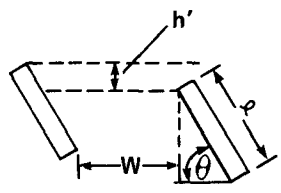
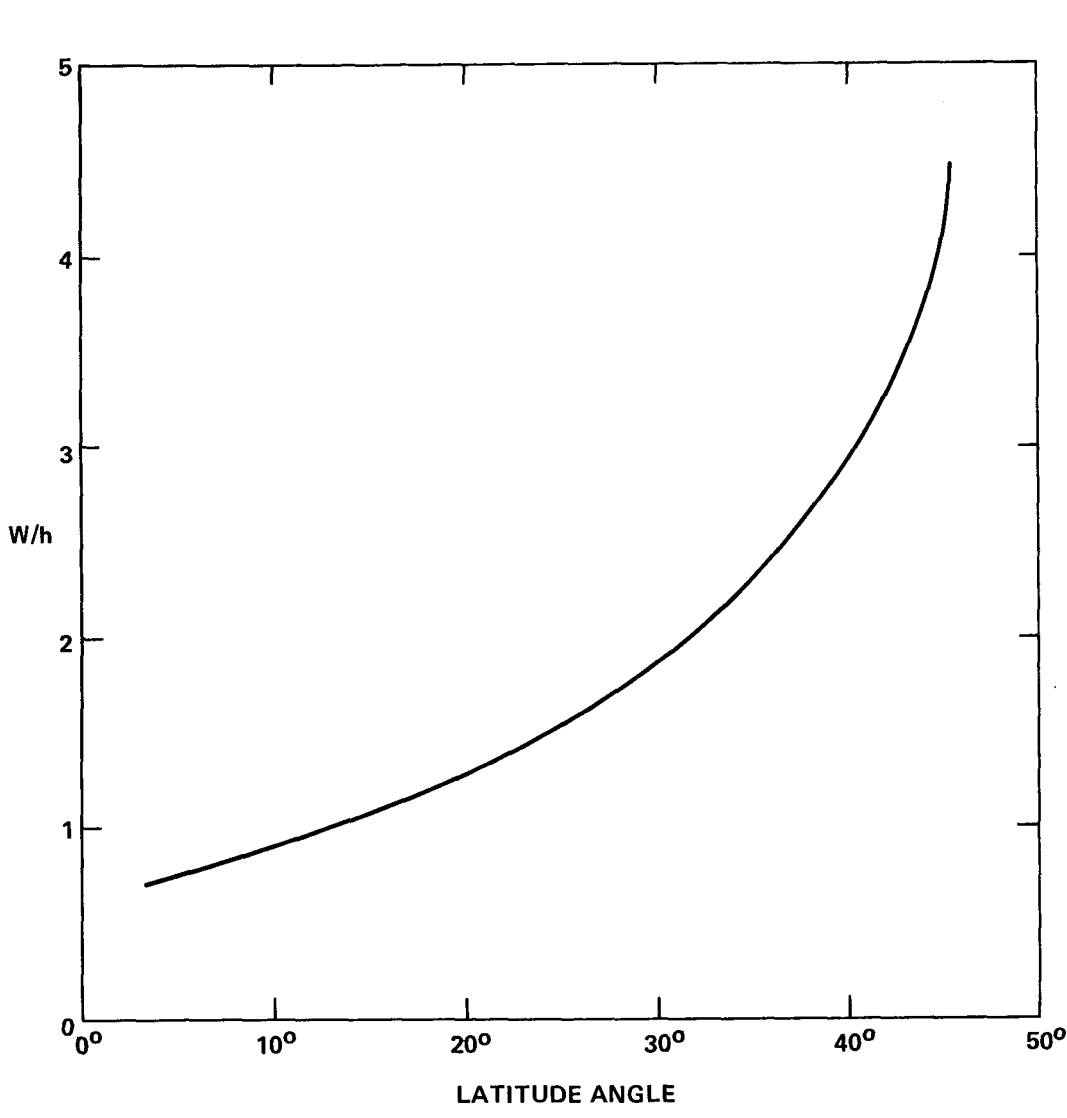
AZIMUTH OF EAST CORNER OF BUILDING = 12° E
 ALTITUDE OF EAST CORNER OF BUILDING = $\tan^{-1}\left(\frac{30}{102}\right) = \underline{\underline{16^\circ}}$

AZIMUTH OF CENTER OF BUILDING = 14° W
 ALTITUDE OF CENTER OF BUILDING = $\tan^{-1}\left(\frac{30}{103}\right) = \underline{\underline{16^\circ}}$

AZIMUTH OF WEST CORNER OF BUILDING = 37° W
 ALTITUDE OF WEST CORNER OF BUILDING = $\tan^{-1}\left(\frac{30}{125}\right) = \underline{\underline{13.5^\circ}}$

SUN CHART FOR 40°N





W \equiv FRONT TO BACK SPACING BETWEEN ROWS
 h \equiv $l \sin \theta - h'$
 l \equiv LENGTH OF PV MODULE(S)
 θ \equiv TILT ANGLE OF ARRAY
 h' \equiv HEIGHT DIFFERENTIAL BETWEEN ROWS

Exhibit 11.5-1

MINIMUM ROW-TO-ROW SPACING REQUIRED FOR NO SHADING BETWEEN 0900 AND 1500 HOURS ON DECEMBER 21 (JUNE 21)

11-24

SECTION 12 PHOTOVOLTAIC SYSTEM COMPONENTS

A brief survey of manufacturers and standard catalogs reveals the availability and costs of the major components for photovoltaic power systems. The results of this survey are presented in the exhibits of this section. For typical systems under 1.5 kWp array sizes, there are components available off the shelf (within approximately 16 weeks). In the following subsections, each of the components will be discussed individually. The data are arranged in the order that the components appear in the system, starting with the solar array.

12.1 SOLAR CELL MODULES

Exhibit 12.1-1 lists data obtained from representative module manufacturers. The specifications were obtained from GSA lists, brochures and telephone calls. The prices referred to as minimum are based on small quantities, typically less than 5 kWp. Most suppliers reserve the right to determine large quantity prices at the time of the contract based on supply and demand. It should be noted that at the present, the demand exceeds the immediately available supply. Thus, some delays in delivery may be experienced. Also there are several firms not listed here which are developing new processes that will substantially effect the cost in the future. Some of these firms may enter the market as suppliers. This is meant to be a sampling of what is available and not a complete reference for these products.

The most popular modules for terrestrial power are made with silicon cells, although much research and development is being done with cadmium sulfide solar cells and other semi-conductor materials. Availability of cadmium sulfide cells is limited at present, and therefore specifications are limited too. It has been projected that the cadmium sulfide cells will become available in quantities at competitive prices (less than \$8/Wp) within the year. Furthermore, an anticipated price in the range of \$3/watt peak for installed dc power systems may offset the relatively low (typically 3-8 percent) efficiency posed by a cadmium sulfide manufacturer.

The efficiency of silicon cells depends primarily on their purity. Lab experiments have produced samples at near theoretical maximum. Yet the variables of mass production tend to limit the efficiency of silicon cells to about 17 percent and average close to 10 percent. When the fill factor of a module or space between the cells is considered it can be understood why module sizes have not been standardized for commercial applications; however, most manufacturers supply their own structures, so standardization is of lesser importance unless it is desired to have the capability to interchange different manufacturers modules.

Although manufacturers may vary from one to another in the relative-ness of their test data, some general conclusions can be drawn: photovoltage is independent of area (typically 0.5 V/cell), while current is directly related to area and light intensity. The change in current is directly proportional to the change in temperature by about 25 micro amperes per centimeter squared per degree celsius. 100 milliwatts per centimeter squared is the typical maximum intensity of sunlight. As discussed in Section 6.2 on pv arrays, the open-circuit voltage (V_{oc}), short-circuit current (I_{sc}) and series resistance (R_{series}) are important in combining arrays. For the same reason, the temperature coefficients are important. Arrays matched at one temperature may not be matched at another. The JPL (I-V) current per voltage tests are cited by one cell manufacturer; based on their findings a cell temperature of 28°C is standard. Yet, under nominal working conditions there is an increase in cell temperature of 15° -20° C above ambient temperature. As mentioned before, manufacturers may vary on this point.

Some arrays come with dual leads from each cell. If one should fail, the other will suffice. Few of the GSA listed arrays come with an intermediate tap that would permit the use of a partial-shunt regulator. In total, there are approximately nine manufacturers from whom modules can be bought off the shelf. At present there is a greater demand for P.V. modules than is being supplied. This is an unusual condition. Partially due to the effects of supply and demand and partially due to mass production techniques, there is a wide range in cost per watt peak from about \$26/Wp to \$8/Wp. Typically the mean price is about \$15/Wp.

Exhibit 12.1-1

COMPARISON OF TYPICAL SPECIFICATIONS
FOR PHOTOVOLTAIC MODULES

Manufacturer:					
Model #:	60-3012	60-3013	60-3014	60-3015	60-3016
Price/pc. min/max: ⁽¹⁾	\$34-41	\$62-74	\$103-124	\$83-99	\$150-180
\$/Watt peak: ⁽¹⁾	\$11.81-14+	\$11.78-14+	\$9.78-11+	\$16.12-19+	\$14.25-17+
Efficiency: ⁽²⁾	7.22%	7.79%	7.92%	7.67%	8.71%
Standard Operating Conditions: ⁽³⁾	T _a : 20°C Wind: 1m/s NOCT: oc	same	same	same	same
Watts Peak: (I _p • V _p)	2.88	5.265	10.53	5.148	10.53
Volts Peak:	9.0	8.1	8.1	16.2	16.2
Amps Peak:	0.32	0.65	1.30	0.32	0.65
V. open circuit:					
V. Temp. Coeff.:					
I. short circuit:					
I. Temp. Coeff.:					
R. series/cell:					
R. Temp. Coeff.:					
Temp. cell-Temp. air					
P. Temp. Coeff.:					
No. of Cells & Size:	20@½ of 3"	18@½ of 3"	18@ 3"	36@½ of 3"	36@½ of 3"
Configuration:	20s x 1p	18s x 1p	18s x 1p	36s x 1p	36s x 1p
Dual Leads:					
Intermediate Tap:					
Failure Rate (MTBF):					
Protection:					
Fill Factor:					
Panel Dimensions: l. x w. x h.	1.75 x 6.87 x 9"	6.87 x 15.25"	6.87 x 30"	6.87 x 15.25"	12 x 15.62"
Front Surface Area:	61.83" ²	104.77" ²	206.1" ²	104.77" ²	187.44" ²
Cover Material:	Glass	Glass	Glass	Glass	Glass
Weight:	2 lbs.	3 lbs.	5.75 lbs.	3 lbs.	4 lbs.
Ambient Temp. Limit:					
Insulation:					
Max. Snow Load:					
Max. Wind Load:					
Max. Impact:					
JPL Tested:					
GSA Listed:	yes	yes	yes	yes	yes
Delivery:					

- (1) Based on present 1980 \$ value Domestic Price List effective March 1, 1979
(2) Based on gross frontal area
(3) Based on 100 mw/cm², 28° cell temp. (or State Other Conditions)

Exhibit 12.1-1 (Con't)

COMPARISON OF TYPICAL SPECIFICATIONS
FOR PHOTOVOLTAIC MODULES

Manufacturer:					
Model #:	ASI16-2000				
Price/pc. min/max: ⁽¹⁾	\$264-495				
\$/Watt peak: ⁽¹⁾	\$8 -\$15				
Efficiency: ⁽²⁾	8.97%				
Standard Operating Conditions: ⁽³⁾					
Watts Peak: ⁽⁴⁾	33				
Volts Peak:	16.1				
Amps Peak:	2.05				
V. open circuit:	20.3				
V. Temp. Coeff.:	2.5-3mV/C/°C				
I. short circuit:	2.3				
I. Temp. Coeff.:					
R. series/cell:					
R. Temp. Coeff.:					
Temp. cell-Temp. air	40°C				
P. Temp. Coeff.:					
No. of Cells & Size:	35@ 4"				
Configuration:	35series				
Dual Leads:	yes				
Intermediate Tap:					
Failure Rate (MTBF):					
Protection:	yes/op.				
Fill Factor:					
Panel Dimensions:	47.9x11.9x1.5"				
Front Surface Area:	570.01"²				
Cover Material:	Glass				
Weight:	11 lbs.				
Ambient Temp. Limit:	-40to+90°C				
Insulation:					
Max. Snow Load:					
Max. Wind Load:					
Max. Impact:					
JPL Tested:					
GSA Listed:					
Delivery:					

(1) Based on present 1980 \$ value

(2) Based on gross frontal area

(3) Based on 100 mw/cm², 28° cell temp. (or State Other Conditions)

(4) Recent production units have 37 watts peak which may result in a second module becoming available soon.

Exhibit 12.1-1 (Con't)

COMPARISON OF TYPICAL SPECIFICATIONS
FOR PHOTOVOLTAIC MODULES

Manufacturer:	(4)	(4)	(4)	(4)	
Model #:	9200J ⁽⁴⁾	HE50J/JG	HE51J/JG	HE60J/JG	4200C
Price/pc. min/max: ⁽¹⁾	\$335.5-419+	\$499.2-624	\$504-630	\$576-720	\$219-300
\$/Watt peak: ⁽¹⁾	\$13.4-16+	\$15.13-18+	\$14.82-18+	\$15.57-19+	\$10.95-15
Efficiency: ⁽²⁾	7.33%	11.60%	11.95%	11.38%	7.03%
Standard Operating Conditions: ⁽³⁾	T _c : 25 ^o C +3 ^o C	same	same	same	same
Watts Peak:	25.0	33.0	34.0	37.0	20.0
Volts Peak:					
Amos Peak:					
V. open circuit:	23	18/36	20	20/40	20
V. Temp. Coeff.:					
I. short circuit:					
I. Temp. Coeff.:					
R. series/cell:					
R. Temp. Coeff.:					
Temp. cell-Temp. air					
P. Temp. Coeff.:					
No. of Cells & Size:					
Configuration:					
Dual Leads:					
Intermediate Tap:					
Failure Rate (MTBF):					
Protection:					
Fill Factor:					
Panel Dimensions:	23x23"	21x21"	21x21"	21x21"	21x21"
Front Surface Area:	529" ²	441" ²	441" ²	504" ²	441" ²
Cover Material:		/Glass	/Glass	/Glass	Glass
Weight: lbs.	21	23	23	25	19
Ambient Temp. Limit:					
Insulation:					
Max. Snow Load:					
Max. Wind Load:					
Max. Impact:					
JPL Tested:					
GSA Listed:	yes	yes	yes	yes	yes
Delivery:					

(1) Based on present 1980 \$ value GSA Discounts thru April 30, 1980

(2) Based on gross frontal area

(3) Based on 100 mw/cm², 28^o cell temp. (or State Other Conditions)

(4) J: Integral mounting frame with junction box

Exhibit 12.1-1 (Con't)

COMPARISON OF TYPICAL SPECIFICATIONS
FOR PHOTOVOLTAIC MODULES

Manufacturer:					
Model #:	1263-4G	1294-G	1263-S	1203-S	1264-S
Price/pc. min/max: ⁽¹⁾	\$136-152	\$450-502	\$301-337	\$310-346	\$395-441
\$/Watt peak: ⁽¹⁾	\$34-38	\$12.86-14	\$13.68-15	\$13.48-15	\$12.34-13+
Efficiency: ⁽²⁾	8.86%	7.66%	8.81%	7.78%	7.05%
Standard Operating Conditions: ⁽³⁾					
Watts Peak:	4	35	22	23	32
Volts Peak:					
Amps Peak:					
V. open circuit:					
V. Temp. Coeff.:					
I. short circuit:					
I. Temp. Coeff.:					
R. series/cell:					
R. Temp. Coeff.:					
Temp. cell-Temp. air					
P. Temp. Coeff.:					
Nc. of Cells & Size:	36@ 4 -3"	39@4"	36@3"	42@3"	36@4"
Configuration:					
Dual Leads:					
Intermediate Tap:					
Failure Rate (MTBF):					
Protection:					
Fill Factor:					
Panel Dimensions: ⁽⁴⁾	20x3.5	30x23.6	21.8x17.75	22.9x20	46x15.3
Front Surface Area:	70" ²	708" ²	386.95" ²	458" ²	703.8" ²
Cover Material:	Glass	Glass	Silicone	Silicone	Silicone
Weight: lbs.	2.5	24.9	4	5	7
Ambient Temp. Limit:					
Insulation:					
Max. Snow Load:					
Max. Wind Load:					
Max. Impact:					
JPL Tested:					
GSA Listed:	Yes	Yes	Yes	Yes	Yes
Delivery:					

(1) Based on present 1980 \$ value GSA Discount list effective thru April 30, 1980

(2) Based on gross frontal area

(3) Based on 100 mw/cm², 28° cell temp. (or State Other Conditions)

(4) Height: Glass-1.75", Silicone-.25"

12.2 BATTERIES

A detailed analysis of various batteries has been presented in Section 4.3. Both nickel cadmium and lead-acid batteries are represented in Exhibit 4.3-1. A distinction should be made between two types of lead-acid batteries, the lead-antimony (typically useful to 5 to 10 percent maximum depth of discharge) and lead-calcium (most useful to 20 percent, some useful to 80 percent maximum depth of discharge). The specifications for depth of discharge and number of cycles per life vary widely. It is therefore difficult to compare the various types. For instance, nickel cadmium batteries are generally capable of being used to 100 percent of the maximum rated depth of discharge for thousands of cycles over many years.

The prime contenders for use with photovoltaic systems are the NiCd and lead-calcium. Some loads may not require battery storage, while some may require the storage to be displaced in a day, and others may require several days of storage or even several weeks where high dependability is demanded. In any case the battery manufacturer should always be consulted before making the final choice as to the appropriate cell for a particular application.

The actual battery size is not usually important, because battery cells, like PV cells, can be grouped to obtain the desired voltage and current.

For very small applications, automotive batteries, sized to prevent more than a 10 percent discharge, might be the most cost-effective.

Exhibit 12.2-1 lists many of the characteristics and specifications of importance in determining the appropriate cell and block of cells for a photovoltaic application. The information asked for here is general and battery manufacturers prefer to quote on specific applications; therefore, companies such as those listed in Section 14 and elsewhere should be referred to for exact specifications.

Exhibit 12.2-1

TABLE OF IMPORTANT BATTERY DESIGN CHARACTERISTICS

Manufacturer:
Type:₁
Model:
Typical Application:
Price:
 total
 \$/kwh
Delivery:
Efficiency:
Input (at 5 hr. rate):
Charging:
 Max. volts
 Max. current
Overcharging:
 Max. volts
 Max. current
Output (at 8 hr. rate):
 at 20 hr. rate:
 at 7 day rate:
 at 3 week rate:
 kwh
 Ah
 volts
 Max. current
Life Cycles:
 10% depth
 20% depth
 50% depth
 80% depth
 90% depth
 100% depth
 Shelf
Self Discharge:
Physical:
 Dimensions:
 Weight:
 Temp. Limits:
 0% charge:
 50% charge:
 100% charge:
\$ (cycle x kwh)*₂
\$ (years x kwh)*₂

1) Nickel Cadmium Calcium or Lead Antimony, etc.
2) Based on 100% discharge except as noted.

12.3 DC REGULATORS

The primary purpose of regulators is to prevent storage batteries from overcharging.

Most solar module manufacturers will supply regulators or recommend if specified. These specifications vary according to the combination of arrays and the configuration of the batteries and the load. Typical data which should be specified are listed in Exhibit 12.3-1. Costs will be on the order of \$1/W.

- Manufacturer
- Model
- Price
- Delivery
- Efficiency
- Input
 - Volts
 - Amps
 - Protection
- Output
 - Waveform
 - Volts
 - Amps
 - Protection
- MTBF
- Physical
 - Dimensions
 - Weight (kg)
 - Temp. Limits
 - Cooling

Exhibit 12.3-1
DC REGULATORS SPECIFICATION REQUIREMENTS

*12.4 DC MOTORS

Direct-Current motors are acknowledged to be unsurpassed for adjustable-speed applications and other applications with severe torque requirements.

Since dc is no longer generally available from most industrial plant buses or utility networks, the most common practice to supply dc motors has been by a solid state rectifier for each motor, or for a group of motors in a process. Manufacturers of dc motors generally offer a very limited selection of dc motors for special applications as compared to ac motors. Exhibit 12.4-1 contains some representative data on dc motors obtained from manufacturers.

Permanent magnet motors are offered in small fractional horsepower ranges, sometimes in integral ratings, but rarely above 10 hp. Wound field motors are offered with either shunt, series or compound field configurations. For efficiency data and discount multipliers against List Prices, it is recommended that the manufacturer's factory be contacted directly for the specific application at hand.

Exhibit 12.4-1
 REPRESENTATIVE DATA ON DC MOTORS

Permanent Magnet

HP	Speed RPM	Armature Volts	NEMA Frame	Encl [*]	Max. Peak Current	F.L. Amps	List Price	Est. Shpg. Wt. (Lbs.)
1/4	1725	90	56C	TENV	30	2.8	\$149.00	20
1/3	1725	90	56C	TENV	40	3.6	165.00	26
1/2	1725	90	56C	TEFC	52	5.5	181.00	32
3/4	1725	90	56C	TEFC	70	8.0	221.50	40
		180	56C	TEFC	34	4.0	231.50	40
1	1725	90	56C	TEFC	88	10.7	267.00	46
		180	56C	TEFC	44	5.2	279.00	46

Wound Field

Exhibit 12.4-1 (Continued)
 REPRESENTATIVE DATA ON DC MOTORS

120 Volts, ¼ to 15 Horsepower

Hp	Speed, Rpm		¼ Hour Rating		¼ Hour Rating	
	Series Wound	Compound Wound	Frame	Basic List Price ^① W-26	Frame	Basic List Price ^① W-26
¾	1050	1150	187A	\$ 576	187A	\$ 651
	750	850	187A	744	187A	772
1	1600	1750	187A	580	187A	604
	1050	1150	187A	693	187A	719
	750	850	187A	817	187A	847
1½	1600	1750	187A	668	187A	691
	1050	1150	187A	782	187A	786
	750	850	187A	894	187A	945
2	1600	1750	187A	753	187A	785
	1050	1150	187A	891	187A	945
	750	850	216A	1571	216A	1608
3	1600	1750	187A	838	187A	856
	1050	1150	216A	1067	216A	1098
	750	850	216A	1627	218A	1679
5	1600	1750	216A	1053	216A	1086
	1050	1150	218A	1661	218A	1669
	750	850	256A	1938	256A	2045
7½	1600	1750	216A	1685	218A	1730
	1050	1150	218A	2109	283AT	2142
	750	850	283AT	2499	283AT	2555
10	1600	1750	218A	2008	256A	2118
	1050	1150	283AT	2516	283AT	2572
	750	850	283AT	2958	284AT	3040
15	1600	1750	256A	2640	283AT	2686
	1050	1150	283AT	3120	284AT	3196
	750	850	284AT	3632	286AT	3922

① Prices shown are in U.S.A. dollars.

*Totally-Enclosed Non-Ventilated Series or Compound Wound
 Single Straight Shaft, Class F Insulation, 40°C Ambient
 1.00 Service Factor

SECTION 13

GLOSSARY OF TERMS

This section includes definitions of photovoltaic terminology and conversion factors to convert English units to SI units.

13.1 DEFINITIONS OF PHOTOVOLTAIC TERMINOLOGY

ALTITUDE - Angle between the horizontal plane and the direction of beam radiation.

ANGLE OF INCIDENCE - Angle between the normal to a surface and the direction of incident radiation; applies to aperture plane of a solar collector.

ARRAY - A mechanically integrated assembly of modules together with support structure, exclusive of foundation, inclusive of tracking, heat transfer, and other components, as required to form a dc power producing unit.

ARRAY FIELD SUBSYSTEM - The aggregate of all solar photovoltaic arrays and support foundations generating dc power within a photovoltaic system.

AZIMUTH (of Surface) - Angle between the North direction and the projection of the surface normal into the horizontal plane; measured clockwise from North.

BEAM - Refers to radiation received from the sun without change of direction; applied as beam irradiance or beam irradiation.

BLOCKING DIODE - A semi-conductor connected in series with a solar cell or cells and a storage battery to prevent a reverse current discharge of the battery through the cell when there is no output, or low output from the cell.

