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PHOTOVOLTAIC SYSTEMS CONCEPT STUDY

Final Report. Volume 2 of 5

April 1977

Work Performed Under Contract No. EY-76-C-04-2748

Spectrolab, Inc.
Sylmar, California

U.S. Department of Energy

Solar Energy

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FINAL REPORT
PHOTOVOLTAIC SYSTEMS CONCEPT STUDY

VOLUME II OF V

- SYSTEM COMPONENTS
- RESIDENTIAL SYSTEM DESIGN

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PREFACE

This report documents the work performed in the conceptual design and systems analysis of three sizes of photovoltaic solar electric power systems. Conceptual system designs were developed for a single family residence, a central station power plant, and for two on-site intermediate systems (shopping center and commercial retrofit). The work was carried out by a team consisting of Spectrolab, Inc.; Bechtel Corporation; Ingenasu Associates--a group of faculty members from Arizona State University; Facilities Systems Engineering Corporation; and Midwest Research Institute; with Spectrolab as prime contractor and program manager.

This report has been prepared in nine sections plus appendices, separated into five separate volumes based on subject content. The following outlines the report format and section content:

Volume I Sections 1 and 2

INTRODUCTION AND OVERALL PROGRAM SUMMARY

Volume II Sections 3 and 4

DESCRIPTION OF SOLAR CELL ARRAYS, POWER CONDITIONING,
AND STORAGE COMPONENTS
DETAILED DESIGN OF RESIDENTIAL SYSTEM

Volume III Sections 5 and 6

DETAILED DESIGN OF SHOPPING CENTER SYSTEM, RETROFIT
APPLICATION, AND SIMPLIFIED ON-SITE SYSTEM DESIGN METHOD

Volume IV Sections 7, 8, and 9

DETAILED CENTRAL POWER STATION DESIGN,
ECONOMIC PERFORMANCE CHARACTERISTICS,
AND SOCIAL-INSTITUTIONAL ASSESSMENT

Volume V Appendices

REFERENCE DOCUMENTATION ON ECONOMIC MODELS
TECHNICAL DATA, AND PERFORMANCE ANALYSIS DATA

3.0 SYSTEM COMPONENTS

In this section component design data of a general nature is provided for the residential, shopping center, and central power station applications. In Section 3.1 photovoltaic array designs are described including the efficiency, cooling, and optical characteristics. Section 3.2 provides descriptive material associated with power conditioning equipment, utility interfacing techniques, regulators and the energy storage components.

3.1 PHOTOVOLTAIC ARRAY DESIGNS

Results are presented in this section for three collector types: (1) a fixed flat array module, which is used in the residential and commercial applications; (2) a combined array module with thermal (hot air) as well as electrical output, which is an alternate for the residential systems, and (3) a tracking, concentrator array which is used in the central power application.

All three collectors are designed around silicon solar cells with performance characteristics which are close to those of the best cells which can be made today, regardless of manufacturing cost. Performance limitations of currently available cells have been analyzed and detailed cell designs prepared. We feel quite confident that the projected level of performance can be obtained in low-cost production cells by 1980, and that this level of performance is not far from the ultimate that can be economically achieved, based on our current understanding of performance limitations in silicon solar cells. While it is possible that future developments will lead to improved performance, we consider it equally likely that the methods now under intensive investigation for reducing silicon wafer cost will not prove capable of providing material with quite as good properties as the material used today, and therefore that in future some performance may be sacrificed to reduce cell cost. A summary of the performance characteristics assumed is given in Table 3.1-A.

3.1.1 Flat Collector

The flat collector design is essentially an industrial steel-frame window with solar cells bonded to the back surface with a polyvinyl butyral interlayer and protected by a thin sheet of glass-epoxy laminate. This design was chosen on the basis of results from a parallel company-funded program in which about 50 variations on three basic design concepts were evaluated by fabrication of prototype collectors, followed by high-stress environmental testing in temperature cycle, high-temperature

Table 3.1-A: CELL PERFORMANCE CHARACTERISTICS

Usual expression for I-V characteristic is:

$$I = I_L - I_0 \left[\exp \left(\frac{V}{V_0} \right) - 1 \right]$$

where $V_0 = kT/q$ and the "A-factor" includes effects of series resistance. With a little algebraic manipulation, the expression can be rewritten as:

$$\frac{I}{I_{sc}} = 1 - \exp \frac{V - V_{oc}}{V_0}$$

Values of I_{sc} , V_{oc} and V_0 can either be calculated or determined experimentally; results are in good agreement except for V_{oc} in low-resistivity material.

Bandpass of silicon cell behind glass extends from 400 nm to wavelength where $\alpha L = 1$, where L is the lesser of cell thickness or diffusion length. Taking L as 0.15 mm, integration of AM2 spectrum gives 407.4 A/m² at insolation of 1 kw/m². Quantum efficiency of cell is product of contact coverage factor and absorptivity: taking these as 0.925 and 0.94 gives $I_{sc} = 354$ A/m². Experimental data on best laboratory cells gives $I_{sc} \approx 325$ A/m². Calculation of V_0 and V_{oc} is more involved, but agreement with experiments is also good. The experimental values are $V_0 \approx 0.042$ volts at 28°C for well-designed cells with low series resistance, $V_{oc} \approx 0.600$ -0.620 volts.

Experimentally measured temperature coefficients are -2.2 mV/°C for V_{oc} , .056%/°C for I_{sc} . These values lead to the following expression for maximum-power efficiency:

$$\eta = 0.15 [1 + 0.12 \log H - .0045 (T_c - 28)]$$

where H is insolation in kw/m² and T_c is cell temperature in °C.

high-humidity, and sand and dust resistance tests. Designs passing these environmental tests were further evaluated as to thermal dissipation performance, mechanical integrity, and cost of manufacture and installation. The selected design passed all environmental tests and was among the best on each of the other criteria.

The flat collector design also provides the basis for a simple and inexpensive combined electrical/thermal collector design. The combined collector design is derived by adding a glass cover to reduce front-surface heat loss and a black-painted panel to form the back wall of the air duct. It has been shown that both the electrical and thermal output from a combined collector can be expressed by generalizing the well-known Hottel-Whillier-Bliss model for a thermal collector. Using this model, it can be further shown that (1) fins in the duct are not cost-effective, since a simple parallel-wall duct provides ~90% of the thermal energy gain attainable with infinite heat transfer coefficient to the air stream; (2) choosing air stream velocity for optimum thermal transfer automatically optimizes electrical output; (3) a combined collector will provide about 80% of the thermal output of a similar thermal-only collector and about 80% of the electrical output of the electrical-only collector design; and (4) this results in the combined collector being less cost effective than separate electrical and thermal collectors in most cases, except if cell cost is a small fraction of installed collector cost or available area is insufficient for separate collectors.

Figure 3.1-A is a sketch of the construction of the two non-concentrating collector designs. Table 3.1-B is a cost summary for each design. Table 3.1-C is an energy balance for the electrical-only collector under 1 kw/m^2 , AM2 spectrum illumination, and includes a calculation of K_e , the overall thermal conductance from cells to ambient air. The temperature difference between cells and ambient equals the insolation on the collector divided by K_e . Figures 3.1-B and 3.1-C refer to the combined collector design. The abscissa of both figures is the heat transfer coefficient from the absorber plate to the air stream. For reasonable flow velocities, values of 25 to 35 $\text{watts/m}^2\text{-}^\circ\text{C}$ are obtained for smooth surfaces, while larger

COMBINED ELECTRICAL-THERMAL

FIGURE 3.1-A: FIXED COLLECTOR DESIGNS

Table 3.1-B: FIXED COLLECTOR COST SUMMARY

3' x 8' Module

<u>MATERIALS</u>	<u>kg/Module</u>	<u>Elec. Only \$/Module</u>	<u>Combined \$/Module</u>
Glass, 3/32" low iron	22.5	\$ 6.24	\$ 9.36
Polyvinyl butyral interlayer	0.1	4.01	4.01
Aluminum frame and mounting hardware	5.9	9.19	17.28
Silicone rubber seal strip	0.1	4.50	9.00
Electrical connectors	0.2	1.80	1.80
Insulation	-	-	3.00
	28.8	\$25.74	\$44.45
<u>LABOR (At \$12/hr including overhead)</u>	<u>Hrs/Module</u>	<u>\$/Module</u>	<u>Combined \$/Module</u>
Cell interconnection and test	1.00	\$12.00	\$12.00
Laminate and assemble to frame	0.75	9.00	9.00
Add terminations, final test & inspection	0.25	3.00	4.50
Packing for shipping	0.05	0.60	1.20
	2.05	\$24.60	\$26.70
Manufacturing cost (excl. cells)		\$50.34	\$71.15
Distribution expense (15%)		7.55	10.67
Profit (20%)		10.07	14.23
Selling price per module (excl. cells)		\$67.96	\$96.05
per square meter		\$30.48	\$43.08
Elec. Output (15% cells, 0.74 packing, std. test cond.)		247.5 watts	198.0 watts
Allowable cost at \$500/kW		\$123.75	
Allowable cell cost		\$ 55.79	
per square meter of cells		\$ 33.81	
per kW - cells only		\$225.40	

Table 3.1-C: ENERGY BALANCE, FIXED COLLECTOR

<u>Input:</u> AM2 insolation at 1000 watts/m ²		
Reflection at front surface:	50 w/m ²	
Absorption in glass (KL = .0125):	12.5 w/m ²	
Incident on cells (PF = 0.74):	693.75 w/m ²	
Reflected from contacts:	52 w/m ²	
Reflected from silicon:	38.5 w/m ²	
Reflected from back contact and out of cell:	79.3 w/m ²	
Converted to electricity (150 watts/m ² x 0.74) =	111 w/m ²	
Incident on spaces between cells:	243.75 w/m ²	
80% transmitted =	195 w/m ²	
5% absorbed =	12.2 w/m ²	
15% reflected =	36.55 w/m ²	
<u>Totals:</u>		
Reflected energy		256.35
Transmitted energy		195.00
Converted to electricity		111.00
Converted to heat		437.65

Calculation of K_e

From wind tunnel tests, single-sided convective heat transfer coefficient (45° angle between wind and surface) is $h_c = 8.73 + 5.33V$ (h in w/m²-°C, V in m/s).

Single-sided radiative heat transfer coefficient (collector 311°K, sky 301°K, $\epsilon = 0.88$) is $h_r = 6.26 \text{ w/m}^2\text{-}^\circ\text{C}$.

K_e equals $(h_c + h_r)/0.44 = .0341 + .0121V$ in units of kW/m²-°C.

Figure 3.1-B. COLLECTOR EFFICIENCY FACTOR VERSUS ABSORBER TO AIR STREAM HEAT TRANSFER COEFFICIENT

Figure 3.1-C. REDUCED ELECTRICAL EFFICIENCY VERSUS ABSORBER TO AIR HEAT TRANSFER COEFFICIENT

values of h can be obtained with finned surfaces. U_L is the collector thermal loss coefficient which ranges from 5 for a high-quality single-glazed collector to 30 for an unglazed collector. Figure 3.1-B plots the collector efficiency factor (modified to include both electrical and thermal output) against h , and it can be seen that a simple unfinned duct provides 80% to 90% of the efficiency attainable with h infinite. Figure 3.1-C plots the reduced electrical efficiency, the ratio of the electrical output from the combined collector to the electrical output which would be obtained if the cells were at ambient temperature, against h . It can be seen that the reduced electrical efficiency, for a smooth duct, is ~85% for the single-glazed collector and ~95% for the unglazed collector. Subtracting the additional optical loss associated with the glazing leads to the conclusion that the electrical efficiency of the single-glazed collector will be ~80% of the unglazed collector.

3.1.2 Concentrator Unit

The design of the concentrating collector drew on previous Spectrolab/Arizona State University work on concentrating collectors. Optically, the concentrator contains two elements: a primary element consisting of a parabolic trough with a 30° rim angle, and a secondary element consisting of a CEC concentrator with a concentration ratio of 2. The overall aperture/absorber area ratio is 20, and the field of view is $\pm 1.8^\circ$. In earlier work for Argonne National Laboratory, we showed that the addition of a low-power CEC to several different types of primary concentrators had the following advantages:

- 1) The concentration ratio attainable for a given field of view is nearly equal to a CEC alone and much better than the primary concentrator alone; for example, at 1.6° field of view the maximum concentration ratio, including shading losses (mirror reflectivity equals unity) is 35.8 for the CEC, 16.9 for an optimized parabolic trough (45° rim angle), 30.8 for the optically optimum two-element combination (17.4° parabola, 3.35 power CEC), and 29.0 for the combination selected (30° parabola, 2.0 power CEC).

2) The cost of the two-element concentrator is less than the cost of a parabolic trough of the same total concentration ratio, and at least an order of magnitude less than the cost of a CEC, because the reflective surface area is less. Also, the small CEC can be fabricated as an aluminum extrusion and functions as a structural and thermal dissipation element as well as an optical element.

3) The two-element concentrator provides nearly uniform illumination of the cells while one-element concentrators do not; for example, the ratio of maximum local to average illumination for optimized concentrators with 2.5° field of view is nearly 20 for the parabolic trough, 3 for the CEC, and 1.2 for the two-element combination. The series resistance losses in the cell are proportional to the square of the local, rather than average, illumination intensity.

In the course of ASU/Spectrolab work on photovoltaic concentrating systems, it was found that the simplest tracking system -- fixed arrays mounted on a turntable that tracks the sun in azimuth -- provided better than 90% of the output of a full 2D tracking system. Turntable mounting has the advantage that multi-point support of the array is easily achieved, which reduces structural costs; also, only one drive system is required.

Having made the choices of a two-element optical concentrator and turntable mounting, the major design effort was directed to two problems: the design of a heat-exchange surface for the array which would provide large heat transfer coefficients at low manufacturing cost, and would obviate the requirement for liquid cooling; and the design of the structural components of the array to meet wind loading and building code requirements at the lowest possible cost. Both problems proved to be much more difficult than originally anticipated.

The elimination of liquid cooling was considered essential because the development of additional power generation facilities in the Southwest is severely constrained by the lack of cooling water. A system which did

not require cooling water was judged to be significantly more attractive to utilities, and much less limited as to location, than a water-cooled system. Experience with the construction and operation of concentrating photovoltaic systems had shown that structural integrity under high wind velocity conditions was of major importance in determining system reliability and maintenance costs. We proceeded to attack both problems by establishing design goals on the basis of analytical studies, and then exploring design options, utilizing both computational and experimental results, to establish the most cost-effective means for reaching these goals.

Passive Cooling

The design goal was chosen for heat transfer performance was a K_e factor of $0.3 \text{ kW/m}^2\text{-}^\circ\text{C}$. From analytical investigations of the influence of heat transfer coefficient on array efficiency, a K_e factor of 0.3 would result in a performance penalty of $\sim 12\%$ relative to an ideal system ($K_e = \infty$). These investigations are reviewed below:

A simple model combining cooling system and cell performance characteristics can be developed if it is assumed that the solar irradiation and cell heat rejection are uniform over the absorber surface, and that the heat rejection rate is proportional to the temperature difference between the cell and ambient air for passive cooling, or between cell and coolant for active cooling [1]. In addition, it is assumed that the cell efficiency decreases linearly with temperature. Such a model, though quite simple, is also quite useful for preliminary assessment of cooling schemes and basic system simulation.

The above noted assumptions, combined with an energy balance on the absorber, lead to the following result for cell power output, P , or cell efficiency, η , in normalized form:

$$\frac{P}{P_0} = \frac{\eta}{\eta_0} = \frac{1 - \left(\frac{\alpha q_s \beta_0}{K_e} \right)}{1 - \left(\frac{\alpha q_s \beta_0}{K_e} \right) \left(\frac{A_c}{A_a} \frac{\eta_0}{\alpha} \right)}$$

Here P_0 and η_0 are the power output and cell efficiency which would exist if the cells were at the ambient air or inlet coolant temperature, T_0 , depending on whether passive or active cooling is being considered. q_s is the solar irradiation seen by the absorber A_c/A_a is the fractional cell coverage of the absorber, and α is its effective solar absorptance. K_e is the effective thermal conductance, defined as the heat rejection rate per unit absorber area per unit temperature difference between cell and ambient for passive cooling or between cell and coolant inlet for active cooling. The defining equation for K_e is $Q = K_e A_a (T_c - T_0)$. β_0 is the fractional decrease in cell efficiency per unit increase in cell temperature.

Based on this model, the effective thermal conductance vs. solar irradiation is shown in Fig. 3.1-D for silicon cells, with output at various fractions of that for the limiting case of cells operating at ambient air or coolant inlet temperature. For example, the effective thermal conductance required to achieve P/P_0 of 80% at an irradiation of 25 kW/m^2 is about $0.3 \text{ kW/m}^2 \cdot ^\circ\text{C}$. Prior work [1 , 2] indicated that for linear reflective concentrator systems thermal conductances of this magnitude were possible with a passive cooling system. The current central station plant design uses a linear reflective concentrating system with a secondary concentrator. The additional surface area associated with the secondary concentrator can be used to advantage in providing passive cooling.

With the current system design the nominal cell irradiation level will be about 14 kW/m^2 . The normalized power output for this irradiation level is plotted in Fig. 3.1-E as a function of effective thermal conductance. It may be observed that an effective thermal conductance of $0.3 \text{ kW/m}^2 \cdot ^\circ\text{C}$ will provide a normalized power output of 88%, and that only very small percentage gains are realized by further increases in K_e . Active cooling using water can provide K_e values of up to about $3 \text{ kW/m}^2 \cdot ^\circ\text{C}$, which from Fig. 3.1-D gives $P/P_0 = 98\%$ for $q_s = 14 \text{ kW/m}^2$. However, when one additionally accounts for the temperature drop which must be accommodated for final heat rejection from the water coolant to the atmosphere via an external heat exchanger, the effect of the gain in K_e by water cooling is negated. (This would not, however, remain true as irradiation or concentration levels were increased.) Since little, if any, gain in performance would be achieved at the design concentration level by using active cooling with all of its additional complications (water requirement, corrosion problems, auxiliary power, pump and/or fan maintenance), it was decided to rely on passive cooling directly to ambient air for the central station plant design.

To achieve the passive cooling thermal conductance values required, finned or extended heat transfer surfaces must be used. For a given geometric design of the heat sink the effective thermal conductance will vary with the local wind speeds to which the heat sink is exposed. The yearly electrical output of the plant will, then, depend on the wind speeds which occur during collection hours. In assessing and comparing heat sink designs it is helpful to select an appropriate wind speed at which to estimate the thermal conductance values. It is reasonable to establish this in relation to the mean wind speed at the plant site during collection hours. The question as to whether a constant thermal conductance value established in relation to such a mean wind speed is adequate to estimate annual system performance was previously examined [3.1-F]. The annual system efficiency was determined based on a computer simulation with results compared for three different models for thermal conductance, K_e , as a function of wind speed. K_e was assumed constant at a value corresponding to the yearly mean wind speed during collection hours, varied linearly with wind speed, and varied as the square root of the wind speed. The results (Fig.3.1-F) indicate that for an effective aperture-to-cell area ratio of about 17 as in the current design, the annual system efficiency varies at most by about 8%. The maximum variation occurred between the constant and linear models for Edwards AFB, CA. This is due to the fact that wind speeds at Edwards are significantly below the yearly average in the winter months and significantly above average in the summer months. For Yuma, AZ the corresponding variation in predicted annual system efficiencies is negligible. Examination of Yuma wind speeds indicates they are relatively uniform throughout the year.

An 11 year average wind speed (1948-58) for Phoenix (site for present central station plant design) was computed for the 2, 4, 6 and 8 hour periods centered around solar noon (data obtained from National Weather Service tape).

The values ranged from 2.70 m/s for the 2 hour period to 2.77 m/s for the 8 hour period. Monthly averages showed relatively small variations from the yearly average similar to those for Yuma but much less than those for Edwards. It is concluded that thermal conductance values estimated in relation to the Phoenix 11 year average wind speed during collection hours (2.74 m/s), are appropriate for assessing the central station plant passive cooling system performance. However, since the Phoenix plant site will not be identically the Phoenix weather station site and since the presence of the plant arrays will in some degree alter local wind flow patterns, all subsequently presented values of thermal conductance for finned heat sink designs are for a mean wind speed which has been reduced by 25% to 2 m/s, unless otherwise indicated.

A schematic representation of a cross-section of the secondary concentrator is shown in Fig. 3.1-G. The width of the absorber strip to which the solar cells are bonded is $a = 7.62 \text{ cm}$ (3 in.). The aperture width of the secondary reflector is $2a$, and the length of the secondary reflector wall is about $2.7a$. Finned surfaces appear at the back of the absorber. The walls of the secondary reflector act as fins themselves to which additional fins are shown attached. The fins may cover only a part of the secondary concentrator (as shown) or may cover the entire outer surface. In the latter case the fins located nearest the aperture would cause a very small percentage increase in the shading of the primary reflector by the secondary concentrator unit. Most of the heat will be rejected through the back of the cells. The thermal resistance across the cell-heat sink bond is negligible compared with that from the heat sink to the ambient air [1 , 2] and has therefore not been considered in estimates of K_e values to be presented.

An indication of the advantage to be gained by extending the finned heat sink base area beyond the absorber area can be obtained by examination of

Figs. 3.1-H and 3.1-I. The quantity K appearing in these figures is the thermal conductance of the finned heat sink per unit heat sink base area, whereas K_e , as previously defined is the thermal conductance referred to the absorber area. If the heat sink base plate material had an infinite thermal conductivity or were infinitely thick the ratio of K_e/K would be in direct proportion to the ratio of total heat sink base area to absorber area.

Figure 3.1-H shows K_e/K as a function of base plate thickness for steel and aluminum for several values of K . This is for a base plate extending 3.81 cm (1.5 in.) on either side of the absorber, so that the asymptotic value is two for the 7.62 cm (3 in.) absorber width. The effect of base plate thickness and material thermal conductivity is clearly seen. Aluminum has a thermal conductivity about four times that of steel. It appears that a thickness of 1/4 inch would be desirable.

Figure 3.1-I shows values of K_e vs K for designs in which the entire outer surface of the secondary concentrator is covered with fins so that the base plate extension consists of both secondary reflector walls [length of each, 20.6 cm (8.1 in.)]. The reflector wall thickness for this plot was taken as 1/4 inch. This thickness is essential for such designs because of the long conduction path being utilized along the reflector wall. A larger thickness would be desirable from this standpoint, particularly if steel is used, but may not be practical from a manufacturing standpoint.

A secondary concentrator/heat sink design which could be extruded as a single unit from aluminum is attractive for the simplicity of the manufacturing process. This limits the heat sink design basically to straight fins oriented parallel to the major axis of the base surface. Values of K for an aluminum heat sink having straight longitudinal fins of tapered cross-section were extensively tested in a low-speed wind tunnel as part of another ERDA sponsored program [3]. These fins were 0.76 mm thick at the base,

0.38 mm thick at the tip, 8.1 mm high, spaced at a 4.6 mm pitch. They were tested at various orientations relative to the air flow direction. At a flow speed of 2 m/s, the largest conductance value measured was about 1.5 times the smallest value depending on orientation. The highest values occur when the base surface is facing directly into the airflow, while the smallest values occur for the base surface facing from the flow. A heat sink design in which all outer surfaces are covered with fins has the advantage that at least one base surface will almost always be facing toward the wind. Based on the wind tunnel measurements the value of K for the above described straight longitudinal aluminum fins may be taken as $0.06 \text{ kW/m}^2\text{°C}$ at 2 m/s (this includes radiation, here about 10% of the total heat rejection assuming an apparent infra-red emittance of 0.9). If fins of this design cover the entire outer surface of the secondary concentrator with an aluminum reflector wall thickness of 1/4 inch the value of K_e will be about $0.25 \text{ kW/m}^2\text{°C}$ (see Fig.3.1-I). According to Fig.3.1-E, cooling of this effectiveness will provide an average normalized power output of 85%. During an absolute calm where heat rejection is by natural convection and radiation the value of K is about $0.016 \text{ kW/m}^2\text{°C}$ (~50% radiation and ~50% natural convection), leading to K_e of about $0.1 \text{ kW/m}^2\text{°C}$. This means that even under the worst possible wind conditions (a very rare occurrence) the normalized power output would still be about 60%.

The aspect ratio (fin height to spacing ratio) of the above relatively short fins is about two.

A second set of straight longitudinal fins tested under the same program as the above had both a larger height (30.5 mm) and pitch (9.1 mm), a base thickness of 2.5 mm and a tip thickness of 0.5 mm. The aspect ratio is about four. This design provides somewhat larger K values (about 25%) when facing

the flow but the smaller values are about the same as those for the set of short fins. Judging from these test results an optimum design might be one similar to the short fins, but with the height increased by perhaps 50%. Further testing would be required to determine the optimum design. However, it appears at this point that a K_e of at least $0.25 \text{ kW/m}^2 \cdot ^\circ\text{C}$ is possible with a secondary concentrator/heat sink design which could be formed by a single aluminum extrusion, but such designs cannot provide values in excess of about $0.30 \text{ kW/m}^2 \cdot ^\circ\text{C}$ (unless the secondary reflector wall thickness is increased beyond $1/4"$). It should be noted that for a final design of this type the secondary reflector wall thickness should be at least $1/4"$ at the absorber end, but could be tapered somewhat toward the aperture end, if desired, without a significant adverse affect on the heat rejection capability.

Heat sink performance can usually be improved, relative to straight fin designs by using interrupted fins, such as pin fins. An aluminum heat sink of this type was made for testing by cross-cutting 3.2 mm ($1/8$ in.) slots at 6.4 mm intervals on the high straight fin model mentioned previously. This resulted in an array of tapered rectangular cross-section pin fins 30.5 mm high in a rectangular pattern with 6.4 mm X 9.1 mm pitch dimensions. The base dimensions of the test model were 10.3 X 46.2 cm. Test results for K-values for this model at six different orientations to the airflow are shown in Fig. 3.1-J. At 2 m/s these K values are from 5 to 70% larger than those for the corresponding straight fin model. Using a value for K at 2 m/s for this rectangular pin fin array which is intermediate between the most and least favorable orientations results by use of Fig. 3.1-I in a K_e of $0.4 \text{ kW/m}^2 \cdot ^\circ\text{C}$ and a normalized power output of 91%. However, this is probably not a practical design since after extrusion of the aluminum secondary concentrator with straight fins, slots would have to be cut across the fins, both on the absorber plate

and on the secondary reflector wall. Even in mass production this would likely prove to be a costly operation for a marginal increase in performance.

If an economical manufacturing process for this application can be devised the best fin design would utilize pin fins of circular cross-section placed on a square pitch pattern. Test results for circular pin fins in an unconfined flow do not appear to be readily available. However, test results do appear in the literature for arrays of circular pin fins placed across parallel plate passages, i.e., in a confined flow [4 , 5 , 6]. Comparison of these results with predictions based on correlations for heat transfer coefficients for single circular cylinders in cross-flow indicates that the single cylinder predictions are reasonably accurate when applied to the arrays. It is not unreasonable to assume that the same holds true for arrays of circular pins in unconfined flows. Therefore, estimates of K_e values achievable with arrays of circular pin fins have been made using as a basis heat transfer characteristics of single circular cylinders in cross flow.

Figure 3.1-K shows the effect of aluminum pin fin length on heat rejection performance relative to fins of infinite length for several pin diameters and airflow speeds across the pins. Fig. 3.1-L shows similar results for steel pins. Because of its greater thermal conductivity, an increase in length of an aluminum pin can be utilized to greater advantage than a corresponding length increase of a steel pin. Table 3.1-D displays values of K for convection from the circumferential surfaces of arrays of aluminum and steel pins of several diameters, lengths, and pitches at airflow speeds of 2 m/s. These values were used to estimate K_e values for the secondary concentrator/heat sink design in which the entire outer surface of the concentrator is

covered with fins, and the reflector wall thickness is 1/4 inch. The resulting K_e values are displayed in Table 3.1-E. These values were determined by reducing the K value appearing in Table 3.1-D by 25%, then entering Fig. 3.1-I to read the resulting K_e values. The 25% reduction was used because the average heat rejection from a pin in an array will be somewhat less than the single pin value. The K_e values in Table 3.1-E should be slightly conservative because of this perhaps excessive 25% reduction in the K value used, and also because no credit was taken for convection losses directly from the exposed exterior base surfaces between the pins, convection from the smooth interior surfaces of the concentrator, or radiation losses. These contribute a relatively small amount compared to the convection from the pin fins themselves. It may be noted from Table 3.1-E that some rather high K_e values appear, particularly for the aluminum and for the smallest diameter pins with the smallest pitches. However, these would undoubtedly be very costly to manufacture, particularly from aluminum. To ascertain reasonable design alternatives, return to Fig. 3.1-E. For P/P_0 of 90%, a K_e of $0.37 \text{ kW/m}^2 \cdot ^\circ\text{C}$ is required while for P/P_0 of 88% a value of 0.30 is adequate. For an all aluminum secondary concentrator/heat sink these values are essentially achieved or exceeded with (see Table 3.1-E) the following basic configurations:

Diameter (inches)	Pitch (inches)	Length (inches)
1/16	3/8	1.0
1/16	1/4	0.5
1/8	3/8	0.625
1/8	1/2	1.0
1/4	1/2	0.75
1/4	3/4	2.0

For a steel unit the following configurations meet the above requirement:

Diameter (inches)	Pitch (inches)	Length (inches)
1/16	1/4	1.0
1/16	3/16	0.5
1/8	1/4	0.5
1/8	3/8	2.0
1/4	1/2	2.0

To sum up: Two main heat sink design alternatives have been presented. One uses straight longitudinal aluminum fins on an aluminum secondary concentrator. This would be simply manufactured by an extrusion process and could provide a performance in terms of normalized power output of 85%. The second alternative uses circular pin fins of aluminum or steel on a secondary concentrator of the same material. These designs can provide a normalized power output of about 90%. For this alternative the manufacturing process would need to be developed, with steel having the edge in potential for a low cost process. It should be emphasized again that the secondary reflector wall thickness need not be as much as 1/4 inch over the entire length of its cross-section but may be tapered from the absorber base plate to a narrow tip at the aperture. In addition, if a basic circular pin fin design with relatively long pins is selected the length of the pins may also be reduced somewhat over that portion of the reflector wall nearest the aperture without significantly affecting cooling performance.

The previous NSF/ERDA-sponsored work by ASU and Spectrolab had assumed that concentrator cost (including reflective surface, structure, tracking mechanisms and foundations) could be reduced to $\$60/\text{m}^2$. This number had been taken from the literature on solar-thermal system cost analysis. Initial concentrator designs resulted in cost estimates of $\$60$ per square meter of aperture for the structure alone, as compared to a design cost goal of $\$20/\text{m}^2$ for structure. These cost estimates were obtained from quotations from engineering and construction firms, based on designs derived from

Table 3.1-D. VALUES OF THERMAL CONDUCTANCE (K) REFERRED TO BASE AREA ($\text{kw/m}^2\text{°C}$) FOR CONVECTION FROM CIRCUMFERENTIAL SURFACES OF CIRCULAR PIN FINS AS A FUNCTION OF FIN DIAMETER, LENGTH, PITCH, AND MATERIAL*

Fin Diameter (cm) and (inches)	Fin Length cm (inches)	Fin Pitch in (cm) and (inches) Number of Fins per m^2 of Base Area											
		0.318 cm 1/8 in 99,200		0.476 cm 3/16 in 44,089		0.635 cm 1/4 in 24,800		0.952 cm 3/8 in 11,022		1.270 cm 1/2 in 6,200		1.905 cm 3/4 in 2,756	
		Aluminum	Steel	Aluminum	Steel	Aluminum	Steel	Aluminum	Steel	Aluminum	Steel	Aluminum	Steel
0.159 cm 1/16 in	1.27 (0.5)	0.69	0.58	0.31	0.26	0.17	0.15	0.08	0.06	0.04	0.04	0.02	0.02
	2.54 (1.0)	1.15	0.74	0.51	0.33	0.29	0.19	0.13	0.08	0.07	0.05	0.03	0.02
	5.08 (2.0)	1.49	0.77	0.66	0.34	0.37	0.19	0.16	0.08	0.09	0.05	0.04	0.02
	7.62 (3.0)	1.53	0.77	0.68	0.34	0.39	0.19	0.17	0.08	0.10	0.05	0.04	0.02
	∞	1.55	0.78	0.69	0.34	0.39	0.19	0.17	0.08	0.10	0.05	0.04	0.02
0.318 cm 1/8 in	1.27 (0.5)					0.25	0.23	0.11	0.10	0.06	0.06	0.03	0.03
	2.54 (1.0)					0.46	0.37	0.20	0.16	0.12	0.09	0.05	0.04
	5.08 (2.0)					0.73	0.44	0.32	0.19	0.19	0.11	0.08	0.05
	7.62 (3.0)					0.85	0.45	0.37	0.20	0.21	0.11	0.09	0.05
	∞					0.91	0.46	0.40	0.20	0.23	0.12	0.10	0.05
0.635 cm 1/4 in	1.27 (0.5)									0.09	0.09	0.04	0.04
	2.54 (1.0)									0.17	0.16	0.08	0.07
	5.08 (2.0)									0.31	0.23	0.14	0.10
	7.62 (3.0)									0.41	0.26	0.18	0.11
	∞									0.54	0.27	0.24	0.12

* Flow condition assumed: cross flow at right angles to pin fins at free stream velocity of 2 m/s

Table 3.1-E. ESTIMATED VALUES OF EFFECTIVE THERMAL CONDUCTANCE (K_e -kW/m²·°C) FOR SECONDARY CONCENTRATORS WITH CIRCULAR PIN FINS COVERING EXTERIOR SURFACES AS A FUNCTION OF FIN DIAMETER, LENGTH, PITCH, AND MATERIAL*

Fin Diameter (cm) and (inches)	Fin Length cm (inches)	Fin Pitch in (cm) and (inches) Number of Fins per m ² of Base Area											
		0.318 cm 1/8 in 99,200		0.476 cm 3/16 in 44,089		0.635 cm 1/4 in 24,800		0.952 cm 3/8 in 11,022		1.270 cm 1/2 in 6,200		1.905 cm 3/4 in 2,756	
		Aluminum	Steel	Aluminum	Steel	Aluminum	Steel	Aluminum	Steel	Aluminum	Steel	Aluminum	Steel
0.159 cm 1/16 in	1.27 (0.5)	1.22	0.75	0.69	0.41	0.46	0.28	0.26	0.14	0.15	0.10	0.09	0.05
	2.54 (1.0)	1.70	0.90	0.97	0.49	0.67	0.32	0.38	0.18	0.24	0.12	0.12	0.05
	5.08 (2.0)	2.10	0.94	1.17	0.50	0.79	0.32	0.44	0.18	0.29	0.12	0.15	0.05
	7.62 (3.0)	2.17	0.94	1.20	0.50	0.81	0.32	0.46	0.18	0.31	0.12	0.15	0.05
	∞	2.18	0.95	1.22	0.50	0.81	0.32	0.46	0.18	0.31	0.12	0.15	0.05
0.318 cm 1/8 in	1.27 (0.5)					0.60	0.36	0.33	0.21	0.21	0.14	0.12	0.08
	2.54 (1.0)					0.91	0.53	0.51	0.29	0.36	0.19	0.18	0.10
	5.08 (2.0)					1.26	0.60	0.71	0.32	0.52	0.21	0.26	0.12
	7.62 (3.0)					1.40	0.62	0.79	0.34	0.53	0.22	0.29	0.12
	∞					1.47	0.63	0.83	0.34	0.56	0.24	0.31	0.12
0.635 cm 1/4 in	1.27 (0.5)									0.29	0.19	0.15	0.10
	2.54 (1.0)									0.46	0.29	0.26	0.16
	5.08 (2.0)									0.70	0.37	0.40	0.21
	7.62 (3.0)									0.84	0.41	0.48	0.22
	∞									1.01	0.42	0.58	0.24

* Based on values from Table

Concentrator wall thickness 1/4 inch. See text for explanation.

Effective thermal conductance requirement vs. solar irradiation for silicon cells with output at various fractions of that for limiting case of cells operating at coolant temperature. Temperature rise of cell above coolant ($T_0 = 25^\circ\text{C}$) is also indicated.

Figure 3.1-D

Power output relative to that for solar cells at ambient temperature as function of cooling system effective thermal conductance. Silicon cells ($\beta_0 = 0.0040^\circ\text{C}^{-1}$) at irradiation level of 14 kW/m^2 .

Figure 3.1-E

Effect of wind speed dependence of effective thermal conductance (K_e) on annual electrical output for passively cooled system. Silicon cells, reference efficiency 15% at 25°C. East-west trough concentrator tracked north-south.

Figure 3.1-F

Figure 3.1-G. Schematic cross-sectional view of secondary concentrator/heat sink unit with fins.

Figure 3.1-H. Factor by which effective thermal conductance is increased due to extension of heat sink width beyond each edge of absorber by 3.81 cm (1.5 inches).

Figure 3.1-I. Effective thermal conductance (referred to absorber area) vs. thermal conductance referred to heat sink base plate area for secondary concentrator/heat sink design in which all exterior surfaces of secondary concentrator are covered with fins. Secondary reflector wall material is aluminum or steel, thickness is 0.635 cm (1/4 inch).

Figure 3.1-J. Low speed wind tunnel test results for thermal convection conductance as function of airflow speed and direction for tapered rectangular cross-section pin fin array. Base dimensions 10.3 X 46.2 cm. Pins 30.5 mm high in rectangular pattern with 6.4 mm X 9.1 mm pitch dimensions.

Figure 3.1-K. Effect of fin length on relative heat rejection capability at several airflow speeds and diameters for circular pin fins constructed of aluminum.

Figure 3.1-L. Effect of fin length on relative heat rejection capability at several airflow speeds and diameters for circular pin fins constructed of steel.

solar-thermal concentrators described in the literature. It therefore was necessary to make a more detailed analysis of concentrator costs.

Analysis showed that the dimensions of the array module had an important effect on costs; large modules required more steel per m^2 of aperture area and involved more on-site construction labor, while small modules could be prefabricated but required non-standard framing members for maximum structural efficiency and involved larger costs for foundations and tracking drives. Minimum costs were found to be associated with the largest module which could be shop-fabricated as an integral unit.

Final dimensions of the concentrator array are described in detail in Section 7.2. Tentative dimensions of the conceptual design are an aperture area 56' wide by 40', inclined 45° ; made up of 14 trough units each 4' wide by 40' long. The geometrical area is therefore 213.3 m^2 per array module. The array module is supported on 4 wheels at the corners of a 30' square, riding on a circular track of 42' diameter. Each trough is fabricated from sheet steel to which a reflecting surface is mounted. The steel troughs are supported by special design steel roof joists and steel member cross-bracing. Major columns and beams are 9.5" square steel box beams fabricated from 3/16" plate.

Figure 3.1-M is a pictorial drawing of the array module. Figure 3.1-N is a cross-sectional drawing of the optical system. The dimensions (in meters) are $m \approx .61 \text{ m}$, $f \approx 1.06 \text{ m}$, $y \approx 0.19 \text{ m}$. The width of the absorber is 6 cm. Figure 3.1-O provides monthly energy output data for the array module.

Figure 3.1-M. Photograph of one array module(model) showing general design and size.

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Figure 3.1-0. SYSTEM EFFICIENCY COMPUTED USING TWO DIFFERENT METHODS. METHOD ONE (TOP CURVE) CALCULATES EFFICIENCY AS A FUNCTION OF BOTH TEMPERATURE AND IRRADIANCE LEVEL. METHOD TWO (BOTTOM CURVE) IS COMPUTED AS A FUNCTION OF TEMPERATURE ONLY. THESE CURVES ARE FOR A SYSTEM IN PHOENIX, TURNTABLE TILT = 45° , $K_E = 0.3 \text{ kW/M}^2\text{-}^\circ\text{C}$, APERTURE AREA/CELL AREA = 31. VALUES IN THE TABLE SHOW PERFORMANCE OF SYSTEMS WITH VARIOUS THERMAL CONDUCTANCES FOR BOTH METHODS OF CALCULATING SYSTEM EFFICIENCY.

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3.2 POWER CONDITIONING AND STORAGE COMPONENTS

3.2.1 Introduction

This section addresses the electrical energy storage and power conditioning aspects of photovoltaic solar power systems (heavy lines in Figure 3.2.1-A).

For purposes of this study, three photovoltaic system applications and power levels were considered:

- Residential — 2.5 kilowatts
- Shopping center — 1 megawatt
- Electric utility central station — 50 to 1000 megawatts

A photovoltaic system consists of a photovoltaic collector, a power conditioning system and an energy storage system. The energy storage system provides dc voltage during periods of low or absent insolation. In order to match the requirements of the ac and dc electrical loads with the dc from the photovoltaic and storage systems, a power conditioning system is necessary. In general, the power conditioning system consists of: a regulator to regulate the dc voltage and current from the solar array; an inverter to convert dc voltage to ac; and an interface to connect the solar power system to a utility or other ac loads. The central station differs from the other two systems (i.e., residential and shopping center) in that its "load" is the utility line itself. The residential and shopping center systems will be interfaced with utility lines and passive loads (e.g., lighting, motors, etc.) and will not be permitted to deliver power into the utility lines.

Of all storage systems, only batteries have technical and economic characteristics compatible with all three system sizes and applications considered.

Figure 3.2.1-A. PHOTOVOLTAIC SOLAR POWER SYSTEM

At present, lead-acid batteries are best suited to serve as the energy storage element in a photovoltaic system. The characteristics of these lead-acid batteries include:

- Energy efficiencies of 70 to 80 percent
- Cycle life of 2000 cycles
- Operating temperature range of 30 to 130°F
- Cost on the order of \$50 per kWh *
- Relatively high salvage value (e.g., 10 to 20 percent of purchase price)

* Unless otherwise specified all costs in this report are in terms of 1975 dollars.

Many advanced types of batteries are currently in various stages of development and will be available as photovoltaic systems come into widespread use. Included among these developmental cells are:

- Sealed, cycle-service-type, lead-acid batteries that will be maintenance free
- Large lead-acid cells at a cost of \$30 per kWh
- Advanced batteries utilizing electrochemical couples such as zinc/chlorine, sodium/sulfur and lithium/sulfur. Such batteries will have higher energy densities than lead-acid cells with projected prices of \$10 to \$25 per kWh.

Although the equipment required for the inverter portion of the power conditioning system is not currently available as "off-the-shelf" hardware, it can be built using present-day technology, but some design effort and associated expense will be required. For the power levels involved, only switching-type, solid state (e.g., SCR) inverters are considered. Many variations of this type of circuit are in use. The cost per kilowatt of commercially available inverter equipment, similar to that required, varies considerably with power level and design; ranging from \$150 to \$1,500 per kW at the 2.5 kW power level, \$75 to \$450 per kW at 1 MW and \$45 to \$105 at 50 MW. Prices, particularly for lower power units where high volume production is likely, also vary with quantity.

Similarly, switching-type, series regulators are most suitable for use at the power levels considered. Again, the exact equipment required is not commercially available. One similar device with an efficiency of 98 percent at its rated power of 625 kW is currently being produced for \$5 per kW.

For the residential and shopping center systems, the electrical interface connections between the utility, inverter and ac loads can be made either by operating the inverter in parallel with the utility or by switching the

load to either source. In these schemes, controls are designed to limit the inverter to its maximum power rating, while still assuring that load demands are met, and also to prevent power flow into the utility line. The central plant interface differs in that its load is the utility itself. All of the proposed interface schemes utilize commercially available components.

3.2.2

ENERGY STORAGE

Due to variations in insolation, some form of energy storage should be incorporated into photovoltaic power systems. In addition to permitting the system to continue supplying load demands during short-term decreases in insolation (e.g., transient cloud cover), an energy storage system can also enable the use of solar derived energy at night or during days when there is insufficient insolation.

3.2.2.1 ENERGY STORAGE SYSTEMS

Several schemes to enable storage of electric utility energy have been proposed or are in use. The most successful energy storage system in use today is pumped hydroelectric power. However, it is obvious that the size of these plants prohibits this form of storage from being considered for the residential and commercial applications. Further, pumped hydroelectric plants require a specific site geology which has limited their use and will likely prohibit their use for most photovoltaic central station sites.

Several proposed systems, such as compressed air storage, super conducting magnets, thermal storage, hydrogen storage etc., are similarly excluded from consideration for application in a photovoltaic system due to their projected minimum economic size and other incompatible characteristics.

Flywheel energy storage offers some potential for use in conjunction with a photovoltaic system, but generally economics dictate a minimum system size in excess of one megawatt, and standby losses indicate that this system is best suited to applications with storage times shorter than required for photovoltaic systems.

Of all potential storage systems, only batteries have characteristics and economics that are favorable to all three of the photovoltaic system sizes being evaluated in this study. Therefore, only batteries are considered in subsequent sections of this report.

3.2.2.2 BATTERY TERMINOLOGY

The batteries considered for energy storage applications are classified as secondary (rechargeable) batteries. Primary batteries are essentially nonrechargeable. Electric energy applied to the terminals of a secondary battery is electrochemically converted, stored as chemical potential energy and subsequently reconverted to electric energy.

Since electrochemical reactions characteristically result in potentials on the order of a few volts, battery systems for energy storage will require a series connection of cells to attain a practical system voltage. Also, achievable electrode current densities in conjunction with cell construction techniques limit the current per cell and thereby require parallel interconnection of cells to achieve a desired capacity. Paralleling can also result in redundancy and thereby permit continued, limited operation in the event of a cell failure. The optimum series and parallel cell configuration in a battery will vary with cell type and manufacturer's design.

The capacity of a battery refers to the quantity of discharge current obtainable for a specified length of time and is expressed in ampere-hours. Since a battery's capacity can decrease with increasing discharge rates, capacity is usually given for a specified time (e.g., 100 ampere-hours at the five-hour rate). Capacity is also a function of cutoff voltage. The output voltage of a battery decreases during discharge, and eventually the internal chemistry reaches a state such that further discharge will result in a very rapid decrease in output voltage. Manufacturers usually specify a cutoff voltage near the upper bound of this region, and cells may be damaged by discharge beyond this point. Charge and discharge rates are sometimes

referenced to a cell's capacity. With this type of notation, a current's magnitude is inferred by the length of time (in hours) required to completely discharge (or charge) a cell with a given ampere-hour capacity. For example, drawing 20 amperes from a 100-ampere-hour cell would be termed a C/5 discharge rate. Depth of discharge refers to the percentage of a cell's capacity that has been discharged.

The energy capacity of a battery is the time integral of the product of discharge voltage and current from full charge to cutoff voltage. It is given approximately by the product of capacity and average output voltage and is expressed in watt-hours. Comparisons of batteries are often made on the basis of watt-hour per unit weight or per unit volume. This characteristic is particularly important for vehicle propulsion applications, a market being pursued by most battery developers.

A complete discharge and recharge is referred to as a cycle, and the number of cycles which a battery can yield before degrading appreciably (i.e., cycle life) is an important parameter for comparing batteries for use in energy storage applications.

3.2.2.3 BATTERY DATA SUMMARY

A brief summary of battery characteristics is presented in Table 3.2.2.3-A. Sections 3.2.2.4 through 3.2.2.7 discuss these electrochemical systems in detail. The data presented for advanced batteries are tentative and can change as the various research programs proceed.

In addition to currently available lead-acid batteries, any one of several advanced batteries may be suitable in the future for energy storage in a photovoltaic system. There are over 20 major research programs, in the U.S. and abroad directed toward developing and producing new types of secondary batteries. These efforts reflect government, industry and utility sponsorship.

Many of these advanced batteries are in a laboratory prototype stage of development, and commercial systems will not be available before the

Table 3.2.2.3-A
BATTERY CHARACTERISTICS

Parameter	Battery						
Chemistry	Lead-Acid	Li-Al/FeS	Li/FeS _{1.5}	Na/S	Na/S	Zn/Cl	Na/Cl
Manufacturer	several	ANL	AI	GE	TRW	EDA	ESB
Charge Cutoff, (V/cell)	2.5	1.55	2.4	2.75	2.35	2.21	3.7
Discharge Cutoff, (V/cell)	1.75	0.85	1.0	1.83	1.60	1.98	2.3
Operating Temperature (°C)	25	425	400	315	300	32	200
Energy Efficiency (%)	75-80	70	70	85	80	70	80+
Cycle-Life Goal	2000*	1500+	3000	1500+	1500+	2500	2500+
Cost Goal (\$/kWh)	50-90*	15-25	25	10-20	20	10-20	—
Availability	commercial	1983	1983	1983	1983	1981	—

*Currently available batteries suitable for energy storage.

mid-1980's. Notably, demonstrations of kilowatt-size batteries have come about in electric vehicle propulsion programs (e.g., EDA's zinc/chlorine, SOHIO's lithium/chlorine, General Motors' zinc/air.) While these battery configurations are not identical to those required for energy storage systems, the technology is directly applicable and will facilitate the development of megawatt-size test or demonstration battery systems in the early 1980's.

3.2.2.4 LEAD-ACID BATTERIES

Available Lead-Acid Batteries

Of the several battery types that may find application in electric energy storage service, only lead-acid batteries are commercially available at present. Nickel-cadmium and silver-zinc are also in commercial use today; however, they are too costly to be considered for large-scale energy storage systems. Several proposals for the construction of a pilot or demonstration battery storage plant utilizing lead-acid cells

have been advanced (Ref. 1). An installation of this type can be built with present day technology and is similar to the storage system required by the photovoltaic central plant. However, the technology for fabricating large cells must be improved to approach that of the highly automated (and very competitive) automobile battery industry in order to reduce costs and make lead-acid battery energy storage installations economically competitive.

Chemistry and Construction. Lead-acid batteries can be grouped into two broad categories by the type of service for which they are intended, i.e., "float" or "cycle" service. In float service, a battery is maintained in a charged state and only discharged occasionally to a low depth of discharge. Emergency power and SLI (automobile starting, lighting, and ignition) batteries are two examples of this category. Float service batteries usually have a low self-discharge rate, low cycle-life (150 to 250 cycles) and low rates of gas evolution (thereby requiring makeup water less often). For batteries in this application, life is often expressed in terms of years instead of the number of cycles.

In cycle service, a battery is charged and discharged on a regular basis. Motive power batteries, such as those used to power electric forklifts, golf carts, etc., typify the cycle service category. Cycle lives of up to 2000 cycles are currently achievable. Motive power cells used on diesel-electric submarines have capacities up to 10,000 ampere-hours (at a six-hour rate), but their life usually does not exceed 500 cycles. It is likely that large cells such as these, with construction modified to improve life, could be the type of lead-acid battery used for electric energy storage in the photovoltaic central plant.

Lead-acid cells are comprised of lead (Pb) negative electrodes and lead dioxide (PbO_2) positive electrodes with a dilute solution of sulfuric acid

(H₂SO₄) as the electrolyte. The equation for this system's reversible electrochemical reaction is:

The active materials of both electrodes are converted to lead sulfate during the discharge cycle. In actual batteries, side reactions occur and are responsible for the evolution of hydrogen and oxygen by a mechanism similar to electrolysis. Also, other side reactions involving alloying constituents or impurities in the electrodes can cause the evolution of gases such as stibine or arsine. The design of a lead-acid battery energy storage installation must take into account the possible presence of these toxic gases (Ref. 2) and provide for the addition of makeup water to the batteries.

Both positive and negative plates for most batteries are fabricated by "pasting" the active electrode materials onto lead alloy grids. These materials are applied as various chemicals and converted to their final chemical composition during a "formation" process. To increase available surface area, a porous sponge form of lead is used for the negative plate. The grids serve to support the active material and conduct electricity. Their construction and alloy composition are governed by the type of service for which the battery is intended. Float service battery grids usually have 0.4- to 0.8-percent calcium alloyed with the lead, while cycle service battery grids are made of a lead alloy with 4- to 8-percent antimony. Plates for cycle service batteries are made two to three times thicker than those intended for float service. Positive plates may be wrapped with cords of fiberglass of similar material to reduce peeling or loss of material caused by operation or mechanical shock. Porous separators made of acid impervious materials such as rubber or plastic keep the assemblies of positive and negative plates from shorting. The number of plates and their size determine the battery's capacity. Electrode assemblies and electrolyte are housed in containers (jars) usually made of hard rubber or plastic.

Characteristics. Figure 3.2.2.4-A shows the voltage characteristics of a typical lead-acid cell during constant current discharge. Different manufacturing techniques and cell types will cause some variation in the curves for actual cells. As can be seen, the decrease in cell voltage is greater at high rates of discharge. Connector and grid structure resistance contribute to the lowering of the terminal voltage during discharge. Similarly, material type, utilization and construction affect concentration polarization, which decreases the terminal voltage during discharge. These effects also contribute toward increasing the voltage required to recharge a cell. Actual operation of a photovoltaic system will likely entail operation of the battery in a constant power discharge mode for short periods of time. A set of curves for constant power (e.g., voltage as a function of time) can be derived from Figure 3.2.2.4-A. The voltage curves for that mode of operation would drop off faster than those of a constant current mode.

Figure 3.2.2.4-A TYPICAL DISCHARGE VOLTAGE CHARACTERISTICS

Charging a lead-acid cell can be accomplished by several methods. Generally, any method that does not result in excessive gassing or high temperature is acceptable. Charging at a rate that produces these phenomena will lower efficiency and tend to shorten cell life. Recharge to approximately 80 percent of capacity can be accomplished at high rates (e.g., C/5 or higher). The last portion of the charge should be carried out at a lower rate (e.g., C/20) in order to promote longer cell life and higher efficiency. Figure 3.2.2.4-B shows the voltages required to recharge a typical lead-acid cell as a function of its state of charge.

Figure 3.2.2.4-B. TYPICAL CHARGE VOLTAGE CHARACTERISTICS

Lead-acid cells typically have coulombic efficiencies of 90 to 95 percent (when recharged in a manner prescribed by the manufacturer). Thus, 111 ampere-hours are required to recharge a 100 ampere-hour cell with a 91-percent coulombic efficiency. These ampere-hours are put back into a battery at voltages higher than the discharge voltage. Therefore, a lead-acid battery's energy (watt-hour) efficiency is on the order of 70 to 80 percent.

Heat produced in a cell due to losses (or any other source) must be removed in order to prevent excessive cell temperature. The majority of the heat is generated during recharge. In addition to resistive loss, the electrochemistry of charging is exothermic. Most manufacturers recommend an operating temperature of 77°F and give data on their cells based on operation at this "standard" temperature. Operating temperature limits vary among manufacturers, but minimum temperatures range from 30 to 50°F. Figure 3.2.2.4-C shows how the capacity of a typical lead-acid cell decreases with temperature.