BRANCH CIRCUIT - A group of modules or paralleled modules connected in series to provide dc power at the dc voltage level of the power conditioning subsystem. A branch circuit may involve the interconnection of modules located in several arrays.

BYPASS DIODE - A semiconductor connected in parallel with a series block of parallel strings to prevent excessive current from flowing through any unfailed substring in the series block upon partial shading of another substring in the same block.

DIFFUSE - Refers to radiation received from the sun after reflection and scattering by the atmosphere; also scattered; applied as diffuse irradiance or diffuse irradiation.

ELECTRIC POWER BUS - A conductor, or group of conductors, that serve as a common connection for two or more circuits.

EQUINOX - The time when the sun in its apparent motion in the celestial sphere crosses the equator; c. March 21 is the vernal equinox (northern hemisphere) and c. September 23 is the autumnal equinox (northern hemisphere); declination is zero; vernal equinox more precisely defined as the point of intersection of the ecliptic and the equator on the celestial sphere.

FILL FACTOR - The ratio of maximum power output of a cell or array to the product of the open circuit voltage and the short circuit current.

HOUR ANGLE - The angle between the hour circle of the sun and the observer's meridian.

INSOLATION - The solar radiation incident on an area. Usually expressed in milliwatts per square centimeter or watts per square meter.

LIFE CYCLE COST - An estimate of the cost of owning and operating a system for the period of its useful life; usually expressed in terms of the present value of all lifetime costs.

MAXIMUM POWER - Refers to a photovoltaic cell; the power at the point on the current-voltage curve where the current-voltage product is a maximum.

MODULE - The smallest, complete, environmentally-protected assembly of solar cells, optics, and other components designed to generate dc power.

ORIENTATION - Placement with respect to the cardinal directions, N, S, E, W; azimuth is the measure of orientation.

PHOTOVOLTAIC CELL - A photovoltaic cell is one that generates electrical energy when light falls on it. This term distinguishes it from a photoconductive cell (photoresistor) which changes its electrical resistance when light falls on it.

PHOTOVOLTAIC SYSTEM - An installed aggregate of solar arrays and other subsystems transmitting power to a given application. A system will generally include the following sub-systems:

- Array field
- Power conditioning and control
- Storage (if required)
- Backup (if required)
- Thermal (if required, noting that portions of a thermal subsystem may be included in the fabrication of the array)
- Land, security systems and buildings
- On-site conduit/wiring
- Instrumentation
- Maintenance and repair equipment

POWER CONDITIONING - The function of a subsystem which generally renders the variable dc output of an alternate energy source to be suitable to meet the power supply requirements of more traditional loads. The power conditioning subsystem of a dc photovoltaic power system would typically include voltage regulation, energy storage and possibly a dc/dc converter interface with loads. The power conditioning subsystem of an ac photovoltaic power system may also typically include energy storage, and conversion of the dc output to an ac waveform, wave form filtering and voltage transformation to meet the requirements of the load.

SOLAR CELL - Photovoltaic cell.

SOLSTICE - The time when the sun in its apparent motion in the celestial sphere attains the maximum distance from the equator; c. June 21 is the summer solstice (northern hemisphere) and c. Dec. 22 is the winter solstice (northern hemisphere); declination is a maximum.

SPECTRAL - refers to reflection in which the angle of incidence is equal to and in the same plane as the angle of reflection; reflection as in a mirror.

TILT (of Surface) - Angle of inclination of collector.

13.2 CONVERSION FACTORS

The following tables express the definitions of miscellaneous units of measure as exact numerical multiples of coherent SI units, and provide multiplying factors for converting numbers and miscellaneous units to corresponding new numbers and SI units.

The first two digits of each numerical entry represent a power of 10. An asterisk follows each number which expresses an exact definition. For example the entry "-02 2.54*" expresses the fact that 1 inch = 2.54×10^{-2} meter, exactly, by definition. Numbers not followed by an asterisk are only approximate representations of definitions, or are the results of physical measurements. The primary source of these tables is Reference 13-1. Most of the definitions are extracted from National Bureau of Standards documents.

To convert from	to	multiply by
acre	meter ²	+03 4.046 856 422 4*
atmosphere	newton/meter ²	+05 1.013 25*
British thermal unit (thermochemical)	joule	+03 1.054 350
Btu (thermochemical)/foot ² hour	watt/meter ²	+00 3.152 480 8
calorie (International Steam Table)	joule	+00 4.1868
Celsius (temperature)	kelvin	$t_K = t_C + 273.15$
circular mil	meter ²	-10 5.067 074 8
degree (angle)	radian	-02 1.745 329 251 994 3
Fahrenheit (temperature)	kelvin	$t_K = (5/9)(t_F + 459.67)$
Fahrenheit (temperature)	Celsius	$t_C = (5/9)(t_F - 32)$
foot	meter	-01 3.048*
footcandle	lumen/meter ²	+01 1.076 391 0
footlambert	candela/meter ²	+00 3.426 259
gallon (U.S. liquid)	meter ³	-03 3.785 411 784*
horsepower (550 foot lbf/second)	watt	+02 7.456 998 7
inch	meter	-02 2.54*
kilocalorie (thermochemical)	joule	+03 4.184*
lambert	candela/meter ²	+03 3.183 098 8
langley	joule/meter ²	+04 4.184*

To convert from	to	multiply by
mil	meter	-05 2.54*
mile (U.S. statute)	meter	+03 1.609 344*
mile/hour (U.S. statute)	meter/second	-01 4.4704*
ounce force (avoirdupois)	newton	-01 2.780 138 5
ounce mass (avoirdupois)	kilogram	-02 2.834 952 312 5*
phot	lumen/meter ²	+04 1.00
pound force (lbf avoirdupois)	newton	+00 4.448 221 615 260 5*
pound mass (lbm avoirdupois)	kilogram	-01 4.535 923 7*
psi (lbf/inch ²)	newton/meter ²	+03 6.894 757 2
Rankine (temperature)	kelvin	$t_k = (5/9) t_R$
yard	meter	-01 9.144*

13-6

SECTION 14
PHOTOVOLTAIC POWER SYSTEM EQUIPMENT SUPPLIERS*

14.1 PHOTOVOLTAIC CELLS, MODULES

APPLIED SOLAR ENERGY CORP.
15251 E. Don Julian Road
P.O. Box 1212
City of Industry, CA 91749
ATTN: George Holme III
Product Marketing Manager
(213) 968-6581

SOLAREX CORP.
1335 Piccard Drive
Rockville, MD 20850
ATTN: Theodore Blumenstock
Director of Marketing
(301) 948-0202

ARCO SOLAR INC.
20554 Plummer Street
Chatsworth, CA 91311
ATTN: Tim Geiser
Eastern Region Sales Manager
(213) 998-0667

SOLAR POWER CORP.
Affiliate of Exxon Enterprises
20 Cabot Road
Woburn, MA 01801
ATTN: Kurt Grice
Marketing Services
(617) 935-4600

MOTOROLA INC.
Solar Products Operations
5005 East McDowell Road
Phoenix, AZ 85008
ATTN: Pat Walton
Solar Product Marketing
(602) 244-6511

SOLEC INTERNATIONAL, INC.
12533 Chadron Avenue
Hawthorne, CA 90250
ATTN: Ishaq Shahryar, President
(213)970-0065

PHOTON POWER
10767 Gateway West
El Paso, TX 79935
ATTN: Martin F. Wenzler
(915) 593-2861

SOLENERGY CORP.
23 North Avenue
Wakefield, MA 01880
ATTN: Bob Willis, President
(617) 246-1855

PHOTOWATT INTERNATIONAL INC.
2414 W. 14th Street
Tempe, AZ 85281
Vice President & Tec. Dir.
(602) 894-9564

SOLLOS, INC.
2231 S. Carmelina
Los Angeles, CA 90064
(213) 820-5181

SES, INC.
Tralee Industrial Park
Newark, DE 19711
ATTN: Greg T. Love
Manager, Industrial Sales
(302) 731-0990

TIDELAND SIGNAL CORP.SES, INC.
4310 Directors Road
P.O. Box 52430
Houston, TX 77052
(713) 681-6101

*See footnote on p. 14-5

14.2 BATTERIES*

CHLORIDE.
Mallard Lane
North Haven, CT 06473
(203) 624-7837

C & D BATTERIES DIV.
3043 Walton Road
Plymouth Meeting, PA 19462
ATTN: Clayton J. Molnar
Sales Manager
(215) 828-9000

DELCO-REMY
Division of G.M.
2401 Columbus Avenue
Anderson, IN 46011
ATTN: Charlie Erk
(317) 646-7816

EAGLE-PICHER INDUSTRIES, INC
Department G
P.O. Box 130
(417) 776-2258

THE EXIDE CORP.
"Horsham I"
101 Gibraltar Road
ATTN: Mr. Gene Cook
Specialty Battery Division
(215) 674-9500

GENERAL ELECTRIC CO.
Battery Business
Department G
P.O. Box 861
Gainesville, FL 32602
(904) 462-3911

GLOBE-UNION
Battery Division
Gel/Cell Marketing
5757 N. Green Bay Avenue
Milwaukee, WI 53201
ATTN: Fred Gruner
Reg. Marketing Manager
(414) 228-2393

KEYSTONE BATTERY CORP.
35 Holton Street
Winchester, MA 01890
ATTN: Edward J. Modest
Vice President

MC GRAW-EDISON COMPANY
Power Systems Division (Batteries)
P.O. Box 28
Bloomfield, NJ 07003
ATTN: Mr. Robert Enters
Chief Engineer

NIFE INCORPORATED
P.O. Box 100
George Washington Hwy.
Lincoln, RI 02865
ATTN: Richard V. Barone, Sc. D
Manager, Applications Engineering
(800) 556-6746

SGL BATTERY MANUFACTURING CO.
14650 Dequindre
Detroit, MI 48212
ATTN: Paul Rosser
Sales & Service Coordinator
(313) 868-6410

SURRETTE STORAGE BATTERY CO., INC.
Engineering Division
15 Park Street Tilton, NH 03276
ATTN: Archie McGowan
(603) 286-8974

*See footnote p. 14-5

ABACUS CONTROLS, INC.
P.O. Box 893
80 Readington Road
Somerville, NJ 08876

EMERSON ELECTRIC CO.
8100 W. Florissant Avenue
St. Louis, MO 63136

ADVANCE CONVERSION DEVICES CO. EMERSON ELECTRIC CO.
109 Eighth St. 3301 Spring Forest Road
Passaic, NJ 07055 Raleigh, NC 27604

AVIONIC INSTRUMENTS, INC.
943 East Hazelwood Ave.
Rahway, NJ 07065

GARRETT CORP.
1 Huntington Quadrangle
Suite 4 S04
Huntington Station, NY 11746

BEHLMAN ENGINEERING CORP.
P.O. Box 4518
Santa Barbara, CA 93103

LAMARCHE MFG. CO.
106 Bradock Drive
Des Plaines, IL 60018

CALIFORNIA INSTRUMENTS
5151 Convoy St.
San Diego, CA 92111

LOR TEC POWER SYSTEMS, INC.
5214 Mills Industrial Parkway
North Ridgeville, OH 44305

COMPUTER POWER INC.
124 West Main St.
High Bridge, NJ 08829

MCGRAW EDISON CO
P.O. Box 23
Bloomfield, NJ 07003

DELTA ELECTRONIC CONTROL CORP NOVA ELECTRIC MFG., CO.
2801 S.W. Main Street 263 Hillside Avenue
Irvine, CA 92714 Nutley, NJ 07110

DELTEC CORP.
980 Buenos Ave.
San Diego, CA 92110

PACIFIC POWER SOURCE DIV.
5219 Systems Drive
Huntington Beach, CA 92649

DUEL-LITE, INC.
Simm Lane Newton, CT
Newton, CT

RATELCO, INC.
1260 Mercer Street
Seattle, WA 98109

ELGAR CORP.
8225 Mercury Court
San Diego, CA 92111

RELIANCE ELECTRIC CO.
1130 F. Street
Lorain, OH 44052

*See footnote on p. 14-5

SOLEQ CORP.
5969 North Elston Avenue
Chicago, IL 60646

STACO ENERGY PRODUCTS CO.
301 Gaddis Blvd
Dayton, OH 45403

TELEDYNE, INC.
1901 Avenue of the Stars
Los Angeles, CA 90067

TOPAZ ELECTRONICS
3855 Ruffin Road
San Diego, CA 92123

TRIPP MANUFACTURING CO.
133 N. Jefferson St.
Chicago, IL 60606

UNITED TECHNOLOGY CORP.
Power Systems Division
P.O. Box 109
South Windsor, CT 06074

VARO, INC., POWER SYSTEMS DIV.
2201 Walnut St.
Garland, TX 75040

VERSACOUNT PRODUCTS
553 Libley Blvd.
Elk Grove Village, IL 60007

WESTINGHOUSE ELECTRIC CO.
P.O. Box 989
Lima, OH 45802

WILMORE ELECTRONICS CO., INC.
P.O. Box 1329
Hillsborough, NC 27278

WINDWORKS INC.
Route 3, Box 44 A
Mukwonago, WI 53149

14.4 DIRECT CURRENT MOTORS AND LOAD DEVICES*

GENERAL ELECTRIC CO.
General Purpose Motor Dept.
2000 Taylor St.
Fort Wayne, IN 46804

GOULD INC.
Electric Motor Division
1831 Chestnut St.
St. Louis, MO 63166

INLAND MOTORS
Industrial Drives Division
609 Rock Road
Radford, VA 24141

LOUIS ALLIS
Drives & Systems Division
New Berlin, WI 53151

PMI MOTORS
Division of Kollmorgen Corp.
5 Aerial Way
Syosset, NY 11791

WESTINGHOUSE ELECTRIC CORP.
Defense Group
P.O. Box 9892
Lima, OH 45802

WESTINGHOUSE ELECTRIC CORP.
Large Motor Division
Buffalo, NY 14240

*Note: This compendium is not intended to be an exhaustive listing of equipment suppliers for photovoltaic power systems, but rather a representative sampling of manufacturers in a dynamic and changing field. It is expected that additional firms will be developing products for the photovoltaic market in the future. This list does not in any way constitute endorsement of any manufacturer, any supplier, or any product by MONEGON, Ltd., or NASA, or the U.S. DOE, or any of their employees or subcontractors.

14-6

APPENDIX A
WORLDWIDE INSOLATION DATA

Note:

The data have been generated from the SOLMET (Reference A-1) and the University of Wisconsin reports (Reference A-2). The data are presented as values of monthly average K_H , the ratio of insolation on a horizontal surface to the insolation on an extraterrestrial horizontal surface. The values of the monthly average K_H are listed in per unit ($\times 10^3$).

The key to the abbreviations used is as follows:

General

- Data Missing
- * Theory Not Applicable
- [1] The data should read as if it were preceded by a decimal point. I.e., the datum 495 is $K_H = 0.495$.
- CFP Computed From Percent Sunshine
- PPS Data is in Percent Possible Sunshine (conversion values not available). Note [1] does not apply to these data as they are listed in percent, i.e. the datum 057 is 57% possible sunshine.

Specific

- LAT/LONG data for Hochserfaus, Switz. could not be found. Used LAT/LONG values for Hochdorf.
- All data under 'United States' comes from Input Data For Solar Systems (SOLMET data), Ref. A-1.
- New York City has two separate stations: Central Park (CN. PRK) and La Guardia (LGA).

APPENDIX A (CON'T)

STATION	LAT	LONG	ELEV	VALUES OF MONTHLY AVG. KH * 1000 [1]											
				JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
ADEN															
=====															
ADEN	12 50'N	45 01'E	4	573	607	627	656	634	592	562	597	618	663	668	632
ALGERIA															
=====															
ADRAR	27 52'N	0 17'W	258	716	708	730	706	699	723	721	716	686	665	666	658
AIN SEFRA	32 45'N	0 36'W	1072	693	694	690	700	687	703	704	701	702	672	672	672
AOULEF	26 58'N	1 05'E	290	700	681	697	693	689	673	691	682	694	671	653	622
BENI ABBES	30 08'N	2 11'W	498	702	690	668	690	666	656	666	664	661	629	610	639
BISKRA	34 51'N	5 44'E	124	602	619	611	590	593	609	631	638	599	584	566	574
CHOTTECH CHEROUI	34 00'N	1 00'E	-	505	577	672	622	612	638	634	663	586	719	651	566
COLOMB-BECHAR	31 36'N	2 13'W	-	669	677	680	672	676	654	664	666	644	644	633	625
DJANET	24 33'N	9 29'E	-	677	801	719	698	670	700	717	703	659	663	620	675
DJELFA	34 41'N	3 15'E	160	553	581	567	554	603	609	620	627	624	566	564	545
EL GOLEA	30 35'N	2 53'E	397	690	696	699	680	687	686	707	709	689	663	636	670
EL OUED	33 22'N	6 53'E	70	766	790	664	806	787	674	725	676	798	722	716	786
FORT FLATTERS	28 06'N	6 49'E	381	680	693	678	673	678	671	710	705	687	680	668	640
FORT DE POLIGNAC	26 30'N	8 29'E	566	674	690	694	680	668	684	703	704	692	680	663	633
GERRYVILLE	33 41'N	1 01'E	1305	558	603	587	586	613	620	621	625	630	588	548	550
GHARDAIA	32 29'N	3 40'E	527	698	700	697	697	697	694	705	711	672	679	659	678
LAGHOUAT	33 48'N	2 53'E	767	589	594	582	584	603	601	621	613	601	565	558	561
OUALLEN	24 36'N	1 14'E	347	703	808	715	697	681	681	687	681	681	685	694	630
OUARGLA	31 57'N	5 20'E	138	676	683	683	673	655	633	705	689	659	648	639	632
TAMARRASSET	22 42'N	5 30'E	1376	716	717	723	709	691	658	687	654	611	643	654	676
TIMIMOUN	29 15'N	0 14'E	284	704	710	715	699	698	699	708	696	694	664	597	643
TOUGGOURT	33 07'N	6 04'E	69	655	698	665	607	676	652	704	702	690	644	617	631
ANGOLA															
=====															
DUNDO	7 04'S	20 08'E	745	470	472	482	538	584	578	520	476	490	509	490	471
LUANDA	8 49'S	13 13'E	42	536	558	527	525	556	542	420	416	462	477	512	558
LUSO	11 08'S	19 09'E	1328	465	539	509	641	690	729	741	760	606	550	532	507
MALANGE	9 33'S	16 22'E	1151	489	543	515	509	614	664	610	549	514	514	488	506
MOCAMEDES	15 02'S	12 02'E	44	578	586	591	584	590	459	449	450	471	516	589	576
ANTARCTICA															
=====															
AMUNDSEN-SCOTT	90 00'S		2800	*	*	*	-	-	-	-	-	*	*	*	*
BASE ROI BAUDOUIN	70 26'S	24 19'E	37	*	651	532	438	*	-	*	571	619	627	669	*
BYRD STATION	79 59'S	120 01'W	1515	-	-	-	*	*	*	*	*	535	541	*	*
CHARCOT	69 22'S	139 01'E	2401	*	381	-	-	-	-	*	613	754	785	845	*
ELLSWORTH STATION	77 44'S	41 07'W	43	*	*	578	-	-	-	-	-	617	646	*	*
HALLETT STATION	72 18'S	170 19'E	5	*	449	384	383	*	*	*	-	675	680	*	*
HALLEY BAY	75 31'S	26 36'W	30	*	528	550	543	*	*	*	*	582	669	*	*
LITTLE AMERICA V	75 31'S	26 36'W	30	*	466	487	230	*	*	*	*	514	590	*	*
MAWSON	67 37'S	62 53'E	8	643	584	534	614	769	*	882	*	746	697	684	*
MIRNY	66 33'S	93 01'E	37	729	768	679	595	571	*	*	596	694	773	820	712
NORWAY STATION	70 30'S	2 32'W	58	*	614	564	513	*	*	*	581	622	673	718	*
PIONERSKAJA	69 44'S	95 30'E	2700	-	900	830	518	978	-	-	584	622	775	848	*
SCOTT BASE	77 15'S	166 48'E	16	*	*	488	429	-	-	-	*	572	719	*	*
WILKES STATION	66 16'S	110 34'W	12	-	-	476	366	333	985	412	507	529	576	545	576
ARCTIC OCEAN															
=====															
DRIFTING STATION A	84 30'N	148 00'W	2	-	-	-	*	-	-	-	-	-	-	-	-

APPENDIX A (CON'T)

VALUES OF MONTHLY AVG. KH * 1000 [1]

STATION	LAT	LONG	ELEV	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	NOTES
ARCTIC OCEAN (CON'T)																
=====																
ICE ISLAND T-3	83 00'N	102 30'W	8	*	*	*	*	*	*	*	*	602	*	*	*	
NP-6	82 18'N	123 08'E	0	*	*	642	*	*	*	*	*	451	*	*	*	
NP-7	85 40'N	24 30'W	0	*	*	*	*	*	*	*	*	490	*	*	*	
ARGENTINA																
=====																
ANDALGALA	27 36'S	66 20'W	1081	575	562	571	587	494	450	564	616	645	678	616	548	CFP
ARGENTINE IS.	65 15'S	64 16'W	10	466	459	358	413	431	*	704	570	540	590	518	558	
BARILOCHE	41 09'S	71 01'W	826	591	507	569	413	382	362	365	486	534	545	576	621	
BUENOS AIRES OBS.	34 35'S	58 29'W	25	623	599	562	543	522	482	505	540	558	568	575	614	
CASTELAR	34 36'S	58 40'W	16	600	552	554	530	473	413	513	558	571	594	584	578	
CIPOLLETTI	38 57'S	67 59'W	265	666	659	630	552	480	423	488	532	609	602	601	674	CFP
COLONIA SARMIENTO	45 35'S	69 04'W	272	543	564	522	528	518	432	495	567	527	551	528	502	CFP
COMODORO RIVADAVIA	45 47'S	67 30'W	61	-	650	-	478	-	-	329	438	537	501	632	604	
CONCORDIA	31 23'S	58 02'W	37	633	633	587	-	451	344	450	508	542	607	633	608	
CORDOBA	31 19'S	64 13'W	484	-	-	-	-	509	429	381	469	652	516	545	548	
CORRIENTES	27 28'S	58 49'W	52	590	581	570	549	535	527	524	550	565	566	590	573	
ESQUEL	42 54'S	71 21'W	568	585	579	500	479	409	403	432	495	559	577	552	562	CFP
HUINCA RENANCO	34 50'S	64 22'W	182	613	625	610	556	470	508	527	528	561	590	612	611	
LA QUIACA	22 06'S	65 36'W	3458	-	-	749	822	793	798	806	841	876	871	835	796	
LABOULAYE	34 08'S	63 24'W	0	624	583	584	612	946	-	-	640	609	644	628	627	
LAS LAJAS	38 32'S	70 23'W	713	674	676	639	586	497	448	522	549	626	636	618	691	CFP
LAS LOMITAS	24 42'S	60 35'W	130	-	-	-	-	449	360	455	466	457	469	482	537	
LAURIE IS.	60 00'S	45 00'W	8	177	171	151	181	145	165	211	274	312	211	178	196	CFP
LORETO	27 21'S	55 30'W	163	575	546	587	509	458	431	448	443	463	525	585	556	
MAR DEL PLATA	37 56'S	57 35'W	19	624	601	568	493	-	-	365	523	530	512	-	-	
MAZARUCA	33 35'S	59 24'W	4	658	591	569	483	483	394	474	499	625	607	613	633	
MENDOZA	32 53'S	68 52'W	827	702	693	318	545	518	539	544	564	657	690	686	646	
NEUGUEN	38 57'S	68 09'W	270	599	539	479	444	411	315	289	545	616	490	520	546	
ORCADAS	60 44'S	44 44'W	0	-	-	-	-	-	-	-	-	-	361	329	269	
PASO DE LOS LIBRES	29 43'S	57 06'W	66	617	594	556	568	545	518	557	575	538	572	580	521	
PATAGONES	40 48'S	62 59'W	34	584	587	571	556	519	514	473	552	553	544	567	579	
PILAR	31 40'S	63 53'W	338	617	579	545	553	485	441	521	573	594	618	590	582	
POSADAS	27 22'S	55 56'W	117	551	570	568	530	511	479	517	512	508	543	560	545	
PUELCHES	38 08'S	65 66'W	160	-	731	-	-	447	383	328	456	513	614	647	683	
PUERTO MADRYN	42 46'S	65 02'W	8	576	572	558	543	531	641	552	539	557	566	550	379	
RAFAELE	31 15'S	61 30'W	130	431	440	390	333	356	266	427	361	380	398	430	432	
RESISTENCIA	27 28'S	58 29'W	49	538	469	465	347	343	409	415	454	476	528	523	515	
ROSARIO	32 56'S	60 42'W	222	594	589	573	536	509	500	495	524	561	559	570	536	
SAN CARLOS DE BAR LO	41 09'S	71 18'W	825	594	615	573	502	441	339	410	473	544	576	604	553	CFP
SAN JUAN	31 36'S	68 33'W	630	541	529	543	517	556	684	642	552	636	611	559	499	
SAN LUIZ	33 16'S	66 21'W	716	-	-	-	525	436	437	453	486	656	663	644	733	
SAN MIGUEL	34 33'S	58 42'W	27	539	515	461	388	406	344	380	422	483	496	456	511	
SANTA CRUZ	50 01'S	68 32'W	11	348	580	524	456	372	360	280	*	516	552	508	476	CFP
SANTIAGO DEL ESTERO	27 47'S	64 18'W	0	560	550	548	521	502	490	548	570	553	590	580	563	
TRELEW	43 14'S	63 18'W	39	676	609	582	509	403	336	345	492	572	536	555	515	
TRES CRUCES	23 05'S	65 44'W	4580	802	565	720	934	913	907	892	-	942	860	782	753	
TUCUMAN	26 50'S	65 12'W	421	365	571	524	473	431	419	543	054	567	552	550	510	
ATLANTIC OCEAN NORTH																
=====																
A	62 00'N	33 00'W	6	256	408	266	327	414	240	347	433	-	154	335	-	
I	59 00'N	19 00'W	6	355	201	420	326	371	340	401	399	433	270	356	261	
J	52 30'N	20 00'W	6	351	-	419	-	187	481	446	401	359	342	258	292	

APPENDIX A (CON'T)

VALUES OF MONTHLY AVG. KH * 1000 [1]

STATION	LAT	LONG	ELEV	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	NOTES
ATLANTIC OCEAN NORTH (CON'T)																
=====																
K	45 00'N	16 00'W	6	-	484	434	482	555	-	-	600	525	442	-	-	
AUSTRALIA																
=====																
ALICE SPRINGS	23 48'S	133 53'E	546	642	653	658	656	628	645	664	718	713	661	637	631	
ASPENDALE	38 02'S	145 06'E	-	663	598	514	565	470	472	496	489	469	517	491	566	
BOX HILL	37 48'S	145 08'E	100	549	541	538	458	423	423	444	471	493	507	508	542	
BRISBANE	27 28'S	153 02'E	-	551	550	546	549	553	549	564	567	565	566	560	554	
DARWIN	12 26'S	130 52'E	27	464	488	541	547	632	658	675	704	653	612	563	509	
DRY CREEK S. A.	34 50'S	138 35'E	4	672	648	632	717	521	526	524	559	586	565	612	632	
GUILDFORD	31 56'S	115 57'E	15	649	652	637	562	526	529	542	581	602	615	636	659	
GARBUTT	19 15'S	146 46'E	4	511	518	557	596	584	626	644	664	689	660	644	623	
MELBOURNE	37 49'S	144 58'E	35	625	592	423	519	529	528	531	507	520	523	479	510	
MOUNT STROMLO	35 21'S	149 10'E	-	611	598	587	594	609	567	590	610	643	606	615	616	
SYDNEY	33 52'S	151 12'E	42	428	537	527	529	522	542	559	573	554	551	540	535	
WILLIAMTOWN	32 49'S	151 50'E	4	513	483	559	507	526	513	550	615	551	620	593	527	
AUSTRIA																
=====																
GMUNDEN	47 55'N	13 47'E	425	369	400	431	401	453	395	406	425	453	370	725	275	
GRAFENHOF	47 19'N	13 10'E	766	412	584	474	481	450	369	414	413	585	489	374	351	
GUMPENSTEIN	47 30'N	14 06'E	710	388	442	483	453	493	400	420	442	441	422	317	319	
KLAGENFURT	46 38'N	14 19'E	448	446	505	563	452	510	434	488	485	481	439	226	271	
KRIPPENSTEIN	47 32'N	13 41'E	2064	591	581	551	550	510	380	388	410	506	556	530	486	
LUNZ-AM-SEE	47 50'N	15 00'E	615	284	391	464	384	444	399	368	395	388	402	270	241	
MONICKIRCHEN	47 32'N	16 02'E	978	498	418	464	415	469	378	415	449	446	495	395	454	
NEUSIEDLAM SEE	47 57'N	16 51'E	116	365	284	449	452	559	431	470	508	400	394	231	281	
OBBERGUGL	46 52'N	11 02'N	1950	409	494	563	605	533	300	456	457	448	468	359	324	
OBERSIEBEN-BRUHN	48 46'N	16 43'E	150	358	330	441	428	489	421	425	477	444	379	230	242	
PERTISAU/ACHENSEE	47 26'N	11 42'E	933	475	377	516	425	430	354	345	370	424	434	339	303	
RETZ	48 46'N	15 58'E	243	262	347	379	402	493	445	433	459	454	679	183	211	
SALZBURG	47 48'N	13 00'E	437	395	431	446	420	452	387	396	274	434	423	260	311	
SEMMERING	47 39'N	15 50'E	995	326	359	362	386	454	368	381	422	383	450	299	243	
SONNBLICK	47 03'N	12 57'E	3106	594	660	621	586	561	461	421	433	561	587	537	520	
STEYR	48 04'N	14 35'E	309	368	392	427	463	456	417	417	457	451	385	225	240	
VIENNA	48 15'N	16 22'E	-	292	359	398	438	473	461	473	467	581	355	273	248	
YBBS-PERSENBEUG	48 11'N	15 13	228	374	383	435	482	490	408	414	448	443	377	244	227	
AZORES																
=====																
ANGRA	38 07'N	27 02'W	92	416	431	438	498	544	582	533	546	533	499	429	433	
CORVO	39 40'N	31 07'W	28	442	431	469	514	536	525	563	582	559	483	415	403	
PONTA DELGADA	37 45'N	25 40'W	36	488	497	514	507	554	520	570	610	616	586	479	488	
BELGIUM																
=====																
BRUSSEL-UCCLE	50 48'N	4 22'E	100	290	323	353	392	422	402	402	403	390	344	277	241	
BOLIVIA																
=====																
LA PAZ	16 31'S	68 93'W	3658	425	457	519	556	658	756	611	542	611	613	552	516	CEP
BRAZIL																
=====																

APPENDIX A (CON'T)

VALUES OF MONTHLY AVG. KH * 1000 [1]

STATION	LAT	LONG	ELEV	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	NOTES
BRAZIL (CON'T)																
=====																
ALEGRETE	29 47'S	55 47'W	-	607	616	594	569	546	519	536	559	552	573	600	608	
ARACAJU	10 55'S	37 03'W	-	625	588	515	454	384	353	374	418	483	550	609	649	
ARAXA	19 36'S	46 56'W	-	425	533	519	539	590	552	569	567	501	477	501	371	CFP
BAGE	31 20'S	54 06'W	-	586	576	552	553	548	521	516	541	521	543	580	586	
BARBACENA	21 15'S	43 46'W	-	464	490	482	514	561	608	622	592	472	453	418	377	CFP
BARRA CORDA	5 30'S	45 16'W	-	404	400	393	414	441	526	550	509	496	491	465	473	CFP
BAURU	22 19'S	49 04'W	-	489	473	516	607	595	591	605	609	523	512	554	505	
BELEM	1 28'S	48 29'W	-	518	459	456	495	576	652	682	682	672	673	652	642	
BELO HORIZONTE	19 56'S	43 57'W	-	504	516	521	550	585	612	626	617	550	509	495	451	
BLUMENAU	26 55'S	49 04'W	-	470	489	511	479	460	477	434	437	398	430	433	458	CFP
CABO FRIO	22 52'S	42 01'W	-	488	516	517	514	518	543	540	538	462	446	471	455	
CAMPINAS	22 53'S	47 05'W	-	558	558	565	584	602	599	613	600	564	568	563	544	
CAMPOS	21 45'S	41 20'W	-	480	515	479	493	523	529	545	528	444	422	441	437	
CAMPOS DE JORDAO	22 52'S	43 22'W	-	438	442	470	473	518	543	558	569	487	457	440	405	
CANANEIA	25 01'S	47 56'W	5	502	477	446	446	426	448	449	421	342	374	462	453	
CATALAO	18 10'S	47 57'W	-	488	506	539	591	613	640	637	644	567	540	518	476	
CAXIAS	4 52'S	43 22'W	-	504	506	500	515	543	584	615	624	608	589	559	543	
CAXIAS	29 10'S	51 12'W	-	529	530	529	518	519	532	540	534	521	525	539	531	
CORRENTES	9 06'S	36 21'W	-	540	492	472	446	396	444	394	428	574	577	626	568	CFP
CORUMBA	19 00'S	57 39'W	-	405	411	415	424	435	429	448	449	422	419	424	413	
CRUZ ALTA	28 38'S	53 37'W	-	559	561	539	528	531	502	540	546	504	547	570	571	
CUIABA	15 36'S	56 06'W	-	396	391	402	490	527	518	541	484	445	483	474	422	CFP
CURITIBA	25 26'S	49 16'W	-	504	506	502	504	511	519	536	530	500	506	510	509	
DIAMANTINA	18 15'S	43 36'W	-	458	580	512	459	514	538	536	620	528	477	405	374	CFP
FLORINOPOLIS	27 36'S	48 34'W	-	513	523	545	521	537	502	502	488	466	472	485	509	CFP
FORTALEZA	3 46'S	38 31'W	-	565	520	500	489	525	577	582	607	618	624	608	606	
GOIANIA	16 40'S	49 15'W	-	491	507	353	569	613	637	635	631	549	528	500	450	
GOIAS	15 56'S	50 08'W	-	483	486	512	552	591	628	595	611	546	528	501	462	
GRAJAU	5 49'S	46 09'W	-	387	366	402	439	492	560	609	569	530	474	482	456	CFP
GUANABARA OBS.	22 54'S	43 10'W	-	498	505	506	514	518	524	541	523	462	446	471	474	
GUARAMIRANGA	4 16'S	39 01'W	-	468	426	389	405	442	449	490	479	482	498	491	483	CFP
IGUATU	6 22'S	39 18'W	-	550	523	534	545	581	587	604	623	612	609	595	577	
ILHEUS	14 48'S	39 02'W	-	590	565	543	544	555	587	553	627	569	590	524	549	CFP
JUIZ DE FORA	21 46'S	43 21'W	-	430	452	444	466	474	511	492	498	419	411	411	387	
JOAO PESSOA	7 06'S	34 52'W	-	589	586	568	561	562	554	558	579	591	596	601	593	
LAGES	27 49'S	50 20'W	-	521	508	511	492	502	490	528	537	499	522	529	524	
LAGUNA	28 29'S	48 47'W	-	521	508	554	560	613	601	554	520	525	497	546	541	CFP
LORENA	22 42'S	45 05'W	-	459	473	470	485	500	485	538	521	435	445	471	435	
MACEIO	9 34'S	35 47'W	-	602	581	569	568	562	557	560	564	572	595	594	594	
MANAUS	3 08'S	60 02'W	-	418	398	400	407	462	525	556	571	538	513	473	446	
NATAL	5 46'S	35 12'W	-	588	580	556	553	562	566	570	593	610	621	621	605	
NITEROI HORTO BOTANI	22 54'S	43 07'W	-	478	484	494	501	485	487	505	523	449	446	450	445	
OLINDA	8 01'S	34 51'W	-	624	531	526	527	512	519	468	568	620	616	600	625	CFP
OURO PRETO	20 23'S	43 30'W	-	398	487	418	467	472	538	519	552	452	417	379	339	CFP
PALMAS	26 29'S	51 56'W	-	522	528	530	526	523	534	569	557	519	530	540	526	
PARANAGUA	25 31'S	48 31'W	-	453	455	502	479	503	545	477	445	441	421	425	433	CFP
PASSO FUNDO	28 16'S	52 25'W	-	550	540	537	525	526	518	535	542	515	534	549	542	
PESQUERIA	8 24'S	36 46'W	-	568	535	547	517	436	474	479	557	631	684	631	629	CFP
PERTOPOLIS	22 31'S	43 11'W	-	449	410	469	484	514	538	536	535	460	434	430	416	
PIRACICABA	21 43'S	47 38'W	-	489	541	601	556	553	617	648	677	566	538	546	471	CFP
POCOS DE CALDAS	21 47'S	46 33'W	-	407	478	495	561	557	581	604	612	520	553	507	433	CFP
PORTO NACIONAL	10 42'S	48 25'W	-	510	482	493	539	615	645	645	652	577	528	492	490	
RIO GRANDE	32 02'S	52 06'W	-	585	577	555	559	538	533	504	531	469	556	580	595	
SALVADOR	12 56'S	38 31'W	-	616	582	586	569	521	579	553	618	603	616	575	583	CFP

APPENDIX A (CON'T)

STATION	LAT	LONG	ELEV	VALUES OF MONTHLY AVG. KH * 1000 [1]												NOTES
				JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	
BRAZIL (CON'T)																
=====																
SAN PAULO	23 33'S	46 38'W	-	467	484	461	491	474	514	476	466	490	491	481	463	
SANTA CRUZ	22 56'S	43 22'W	-	478	494	506	501	519	544	541	538	449	435	461	445	
SANTA MARIA	29 41'S	53 49'W	-	548	552	531	522	506	495	513	505	497	526	549	559	
SANTAREM	2 45'S	54 43'W	-	434	400	389	405	433	466	498	530	525	515	499	474	
SANTOS	23 56'S	46 20'W	-	437	453	462	465	495	519	480	469	402	425	439	403	
SAO LUIZ	2 32'S	44 18'W	-	468	434	411	428	457	517	536	530	513	503	511	520	
SOURE	0 44'S	48 31'W	-	548	473	456	493	582	657	674	701	705	699	693	686	
TEREZINA	5 05'S	42 49'W	-	522	515	511	542	587	619	583	655	621	599	588	560	
TERE-ZOPOLIS	22 27'S	42 56'W	-	449	463	446	470	481	500	500	504	447	412	420	396	
UAUPES	0 08'S	67 05'W	-	454	473	456	436	437	442	462	499	500	484	484	461	
UBERABA	19 45'S	47 56'W	-	484	516	520	562	630	592	606	615	549	531	526	482	
URUGUAIANA	29 45'S	57 05'W	-	587	595	569	553	546	519	557	558	552	538	580	502	
VASSOURAS	22 24'S	43 40'W	-	459	484	481	484	513	537	535	488	460	445	451	446	
VITORIA	20 19'S	40 19'W	-	503	526	510	512	525	423	528	546	489	454	453	460	
BRITISH GUIANA																
=====																
GEORGETOWN	7 45'N	58 04'W	-	495	512	498	504	470	469	513	536	555	538	521	480	
MAZARUNI	5 58'N	59 37'W	-	433	421	427	416	453	442	451	437	419	427	437	455	
BULGARIA																
=====																
KARDJALI	41 39'N	25 22'E	231	379	446	393	382	-	436	418	463	447	390	270	206	
POLIANOVGRAD	42 31'N	26 51'E	196	484	626	504	532	592	557	607	603	612	555	461	520	
SOFIA OBS.	42 49'N	23 23'E	582	342	521	442	041	460	503	574	555	485	436	321	324	
SOMMET STALIN	42 11'N	23 35'E	2925	335	524	550	491	409	344	439	490	481	495	490	450	
TCHERNI-VRAH	42 34'N	23 17'E	2286	670	813	665	603	539	523	669	664	617	718	650	632	
TCHIRPAN	42 12'N	25 20'E	170	425	626	539	484	598	569	642	647	601	575	474	396	
VARNA	43 12'N	27 55'E	51	429	520	458	420	447	475	488	594	554	*	365	388	
BURMA																
=====																
RANGOON	17 00'N	96 00'E	30	727	743	701	678	576	424	414	386	405	595	697	708	
CANADA																
=====																
AKLAVIK	68 14'N	135 00'W	9	*	612	719	697	622	*	482	432	386	381	441	*	
CHURCHILL	58 45'N	94 04'W	35	697	704	731	676	587	543	541	499	427	383	435	515	
DARTMOUTH	44 36'N	63 28'W	31	414	444	467	478	491	454	498	498	512	474	354	387	
DEPARTURE BAY	49 13'N	123 57'W	-	359	370	418	429	560	320	640	597	457	438	360	-	
EDMONTON	53 34'N	113 31'W	676	551	611	640	582	570	522	556	512	506	503	529	497	
FORT SIMPSON	61 52'N	121 21'W	129	534	534	615	623	586	534	497	502	451	431	309	290	
GOOSE BAY	53 19'N	60 25'W	44	424	548	591	534	492	437	443	412	406	371	375	441	
GUELPH	43 33'N	80 16'W	320	475	475	531	473	495	529	570	530	512	461	367	384	
KAPUSKASING	49 25'N	82 28'W	229	500	546	573	496	451	486	502	484	425	371	297	422	
NOB LAKE	54 48'N	66 49'W	512	414	518	658	602	451	438	381	418	366	336	364	429	
LETHBRIDGE	49 38'N	112 48'W	920	553	609	632	564	572	587	638	631	585	560	526	483	
MONCTON	46 07'N	64 41'W	76	374	455	499	491	477	454	488	485	463	441	347	381	
MONTREAL	45 30'N	73 37'W	133	398	495	543	514	509	494	530	519	459	413	307	326	
MOOSONEE	51 16'N	80 39'W	10	490	529	589	541	449	477	457	424	439	369	309	427	
NANAIMO	49 00'N	123 00'W	-	363	359	434	570	594	526	680	590	460	444	389	292	
NORMANDIN	48 51'N	72 32'W	137	504	842	648	473	504	470	475	470	445	387	378	456	
OTTAWA	45 27'N	75 37'W	98	519	563	568	518	538	563	568	553	525	456	377	443	
RESOLUTE BAY	74 43'N	94 59'W	64	*	*	*	766	*	*	*	413	397	443	*	*	

APPENDIX A (CON'T)

VALUES OF MONTHLY AVG. KH * 1000 [1]

STATION	LAT	LONG	ELEV	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	NOTES
CANADA (CON'T)																
=====																
ST. JOHN'S WEST	47 31'N	52 47'W	114	324	400	425	420	436	434	458	406	428	372	270	324	
SASKATOON	52 08'N	106 38'W	515	551	631	632	575	556	538	589	557	537	507	456	493	
SUFFIELD	50 16'N	111 11'W	775	553	700	605	623	582	546	634	605	521	498	517	535	
SUMMERLAND	49 34'N	119 39'W	454	367	405	501	577	539	536	586	582	521	419	374	320	
TORONTO	43 40'N	79 24'W	116	399	430	478	470	515	524	546	506	496	441	349	350	
VANCOUVER	49 33'N	123 30'W	-	349	300	347	460	515	488	570	482	398	372	355	298	
WINNIPEG	49 54'N	97 14'W	240	615	659	679	592	562	532	595	574	507	482	454	504	
CANTON ISLAND																
=====																
CANTON ISLAND	2 46'S	171 43'W	9	674	690	698	699	694	706	699	715	729	730	685	670	
CAPE VERDI ISLANDS																
=====																
MINDELO	16 52'N	25 00'W	2	634	669	739	752	745	689	637	581	629	617	612	582	
PRRIA	14 54'N	23 31'W	27	666	686	738	746	703	684	590	548	590	635	614	575	
CAROLINE ISLANDS																
=====																
TRUK	7 23'N	151 54'E	110	057	063	056	058	050	056	055	050	056	053	050	048	PPS
YAP	9 30'N	138 07'E	35	056	065	067	061	058	056	042	041	048	055	055	056	PPS
CENTRAL AFRICA																
=====																
BANGUI	4 22'N	18 34'E	-	474	516	562	552	549	496	460	462	496	521	480	467	
CEYLON																
=====																
BATTICALOA	7 43'N	81 42'E	3	558	607	622	605	619	598	606	604	611	584	583	545	
COLOMBO	6 54'N	79 52'E	7	589	625	620	595	565	556	576	573	589	558	589	589	
CHAD																
=====																
FORT LAMY	12 08'N	15 02'E	297	689	711	725	668	666	649	605	556	625	699	729	713	
CHILE																
=====																
ATACAMA DESERT	23 40'S	69 45'W	-	757	755	748	765	749	748	809	849	818	801	779	780	
SANTIAGO	33 27'S	70 40'W	520	662	708	652	607	473	432	455	473	478	608	591	669	
CHINA																
=====																
AIGUN	50 15'N	127 29'E	131	529	595	547	487	485	506	482	500	479	476	505	506	
CHANGCHUN	43 52'N	125 20'E	215	533	562	543	519	506	504	497	502	521	514	515	521	
CHEFOO	37 34'N	121 31'E	27	510	526	532	553	531	516	496	498	522	531	501	498	
CHINCHOW	41 08'N	121 07'E	52	558	559	548	531	513	504	496	494	530	537	515	551	
CHINKIANG	32 10'N	119 40'E	12	362	411	397	442	433	398	446	478	444	495	506	477	
DARIEN	38 54'N	121 14'E	97	550	557	566	569	525	540	498	463	539	553	528	524	
HANKOW	30 35'N	114 17'E	36	487	448	457	484	507	502	478	520	476	467	505	454	
HARBIN	44 50'N	126 38'E	145	559	580	536	511	497	504	498	505	499	507	507	510	
HULUN	49 13'N	119 44'E	619	539	598	552	508	516	516	502	508	487	507	661	520	
KHINGAN	48 50'N	121 40'E	984	526	589	565	519	493	496	491	506	484	478	576	556	
KOSHAN	48 04'N	125 52'E	223	543	571	538	502	492	505	490	492	493	511	519	528	
LUSKAING	47 20'N	123 56'E	147	560	582	476	511	501	505	458	501	503	522	501	548	

APPENDIX A (CON'T)

VALUES OF MONTHLY AVG. KH * 1000 [1]

STATION	LAT	LONG	ELEV	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	NOTES
CHINA (CON'T)																
=====																
MANCHOULI	49 35'N	117 26'E	641	552	687	575	524	495	506	513	497	490	536	674	534	
MUKDEN	41 47'N	123 24'E	43	544	548	538	509	514	504	496	508	521	564	527	501	
NAIJUMATU	50 28'N	120 06'E	-	537	681	549	516	508	496	503	488	465	503	472	515	
SHANGHAI	31 17'N	121 28'E	3	477	387	461	474	497	429	540	577	541	518	476	464	
SUIFENHO	44 23'N	131 09'E	-	546	548	532	509	475	484	498	492	481	521	497	497	
TRILEN	38 54'N	121 38'E	96	536	525	543	534	521	515	475	501	530	528	524	498	
TIENTSIN	39 09'N	117 09'E	3	542	528	530	523	532	515	506	501	518	531	528	503	
TSINAN	36 40'N	116 58'E	-	543	514	525	525	498	516	516	507	530	538	531	508	
TSINGTAU	36 04'N	120 19'E	77	580	544	549	535	509	506	527	529	514	565	544	548	
COLOMBIA																
=====																
BOGOTA	4 38'N	74 05'W	2560	554	517	469	423	441	474	487	478	470	408	464	500	
CONGO																
=====																
ALBERTVILLE	5 53'S	29 11'E	790	486	527	522	527	672	642	644	588	612	537	471	531	
BAMBESA	3 27'N	25 43'E	621	483	-	506	507	543	504	433	465	496	524	554	531	
BOENDE	0 13'S	20 51'E	379	467	489	476	500	480	494	429	455	500	471	450	424	
BUKAVU	2 31'S	28 51'E	1635	-	-	487	509	561	575	551	530	427	508	487	481	
BUNIA-RUAMPARA	1 32'N	30 10'E	1225	516	549	544	575	554	520	479	515	524	507	525	550	
COQUILHATVILLE	0 03'N	18 16'E	325	441	489	497	490	503	460	434	439	466	472	479	459	
ELIZABETHVILLE-KARAV	11 39'S	27 25'E	1260	468	439	509	571	659	691	690	684	650	620	515	464	
GANDAJIKA	6 45'S	23 57'E	780	481	467	513	624	586	568	542	502	501	505	513	517	
KAMINA-BAKA	8 38'S	25 15'E	1085	459	415	524	615	721	684	701	597	557	512	508	477	
KINDU	2 57'S	25 55'E	475	-	-	-	-	-	417	350	435	463	459	421	405	
KIYAKA-PLATEAU	5 16'S	18 57'E	735	-	-	-	480	559	536	509	503	477	506	501	476	
LEOPOLDVILLE	4 22'S	15 15'E	445	422	464	498	505	466	423	377	416	421	425	464	438	
LULUABOURG	5 53'S	22 25'E	670	488	508	512	530	605	551	531	510	543	522	515	486	
LWIRO	2 03'S	28 08'E	1680	515	502	528	528	497	492	520	496	536	514	538	536	
RUBONA	2 29'S	29 46'E	1706	497	495	531	504	557	589	573	580	550	526	513	545	
SIMAMA	9 37'S	27 01'E	852	-	-	-	575	662	666	640	606	551	451	461	450	
STANLEYVILLE	0 31'N	25 11'E	415	459	496	507	513	509	468	424	419	481	486	491	461	
YANGAMBI	0 49'N	24 29'E	500	478	508	510	511	530	499	438	433	464	462	489	442	
CONGO REPUBLIC																
=====																
BRAZZAVILLE	4 15'S	15 14'E	320	479	486	509	544	472	445	387	430	446	443	504	474	
CZECHOSLAVAKIA																
=====																
BRATISLAVA	48 10'N	17 06'E	289	378	393	429	481	551	498	509	563	489	426	258	232	
DOKSANY	50 27'N	14 10'E	158	331	405	441	494	525	510	461	498	500	374	228	217	
HURBANOVO	47 52'N	18 12'E	120	392	410	486	539	593	544	539	576	539	488	312	308	
LOMNICKY STIT	49 12'N	20 13'E	2638	637	646	662	594	526	407	453	438	527	596	576	587	
MILESOVKA	50 33'N	13 56'E	835	417	497	475	482	516	508	459	491	517	433	285	299	
NOVY HRADEC KRALOVE	50 11'N	15 50'E	280	359	409	463	480	523	489	454	496	472	385	256	257	
PODERSAM	50 13'N	13 24'E	320	254	351	397	390	450	409	428	441	402	309	233	230	
PRAHA-KARLOV	50 04'N	14 26'E	254	271	336	398	424	468	455	420	455	446	329	215	200	
SKALNATE PLESO	49 11'N	20 15'E	1783	564	609	546	496	444	352	376	397	427	501	491	477	
EQUADOR																
=====																
AMBATO	1 15'S	78 44'W	2621	395	362	286	419	344	306	309	337	279	374	408	419	CFP