Temperature also influences other operating characteristics of a cell. Figure 3.2.2.4-D indicates the variation in charge cutoff voltage as a function of temperature for an SLI-type cell. This effect must be taken into account when specifying the maximum operating voltage of the dc system.

Although Figure 3.2.2.4-C indicates that a cell's capacity increases with temperature, high temperature operation is not conducive to long cell life. Manufacturers disagree on the exact amount of reduction in life with temperature, but it is estimated that cell life will be cut in half if the average operating temperature is raised from 77°F to somewhere between 95 and 125°F. Also, internal loss mechanisms, such as electrolyte resistance, show exponential increases with temperature, so that energy efficiency decreases with increasing temperature. Maximum operating temperatures range from 90 to 130°F, with operations at 130°F permitted but not recommended.

Figure 3.2.2.4-C RELATIVE CAPACITY AS A FUNCTION OF TEMPERATURE

Figure 3.2.2.4-D.CHARGE CUTOFF VOLTAGE AS A FUNCTION OF TEMPERATURE

Lead-acid batteries are cooled mainly by air, either by free or forced convection. In some applications, (e.g., on submarines), batteries are water-cooled by means of channels in the terminal structures. Due to poor thermal conductivity of the case and limited amount of exposed surface area of terminals, water cooling is much more effective than air cooling. However, water cooling is also more costly.

The energy density of lead-acid batteries ranges from 0.5 to 2.5 kWh/ft³. The type of batteries used in photovoltaic energy storage applications will likely resemble high density motive power cells, but since they will not be exposed to the same levels of mechanical shock and vibration, a lighter construction could be used. Energy density for this application will likely be on the order of 1.8 kWh/ft³.

Safety and Maintenance. Several safety aspects must be considered when designing a lead-acid battery system. There is, of course, the potential hazard of dc electrical shock. Unlike other electrical equipment, a battery cannot be switched off or deactivated. Even pumping out the electrolyte could leave enough electrolyte in the porous separator material to have the battery system remain a potential shock hazard. Another potential hazard is the acid electrolyte. Large industrial installations require the presence of eyewash stations, deluge showers and sodium carbonate or similar neutralizing material. Plastic squeeze-bottle eye-wash devices are available for smaller installations. Also, protective clothing (e.g., rubberized aprons, gloves, face shields) are used when servicing lead-acid batteries. Tools used for servicing are usually taped or otherwise insulated to prevent shorting of the terminals. On a bolted short, a battery can deliver currents high enough to melt metal conductors and result in a burn injury.

The size of the residential battery systems is some 100 times larger than the familiar automotive SLI battery and as such can offer a potential safety problem equal to that of the household ac systems in common use today.

Therefore, it is recommended that most battery servicing be carried out by trained personnel. For residential systems, this implies the use of servicemen from either a private company or from the local utility. For the shopping center and central power plant applications, it is likely that the facility's operating engineer would perform most of the maintenance duties.

Operation of the battery system introduces another potential safety problem, the generation of hydrogen. For the most part, hydrogen is generated toward the last part of the charge, at a rate proportional to the current (i.e., 0.0147 cubic feet per ampere-hour of overcharge). Design of the installation must include a ventilation system that will keep the hydrogen concentration well below the 4.1 percent required for combustion; detonation occurs above 8 percent. As mentioned, side reactions with grid alloys can produce trace amounts of stibine (SbH_3) or arsine (AsH_3) gases, but the ventilation system required for hydrogen will likely be adequate for these toxic gases even though they are slightly more dense than air and do not rise as hydrogen does. Use of grids without these alloying elements or use of sealed cells would eliminate these gases.

One maintenance service that may be required is the addition of makeup water to the cells. It is likely that this maintenance could be performed by an automated or semiautomated water distribution system. The frequency of this service will be determined by the duty cycles to which the cell is exposed, the temperature and the type of cell. Calcium cells in float duty have one-tenth the water loss of a new lead antimony type cell and only one-hundredth that of an old antimony cell.

Antimonial grid battery systems will likely require an occasional equalizing charge. During this period, the charging voltage is raised about 10 percent above the normal end-of-charge value for several hours. The frequency of this type of service will depend on the duty to which a cell is exposed but will be on the order of once per month.

Other maintenance may include occasional (once every several years) cleaning of acid misting deposits from cell tops and tightening of electrical connections.

Cost Data. The cost of a lead-acid battery is affected by the production rate, degree of automation used in production and cell design (e.g., grid thickness). Automotive SLI batteries are the least expensive on a \$ per kWh basis and range in price (OEM) from \$12 to \$25 per kWh. Their production rate is about 5×10^7 units per year, and competitive pressures maintain low prices. It must be remembered that these cells have relatively thin grids and a low cycle life on deep discharge. Motive power cell costs range from \$50 to \$90 per kWh with an annual production of about 10^5 units per year. For this type of cell, about 25 percent of the price is attributable to material cost, compared to about 50 percent for SLI cells. The largest submarine-type cell (10^4 ampere-hours) costs approximately \$80 per kWh. As with any quantity purchasing, the use of large numbers of lead-acid cells for energy storage would tend to lower the cost per cell. Also, extensive use would warrant the development and application of automated production techniques and spawn lower costs per kWh. Additional cost reduction may be realized from the current practice of rebuilding large cells one or more times and from the relatively high salvage value of expended cells. The value of reclaimed lead may represent 10 to 20 percent of the original OEM purchase price of a lead-acid battery. A cost of \$50 per kWh for large cells suitable for use as the storage element in photovoltaic systems could be realized today (with high volume production). A goal for an eventual cost of \$27 to \$30 per kWh has been set by Gould for large energy storage lead-acid cells (Ref. 1).

Advanced Lead-Acid Batteries

Although the lead-acid battery industry is a mature one, research programs are being conducted to improve performance characteristics and lower costs. Several prospects that could affect the use of lead-acid batteries in photovoltaic systems are discussed in this section.

Sealed Cells. Recently, sealed automotive SLI batteries have appeared in the replacement market and will likely be installed as original equipment in the very near future. Small (1 to 40 ampere-hour), sealed lead-acid batteries and cells are also available for other applications that require a secondary battery. These cells use grids fabricated with calcium and other alloying elements. The other alloying elements and exact compositions of the electrodes are proprietary. Basically, the low rates of gas evolution of calcium-type grids allow the cell to be "sealed." Actually, the cells are provided with pressure relief valves and will vent hydrogen if exposed to improper charging. As with most calcium grid designs, the life of these sealed cells is limited to 200 to 300 deep discharge cycles.

At least one manufacturer is in the process of developing a sealed cell designed for cycle service in applications such as forklift motive power. For this type of sealed cell, an antimonial grid is being considered. Again, exact compositions and alloying elements are proprietary. It is expected that this design will yield a cell with a cycle life in excess of 2000 cycles and that the manufacturing techniques can eventually be applied to large (20 kWh) cells. The electrical characteristics of this cell are expected to be nearly identical to those of available cells with the exception that cell voltages rise much faster as full charge is reached.

This type of sealed cell design will be ideally suited for the energy storage element in residential photovoltaic systems. Its use would virtually eliminate routine maintenance requirements (such as adding makeup water) and would offer the potential of having a battery system that need not be accessed by the homeowner. Further, the hydrogen ventilation problem would be mitigated. These features would also be an asset to a shopping center installation, but they are less important in the central plant design.

The projected OEM selling price for the sealed cycle-service-type cell is on the order of \$55 per kWh at a production level of 50,000 units per year.

Distribution and sales costs would double this cost for the purchase of individual units. Salvage value will be 10 to 15 percent of the OEM price.

Material Utilization. Present lead-acid cell designs utilize on the order of one-fourth of the theoretical capacity of the component materials. Since material cost can represent up to one-half of a battery's cost (e.g., for SLI batteries), improvements in utilization can significantly reduce costs and increase energy density. Recognizing this fact, several manufacturers are conducting research in this area. Depending on the outcome of this research, lower cost (based on 1975 prices) lead-acid batteries may be available as photovoltaic systems come into wide use.

Cell Life. In addition to lowering initial cost, it would be desirable to increase the useful life of lead-acid cells. Their prime failure mode is corrosion of the positive electrode. At present, large expensive cells (e.g., submarine batteries) are rebuilt one or more times by replacing the positive electrodes. Research is proceeding to determine the exact mechanism of the failure mode and attempt to extend cell life.

3.2.2.5 LITHIUM BATTERIES

Argonne National Laboratory

In 1966, Argonne National Laboratory (ANL), in a continuation of earlier related work, initiated a program to develop a lithium/ halogen secondary battery. Included among ANL's current programs are efforts directed toward developing lithium/sulfur-type secondary batteries, which will be suitable for use in utility load leveling and motive power applications. A second objective is the dissemination of sufficient knowledge to permit manufacturers to bid on construction of these types of cells. ANL has reported testing 150 ampere-hour engineering test cells and achieving energy efficiencies up to 80 percent (Ref. 3).

Chemistry and Construction. A basic lithium/sulfur cell has a lithium anode, a sulfur cathode and a suitable electrolyte. The electrochemical reaction for this simplified cell is:

The exact composition of the sulfide formed during discharge depends on active materials in the cell and its state of charge (Ref. 4).

For the engineering cells currently being tested, the electrolyte is a lithium chloride/potassium chloride eutectic (59 mol% LiCl, 41 mol% KCl). Use of this salt dictates an operating temperature of approximately 400°C. The life of earlier cells was limited by loss of sulfur from the molten elemental sulfur cathode due to vaporization and formation of compounds with the electrolyte. This effect was mitigated by the addition of arsenic or selenium. Present cells have longer lives due to the use of iron sulfide (FeS or FeS₂) cathodes. Of these two sulfides, FeS₂ results in cathodes with higher performance capability, and recently most cells have been constructed with this type of cathode. However, FeS cathodes can result in longer life, less corrosion and lower cost. The use of FeS cathodes is still under consideration. Current collection in either cathode is provided by the use of various expanded metal screens or the addition of carbon to the active sulfide material.

Two approaches to the construction of the anode are being evaluated. Molten lithium results in a high capacity anode, but this material severely corrodes electrode separators and electrical feedthroughs. Efforts are being directed to develop suitable corrosion-resistant components. Materials such as BN, Y₂O₃ and ZrO₂ are being evaluated. The second approach utilizes a solid lithium aluminum alloy developed by SOHIO for their Li-Al/LiCl-KCl/TeCl₄(C) battery. This less active material is not as corrosive as molten lithium but has the disadvantage of requiring operation at a lower current density. Cells being tested at present utilize porous Li-Al anodes.

A schematic diagram of the type of lithium/sulfur cell currently being tested is presented in Figure 3.2.2.5-A. The FeS_2 is contained in a boron nitride fabric separator. Further research is planned to improve this separator. The cell is housed in a cylindrical stainless steel container. As presently conceived, production batteries for load leveling applications will have vertical electrodes approximately one-foot square and will be packaged with multiple electrodes in a cell, similar to present day lead-acid cells.

Figure 3.2.2.5-A. ANL LITHIUM/SULFUR TEST CELL

Characteristics. Figure 3.2.2.5-B shows typical test cell voltages during constant current charging and discharging. Utilization in excess of 60 percent of the theoretical capacity for this test cell is also indicated by the curve. The bus voltage of a large battery comprised of such cells would have similar characteristics, and a photovoltaic system incorporating such a battery would then require a power conditioning system to interface with these characteristics. As with other electrochemical systems, a lithium/sulfur cell can be

damaged by applying excessive voltage. When large numbers of cells are connected in series, manufacturing tolerances can result in nonuniformities in capacities and thereby expose a given cell in a series string to an over-voltage. ANL is developing an external, electronic bypass circuit to preclude this possibility. Some design programs will be required to produce a suitable power conditioning system, but there is no basic problem in using a fully developed lithium/sulfur battery as the energy storage element in future photovoltaic systems.

Figure 3.2.2.5-B. TYPICAL LITHIUM/SULFUR TEST CELL VOLTAGES

In order to maintain an operating temperature of 400°C , the cells must be housed in an insulated module. Cell cooling and heating (during standby or startup) can be accomplished by a recirculating air system, with electric heaters used as the heat source. For well defined duty cycles, such as would be seen in electric utility load leveling service, ANL has proposed that cell temperatures be allowed to rise to their maximum values at the

end of charge and discharge cycles and slowly decrease during ensuing standby periods, thus minimizing parasitic heating power. This technique may also be applicable to photovoltaic systems, where load demands and insolation can be predicted to some extent. For large systems, such as a central power plant or shopping center, a lithium/sulfur battery would likely resemble the system that ANL is developing for load leveling applications. At present, ANL is consulting industrial firms regarding cell manufacturability. However, cell and module designs will likely undergo many changes before becoming commercially available.

Safety and Maintenance. Any design for a lithium battery system must consider the safety requirements imposed by the presence of molten lithium, sulfur and electrolyte salts. Cells will be completely sealed, and the use of solid Li-Al anodes serves to further mitigate safety problems. In addition to containing heat, the proposed modules will serve to contain reactive components. ANL's present designs include three walls between the molten components and exterior surfaces. Even in the unlikely event of a cell rupture, ANL tests indicate that ensuing reactions are not necessarily violent. However, cognizant fire fighting departments and operating personnel must be instructed not to use water in the vicinity of lithium cells. Fire extinguishers charged with MET-L-X or similar oxygen barrier agents should be maintained on the premises.

The exterior surfaces of lithium battery modules will be designed to be safe to touch (i.e., 60°C or lower). In addition, the energy storage system design will include provisions to safely vent cooling air with a temperature near 400°C. Although the amount of heat released by the module most likely will be small, it may be possible to incorporate this heat into residential thermal storage systems. An instrumentation package (e.g., thermocouples etc.) in conjunction with control logic would be included as a part of the design in order to ensure safe operation of the battery system.

Since the cells will be completely sealed, the only routine maintenance required would be for ancillary systems (e.g., cooling air intake filters). Qualified service personnel should be utilized for installation or removal of cells. It is also likely that an entire module would be installed or removed as a sealed unit and serviced only at a factory or service center.

Goals. A life cycle of 1500+ cycles, energy density of 120 to 150 Wh/kg and energy efficiency of 70 percent have been given as performance goals for ANL's lithium/sulfur energy storage battery (Ref. 3). The ultimate cost goal has been set at \$15 to \$25 per kWh. These costs are, of course, based on the premise that a battery suitable for mass production has been developed and a mass production facility is available.

Atomics International

Since early 1972, the Atomics International (AI) Division of Rockwell International has been conducting research aimed at producing a lithium/sulfur battery for load leveling and vehicle propulsion applications. Various portions of this work have been sponsored by the Tennessee Valley Authority, the Edison Electric Institute (and the Electric Power Research Institute since April 1973), Argonne National Laboratory and AI's own Independent Research and Development funds.

Chemistry and Construction. The basic reaction for the lithium/sulfur-type battery was given previously. A 400°C, LiCl-KCl molten salt electrolyte, saturated with Li_2S , has been used by AI in their tests. Initial tests showed a decrease in cell capacity due to the loss of sulfur from the elemental sulfur cathode. Residual activity of sulfides formed with molybdenum cell components led to the testing of a K_2MoS_4 cathode. This cell had a vastly improved life (about 300 cycles).

Thermodynamic analysis of transition metal sulfides and subsequent tests produced two likely candidates (i.e., Cu_2S and FeS) to replace the

elemental sulfur cathode. Copper sulfide (Cu_2S) cathode test cells had the lowest self-discharge rates; but they also resulted in the lowest energy density. Iron sulfide produced the highest energy density and the highest self-discharge rate. Discharge voltage curves of iron sulfide cells have two plateaus, indicating that both FeS and FeS_2 are involved in the reaction. Current research includes efforts to determine an optimum FeS_x compound with $1 < x < 2$ and to improve the self-discharge characteristics of iron sulfide. In most cases, cathodes for test cells were formed by containing the active sulfide material in a dense graphite cavity covered by a porous ceramic, similar to the construction shown in Figure 3.2.2.5-C.

Figure 3.2.2.5-C. AL LITHIUM/SULFUR TEST CELL

AI's approach to producing a viable lithium anode system involves the containment of lithium in a porous metal substrate by capillary forces. Investigations have been conducted to determine the optimum substrate material and interstice size. Research efforts have also been directed toward increasing lithium retention in the substrate by the addition of metals, such as copper, to improve wetting of the substrate by the lithium. Most metals that are resistant to attack by molten lithium are not wetted by the lithium. Test cell anodes are similar to those shown in Figure 3.2.2.5-C, but solid alloy anodes are also under investigation. Li-Al anodes are less corrosive and more readily contained than molten lithium anodes; but this alloy results in a 0.3-volt reduction in potential and thereby results in a lower energy density. Other solid alloy anodes, such as Li-Si, are also under consideration (Ref. 5).

Several ceramic materials are being evaluated for use as separators in the cell. Thus far, it has been found that high purity is essential to resist attack by molten lithium.

Characteristics. The charge/discharge voltage characteristics of AI's cells are similar to those presented for ANL's cells previously. Presentation of more detailed characteristics must await further determination of cell design by the manufacturer.

Safety and Maintenance. It is likely that production versions of the lithium/sulfur battery will have safety and maintenance requirements essentially as described previously for the ANL system.

Goals. AI hopes to ultimately develop a battery with a life of 3000 cycles, an energy density of 170 Wh/kg and a 70-percent energy efficiency. The estimated cost for production-type units is approximately \$25 per kWh. Cells with nominal energy capacities of 100 Wh have been tested with cathode and anode lives of 1200 and 300 cycles, respectively.

Other Lithium Battery Programs

Standard Oil of Ohio (SOHIO) has been developing a lithium/chloride battery that utilizes a solid Li-Al anode. The electrolyte is a LiCl-KCl molten salt. Porous carbon with tungsten or TeCl_4 additives is used for the cathode. Testing of a 2 kW battery has been reported (Ref. 4).

Westinghouse has a program to investigate and develop high temperature batteries. A Li/Cl_2 system with a molten salt electrolyte is one of the batteries under study (Ref. 4).

In England, Admiralty Materials Laboratory is developing a lithium/sulfur cell similar to that of Argonne National Laboratory.

3.2.2.6 SODIUM BATTERIES

General Electric

General Electric has been pursuing the development of a solid electrolyte, high temperature, sodium/sulfur cell. Since 1973, a portion of the work has been sponsored by the Electric Power Research Institute (EPRI).

Chemistry and Construction. Typically, a fully charged sodium/sulfur cell consists of a molten sodium anode, a molten sulfur cathode and a solid electrolyte. During discharge, several sodium polysulfides are formed. The basic electrochemical reaction is:

where x ranges from 2 to 5. The operating temperature is 300°C . Na_2S_5 is formed during the initial portion of the discharge. The cell is usually considered 100-percent discharged when the cathode is principally Na_2S_3 . Further discharge results in the precipitation of Na_2S_2 and an accompanying loss of cell performance.

A unique feature of Na/S batteries is the use of a solid electrolyte, which serves to separate the active materials of the anode and cathode, while at the same time provides for the transport of ionic sodium. This technique can result in a cell with very low self-discharge. General Electric utilizes beta-alumina ($\text{Na}_2\text{O} \cdot 11\text{Al}_2\text{O}_3$) tubes in its cells, as shown in Figure 3.2.2.6-A, because of this material's resistance to attack by liquid sodium and its polysulfides. Although beta-alumina has the external appearance of ordinary alumina (an insulator), its sodium conductivity reaches 0.16 mho/cm at 350°C . The temperature dependence of this electrolyte's conductivity, along with the boiling point of sulfur and the melting point of Na_2S_4 , governs the operating temperature range of this cell. The majority of abrupt test cell failures has been due to cracking or deterioration of the beta-alumina ceramic. The exact failure mechanism is not known, but it is at least partially attributed to local high current densities and impurities. The main thrust of GE's research program has been directed toward studying and improving the solid electrolyte. Several sodium aluminate compounds and additives are being evaluated. Deterioration of seals has also been a major cause of test cell failures. However, GE feels that this area is no longer a problem.

A schematic representation of GE's test cell is presented in Figure 3.2.2.6-A. Due to sulfur's poor electrical conductivity, carbon felt is incorporated into the cathode compartment to act as a current collector. The energy capacity of these test cells has been approximately 300 Wh, and their operating temperature has been in the 300 to 350°C range. As with other high temperature molten salt batteries, production versions will consist of an array of interconnected cells in insulated modules and will be aircooled.

Characteristics. Figures 3.2.2.6-B and 3.2.2.6-C indicate typical cell voltage behavior during constant power discharge and charge. The curves shown are for 300°C . Operation at higher temperatures decreases the electrolyte resistance and thereby decreases the spacing between the curves.

Figure 3.2.2.6-A. GE SODIUM/SULFUR TEST CELL

Safety and Maintenance. The safety and maintenance requirements of a sodium battery are similar to those of the lithium system described previously.

Goals. GE has tested 30 Wh cells with energy efficiencies up to 81 percent and with cycle lives on the order of 100 cycles. GE is projecting the development of load leveling Na/S batteries with a life of 1500 cycles, an energy efficiency of 85 percent and costs in the \$10 to \$20 per kWh range (Ref. 6).

TRW

Over the past six years TRW has had an internally funded program to develop a solid electrolyte battery. Also, the U.S. Army Electronics Command (USAECOM) and EPRI have provided additional sponsorship.

Figure 3.2.2.6-B. TYPICAL DISCHARGE VOLTAGE CHARACTERISTICS

Figure 3.2.2.6-C TYPICAL CHARGE VOLTAGE CHARACTERISTICS

Chemistry and Construction. The electrochemical reactions for TRW's Na/S cell are as described above in Section 4.6.1. As in the GE program, TRW has concentrated on developing the technology required to produce a suitable beta-alumina solid electrolyte. Various magnesium oxide-enriched beta-aluminas and lithium oxide-stabilized beta-aluminas have been fabricated and tested. Uniaxial cold pressing followed by sintering and uniaxial hot pressing of these sodium aluminates has been evaluated. After fabrication, blanks are machined and ground to a final shape. Sealing and joining technology for the several ceramic and metal components has been developed (Ref. 7).

Two types of cells have been utilized in the TRW program, laboratory cells and 20 Ah cells for USAECOM. The laboratory cells are rapidly demountable to facilitate testing. Their solid electrolytes are cup shaped slightly over one meter in height and diameter. The solid electrolyte and overall configuration of the 20 Ah cell is shown in Figure 3.2.2.6-D. Both cell types have molten sodium anodes and sulfur impregnated felt graphite cathodes.

Characteristics. Although cell geometry and construction differ, the external electrical characteristics of TRW's cells will generally resemble those presented previously for the GE cells.

Safety and Maintenance. Safety and maintenance requirements are essentially similar to those of the lithium system described previously.

Goals. Although one test cell was cycled over 1500 times, other test cell lives were limited to several hundred cycles due to failures in the seal and solid electrolyte. TRW hopes to develop a one-kilowatt battery stack in 1976 (depending on the level of future funding) and ultimately to develop megawatt sized battery systems for load leveling. Current objectives for these large batteries include a 10-year lifetime, a density in excess of 220 Wh/kg, an 80-percent energy efficiency and cost in the region of \$20 per kWh.

Figure 3.2.2.6-D. TRW SODIUM/SULFUR TEST CELL BUILT FOR USAECOM

Other Sodium Battery Programs

The Ford Motor Company has been developing a sodium/sulfur battery for vehicle propulsion. Ford's cells utilize beta-alumina tubes and operate in the 300 to 350°C temperature range. Batteries with powers up to several hundred watts have been tested (Ref. 4).

General Motors has been working on a sodium beta-alumina/sulfur cell and doing research on lithium-chloride and zinc-air batteries (Ref. 4).

Dow Chemical has been conducting research on a sodium/sulfur cell with a solid electrolyte made up of glass tubes sealed into a header on a sodium reservoir. The outer surfaces of the tubes are immersed in a sulfur compartment with aluminum foil current collectors (Ref. 8).

In Japan, Yuasa Battery Company and Toshiba Electric Company are jointly developing a Na/S battery for electric vehicle application.

3.2.2.7 CHLORINE BATTERIES

Energy Development Associates

A zinc/chlorine battery for utility load leveling and vehicle propulsion applications is being developed by Energy Development Associates (EDA). EDA is a joint venture of Occidental Petroleum and Gulf & Western.

Chemistry and Construction. The basic reaction of the zinc/chlorine cell is:

This battery is unique among the advanced batteries in that it operates at room temperature. The EDA system has a second unique feature in that an aqueous electrolyte is pumped through an electrode assembly; the system functions as a small chemical plant. A schematic diagram of the EDA system is presented in Figure 3.2.2.7-A. As the battery is charged, zinc is plated onto the anode substrate, and chlorine gas is formed at the cathode. The chlorine gas is carried away by the flowing electrolyte and stored as chlorine hydrate ($\text{Cl}_2 \cdot 6\text{H}_2\text{O}$) in a separate tank. Formation of chlorine hydrate releases

Figure 3.2.2.7-A. FUNCTIONAL SCHEMATIC OF EDA Zn/Cl SYSTEM

18 kcal/mole of heat, which must be removed during discharge. The hydrate can be stored at 9°C and atmospheric pressure. During standby the electrolyte flow is stopped. At present, EDA considers the construction details of its battery to be proprietary.

Characteristics. Due to the nature of the system, the charge and discharge voltage curves (not illustrated) for EDA's zinc/chlorine battery are very flat. Also, the cell's polarization characteristics are such that for anticipated rates, the cell voltages will be within about ± 0.1 volt of the open circuit voltage of 2.12 volts at C/5 rates.

Safety and Maintenance. Design details of EDA's zinc/chlorine system have not been published. However, safety aspects will involve consideration of chlorine handling. Unless there is an upset condition, this battery will essentially be a closed system that does not vent to the atmosphere. EDA has considered venting through an absorbing caustic solution for emergency situations. It is likely that a zinc/chlorine residential system would be a sealed unit with penetrations for dc and control wiring and air ducts for a

heat exchanger . A 24 MWh shopping center storage system would likely consist of a multiplicity of such units.

Maintenance requirements for this system may include servicing pumps and heat exchanger systems. Any servicing of the electrode stacks would likely be carried out at the factory.

Goals. EDA has tested cells configured into batteries with energy capacities of up to 50 kWh, an energy capacity of 154 Wh/kg and coulombic efficiencies up to 90 percent. EDA is striving to develop a load leveling battery system with an energy efficiency of 70 percent, a life of 2500 cycles and an ultimate cost in the range of \$10 to \$20 per kWh. This system is likely the most developed of the advanced batteries for load leveling and may be the first (exclusive of lead-acid batteries) to achieve commercial status.

Other Chlorine Battery Programs

ESB has been developing a sodium/chlorine battery. Several U.S. patents (e.g., #3,877,984) on this system have been issued and others are pending. ESB has not published details of their cell and considers most of its research information as proprietary. Recently, ESB formed a joint venture with ASEA of Sweden to develop and market complete load leveling systems.

The ESB system utilizes a molten sodium anode and operates near 200°C. The electrolyte is a beta-alumina tube. A high surface area carbon is used in the cathode along with additives of aluminum and sodium chlorides (Ref. 9).

Although not stated specifically, the production costs of this system are expected to be similar to other advanced battery systems, i.e., \$10 to \$20 kWh.

3.2.3 POWER CONDITIONING

The output from a solar array must be controlled to match the requirements of the energy storage system and the electrical loads. The dc output of a solar cell or a battery energy storage system must be converted into ac in order to be connected to electric utility lines or to most existing electrical equipment. Power conditioning systems needed to perform these functions are discussed in this section.