APPENDIX A (CON'T)

VALUES OF MONTHLY AVG. KH * 1000 [1]

STATION	LAT	LONG	ELEV	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	NOTES
EQUADOR (CON'T)																
=====																
QUITO	0 17'S	78 32'W	2851	585	490	397	428	437	476	585	584	449	467	484	487	CFP
EL SALVADOR																
=====																
SAN SALVADOR	13 34'N	89 13'W	698	696	692	653	689	582	499	589	664	519	621	688	727	
FALKLAND ISLANDS																
=====																
PORT STANLEY	51 42'S	57 52'W	-	455	431	468	431	421	384	401	453	504	515	491	459	
FINLAND																
=====																
HELSINGFORS	60 18'N	24 57'E	40	250	358	485	443	456	480	474	397	359	293	185	230	
HELSINKI	60 12'N	24 55'E	60	305	432	561	536	500	519	518	484	432	337	219	174	
JOKIONEN	60 49'N	23 28'E	104	279	387	530	493	475	501	487	441	415	266	190	221	
LUONETJARVI	62 25'N	25 39'E	145	340	436	558	485	448	509	472	482	418	263	189	239	
SODANKYLA	67 22'N	26 39'E	180	833	473	527	548	459	*	481	419	344	325	300	*	
FORMOSA																
=====																
KOSHUN	22 00'N	120 45'E	22	538	554	585	499	500	530	485	382	475	472	487	535	
KWARENKO	23 58'N	121 37'E	176	475	394	342	397	472	601	571	587	550	558	490	485	
SHINCHIKU	24 48'N	120 58'E	-	461	369	291	473	484	633	507	512	561	-	-	-	
TAICHU	24 09'N	120 41'E	-	461	474	363	435	483	439	464	417	489	486	468	446	
TAINAN	23 00'N	120 13'E	13	649	623	496	495	522	520	425	435	532	590	590	672	
TAIPEI	25 02'N	121 31'E	23	327	323	331	352	405	410	421	453	410	472	488	416	
TAITO	22 45'N	121 09'E	10	524	468	416	436	514	681	599	527	560	615	557	524	
FRANCE																
=====																
AGEN	44 10'N	0 40'E	-	372	426	496	508	485	504	560	550	494	459	377	302	
ALENCON	48 25'N	0 05'E	-	341	414	452	477	482	475	501	493	434	427	352	295	
ANGERS	47 30'N	0 35'W	-	364	426	478	538	491	495	531	526	473	459	370	369	
ANGOULEME	45 40'N	0 10'E	-	438	448	511	541	509	525	561	543	505	477	402	371	
AUXERRE	47 15'N	3 35'E	-	358	422	493	523	501	505	541	525	487	456	366	318	
BAGNERES-DE-BIGORRE	43 05'N	0 05'E	-	417	434	470	440	419	434	455	453	430	466	444	357	
BAUGE	47 35'N	0 05'W	-	365	427	461	552	491	495	531	526	474	438	338	325	
BERGERAC	44 50'N	0 30'E	-	384	411	503	511	475	504	539	517	484	446	388	353	
BESANCON	47 20'N	6 02'E	-	360	397	512	498	501	525	552	537	503	479	367	320	
BREST	48 35'N	4 30'W	-	345	389	472	465	471	455	470	494	435	429	355	348	
CHATEAU-CHINON	47 09'N	0 13'E	-	396	394	492	497	479	495	531	500	471	476	397	316	
CHATEAU ROUX	46 50'N	1 40'E	-	389	415	489	482	468	495	531	499	469	450	359	310	
CLERMONT-FD	49 25'N	2 25'E	-	364	460	499	496	473	496	544	521	488	487	408	422	
DIJON	47 20'N	5 02'E	-	360	423	529	524	512	535	562	549	518	479	367	320	
LA MOTHE-ACHARD	46 44'N	0 17'W	-	425	440	505	547	533	505	562	535	483	470	390	396	
LE MANS	48 00'N	0 10'E	-	375	380	483	541	492	495	532	503	462	444	380	334	
LE PUY	45 05'N	3 50'E	-	389	463	522	512	497	545	591	553	530	490	422	398	
LIMOGES	48 50'N	1 15'E	-	438	449	511	519	482	496	543	531	515	523	432	405	
LILLE	50 04'N	3 03'E	-	380	413	432	473	463	466	461	450	414	426	308	333	
LYON	45 45'N	4 50'E	-	366	399	529	541	531	545	592	567	520	458	341	331	
LUXEMBOURG-VILLE	49 35'N	6 08'E	-	322	376	464	470	473	466	481	473	427	419	300	321	
MARSEILLE	43 20'N	5 20'E	-	454	506	521	541	516	585	642	593	575	488	476	434	
MONTLIMAR	44 33'N	4 47'E	-	413	575	550	573	540	605	664	609	599	524	442	386	
MONTPELLIER	43 35'N	3 50'E	-	493	557	556	581	560	635	704	629	605	511	481	440	

APPENDIX A (CON'T)

STATION	LAT	LONG	ELEV	VALUES OF MONTHLY AVG. KH * 1000 [1]												NOTES
				JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	
FRANCE (CON'T)																
=====																
MONTPELLIER	43 15'N	3 50'E	-	485	528	488	528	516	605	663	570	545	468	475	432	
NANTES	47 15'N	1 35'W	-	398	422	440	497	501	495	531	501	441	434	366	363	
NICE	43 42'N	7 18'E	-	545	559	539	558	567	637	671	663	567	530	489	494	
NIMES	43 50'N	4 20'E	-	499	538	542	569	538	615	684	607	579	494	486	445	
PARIS-ST. MAUR	48 49'N	2 30'E	50	328	367	452	449	472	486	476	461	454	387	306	313	
PERPIGNAN	42 45'N	2 50'E	-	505	565	548	551	526	565	621	580	570	519	520	456	
POITIERS	46 40'N	2 50'E	-	385	439	504	546	511	515	562	535	513	491	388	350	
REIMS	49 20'N	4 02'E	-	362	401	461	495	483	465	491	472	441	416	333	315	
ROUEN	49 30'N	1 05'E	-	320	375	444	483	473	466	481	460	426	395	336	319	
ST. QUENTIN	49 50'N	3 20'E	-	327	380	429	471	451	445	461	437	413	399	304	327	
ST. RAPHAEL	43 25'N	6 50'E	-	489	577	587	605	581	645	725	664	647	548	534	472	
STRASBOURG	48 40'N	7 00'E	-	347	390	454	452	493	506	522	518	451	453	321	300	
SUR SEINE	48 48'N	0 06'W	-	358	423	439	496	556	524	482	494	463	477	356	237	
TARARE	45 55'N	4 25'E	-	370	402	480	490	477	515	561	532	507	460	375	334	
TOULON	43 05'N	5 55'E	-	513	571	567	590	580	645	714	651	630	543	527	499	
TOULOUSE	43 40'N	0 45'E	-	396	465	524	518	495	504	559	560	534	492	426	368	
TOURS	47 20'N	0 45'E	-	360	423	476	537	480	485	531	501	472	457	334	320	
VICHY	46 10'N	3 25'E	-	375	405	482	518	499	525	561	545	494	463	380	339	
VILLEFRANCHE-DE-ROUE	44 20'N	3 25'E	-	375	404	498	508	485	504	560	538	510	461	379	343	
GERMANY																
=====																
BOCHUM	51 29'N	7 13'E	118	205	258	317	378	356	362	341	357	335	288	217	187	
BRAUNLAGE	51 43'N	10 37'E	-	262	359	416	435	399	408	372	396	358	368	250	260	
BRAUNSCHWEIG-VOLKENR	52 18'N	10 27'E	97	385	378	420	434	459	455	447	422	473	396	246	247	
COLLM OBS.	51 19'N	13 00'E	247	326	427	439	422	461	506	426	469	505	368	248	251	
DRESDEN	51 07'N	13 41'E	271	306	328	398	435	441	441	432	442	430	392	270	265	
FICHELBERG	50 26'N	12 57'E	1214	307	573	479	460	422	433	421	413	534	436	318	268	
FREIBURG	48 01'N	7 52'E	285	237	304	457	413	446	494	471	482	474	408	249	306	
GOTHA	50 57'N	10 41'E	335	353	414	403	433	440	466	450	441	466	380	222	232	
GRIEFSWALD	54 06'N	13 23'E	23	246	317	424	460	509	525	493	493	448	385	257	223	
HAMBURG-FUHLBUTTEL	53 38'N	10 00'E	14	317	355	405	449	462	439	425	423	434	367	263	250	
HANNOVER-LANGENHAGEN	52 28'N	9 42'E	-	254	362	382	448	429	403	392	418	394	444	284	264	
HEILIGENDAMM	54 09'N	11 51'E	21	280	300	363	475	566	535	487	456	519	415	218	240	
HOEFCHEN	51 06'N	7 06'E	-	250	259	339	390	413	379	409	402	393	321	175	205	
HOHENPEISSENBERG	47 48'N	11 01'E	1005	498	512	535	473	479	456	467	502	494	485	414	438	
KARLSRUHE	49 01'N	8 25'E	130	301	418	440	456	551	524	549	447	473	462	251	267	
KONIGSTEIN-TAUNUS	50 11'N	8 29'E	-	325	356	435	469	472	464	465	471	452	397	271	235	
LEIPZIG	51 18'N	12 28'E	146	259	349	387	438	494	479	452	463	479	380	211	202	
LINDENBERG	52 13'N	14 07'E	98	360	387	305	402	453	473	418	441	417	372	231	252	
MUNCHEN-RIEM	48 08'N	11 42'E	528	474	491	488	476	500	471	482	490	460	459	264	357	
OBERSTDORF	47 24'N	10 17'E	-	341	358	401	409	386	373	397	400	390	371	312	321	
POTSDAM	52 23'N	13 04'E	105	326	341	421	443	461	478	464	451	455	366	269	269	
QUICKBORN	33 44'N	9 53'E	14	116	220	289	372	392	417	365	389	326	204	102	089	
SARBRUCKEN	49 13'N	7 01'E	-	229	293	392	427	464	430	435	445	416	355	272	244	
TRIER-PETRISBERG	49 45'N	6 40'E	276	-	-	510	502	-	419	450	420	385	361	242	276	
TUBINGEN	48 31'N	9 03'E	-	249	324	388	360	380	372	387	380	345	363	298	233	
WURZBURG-STEIN	49 48'N	9 54'E	263	420	391	442	450	438	432	477	472	539	401	212	250	
WYK/FOHR	54 43'N	8 35'E	-	343	387	436	520	513	460	433	450	460	400	310	280	
GHANA																
=====																
ACCRA	5 36'N	0 10'W	65	445	509	543	559	558	461	432	427	473	542	558	506	
HO	6 00'N	0 00'	-	437	475	543	559	558	487	364	317	431	499	592	540	

APPENDIX A (CON'T)

VALUES OF MONTHLY AVG. KH * 1000 [1]

STATION	LAT	LONG	ELEV	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	NOTES
GHANA (CON'T)																
=====																
KUMASI	6 43'N	1 36'W	287	292	356	441	465	413	308	254	206	278	355	371	328	CFP
TAFU	6 00'N	0 00'	-	420	450	492	517	481	393	313	283	295	397	456	455	CFP
TAKORADI	4 53'N	1 46'W	4	437	509	552	551	499	402	432	376	362	474	541	481	CFP
TAMALE	9 25'N	0 53'W	183	600	582	570	580	565	552	505	463	499	569	623	602	
GREECE																
=====																
ATHENS	37 58'N	23 43'E	107	466	543	496	551	548	563	591	564	532	477	432	453	
GREENLAND																
=====																
THULE	76 00'N	70 00'W	-	*	*	664	711	*	*	*	*	-	-	*	*	
GUINER																
=====																
BOKE	10 56'N	14 19'W	69	067	074	078	075	060	047	030	020	039	054	059	062	PPS
CONAKRY	9 34'N	13 37'W	46	041	056	066	057	042	029	016	013	027	044	047	028	PPS
LABE	11 19'N	12 18'W	1025	079	079	075	067	055	044	036	025	041	052	061	070	PPS
HONG KONG																
=====																
HONG KONG	22 18'N	114 10'E	65	528	449	382	367	417	438	506	441	443	623	621	566	
HUNGARY																
=====																
BEKESCSABA	46 41'N	21 05'E	88	401	369	487	471	537	501	531	524	538	495	337	311	
BUDAPEST	47 26'N	19 11'E	140	382	393	492	526	580	495	566	578	563	515	292	280	
DEBRECEN	47 30'N	21 38'E	113	384	357	524	500	610	568	590	595	597	544	381	328	
KALOCSA	46 32'N	18 59'E	108	428	401	507	535	600	522	583	581	594	534	331	339	
KECSKEMET	46 54'N	19 46'E	116	398	409	507	511	585	533	566	578	572	548	357	364	
KEKESTETO	47 52'N	20 01'E	991	413	502	486	469	581	511	562	589	587	563	377	336	
KESZTHELY	46 46'N	17 14'E	143	426	425	560	643	631	541	602	619	608	548	328	335	
KISVARDA	48 14'N	22 07'E	114	312	348	527	548	494	492	489	456	460	480	321	204	
MARTONVASAR	47 21'N	18 49'E	150	409	410	575	528	633	513	557	579	521	481	284	283	
PECS	46 04'N	18 12'E	124	403	427	512	551	570	501	551	556	530	468	299	321	
SIOFOK	46 54'N	18 03'E	112	425	432	542	571	617	533	620	594	581	524	321	293	
SOPRON	47 41'N	16 35'E	234	343	340	469	486	543	456	492	549	490	486	268	285	
SZEGED	46 15'N	20 06'E	83	354	389	479	466	535	497	541	531	529	487	324	320	
TISZAORS	47 32'N	20 50'E	99	389	346	501	482	556	495	537	534	542	514	310	278	
ICELAND																
=====																
KEFLAVIK	64 00'N	22 40'W	-	238	375	449	491	431	506	463	526	434	312	424	704	
REYKJAVIK	64 08'N	21 54'W	56	371	410	405	439	470	375	440	414	360	297	260	343	
INDIA																
=====																
ADARTAL	23 05'N	79 56'E	-	722	709	684	695	672	526	445	406	571	691	729	633	
ADUTHURAI	11 01'N	79 32'E	-	658	692	724	667	670	634	577	594	648	553	626	649	
AGRA	27 10'N	78 02'E	-	592	574	569	568	551	507	482	473	525	572	586	567	
AHMEDABAD	23 02'N	72 38'E	-	738	738	721	740	715	642	488	439	642	731	744	668	
AKOLA	20 45'N	77 00'E	-	751	740	720	714	729	606	460	484	599	698	743	733	
ALLAHBAD	25 28'N	81 52'E	-	728	708	674	700	690	573	515	495	579	699	731	728	
BABBUR	13 57'N	76 37'E	-	760	754	758	722	715	587	499	534	584	591	746	697	

APPENDIX A (CON'T)

VALUES OF MONTHLY AVG. KH * 1000 [1]

STATION	LAT	LONG	ELEV	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	NOTES
INDIA (CON'T)																
BANGALORE	12 58'N	77 35'E	-	706	707	731	688	663	513	446	513	525	549	669	699	
BARODA	22 15'N	73 15'E	-	742	743	716	728	737	633	479	439	639	630	748	724	
BOMBAY	18 56'N	72 50'E	-	708	708	698	679	680	494	421	407	536	659	734	721	
CALCUTTA	22 30'N	88 20'E	-	630	602	607	594	577	506	457	461	521	565	611	607	
CALCUTTA/DUM DUM	22 39'N	88 27'E	10	*	613	604	579	579	483	450	475	463	508	635	630	
CHINSURA	22 52'N	88 25'E	-	735	721	695	695	683	516	478	505	570	635	694	718	
COIMBATORE	11 00'N	76 55'E	-	685	692	712	667	659	544	486	583	637	589	599	676	
DELHI	28 40'N	77 15'E	-	693	686	671	663	666	628	522	552	555	702	714	714	
DHARWAR	15 27'N	75 00'E	-	751	741	729	666	645	461	396	443	529	574	722	747	
HAGARI	15 10'N	77 04'E	-	704	752	740	710	679	571	506	565	586	597	746	743	
JAIPUR	26 55'N	75 50'E	-	736	726	723	715	710	590	471	484	645	727	738	718	
JALGAON	21 03'N	75 34'E	-	755	730	722	726	729	595	460	495	588	714	732	738	
JODHPUR	26 18'N	73 01'E	-	743	734	718	714	721	706	556	528	655	721	745	726	
JULLUNDAR	31 25'N	75 35'E	-	666	692	652	706	697	674	550	577	668	718	726	710	
KARJAT	18 55'N	73 18'E	-	739	735	722	723	723	526	410	407	547	646	734	736	
KODAIKANAL	10 14'N	77 28'E	-	664	675	675	635	640	524	421	484	523	490	529	654	
KOILPATTI	9 12'N	77 53'E	-	652	667	695	636	644	587	562	576	658	557	635	655	
LABANDHE	21 20'N	81 45'E	-	744	704	674	659	664	530	448	418	554	663	705	709	
LAHORE	31 35'N	74 18'E	-	669	694	694	707	697	664	571	632	694	736	748	691	
MADRAS	13 05'N	80 15'E	-	708	721	719	700	663	569	513	524	583	586	643	687	
MADRAS	13 11'N	80 11'E	16	661	704	706	637	627	540	481	508	608	485	478	530	
NAGPUR	21 09'N	79 07'E	-	741	717	698	681	675	509	427	418	565	662	733	706	
NEW DELHI	28 35'N	77 12'E	210	676	752	738	688	687	624	416	531	582	697	730	684	
NIPHAD	20 06'N	74 07'E	-	757	747	728	725	731	629	451	484	621	706	749	739	
PATTAMBI	10 48'N	76 12'E	-	736	716	700	667	660	477	464	516	648	576	676	715	
PEDEGAON	18 12'N	74 10'E	-	744	741	718	701	703	582	455	540	581	666	725	726	
POONA	18 32'N	73 51'E	559	735	771	739	735	718	571	436	441	551	636	678	686	
POWERKHERA	22 50'N	78 00'E	-	752	735	695	706	704	589	456	439	546	702	757	734	
RAICHUR	16 12'N	77 12'E	-	746	748	732	711	665	524	503	553	553	641	730	727	
SAKHARNAGAR	18 39'N	77 45'E	-	751	732	721	701	691	548	443	463	535	657	745	732	
SAMALKOT	17 03'N	82 13'E	-	743	730	701	700	673	543	523	486	520	621	697	724	
SHOLAPUR	17 40'N	76 00'E	-	752	736	740	700	693	530	434	474	522	663	762	749	
SRINAGAR	34 05'N	74 50'E	1593	456	396	439	520	595	571	648	598	652	651	646	334	CFP
SURAT	21 12'N	72 52'E	-	742	745	723	726	728	626	481	462	647	728	734	724	
TRIVANDRUM	8 29'N	76 58'E	-	683	709	670	558	603	464	462	544	555	518	540	686	
VIRANGAM	23 02'N	72 07'E	-	755	738	709	740	725	705	520	472	701	731	744	668	

INDONESIA

DJAKARTA	6 11'S	106 50'E	8	397	416	445	469	482	493	520	531	520	467	437	411	
SOEMOBITO	7 32'S	112 20'E	16	461	455	426	460	519	539	547	515	530	510	469	388	

IRAN

BABOLSAR	36 43'N	52 39'E	-21	043	043	034	075	034	054	058	048	034	041	044	034	PPS
ESFAHAN	32 37'N	51 40'E	1590	067	073	075	-	059	070	083	083	081	087	070	061	PPS
KERMANSHAH	34 19'N	47 07'E	1298	071	047	054	074	057	061	078	086	093	077	063	057	PPS
MESHHAD	36 16'N	59 38'E	985	058	059	028	070	056	082	086	084	087	075	054	044	PPS
PAHLAVI	38 05'N	46 17'E	1405	034	032	022	050	-	047	059	042	028	023	032	032	PPS
SHIRAZ	29 36'N	52 32'E	1530	070	068	077	069	070	084	083	080	087	090	077	071	PPS
TEHERAN	35 41'N	51 19'E	1191	065	050	054	074	049	072	080	079	083	075	066	063	PPS

IRELAND

APPENDIX A (CON'T)

VALUES OF MONTHLY AVG. KH * 1000 [1]

STATION	LAT	LONG	ELEV	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	NOTES
IRELAND (CON'T)																
=====																
VALENTIA	51 56'N	10 15'W	14	407	378	411	486	505	479	403	430	403	353	330	343	
ISRAEL																
=====																
DEAD SEA	31 15'N	35 25'E	-	584	597	638	659	673	716	720	716	-	678	620	583	
JERUSALEM	31 46'N	35 15'E	789	610	614	622	680	712	752	750	749	732	698	620	588	
LOD	32 00'N	34 54'E	40	580	668	681	676	713	739	722	713	701	684	628	635	
ITALY																
=====																
ALGHERO	40 38'N	8 17'E	40	472	420	433	475	565	575	655	618	581	483	379	373	
ANCONA	43 37'N	13 31'E	105	299	386	375	472	513	516	562	533	505	436	295	301	
BARI	41 07'N	16 52'E	28	432	563	460	488	509	540	566	527	493	448	340	356	
BOLOGNA	44 31'N	11 18'E	43	313	388	346	461	518	488	534	504	479	423	279	281	
BOLZANO	46 28'N	11 19'E	237	381	425	450	480	507	456	470	466	490	460	369	337	
BRINDISI	40 39'N	17 57'E	21	455	515	422	455	508	513	564	540	523	483	387	415	
CAGLIARI	39 14'N	9 03'E	12	416	422	456	494	549	580	611	589	532	481	400	392	
CAMPO IMPER. M.	42 27'N	13 34'E	2138	290	316	477	462	558	502	593	596	522	512	379	418	
CAPO-PALINURO	40 01'N	15 16'E	185	463	516	488	504	562	573	591	508	582	531	428	458	
COZZO SPADARO	36 41'N	15 09'E	46	-	-	-	677	572	656	675	665	578	-	-	433	
CROTONE	39 00'N	17 05'E	154	428	502	438	443	556	551	573	583	520	471	337	412	
ETNA C. C. M.	37 42'N	15 00'E	1884	476	457	589	401	565	605	699	602	544	469	451	468	
FIRENZE	43 48'N	11 12'E	48	285	332	365	483	545	557	574	545	487	411	300	263	
FOGGIA	41 26'N	15 33'E	82	405	490	415	433	454	468	506	507	478	418	341	368	
GENOVA	44 24'N	8 58'E	98	345	365	382	440	444	493	557	525	497	459	351	322	
GRAPPA M.	45 53'N	11 48'E	1776	517	547	633	677	489	441	528	486	495	447	496	492	
MARSALA	37 49'N	12 27'E	2	425	427	498	515	582	634	693	630	553	503	416	411	
MESSINA	38 12'N	15 33'E	54	394	440	470	477	544	576	613	584	522	461	388	387	
MILANO	45 28'N	9 17'E	120	224	329	373	470	534	503	535	507	481	388	257	191	
MODENA	44 39'N	10 44'E	64	447	490	391	393	526	575	623	565	553	525	314	353	
MONTE CIMONE	44 12'N	10 42'E	2173	599	-	409	-	504	414	478	489	452	409	380	-	
MONTE TERMINILLO	42 28'N	12 59'E	1875	505	511	381	387	444	428	526	491	490	503	360	373	
NAPOLI	40 53'N	14 17'E	110	628	389	427	488	517	556	586	552	487	466	362	368	
NAPOLI (I. U. N.)	40 50'N	14 15'E	25	342	369	448	527	534	573	571	561	530	487	397	393	
OLBIA	40 56'N	9 30'E	2	449	458	432	460	511	519	567	540	512	418	371	388	
PALLANZA	45 55'N	8 33'E	222	577	532	411	515	512	520	551	499	511	483	382	426	
PANTELLERIA	36 49'N	11 57'E	254	432	428	424	445	474	477	502	486	469	410	414	403	
PESCARA	42 26'N	14 13'E	16	417	492	388	450	534	533	616	552	511	445	319	349	
PIANOSA	42 35'N	10 06'E	17	445	449	435	538	579	576	591	489	532	508	400	414	
PIAN ROSA'M.	45 56'N	7 42'E	3448	477	580	586	639	612	575	570	528	532	548	491	477	
PISA	43 41'N	10 24'E	11	469	452	380	480	530	508	542	530	537	534	429	390	
PROCIDA	40 45'N	14 02'E	80	416	400	407	396	489	504	518	475	431	440	355	350	
ROMA CIAMPINO	41 48'N	12 36'E	131	445	452	407	462	516	551	578	557	511	493	404	395	
SAN REMO	43 49'N	7 50'E	113	455	484	452	526	563	531	584	550	537	520	414	427	
SASSARI	40 43'N	8 33'E	512	289	346	401	518	566	573	624	577	565	471	406	352	
SERPEDI M.	39 22'N	9 18'E	1048	290	301	378	466	576	621	708	670	521	420	343	323	
SIRACUSA	37 04'N	15 17'E	15	405	415	428	447	488	492	500	505	455	407	365	380	
SORATTE M.	42 15'N	12 30'E	660	355	376	439	615	620	687	665	635	576	488	416	362	
STROMBOLI	38 48'N	15 15'E	5	366	338	479	541	602	623	646	575	508	462	365	356	
TARANTO	40 28'N	17 17'E	41	374	420	498	566	647	645	683	664	598	521	410	455	
TORINO	45 12'N	7 39'E	282	374	419	378	468	469	469	512	471	460	428	321	329	
TRIESTE	45 39'N	13 46'E	12	346	383	378	387	414	475	524	480	466	417	362	333	
UDINE	46 02'N	13 11'E	92	439	419	441	414	477	432	523	502	493	488	396	379	
USTICA	38 42'N	13 11'E	259	484	518	492	498	562	565	548	576	542	489	444	430	

APPENDIX A (CON'T)

VALUES OF MONTHLY AVG. KH * 1000 [1]

STATION	LAT	LONG	ELEV	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	NOTES
ITALY (CON'T)																
=====																
VENEZIA	45 26'N	12 23'E	17	328	375	407	466	534	504	538	515	493	456	337	288	
VIESTE	41 53'N	16 11'E	67	292	312	411	574	671	662	673	678	593	501	360	413	
VIGNA DI VALLE	42 05'N	12 13'E	270	383	383	388	496	584	610	654	612	540	477	371	353	
JAPAN																
=====																
ABASHIRI	44 01'N	144 17'E	-	530	569	594	531	486	455	465	389	486	532	539	540	
AKITA	39 43'N	140 06'E	9	413	469	483	508	502	465	450	501	484	495	426	370	
ADMORI	40 49'N	140 47'E	4	467	496	529	496	491	470	459	490	473	520	455	418	
ASAHIKAWA	43 46'N	142 22'E	-	351	401	489	463	417	436	434	383	429	411	348	348	
ASHIZURI	32 43'N	133 01'E	-	597	609	408	499	364	396	466	525	422	422	555	588	
ASOSAN	32 52'N	131 05'E	-	400	480	420	422	397	314	377	379	363	464	504	472	
ESASHI	41 52'N	140 00'E	-	310	391	441	465	424	373	454	494	476	433	381	359	
FIUKUOKA	33 35'N	130 23'E	2	378	396	417	417	389	338	358	408	386	458	463	410	
FUKUSHIMA	37 45'N	140 28'E	-	503	536	484	503	438	369	365	466	397	450	490	558	
HACHIJO-JIMA	33 06'N	139 47'E	-	370	341	372	329	345	260	373	441	407	360	361	366	
HACHINOHE	40 32'N	141 32'E	-	490	459	423	461	410	383	397	414	389	453	458	450	
HAKODATE	41 49'N	140 45'E	-	633	637	608	544	492	470	446	437	493	551	560	676	
HAMADA	34 54'N	132 04'E	-	320	407	425	464	442	381	420	498	413	488	481	420	
HAMAMATSU	34 42'N	137 43'E	-	544	436	436	404	353	279	329	394	342	330	363	427	
HIKONE	35 16'N	136 15'E	-	486	532	483	521	524	411	453	510	469	499	571	496	
HIROSHIMA	34 22'N	132 26'E	-	497	533	474	484	441	404	430	501	435	512	558	544	
HOFU	34 03'N	131 32'E	-	512	572	497	507	448	382	434	543	485	581	623	630	
IIDA	35 31'N	137 50'E	482	512	537	509	488	464	403	430	519	443	450	488	529	
INAWASHIRO	37 34'N	140 07'E	-	599	639	603	517	555	472	512	552	487	538	522	540	
ISHIGAKI-JIMA	24 20'N	124 10'E	-	406	368	361	358	415	395	456	466	580	501	518	457	
ISHINOMAKI	38 23'N	141 18'E	-	513	516	444	529	419	402	322	438	413	371	545	487	
IZUHARA	34 12'N	129 18'E	-	508	538	417	503	487	404	429	481	389	539	624	597	
KAGOSHIMA	31 34'N	130 33'E	20	458	493	454	431	400	342	437	490	471	493	525	528	
KOBE	34 41'N	135 11'E	58	426	415	399	384	376	319	367	404	353	382	409	417	
KOCHI	33 34'N	133 33'E	-	562	557	469	471	383	355	393	483	437	498	578	570	
KUMAMOTO	32 49'N	130 43'E	38	449	459	464	430	411	358	386	453	440	491	505	483	
KUSHIRO	43 59'N	144 24'E	-	576	590	579	594	527	495	464	427	512	562	621	632	
KUTCHAN	42 54'N	140 45'E	-	582	577	585	578	502	465	483	467	521	572	523	537	
MAEBASHI	36 24'N	139 04'E	-	555	458	464	379	437	293	274	440	418	492	562	627	
MAIZURU	35 28'N	135 23'E	-	412	429	387	472	435	411	454	487	416	407	508	485	
MINAMI-DAITO-ZIMA	25 50'N	131 14'E	15	321	291	274	300	296	325	369	334	359	320	317	285	
MITO	36 23'N	140 28'E	29	532	482	428	405	402	320	369	386	354	368	437	502	
MIYAKO	39 39'N	141 58'E	-	580	561	482	510	434	383	367	419	443	467	574	581	
MIYAZAKI	31 55'N	131 25'E	-	595	578	473	453	394	388	416	520	487	509	551	600	
MIZUSAWA	39 08'N	141 08'E	-	457	494	454	460	432	366	379	407	426	453	458	432	
MORIOKA	39 42'N	141 10'E	-	720	720	642	601	495	455	478	486	510	586	641	643	
MURORAN	42 19'N	140 59'E	-	514	584	579	631	521	432	482	465	496	586	573	569	
MUROTOMISAKI	33 15'N	134 11'E	-	695	706	574	599	511	486	568	666	593	577	706	882	
NAGANO	36 40'N	138 12'E	418	533	537	533	510	488	432	450	494	435	471	518	534	
NAGASAKI	32 44'N	129 53'E	-	329	403	402	381	401	372	456	551	421	473	498	431	
NAGOYA	35 10'N	136 58'E	-	583	617	522	526	436	398	427	466	432	474	612	611	
NAZE	28 23'N	129 30'E	-	329	332	338	355	311	401	486	461	466	390	351	336	
NEMURO	43 30'N	145 35'E	26	556	585	547	493	450	411	387	399	435	498	525	540	
OBIHIRO	42 55'N	143 13'E	-	576	600	595	532	450	423	369	397	456	524	598	598	
OITA	33 14'N	131 37'E	5	525	481	464	443	419	364	402	452	428	471	487	530	
OKI-DAITO-ZIMA	24 24'N	137 17'E	25	537	470	504	522	510	539	550	547	526	499	499	400	
ONAHAMA	36 57'N	140 54'E	-	578	533	376	424	361	348	357	424	386	352	474	594	
OSAKA	34 39'N	135 32'E	-	490	455	398	396	314	253	355	385	345	393	425	446	

APPENDIX A (CON'T)

VALUES OF MONTHLY AVG. KH * 1000 [1]

STATION	LAT	LONG	ELEV	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	NOTES
JAPAN (CON'T)																
=====																
OSHIMA	34 46'N	139 23'E	-	386	496	417	388	389	253	260	438	406	347	418	415	
OWASHI	34 04'N	136 12'E	-	510	433	438	399	388	327	376	439	372	424	416	458	
RUMOI	43 57'N	141 38'E	-	358	343	402	400	334	360	352	292	342	355	322	321	
SAGA	33 15'N	130 18'E	-	453	518	459	459	403	328	388	495	447	550	597	537	
SAIGO	36 12'N	133 20'E	-	488	538	547	592	604	484	528	617	551	626	624	540	
SAKATA	38 54'N	139 58'E	-	367	396	395	467	420	407	452	412	495	412	405	381	
SAPPORO	43 03'N	141 20'E	17	407	445	457	451	436	415	404	405	428	436	413	413	
SENDAI	38 16'N	140 54'E	-	618	619	572	591	514	419	412	495	460	528	587	619	
SHIMIZU	32 47'N	132 58'E	-	512	547	439	424	393	338	383	491	459	465	564	606	
SHIMONOSEKI	33 57'N	130 56'E	-	308	375	390	392	353	317	348	459	374	447	425	365	
SHIONOMISAKI	33 27'N	135 46'E	-	560	598	482	480	418	394	449	543	489	443	556	605	
SHIRAKAWA	37 07'N	140 13'E	-	597	605	483	540	417	363	337	413	400	387	656	650	
TADOTSU	34 17'N	133 46'E	-	414	350	378	387	429	368	401	440	-	-	-	-	
TAKAMATSU	34 19'N	134 03'E	9	496	498	479	465	452	390	426	485	421	426	442	462	
TATENO	36 03'N	140 08'E	6	599	529	523	515	514	448	487	493	420	439	485	569	
TOHOKU UNIV.	38 15'N	140 52'E	48	471	452	439	471	419	355	291	314	295	389	436	399	
TOKYO	35 41'N	139 46'E	4	443	420	385	363	356	301	340	372	327	327	389	427	
TOMIE	32 37'N	128 46'E	-	270	315	356	288	245	224	229	315	289	463	447	381	
TORISHIMA	30 29'N	140 18'E	81	407	382	350	336	299	326	396	441	483	453	394	433	
TOTTORI	35 31'N	134 11'E	17	336	337	367	410	418	374	392	452	401	432	419	363	
TOYAMA	36 42'N	137 12'E	-	373	434	420	448	472	383	396	473	412	360	426	337	
TSUKUBASAN	36 13'N	140 06'E	-	624	525	489	471	496	396	368	414	377	435	515	622	
URUKAWA	42 10'N	142 47'E	-	381	373	395	364	359	348	310	331	375	402	369	330	
UTSUNOMIYA	36 33'N	139 52'E	120	619	569	518	474	454	358	370	415	393	438	523	593	
WAKAMATSU	37 29'N	139 55'E	-	562	624	537	548	505	488	515	535	524	515	495	524	
WAKKANAI	45 25'N	141 41'E	-	356	392	495	479	456	410	390	382	494	476	367	341	
YAKUSHIMA	30 27'N	130 30'E	-	311	347	293	419	351	410	510	533	528	311	352	329	
YAMAGATA	38 15'N	140 21'E	-	523	543	506	488	450	417	440	520	467	458	487	479	
YONAGO	35 26'N	133 21'E	6	418	432	457	496	511	434	455	535	471	515	499	443	
KENYA																
=====																
FORT ESSEX	00 42'S	36 42'E	2463	662	662	621	552	473	496	355	364	571	583	558	590	
KERICHO	00 19'S	35 28'E	2042	657	666	663	544	554	574	503	496	530	501	530	612	
MARIGAT	00 35'N	36 00'E	1219	795	776	784	726	760	767	642	754	793	789	699	742	
MUGUGUA	01 12'S	36 38'E	2073	595	585	557	499	457	490	427	443	581	468	550	554	
NAIROBI	01 18'S	36 45'E	1799	642	665	622	560	510	509	410	439	529	552	555	608	
KOREA																
=====																
INCHON	37 29'N	126 38'E	69	534	544	516	504	510	506	475	498	508	530	523	524	
KANGNUNG	37 45'N	128 54'E	26	590	529	518	505	478	455	465	498	550	516	527	530	
PUZAN	35 06'N	129 02'E	71	696	634	604	580	569	489	464	539	554	561	632	670	
PYONGYANG	39 01'N	125 49'E	-	566	547	544	522	500	485	454	455	503	530	526	530	
SEOUL	37 34'N	126 58'E	86	535	526	517	505	510	506	465	475	509	531	501	498	
TAIKYU	35 53'N	128 37'E	61	804	726	619	580	540	488	460	491	514	603	638	744	
UNGGI	42 19'N	130 24'E	88	588	579	543	499	461	424	424	440	496	533	511	515	
WONSAN	39 11'N	127 26'E	35	597	570	530	523	490	464	423	433	477	532	529	534	
YOGAMPO	39 56'N	124 22'E	12	503	540	537	514	512	505	475	503	523	540	518	551	
LEBANON																
=====																
KSARA OBSERVATORY	33 49'N	35 53'E	927	486	562	580	628	679	737	741	732	709	642	558	481	
MACAU																
=====																

APPENDIX A (CON'T)

STATION	LAT	LONG	ELEV	VALUES OF MONTHLY AVG. KH * 1000 [1]												NOTES
				JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	
MACAU (CON'T)																
=====																
MACAU	22 12'N	113 33'E	65	445	280	337	419	441	482	564	561	550	635	642	579	
MADEIRA ISLANDS																
=====																
FUNCHAL	32 38'N	16 54'W	58	531	521	571	564	571	537	578	583	599	566	489	543	
PORTO SANTO	33 01'N	16 03'W	45	548	527	612	574	630	642	648	588	618	581	526	512	
MALIGASY																
=====																
TANANARIVE	18 54'S	47 32'E	1310	520	539	564	617	630	624	631	682	697	683	645	585	
MALAYA																
=====																
SINGAPORE	1 19'N	103 49'E	36	432	428	420	422	417	456	389	363	519	520	408	473	
MALI																
=====																
GAO	16 16'N	0 03'W	270	645	617	603	611	599	567	580	575	588	603	633	607	
TESSALIT	20 12'N	0 59'E	496	790	748	729	714	698	661	697	682	691	707	691	691	
MALTA																
=====																
QRENDI	35 50'N	14 26'E	135	549	511	623	594	654	689	712	726	649	604	520	556	
MARIANA ISLANDS																
=====																
SAIPAN	15 14'N	145 46'E	212	561	597	658	688	646	637	517	532	506	535	553	550	
WOLEAI	7 22'N	143 55'E	2	545	571	611	582	584	504	525	502	498	538	546	571	
MARSHALL ISLANDS																
=====																
JALUIT	5 55'N	169 39'E	2	056	060	048	048	051	050	051	050	056	049	050	048	PPS
PONAPE	6 58'N	158 13'E	30	042	047	043	040	040	041	045	048	043	045	043	038	PPS
MAURITANIA																
=====																
ATAR	20 31'N	13 04'W	227	700	724	706	736	698	713	686	682	610	644	649	680	
FORT GOUROUD	22 41'N	12 42'W	297	732	705	719	740	726	695	669	637	617	566	629	732	
NEMA	16 37'N	7 16'W	269	634	633	616	600	587	533	568	575	577	593	565	565	
NOUAKCHOTT	18 07'N	15 56'W	5	743	713	742	745	714	712	672	672	673	691	681	693	
PORT ETIENNE	20 56'N	17 03'W	8	706	714	709	726	718	722	674	681	682	673	669	669	
MEXICO																
=====																
ALTOZOMONI	19 07'N	98 38'W	3975	618	847	817	525	317	400	497	619	544	666	697	-	
CHIHUAHUA	28 38'N	106 05'W	1430	342	563	390	343	402	387	339	468	513	465	510	346	
CIUDAD UNIV.	19 20'N	99 11'W	2268	546	706	786	595	555	461	461	518	503	502	557	594	
TACUBAYA	19 24'N	99 06'W	2300	594	623	633	578	531	514	455	483	449	501	570	592	
VERACRUZ	19 12'N	96 08'W	12	503	594	-	-	643	664	541	616	616	654	630	657	
-	27 30'N	110 00'W	-	672	687	688	683	688	682	649	650	685	762	678	631	
-	27 30'N	107 00'W	-	672	687	688	683	688	651	649	650	685	719	678	631	
-	25 00'N	109 00'W	-	562	583	582	586	584	584	527	550	553	611	560	517	
-	23 00'N	110 00'W	-	570	578	584	583	629	621	583	615	582	609	585	527	
-	20 00'N	106 00'W	-	582	594	594	568	570	555	569	572	550	575	568	541	

APPENDIX A (CON'T)

VALUES OF MONTHLY AVG. KH * 1000 [1]

STATION	LAT	LONG	ELEV	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	NOTES
MEXICO (CON'T)																
=====																
-	20 00'N	91 00'W	-	535	594	594	524	527	491	494	528	515	562	553	508	
-	17 30'N	93 00'W	-	494	534	488	445	444	411	446	441	405	445	487	482	
-	17 00'N	100 00'W	-	624	610	594	567	576	554	567	574	543	570	597	616	
-	30 00'N	110 00'W	-	699	721	681	724	729	687	687	686	723	717	719	679	
MONGOLIA																
=====																
ULAN-BATOR	47 51'N	106 45'E	-	639	653	657	568	619	548	530	551	553	583	538	558	
MOZAMBIQUE																
=====																
BEIRA	19 08'S	34 08'E	7	566	516	629	640	614	665	637	676	601	574	593	532	
LOURENCO MARQUEZ	25 58'S	32 36'E	59	572	593	610	639	672	690	669	657	555	484	535	506	
LUMBO	15 00'S	40 07'E	10	559	534	571	635	640	614	660	708	731	716	718	585	
NETHERLANDS																
=====																
DE BILT	52 06'N	5 11'E	42	341	323	414	428	466	462	432	407	416	337	269	256	
WAGENINGEN	52 00'N	5 36'E	20	305	306	392	424	444	425	393	398	412	338	258	267	
NEW GUINEA																
=====																
BALIEM	4 04'S	138 57'E	1615	-	-	607	637	626	659	625	629	547	659	629	570	
HOLLANDIA	2 34'S	140 29'E	99	455	474	509	352	490	531	492	495	480	489	485	473	
MERAUKE	8 28'S	140 23'E	3	523	516	489	485	480	360	451	502	547	542	558	458	
RABUAL	4 00'S	152 00'E	6	517	503	529	516	565	592	520	556	548	534	510	486	
NEW ZEALAND																
=====																
INVERCARGILL	46 25'S	168 19'E	0	518	511	473	429	433	399	479	504	522	508	489	495	
NANDI	17 45'S	177 27'E	16	650	612	541	556	599	646	657	652	644	640	616	609	
OHAKA	40 12'S	175 23'E	51	577	537	522	502	457	486	477	520	557	531	535	544	
RAOUL ISLAND	29 15'S	177 55'W	49	590	545	565	532	566	478	535	520	563	553	596	658	
WELLINGTON	41 17'S	174 46'E	126	549	502	506	483	420	455	435	486	542	513	502	494	
WHENUAPAI	36 47'S	174 39'E	31	532	501	509	515	461	478	478	483	523	483	511	501	
NIGER																
=====																
AGADEZ	16 59'N	7 59'E	496	757	742	701	711	684	684	687	674	705	734	753	739	
BILMA	18 41'N	12 55'E	362	674	692	625	645	637	656	605	661	640	683	702	669	
NAIMEY	13 29'N	2 10'E	223	698	742	724	671	662	650	601	562	622	703	732	750	
NIGERIA																
=====																
BENIN CITY	6 33'N	5 37'E	109	394	441	452	441	429	414	339	330	367	433	464	458	
ENUGU	6 28'N	7 33'E	137	501	508	462	494	496	567	400	378	419	453	516	538	
IBADAN	7 26'N	3 54'E	228	508	512	486	481	481	445	373	342	385	456	521	519	
IKEJA	6 35'N	3 20'E	38	503	571	565	559	501	454	432	402	430	484	607	528	CFP
ILORIN	8 29'N	4 35'E	287	586	601	556	545	530	635	460	429	419	504	593	598	CFP
JOS	9 52'N	8 54'E	1286	639	630	581	558	531	530	482	463	499	568	648	655	
KADUNA	10 36'N	7 27'E	646	627	628	596	579	560	546	488	449	500	563	635	644	
KANO	12 03'N	8 23'E	476	628	613	589	589	578	573	561	514	570	618	634	632	
MAIDUGURI	11 51'N	13 05'E	354	653	636	588	600	601	585	540	503	570	629	659	644	
MAKURDI	7 41'N	8 37'E	970	595	585	530	579	564	635	485	404	487	530	584	632	CFP

APPENDIX A (CON'T)