3.2.3.1 SYSTEM REQUIREMENTS

Figure 3.2.3.1-A presents a block diagram of a solar power system. While the system shown applies mainly to residential or shopping center installations, the basic elements of the power conditioning system are generally included in all three of the system sizes being considered. The power conditioning system consists of a power regulator, an inverter and the system interface with the utility and ac loads. Although not shown specifically in Figure 3.2.3.1-A, control logic and equipment for the solar power system will be required. A portion of this requisite control system will therefore be a part of or interface with the power conditioning system.

As discussed in Section 3.2.2, only batteries were considered for use as the energy storage element. Therefore, discussions of the power conditioning system assume operation with a battery storage system. Inverters are emphasized in the following discussion, since they are the major cost factor in the power conditioning system.

Figure 3.2.3.1-A. PHOTOVOLTAIC SOLAR POWER SYSTEM

Inverter.

The primary function of the inverter is to convert the dc output of the photovoltaic array and battery energy storage system into a 60 Hz ac waveform, compatible with the loads it serves. The inverter must be capable of tracking the variable voltage output from a solar cell and battery system, while providing a regulated ac voltage. Transformers within an inverter enable optimization of the dc system voltage level independent of the ac system voltage. Depending on system design, the inverter may supply all or part of the reactive power requirements of the load. Also, inverters can be bidirectional, permitting the storage battery to be charged from the utility lines during off-peak hours if prolonged periods of low insolation are forecast. The design of the inverter (in conjunction with the interface system design) will govern the response of the solar power system to load stimuli.

Regulator.

The output voltage and current of a solar cell varies with insolation, temperature and load impedance. The primary function of the regulator is to control the charging of the battery and maintain voltages and currents from the photovoltaic array within the limits recommended by the battery manufacturer in order to maximize battery life. Similarly, the regulator provides some degree of control for the inputs to the inverter and to the dc loads. Regulators can also be designed to track a solar cell's characteristics and provide the impedance required for maximum power transfer as a function of insolation and solar cell temperature.

Interface.

For residential and shopping center installations, the interface system must provide for switching between utility and solar power. The interface may also be designed to provide load sharing, with the solar power system operating in parallel with the utility. With such designs, the solar power system would supply power (up to its rated maximum), and the utility would supply any demand in excess of this value. Provisions for synchronizing and matching voltage levels would also have to be included in the interface and inverter designs. Inverter efficiency characteristics are such that it may be desirable to have the utility supply power when the load demand is a small fraction (e.g., 5 percent) of the inverter's rated power. The interface system design must also prevent the flow of power into the utility lines for the residential and shopping center installations.

Interface requirements for the central station are somewhat different from those of the other two applications. In this case, the utility grid is the load, and the primary function of the plant is to supply power to the grid. System designs and equipment must provide for controlling voltage level, synchronizing and fault protection. For the most part, the requisite equipment could be considered as a part of the inverter system. A parallel utility interface will be used to supply station power (e.g., lighting, control system power etc.), but its size will be a small fraction of the plant's rating.

Available Equipment

In general, the power conditioning requirements for the three photovoltaic system applications under consideration cannot be met by "off-the-shelf" equipment. This is particularly true for high power inverters and regulators. However, the equipment can be built using present day technology. Some efforts and associated expenditures will be required to tailor existing design technology to suit the present applications, but similar efforts are required for other types of advanced power systems currently being planned for electric utility application. Systems such as fuel cells, MHD, battery energy storage and magnetic energy storage need inverters to interface their dc power output with ac utility lines. This common need is tending to further the development of the required technology in general, but each system will still require individual design efforts.

3.2.3.2 INVERTER

The term inverter applies to a broad variety of equipment that functions to change dc into ac. Motor-generator sets have been used as inverters, but due to the maintenance problems associated with rotating equipment, this type of device is being replaced by static, solid state inverters. Only solid state inverters are considered here.

Basic Inverter Circuits. Due to their power handling capability and efficiency, switching-type inverter circuits are the most suitable for power conditioning. With this circuit, the main active elements are alternately switched between full on and off conditions. Figure 3.2.3.2-A presents a simplified schematic of a switching-type inverter circuit. A single-phase, bridge configuration is shown.

Inversion is accomplished as follows. Closing switches 1 and 4 causes a dc current to flow through the transformer winding. After 8.3 milliseconds (for 60-Hz, single-phase devices), switches 1 and 4 are opened, and switches 2 and 3 are closed for 8.3 milliseconds. This cycle is repeated 60 times.

Figure 3.2.3.2-A. SIMPLIFIED INVERTER SCHEMATIC

per second. Thus, by this switching action an alternating current flow is produced in the transformer. Also, by proper sequential operation of the switches in synchronism with an ac input, the circuit can be made to function as a rectifier. In actual equipment, the switches are replaced by transistors or silicon controlled rectifiers, and other circuit elements (not shown) are included to provide for proper operation.

Most low power inverters (less than 1 kW) on the market utilize transistors as the switching element. Unfortunately, transistors require relatively high drive power. This effect can be mitigated by the use of Darlington transistor configurations, but these devices are generally rated for lower power levels and tend to be more costly. Development programs are resulting in transistors with ever increasing power levels. However, at present, it appears doubtful that transistors will be utilized for inverters rated above several kilowatts.

Generally, SCR's are used as the switching element in high power inverters and related applications such as controllers for large motors. Multiple SCR bridges in high voltage dc (HVDC) transmission line terminals are currently being operated at hundreds of megawatts. Unlike transistors, SCR's cannot be turned off by a control signal. The current through the SCR must go to zero before these devices are turned off and a blocking ("open switch") condition is established. The energy to accomplish this may be supplied either internally from energy storage circuit elements such as capacitors (self-commutated) or externally by connecting the inverter to a "stiff" ac line (line-commutated). A new type of thyristor, the gate turnoff SCR, is beginning to emerge from the laboratory. Unlike SCR's in common usage today, this device can be turned off by a gate pulse. The power handling capability of devices currently available is less than that of Darlington's, but continued research may lead to the marketing of gate turnoff SCR's with ratings comparable to those available SCR's. This would facilitate the design of high power, self-commutated inverters.

Inverter circuits are broadly categorized as either line or self-commutated. Commutation is the switching of current flow from one branch of a circuit to another. Line-commutated inverters rely on the voltage from a stiff ac bus to provide the energy required to turn off SCR's, and therefore this type of circuit is operated in parallel with a utility line (e.g., HVDC terminal equipment). Line-commutated inverters can be forced to operate in a self-commutating mode by the addition of external capacitors, but then their cost approaches or exceeds that of similar self-commutated equipment. Self-commutated inverters can operate into a passive load. Since transistors can be biased off, transistorized inverters are inherently self-commutating. Internal circuits across SCR bridge legs supply the energy required for commutation. These additional circuit components contribute to the generally higher cost for self-commutated inverters. Further, losses associated with the circulating energy in these commutating circuits cause the efficiency of self-commutated inverters to fall off

more rapidly as output power is reduced. Reversal of power flow in line-commutated inverters is generally accomplished by reversal of voltage polarity, thereby requiring the use of a polarity reversing switch if the energy storage battery is to be charged from the utility line. Self-commutated circuits can be designed to reverse dc current flow, thereby obviating the need for a polarity reversing switch. Also power factor control can be designed into self-commutated inverters. External, switched power factor capacitors are generally used with line-commutated inverters.

HVDC. High voltage dc transmission line terminal inverters represent one type of available equipment. These inverters operate at power levels of several hundred megawatts and dc voltage levels in the hundreds of kilovolts. There are three thyristor (SCR) valve HVDC systems presently operating in the world; similar facilities are under construction. At this time, the trend is toward the use of solid state thyristor valve assemblies as opposed to mercury arc systems, and every HVDC system ordered since 1968 has been designed for solid state inverters (Ref. 10). The Duluth Center project recently awarded to General Electric will be the first domestic thyristor valve installation and will be patterned after the Eel River facility, which has transmitted over two billion kWh during the first year and one-half of operation (Ref. 11). ASEA will also utilize solid state valves on the Underwood/Minneapolis HVDC system. The Caborra Bassa-Apollo system is the largest thyristor valve system planned. It is scheduled for initial operation at 1000 MW in 1976, with an eventual doubling of that power (Ref. 12).

HVDC inverters are comprised of six-pulse, three-phase bridges with line-commutation as typified by the Graetz bridge shown in Figure 3.2.3.2-B. Thyristor valve systems evolved from older mercury arc designs. The "valves" in a HVDC thyristor system are actually several hundred (depending on the voltage) individual thyristors connected in series. Paralleling is used to obtain the desired current rating. Associated with the series configuration are voltage grading circuits to assure a uniform distribution of

Figure 3.2.3.2-B.BASIC GRAETZ BRIDGE

voltage to each thyristor and circuits to provide simultaneous gating for all thyristors in any series string. Present day thyristor valves are limited to about 150 kV. Current designs use a modular approach with several bridges in series to obtain the operating voltage. This is shown in Figure 3.2.3.2-C, which presents a single-line diagram of the Caborra Bassa system. The selection of thyristors and circuit design must include considerations of overvoltages generated by switching or lightning strikes and overcurrents due to system faults. Current design procedures include the use of computer modeling to predict stresses on individual components and circuit behavior. Synthetic testing is also employed for component and system evaluation prior to commencing full-scale construction.

UPS Systems. A second type of available inverter is typified by the uninterruptible power supply (UPS). These systems are used to supply power to critical loads such as computers or process control equipment in the event of an ac line failure. Generally, a UPS will consist of a rectifier (separate from and in addition to an inverter), a secondary battery and a self-commutated inverter. Figure 3.2.3.2-D presents a functional block diagram of a basic UPS system. Additional equipment (not shown) may include a static

Figure 3.2.3.2-C. HVDC SYSTEM

transfer switch, modularized inverters and control circuitry. The rectifier provides sufficient dc current to simultaneously supply the full-load inverter requirements and (slowly) recharge the battery. Battery system voltages range from 250 to 400 volts, depending on the manufacturer. When the line voltage fails, the inverter is supplied by battery energy. Transfer is so fast that it is seen as a barely perceptible jog on an oscilloscope display of the equipment voltage sine wave. Usually, battery energy is only supplied for a few minutes, until a gas turbine generator set or alternative power source is activated. As an additional benefit, UPS systems also suppress line transients. Standard high power UPS systems are available from about a dozen companies in the U.S. For large installations, systems are made up of modules. The largest modules range

Figure 3.2.3.2-D. SIMPLIFIED BLOCK DIAGRAM OF A UPS SYSTEM

in size from 250 to 400 kVA, depending on the manufacturer. To date the highest power UPS is a 1.8 MVA system installed at the Chase Manhattan Bank in 1971. Systems above several kVA are manufactured on demand with little or no redesign of the component modules. However, manufacturers are working to develop higher power modules.

A UPS is installed to provide a highly reliable source of power. In many instances, extra modules are added in parallel to provide redundancy. Mean times between failure (MTBF) of 20,000 hours are typical for a module, with redundancy used to increase the system MTBF to 200,000 hours (23 years) in some cases.

Since the primary application of this type of unit involves passive loads, the inverters must be self-commutating. Several companies use versions of impulse commutation (a form of self-commutation) for the basic inverter section. Two or more six-pulse bridge circuits are combined with the proper phase difference to give a 12-pulse (24 in one instance) output

waveshape. Relative phase displacement is used by several companies to achieve output voltage control and battery voltage tracking. Two manufacturers utilize a ferroresonant transformer approach. All of these circuits are in use, and each manufacturer believes his design to be the optimum.

Low Power Inverters. Several types of low power inverters are currently available. Included among these are low power, single-phase UPS systems similar to the larger systems discussed. Generally, these are produced by electronics companies different from those manufacturing the higher power (>100 kW) UPS systems.

Small units are also available to convert the 12-volt dc from automobile batteries into 120-volt ac household current to permit operation of standard ac equipment at remote locations. These inverters are usually transistorized. The degree of sophistication of these units varies greatly, with some putting out a 60 Hz square wave. Higher priced units are regulated, filtered, frequency stable and are capable of being operated as rectifiers. Low power inverter prices vary over a 10:1 range at a given power level.

Other low power inverter systems are currently being custom manufactured for various applications including terrestrial and extraterrestrial photovoltaic systems.

Inverter Filtering. All of the available inverter systems described include filters on the ac output, with the possible exception of some of the least expensive, low power equipment. The outputs of the basic circuits discussed are basically rectangular pulses. These waveshapes have a high harmonic content and must be filtered to produce a sine wave compatible with existing ac equipment. Waveforms with a high harmonic content tend to overheat iron core electrical equipment such as motors and transformers.

The symmetry of the waveshape is such that only odd numbered harmonics are present. For single-phase equipment, these odd harmonics must be filtered. This is usually accomplished by series LCR tuned traps across the line for the lowest harmonics and a high pass filter for the remaining harmonics. For higher power inverters, the three-phase interconnection eliminates the third harmonic and its multiples. A wye-delta pair transformer connection, as shown in Fig. 3.2.3.2-C, produces a 12-pulse waveform by combining output of two 6-pulse bridges (Ref. Fig. 3.2.3.2-B.) This theoretically eliminates the fifth and seventh harmonics. In practice, some manufacturer's include filters at these frequencies to compensate for errors in SCR firing angle. This procedure is carried further by several UPS system manufacturers. Four 6-pulse bridges can be combined in a summing transformer to produce a 24-pulse waveshape, where the lowest harmonics present are the 23rd and 25th. All of the multiple bridge approaches require that the SCR firing angles be properly phased in order to compensate for the phase shifts in the different transformer windings. Whatever scheme or combination of schemes is used, the total harmonic content is usually brought down to between three and five percent to comply with telephone interference factor requirements.

In addition to harmonics, an inverter can generate unwanted electromagnetic interference (EMI). This problem can be overcome by packaging the inverter equipment in EMI-proof cabinetry and using suitable filters on cabinet penetrations. Alternatively, the entire room of inverter equipment may be enclosed in a Faraday cage, as is done in HVDC terminals.

Size. The size of available inverter equipment varies from about $0.5 \text{ ft}^3/\text{kW}$ at the 1 kW level to $1.5 \text{ ft}^3/\text{kW}$ at the 1 MW level. Above 1 MW, the units would likely be installed outdoors in switchyard-type construction.

Safety and Maintenance. From the standpoint of safety, inverter equipment is identical to most other electronic or electrical equipment. A

potential hazard exists, in that the operating voltages can deliver an electric shock. Further, the capacitors within the inverter can still deliver a shock when the unit is disconnected. Equipment design will likely include door interlocks. Fusing will be used to protect the equipment and surroundings in the event of an internal fault.

Only qualified service personnel should be allowed access to the interior of the inverter in residential applications. For the shopping center photovoltaic system, the facility's operating staff may be able to perform rudimentary servicing on a defective inverter, but they likely would not have the equipment or training for extensive repairs. Equipment in the central station would be serviced and maintained by utility personnel except for major repairs.

The inverter equipment for photovoltaic systems will be essentially free from routine maintenance.

Costs. Since the required inverter equipment is not currently mass produced, determining costs is difficult. However, data are available for similar commercial equipment. Such data are presented in Figure 3.2.3.2-E in terms of cost per kw as a function of power level. Line segments on the figure denote cost of a single manufacturer's line of inverter equipment as a function of power. Sources of this data are vendor literature, vendor contact, budgetary price quotations and published technical literature. Figure 3.2.3.2-E is intended to provide a basis for estimating the cost of inverters in photovoltaic power systems by providing cost data on similar, commercially available equipment.

Two important conclusions may be drawn from the data. First, there is an obvious trend indicating that the cost per kW decreases with increasing power level. As may be inferred from the wide range of power levels

Figure 3.2.3.2-E. INVERTER COST VERSUS POWER

encompassed, the cost data are for a variety of inverter types. However, the line segments in the figure show that the cost per kW of a single type of inverter from any one manufacturer decreases with increasing power. Second, there is considerable price spread at any given power level. This reflects both different design approaches by various manufacturers and design alternatives at a given power level. For example, the data points at 40 MW represent budgetary cost estimates by four manufacturers for the same set of equipment specifications. The line segment at 2.5 MW indicates one result of a recent study which found that at a fixed power level, inverter

costs decrease with increasing voltage. This fact was confirmed by respondents on the 40 MW equipment. The cost per kW is highest toward the low end of a 10:1 range in voltage, which may be practical at a given power level.

The data presented are for the purchase of single units. At the lower power levels (e.g., 2.5 kW), many units would be manufactured as residential photovoltaic power systems come into widespread use, thereby permitting a price reduction due to quantity purchasing. Components for the inverter (e.g., SCR's, capacitors, transformers etc.) exhibit a characteristic reduction in price of about 20 percent per decade with volume purchasing, as indicated by Figure 3.2.3.2-F. Mass produced products, such as small power supplies similar to the requisite inverter, also exhibit this cost characteristic. Between 10^3 and 10^4 units, the cost per unit levels off as the maximum component discount has been reached and assembly techniques have been optimized. Above these volumes, prices would likely be negotiated. Also, several manufacturers pursuing the same market would cause competitive pricing.

Figure 3.2.3.2-F, COST VERSUS QUANTITY

At the higher power levels, there is less likelihood of multiple purchase, and the price would likely be set by open bidding. At the 40 MW level, price reduction estimates ranged from 10 to 25 percent for the production of 10 units per year.

3.2.3.3 REGULATOR

The simplest and least expensive method of power regulation is to rely solely on the characteristics of the cell array and battery. This approach is currently used in low power terrestrial and extraterrestrial applications. With this method, the array must be designed so that its maximum voltage does not exceed the cutoff voltage of the storage battery in order to prevent damage to the battery. Unfortunately, the voltage available from a silicon photovoltaic cell increases with decreasing temperature faster than the cutoff voltage of lead-acid cells. Also, roof-mounted arrays will be exposed to greater temperature variations than the battery, which will likely be in a protected location. As mentioned previously, the projected cutoff voltage characteristics of one manufacturer's developmental lead-acid battery design may mitigate this effect. In general, the advanced batteries discussed in Sections 3.2.2.5 through 3.2.2.7 will not tolerate over-voltages. Another factor that must be considered if a regulator is not used is the maximum rate of charging, since a battery may be damaged by high charging rates, particularly toward the end of charge.

Basically, regulators are either in a series or shunt configuration. For low power applications, transistors are used as a controlled dissipative element in both series and shunt regulators. For the power levels of the three sizes of photovoltaic solar power systems being considered, a series, switching-type regulator using SCR's will likely be used. As mentioned in the discussion on inverters in Section 3.2.3.2, SCR switching circuits generally have a high power handling capability and efficiency. One such applicable device, a time-ratio control dc chopper, is currently being manufactured and sold for about \$5 per kW. It is rated at 625 kW and has an

efficiency of 98 to 99 percent (at full power). It is likely that the cost of similar equipment at other power levels will follow the cost pattern presented by Figure 3.2.3.2-E. The data in Figure 3.2.3.2-E also indicate that the cost of an inverter at the 625 kW power level ranges from \$80 to \$480 per kW. Thus, the cost of the regulator is between 1 and 6 percent of the inverter cost. With the addition of instrumentation and control logic, this type of equipment could be used to track the peak power of a photovoltaic cell array. Similar systems have been used on the Apollo spacecraft. (Ref. 13).

The safety and maintenance characteristics of the regulator equipment will be essentially the same as those of the inverter equipment.

3.2.3.4 INTERFACE

The electrical energy derived from solar cell arrays, storage battery and power conditioning system must be connected to loads and a utility line. The central station differs from the other two systems (i.e., residential and shopping center) in that its "load" is the utility line itself. This interface will be considered in detail in the central station conceptual design. The residential and shopping center systems are similar to each other in that they both must be interfaced with passive loads and the utility lines. This may be accomplished in several ways by the use of commercially available components.

Residential Interface A. One possible residential interface system is to have the ac loads supplied by either the inverter or the utility but not by both simultaneously. With this scheme, the inverter would supply power to the loads until the load demands exceed the inverter rating. At this point, the loads would be switched to the utility lines, and when the load demand decreases below this value, the load would be switched back to the inverter. This scheme does not fully utilize the energy available from the solar power system and can cause switching transients. No provision was made to charge the storage battery or operate dc loads from the utility line through the inverter.

The hardware required to implement this system is schematically presented in Figure 3.2.3.4-A. Normally, solar derived energy will be supplied by the

Figure 3.2.3.4-A. RESIDENTIAL INTERFACE A

inverter with the control switch HS in the "auto" position. This closes 42I contacts and opens 42U contacts. Interlocks (mechanical and electrical) prevent parallel operation of the inverter and utility. When the load current exceeds a preset value (i.e., corresponding to the maximum rating of the inverter) as sensed by the current-operated meter relay 95, an automatic transfer is made from the inverter to the utility. During the transfer period, the load current is interrupted. To prevent the contactor from reverting back to the previous position and possible hunting, a time delay relay 95X is used to keep the transfer control circuit energized and uninterrupted during the transfer. Future design should consider the use of a meter relay with hysteresis (i.e., dropout current lower than the pull-in current) to assure stable operation when the system is operated very close to the inverter power rating switch point. The control switch also includes a position for direct connection to the utility line and an off position. Since the inverter will be connected to passive loads, it must be self-commutated. Also, this scheme does not allow the inverter to be connected to the utility line to charge the battery or operate dc loads. Therefore, the inverter need not be bidirectional (i.e., operate in a rectifier mode).

It may be desirable to add a second meter or use a dual-contact relay (not presently included) to switch to utility line operation when the load demand is very low and the inverter efficiency is low.

This interface system (as well as all of the others to be discussed) is comprised of standard, proven components and will be free of routine maintenance. Any repair work of defective equipment will require the services of a qualified electrician. Safety will be dictated by existing codes covering electrical wiring and equipment housing.

Typical costs for the hardware utilized with this interface system are presented in Table 3.2.3.4-A. The equipment shown is for a 2.5 kW, 120 volt, single-phase system. Costs for cabinetry are not included, since the hardware

Table 3.2.3.4-A
EQUIPMENT COSTS FOR RESIDENTIAL INTERFACE A

Equipment	Ratings and Description	Typical Manufacturer	Quantity	Unit Price
Reversing Contactor 42	115 V, 25 A, 2-pole with 2 NO contacts, mechanically interlocked, 115 V coil	ITE	1	\$57.00
Circuit Breaker 52	120/240 Vac, 25 A trip, 100 A frame, 2-pole, molded case with face mounting	ITE	2	\$11.10
Meter Relay 95	120V, 5 A, one NO and one NC contacts	GE	1	\$25.00
Time Delay Relay 95X	10A DPDT contacts 120 V coil, time delay to drop out, 0-1 sec.	TimeMark	1	\$20.75
Control Switch HS	2 NO and 2 NC contacts, double-block (miniature)	GE	1	\$19.40

would likely be mounted within the inverter cabinet. Similarly, the equipment cost is not totaled, since a portion of the interface hardware may be included in other systems. For instance, the circuit breaker 52I may be part of the inverter, and circuit breaker 52U may be considered as a normal part of the residence.

Residential Interface B. This system is quite similar to interface A, described above. Figure 3.2.3.4-B presents a schematic of this system. However, additional relaying is provided to enable operation of dc loads or charging of the battery from the utility. The circuit logic will permit the inverter to be connected to the utility only when an internal contact indicates that the inverter is set to operate as a rectifier. Thus, the inverter (rectifier) is paralleled with the utility only as a passive load. With this scheme, the inverter must be bidirectional and self-commutated.

Figure 3.2.3.4-B. RESIDENTIAL INTERFACE B

The interface has two circuit breakers, a reversing contactor, a charging contactor, a meter relay and a control switch. The basic operation is similar to that of system A. Power is normally taken from the inverter. An automatic transfer to the utility is made when the load power is above the rated inverter power as sensed by a meter relay 95. When battery charging or operation of the dc loads from the utility is desired, as indicated by a contact internal to the inverter S2, contactor 42C connects the inverter to the utility provided that the ac loads have previously been connected to the utility line. If desired, a dc circuit breaker or switch could be added in series with the battery to permit operation of the dc loads without simultaneously charging the battery.

The equipment costs are as presented in Table 3.2.3.4-A plus \$27.00 for a 115 V, 25 A, two-pole nonreversing contactor (42C). Contact S2 to sense when the inverter is set to operate as a rectifier is considered as part of the inverter and is not included in the cost.

Residential Interface C. With this system, the inverter and utility are operated in parallel. As with large plants that generate a portion of their electricity, load sharing with the utility is accomplished by controlling the phase angle of the inverter (generator). The inverter will supply all power up to its maximum rating with the utility supplying all power in excess of the inverter rating. Circuit controls are provided to ensure that power does not flow into the utility line. In this system, the inverter must be bidirectional (to charge the battery or operate dc loads) and capable of operating in parallel with a utility; and may be either line- or self-commutated.

Figure 3.2.3.4-C presents a single-line diagram of this system. The interface equipment includes two circuit breakers, two millivolt transducers, a meter relay, a contactor and a hand switch. To utilize the solar power system,

Figure 3.2.3.4-C. RESIDENTIAL INTERFACE C

the control switch HS is turned to "auto." This closes contactor 42. The inverter is normally synchronized, and the switching does not cause a significant transient. The output of the transducer $\frac{W-mV}{I}$ is subtracted from that of $\frac{W-mV}{L}$. The difference, if positive, results in a phase advanced signal input to the inverter phase control. This increases the power output of the inverter. When the signal is zero, this indicates all load is supplied from the inverter. When this signal is negative, the phase is retarded. If the signal remains negative, an abnormal condition exists (i.e., the inverter is supplying power to the utility in addition to the load and will result in a contactor trip). The same condition may be attained in case of battery charging mode. Hence an interlock from the charging control switch is necessary to permit the process. As an added precaution in either mode, a meter relay trips the contactor when a preset limit is reached.

Equipment costs for interface C are presented in Table 3.2.3.4-B.

Table 3.2.3.4-B

EQUIPMENT COSTS FOR RESIDENTIAL INTERFACE C

Equipment	Ratings and Description	Typical Manufacturer	Quantity	Unit Price
Contactor 42	115 V, 25 A, 2-pole, non-reversing, 115 Vac coil	ITE	1	\$27.00
Meter Relay 95	120 V, 5 A, 1 NO and 1 NC contact, 25 A input current	GE	1	\$25.00
W-mV Transducer	Dual Element — 125 V 25 A, single-phase, 0-2.5 V dc output into 5000 ohm load	Leeds & Northrup	1	\$50.00
Control Switch HS	1 NO and 1 NC contact, single-block (miniature)	ITE	1	\$13.40
Circuit Breaker 52	120/240 Vac, 25 A trip, 100 A frame, 2-pole, molded case	GE	2	\$11.10

DC Loads. It is technically possible to have a major portion of the electrical loads for a residence served by dc. Lighting, electric ranges, electric heating, motors etc. could all operate on dc. In general, this would require the use of custom manufactured appliances that are not readily available or in common use today. Other devices such as most televisions and clocks require ac. The simplest compromise would be to operate heating elements (for ovens, ranges, clothes dryers, water heaters, etc.) on dc, with a separate ac line to such appliances for timers and controls. At present, most residences already incorporate a separate 220 Vac circuit for this type of load. Similarly, wiring could be dedicated to serving electric heating element loads in a solar power system. It would be desirable to have only heating elements wired to this circuit. Such an arrangement would allow these dc loads to be switched to the ac utility lines when solar derived energy is not available. This switching arrangement would avoid losing energy to the inverter efficiency and also may permit a reduction in the inverter rating.