STATION	LAT	LONG	ELEV	VALUES OF MONTHLY AVG. KH * 1000 [1]												NOTES
				JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	
NIGERIA (CON'T)																
=====																
MAMFE (Camaroon)	5 43'N	9 17'E	152	470	503	461	439	453	406	368	345	374	427	449	467	
MINNA	9 37'N	6 32'E	260	585	577	562	571	569	478	411	407	492	563	644	627	OFF
PORT HARCOURT	4 51'N	7 01'E	20	452	452	437	440	433	386	347	359	362	390	420	485	
SOKOTO	13 01'N	5 15'E	352	651	632	603	600	575	602	536	513	571	623	643	643	
YOLA	9 14'N	12 28'E	175	626	630	570	580	576	553	516	497	533	592	636	642	
NORWAY																
=====																
BERGEN	60 24'N	5 19'E	44	301	301	507	387	487	427	361	369	298	232	233	202	
BLINDERN	59 56'N	10 44'E	-	022	031	040	047	043	046	045	044	035	029	022	017	PPS
BRONNOYSUND	65 29'N	12 13'E	13	017	034	043	040	031	033	026	035	033	021	020	006	PPS
GJERMUNDNES	62 37'N	7 10'E	51	019	040	038	034	036	035	028	032	034	027	024	010	PPS
GREEN HARBOR	78 00'N	14 05'E	-	*	*	442	515	*	*	*	*	317	351	*	*	
HAUGASTOL	60 31'N	7 52'E	988	026	033	048	054	048	047	040	036	036	031	029	019	PPS
HORNSUND	77 00'N	15 33'E	11	*	*	007	160	*	*	*	*	616	278	*	*	
KJEVIK	58 12'N	8 05'E	15	026	032	041	052	049	057	049	047	043	032	022	022	PPS
LILLEHAMMER	61 06'N	10 29'E	228	019	034	051	050	045	041	038	038	036	032	026	018	PPS
MURCHISON BAY	80 03'N	18 15'E	7	*	*	576	648	*	*	*	*	372	*	*	*	
SOLA	58 53'N	5 38'E	13	020	033	038	044	045	045	035	035	037	026	021	013	PPS
TROMSO	69 39'N	18 57'E	118	*	422	423	492	413	*	*	368	351	309	391	*	
TRONDHEIM	63 25'N	10 27'E	133	016	039	040	035	039	036	030	036	033	026	018	015	PPS
ULLENSVANG	60 20'N	6 40'E	988	023	037	047	048	044	043	040	030	037	022	021	017	PPS
UTSIRA	59 18'N	4 53'E	56	017	029	037	046	044	044	033	035	035	024	020	014	PPS
PAKISTAN																
=====																
KARACHI	24 54'N	67 08'E	-	630	653	670	614	574	542	409	449	472	605	634	642	
MULTAN	30 12'N	71 26'E	-	607	609	557	590	566	579	573	546	570	599	530	547	
PESHAWAR	34 00'N	71 31'E	-	556	641	552	569	546	594	559	555	595	638	565	530	
QUETA	30 12'N	66 57'E	-	663	638	613	680	712	750	729	747	735	754	643	585	
PALAU ISLAND																
=====																
PALAU ISLAND	7 20'N	134 29'E	-	507	499	520	515	481	492	443	467	476	479	471	545	
PANAMA																
=====																
ALBROOK R. B.	8 39'N	79 34'W	6	505	572	596	554	459	390	428	422	508	457	478	554	
PERU																
=====																
HUANCAYO	12 02'S	75 19'W	3313	705	552	645	669	695	736	760	752	707	696	669	629	
PHILIPPINES																
=====																
QUEZON CITY	14 40'N	121 05'E	-	439	389	510	575	505	477	389	404	407	451	484	511	
POLAND																
=====																
BIALOWIEZA	52 42'N	23 51'E	200	346	352	-	501	513	-	475	-	-	422	207	222	
BRWINDW	52 08'N	20 43'E	96	308	350	440	526	507	490	424	431	458	429	256	296	
DANZIG	54 23'N	18 37'E	-	332	528	422	473	511	525	484	483	466	378	287	270	
GDYNIA	54 30'N	18 36'E	-	296	379	433	448	494	516	465	451	429	366	300	232	
KASPROWY-WIERCH	49 14'N	19 59'E	2007	517	405	596	506	466	358	380	364	419	541	515	422	

APPENDIX A (CON'T)

VALUES OF MONTHLY AVG. KH * 1000 [1]

STATION	LAT	LONG	ELEV	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	NOTES
POLAND (CON'T)																
=====																
KOLOBRZEG	54 11'N	15 35'E	19	431	408	446	489	564	519	490	506	495	394	268	361	
SUWALKI	54 06'N	22 57'E	165	467	432	576	551	595	560	539	546	511	447	282	366	
SZCZAWNO-ZDROJ	50 48'N	16 16'E	441	424	378	420	414	475	475	413	469	429	412	305	405	
SZRENICA	50 48'N	15 31'E	1364	-	-	-	328	359	323	353	310	337	344	373	-	
WARSAW	52 19'N	20 59'E	113	246	326	395	418	468	363	406	406	385	322	228	187	
WROCLAW	51 07'N	17 05'E	116	327	361	358	377	360	487	484	458	441	390	257	265	
ZAKOPANE	49 17'N	19 58'E	486	415	508	468	426	365	-	315	491	484	498	402	387	
PORTUGAL																
=====																
BRAGANCA	41 49'N	6 46'W	725	427	558	499	617	620	672	744	691	632	600	573	422	
CALDAS DA SAUDE	41 22'N	8 29'W	74	424	453	464	567	584	622	649	578	524	564	488	439	
COIMBRA	40 12'N	8 25'W	141	503	582	481	614	592	595	627	618	591	618	565	509	
EVORA	38 34'N	7 54'W	309	492	570	518	646	644	701	743	695	640	596	544	479	
FARO	37 01'N	7 55'W	14	550	626	599	700	721	763	769	746	715	652	569	555	
LISBOA	38 07'N	9 01'W	77	507	585	545	652	665	698	743	710	649	613	559	490	
M. ESTORIL	38 07'N	9 06'W	31	559	563	590	676	673	710	751	695	650	629	603	510	
PENHAS DOURADAS	40 25'N	7 33'W	1383	470	611	512	624	646	701	784	722	672	634	564	492	
PORTO	41 08'N	8 36'W	96	435	523	509	655	659	664	685	644	614	589	533	431	
VENDAS NOVAS	38 07'N	8 05'W	127	500	538	483	603	525	668	706	671	619	603	457	357	
PORT. GUINEA																
=====																
BISSAU	11 52'N	15 30'W	29	615	631	707	716	676	579	525	420	554	596	594	605	
KANKAN	10 23'N	9 18'E	377	625	614	596	568	561	558	500	483	523	586	595	601	
SIGUIRI	11 26'N	9 10'W	362	622	633	610	589	569	564	519	482	535	591	590	598	
PORT. TIMOR																
=====																
DILI	8 06'S	125 06'E	3	530	529	557	576	608	605	593	622	616	617	587	534	
PUERTO RICO																
=====																
SAN JUAN	18 28'N	66 06'W	26	655	661	697	675	600	659	695	632	630	636	623	679	
RHODESIA AND NYASALAND																
=====																
BULAWAYO	20 09'S	28 37'E	1330	552	539	625	668	706	696	718	723	676	622	556	502	
ZOMBA	15 23'S	35 18'E	-	039	036	038	053	054	047	046	064	061	065	050	036	PPS; 86
SAMOA																
=====																
APIA	13 48'S	172 00'W	5	037	039	045	045	050	046	053	056	050	048	043	037	
SAO TOME																
=====																
ILHA DE	0 23'N	6 43'E	8	378	404	392	438	485	479	431	420	414	396	412	385	
SENEGAL																
=====																
DAKAR	14 43'N	17 26'W	17	563	594	631	629	610	594	503	424	476	517	550	536	
SIERRA LEONE																
=====																

APPENDIX A (CON'T)

VALUES OF MONTHLY AVG. KH * 1000 [1]

STATION	LAT	LONG	ELEV	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	NOTES
SIERRA LEONE (CON'T)																
=====																
LINGI	8 37'N	13 12'W	38	499	508	546	590	473	498	336	386	426	568	513	535	
SPAIN																
=====																
ALMERIA	37 00'N	2 30'W	-	537	568	590	602	586	595	614	611	589	570	539	514	
BADAJOS	39 00'N	7 00'W	-	442	516	458	435	448	600	630	619	570	522	492	438	
LAS ROZAS	40 30'N	3 30'W	-	449	540	513	582	567	580	626	616	558	518	470	443	
SAN PABLO	37 30'N	6 00'W	-	392	531	530	572	565	573	592	571	552	503	446	425	
SPANISH W. AFRICA																
=====																
CABO JUBY	27 56'N	12 55'W	6	585	583	574	570	550	506	491	529	540	564	544	539	
SUDAN																
=====																
EL-FASHER	13 37'N	25 20'E	730	620	639	636	574	582	573	570	595	609	625	632	605	
JUBA	4 52'N	31 37'E	457	557	553	522	537	593	583	628	565	589	604	582	580	
KHARTOWN	15 36'N	32 33'E	380	649	650	650	627	613	576	574	570	589	611	639	647	
PORT SUDAN	19 35'N	37 13'E	3	629	632	660	666	654	602	605	596	633	601	609	552	
TOZI	12 30'N	34 00'E	440	570	572	580	531	550	524	500	516	547	558	550	566	
WAD MEDANI	14 24'N	33 29'E	485	632	639	632	599	614	573	528	560	595	670	646	653	
SWAN ISLAND																
=====																
SWAN ISLAND	17 24'N	83 56'W	18	657	632	692	680	652	571	609	585	625	543	587	582	
SWEDEN																
=====																
ERKEN	59 50'N	18 38'E	-	363	486	512	473	483	483	474	422	436	316	210	233	
FROSON	63 12'N	14 29'E	364	383	595	589	541	543	515	463	487	414	314	249	270	
HARADS	66 05'N	20 57'E	-	267	400	400	364	350	406	501	409	360	248	171	829	
KARLSTAD	59 22'N	13 28'E	47	362	456	509	448	527	567	485	476	460	326	208	246	
KIRUNA	67 48'N	20 24'E	-	*	550	584	615	499	*	430	421	395	355	378	*	
SANDVIKEN	60 37'N	16 48'E	-	255	419	445	488	533	472	494	450	438	329	256	254	
STOCKHOLM	59 21'N	17 57'E	43	326	406	494	457	501	500	499	482	435	343	246	278	
SVALOV	55 55'N	13 07'E	72	308	299	438	440	475	517	440	430	493	390	215	147	
TEG	63 49'N	20 04'E	-	367	468	480	488	506	582	580	504	441	331	137	117	
TORSLANDA	57 42'N	11 58'E	6	263	324	431	474	490	549	449	454	493	349	177	137	
ULTUNA	59 49'N	17 49'E	-	325	476	566	474	467	464	429	449	309	284	275	286	
VISBY	57 39'N	18 20'E	47	243	398	492	530	561	582	498	480	474	326	183	161	
SWITZERLAND																
=====																
BASLE	47 35'N	7 35'E	317	390	486	385	437	515	457	-	-	500	316	206	316	
DAVOS	46 48'N	9 49'E	1590	532	576	605	606	546	521	533	511	520	518	498	512	
GENEVE	46 15'N	6 10'E	-	019	032	047	052	052	057	064	061	054	040	022	014	PPS
HOCHSERFAUS	47 13'N	8 17'E	1817	533	701	642	611	604	608	584	536	582	583	485	539	HOC
JUNGFRAUJOCH	46 32'N	7 58'E	3472	612	670	718	699	573	571	664	630	508	557	589	599	
LOCARNO-MONTL	46 10'N	8 48'E	379	506	542	532	498	479	534	562	529	507	459	455	471	
WEISSFLUJJOCH	46 50'N	9 48'E	2670	688	826	679	757	579	422	469	439	639	583	610	628	
ZURICH	47 23'N	8 33'E	-	309	358	443	472	444	520	513	491	463	331	295	284	
THILAND																
=====																

APPENDIX A (CON'T)

STATION	LAT	LONG	ELEV	VALUES OF MONTHLY AVG. KH * 1000 [1]												NOTES
				JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	
THILAND (CON'T)																
BANGKOK	13 44'N	100 30'E	20	600	619	526	537	532	504	431	447	429	469	620	628	
CHIANGMAI	18 47'N	98 59'E	-	603	596	509	550	547	478	395	503	522	578	631	663	
NAKHON PHANOM	17 30'N	104 40'E	142	656	511	503	507	518	381	373	469	391	592	622	641	
SONGKHLA	7 11'N	100 37'E	15	658	676	583	568	550	572	528	529	506	460	521	564	
TRINIDAD																
PORT-OF-SPAIN	10 38'N	61 24'W	-	587	647	674	562	518	503	507	587	613	570	555	587	
TUNISIA																
TUNIS-EL ROUINA	36 50'N	10 14'E	3	606	589	562	628	679	653	704	696	-	542	559	543	
UGANDA																
MOROTO	2 31'N	34 40'E	1372	716	672	660	642	674	676	559	644	664	793	687	691	
UNION OF SOUTH AFRICA																
ALEXANDER BAY	28 34'S	16 32'E	21	727	712	693	707	687	684	662	697	712	713	715	706	
BLOEMFONTEIN	29 07'S	26 13'E	1422	635	617	609	663	658	695	710	734	716	670	685	645	
CAPETOWN	33 54'S	18 27'E	19	712	681	675	607	527	594	586	589	640	646	687	696	
CAPETOWN (WINGFIELD)	33 54'S	18 32'E	17	715	682	682	610	632	602	567	580	633	652	660	684	
DURBAN	29 50'S	31 02'E	5	475	507	544	557	574	624	595	575	532	474	470	486	
KEETMANSHOOP	26 34'S	18 07'E	1066	723	707	675	724	737	753	769	762	759	741	746	727	
KIMBERLY	28 48'S	24 46'E	1197	592	608	595	645	640	671	676	724	711	693	684	659	
MARION ISLAND	46 51'S	37 45'E	23	477	505	492	453	460	453	499	541	535	551	530	497	
MAUN	19 59'S	23 25'E	945	536	524	575	589	645	660	692	708	682	613	588	547	
PIETERSBURG	23 52'S	29 27'E	1230	613	594	620	648	703	717	658	678	625	632	635	581	
PORT ELIZABETH	33 59'S	25 36'E	61	594	630	592	563	583	632	622	619	603	587	630	589	
PRETORIA	25 45'S	28 14'E	1369	575	557	588	607	644	690	686	711	650	605	587	552	
ROODEPLAAT	26 35'S	28 21'E	1189	514	606	606	641	676	696	663	705	634	615	613	558	
SWAKOPMUND	22 41'S	14 31'E	-	603	585	619	609	601	643	552	631	607	641	656	620	
UPINGTON	28 26'S	21 16'E	814	648	631	621	641	672	731	701	705	678	652	649	637	
WINDHOEK	22 34'S	17 06'E	1217	638	609	615	680	744	758	787	778	740	698	683	669	
U. S. S. R.																
ARALSKOYE MORE	46 41'N	61 40'E	62	609	625	606	589	696	693	614	634	660	551	447	451	
ARARAT PLAIN	40 11'N	44 24'E	-	534	485	481	560	654	693	704	706	677	694	512	434	
ARKHANGLSK	64 30'N	40 42'E	4	347	350	512	574	414	473	500	462	311	272	216	422	
CAPE CHELYUSKIN	77 43'N	104 17'E	12	*	*	595	672	*	*	*	*	356	462	*	*	
CHETYREHSTOLBOVOY I	70 37'N	162 24'E	30	*	612	668	702	630	*	*	397	377	326	833	*	
CHITA (TCHITA)	52 03'N	113 29'E	671	547	629	631	600	559	519	461	464	498	521	510	457	
DIXON ISLAND	73 30'N	80 24'E	17	*	756	594	726	*	*	*	416	347	440	*	*	
HAYES ISLAND	80 37'N	58 03'E	20	*	*	565	509	*	*	*	*	276	879	*	*	
JAKUTSK	62 01'N	129 43'E	98	532	589	694	705	575	571	476	531	492	482	483	484	
KAUNAS	54 56'N	23 59'E	71	322	350	515	471	501	503	496	463	433	352	205	261	
KHARBOROVSK	48 31'N	135 07'E	86	605	651	590	482	497	479	458	468	509	478	535	569	
KIEV	50 24'N	30 32'E	167	340	392	420	380	528	490	515	509	457	438	251	273	
KICHINEV	49 00'N	28 51'E	90	425	455	471	468	555	542	611	570	540	528	298	384	
KOTELNYI ISLAND	76 00'N	137 54'E	10	*	*	585	690	*	*	*	*	327	360	*	*	
KUIBYCHEV	53 14'N	50 10'E	137	385	478	520	573	535	516	536	516	417	330	359	292	
LENINGRAD	59 57'N	30 42'E	71	293	271	529	467	472	510	527	464	392	265	213	257	

APPENDIX A (CON'T)

VALUES OF MONTHLY AVG. KH * 1000 [1]

STATION	LAT	LONG	ELEV	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	NOTES
U. S. S. R. (CON'T)																
=====																
NOVOSIBIRSK	54 54'N	82 57'E	130	516	554	594	583	513	505	493	495	494	332	324	390	
ODESSA	46 26'N	30 46'E	43	350	399	460	462	577	537	598	579	535	517	288	328	
OIMYAKON	63 16'N	143 09'E	740	634	686	752	740	608	510	496	567	496	515	603	647	
OKHOTSK	59 22'N	143 12'E	6	584	696	741	610	520	449	358	480	452	522	516	591	
OLENEK	68 30'N	112 26'E	127	*	587	664	697	578	*	*	419	364	428	578	*	
OMSK	55 01'N	73 23'E	120	508	524	581	564	521	548	485	506	486	334	369	439	
PREOBRAZHENIA ISLAND	74 40'N	112 50'E	24	*	919	586	617	*	*	*	373	308	302	*	*	
SEMIPALATINSK	50 25'N	80 18'E	190	651	674	696	587	578	579	574	567	636	486	408	524	
SVERDLOVSK	56 44'N	61 04'E	290	445	471	615	570	501	491	496	483	415	301	338	369	
TASHKENT	41 20'N	69 18'E	478	394	422	435	485	566	618	653	649	638	528	467	402	
TBILISI	41 43'N	44 48'E	403	389	466	406	499	514	522	584	580	518	488	355	390	
TIKHAYA BAY	80 20'N	52 48'E	16	*	*	-	-	*	*	*	*	373	-	*	*	
TURUKHANSK	65 47'N	87 57'E	38	575	561	593	685	569	497	510	479	293	378	399	*	
UEDINENIA ISLAND	77 30'N	82 14'E	17	*	*	581	676	*	*	*	*	280	377	*	*	
VERKHOVANSK	67 33'N	133 23'E	137	*	596	653	706	578	*	460	501	428	504	476	*	
VLADIVOSTOK	43 16'N	132 03'E	80	605	641	584	495	518	413	434	388	551	540	587	555	
WELLEN	66 10'N	169 53'E	6	488	477	600	649	601	529	442	354	262	353	239	973	
WRANGEL ISLAND	70 58'N	178 32'E	3	*	581	658	692	561	*	*	359	311	388	*	*	
YUZNO-SAKHALINSK	46 57'N	142 43'E	22	556	641	595	534	498	422	402	414	463	475	525	642	
UNITED ARAB REPUBLIC																
=====																
GIZA	30 02'N	31 13'E	21	580	623	672	670	656	671	667	664	659	626	570	565	
UNITED KINGDOM																
=====																
ABERPORTH	52 08'N	4 34'W	115	353	363	423	457	521	589	431	454	471	360	300	309	
CAMBRIDGE	52 13'N	0 06'E	23	333	331	376	394	443	434	434	396	407	384	292	278	
ESKDALEMUIR	55 19'N	3 12'W	246	406	297	355	410	433	371	379	368	385	352	275	264	
GARSTON; WATFORD	51 42'N	0 23'W	85	235	279	322	372	394	388	375	367	367	300	228	215	
KEW OBSER.	51 28'N	0 19'W	5	251	282	330	394	413	416	395	390	382	322	263	236	
LERWICK OBSERV.	60 08'N	1 11'W	82	354	383	382	404	415	432	345	328	382	318	301	286	
ROTHANSTED	51 48'N	0 21'W	128	312	344	374	408	429	425	386	379	376	324	272	243	
UNITED STATES																
=====																
AK ADAK	51 53'N	176 38'W	5	339	375	381	386	355	325	319	317	339	360	357	326	
ANNETTE	55 02'N	131 34'W	34	341	380	415	448	451	405	414	400	385	324	312	291	
BARROW	71 18'N	156 47'W	4	*	446	565	545	374	*	*	348	310	285	356	*	
BETHEL	60 47'N	161 48'W	46	380	466	514	511	459	422	376	335	378	370	330	286	
BETTLES	66 55'N	151 31'W	205	306	472	555	583	553	*	459	418	432	376	286	*	
BIG DELTA	64 00'N	145 44'W	388	363	484	562	559	536	495	474	463	451	394	353	156	
FAIRBANKS	64 49'N	147 52'W	138	315	471	552	544	517	486	454	425	427	373	328	056	
GULKANA	62 09'N	145 27'W	481	368	472	555	568	514	489	472	462	445	421	336	239	
HOMER	59 38'N	151 30'W	22	399	451	508	521	496	486	465	427	415	412	376	299	
JUNEAU	58 22'N	134 35'W	7	321	350	391	428	402	392	371	349	325	284	280	228	
KING SALMON	58 71'N	156 39'W	15	451	494	527	500	464	428	402	374	404	437	416	392	
KODIAK	57 45'N	152 20'W	34	382	423	491	490	427	424	408	411	399	421	368	330	
KOTZEBUE	66 52'N	162 38'W	5	236	447	535	560	535	*	449	406	416	385	225	000	
MC GRATH	62 58'N	155 37'W	103	350	457	524	524	476	441	405	379	398	359	325	212	
NOME	64 30'N	165 26'W	7	273	459	509	538	507	487	416	376	402	381	268	046	
SUMMIT	63 20'N	149 08'W	733	370	459	537	551	523	454	414	390	406	399	365	206	
YAKUTAT	59 31'N	139 40'W	9	324	356	415	438	397	373	351	338	332	323	287	233	
AL BIRMINGHAM	33 34'N	86 45'W	192	425	464	490	531	532	529	508	521	507	520	470	427	

APPENDIX A (CON'T)

VALUES OF MONTHLY AVG. KH * 1000 [1]

STATION	LAT	LONG	ELEV	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	NOTES
UNITED STATES (CON'T)																
=====																
MOBILE	30 41'N	88 15'W	67	457	495	513	538	536	519	483	493	492	531	485	446	
MONTGOMERY	32 18'N	86 24'W	62	435	472	499	545	544	545	517	526	505	530	485	445	
AR FORT SMITH	35 20'N	94 22'W	141	474	499	508	518	549	574	579	571	532	533	491	469	
LITTLE ROCK	34 44'N	92 14'W	81	457	494	504	515	553	580	570	565	535	539	480	453	
AZ PHOENIX	33 26'N	112 01'W	339	613	657	685	747	767	756	698	693	701	676	628	600	
TUCSON	32 07'N	110 56'W	779	633	665	692	744	765	755	658	657	680	671	637	612	
WINSLOW	35 01'N	110 44'W	1488	622	658	687	731	744	746	657	650	681	668	639	608	
YUMA	32 40'N	114 36'W	63	642	678	718	762	782	777	689	703	709	687	650	627	
CA ARCATA	40 59'N	124 06'W	69	418	460	479	531	534	536	506	492	507	468	411	409	
BAKERSFIELD	35 25'N	119 03'W	150	490	551	619	673	720	756	752	736	706	649	545	468	
CHINA LAKE	35 41'N	117 41'W	681	587	619	675	718	732	755	732	796	704	658	602	586	
DAGGETT	34 52'N	116 47'W	588	602	632	682	728	744	761	730	723	708	667	617	593	
EL TORO	33 40'N	117 44'W	116	572	594	610	613	594	605	663	652	606	584	564	564	
FRESNO	36 46'N	119 43'W	100	440	524	619	678	714	750	752	741	714	653	535	417	
LONG BEACH	33 49'N	118 09'W	17	563	586	611	616	592	590	645	635	594	573	554	552	
LOS ANGELES	33 56'N	118 24'W	32	564	587	615	621	590	584	647	630	588	570	556	555	
MOUNT SHASTA	41 19'N	122 19'W	1093	450	502	532	589	634	666	722	691	665	582	463	446	
NEEDLES	3 46'N	114 37'W	270	322	423	554	711	848	922	833	719	619	476	362	304	
OAKLAND	37 44'N	122 12'W	2	492	540	585	627	637	644	650	630	619	565	510	489	
POINT MUGU	34 07'N	119 07'W	4	568	592	623	622	579	566	504	586	563	563	560	564	
RED BLUFF	40 09'N	122 15'W	108	436	506	565	635	687	711	748	717	690	602	476	428	
SACRAMENTO	38 31'N	121 30'W	8	427	509	593	657	702	735	753	729	699	622	498	420	
SAN DIEGO	32 44'N	117 10'W	9	572	596	610	613	574	570	614	621	594	582	569	567	
SAN FRANCISCO	37 37'N	122 23'W	5	490	534	583	626	641	651	669	649	633	570	508	483	
SANTA MARIA	34 54'N	120 27'W	72	537	564	609	615	614	646	656	639	611	596	554	544	
SUNNYVALE	37 25'N	122 04'W	12	507	546	593	632	655	672	683	664	637	578	518	493	
CO COLORADO SPRINGS	38 49'N	104 43'W	1881	645	643	633	635	614	649	619	624	647	647	607	618	
DENVER	39 45'N	104 52'W	1625	632	632	634	622	617	643	636	633	642	632	587	602	
EAGLE	39 39'N	106 55'W	1985	565	602	621	639	652	686	668	645	656	634	575	566	
GRAND JUNCTION	39 07'N	108 32'W	1475	580	616	637	655	687	711	690	674	677	645	597	586	
PUEBLO	38 17'N	104 31'W	1439	635	630	633	641	623	667	647	647	651	641	603	605	
CT HARTFORD	41 56'N	72 41'W	55	394	426	421	443	455	461	462	445	441	436	357	351	
CU GUANTANAMO BAY	19 54'N	75 09'W	16	597	617	633	641	594	568	606	597	579	560	579	582	
DC WASHINGTON	38 57'N	77 27'W	88	417	447	460	480	496	520	509	499	494	479	420	383	
DE WILMINGTON	39 40'N	75 36'W	24	428	462	476	490	494	515	510	500	490	477	427	401	
FL APALACHICOLA	29 44'N	85 02'W	6	458	497	532	585	599	556	512	506	518	553	516	466	
DAYTONA BEACH	29 11'N	81 03'W	12	507	530	555	585	564	509	504	503	496	500	507	489	
JACKSONVILLE	30 30'N	81 42'W	9	494	523	554	580	561	524	508	508	489	499	504	477	
MIAMI	25 48'N	80 16'W	2	513	540	555	570	530	481	502	486	477	496	508	521	
ORLANDO	28 33'N	81 20'W	36	520	537	563	588	571	511	510	500	500	516	529	510	
TALAHASSEE	30 23'N	84 22'W	21	480	509	538	569	555	523	493	503	506	537	509	473	