To be compatible with as many existing element devices as possible, it is recommended that the battery dc system voltage be set near 220 volts. Unfortunately for a 60 kWh residential storage system, the resulting cell size may be too small. Also, consideration should be given to the voltage requirements for motors in the space conditioning system, since this can be an appreciable load.

Shopping Center Interface A. This scheme is similar to the residential system A in that the ac loads are supplied by either the inverter or the utility but not by both simultaneously. The ac loads are supplied by the inverter until the load demands exceed the inverter rating. At this point, the loads would be switched to the utility lines, and when the load demand decreases below this value, the load would be switched back to the inverter. As with the residential switching schemes, this system does not fully utilize the energy available from the solar power system. No provision is made to charge the storage battery or operate dc loads from the utility line.

Figure 3.2.3.4-D presents a single-line diagram and control logic for this shopping center interface system. The components shown are for a 1 MW, 480 V, three-phase system. To energize the ac load distribution bus, control switch HS is set to the on position, and selector switch HSS is set to either the auto or utility position. With HSS in the utility position, the load bus is tied to the utility line only through circuit breaker 52U. With HSS in the auto position, circuit breaker 52I will close (provided 52U is open), and the inverter will supply power to the ac load bus. If the load current exceeds a preset value, as sensed by meter relay 95 through a current transformer CT2, breaker 52I trips, and breaker 52U closes automatically, thereby transferring the load to the utility when the inverter's power rating is exceeded. During the transfer period, the load current is interrupted. To prevent the control circuit contacts from reverting back to their previous position and possible hunting, a time delay relay 95X is used to keep the transfer control circuit energized and uninterrupted during the transfer. Manual transfer is also possible by use of the selector switch. However, transfer is locked out if the current limit is exceeded. At any time, over-currents will trip a closed breaker by means of a direct-acting trip device.

SWITCH DEVELOPMENT

CONTACTS	POSITIONS	
	UTILITY	AUTO
1-2 3-4		X
5-6 7-8	X	
9-10 11-12		X
13-14 15-16	X

CONTACTS	POSITIONS	
	ON	OFF
1-2 3-4	X	
5-6 7-8	X	
9-10 11-12		X
13-14 15-16		X

Figure 3.2.3.4-D. SHOPPING CENTER INTERFACE A

As with the residential system A, the inverter will be connected to passive loads and must therefore be self-commutated. This system does not allow the inverter to be connected to the utility line to charge the battery or operate dc loads, and therefore the inverter need not be bidirectional. It may be desirable to add a second meter relay (not presently included) to switch to utility line operation when the load demand is very low and the inverter efficiency is low and to devise a load shedding (or transferring) scheme to avoid transferring the entire load to the utility as the inverter's rating is exceeded.

Typical equipment costs are presented in Table 3.2.3.4-C. Equipment such as circuit breaker 52U, current transformer CT1, potential transformer Pt and meters WH and V are normally included as part of a 480 V installation and therefore do not represent an additional cost. Similarly circuit breaker 52I may be included as part of the inverter system. Cabinets are not included in the cost.

Table 3.2.3.4-C

EQUIPMENT COSTS FOR SHOPPING CENTER INTERFACE A

Equipment	Ratings and Description	Typical Manufacturer	Quantity	Unit Price
Switch HS, HSS	2-position, maintained contact 2 NO and 2 NC contacts, double-block (miniature)	GE	2	\$19.40
Current Transformer CT	1500-5 A, accuracy: 0.6-B.2 (ANSI)	W	1	\$42.60
Meter Relay 95	120 V, 5 A, 2 NO and 2 NC contacts, 5 A input	GE	1	\$25.00
Time Delay Relay 95X	10A DPDT Contacts, Time delay to drop out 0-1 sec., 48 Vac coil	TimeMark	1	\$25.00
Circuit Breaker	480 V, 3-phase, 1600 A con- tinuous, 50,000 A interrupting, 48 V dc operating coil, 1 NC auxiliary contact	W	1	\$2,030.00

Shopping Center Interface B. With this system, a permissive contact in the inverter and a normally open contact in the circuit breaker 52I are added to the shopping center interface A. The series connection of the inverter permissive contact and breaker contact 52I/a shunts the contacts in the closed circuit of 52I. This enables operation of dc loads or charging of the battery from the utility line. The inverter must, of course, be bi-directional and self-commutated.

Operation is the same as for shopping center interface A, with the exception that a charge mode is possible. A manual transfer to the utility is first made by the use of switch HSS. When the charge control is set to charge, the inverter permissive contact enables breaker 52I to close with 52U previously closed. This allows the utility to supply both the load and the battery charger.

The costs for interface B equipment are essentially the same as presented in Table 3.2.3.4-C for interface A.

Shopping Center Interface C. With this interface system, the inverter and utility are operated in parallel in a manner similar to residential interface C. A single-line diagram is presented in Figure 3.2.3.4-E. To supply the ac load bus with power from the solar system, the control switch HSI is turned to inverter. This closes circuit breaker 52I. The inverter is normally synchronized, and the breaker closure will not cause a significant transient. The output of the transducer $\frac{W-mV}{I}$ is subtracted from that of $\frac{W-mV}{L}$. The difference, if positive, results in a phase advance signal to the inverter phase control. This increases the power output of the inverter. If this signal is negative, the phase is retarded. If the signal remains negative, an abnormal condition exists (i.e., the inverter is supplying power to the utility in addition to the load), and breaker 52I will be tripped. The same condition may be attained in case of battery charging mode. Hence, an interlock from the charging control switch

Figure 3.2.3.4-E. SHOPPING CENTER INTERFACE C

is necessary to permit the process. At any time, over-currents will trip a closed breaker by means of a direct acting trip device.

Equipment costs for this interface are presented in Table 3.2.3.4-D. Only the equipment which must be added to that already installed in a normal utility/load interface is costed.

Table 3.2.3.4-D.

EQUIPMENT COSTS FOR SHOPPING CENTER INTERFACE C

Equipment	Ratings and Description	Typical Manufacturer	Quantity	Unit Price
Circuit Breaker 52	480 V, 3-phase, 1600 A continuous, 22,000 A symmetrical interrupting, 48 Vdc operating coil	W	1	\$2,030.00
Current Transformer CT	1500-5 A, accuracy: ANSI 0.380.2, 10 kV BIL	W	4	\$42.00
Potential Transformer PT	480-120 V, single-phase, ANSI class 0.6, 10 kV BIL	W	2	\$49.80
W-mW Transducer	208/120 V, 3-phase, 5A	W	2	\$267.00

Central Station Interface. The function of the central station is to deliver power into a utility grid. Therefore, it will be operated in parallel with utility lines. For the power levels involved (i.e., 50 to 1,000 MW), the interface connection to the utility will likely be at 115 kV or above and will be accomplished with standard substation equipment (i.e., isolating switches, breakers, station transformer(s) etc.). A second connection to the utility will serve to provide station power.

3.2.4 CONCLUSIONS AND RECOMMENDATIONS

CONCLUSIONS

- Batteries are best suited to serve as the energy storage element in all three photovoltaic solar power systems considered.
- Immediate and near-term (less than 7 years) installations would use lead-acid batteries. Their cost will be on the order of \$50 per kWh, and they will last 10 to 20 years, depending on the charge/discharge duty cycle that they are subjected to.
- Future installations will likely use any one of the several advanced batteries currently being developed, since their projected cost ranges from \$10 to \$25 per kWh. Use of these batteries will also result in a more compact installation.
- Advanced lead-acid batteries with improved performance characteristics will be developed, but their cost is expected to be \$50 per kWh.
- Although the equipment to meet the specific inverter and regulator requirements is not commercially available, it can be constructed using present day technology. Implicit in this is the requirement for development and design programs and their associated costs.
- The cost per kW for commercially available inverter equipment (similar to that required by photovoltaic systems) decreases with increasing power level, varying over a 100:1 range between 10^2 and 10^9 watts. The cost per kW at any given power level also varies depending on equipment design and manufacturer.
- In general, interfacing the solar power system with the utility line and ac loads may be accomplished either by switching the load between the utility line and inverter or by operating the inverter in parallel with the utility. Both interface designs use standard, commercially available components.

RECOMMENDATIONS

- The battery voltage for the residential system should be set near 220 volts to facilitate operation of heating elements (in ovens, ranges etc.) on either ac or dc. This permits a reduction in the size of the inverter and results in an increase in system efficiency by having the energy for these heating elements bypass the inefficiency of the inverter. A similar dc load system may determine the optimum battery voltage for the shopping center system.
- As data on transient variations in insolation and loads become better defined, battery manufacturers should be recontacted to assist in evaluating tradeoffs between installed storage capacity, duty cycle, battery life, cell design and cost for the type of service anticipated. With the projected magnitude of the market for photovoltaic systems, battery manufacturers may be willing to design and manufacture cells optimized for this type of energy storage service. This would apply to both lead-acid and developmental batteries.
- Line commutated inverters operating in parallel with the utility should be used in all three systems, since line-commutated inverters have a higher efficiency at partial load and tend to have a lower cost. Also, operating in parallel with the utility would virtually eliminate switching transients and would utilize the energy available from the solar power system more fully.
- Initial evaluations indicate that series switching regulators should be included in the systems. Their use permits the regulation of solar cell output currents at values conducive to extended battery life and, with the addition of control logic and instrumentation, permits tracking of the array's optimum power transfer impedance. These benefits outweigh the relatively small costs estimated for regulators.
- As regulator and inverter specifications become better defined, equipment manufacturers should be recontacted to perform design tradeoff studies for this application and to determine equipment costs with greater accuracy than is possible with present data.

SECTION 3.2
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4.0 RESIDENTIAL ON-SITE APPLICATION

Residential on-site applications are addressed in this section. Recognizing the importance of minimizing the load in achieving viable photovoltaic systems, considerable effort was devoted to thermal design of the building and careful selection of space conditioning equipment and systems. Two houses were defined, one for eastern locations and one for western locations. Site locations of Phoenix and Riverside were chosen for the western style house. Cleveland and Washington D.C. were chosen for the eastern style house.

Several space conditioning systems were evaluated, including conventional and integrated solar-thermal systems. A baseline system utilizing a commercial heat pump was evaluated for all locations. An alternate heating and cooling system concept was also selected for each location for evaluation. These houses are described and the space-conditioning method defined in Section 4.1.

Various methods of establishing space conditioning load requirements were devised and evaluated in the effort to determine thermal loads accurately and efficiently. These methods and their results are reviewed in Section 4.2. To equate space conditioning loads to electrical power requirements required development of analytical models for the various space conditioning equipment. Also, control sequence and control philosophy and/or criteria had to be established. These models and control criteria are reviewed in Section 4.3. The electrical loads computed for the selected systems and locations are presented in Section 4.4.

In Section 4.5 the photovoltaic power system is defined including the utility grid interface and power conditioning equipment. Array-storage trade-off studies were conducted to determine the optimum ratio of array to storage as a function of the fraction of electrical energy supplied by the photovoltaic system. The techniques developed for this optimization study along with the results and conclusions are given in Section 4.6. A cost-performance trade-off study was performed to optimize the size of inverter to be used for the various applications. This work is documented in Section 4.7.

The economic performance evaluation of these residential on-site systems is reviewed in Sections 4.8 and 4.9. General observations along with specific conclusions are summarized in Section 4.10.

4.1 RESIDENCES - EASTERN AND WESTERN

Design and performance evaluation of the residential photovoltaic system requires knowledge of typical electrical power demand for the residences, and space conditioning represents a major component of this demand. Studies were therefore undertaken to estimate the power required for space conditioning at each of four locations: Phoenix, Riverside, Cleveland and Washington, D.C.

Residential space conditioning power requirements are highly dependent upon building characteristics, space conditioning method and equipment, and weather variations. Each of these factors must therefore be established before loads can be determined. ERDA established the weather factors by stipulating that 1962 and 1963 weather tapes prepared by the Aerospace Corporation were to be used in the study. Building characteristics and space conditioning equipment were established in the course of the study as discussed below.

4.1.1 Building Definitions

The residential buildings for the study were defined so as to be somewhat representative of local architecture in the different locations. Rather than executing a complete architectural design, two solar homes for which existing designs were well-defined and available were selected.

The first of these was developed by Massdesign and is described in Reference 1. This two-story single-family residence emphasizes energy conservation and, in the configuration proposed by Massdesign, employs flat plate air-type solar thermal collectors and rock-bin storage. It is shown in Figure 4.1.1-A. This design was used in this study for both the Cleveland and the Washington, D.C. locations. However, the air collectors were removed for the Cleveland location for reasons discussed below. This basic design is referred to as the Eastern House in this study.

Solar Saltbox -- Air Auxiliary Heat Saved **84%**

FIRST FLOOR PLAN

SECOND FLOOR PLAN

FRONT ELEVATION

massdesign
Architects and Planners Inc.
Cambridge, Mass.

Figure 4.1.1-A. Eastern House-Solar Saltbox
by Massdesign, Cambridge, Mass.

A residence more typical of western architecture, shown in Figures 4.1.1-B1 & 4.1.1-B2, was used in the study for the Phoenix and Riverside locations. This design was developed by the Habitat Group of Orange County, California, under the leadership of Richard Dodd, Architect. It was selected by the Department of Housing and Urban Development for funding under their solar demonstration program, and at least one unit will be built in Brea, California during 1976. The solar thermal heating system originally designed for the Habitat house was not used in the present study, however.

Preliminary calculations revealed that it is extremely important to minimize space conditioning electrical power requirements if a viable photovoltaic system is to be realized. This is especially true in extreme climates, such as Phoenix. For example, using standard ASHRAE methods it can be shown that the thermal load introduced by 20 m² of west-facing windows, unshaded, in Phoenix in July requires over 90 m² of photovoltaic cells to power a conventional heat pump for its removal. By providing external shading devices such as louvered screens in addition to internal drapes or curtains, this load component can be reduced by a factor of 4. With projected cost of silicon cell arrays at \$100/m², the savings realized by a smaller array are roughly 10 times the cost of window treatment. Similar trade-offs can be done for insulation, weather-stripping, insulating (double-pane) windows and other energy conservation measures, with similar, although less dramatic, results. For this reason, the residences for the study were designed taking all reasonable steps to reduce the thermal load. Table 4.1.1-A summarizes the principal design features of both the Eastern and Western houses.

4.1.2 Space Conditioning Systems Definition

A wide variety of residential space conditioning systems are in use, some of which are shown in Table 4.1.2-A. The most widely used combinations of heating and cooling systems today are shown in the upper left hand corner. Several broad categories of solar-thermal systems which have been

WEST

SOUTH

EAST

NORTH

4-6

Western House Elevations
Habitat-I, by the Habitat Group,
Orange County, California

Figure 4.1.1-B1

SECOND FLOOR

FIRST FLOOR

area	sq ft
first floor	886
second floor	1102
total	2088
garage	414

Figure 4.1.1-B2. Western House Plan

Table 4.1.1-A
HOUSE DESCRIPTIONS

	<u>EASTERN</u>	<u>WESTERN*</u>
<u>AREA -m² (ft²)</u>	171 (1844)	192 (2068)
<u>EST. 1975 BUILDING COST (\$)</u>	45,800	41,400
<u>OVER-ALL HEAT GAIN/LOSS COEFFS.</u>		
Summer -kJ/Hr-C (BTU/Hr-°F)	653 (344)	779 (410)
Winter -kJ/Hr-C (BTU/Hr-°F)	725 (382)	927 (488)
<u>CONSTRUCTION:</u>		
Floor	Plywood on Joists	Slab Concrete
Walls	Plywd. & Gyp. Bd.	Stucco & Gyp. Bd.
Ceilings	Gyp. Bd.	Gyp. Bd.
Roof	Comp. Shingle on Plywd.	Wd. Shakes on Slats
Windows and Glass Doors	Double Glaze	Double Glaze
Doors	1-3/4" Wd.	1-3/4" Wd.
Insulation & Thermal Provisions		
Walls	R13	R13
Ceiling	R22	R22
Roof	R22	R13
Floor	R2	-
Windows & Doors	Weather Stripped	Weather Stripped
Windows & Glass Doors	External Sun Screens & Internal Drapes	External Sun Screens & Internal Drapes
<u>WINDOWS:</u>		
South -m ² (ft ²)	7.1 (76)	17.1 (184)
Other -m ² (ft ²)	15.8 (170)	10.6 (114)
Total -m ² (ft ²)	22.9 (246)	27.7 (298)

*North-Facing Version of Figure 4.1.1-B1

Table 4.1.2-A

MATRIX OF POTENTIAL SPACE CONDITIONING SYSTEMS

HEATING COOLING	1	2	3	4	5	6
	Gas/Oil Furnace	Heat Pump	Elec. Resist.	Solar Thermal + Gas/Oil	Sol. Th. (Rockbed) + Heat P.	Sol. Th. Passive
1 Evaporative	Phoenix Riverside	*	*	*	*	
2 Heat Pump	Cleveland	Phoenix Riverside Cleveland Washington	*	*	Washington	
3 Evaporative + Heat Pump						
4 Solar (Nocturnal)						
5 Solar (Absorption)						

 Not considered in this study

* Cursory Evaluation Only

proposed and/or investigated are identified in this table also. Each element of this matrix represents a potential space conditioning system which could be employed at one or more of the four locations addressed in this study, and each one would impose different requirements for electrical power on the photovoltaic system. Although time did not permit thorough analysis of each of these systems, those enclosed in the dark rectangle were considered in varying degrees of depth for the locations which seemed most appropriate. The primary selection criterion was compatibility with the photovoltaic system.

The 10 systems in the dark rectangle of Table 4.1.2-A were screened by cursory examination in order to reduce the number of systems requiring detailed analysis. For example, systems combining evaporative cooling with solar thermal/heat pump heating were eliminated, since locations permitting evaporative cooling (Phoenix and Riverside) have very mild winters, suggesting that careful thermal design of the building can reduce the heating load to a nearly-negligible level. Since a small load should be satisfied with the least initial cost system, homes in these areas should probably be heated by electrical resistance or a forced air gas furnace*. This represents the current practice in these areas.

Several configurations for the solar thermal system with heat pump backup were considered in some detail. At the onset of the study it was felt that a system using a water-source heat pump in series with a thermal solar collector, perhaps integral with the photovoltaic array, would be a good system for all locations. Such a system is shown in Figure 4.1.2-A. It was argued that the storage tank, supplied with heat from the thermal collector, would provide a more nearly constant source temperature for the heat pump, thus improving its low-ambient performance relative to a conventional air-source heat pump. However, review of recent solar literature (Reference 3) revealed important shortcomings of the series system. It became apparent that in this system, all

*It is recognized that pure solar-thermal heating studies and demonstration projects have not ruled out these areas. If such studies prove that solar thermal heating is competitive in mild climates, these systems will deserve further consideration in combination with photovoltaics.

Figure 4.1.2-A. Early Concept of Water-Source Heat Pump and Integrated Photovoltaic/Solar-Thermal System.

heat "pumped" out of the storage tank must be replenished by the thermal collector array. In an interval when the collector or storage tank are inadequate, the store will be depleted and the heat pump must shut off, necessitating auxiliary heating. As pointed out in Reference 3, the auxiliary heating will likely be at a COP equal to 1. If the heat pump was in parallel instead, and had an outside air source, as shown in Figure 4.1.2-B, many of these periods may be met with the heat pump at a COP greater than 1. Figure 4.1.2-C, reproduced from Reference 3, clearly shows the parallel configuration to be superior.

Another serious drawback to the series water-source heat pump system is that it is incompatible with an integrated thermal-photovoltaic array in the cooling season. In the cooling mode the storage tank must receive the heat removed from the house, the heat pump shaft work, and the heat removed from the photovoltaic array. This heat must be rejected ultimately to the outside air, or to the night sky. Cursory calculations revealed that nocturnal radiation from the collector array would not be sufficient, necessitating the addition of a cooling tower. In locations with mild winter climate, the economic value of the thermal energy captured and used during the heating season is small relative to the initial cost of equipment in this system. Moreover, in such climates the outside air temperature seldom becomes low enough to seriously reduce performance of improved air-source heat pumps.

The parallel system in Figure 4.1.2-B removes some of the problems foreseen for the series system, but it too has serious disadvantages. For example, the integrated collector results in performance degradation of both the photovoltaic array and the thermal array. An analysis of the combined photovoltaic/thermal flat plate collector was performed by Dr. Florschuetz of ASU. Results of this work were presented in a paper which is included as Appendix H in this report. The electrical output is reduced due to additional optical interfaces, and due to cell temperature elevation. The combined effect is reflected in terms of additional photovoltaic array area required if mounted on a thermal collector. Approximately 20-25% more area is required, and the economic value of the heating-season useful thermal collection is likely to be a good deal less than the cost of this extra cell area.

Figure 4.1.2-B. Parallel Air-Source Heat Pump and Integrated Photovoltaic/
Solar Thermal System.

Economic Comparison of Parallel vs. Series Heat Pump Augmenting Solar Heating (From Ref. 3). Study was done for an Albuquerque residence.

Figure 4.1.2-C

There is also a mismatch between photovoltaic and thermal collector area required for all areas considered. In Phoenix the size of a photovoltaic array to meet cooling demand is roughly $2\frac{1}{2}$ times the size of a thermal collector to meet the winter heating demand. In Cleveland, the size of the thermal collector required to meet 100% of the heating load in January is roughly 4 times the size of a photovoltaic array needed for 100% heat pump cooling in August. These findings resulted in dropping the integrated collector from further consideration in this study*. A similar integrated air thermal collector was rejected for many of the same reasons.

Attention was then turned to nonintegrated air thermal systems, which offer some advantages in rejecting collected heat to the atmosphere in the summer. Two such systems are shown in Figures 4.1.2-D and 4.1.2-E. Figure 4.1.2-D shows the system conceived by Spectrolab and referred to as the rock-bed source heat pump system. Here, the heat pump simultaneously adds and removes heat at opposite ends of the rock-bed. In the heating season the system is closed, but during the cooling season the night-time hours are used to flush out heat added to the bed during the day. If the bed is large (but finite) and sufficiently stratified, this system combines the best features of both the series and the parallel heat pump configurations, without the previously mentioned limitations of each. This system was selected for more detailed study, described in a later section; unfortunately, practical rock bed sizes and stratifications proved to be inadequate to achieve the theoretical promise of this system.

A conventional air-type solar heating system with rock bed storage and parallel heat pump augmentation is shown in Figure 4.1.2-E. It is represented

*Further work, however, is recommended to evaluate the merits of hybrid systems using multistage design concepts. A simple version possibly well suited for locations with a high heating to cooling load ratio is a two stage solar thermal system where the first stage is an integrated photovoltaic-thermal collector system without glazings. The second stage would be a thermal only system with glazings. With such a system the photovoltaic array could conceivably operate with a higher year-round efficiency than a passively cooled unit and still contribute significantly to the solar heating task in the winter.

Figure 4.1.2-D Air solar-thermal heating/cooling system using rock bed for source and sink. In summer, heat is flushed from the rockbed at night. In the air circuits, solid arrows denote heat, hollow arrows denote cool.

Figure 4.1.2-E. Air-Type Solar-Thermal Heating/Cooling System with Rockbed Storage and Parallel Heat Pump Augmentation.

by column 5 of Table 4.1.2-A, where it is indicated that this system was selected as one of the two studied for Washington. A similar water system was investigated thoroughly in Reference 3.

Having thus specified the solar thermal + heat pump system indicated in Table 4.1.2-A, there still remained a number of solar-thermal systems, and the conventional systems. With the objective of providing comparative results, a base line system using a heat pump with back-up resistive heating plus one alternate system was selected for detailed study and electrical load determination for each of the four locations. These systems are defined in Table 4.1.2-B.

It will be noted that most of the space conditioning systems in the final selection are conventional systems; only in Washington do the systems employ integrated solar-thermal heating. The principal reason for this is that photovoltaic-supplied heat pump systems sized for summer cooling in Phoenix are quite adequate for meeting the winter heating load without solar-thermal augmentation. In Washington, Riverside, and Cleveland this is not true, hence all of these locations may be well-suited for solar-thermal augmented heat pump for winter heating. The Riverside heating load is small and Cleveland's large relative to winter insolation. Washington was selected to evaluate this concept, using a system such as shown in Figure 4.1.2-E.

4.2 METHOD OF SPACE-CONDITIONING POWER REQUIREMENTS CALCULATION

Calculation of energy requirements for space conditioning is a three step process:

- (1) Calculation of basic thermal parameters of the building, such as overall heat transmission factors (UA values), window shading coefficients and infiltration rates.
- (2) Calculation of heat rates across the building envelope (heat gain or loss); this leads directly to the so-called heating or cooling "load" by the use of some form of "lagging" to account for internal storage.

Table 4.1.2-B

SPACE CONDITIONING SYSTEM DEFINITION

Location	Heating	Cooling	Other Appliances Electrical
<u>Base Line</u>			
All Locations	Air Sink Heat Pump + Resistance Heating	Air Sink Heat Pump	20% of Hot Water Heating and All Other
<u>Alternatives</u>			
Phoenix	Forced Air Gas Furnace	Evaporative Cooler	All Except Dryer, Range, & Hot Water *
Riverside	Same	Same	Same
Cleveland	Same	Conventional (Vapor Comp.)	Same
Washington	Solar Assisted Heat Pump + Resistance Heating	Air Sink Heat Pump	20% of Hot Water Heating and All Other

* Dryer, Range, and Hot Water Heater normally gas operated.

- (3) The heating or cooling loads can then be "matched" to the capacities of the space conditioning equipment, and the corresponding power consumption of this equipment determined. This establishes the electrical demand for space conditioning.

Step (2) is commonly called "load" calculation, and step (3) the "simulation" phase.

A distinction must also be made between the so-called "design" calculations of load, routinely done in the process of sizing the equipment, and the hour-by-hour energy requirement calculation. The latter is complicated by the need for hour-by-hour weather information, the need to represent off-design conditions of the building and the equipment. Moreover, whereas the design calculation needs to be done only twice (summer and winter) the energy calculation must be done at least 8760 times per year (once each hour) if the best-achievable accuracy is desired.

In this study, step (1) and the design loads for step (2) were executed using procedures described in detail in the ASHRAE Handbook of Fundamentals (Reference 2, Chapters 19-22). A number of different methods were considered and tried for the energy calculations, seeking a compromise between accuracy and computational economy. The TRNSYS load model described below in Section 4.2.1 was found to be uneconomical for long term energy calculations and hence was limited to short term transient performance studies.

A long-term average load model using a degree-day method based on ASHRAE-recommended procedures was evaluated and used early in this program for estimating long-term average space conditioning loads. This approach, described in Section 4.2.2 underwent several modifications in the evolutionary process to improve overall accuracy. Section 4.2.3 describes the first level of modification establishing a load model referred to as the "Simplified Hourly Method." This model introduced hourly averages for outside air temperature instead of daily average values and also used average hourly insolation for that hour during the month.

The next and final modification referred to as the "Improved Hourly Method" is described in Section 4.2.4. This modification improved the overall accuracy of the load model by using actual hour by hour weather data simulation per 1962-1963 Aerospace Corporation weather tapes. It is this method which was implemented in a computer subroutine program for purposes of thermal load calculations in the simulation studies.

4.2.1 The TRNSYS Load Model

The most elaborate method considered was a direct simulation of the building as a 12-node thermal analog. This model was developed as a TRNSYS (Reference 4) subroutine and is thought to be the most accurate method considered, since it calculates inside air temperature, allowing it to drift within the control band in a realistic manner. It also calculates the solar load on an hourly basis using weather tape data for insolation. Effects of external shading devices are also accounted for by the use of a file of solar heat gain "effective areas," precalculated by the methods employed in the National Bureau of Standards program, NBSLD. A general heat pump subroutine was also developed. Typical results obtained with this program are shown in Figure 4.2.1-A.