APPENDIX A (CON'T)

VALUES OF MONTHLY AVG. KH * 1000 [1]

STATION	LAT	LONG	ELEV	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	NOTES
UNITED STATES (CON'T)																
=====																
FL TALLAHASSEE	30 23'N	84 22'W	21	480	509	538	569	555	523	493	503	506	537	509	473	
FL TAMPA	27 58'N	82 32'W	3	518	538	564	590	573	517	496	494	496	528	527	507	
FL WEST PALM BEACH	26 41'N	80 06'W	6	495	514	543	558	530	479	505	496	467	471	491	501	
GA ATLANTA	33 39'N	84 26'W	315	433	465	494	536	531	528	508	517	496	516	485	437	
GA AUGUSTA	33 22'N	81 58'W	45	450	484	505	548	535	525	506	504	490	522	500	462	
GA MACON	32 42'N	83 39'W	110	450	479	510	549	540	530	501	518	497	528	503	457	
GA SAVANNAH	32 08'N	81 12'W	16	458	484	519	555	531	510	501	488	469	510	496	464	
HI BARBERS POINT	21 19'N	158 04'W	10	529	550	547	555	573	582	584	587	579	559	540	533	
HI HILO	19 43'N	155 04'W	11	475	465	442	433	453	481	473	475	490	484	446	450	
HI HONOLULU	21 20'N	157 55'W	5	517	533	539	544	566	576	580	586	578	554	526	518	
HI LIHUE	21 59'N	159 21'W	45	490	501	493	498	529	535	538	542	558	525	485	489	
IA BURLINGTON	40 47'N	91 07'W	214	455	495	492	513	543	580	584	569	534	528	457	415	
IA DES MOINES	41 32'N	93 39'W	294	470	508	504	523	542	581	588	571	545	541	466	435	
IA MASON CITY	43 09'N	93 20'W	373	482	519	514	517	552	578	585	577	546	532	452	430	
IA SIOUX CITY	42 24'N	96 23'W	336	479	510	508	534	553	581	595	579	547	537	470	438	
ID BOISE	43 34'N	116 13'W	874	432	528	578	625	664	674	734	694	679	605	482	434	
ID LEWISTON	46 23'N	117 01'W	438	349	422	478	505	542	551	658	621	584	493	357	334	
ID POCATELLO	42 55'N	11 23'W	1365	465	543	601	619	664	678	729	705	685	630	514	457	
IL CHICAGO	41 47'N	87 45'W	190	416	451	475	491	519	549	545	538	516	493	404	363	
IL MOLINE	41 27'N	90 31'W	181	432	478	477	490	509	539	543	535	516	503	420	385	
IL SPRINGFIELD	39 50'N	89 40'W	187	441	483	475	502	539	574	576	559	541	520	450	405	
IN EVANSVILLE	38 03'N	87 32'W	118	404	440	464	490	513	543	538	533	512	510	428	381	
IN FORT WAYNE	41 00'N	85 12'W	252	361	405	416	455	484	504	501	497	481	462	358	322	
IN INDIANAPOLIS	39 44'N	86 17'W	246	372	418	430	463	488	511	506	509	493	475	384	343	
IN SOUTH BEND	41 42'N	86 19'W	236	339	391	425	467	500	525	519	521	492	462	354	307	
KS DODGE CITY	37 46'N	99 58'W	787	575	596	593	615	602	646	643	631	613	606	555	553	
KS GOODLAND	39 22'N	101 42'W	1124	584	585	586	604	595	645	649	632	608	612	561	562	
KS TOPEKA	39 04'N	95 38'W	270	498	517	515	541	553	582	596	590	560	549	500	466	
KS WITCHITA	37 39'N	97 25'W	408	543	560	563	581	586	621	627	623	587	581	539	519	
KY LEXINGTON	38 02'N	84 36'W	301	383	417	443	484	503	520	518	518	497	489	412	371	
KY LOUISVILLE	38 11'N	85 44'W	149	386	424	446	480	495	521	514	517	497	490	411	375	
LA BATON ROUGE	30 32'N	91 09'W	23	432	473	502	525	536	535	492	503	497	531	466	431	
LA LAKE CHARLES	30 07'N	93 13'W	3	396	449	476	490	530	548	504	497	502	560	459	407	
LA NEW ORLEANS	29 59'N	90 15'W	3	451	494	512	555	564	557	511	515	511	540	486	448	
LA SHREVEPORT	32 28'N	93 49'W	79	444	486	500	509	540	571	566	566	536	550	494	454	
MA BOSTON	42 22'N	71 02'W	5	400	429	441	448	471	497	491	466	484	459	367	376	
MD BALTIMORE	39 11'N	76 40'W	47	431	463	477	490	495	514	510	494	492	479	430	401	
MD PATUXENT RIVER	38 17'N	76 25'W	14	432	464	478	504	508	519	508	501	496	481	446	415	
ME BANGOR	44 48'N	68 49'W	62	429	475	496	498	506	508	523	513	499	461	380	401	
ME CARIBOU	46 52'N	68 01'W	190	443	510	537	500	465	481	497	484	452	400	324	373	
ME PORTLAND	43 39'N	70 19'W	19	402	429	430	446	457	468	466	461	453	439	353	361	
MI ALPENA	45 04'N	83 34'W	210	347	407	469	488	504	514	530	505	461	411	312	291	
MI DETROIT	42 25'N	83 01'W	191	352	412	434	474	499	510	515	494	482	453	349	321	
MI FLINT	42 58'N	83 44'W	233	331	392	419	456	483	496	504	489	463	434	321	296	
MI GRAND RAPIDS	42 53'N	85 31'W	245	318	399	444	480	511	535	537	527	489	449	332	297	
MI HOUGHTON	47 10'N	88 30'W	329	262	345	445	484	490	503	519	492	416	393	262	234	
MI SAULT STE. MARIE	46 28'N	84 22'W	221	335	419	483	487	497	495	517	490	427	387	288	295	
MI TRAVERSE CITY	44 44'N	85 35'W	192	292	371	454	486	506	523	537	512	463	413	303	271	
MN DULUTH	46 50'N	92 11'W	432	409	473	489	485	484	484	523	498	449	421	336	349	
MN INTERNATIONAL FAL	48 34'N	93 23'W	361	410	498	514	519	510	508	544	528	472	430	332	365	
MN MINNEAPOLIS-ST. P	44 53'N	93 13'W	255	441	501	502	499	509	527	554	537	499	473	389	377	
MN ROCHESTER	43 55'N	92 30'W	402	432	478	483	484	495	520	536	526	491	467	384	374	
MO COLUMBIA	38 49'N	92 13'W	270	443	477	481	501	542	572	592	579	534	524	452	413	
MO KANSAS CITY	39 18'N	94 43'W	315	478	495	495	520	541	569	589	575	537	526	482	453	

APPENDIX A (CON'T)

VALUES OF MONTHLY AVG. KH * 1000 [1]

STATION	LAT	LONG	ELEV	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	NOTES
UNITED STATES (CON'T) (CON'T)																
=====																
SPRINGFIELD	37 14'N	93 23'W	387	466	484	492	521	541	569	578	574	535	527	474	446	
ST. LOUIS	38 45'N	90 23'W	172	453	482	491	514	540	573	574	560	537	523	461	418	
MS JACKSON	32 19'N	90 05'W	101	436	478	510	539	556	560	536	537	520	535	478	439	
MERIDIAN	32 20'N	88 45'W	94	431	472	494	524	533	543	512	524	501	529	475	433	
MT BILLINGS	45 48'N	108 32'W	1088	484	517	551	533	562	595	671	648	593	557	473	474	
CUT BANK	48 36'N	112 22'W	1170	471	518	555	534	559	561	647	619	569	534	463	451	
DILLON	45 5'N	112 33'W	1588	505	560	584	569	583	586	673	645	607	567	492	486	
GLASGOW	48 13'N	106 37'W	700	444	498	538	534	542	561	620	606	561	531	452	439	
GREAT FALLS	47 29'N	111 22'W	1116	460	519	562	529	546	576	658	626	570	547	454	420	
HELENA	46 36'N	112 00'W	1188	436	494	539	524	548	558	658	621	577	535	456	430	
LEWISTOWN	47 03'N	109 27'W	1264	448	491	536	511	533	564	646	614	564	529	449	441	
MILES CITY	46 26'N	105 52'W	803	471	517	556	543	558	587	646	636	588	552	478	467	
MISSOULA	46 55'N	114 05'W	972	329	405	465	489	526	529	657	607	557	473	364	322	
NC ASHEVILLE	35 26'N	82 32'W	661	462	486	507	535	518	510	498	495	483	511	491	454	
CAPE HATTERAS	35 16'N	75 33'W	2	436	475	513	569	563	560	538	519	521	504	502	452	
CHARLOTTE	35 13'N	80 56'W	234	457	484	510	544	532	528	513	515	501	520	497	461	
CHERRY POINT	34 54'N	76 53'W	11	476	507	534	574	552	533	513	496	504	515	516	487	
GREENSBORO	36 05'N	79 57'W	270	468	494	514	543	537	536	522	517	506	514	495	466	
RALEIGH	35 52'N	78 47'W	134	451	477	498	530	519	512	497	491	491	496	476	446	
ND BISMARCK	46 46'N	100 45'W	582	490	544	552	515	545	564	616	685	554	526	447	444	
FARGO	46 54'N	96 48'W	274	438	498	520	521	541	546	598	589	535	509	406	406	
MINOT	48 16'N	101 17'W	522	439	487	510	524	548	541	593	586	535	515	415	409	
NE GRAND ISLAND	40 58'N	98 19'W	566	523	532	535	566	571	613	621	604	570	568	512	496	
NORTH OMAHA	41 22'N	96 01'W	404	510	524	521	523	543	580	590	580	521	529	453	454	
NORTH PLATTE	41 08'N	100 41'W	849	551	559	566	577	576	620	638	620	592	591	530	531	
SCOTTSBLUFF	41 52'N	103 36'W	1206	555	566	562	562	561	611	640	626	611	585	519	523	
NH CONCORD	43 12'N	71 30'W	105	401	426	429	449	461	466	470	459	443	431	349	352	
NJ LAKEHURST	40 02'N	74 20'W	37	425	450	462	483	484	485	477	475	471	467	417	396	
NEWARK	40 42'N	74 10'W	9	431	457	467	483	489	491	493	487	479	472	410	391	
NM ALBUQUERQUE	35 03'N	106 37'W	1619	643	666	682	714	728	737	697	696	697	683	648	632	
CLAYTON	36 27'N	103 09'W	1515	638	637	650	659	638	664	639	640	646	651	613	618	
FARMINGTON	36 45'N	108 14'W	1677	633	662	670	691	705	731	694	689	696	675	630	608	
ROSWELL	33 24'N	104 32'W	1103	627	655	682	703	705	720	685	678	666	655	617	611	
TRUTH OR CONSEQU	33 14'N	107 16'W	1481	666	690	710	741	733	731	664	669	674	675	661	640	
TUCUMCARI	35 11'N	103 36'W	1231	640	645	662	673	664	683	658	658	647	639	616	623	
ZUNI	35 06'N	108 48'W	1965	625	644	652	695	710	716	634	632	670	662	623	609	
NV ELKO	40 50'N	115 47'W	1547	541	598	618	634	667	693	735	721	713	659	561	534	
ELY	39 17'N	114 52'W	1906	605	631	661	663	667	688	685	689	716	677	605	583	
LAS VEGAS	36 05'N	115 10'W	664	641	681	714	748	760	763	725	718	728	694	640	623	
LOVELOCK	40 04'N	118 33'W	1190	613	659	690	719	739	752	779	770	757	711	624	597	
RENO	39 30'N	119 47'W	1341	596	639	681	714	729	739	754	744	741	692	601	575	
TONOPAH	38 04'N	117 08'W	1653	646	682	717	736	742	764	756	749	745	713	647	633	
WINNEMUCCA	40 54'N	117 48'W	1323	544	595	622	658	684	703	750	731	720	660	560	537	
YUCCA FLATS	36 57'N	116 03'W	1197	644	662	700	729	741	750	743	729	729	695	631	624	
NY ALBANY	42 45'N	73 48'W	89	390	421	430	453	457	473	484	471	452	426	339	338	
BINGHAMTON	42 13'N	75 59'W	499	322	346	372	420	435	460	465	447	434	401	300	275	
BUFFALO	42 56'N	78 44'W	215	301	336	389	447	465	493	498	476	446	411	301	272	
MASSENA	44 56'N	74 52'W	63	372	408	445	465	473	486	492	473	447	406	314	315	
NEW YORK (CN. PRK)	40 47'N	73 58'W	57	393	416	438	455	474	468	473	462	457	446	367	349	
NEW YORK (LGA)	40 46'N	73 54'W	16	429	458	471	486	490	493	500	493	482	473	408	394	
ROCHESTER	43 07'N	77 40'W	169	317	346	397	456	468	497	500	479	450	411	303	271	
SYRACUSE	43 07'N	76 07'W	124	335	354	391	451	460	486	493	474	453	409	300	276	
OH AKRON-CANTON	40 55'N	81 26'W	377	338	376	408	454	483	503	500	497	480	453	349	307	
CINCINNATI	39 04'N	84 40'W	271	366	406	421	461	483	503	496	504	484	474	382	345	

APPENDIX A (CON'T)

VALUES OF MONTHLY AVG. KH * 1000 (1)

STATION	LAT	LONG	ELEV	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	NOTES
UNITED STATES (CON'T) (CON'T)																
=====																
CLEVELAND	41 24'N	81 51'W	245	313	352	393	453	488	504	512	494	471	438	329	282	
COLUMBUS	40 00'N	82 52'W	254	349	381	408	449	476	496	491	508	478	462	360	322	
DAYTON	39 54'N	84 13'W	306	370	408	426	465	491	513	507	510	491	472	377	338	
TOLEDO	41 36'N	83 48'W	211	353	402	426	465	498	514	518	505	485	462	353	319	
YOUNGSTOWN	41 16'N	80 40'W	361	389	343	379	429	460	481	486	470	452	428	320	278	
OK OKLAHOMA CITY	35 24'N	97 36'W	397	512	528	543	554	551	589	596	593	551	548	521	500	
TULSA	36 12'N	95 54'W	206	481	499	512	517	524	555	569	569	527	525	490	469	
OR ASTORIA	46 09'N	123 53'W	7	319	374	404	440	473	445	492	481	480	407	332	299	
BURNS	43 35'N	119 03'W	1271	436	498	527	564	599	623	691	658	633	555	455	427	
MEDFORD	42 22'N	122 52'W	396	342	446	491	554	591	623	694	665	611	507	369	313	
NORTH BEND	43 25'N	124 15'W	5	387	440	467	516	542	545	592	563	537	473	399	374	
PENDLETON	45 41'N	118 51'W	456	345	414	482	524	566	587	674	638	605	511	368	327	
PORTLAND	45 36'N	122 36'W	12	306	373	413	456	488	485	574	535	489	406	324	285	
REDMOND	44 16'N	121 09'W	940	452	498	535	579	608	625	687	656	625	542	451	437	
SALEM	44 55'N	123 01'W	61	316	387	431	475	509	506	603	565	529	424	333	296	
PA ALLENTOWN	40 39'N	75 26'W	117	411	439	454	470	474	486	494	481	466	460	390	369	
ERIE	42 05'N	80 11'W	225	287	346	397	459	478	505	514	456	460	425	301	255	
HARRISBURG	40 13'N	76 51'W	106	410	438	453	469	478	494	494	481	474	459	390	376	
PHILADELPHIA	39 53'N	75 15'W	9	420	447	460	475	480	496	492	488	477	467	413	390	
PITTSBURG	40 30'N	80 13'W	373	329	358	396	438	463	482	473	469	454	443	344	295	
WILKES-SCRANTON	41 20'N	75 44'W	289	366	404	422	449	461	481	489	472	455	452	344	325	
PN KORROR ISLAND	7 20'N	134 29'E	33	480	502	500	513	487	463	456	458	469	477	487	471	
KWAJALEIN ISLAND	8 44'N	167 44'E	8	549	570	553	527	502	507	505	519	496	486	496	518	
WAKE ISLAND	19 17'N	166 39'E	4	567	583	593	590	600	595	562	558	550	552	575	573	
PR SAN JUAN	18 26'N	66 00'W	19	548	563	581	570	531	531	549	549	528	528	540	521	
RI PROVIDENCE	41 44'N	71 26'W	19	414	438	442	462	481	485	475	463	461	461	383	378	
SC CHARLESTON	32 54'N	80 02'W	12	439	470	502	548	533	509	505	479	483	507	503	455	
COLUMBIA	33 57'N	81 07'W	69	464	493	515	557	543	536	516	515	503	524	510	473	
GREENVILLE	34 54'N	82 13'W	296	459	485	512	543	527	528	513	516	496	520	501	454	
SD HURON	44 23'N	98 13'W	393	452	481	501	528	547	575	613	601	560	537	458	420	
PIERRE	44 23'N	100 17'W	526	491	513	543	556	575	600	640	632	591	571	493	458	
RAPID CITY	44 03'N	103 04'W	966	494	528	550	546	551	583	625	622	597	573	505	485	
SIOUX FALLS	43 34'N	96 44'W	435	473	504	511	528	552	574	604	583	551	535	465	438	
TN CHATTANOOGA	35 02'N	85 12'W	210	398	426	454	496	497	504	486	495	472	489	441	395	
KNOXVILLE	35 49'N	83 59'W	299	402	436	464	515	518	522	505	507	493	502	444	399	
MEMPHIS	35 03'N	89 59'W	87	431	468	493	525	541	562	553	554	520	532	467	428	
NASHVILLE	36 07'N	86 41'W	180	380	419	443	498	524	539	530	530	499	502	420	369	
TX ABILENE	32 26'N	99 41'W	534	537	553	588	582	584	610	601	590	551	554	535	537	
AMARILLO	35 14'N	101 42'W	1098	611	620	631	648	635	658	639	639	623	622	593	590	
AUSTIN	30 18'N	97 42'W	189	472	503	519	501	525	576	593	579	544	542	496	479	
BROWNSVILLE	25 54'N	97 26'W	6	444	467	505	533	554	596	630	604	555	548	480	442	
CORPUS CHRISTI	27 46'N	97 30'W	13	458	488	505	507	536	586	620	595	560	554	494	455	
DALLAS	32 51'N	96 51'W	149	484	505	533	514	541	589	596	589	549	542	503	492	
KINGSVILLE	27 31'N	97 49'W	17	462	492	505	513	535	570	599	574	538	542	487	454	
LAREDO	27 32'N	99 28'W	158	485	506	534	533	560	581	604	600	565	549	490	476	
LUBBOCK	33 39'N	101 49'W	988	622	639	667	689	687	702	676	668	635	632	613	605	
LUFKIN	31 14'N	94 45'W	96	445	487	505	509	535	570	565	560	522	557	496	459	
MIDLAND-ODESSA	31 56'N	102 12'W	871	619	639	681	690	696	709	672	666	633	636	617	611	
PORT ARTHUR	29 57'N	94 01'W	7	432	475	489	502	536	559	521	521	516	534	475	433	
SAN ANGELO	31 22'N	100 30'W	582	541	552	591	581	582	606	597	591	549	553	539	537	
SAN ANTONIO	29 32'N	98 28'W	242	478	508	522	502	543	576	599	583	551	543	498	481	
SHERMAN	33 43'N	96 40'W	233	480	499	517	512	531	583	582	584	551	547	506	483	
WACO	31 37'N	97 12'W	155	472	504	527	507	508	585	599	589	548	541	498	486	
WICHITA FALLS	33 58'N	98 29'W	314	526	543	560	561	578	612	608	596	560	559	531	523	

APPENDIX A (CON'T)

VALUES OF MONTHLY AVG. KH * 1000 [1]

STATION	LAT	LONG	ELEV	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	NOTES
UNITED STATES (CON'T) (CON'T)																
=====																
● BRYCE CANYON	37 42'N	112 09'W	2313	634	655	676	696	706	728	678	662	698	682	630	618	
● CEDAR CITY	37 42'N	113 06'W	1712	613	625	656	682	710	742	701	688	715	679	615	593	
● SALT LAKE CITY	40 46'N	111 58'W	1288	501	570	613	632	684	700	726	701	694	644	542	491	
VA NORFOLK	36 54'N	76 12'W	9	457	483	508	544	543	549	519	514	503	496	491	456	
● RICHMOND	47 30'N	77 20'W	50	691	633	581	557	521	513	501	518	558	612	669	709	
● ROANOKE	37 19'N	79 58'W	358	452	472	493	514	507	516	503	496	492	499	468	439	
VT BURLINGTON	44 28'N	73 09'W	104	358	393	424	447	461	473	484	468	444	403	298	295	
WA OLYMPIA	46 58'N	122 54'W	61	285	355	401	444	481	464	540	500	475	371	302	267	
● SEATTLE-TACOMA	47 27'N	122 18'W	122	285	357	407	460	506	493	635	523	475	388	307	263	
● SPOKANE	47 38'N	117 32'W	721	348	439	501	532	567	570	666	630	595	500	365	322	
● WHIDBEY ISLAND	48 21'N	122 40'W	17	325	396	449	483	522	499	561	519	492	398	339	309	
● YAKIMA	46 34'N	120 32'W	325	379	464	528	563	592	594	665	635	605	514	388	347	
WI EAU CLAIRE	44 52'N	91 29'W	273	428	492	496	494	492	512	531	516	476	455	364	362	
● GREEN BAY	44 29'N	88 08'W	214	420	469	498	496	503	522	531	515	482	447	370	364	
● LA CROSSE	43 52'N	91 15'W	205	434	485	491	489	500	521	534	527	487	463	383	372	
● MADISON	43 08'N	89 20'W	262	449	499	500	476	508	532	543	538	505	479	380	376	
● MILWAUKEE	42 57'N	87 54'W	211	414	454	477	491	515	541	550	541	508	476	392	363	
WV CHARLESTON	38 22'N	81 36'W	290	355	381	409	444	472	486	471	466	466	459	389	342	
● HUNTINGTON	38 22'N	82 33'W	255	375	408	432	474	493	505	495	486	478	474	404	362	
WY CASPER	42 55'N	106 28'W	1612	589	624	631	628	642	684	711	700	678	638	572	570	
● CHEYENNE	41 09'N	104 49'W	1872	610	623	608	593	578	618	625	613	631	623	574	590	
● ROCK SPRINGS	41 39'N	109 04'W	2056	599	645	655	654	680	704	714	700	698	663	588	585	
● SHERIDAN	44 46'N	106 58'W	1209	488	516	546	532	551	590	655	638	597	552	476	467	
URUGUAY																
=====																
● MONTEVIDEO	34 52'S	56 10'W	25	652	658	636	606	582	535	528	548	576	590	632	639	
● SAN JORGE	32 05'S	56 00'W	122	663	705	619	592	559	486	551	587	555	591	631	623	
VENEZUELA																
=====																
● BARCELONA	10 07'N	64 41'W	7	596	603	588	546	527	500	544	561	595	567	577	592	
● BARQUISIMETO	10 04'N	69 19'W	591	545	598	540	530	519	559	584	568	588	599	505	587	
● CALABOZO	8 48'N	67 27'W	100	579	613	602	558	512	545	509	522	431	553	566	554	
● CARACAS	10 30'N	66 53'W	862	594	647	612	573	479	503	536	561	564	523	529	576	
● CIUDAD BOLIVAR	8 09'N	63 33'W	50	562	572	554	543	541	485	547	584	607	574	563	588	
● CORD	11 25'N	69 41'W	20	678	690	705	641	602	630	673	663	678	621	639	656	
● GUIRIA	10 35'N	62 18'W	8	494	496	502	516	531	491	521	538	542	481	479	507	
● L ORCHILA	11 48'N	66 11'W	3	613	660	662	652	538	590	503	642	663	644	607	663	
● MAIQUETIA	10 36'N	66 59'W	43	594	661	564	496	475	617	661	636	675	598	596	609	
● MARACAIBO	10 39'N	71 30'W	40	580	562	510	535	468	511	553	575	687	538	576	631	
● MARACAY	10 15'N	67 39'W	442	715	725	689	645	514	589	619	637	674	570	622	652	
● MATURIN	9 45'N	63 11'W	70	518	536	508	475	461	415	441	495	474	487	474	487	
● MERIDA	8 30'N	71 15'W	1495	681	665	649	636	592	548	598	637	633	594	635	716	
● MORON	10 31'N	68 11'W	4	722	696	692	630	591	619	733	699	700	661	685	698	
● PUERTO AYACUCHO	5 41'N	67 38'W	134	551	532	481	508	393	421	406	497	483	499	512	514	
● SAN ANTONIO	7 51'N	72 27'W	404	566	567	466	416	493	476	507	522	517	522	533	556	
● SANTA ELENA	4 36'N	61 67'W	907	546	522	551	554	467	491	512	553	592	534	541	507	
● SAN FERNANDO	7 54'N	67 25'W	73	538	552	531	459	394	391	424	429	452	476	514	536	
● TUMEREMO	7 18'N	61 27'W	180	465	451	452	470	472	452	485	476	567	523	515	486	
VIETNAM																
=====																
● CHAPA	22 21'N	103 49'E	1570	395	442	574	376	404	363	403	378	439	389	478	607	