While the TRNSYS model is the most accurate, it is also the most expensive method of arriving at energy consumption. Mathematical convergency requires a 15 minute integration step so that over 35,000 energy balances are required per year of simulation. Computing costs prohibit extensive parametric studies with this model. Its principle value is for the study of the system transient performance over short periods of time, e.g., 1 to 2 weeks.

4.2.2 Long-Term Average Load Models

Several simplified calculation procedures were tried in an effort to determine long-term average space conditioning loads more economically. For example, the degree day method, described in References 6 and 7 was tried and compared to hand-calculated loads, with the results shown in Figure 4.2.2-A.

Typical Results of TRNSYS Residential Space Load Model. Results Shown Are For Rock-Bed/Solar Air Heating System.

Figure 4.2.1-A

COMPARISON OF CALCULATED LOADS WITH
DEGREE-DAY METHOD PREDICTION.

Figure 4.2.2-A

The hand calculation procedure for this figure employed long term average weather data from References 8 and 9. The method itself is described below. It is apparent that a wide disparity exists between results of the two methods, especially in mild climates in the winter. The probable source of this difference is the thermal improvements in the buildings of this study compared to those involved in the original work in which the 65°F (18.3°C) degree-day base was defined. Figure 4.2.2-A suggests that a downward shift in the base to perhaps 55°F (12.8°C) in the winter and to about 60°F (15.6°C) in the summer would improve the degree-day estimate. However, without extensive correlation this procedure would be in more doubt than a method based on actual building thermal properties and average weather data. It was therefore abandoned in this study.

The method actually used for early estimates of long-term average space conditioning load treats five separate load components:

Q_c : The heat gain/loss by conduction neglecting solar radiation. It is found from

$$Q_c = \overline{UA}_T (T_{OSA} - T_{ISA}) \times 24 \text{ (kJ/day)}$$

$\overline{UA}_T$ = Overall structural conductance, including opaque and glass (kJ/Hr°C)

$\overline{T}_{OSA}$ = Long term daily average outside air temperature (°C)

T_{ISA} = Inside air temperature (°C)

Q_v : Heat gain/loss due to infiltration

$$Q_v = 1.22 \dot{V}_{INF} (\overline{T}_{OSA} - T_{ISA}) \times 24 \text{ (kJ/day)}$$

$\dot{V}_{INF}$ = infiltration volumetric flow (m³/hr)

Q_R : Heat gain due to solar radiation on opaque surfaces

$$Q_R = \overline{UA}_O (\alpha/h)(Q_s) - (\epsilon/h)(\Delta R) \times 24 \text{ (kJ)}$$

$\overline{UA}_O$ = Opaque surface over-all conductance (kJ/hr°C)

Q_s = Daily total insolation on the surface in question. Estimated by multiplying daily total figures from ASHRAE Handbook of Fundamentals, Table 2-6, Ch. 28, by ratio of long-term average insolation on horizontal surface (National Weather Service) to horizontal surface figure from ASHRAE tables, (kJ/m²-day).

$\frac{\epsilon}{h} \Delta R$ = long-wave correction (0 for walls, -3.9°C for roofs).

α/h = ratio of surface absorptance (short wave) to outside film coefficient.

Q_w : Solar heat gain through windows (kJ/Hr)

$$Q_w = Q_s A_G \times SC$$

A_G = Glass area of surface in question (m^2)

SC = Shading coefficient (see Ref. 2)

Q_F = Heat gain due to occupancy and internal load (kJ/day)

This method is based on ASHRAE-recommended procedures, but neglects storage effects of the structure. It provides a useful break-down of the load, revealing the major sources and thus suggesting the most important areas for design improvement. The neglect of storage will result in low predictions for winter heat loss, since the method assumes instantaneous and complete entry of opaque-surface solar radiation, whereas in fact a portion of this will be stored in the walls and transfer back to the atmosphere in the evening. In the summer, the predicted load will be too high for the same reason.

Another difficulty with this method is that it is based on daily totals, therefore confounding heat gains during one part of the day with heat losses during another part. For example, on a day in which the average outside temperature is equal to the inside temperature, the model would predict zero conduction and infiltration load, whereas in fact the space conditioning equipment would have to operate during some portion of the daily cycle. Also, the equipment efficiency is often dependent on weather parameters, so that energy consumption estimates based on daily load totals will necessarily be very approximate. The magnitude of these errors has not been determined, but is thought to be less than 20%. Calculations were done for the four locations, summer and winter, and these are the results shown in Figure 4.2.2-A.

4.2.3 Simplified Hourly Method

In order to determine energy requirements more accurately, but still less so than by the TRNSYS simulation, the above daily method was modified to predict hourly loads. The conduction term, Q_C , was calculated as before, but with long-term average hourly outside air temperature instead of the daily average, and the resulting heat gain was shifted later in time by the approximate building thermal lag (3 hours). This shifting helps to predict

the time of peak load more correctly, but of course does not reflect the attenuation effect of the thermal mass. The solar portion of the load was calculated hourly by two alternate procedures. In the simplest of these, the previously calculated daily total $Q_R + Q_W$ was apportioned over the day in accordance with the distribution of average hourly insolation on a horizontal surface. That is, the solar load for a particular hour was

$$Q_{\text{SOLAR}} = (Q_R + Q_W)_{\text{Daily}} \times (I/I_{\text{Daily}}) \quad (\text{kJ/Hr})$$

where I is the average insolation for that hour in that month for the year 1962, as determined from the Aerospace weather tape. I_{daily} was the daily total from the same source. This method was employed in the estimation of long-term average hourly loads.

4.2.4 Improved Hourly Method

The second method of calculating hourly solar loads attempted to improve the accuracy with respect to load magnitude and time of peak load occurrence. It will be observed that the simple method described above predicts the peak solar load at solar noon, whereas in fact it may occur early in the morning or late in the afternoon due to east or west windows. This can be of substantial importance, since an early-morning solar load in the cooling season may be offset by conduction heat loss, and not require mechanical cooling at all. The method employed to achieve more accuracy in this respect is based on actual hour-by-hour calculation of sol-air temperatures and solar heat gain factors, as described in Reference 2. That is, solar angles are computed hourly and used to calculate window transmittance, window solar gain and wall solar irradiation. The latter is converted to an equivalent sol-air temperature permitting calculation of an instantaneous solar load on opaque surfaces. While the full complexity and generality of the ASHRAE algorithms is not employed, the calculation does reflect the factors of major importance and yields an approximate hourly solar load. Conduction and convection calculations are substantially as described above. Daily total heat gain (or loss) predicted by this method agree with the previously described daily method within $\pm 15\%$.

A computer program was developed implementing this load model. It proved to be sufficiently economical in operation to permit hour-by-hour calculations of thermal load for the two-year period 1962-63, using actual weather tape data instead of averages.

4.3 ANALYTICAL MODELS FOR SPACE CONDITIONING EQUIPMENT

As mentioned previously the actual energy requirements for space conditioning are determined by matching the capacity of the equipment to the previously calculated thermal load. Equipment performance characteristics then indicate the level of energy consumption while delivering this capacity. Analytical models were developed for each piece of equipment in order to make these calculations. These included evaporative coolers, gas furnaces and vapor compression heat pumps.

4.3.1 Evaporative Cooler

The model for evaporative coolers is based on a performance parameter which expresses the degree to which the device reduces the output air dry bulb temperature to the incoming air wet-bulb. That is, the cooler outlet air dry bulb, which is also the room air inlet dry bulb, is expressed as

$$T_{ci} = T_{osa} - \eta_c (T_{osa} - WBT)$$

where

T_{ci} = Cooler outlet dry bulb (C)

T_{osa} = Outside air dry bulb (C)

WBT = Outside air wet bulb (C)

η_c = Cooler effectiveness

According to Reference 11, η_c is about 0.8 for a new, well designed evaporative cooler. If the pads are allowed to deteriorate or do not wet well, this can be seriously reduced. In this study η_c was taken to be 0.8.

The room temperature achievable with an evaporative cooler of specified capacity (air volume) is

$$T_R = T_{ci} - Q_{load} / (1.22 \dot{V})$$

where

$\dot{V}$ = Cooler capacity (m^3/hr)

T_R = Room Temperature ($^{\circ}\text{C}$)

Q_{load} = Thermal cooling load on building (kJ/Hr) (negative)

It was felt that a great electrical energy saving advantage could be gained in using evaporative cooling and gas heating in Riverside and Phoenix. This was confirmed by detailed energy calculations which are summarized in sections 4.4.2 and 4.4.3. Because of the potential importance of this approach in achieving a viable photovoltaic residence in these areas, studies were undertaken to access the current state-of-the-art and potential for improvement of these devices. These studies are summarized in Appendix L.

An attempt was also made to determine the comfort impact of evaporative cooling. Preliminary cooling load calculations showed that the rise over cooler outlet temperature would be at most two degrees centigrade for the $8500 \text{ m}^3/\text{hr}$ capacity cooler selected for Riverside and Phoenix. Room air temperature was calculated from hourly 1962-63 temperature data from the Aerospace tapes for coolers with 70%, 80%, and 90% effectiveness*, assuming a 2°C temperature rise. Figure 4.3.1-A shows that in Riverside a 70% effective cooler would allow room temperature to exceed 26.7°C (80°F), the upper limit of the ASHRAE comfort chart, for less than ten hours per year. In Phoenix this temperature would be exceeded for 4% of the year with a 70% effective cooler (Figure 4.3.1-B). Such a cooler would, however, keep indoor temperatures below 85°F . A well-maintained, high performance cooler (80% efficient) would keep indoor temperature within the comfort range for all but thirty-five hours of the year.

*Recent data indicate that 70% effectiveness is typical of available units, although efficiencies as high as 90% are discussed in Appendix L.

Figure 4.3.1-A EVAPORATIVE COOLER PERFORMANCE--RIVERSIDE, CALIFORNIA

Figure 4.3.1-B. EVAPORATIVE COOLER PERFORMANCE--PHOENIX, ARIZONA

The usual means of capacity control is by blower speed control. This was modeled by first calculating room temperature at full capacity, then reducing the speed if room temperature was too low. Speed was reduced in three steps.

Electrical power consumed by the cooler is the sum of blower motor power and recirculating pump motor power. The latter was taken to be 0.075 kW. Blower motor power at constant efficiency theoretically varies with the cube of volumetric flow, i.e.,

$$P_c = KW_{\max} (\dot{V}/\dot{V}_{\max})^3$$

The maximum power required by the blower is

$$KW_{\max} = 0.746 (\Delta P \times CFM) / (6348 \eta_m \eta_f)$$

where

ΔP = pressure loss through pads and ducts (in. H_2O)

CFM = volumetric flow (FT^3/min)

= $\dot{V}$ (m^3/Hr) $\times 0.588$

η_m = motor efficiency

η_f = fan efficiency

The ΔP employed was 5/16 inches of water, corresponding to a properly designed duct system and pads. The maximum power was found to be 0.63 kW for the 5000 CFM ($8500 m^3/hr$) cooler selected.

Depending on the manner in which speed is reduced the motor efficiency may decrease significantly. In the simplified, long term average hourly load calculations, the power was calculated by the constant-efficiency equation

at the highest three speeds and held constant at the lower three speeds. This represents a high-performance cooler motor which could be developed for minimum energy consumption. At the present, however, only 3-speed motors are available and catalog data indicates that power is only reduced by about one-third at half speed, indicating a serious drop in efficiency with speed reductions. For the actual hour-by-hour power requirement calculations, the available unit performance was employed.

In calculation of evaporative cooler power requirements, the cooler was assumed not to be turned on unless the inside temperature was above 27°C. When not on, the inside room temperature was estimated from

$$T_R = T_{\text{set}} + Q_{\text{load}} / \overline{UA}_T$$

where

T_{set} = temperature at which Q_{load} was calculated (C).

$\overline{UA}_T$ = overall conductance of the residence (kJ/hr-C)

Cooler power requirements were also reduced by assuming maximum reliance on natural ventilation. This was accomplished by calculating a ventilation air rate through windows, assumed open at the appropriate times, based on the formula given in Reference 10, Ch. 19.

$$\dot{V}_{\text{vent}} = EAV \quad (\text{m}^3/\text{hr})$$

where E = effectiveness (taken as 0.25)

A = open window area (m^2)

V = wind velocity, m/hr

The potential for cooling by this means depends upon outside air temperature and wind velocity. An indication of relative potential for ventilation cooling is shown in Figure 4.3.1-C, which is based on 1020 m^3/hr air flow and the average hourly temperature differentials for July. The potential is negligible

Figure 4.3.1-C JULY VENTILATION COOLING POTENTIAL ON AVERAGE DAY

in Phoenix, but very important in Riverside. Note that the $1020 \text{ m}^3/\text{hr}$ assumed for Figure 4.3.1-C is very moderate; much higher air rates are possible with only moderate breezes through properly opened windows. In the evaporative cooling power calculations, maximum use was made of this potential by trying to meet the load by window opening before turning the cooler on.

4.3.2 Gas Furnace

The gas furnace model accounts for both electrical power for the blower motor, and the gas energy input. For the blower power, the equation used is the same as for the cooler, but naturally the power is lower due to a smaller volume of air. Heating loads for all locations considered were well below the smallest gas furnace size available, 60,000 BTU/hr (63300 kJ/hr) input, so this unit was selected. The unit was assumed to deliver 600 CFM ($1020 \text{ m}^3/\text{hr}$) through a pressure differential of 0.04 inches of water. The pressure differential is low since the forced air system is assumed to deliver through the ducts designed for summer cooling with over 8 times the heating air flow. The average hourly electrical energy consumption was calculated as the fan power multiplied by the ratio of the hourly heating load to the heating capacity. This is equivalent to the unit being on for that fraction of the hour.

Gas input energy was calculated as the heating load for a particular hour divided by the assumed furnace efficiency of 0.8.

4.3.3 Heat Pump

Heat pumps were modeled by tabular data provided by manufacturers. Typically the manufacturer provides capacity for heating and cooling as functions of source temperature, and some parameter from which input power can be determined. Figures 4.3.3-A and 4.3.3-B show such data for a high-performance heat pump under development by Airesearch. Figures 4.3.3-C and 4.3.3-D show similar data for a currently available energy-efficient heat pump manufactured by Supreme Aire of Santa Fe Springs, California. While system performance data is based on the use of the Supreme Aire unit, the Airesearch unit was evaluated for comparison purposes in the studies of the Washington D.C. solar augmented heat pump system.

Figure 4.3.3-A. Estimated Capacity of Airesearch Variable Speed Heat Pump

$$\text{EER} = \text{Net capacity} / \text{Total power}$$

Figure 4.3.3-B. Estimated Energy Efficiency Rating (EER) of Airesearch Variable Speed Heat Pump

Figure 4.3.3-C. CAPACITY OF SUPREME-AIRE HEAT PUMP (HP 2.5)

Figure 4.3.3-D. Power Required by supreme-Aire Heat Pump(HP 2.5)

The procedure employed in calculation of heat pump power was to look up the capacity at the instantaneous outside air temperature and compare this to the load at that time. If the capacity exceeded the load, the unit was assumed to be on only for the fraction of the hour equal to the ratio of load to capacity. The power required to operate the unit was also looked up from the tabular data, and this value multiplied by the on-time fraction, yielding the energy consumed in that hour. If the load exceeded the capacity in any hour, the heat pump was assumed to be on full-time and the balance of the load picked up by resistance heating. A similar procedure was employed in the cooling season, except that at times of insufficient cooling capacity the inside temperature was allowed to drift upward.

The above described equipment models were programmed along with programs of the simplified hourly load calculation methods described in the previous section. The combined load and equipment program was then used to calculate hour-by-hour electrical power requirements as presented in the following section.

As indicated in Section 4.2 two basic solar thermal augmented heat pump systems were considered for the optional space conditioning system for the Washington residence. These two system concepts were analyzed in some detail in order to determine their relative merits. This analysis is given in Appendix I. The results of this analysis showed some potential sizing problems of the rock bed for the series operated heat pump as shown in Figure 4.1.2-D. For the operational mode assumed the parallel operated heat pump as depicted in Figure 4.1.2-E was clearly superior and hence chosen for the Washington D.C. alternate system.

A TRNSYS subroutine modeling a heat pump was also developed. It was based upon the same technique mentioned above, i.e., interpolation from manufacturers' performance data for capacity and power consumption. This model was used in direct simulation studies of relatively short periods as applied to the Washington D.C. residence with air collectors, rock bed storage, and a parallel heat pump. This work is described in Appendix J.

The residential electrical load can be divided into two parts. One is the seasonal heating, ventilating and air-conditioning load. The other is the non-seasonal appliance and lighting load. The appliance set of the residence represents a principal determinant of the size and timing of both loads.

The base line system selected for evaluation used a $2\frac{1}{2}$ ton Supreme Aire heat pump for both heating and cooling. Supplemental resistance heating is also used for winter heating. For these houses all electric appliances are specified with the exception of hot water heating. A solar thermal hot water heating system is used, and it is assumed to reduce the electrical hot water heating load to 20% of what would normally be required.

The alternate systems selected for each location have smaller electrical space conditioning loads. In Cleveland, Phoenix, and Riverside a conventional gas fired forced air furnace is used for heating. For Washington D.C. a solar heating system using a rock bed storage and a parallel heat-pump is used. Cooling in Cleveland and Washington is accomplished by the air heat pump, and evaporative cooling is used in Phoenix and Riverside.

The appliance set for the alternate systems is identical to the base line all-electric houses except for those houses using gas heating. For those a gas range, dryer, and hot water heater are assumed.

4.4.1 Fixed Appliance and Lighting Load Model

In a residence, loads with power requirements ranging from a few watts to twelve kilowatts (range) are switched on and off throughout the day. The result, particularly for all electric residences, is a load pattern marked by strong peaks as well as periods of very low electrical consumption.

Depending on the living patterns of the occupants, the appliance and lighting load may also show strong daily variations. Weekends and holidays have different electrical usage patterns from weekdays. Cooking for a large

gathering, or washing and drying several loads of clothes on the same day (an electric dryer draws five kilowatts) would strongly increase that day's power consumption.

The available data on residential electrical consumption patterns are in the form of averages for several or many households. Such data obscure the peaks in individual residential loads. Because peaks do have an effect on the performance of residential photovoltaic systems, a synthesized daily non-HVAC load was used for performance calculations.

Tables published by the Federal Power Commission in 1970 showing appliance power ratings and average yearly consumption were used to calculate a load profile. For each appliance daily energy consumption was divided by its rating to find the number of hours per day the appliance was on. Using an assumed pattern of household activities a quarter hourly schedule of electrical loads was produced. This load model for the all electric house is given in Figure 4.4.1-A. This model results in a total daily load of 20 kWh. For the basic appliance (gas) house the load is 11.85 kWh. These loads correspond closely to the 1990 electrical load projections of Tansil (ORNL-NSF-EP-51) reduced by the energy consumption goals of the recently announced NBS/industry joint program. In the model, most electrical consumption is concentrated in four activity periods, morning-breakfast (6:30-8:00 a.m.), housework (10:00-11:00 a.m.), dinner (5:00-7:00 p.m.) and evening (7:00-10:30 p.m.). Daily variations in non-HVAC load were ignored for simplicity, even though they would affect system performance.

4.4.2. Electrical Power Loads for Space Conditioning

The improved hourly load calculation procedure (Section 4.2.5) was used in conjunction with the equipment models to calculate electrical demands in each hour of 1962 and 1963 at all locations*. This was done for the base line and alternate

*Aerospace weather data tapes were used for all locations except Washington. As a result of incomplete Washington D.C. weather data, average daily profiles of weather data were obtained for each month of the year. This was then used for the Washington D.C. hour load calculations.

Figure 4.4.1-A
RESIDENTIAL LOAD MODEL - BASE LOAD (20 kWh/DAY)

SPECTROLAB
a subsidiary of Hughes Aircraft Co.

space conditioning system at each location. The results of these calculations, being too voluminous for convenient tabulation, were stored on magnetic tape for direct use in photovoltaic system studies by different programs.

Summaries of these results in the form of hourly averages for each month are presented in Tables 4.4.2-A - H. In these tables the individual entries represent the average power in kWh consumed by the space conditioning equipment during a particular hour of the day and for a particular month. The average daily consumption in kWh is printed at the bottom of each monthly column. Corresponding hourly and daily figures but averaged for the year are in the right-most column.

Tables 4.4.2-A and B are for Phoenix, representing heat pump and evaporative/gas furnace systems respectively. It is observed that summer cooling represents the greatest seasonal demand; this confirms early predictions by simple models. Winter demand for heat pump systems are about one-third to one-fourth of the summer demand on a daily basis. The calculation method predicts spring and fall demands of about 20% of the summer peak. However, examining the hourly figures and the weather reveals that this demand is a mixture of heating and cooling. Most likely, the space conditioning equipment would not be operated at all in these seasons, suggesting that the demand may actually be zero. However, no adjustment has been made for this, and these results were used directly in photovoltaic system studies. Comparing Tables 4.4.2-A and B, it will be observed that the evaporatively cooled/gas heated residence requires only about 12% of the electrical power required by the heat pump residence on an annual basis. Examining the worst summer months reveals that the evaporative system requires only about 20% of the energy for the heat pump system on a daily basis. An analysis of the comfort penalty associated with evaporative systems was presented in Section 4.3.1.

Tables 4.4.2-C and D present energy requirements for the two systems in Riverside. Here there is an even more dramatic difference between the two systems. In the worst summer month, evaporative cooling requires only 10% of the energy

PHOENIX
AVERAGE ELECTRICAL LOAD
SUPPLEMENTAL AIR HEAT PUMP
KWH

Table 4.4.2-A

1962													
TIME	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	YEAR
0	0.96	0.71	0.71	0.09	0.05	0.31	0.36	1.00	0.48	0.08	0.43	0.80	0.54
1	1.02	0.76	0.84	0.13	0.09	0.18	0.71	0.82	0.28	0.13	0.54	0.83	0.53
2	1.10	0.54	0.72	0.13	0.12	0.12	0.60	0.69	0.25	0.18	0.51	0.93	0.55
3	1.15	0.89	1.00	0.24	0.17	0.09	0.48	0.54	0.20	0.23	0.67	1.00	0.56
4	1.21	0.93	1.04	0.31	0.23	0.15	0.36	0.44	0.17	0.29	0.73	1.03	0.57
5	1.25	0.96	1.10	0.35	0.29	0.11	0.25	0.31	0.13	0.33	0.75	1.03	0.58
6	0.94	0.71	0.87	0.17	0.05	0.07	0.48	0.55	0.19	0.15	0.39	0.79	0.45
7	1.02	0.77	0.71	0.01	0.00	0.25	0.24	0.33	0.30	0.10	0.53	0.65	0.54
8	0.98	0.40	0.21	0.02	0.10	0.21	1.53	1.45	0.76	0.60	0.24	0.75	0.52
9	0.22	0.01	0.03	0.42	0.69	1.22	0.38	2.51	1.55	0.25	0.02	0.07	0.86
10	0.35	0.01	0.32	1.10	1.49	2.53	3.04	3.16	2.40	0.88	0.05	0.02	1.24
11	0.63	0.02	0.12	1.72	1.85	2.77	3.23	3.37	2.66	1.88	0.27	0.03	1.50
12	0.06	0.05	0.20	2.14	2.13	2.33	3.40	3.47	2.35	2.30	0.80	0.07	1.69
13	0.03	0.15	0.29	2.45	2.22	2.94	3.37	3.52	2.22	2.50	1.18	0.16	1.32
14	0.08	0.19	0.32	2.73	2.38	3.21	3.47	3.56	2.99	2.63	1.25	0.17	1.92
15	0.11	0.19	0.48	2.88	2.57	3.35	3.51	3.58	3.01	2.78	1.22	0.17	1.99
16	0.12	0.15	0.45	2.80	2.64	3.34	3.50	3.53	3.02	2.50	1.05	0.14	1.95
17	0.10	0.14	0.44	2.84	2.64	3.39	3.52	3.57	2.96	2.31	0.94	0.07	1.91
18	0.15	0.22	0.27	2.13	2.18	3.16	3.43	3.54	2.60	1.43	0.28	0.03	1.52
19	0.25	0.09	0.12	1.26	1.46	2.67	3.11	3.02	1.90	0.66	0.33	0.10	1.24
20	0.37	0.14	0.05	0.69	0.98	1.25	2.45	2.51	1.53	0.27	0.34	0.18	0.94
21	0.74	0.48	0.36	0.16	0.35	1.00	1.54	1.58	0.81	0.09	0.75	0.57	0.65
22	0.83	0.55	0.44	0.07	0.20	0.57	1.22	1.32	0.63	0.05	0.33	0.68	0.58
23	0.92	0.66	0.57	0.05	0.14	0.45	1.06	1.14	0.50	0.09	0.42	0.75	0.57
TOTAL	13.73	9.90	11.61	25.00	25.01	38.33	48.47	50.17	35.10	22.14	13.22	11.31	25.43
(kWh/day)													

1963													
TIME	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	YEAR
0	1.24	0.50	0.43	0.21	0.17	0.34	1.07	0.56	0.33	0.03	0.39	1.03	0.53
1	1.39	0.59	0.52	0.27	0.12	0.20	0.90	0.47	0.23	0.03	0.45	1.19	0.53
2	1.46	0.63	0.58	0.37	0.07	0.10	0.75	0.37	0.19	0.03	0.47	1.29	0.53
3	1.56	0.70	0.67	0.44	0.07	0.03	0.64	0.32	0.13	0.05	0.50	1.34	0.54
4	1.61	0.77	0.73	0.52	0.10	0.05	0.50	0.27	0.11	0.05	0.55	1.41	0.56
5	1.65	0.80	0.82	0.61	0.13	0.08	0.47	0.24	0.10	0.09	0.58	1.49	0.58
6	1.35	0.58	0.60	0.35	0.00	0.14	0.92	0.45	0.13	0.01	0.35	1.22	0.51
7	1.42	0.52	0.50	0.02	0.06	0.14	1.22	0.75	0.22	0.01	0.42	1.23	0.54
8	1.14	0.20	0.22	0.39	0.35	0.37	1.70	1.13	0.30	0.03	0.20	0.95	0.62
9	0.03	0.04	0.01	0.05	1.50	1.73	2.56	1.91	1.77	0.51	0.03	0.01	0.33
10	0.01	0.01	0.06	0.25	2.30	2.50	3.12	2.58	2.77	1.15	0.10	0.0	1.25
11	0.01	0.17	0.12	0.74	2.64	2.81	3.29	2.82	2.96	1.92	0.17	0.01	1.48
12	0.02	0.40	0.39	0.83	2.39	2.86	3.38	2.93	2.97	2.62	0.41	0.04	1.66
13	0.04	0.57	0.79	1.22	3.01	2.99	3.46	3.01	3.22	2.75	0.49	0.03	1.81
14	0.06	0.71	0.97	1.40	3.18	3.20	3.52	3.11	3.29	2.85	0.71	0.11	1.93
15	0.04	0.95	1.04	1.54	3.15	3.34	3.52	3.10	3.29	2.77	0.56	0.09	1.97
16	0.03	0.72	0.90	1.54	3.19	3.32	3.52	3.03	3.21	2.51	0.57	0.07	1.92
17	0.03	0.34	0.31	1.52	3.24	3.33	3.54	3.17	3.20	2.42	0.59	0.03	1.90
18	0.10	0.31	0.31	1.09	2.92	3.12	3.50	2.73	2.31	1.59	0.17	0.01	1.50
19	0.27	0.65	0.16	0.58	2.20	2.54	3.16	2.18	2.05	1.07	0.07	0.15	1.22
20	0.41	0.06	0.09	0.31	1.59	1.85	2.51	1.70	1.54	0.61	0.07	0.25	0.92
21	0.34	0.24	0.19	0.12	0.75	0.85	1.67	1.03	0.65	0.17	0.25	0.75	0.85
22	0.98	0.31	0.24	0.03	0.52	0.54	1.41	0.33	0.64	0.11	0.25	0.90	0.93
23	1.12	0.40	0.34	0.15	0.35	0.47	1.24	0.65	0.46	0.05	0.35	1.02	0.95
TOTAL	16.82	11.29	11.29	14.40	34.30	37.62	51.46	39.47	37.46	23.74	8.68	14.76	25.77
(kWh/day)													

Table 4.4.2-B

PHOENIX
AVERAGE ELECTRICAL LOAD
EVAPORATIVE COOLER
Kw/l

1962													
TIME	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	YEAR
0	0.01	0.01	0.01	0.00	0.00	0.11	0.26	0.31	0.16	0.00	0.00	0.01	0.07
1	0.01	0.01	0.01	0.00	0.00	0.07	0.24	0.25	0.14	0.00	0.01	0.01	0.06
2	0.01	0.01	0.01	0.00	0.00	0.06	0.22	0.21	0.12	0.00	0.01	0.01	0.06
3	0.01	0.01	0.01	0.00	0.00	0.04	0.20	0.18	0.10	0.00	0.01	0.01	0.05
4	0.01	0.01	0.01	0.00	0.00	0.02	0.15	0.16	0.08	0.00	0.01	0.01	0.04
5	0.01	0.01	0.01	0.00	0.00	0.01	0.12	0.12	0.06	0.00	0.01	0.01	0.03
6	0.01	0.01	0.01	0.00	0.00	0.01	0.11	0.12	0.06	0.00	0.00	0.01	0.03
7	0.01	0.01	0.01	0.00	0.0	0.02	0.12	0.13	0.06	0.00	0.01	0.01	0.03
8	0.01	0.00	0.00	0.0	0.0	0.08	0.24	0.22	0.08	0.0	0.00	0.01	0.05
9	0.00	0.00	0.00	0.0	0.04	0.16	0.27	0.27	0.19	0.0	0.00	0.00	0.06
10	0.00	0.00	0.00	0.06	0.09	0.23	0.30	0.33	0.21	0.04	0.00	0.00	0.11
11	0.00	0.0	0.0	0.10	0.14	0.26	0.37	0.43	0.30	0.09	0.00	0.00	0.14
12	0.00	0.0	0.0	0.14	0.15	0.27	0.46	0.55	0.40	0.14	0.02	0.0	0.16
13	0.00	0.0	0.01	0.16	0.19	0.29	0.50	0.60	0.41	0.20	0.03	0.0	0.20
14	0.00	0.0	0.02	0.19	0.19	0.37	0.58	0.65	0.44	0.21	0.07	0.0	0.23
15	0.00	0.01	0.02	0.21	0.21	0.41	0.61	0.68	0.44	0.23	0.11	0.0	0.25
16	0.00	0.01	0.03	0.23	0.21	0.41	0.62	0.68	0.44	0.23	0.11	0.0	0.25
17	0.00	0.01	0.03	0.24	0.20	0.41	0.62	0.68	0.44	0.23	0.06	0.0	0.25
18	0.00	0.00	0.02	0.20	0.18	0.41	0.61	0.68	0.43	0.15	0.00	0.00	0.22
19	0.00	0.00	0.01	0.14	0.17	0.36	0.54	0.61	0.40	0.07	0.00	0.00	0.19
20	0.00	0.00	0.00	0.07	0.14	0.29	0.47	0.57	0.34	0.04	0.00	0.00	0.16
21	0.01	0.00	0.00	0.02	0.10	0.25	0.36	0.42	0.26	0.01	0.00	0.01	0.12
22	0.01	0.01	0.00	0.00	0.04	0.18	0.32	0.36	0.19	0.00	0.00	0.01	0.09
23	0.01	0.01	0.01	0.00	0.02	0.13	0.29	0.33	0.18	0.00	0.00	0.01	0.08

TOTAL 0.11 0.11 0.20 1.79 2.08 4.85 8.58 9.52 5.94 1.66 0.16 0.09 2.97
(kWh/day)

1963													
TIME	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	YEAR
0	0.01	0.00	0.00	0.00	0.04	0.07	0.28	0.29	0.13	0.00	0.00	0.01	0.07
1	0.01	0.01	0.01	0.00	0.02	0.04	0.29	0.26	0.09	0.00	0.00	0.01	0.06
2	0.01	0.01	0.01	0.00	0.00	0.03	0.26	0.26	0.08	0.00	0.00	0.01	0.06
3	0.01	0.01	0.01	0.00	0.01	0.00	0.21	0.26	0.06	0.00	0.00	0.01	0.05
4	0.01	0.01	0.01	0.01	0.00	0.00	0.18	0.23	0.06	0.00	0.01	0.01	0.04
5	0.01	0.01	0.01	0.01	0.00	0.00	0.13	0.21	0.05	0.00	0.01	0.01	0.04
6	0.01	0.01	0.01	0.00	0.00	0.00	0.14	0.21	0.05	0.00	0.00	0.01	0.04
7	0.01	0.00	0.00	0.00	0.0	0.0	0.18	0.21	0.05	0.00	0.00	0.01	0.04
8	0.01	0.00	0.00	0.0	0.01	0.05	0.25	0.23	0.10	0.0	0.00	0.01	0.05
9	0.00	0.00	0.0	0.00	0.04	0.15	0.26	0.24	0.20	0.01	0.00	0.00	0.08
10	0.00	0.00	0.0	0.0	0.20	0.16	0.32	0.28	0.26	0.10	0.00	0.0	0.11
11	0.00	0.00	0.0	0.02	0.26	0.21	0.39	0.36	0.28	0.12	0.0	0.0	0.14
12	0.00	0.01	0.0	0.06	0.26	0.27	0.46	0.47	0.34	0.16	0.02	0.0	0.17
13	0.00	0.01	0.0	0.07	0.28	0.27	0.53	0.48	0.38	0.21	0.02	0.0	0.19
14	0.00	0.03	0.03	0.09	0.28	0.31	0.58	0.57	0.43	0.24	0.03	0.0	0.22
15	0.0	0.05	0.06	0.07	0.28	0.32	0.62	0.61	0.45	0.24	0.03	0.0	0.23
16	0.0	0.05	0.04	0.09	0.29	0.32	0.62	0.64	0.45	0.25	0.03	0.0	0.24
17	0.00	0.05	0.04	0.09	0.29	0.32	0.64	0.65	0.43	0.23	0.03	0.0	0.23
18	0.00	0.01	0.03	0.09	0.27	0.31	0.60	0.62	0.39	0.21	0.01	0.0	0.21
19	0.00	0.00	0.00	0.08	0.27	0.29	0.57	0.55	0.35	0.15	0.01	0.00	0.19
20	0.00	0.00	0.00	0.03	0.26	0.22	0.54	0.51	0.31	0.10	0.00	0.00	0.17
21	0.01	0.00	0.00	0.01	0.23	0.20	0.42	0.40	0.28	0.04	0.00	0.01	0.13
22	0.01	0.00	0.00	0.00	0.15	0.16	0.36	0.36	0.20	0.02	0.00	0.01	0.11
23	0.01	0.00	0.00	0.00	0.09	0.10	0.32	0.32	0.18	0.00	0.00	0.01	0.09

TOTAL 0.13 0.27 0.28 0.76 3.52 3.31 9.16 9.25 5.61 2.10 0.21 0.12 2.96
(kWh/day)

Table 4.4.2-C

RIVERSIDE
AVERAGE ELECTRICAL LOAD
SUPPLEMENTAL HEAT FROM
KWH

1962													
TIME	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	YEAR
0	1.09	0.99	1.06	0.63	0.60	0.33	0.19	0.07	0.24	0.63	1.02	1.40	0.64
1	1.17	1.05	1.15	0.71	0.64	0.35	0.19	0.12	0.23	0.70	1.07	1.53	0.75
2	1.22	1.11	1.24	0.76	0.71	0.42	0.32	0.13	0.32	0.73	1.22	1.66	0.82
3	1.29	1.14	1.26	0.82	0.75	0.45	0.36	0.23	0.36	0.84	1.23	1.67	0.87
4	1.31	1.13	1.32	0.85	0.79	0.50	0.38	0.27	0.44	0.92	1.31	1.75	0.92
5	1.40	1.22	1.39	0.85	0.84	0.41	0.37	0.23	0.47	0.93	1.33	1.81	0.91
6	1.09	0.88	0.90	0.60	0.69	0.07	0.01	0.52	0.37	0.53	1.12	1.43	0.53
7	1.04	0.97	0.91	0.53	0.53	0.04	0.35	0.35	0.35	0.52	0.94	1.21	0.43
8	0.57	0.57	0.14	0.35	0.34	0.3	0.41	0.65	0.71	0.66	0.12	0.32	0.37
9	0.08	0.09	0.05	0.39	0.15	1.13	1.77	2.05	1.15	0.14	0.09	0.05	0.50
10	0.06	0.05	0.04	0.93	0.94	1.55	2.35	2.33	0.15	0.09	0.17	0.33	0.94
11	0.08	0.07	0.13	1.53	0.82	1.72	2.78	3.13	3.11	1.32	0.45	0.09	1.32
12	0.18	0.05	0.21	1.60	0.86	1.73	2.40	3.23	2.53	1.54	0.55	0.77	1.32
13	0.33	0.13	0.27	1.53	1.01	1.31	2.77	3.20	2.71	1.54	0.70	0.35	1.33
14	0.53	0.14	0.32	1.61	1.07	1.24	2.83	3.20	1.53	1.35	0.53	0.20	1.40
15	0.37	0.16	0.27	1.43	0.93	1.97	2.35	3.15	0.30	1.37	0.51	0.11	1.31
16	0.25	0.13	0.20	1.11	0.78	1.73	2.55	2.84	0.05	0.73	0.25	0.05	1.77
17	0.24	0.09	0.07	0.90	0.56	1.43	2.40	2.61	1.70	0.32	0.02	0.05	0.36
18	0.32	0.12	0.17	0.17	0.24	0.36	1.50	1.59	0.57	0.37	0.16	0.32	0.53
19	0.39	0.13	0.34	0.04	0.25	0.33	0.63	0.70	0.24	0.32	0.23	0.40	0.32
20	0.47	0.53	0.44	0.09	0.11	0.13	0.13	0.25	0.38	0.38	0.31	0.54	0.35
21	0.33	0.37	0.32	0.25	0.39	0.19	0.01	0.92	0.13	0.32	0.72	0.94	0.17
22	0.91	0.93	0.90	0.45	0.44	0.27	0.33	0.02	0.15	0.45	0.32	1.07	0.53
23	1.04	0.99	1.12	0.53	0.52	0.26	0.15	0.05	0.21	0.55	0.23	1.27	0.62
TOTAL	16.29	13.38	13.90	17.73	12.78	20.04	27.24	40.72	23.31	14.45	15.75	16.51	13.93
(kWh/day)													

1963													
TIME	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	YEAR
0	1.40	0.75	1.10	0.92	0.55	0.35	0.10	0.05	0.07	0.34	0.33	1.31	0.65
1	1.49	0.79	1.20	1.02	0.59	0.40	0.17	0.11	0.10	0.40	0.92	1.46	0.72
2	1.62	0.84	1.29	1.09	0.63	0.44	0.21	0.14	0.13	0.44	1.05	1.57	0.74
3	1.72	0.88	1.37	1.13	0.65	0.47	0.27	0.15	0.16	0.45	1.05	1.71	0.84
4	1.75	0.91	1.44	1.19	0.69	0.51	0.32	0.22	0.19	0.51	1.13	1.74	0.88
5	1.81	0.96	1.49	1.17	0.63	0.43	0.22	0.20	0.21	0.55	1.15	1.72	0.84
6	1.45	0.64	0.92	0.45	0.08	0.03	0.13	0.02	0.03	0.21	0.33	1.44	0.52
7	1.23	0.30	0.12	0.07	0.03	0.01	0.04	0.02	0.03	0.03	0.33	1.11	0.29
8	0.50	0.17	0.05	0.03	0.05	0.03	0.34	0.32	0.27	0.32	0.05	0.17	0.16
9	0.17	0.12	0.05	0.03	0.04	0.23	1.15	1.01	1.26	0.56	0.04	0.02	0.32
10	0.11	0.19	0.04	0.07	0.23	0.53	2.25	2.04	0.71	0.14	0.05	0.03	0.54
11	0.08	0.38	0.05	0.09	0.39	0.93	2.74	2.54	2.53	0.56	0.17	0.09	0.35
12	0.07	0.35	0.10	0.44	0.46	1.05	2.77	2.53	2.49	1.08	0.36	0.11	1.02
13	0.03	0.75	0.14	0.49	0.47	1.03	2.55	2.67	2.33	1.11	0.31	0.12	1.02
14	0.02	0.72	0.14	0.47	0.54	1.13	2.72	2.81	2.42	1.22	0.37	0.13	1.06
15	0.05	0.69	0.13	0.47	0.53	1.15	2.71	2.61	2.45	0.86	0.27	0.15	1.31
16	0.07	0.34	0.10	0.15	0.13	1.00	2.40	2.30	2.13	0.52	0.13	0.04	0.45
17	0.12	0.15	0.05	0.03	0.17	0.21	2.21	2.13	1.21	0.33	0.13	0.02	0.54
18	0.47	0.10	0.12	0.17	0.04	0.30	1.40	1.39	0.92	0.22	0.12	0.23	0.15
19	0.58	0.14	0.31	0.12	0.01	0.02	0.31	0.52	0.45	0.03	0.21	0.42	0.22
20	0.75	0.21	0.42	0.23	0.05	0.22	0.13	0.13	0.34	0.03	0.23	0.57	0.27
21	1.17	0.53	0.34	0.65	0.35	0.32	0.32	0.12	0.11	0.22	0.55	1.21	0.44
22	1.27	0.59	0.22	0.73	0.43	0.25	0.3	0.31	0.37	0.25	0.74	1.11	0.54
23	1.32	0.71	1.00	0.43	0.19	0.32	0.05	0.07	0.07	0.22	0.01	1.23	0.50
TOTAL	19.29	12.61	13.35	12.10	8.57	11.21	25.17	30.23	22.14	2.97	12.72	17.54	15.77
(kWh/day)													

Table 4.4.2-D

RIVERSIDE
AVERAGE ELECTRICAL LOAD
EVAPORATIVE COOLER
KWH

1962

TIME	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	YEAR
0	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01
1	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01
2	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01
3	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01
4	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.01	0.01	0.01	0.01
5	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01
6	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00
7	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00
8	0.00	0.00	0.00	0.00	0.00	0.02	0.01	0.04	0.01	0.00	0.00	0.00	0.01
9	0.00	0.00	0.00	0.00	0.00	0.09	0.10	0.15	0.08	0.00	0.00	0.00	0.04
10	0.00	0.00	0.00	0.06	0.04	0.12	0.21	0.22	0.17	0.04	0.00	0.00	0.07
11	0.00	0.00	0.00	0.11	0.06	0.15	0.22	0.29	0.19	0.08	0.04	0.00	0.10
12	0.00	0.00	0.01	0.15	0.07	0.15	0.25	0.34	0.20	0.11	0.04	0.00	0.11
13	0.02	0.00	0.02	0.14	0.09	0.15	0.28	0.35	0.22	0.11	0.04	0.00	0.12
14	0.01	0.00	0.02	0.14	0.10	0.17	0.28	0.35	0.24	0.11	0.04	0.00	0.12
15	0.02	0.00	0.02	0.14	0.10	0.17	0.28	0.36	0.24	0.11	0.04	0.00	0.12
16	0.01	0.00	0.01	0.13	0.06	0.16	0.28	0.33	0.24	0.08	0.02	0.00	0.11
17	0.00	0.00	0.00	0.11	0.07	0.16	0.27	0.30	0.23	0.04	0.00	0.00	0.10
18	0.00	0.00	0.00	0.02	0.01	0.14	0.24	0.24	0.12	0.01	0.00	0.00	0.07
19	0.00	0.00	0.00	0.00	0.00	0.06	0.10	0.13	0.03	0.00	0.00	0.00	0.03
20	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.01	0.00	0.00	0.00	0.01
21	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.01	0.01	0.01
22	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.01	0.01	0.01
23	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01
TOTAL (kWh/day)	0.18	0.11	0.18	1.06	0.68	1.56	2.55	3.13	2.06	0.75	0.31	0.14	1.06

1963

TIME	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	YEAR
0	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01
1	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01
2	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01
3	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01
4	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.01	0.01	0.01	0.01
5	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01
6	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00
7	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00
8	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00
9	0.00	0.00	0.00	0.00	0.00	0.02	0.06	0.04	0.10	0.00	0.00	0.00	0.02
10	0.00	0.00	0.00	0.00	0.01	0.03	0.15	0.14	0.16	0.00	0.00	0.00	0.04
11	0.00	0.01	0.00	0.00	0.02	0.05	0.23	0.21	0.18	0.02	0.00	0.00	0.06
12	0.00	0.04	0.00	0.00	0.03	0.09	0.25	0.23	0.19	0.06	0.02	0.00	0.08
13	0.00	0.06	0.00	0.04	0.03	0.11	0.26	0.24	0.19	0.07	0.03	0.00	0.09
14	0.00	0.05	0.01	0.02	0.04	0.12	0.26	0.26	0.21	0.08	0.02	0.00	0.09
15	0.00	0.05	0.00	0.01	0.04	0.12	0.27	0.27	0.23	0.07	0.02	0.00	0.09
16	0.00	0.04	0.00	0.00	0.03	0.13	0.27	0.27	0.23	0.07	0.01	0.00	0.09
17	0.00	0.01	0.00	0.00	0.01	0.11	0.26	0.27	0.23	0.06	0.00	0.00	0.08
18	0.00	0.00	0.00	0.00	0.01	0.05	0.21	0.22	0.19	0.01	0.00	0.00	0.06
19	0.01	0.00	0.00	0.00	0.00	0.02	0.09	0.10	0.13	0.00	0.00	0.00	0.03
20	0.01	0.00	0.00	0.00	0.00	0.00	0.02	0.02	0.07	0.00	0.00	0.01	0.01
21	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.02	0.00	0.01	0.01	0.01
22	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.01	0.00	0.01	0.01	0.01
23	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01
TOTAL (kWh/day)	0.15	0.34	0.12	0.15	0.25	0.88	2.35	2.28	2.15	0.48	0.19	0.13	0.79

Table 4.4.2-E

CLEVELAND
 AVERAGE ELECTRICAL LOAD
 SUPPLY AIR HEAT PUMP
 DATA

1962													
TIME	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	YEAR
0	3.25	2.83	2.04	1.15	0.22	0.13	0.05	0.10	0.33	0.55	1.24	2.46	1.25
1	3.27	2.30	2.14	1.20	0.35	0.13	0.10	0.13	0.33	0.75	1.26	3.05	1.25
2	3.25	2.83	2.17	1.23	0.33	0.13	0.11	0.15	0.37	0.71	1.27	3.52	1.25
3	3.21	2.42	2.24	1.24	0.34	0.19	0.13	0.17	0.41	0.71	1.35	3.59	1.32
4	3.32	2.47	2.25	1.29	0.35	0.23	0.14	0.19	0.44	0.71	1.35	2.51	1.34
5	3.22	2.49	2.32	1.31	0.34	0.31	0.17	0.25	0.45	0.74	1.34	2.55	1.35
6	2.73	2.41	1.33	0.97	0.15	0.02	0.01	0.02	0.23	0.47	0.99	2.44	1.02
7	2.72	2.39	1.37	0.77	0.07	0.00	0.00	0.00	0.16	0.49	1.01	2.45	0.99
8	3.47	2.33	1.37	0.62	0.06	0.02	0.04	0.01	0.14	0.52	1.35	3.31	1.16
9	2.92	2.45	1.16	0.30	0.22	0.24	0.19	0.17	0.55	0.29	1.32	2.73	0.95
10	2.03	1.45	0.71	0.24	0.40	0.54	0.45	0.55	0.17	0.17	0.61	2.10	0.82
11	1.45	1.47	0.59	0.25	0.57	0.73	0.55	0.73	0.32	0.16	0.42	1.55	0.72
12	1.14	1.13	0.53	0.34	0.72	0.83	0.64	0.93	0.36	0.21	0.37	1.35	0.71
13	0.94	0.83	0.51	0.34	0.65	0.75	0.75	1.02	0.35	0.25	0.37	1.14	0.67
14	0.73	0.84	0.50	0.41	0.77	0.79	0.82	1.02	0.46	0.23	0.39	1.06	0.69
15	0.77	1.25	0.55	0.40	0.75	0.84	0.92	1.11	0.51	0.23	0.40	1.11	0.74
16	1.24	1.26	0.57	0.43	0.81	0.75	0.75	1.07	0.37	0.27	0.47	1.43	0.72
17	1.54	1.24	0.51	0.42	0.87	0.83	0.73	1.23	0.33	0.35	0.43	1.52	0.80
18	2.23	1.34	0.39	0.45	0.75	0.69	0.42	0.93	0.21	0.24	0.67	2.53	0.94
19	2.35	2.33	1.25	0.49	0.51	0.43	0.37	0.42	0.12	0.23	0.73	2.13	0.91
20	2.40	2.27	1.31	0.60	0.35	0.19	0.33	0.14	0.39	0.31	0.77	2.24	0.87
21	3.12	2.60	1.21	0.92	0.25	0.12	0.33	0.06	0.37	0.59	1.11	2.35	1.15
22	3.25	2.70	1.93	0.93	0.24	0.10	0.34	0.05	0.28	0.61	1.25	2.43	1.19
23	3.26	2.76	1.95	1.03	0.37	0.12	0.37	0.04	0.31	0.63	1.25	2.99	1.22
TOTAL	59.41	55.41	33.79	17.33	15.12	9.11	7.39	10.51	7.14	10.47	21.29	55.13	24.25
(kWh/day)													
1963													
TIME	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	YEAR
0	4.09	4.21	1.55	0.24	0.69	0.19	0.15	0.14	0.39	0.43	1.08	3.35	1.42
1	4.15	4.27	1.59	0.95	0.73	0.23	0.12	0.17	0.42	0.51	1.15	3.34	1.45
2	4.14	4.29	1.67	1.02	0.76	0.25	0.14	0.19	0.47	0.55	1.14	3.42	1.49
3	4.25	4.34	1.67	1.55	0.79	0.23	0.16	0.21	0.51	0.59	1.15	3.45	1.52
4	4.74	4.40	1.75	1.11	0.81	0.31	0.15	0.21	0.55	0.62	1.14	3.47	1.53
5	4.36	4.37	1.72	1.15	0.85	0.34	0.25	0.24	0.59	0.61	1.21	3.52	1.54
6	3.94	3.61	1.32	0.85	0.43	0.07	0.04	0.07	0.34	0.55	0.73	2.92	1.21
7	3.72	3.65	1.25	0.59	0.25	0.01	0.10	0.15	0.23	0.77	0.91	2.95	1.15
8	4.32	4.13	1.89	0.39	0.10	0.03	0.01	0.01	0.16	0.35	1.25	3.59	1.39
9	3.35	3.35	0.75	0.17	0.00	0.00	0.00	0.02	0.00	0.25	1.05	3.33	1.12
10	2.68	2.75	0.60	0.10	0.05	0.07	0.73	0.01	0.02	0.34	0.51	2.55	0.67
11	1.94	1.54	0.42	0.08	0.07	0.79	0.37	0.32	0.38	0.15	0.41	1.74	0.75
12	1.74	1.23	0.32	0.15	0.11	0.93	0.23	0.39	0.19	0.13	0.41	1.13	0.61
13	1.26	1.55	0.34	0.07	0.14	0.94	1.32	0.40	0.49	0.55	0.33	1.04	0.61
14	1.17	0.87	0.31	0.07	0.13	0.95	1.15	0.57	0.46	0.55	0.36	0.94	0.61
15	1.27	0.75	0.29	0.09	0.15	1.02	1.15	0.53	0.35	0.65	0.37	1.39	0.65
16	1.79	1.54	0.21	0.11	0.11	0.93	1.17	0.53	0.22	0.43	0.44	1.43	0.72
17	2.12	1.37	0.22	0.08	0.16	0.73	1.45	0.55	0.24	0.29	0.39	1.71	0.85
18	2.14	2.23	0.65	0.09	0.11	0.79	1.15	0.33	0.13	0.11	0.51	2.55	0.89
19	2.25	2.45	0.59	0.05	0.05	0.57	0.41	0.11	0.02	0.15	0.37	2.51	0.91
20	3.09	3.53	1.01	0.17	0.12	0.71	0.71	0.02	0.35	0.13	0.59	3.55	0.91
21	3.47	3.21	1.41	0.22	0.47	0.41	0.15	0.02	0.34	0.39	1.59	3.44	1.31
22	4.35	4.03	1.41	0.11	0.55	0.11	0.15	0.11	0.32	0.41	1.55	3.51	1.35
23	4.07	4.15	1.45	0.93	0.60	0.17	0.35	0.15	0.37	0.45	1.11	3.41	1.39
TOTAL	77.41	75.79	24.91	1.47	2.35	11.14	12.53	9.94	9.35	9.52	19.67	52.99	55.35
(kWh/day)													

Table 4.4.2-F

CLEVELAND
AVERAGE ELECTRICAL LOAD
GAS HEATING-HEAT PUMP
KWH

1962

TIME	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	YEAR
0	0.02	0.02	0.01	0.01	0.00	0.01	0.00	0.00	0.00	0.01	0.01	0.02	0.01
1	0.02	0.02	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.02	0.01
2	0.02	0.02	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.02	0.01
3	0.02	0.02	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.02	0.01
4	0.02	0.02	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.02	0.01
5	0.02	0.02	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.02	0.01
6	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01
7	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01
8	0.02	0.01	0.01	0.00	0.02	0.01	0.01	0.01	0.00	0.00	0.01	0.02	0.01
9	0.01	0.01	0.01	0.01	0.23	0.24	0.19	0.17	0.01	0.00	0.01	0.01	0.00
10	0.01	0.01	0.01	0.06	0.40	0.53	0.46	0.55	0.14	0.02	0.01	0.01	0.13
11	0.01	0.01	0.00	0.11	0.57	0.73	0.55	0.73	0.30	0.05	0.00	0.01	0.25
12	0.01	0.01	0.00	0.22	0.72	0.83	0.64	0.95	0.34	0.11	0.00	0.01	0.32
13	0.01	0.01	0.00	0.23	0.66	0.80	0.75	1.02	0.34	0.10	0.00	0.01	0.33
14	0.01	0.01	0.01	0.30	0.77	0.79	0.82	1.02	0.44	0.14	0.00	0.01	0.36
15	0.01	0.01	0.01	0.28	0.73	0.83	0.92	1.11	0.49	0.12	0.00	0.01	0.38
16	0.01	0.01	0.01	0.27	0.20	0.75	0.76	1.07	0.34	0.10	0.00	0.01	0.39
17	0.01	0.01	0.01	0.29	0.57	0.83	0.73	1.23	0.37	0.07	0.00	0.01	0.37
18	0.01	0.01	0.01	0.23	0.75	0.63	0.42	0.93	0.19	0.01	0.01	0.01	0.27
19	0.01	0.01	0.01	0.08	0.49	0.43	0.27	0.42	0.07	0.00	0.01	0.01	0.15
20	0.01	0.01	0.01	0.01	0.18	0.19	0.03	0.14	0.01	0.00	0.01	0.01	0.05
21	0.02	0.01	0.01	0.01	0.00	0.02	0.00	0.02	0.00	0.00	0.01	0.02	0.01
22	0.02	0.01	0.01	0.01	0.00	0.01	0.00	0.00	0.00	0.01	0.01	0.02	0.01
23	0.02	0.01	0.01	0.01	0.00	0.01	0.00	0.00	0.00	0.01	0.01	0.02	0.01
TOTAL	0.30	0.28	0.25	2.15	7.32	7.71	6.54	9.37	3.08	0.84	0.17	0.29	3.22