APPENDIX A (CON'T)

VALUES OF MONTHLY AVG. KH * 1000 [1]

STATION	LAT	LONG	ELEV	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	NOTES
VIETNAM (CON'T)																
=====																
PHU-LEIN	20 48'N	106 38'E	125	305	-	234	384	474	493	492	-	-	-	505	450	
WAKE ISLAND																
=====																
WAKE ISLAND	19 17'N	166 39'E	12	679	708	688	694	694	694	685	686	685	687	716	644	
YUGOSLAVIA																
=====																
BANJA LUKA	44 47'N	17 13'E	153	366	420	404	488	576	513	559	536	575	470	167	278	
BEOGRAD	44 47'N	20 32'E	243	394	439	459	452	504	528	550	498	523	478	339	344	
HERCAGNOVI	42 28'N	18 31'E	34	299	372	343	402	502	511	575	565	508	439	290	242	
LJUBLJANA	46 04'N	14 31'W	300	224	268	320	401	471	419	483	455	414	302	139	169	
NEGOTIN	44 14'N	22 32'E	39	400	476	381	477	556	570	601	586	518	421	206	326	
PARG	45 36'N	14 38'E	863	378	338	313	341	416	357	450	431	408	358	188	234	
SKOPJE	41 59'N	21 28'E	240	311	472	394	465	553	556	601	582	528	431	303	270	
SLJEME	45 54'N	15 37'W	999	347	366	384	427	492	407	489	461	454	382	231	276	
SPLIT	43 31'N	16 26'E	122	403	417	405	464	488	458	552	539	511	441	313	310	
ULQINJ	41 55'N	19 13'E	53	401	476	457	521	633	661	688	664	574	494	323	306	
ZAGREB-GRIC	45 29'N	15 59'E	157	314	376	396	466	539	460	436	525	499	390	224	253	
ZLATIBOR	43 44'N	19 43'E	1030	476	601	535	495	556	547	593	566	549	459	364	410	

APPENDIX B
FAILURE RATES FOR RELIABILITY ESTIMATION

B.1 FAILURE-RATE TRENDS

A system or equipment of mature design, when operated and maintained under specified conditions or operational environment, should exhibit a relatively constant failure rate throughout a specified period of use. Exhibit B-1 depicts the three failure-rate trends normally encountered in the life cycle of an item — a decreasing failure rate during manufacture or initial installation; a constant failure-rate trend during the useful period; and an increasing failure-rate trend signifying wearout of certain constituent elements of the system.

The "useful" period is defined as the period of operation between the installation "debugging" period and the scheduled replacement of items causing the wearout trend. A constant failure rate can be achieved in PV systems when quality acceptance criteria are applied in the purchase of components (e. g., PV modules, batteries, regulators, etc.) for the system; when the installed PV system is fully debugged of any design-margin and interface tolerance problems; and when wearout failure modes in these constituent components are identified and are circumvented by planned (scheduled) replacement of impending failures as a preventive maintenance policy.

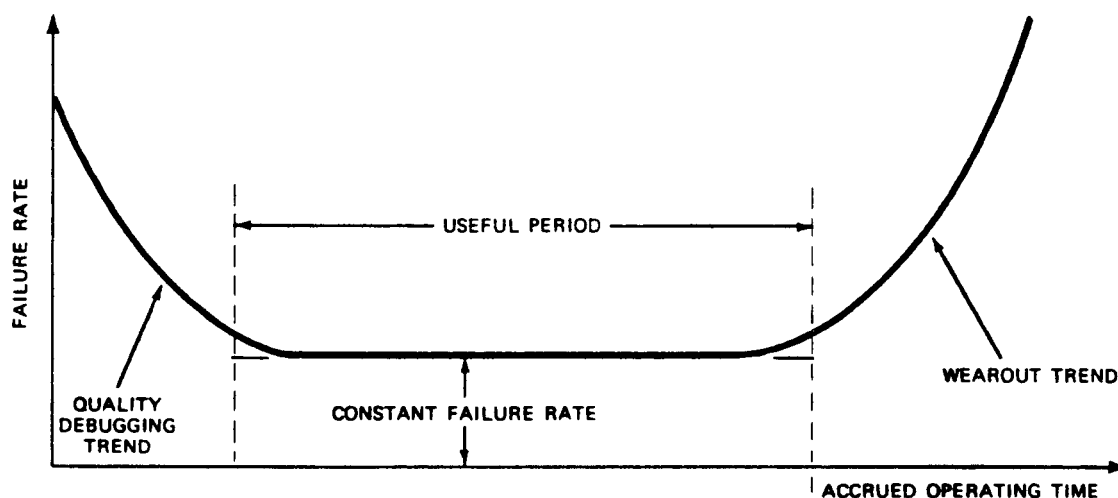


Exhibit B-1
FAILURE RATE OF AN ITEM AS A FUNCTION OF OPERATING TIME

B.2 SOURCES OF FAILURE-RATE DATA

No formal failure experience data collection/analysis system has yet been established specifically for PV system applications. However, failure experience data from other system applications have been collected, analyzed, and periodically updated by several government activities. The data are published in useful handbook format for the guidance of design engineers in estimating and optimizing the reliability and maintainability of their system designs. Until PV-related failure data becomes available, the following existing failure-data sources are useful:

- (a) Basic Electrical/Electronic Failure-Rate vs Stress Data -- Military Standardization Handbook (MIL-HDBK-217B), "reliability prediction of Electronic Equipment", published by the Government Printing Office. Provides basic failure rates under different levels of "use" stress factors (temperature, voltage, current, quality, application, etc.) for generic electrical and electronic part types (semiconductors, tubes, resistors, capacitors, relays, switches, connectors, wires, cables, etc.).
- (b) Nonelectronic Parts Failure-Rate Data -- Nonelectronic Parts Reliability Data Book (NPRD-1), published by the DOD Reliability Analysis Center operated by IIT Research Institute (IITRI/RAC), Griffiss AFB, New York 13441.
- (c) Government-Industry Data Exchange Program GIDEP -- provides summaries of failure-rate data reported by the GIDEP membership and published by GIDEP Operations Center, NWS Seal Beach, Corona, California 91720
- (d) Photovoltaic Module Failure Experience -- monitored and periodically reported by MIT Lincoln Laboratory, Lexington, Massachusetts, under DOE sponsorship.

B.3 ESTIMATED FAILURE RATES FOR
CERTAIN ITEMS IN THE TYPICAL PV SYSTEM

Exhibit B-2 is a table presenting the range and average failure-rate experience for generic part and equipment types which may be used in stand-alone PV systems. These values are derived from the sources described in paragraph B-2 above. They are useful for feasibility estimation in preliminary design, pending receipt of test data pertaining to the specific items actually to be employed in the PVPS final design. Failure rates are expressed in failures per 10^6 calendar hours or 10^6 operating cycles, as appropriate.

Exhibit B-2
PRELIMINARY FAILURE-RATE ESTIMATES OF SELECTED ITEMS

Generic Item (Part or Component)	Range of Failure Rates (failures per 10^6 hrs)			Reference
	Minimum	Average	Maximum	
Photovoltaic Cells:				
Failures (Open Circuit) --				
Estimated From Diode Model	0.01	0.03	0.30	(a)
Experience (Nebraska MIT/LL)	--	0.02	--	(d)
Degradation (Dirt Accumulation Between Cleaning) --				
Nebraska Site Experience	10.0	16.0	26.0	(d)
Cambridge Site Experience	36.0	38.0	40.0	(d)
NYC Site Experience	44.0	53.0	65.0	(d)
Diode (Silicon), General Purpose	0.002	0.02	0.10	(a)
Circuit Breakers (CB)	1.0	3.0	10.0	(b)
Relay	0.5	2.0	8.0	(b)
Connections:				
Weld	--	0.002	--	(a)
Wire Wrap	--	>0.0001	--	(a)
Crimp	--	0.007	--	(a)
Connectors	--	0.5	--	(a)
Switches (All Types)	1.0	3.0	10.0	(b)
Battery Cells (2 Volts/Cell):				
Random Cell Failure (Open/Short)	0.30	0.80	2.40	(b)
Gaussian Wearout (Mean Cycles to Failure)	150 cy.	500 cy.	1500 cy.	Depends on Vendor Data
DC/DC Regulator (Typical 15 KW)	70.0	200.0	500.0	(a)
Engine/Generator Equipment:				
Engine (Diesel)	130.0	350.0	850.0	(c)
Generator (DC)	50.0	100.0	200.0	(c)
Switching Device (Typical)	100.0	200.0	445.0	(a)

APPENDIX C
LISTING OF SPONSORS OF CODES AND STANDARDS

C.1 LIST OF CODES AND STANDARDS AGENCIES AND THEIR ADDRESSES

American National Standards Institute, Inc.
1430 Broadway
New York, New York 10018

American Society for Testing and Materials
1916 Race Street
Philadelphia, Pennsylvania 19103

Building Officials and Code Administrators
International, Inc.
17926 South Halsted Street
Homewood, Illinois 60430

ETL Testing Laboratories, Inc.
Industrial Park
Cortland, New York 13405

Factory Mutual Research
1151 Boston-Providence Turnpike
Norwood, Massachusetts 02062

Institute of Electrical and Electronics Engineers, Inc.
345 East 47th Street
New York, New York 10017

International Conference of Building Officials
5360 South Workman Mill Road
Whittier, California 90901

National Fire Protection Association
470 Atlantic Avenue
Boston, Massachusetts 02210

Occupational Safety and Health Administration
Department of Labor
200 Constitution Ave, N.W.
Washington, D.C. 20004

Solar Energy Research Institute
1536 Cole Boulevard
Golden, Colorado 80401

Southern Building Code Congress International
3617 Eighth Avenue South
Birmingham, Alabama 35222

Underwriters Laboratories, Inc.
333 Pfingsten Road
Chicago, Illinois 60062

C.2 LISTING OF CODES AND STANDARDS BY AGENCIES

American National Standards Institute, Inc.

<u>Std.-No.</u>	<u>Title</u>
ANSI A. 58.1-1972	Building Code Requirements for Minimum Loads in Building and Other Structures
ANSI Z97.1-1975	Safety Performance Specifications and Methods of Test for Safety Glazing Material Used in Buildings

American Society of Testing and Materials

<u>Std.-No.</u>	<u>Title</u>
B 117-73	Standard Method of Salt Spray (Fog) Testing
B 287-74	Standard Method of Acetic Acid - Salt Spray (Fog) Testing
B 368-78	Standard Method for Copper-Accelerated Acetic Acid-Salt Spray (Fog) Testing (Cass Test)

American Society of Testing and Materials (Continued)

<u>Std. No.</u>	<u>Title</u>
C 297-61	Standard Method of Tension Test of Flat Sandwich Constructions in Flatwise Plane
C 355-64	Standard Methods of Test for Water Vapor Transmission of Thick Materials
C 393-62	Standard Method of Flexure Test of Flat Sandwich Constructions
D 568-61	Flammability of Plastics 0.127 cm (0.050 in.) and Under in Thickness
D 635-63	Flammability of Rigid Plastics over 0.127 cm (0.050 in.) in Thickness
D 638-77a	Standard Test Method for Tensile Properties of Plastics
D 750-68	Recommended Practice for Operating Light-and Weather-Exposure Apparatus (Carbon-Arc Type) for Artificial Weather Testing of Rubber Compounds
D 775-73	Standard Method of Drop Test for Shipping Containers
D 790-71	Standard Test Method for Flexural Properties of Plastics and Electrical Insulating Materials
D 822-73	Standard Recommended Practice for Operating Light-and Water-Exposure Apparatus (Carbon-Arc Type) for Testing Paint, Varnish, Lacquer, and Related Products
D 897-78	Standard Test Method for Tensile Properties of Adhesive Bonds
D 1006-73	Standard Recommended Practice for Conducting Exterior Exposure Tests of Paints on wood
D 1014-66	Standard Method of Conducting Exterior Exposure Tests of Paint on Steel
D 1044-76	Resistance of Transparent Plastics to Surface Abrasion Standard Test Method
D 1149-78	Standard Test Method for Rubber Deterioration-Surface Ozone Cracking in a Chamber (Flat Specimen)
D 1433-58	Flammability of Flexible Thin Plastic Sheeting
D 1435-75	Standard Recommended Practice for Outdoor Weathering of Plastics
D 1828-70	Recommended Practice for Atmospheric Exposure of Adhesive-Bonded Joints and Structures
D 1929-68	Ignition Properties of Plastics
D 2247-73	Standard Method for Testing Coated Metal Specimens of 100% Relative Humidity
D 2249-74	Standard Method of Predicting the Effect of Weathering on Face Glazing and Bedding Compounds on Metal Sash D 2305-72 Methods of Testing Polymeric Film Used for Electrical Insulation
D 2565-76	Standard Recommended Practice for Xenon Arc-Type (Water Coded Light-and Water-Exposure Apparatus for Exposure of Plastics)
D 2843-70	Measuring the Density of Smoke from the Burning or Decomposition of Plastics
D 3161-76	Standard Test Method for Wind Resistance of Asphalt Shingles

American Society of Testing and Materials (Continued)

<u>Std. No.</u>	<u>Title</u>
E 72-74a	Standard Methods of Conducting Strength Tests of Panels for Building Construction
E 84-70	Standard Method of Test for Surface Burning Characteristics of Building Materials
E 96-66	Standard Methods of Test for Water Vapor Transmission of Materials in Sheet Form
E 108-58	Standard Methods of Fire Tests of Roof Coverings
E 119-73	Standard Methods of Fire Tests of Building Construction and Materials
E 136-73	Standard Method of Test for Noncombustibility of Elementary Materials
E 424-71	Standard Methods of Test for Solar Energy Transmittance and Reflectance (Terrestrial) of Sheet Materials
F 146-72	Standard Methods of Test for Fluid Resistance of Gasket Materials
G 7-77a	Standard Practice for Atmospheric Environmental Exposure Testing of Nonmetallic Materials
G 21-70	Standard Recommended Practice for Determining Resistance of Synthetic Polymeric Materials to Fungi
G 23-75	Standard Recommended Practice for Operating Light-and Water-Exposure Apparatus (Carbon-Arc Type) for Exposure of Nonmetallic Materials
G 24-73	Standard Recommended Practice for Conducting Natural Light Exposures Under Glass
G 26-77	Standard Recommended Practice for Operating Light-Exposure Apparatus (Xenon-Arc Type) with and without Water for Exposure of Nonmetallic Materials
G 29-75	Method of Test for Algal Resistance of Plastic Films

Institute of Electrical and Electronics Engineers

<u>Std. No.</u>	<u>Title</u>
141	Recommended Practice for Electric Power Distribution for Industrial Plants (IEEE Red Book)
142	Recommended Practice for Grounding of Industrial and Commercial Power Systems (IEEE Green Book)
242	Recommended Practice for Electric Power Systems in Commercial Buildings (IEEE Gray Book)
446	Recommended Practice for Emergency and Standby Power Systems (IEEE Orange Book)
485	Sizing of Large Lead Storage Batteries for Generating Stations and Substations

Federal Specification (General Services Administration)

<u>No</u>	<u>Title</u>
DD-G-451C	Flat Glass for Glazing, Mirrors, and Other Uses

Military Standard

<u>No.</u>	<u>Title</u>
MIL-STD-810C/10 March 1975/Environmental Test Methods:	

Method 501.1 High Temperature
Method 502.1 Low Temperature
Method 508.1 Fungus
Method 509.1 Salt Fog
Method 507.1 Humidity
Method 506.1 Rain
Method 516.2 Shock

National Fire Protection Association

<u>No.</u>	<u>Title</u>
NFPA 70-1981	National Electrical Code
NFPA 78-1975	Lightning Protection Code
NFPA 251-1972	Standard Methods of Fire Tests of Building Construction and Materials NFPA-255-1972 Method of Test of Surface Burning Characteristics of Building Material
NFPA 256-1976	Standard Methods of Fire Tests of Roof Coverings
NFPA 258-1976	Standard Test Method for Measuring the Smoke Generated by Solid Materials

National Bureau of Standards

<u>No.</u>	<u>Title</u>
NBS-23	Hail Resistance of Roofing Products
NBS-Special	Publication 473-003-003-017-15-2 Research and Innovation in the Building Regulatory Process Session 2B, Issues in Building Regulation "Decision-Aiding Communications in the Regulatory Agency: The Partisan Uses of Technical Information," Francis T. Ventre

National Building Codes

<u>Title</u>
Uniform Building Code
International Conferences of Building Officials
Southern Building Code
Southern Building Code Congress International
National Electric Code
National Fire Protection Association
BOCA
Building Officials and Code Administrators International

Underwriters Laboratories

<u>No.</u>	<u>Title</u>
UL 1	Flexible Metal Conduit
UL 6	Rigid Metal Conduit
UL 33	Fusible Links
UL 50	Cabinets and Boxes
UL 94	Tests for Flammability of Plastic Materials
UL 96	Lightning Protection Components
UL 231	Power Outlets
UL 263	Fire Tests of Building Construction & Materials
UL 310	Quick Connect Terminals
UL 360	Liquid-Tight Flexible Steel Conduit
UL 467	Grounding and Bonding Equipment
UL 486	Electric-Wire Connector and Soldering Lugs
UL 514	Outlet Boxes and Fittings
UL 651	Rigid Nonmetallic Conduit
UL 729	Nonmetallic - Sheathed Cable
UL 723	Tests for Surface Buring Characteristics of Building Materials
UL 790	Tests for Fire Resistance of Roof Covering Materials
UL 854	Service Entrance Cables
UL 857	Busways and Associated Fittings
UL 997	Wind Resistance of Prepared Roof Covering Materials
UL 1059	Terminal Blocks

REFERENCES

- 1-1 MONEGON, LTD, Selecting Solar Photovoltaic Power Systems (Seminar-Text), Volumes 1 & 2, Report M102, Gaithersburg, Maryland, 1980.
- 4-1 Ruzek, J.B. and W.J. Stolte, (Bechtel National Inc., San Francisco, California) Requirements Definition and Preliminary Design of a Photovoltaic Central Station Test Facility, Final Report, Sandia Laboratories SAND 79-7012, April 1979.
- 4-2 Crippi, R.A., Module Efficiency Definitions, Characteristics, and Examples. LSSA Report No. 5101-43, Jet Propulsion Laboratory, Pasadena, California October 1977.
- 4-3 Ross, R.G., C.C. Gonzalez, "Reference Conditions for Reporting Terrestrial Photovoltaic Performance". Paper presented at American Section of International Solar Energy Society, 1980 Annual Meeting, Phoenix, Arizona. June 2-6, 1980.
- 4-4 Forman, S.E. Endurance and Soil Accumulation Testing of Photovoltaic Modules at Various MIT/LL Test Sites, MIT Lincoln Laboratory, Lexington Massachusetts Report C00-4094-23 under ERDA Contract EY-76-C-02-4094, Sept. 1978.
- 4-5 Workshop on Flat Plate Photovoltaic Module & Array Circuit Design Optimization, Jet Propulsion Laboratory, Pasadena, California, May 19 & 20, 1980.
- 4-6 Solar Photovoltaic Applications Seminar: Design, Installation and Operation of Small, Stand-Alone Photovoltaic Power Systems, PRC Energy Analysis Co., McLean, Virginia, DOE report DOE/CS/32522-T1, July 1980.
- 4-7 Klein, D.N. Handbook for Photovoltaic Cabling, MIT Lincoln Laboratory, Lexington, Massachusetts, Report C00-4094-90, August, 1980.
- 6-1 Bechtel National Inc., Handbook For Battery Energy Storage Photovoltaic Power Systems, Final Report, San Francisco, California. Work performed under DOE Contract No. DE-AC03-78ET 26902, Sandia National Laboratories, SAND80-7022, February 1980.
- 6-2 Bird Engineering - Research Associates, Inc., Reliability Guides, Vols. 1-4, Prepared for Naval Ordnance Systems Command Under contract N00017-69-C-4441, October 1971.
- 6-3 Bird Engineering - Research Associates, Inc., Maintainability Engineering Handbook, Prepared for Naval Ordnance Systems Command Under Contract N00017-68-C4403, June 1969.

REFERENCES (Continued)

- 6-4 Mood, A.M., Introduction to the Theory of Statistics, McGraw-Hill, New York, NY, 1963.
- 9-1 NASA-Lewis Research Center Photovoltaic Structures Handbook, -- (in preparation).
- 9-2 J.L. Marshall, Lightning Protection, John Wiley & Sons, 1973.
- 10-1 Bifano, W.J., A.F. Ratajczak, W.J. Ice, NASA-Lewis Research Center, "Design and Fabrication of a Photovoltaic Power System for the Papago Indian Village of Schuchuli (Gunsight), Arizona," NASA TM-78948, June 1978.
- 11-1 Collares-Pereira, M., A. Rabl, "The Average Distribution of Solar Radiation -- Correlations Between Diffuse and Hemispherical and Between Daily and Hourly Insolation Values," pp 155-164, Solar Energy, Vol. 22, No. 2, 1979.
- 11-2 Threlkeld, J.L., Thermal Environmental Engineering, Englewood Cliffs, N.J. : Prentice-Hall, Inc. 1962.
- 11-3 1972 ASHRAE Handbook of Fundamentals. New York, N.Y. : American Society of Heating, Refrigerating and Air Conditioning Engineers, Inc., 1972.
- 11-4 Liu, B.H.Y., R.C. Jordan, "The Interrelationship and Characteristic Distribution of Direct, Diffuse and Total Solar Radiation," Solar Energy. Vol. 4, No. 1, 1960.
- 13-1 Mechtly, E.A., University of Illinois The International System of Units Physical Constants and Conversion Factor Second Revision, National Aeronautics and Space Administration Report NASA SP-7012, 1973.
- A-1 Cinquemani, V, J.R. Owenby, Jr., and R.G. Baldwin (National Oceanic and Atmospheric Administration, National Climatic Center, Asheville, N.C.) Input Data for Solar Systems, prepared for USDOE under Interagency Agreement No. E (49-26) - 1041, November 1978.
- A-2 Lof, G.O.G., J.A. Duffie, C.O. Smith, World Distribution of Solar Radiation, College of Engineering University of Wisconsin, Engineering Experimental Station Report No. 21, July 1966.