(kWh/day)

1963

TIME	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	YEAR
0	0.02	0.02	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.01	0.02	0.01
1	0.02	0.02	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.01	0.02	0.01
2	0.02	0.02	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.01	0.01	0.02	0.01
3	0.02	0.02	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.01	0.01	0.02	0.01
4	0.02	0.02	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.01	0.01	0.02	0.01
5	0.02	0.02	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.01	0.01	0.02	0.01
6	0.02	0.02	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01
7	0.02	0.02	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01
8	0.02	0.02	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01
9	0.02	0.01	0.01	0.00	0.00	0.31	0.46	0.02	0.00	0.00	0.01	0.02	0.02
10	0.01	0.01	0.00	0.00	0.00	0.57	0.73	0.08	0.02	0.00	0.01	0.01	0.07
11	0.01	0.01	0.00	0.01	0.07	0.79	0.87	0.32	0.08	0.12	0.00	0.01	0.13
12	0.01	0.01	0.00	0.06	0.11	0.93	0.93	0.39	0.19	0.30	0.00	0.01	0.17
13	0.01	0.01	0.00	0.06	0.13	0.94	1.02	0.40	0.29	0.53	0.00	0.01	0.25
14	0.01	0.01	0.00	0.06	0.13	0.90	1.10	0.57	0.26	0.52	0.00	0.01	0.29
15	0.01	0.00	0.00	0.07	0.15	1.02	1.15	0.63	0.27	0.57	0.00	0.01	0.31
16	0.01	0.01	0.01	0.11	0.14	0.93	1.17	0.57	0.21	0.43	0.00	0.01	0.30
17	0.01	0.01	0.00	0.05	0.16	0.98	1.46	0.56	0.24	0.26	0.00	0.01	0.30
18	0.01	0.01	0.00	0.01	0.14	0.79	1.15	0.38	0.12	0.00	0.00	0.01	0.20
19	0.01	0.01	0.01	0.00	0.01	0.03	0.31	0.11	0.00	0.00	0.01	0.01	0.13
20	0.01	0.01	0.01	0.00	0.00	0.21	0.37	0.02	0.00	0.00	0.01	0.01	0.05
21	0.02	0.02	0.01	0.01	0.00	0.02	0.05	0.00	0.00	0.00	0.01	0.02	0.01
22	0.02	0.02	0.01	0.01	0.00	0.00	0.01	0.00	0.00	0.00	0.01	0.02	0.01
23	0.02	0.02	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.01	0.02	0.01
TOTAL	0.34	0.32	0.33	0.54	1.20	2.11	11.45	4.06	1.74	2.35	0.16	0.32	2.72

(kWh/day)

Table 4.4.2-G

WASHINGTON D.C.
AVERAGE ELECTRICAL LOAD FOR SPACE CONDITIONING
WITH SUPREME AIRE HEAT PUMP

kWh

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0	1.885	1.846	1.690	0	0	0	0	0	0	0	1.058	1.894
1	2.256	2.177	1.302	0	0	0	0	0	0	0	1.075	1.859
2	2.234	2.255	1.323	.634	0	0	0	0	0	0	1.264	2.004
3	2.384	2.269	1.769	.636	0	0	0	0	0	0	1.428	2.380
4	2.270	2.531	1.750	.630	0	0	0	0	0	.571	1.392	2.203
5	2.385	2.222	1.710	.620	.606	0	0	0	0	.557	1.506	2.271
6	2.197	2.345	1.651	1.202	.590	0	0	0	0	.544	1.266	2.221
7	1.835	1.895	1.581	.579	0	0	0	0	0	.525	1.186	1.857
8	1.691	1.667	1.507	.281	0	0	0	0	0	.507	.822	1.642
9	1.648	1.348	.504	.270	0	0	0	0	0	0	.759	1.435
10	1.374	1.302	.313	0	0	.019	.112	.040	0	0	.315	1.059
11	1.344	1.232	.327	0	0	.266	1.827	1.142	0	0	.305	1.110
12	1.083	.917	0	0	0	.835	1.302	1.050	0	0	.154	.849
13	.545	.684	0	0	0	1.056	1.392	1.411	.241	0	0	.293
14	.590	.266	0	0	0	1.187	1.693	1.482	.970	0	0	.268
15	.228	.482	0	0	0	1.325	1.613	1.645	1.226	0	0	0
16	.199	.159	0	0	.047	1.453	1.750	1.664	1.251	0	0	0
17	.590	.208	0	0	.063	1.466	1.734	1.885	.292	0	0	0
18	.445	.514	0	0	.045	1.245	1.686	1.610	.238	0	0	.353
19	.757	.525	0	0	.038	.292	1.744	1.606	.180	0	0	.359
20	.790	.736	0	0	.038	.241	1.606	.292	.081	0	0	.736
21	1.127	1.117	0	0	0	.014	0	0	0	0	0	.758
22	1.284	1.154	0	0	0	0	0	0	0	0	0	1.170
23	1.908	1.572	.958	0	0	0	0	0	0	0	.762	1.595
Tctal	33.05	31.43	16.39	4.85	1.43	9.40	16.46	13.83	4.48	2.70	13.29	28.32

Table 4.4.2-H

WASHINGTON D.C.
 AVERAGE ELECTRICAL LOAD FOR SPACE CONDITIONING
 WITH SOLAR THERMAL AUGMENTED PARALLEL HEAT PUMP

kWh

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0	.027	.020	.009	0	0	0	0	0	0	0	.014	.023
1	.034	.025	.007	0	0	0	0	0	0	0	.014	.023
2	.036	.027	.007	.005	0	0	0	0	0	0	.016	.027
3	.043	.029	.009	.005	0	0	0	0	0	0	.018	.032
4	.047	.036	.009	.005	0	0	0	0	0	.005	.018	.032
5	.063	.036	.009	.005	0	0	0	0	0	.005	.020	.036
6	.086	.045	.009	.009	0	0	0	0	0	.005	.018	.041
7	.419	.045	.009	.005	.006	0	0	0	0	.005	.018	.041
8	1.046	.052	.011	.003	.007	0	0	0	0	.005	.014	.045
9	1.308	.074	.019	.008	.054	0	0	0	0	0	.015	.054
10	.099	.095	.033	.042	.070	.019	.112	.040	0	.030	.041	.050
11	.084	.081	.068	.070	.070	.266	1.827	1.142	0	.070	.066	.081
12	.077	.076	.070	.070	.070	.835	1.302	1.050	0	.070	.072	.075
13	.073	.074	.070	.070	.070	1.056	1.392	1.411	.241	.070	.070	.072
14	.073	.072	.070	.070	.069	1.187	1.693	1.482	.970	.070	.070	.072
15	.072	.072	.069	.069	.024	1.325	1.613	1.645	1.226	.069	.069	.070
16	.068	.037	.035	.035	.047	1.453	1.750	1.664	1.251	.032	.035	.070
17	.019	.045	.008	.006	.063	1.466	1.734	1.885	.292	.001	.015	.012
18	.007	.007	0	0	.045	1.245	1.686	1.610	.238	0	0	.005
19	.011	.007	0	0	.038	.292	1.744	1.606	.180	0	0	.005
20	.011	.009	0	0	.038	.241	1.606	.292	.081	0	0	.009
21	.016	.014	0	0	0	.014	0	0	0	0	0	.009
22	.018	.014	0	0	0	0	0	0	0	0	.009	.014
23	.027	.018	.005	0	0	0	0	0	0	0	.009	.018
Total	3.76	1.01	.53	.48	.67	9.40	16.46	13.83	4.48	.44	.62	.92

required by the heat pump. On an annual basis the evaporative cooling/gas heating system consumes only 5% of the electrical energy used by a year-round heat pump system. There are many factors which may account for the superior performance of the evaporative system in Riverside compared to Phoenix, including differences in wet-bulb temperatures and daily temperature range. The latter factor is much greater in Riverside, allowing more frequent reliance on natural ventilation.

Tables 4.4.2-E - H show electrical loads for two systems in Cleveland and two in Washington, D.C. In these locations heating loads are large and winter solar availability is low. The heat pump and resistance heater would be run primarily on utility backup power if the array is sized to supply about half of the electrical load. Provision of solar power for heating would require additional photovoltaic array area which would convert sunlight to useful heat at 15 to 20 percent efficiency (solar to electrical conversion at a 10% efficiency and heat pump COP of 2). A solar thermal system would be more than twice as efficient in supplying solar heat. The alternate systems use conventional fuels for the heating load (Cleveland), or utilize what solar energy there is in winter by means of a solar thermal collector (Washington). This results in electrical loads which more closely match the availability of solar electricity than the baseline systems.

Results Using Simplified Hourly Methods

The simplified hourly method described in Section 4.2 was also used to calculate the electrical loads for Phoenix, Riverside, and Cleveland. A tabulation of these results is provided in Appendix K. A comparison of these loads generated using averaged weather data with those obtained using hour-by-hour weather data shows the following:

1. The annual daily average ranges between 15 and 20% lower than predicted using the more accurate hourly method.
2. The two methods agree best in the summer and winter, and worst in the intermediate seasons.

4.4.3 Heating and Cooling Load Summary

The monthly heating and cooling loads for all systems are analyzed in Tables 4.4.3-A through D. These tables include the thermal heating and cooling loads as well as the corresponding electrical loads associated with providing the required heating and cooling. The Phoenix load data given in Table 4.4.3-A shows a thermal cooling load exceeding that of the thermal heating load by a factor of approximately 3.6. The electrical loads listed under the baseline system in this table represents the electrical energy required by the heat pump to transfer the required thermal load. It is noted that the COP for the heat pump in the heating mode is approximately 2.51 when averaged over the two-year period. In the cooling mode the COP drops to an average of 1.86. The electrical loads listed under the alternate system column in Table 4.4.3-A correspond to the electrical energy requirements to operate the forced air heating system and the evaporative cooling system.

Table 4.4.3-B gives similar data for the Riverside house. For this location the magnitudes of the heating load and the cooling load are not substantially different. For the Cleveland data given in Table 4.4.3-C we see that the heating requirements far exceed the cooling requirements. Although the cooling requirements in Cleveland are low, they are not significantly lower than the cooling requirements experienced in the Washington D.C. location. Washington data given in Table 4.4.3-D provide totals for only a single year where the other tables provide a two-year total sum of loads.

Table 4.4.3-A

RESIDENTIAL MONTHLY HEATING AND COOLING LOADS, PHOENIX

1962	Thermal Load (kWh)		<u>Baseline</u>		<u>Alternate</u>	
			Load (kWh)		Load (kWh)	
	Heating	Cooling	Heat Pump Heating	Cooling	Evap Cool Heating**	Cooling
Jan	985	216	414	12	3.	0
Feb	653	251	251	27	2.	1.
Mar	705	379	278	82	2.	4.
Apr	139	1318	47	703	0	53.
May	91	1408	30	745	0	64.
Jun	17	1870	5	1145	0	145.
Jul	0	2396	0	1503	0	266.
Aug	0	2443	0	1555	0	295.
Sep	2	1756	1	1053	0	178.
Oct	153	1246	50	636	1.	51.
Nov	504	613	185	212	2.	12.
Dec	838	289	326	25	3.	0
<u>1963</u>						
Jan	1158	139	518	5	4.	0
Feb	487	505	179	137	2.	6.
Mar	461	617	171	179	2.	7.
Apr	265	828	93	339	1.	22.
May	30	1795	11	1059	0	109.
Jun	31	1854	16	1112	0	114.
Jul	4	2508	4*	1591	0	284.
Aug	4	2025	4*	1220	0	287.
Sep	5	1854	4*	1120	0	168.
Oct	30	1348	10	726	0	65.
Nov	416	514	152	114	1.	5.
Dec	1042	270	444	13	4.	0
2-Year Sum	8018	28441	3192	15313	28	2136.

**Furnace Fan

COP 2.51 COP 1.86

*Due to control (Programmer) error, auxiliary heaters were used instead of heat pump.

Note: The evaporative cooler was not always effective in keeping the temperature at 78°F. Also the control method was such that the evaporative cooler was not turned on unless the outside air temperature exceeded 81.5°F (fans were used). The HP cooling system also used fans if the outside air temperature was less than 77°F.

Table 4.4.3-B

RESIDENTIAL MONTHLY HEATING AND COOLING LOADS, RIVERSIDE

	Thermal Load (kWh)		<u>Baseline</u>		<u>Alternate</u>	
			Load (kWh) Heat Pump		Load (kWh) Evap Cool	
<u>1962</u>	<u>Heating</u>	<u>Cooling</u>	<u>Heating</u>	<u>Cooling</u>	<u>Heating*</u>	<u>Cooling</u>
Jan	1083	254	458	47	4.	2
Feb	912	99	364	10	3.	0
Mar	956	228	389	41	3.	2
Apr	519	795	190	342	2.	30
May	500	600	180	216	2.	19
Jun	293	1020	99	502	1.	46
Jul	141	1493	46	800	0.	78
Aug	111	1645	36	916	0	97
Sep	238	1232	80	634	1.	61
Oct	591	730	218	292	2.	21
Nov	917	381	376	96	3.	6
Dec	1213	300	543	31	4.	0
<u>1963</u>						
Jan	1288	110	594	4.	5.	0
Feb	657	379	246	107	2.	7.
Mar	951	256	395	20	3.	0
Apr	746	316	296	67	3.	2.
May	463	429	163	106	2.	6.
Jun	310	631	104	253	1.	25.
Jul	136	1430	45	744	0	72.
Aug	96	1388	31	719	0	70.
Sep	97	1217	31	645	0	64.
Oct	348	660	119	190	1.	14.
Nov	799	323	317	49	3.	3.
Dec	1168	371	524	22	4.	0
2-Year Sum	14533	16286	5845	6855	51.	626.
			COP 2.49	COP 2.38		

*Furnace Fan

Note: The evaporative cooler was not always effective in keeping the temperature at 78°F. Also the control method was such that the evaporative cooler was not turned on unless the outside air temperature exceeded 81.5°F (fans were used). The HP cooling system also used fans if the outside air temperature was less than 77°F.

Table 4.4.3-C

RESIDENTIAL MONTHLY HEATING AND COOLING LOADS, CLEVELAND

1962	Thermal Load (kWh)		Baseline Load (kWh) Heat Pump		Alternate Load (kWh) Gas Heat	
	Heating	Cooling	Heating	Cooling	Heating*	Cooling
Jan	2622	0	1811	0	9.	0
Feb	2214	0	1423	0	8.	0
Mar	1851	8	1046	1	7.	1
Apr	971	124	459	62	3.	62
May	262	467	97	226	1.	226
Jun	127	567	42	231	0	231
Jul	82	248	27	202	0	202
Aug	106	708	36	290	0	290
Sep	338	236	123	91	1.	91
Oct	705	72	302	24	2.	24
Nov	1436	0	639	0	5.	0
Dec	2585	0	1718	0	9.	0
<u>1963</u>						
Jan	3005	0	2340	0	11.	0
Feb	2562	0	1985	0	9.	0
Mar	1460	11	755	5	5.	5
Apr	808	29	361	14	3.	14
May	544	110	224	35	2.	35
Jun	177	643	63	273	1.	273
Jul	96	733	34	355	0	355
Aug	148	397	50	125	1.	125
Sep	378	220	140	51	1.	51
Oct	510	253	193	87	2.	87
Nov	1325	0	591	0	5.	0
Dec	2789	0	1951	0	10.	0
2-Year Sum	27100	5127	16408	2072	95	2072
			COP 1.65	COP 2.47		

*Furnace Fan

Table 4.4.3-D

RESIDENTIAL MONTHLY HEATING AND COOLING LOADS, WASHINGTON

	<u>Thermal Load (kWh)</u>		<u>Baseline</u>		<u>Alternate</u>	
	<u>Heating</u>	<u>Cooling</u>	<u>Load (kWh)</u> <u>Heat Pump</u>		<u>Load (kWh)</u> <u>Solar Heat</u>	
			<u>Heating</u>	<u>Cooling</u>	<u>Heating*</u>	<u>Cooling</u>
Jan	1952		1025	0	117	0
Feb	1710		880	0	28	0
Mar	1101		508	0	16	0
Apr	389		146	0	14	0
May	108	159	37	7	14	7
Jun		668	0	282	0	282
Jul		905	0	510	0	510
Aug		830	0	429	0	429
Sep		431	0	134	0	134
Oct	232		84	0	14	0
Nov	888		399	0	19	0
Dec	1708		878	0	28	0
Year	8088	2993	3957	1362	250	1362

COP 2.04 COP 2.20

*Fans + Aux. Heat

4.5 PHOTOVOLTAIC SYSTEM DEFINITION

In Section 3 the photovoltaic components along with the electrical energy storage and power conditioning aspects of photovoltaic solar power systems were reviewed in some depth. The work addressed the three main system applications including the on-site residential case.

To evaluate the economic system performance characteristics of the residential application it is necessary to establish within certain limits the type of equipment and control interfaces to be used. To some extent the selection is based upon initial performance studies providing feedback and additional information to assist in the equipment selection. In general, the photovoltaic power generating system consists of the photovoltaic array, power conditioning system, and an energy storage system.

4.5.1 Power Conditioning Interface

The solar cell arrays were configured to satisfy a 240 V lead-acid battery storage system. This voltage was selected to facilitate operation of heating elements such as ovens, ranges, dryers, etc., on either AC or DC power. The DC power supplied directly to these loads would not experience losses associated with the inverter. This gain, however, comes at the expense of additional wire circuits in the house. Also, as discussed in the section on loads it is not unusual to achieve very high demands from heating element loads. Because battery life is a function of depth of discharge, additional control circuitry is required to protect the battery system. Finally, a high capacity rectifier must be provided to meet DC heating loads from the utility when no array output is available and the battery is low.

As a result of the above the decision was made not to use a separate DC output from the battery system to supply these loads. All electrical loads are satisfied using AC power. The power conditioning system selected for the residential homes corresponds to the systems noted as residential interface C described in Section 3.2.3.4. With this system the inverter and utility are operated in parallel. Load sharing with the utility is accomplished by controlling the phase angle of the inverter. The inverter supplies all the power up to its maximum rating with the utility supplying all power in excess of the rating. Controlled circuits are provided to insure that power does not flow

into the utility line. This system utilizes a bi-directional converter unit which allows use of utility power for charging the battery system. This inverter unit would be line commutated providing reasonably good efficiencies at partial load and at reasonable cost. The single line diagram of this system is given in Figure 3.2.3.4-C of Section 3. The interface equipment required is tabulated along with ratings, description and price in Table 3.2.3.4-B.

The power conditioning system also includes a regulator. The primary function of the regulator is to control the charging of the battery and maintain voltages and current from the photovoltaic array within the limits recommended by the battery manufacturer in order to maximize battery life. We assume that this regulator would be of a series switching type which, with the addition of control logic and instrumentation, would be used to help optimize the array's operating points in conjunction with the battery storage system. For purposes of system analysis a combined inverter regulator efficiency of .87 was used. The actual efficiency of an inverter will vary, however, with the load. Loads significantly below the inverter rating of lower efficiencies would be anticipated. This subject is discussed further in Section 4.7. The price of the inverter-regulator is estimated at \$200/kw. In general, the cost of such equipment increases with reduced size. Some inverter costs as a function of power level are depicted in Figure 3.2.3.2-E. Inverter costs also increase with decreasing voltage. It is additional justification for going to a high array-storage voltage. The installation costs for the inverter-regulator has been estimated at approximately \$140 per residence.

4.5.2 Array-Storage

The photovoltaic array consists of parallel-series connected modules installed on an inclined south-facing roof at all locations. A drawing of the module-panel concept is given in Figure 3.1-A. The basic module is described in Section 3. A cost breakdown for this module production is plotted in Table 3.1-B.

Solar cells exhibit a 15% efficiency under standard test conditions. Standard test conditions represent 100 mW/cm^2 insolation and a temperature of 28°C . The ratio of cell area to total array area defined as the packing factor is .74. Hence the overall array efficiency of .111 is used. This efficiency, of course, varies with the cell temperature. In all system performance evaluation the cell temperature is computed on an hour-by-hour basis to determine the actual electrical output power under operating conditions. A cost of \$55 per meter² of module area is assumed. An installation cost of \$45 per meter² is also used.

The storage system consists of a series-parallel connected group of advanced lead-acid batteries. Battery selection criteria has been discussed in Section 3.2.2. An initial one-time installation cost of \$300 is used in the system analyses. A ten-year life battery is assumed. This requires two replacements of the battery component during a thirty-year life. The present value of the battery replacement has been computed to \$64.89 per kWh, based on an initial battery cost of \$50/kWh. Overall battery efficiency of .78 has been computed. This computation is discussed in Section 4.6.2. The overall array and battery storage system size is a function of the electrical demand characteristics. As shown in the above sections, this varies significantly with location, method of space heating and cooling, and the type of appliances and lighting used. Battery size will be from zero (no storage) to 100 kilowatt hours and array from 20 m^2 to 200 m^2 depending upon the system concept and the fraction of the electrical demand that is most economically provided. Evaluation studies to determine the most economical array-storage size are reported on in the following section.

4.6 ARRAY-STORAGE OPTIMIZATION

Analysis of the array and storage components and their interaction was focused on four problems. First, what is the optimum design relationship between the array maximum power voltage under standard test conditions and the nominal storage battery voltage? With this design, to what extent is array efficiency reduced below maximum power point efficiency by the direct connection of the storage battery across the array?

Second, what is the seasonal match between loads and insolation? Can it be improved by changes in the handling of the space conditioning loads and in the tilt angle of the array? What criterion should be used to select the tilt angle of a flat fixed array?

Third, what is the optimum proportion between array and storage capacity for a given load? What is the optimum fraction of the load to supply with solar energy?

Fourth, what is the pattern of demand for utility backup power for particular array and storage capacities? Can and should demand for peak-time power be reduced by off-peak battery charging?

The first part of this section presents data on array characteristics including insolation data for the four locations studied, references to analytical models for array performance, and summaries of estimated electrical generation. This is followed by a discussion of analytical models and estimates of battery performance. The remainder of the section gives the results of the analysis of the above questions.

In 4.6.3 a rule for choosing the array output voltage relative to the battery voltage is given, along with an estimate of losses relative to maximum power. Section 4.6.4 discusses monthly load insolation ratios and a criterion for selecting the array tilt angle. The following section contains a discussion of the selection of optimal array-storage combinations and system size on the basis of minimizing the cost of solar electricity. Section 4.6.6 contains some observations on the utility backup load resulting from the use of solar power systems.

4.6.1 Array Performance

The performance of a solar array varies from one location to another depending on the amount of sunlight in each place. Insolation data used for this study were derived from the Aerospace weather tapes for 1962-63. These tapes contain

hourly data for total horizontal insolation and for direct normal insolation. The former are measurements collected by the National Weather Service. The latter are derived from total horizontal insolation by empirical relationship shown in Table 4.6.1-A. (See References 13 and 14.) Computer tabulations of insolation on a latitude tilted array averaged for each hour of the month are presented in Tables 4.6.1-B through D for Phoenix, Riverside and Cleveland. For Washington, monthly insolation totals for a panel at the latitude angle are shown in Table 4.6.1-E. Computer calculations of array insolation for this study utilized the formulas in Table 4.6.1-A. The average daily insolation for the two years on a surface tilted at the latitude angle was 6.49 kWh/day in Washington and 3.85 kWh/day in Cleveland.

Two methods were used to estimate the electricity output by the solar array. The first involved the use of the I-V characteristic of the array (see Table 3.1-A) in conjunction with those of the other electrical system elements. Each electrical component was modeled in a TRNSYS subroutine. A schematic block diagram for the TRNSYS electrical system is shown in Figure 4.6.1-A. TRNSYS was used principally to investigate the effect of operation away from the maximum power point of the array.

In order to perform the array-storage tradeoff, it was necessary to use a computationally simpler method of estimating hourly array output. This was done by means of the equations derived in Table 3.1-A for cell efficiency and in Table 3.1-C for heat transfer from the array. The latter relation was used to derive cell temperature from insolation, wind velocity and ambient temperature. Then the former relation was used to compute cell efficiency. Array output was obtained by multiplying insolation by cell efficiency, packing factor (.74) and a factor for losses associated with operating off the maximum power point (.975). The derivation of this maximum power factor is explained in the next part of this section.

Average electricity generated per square meter of array for each hour of the month is shown in Tables 4.6.1-F - I. These data for panels tilted at the latitude angle in each location were obtained using the second method of calculation above. Monthly efficiencies varied by up to 12% in Phoenix and up to 9% in Riverside. Two-year average efficiency was about ten percent in all locations.

Table 4.6.1-A: INSOLATION CALCULATIONS

1. Aerospace Tapes Direct Normal Insolation (kW/m^2)

$$\text{DN (Direct Normal)} = -.117 + 1.228 \frac{H \text{ (Horizontal)}}{E \cos \theta_z}$$

Where:

$$\text{DN} = 0 \text{ if } H/E \cos \theta_z \leq .25$$

$$E \text{ (Extra-terrestrial insolation)} = 1.353 (1 + .033 \cos \frac{n}{365} \cdot 2\pi)$$

$$\cos \theta_z \text{ (Zenith angle)} = \cos \omega \cos \delta \cos \lambda + \sin \delta \sin \lambda$$

$$\omega: \text{ hour angle} \quad \delta: \text{ declination angle} \quad \lambda: \text{ latitude angle}$$

2. Hourly Total Insolation on South Facing Tilted Surface (kW/m^2)

$$H_T = \text{DN} \cos \theta_T + \text{DF}(\text{VF}) + H(\text{RF}) (1 - \text{VF})$$

Where:

$$\text{DF (Diffuse insolation)} = H - \text{DN} \cos \theta_z$$

$$\text{VF (View factor)} = .5 (1 + \cos s \text{ (tilt angle)})$$

$$\text{RF (Reflection factor)} = .2$$

$$\cos \theta_T \text{ (Incidence angle)} = \cos \omega \cos \delta \cos (\lambda - s) + \sin \delta \sin (\lambda - s)$$

3. Monthly Average Daily Insolation on South Facing Tilted Surface ($\text{kWh/m}^2\text{-day}$)

$$\begin{aligned} \bar{H}_T = \bar{\text{DN}} & \left(\cos \delta \left[\cos (\lambda - s) \frac{1}{\omega'_s} \sin \omega'_s - \text{VF} \cos \lambda \frac{1}{\omega_s} \sin \omega_s \right] \right. \\ & + \sin \delta \left[\sin (\lambda - s) - \text{VF} \cdot \sin \lambda \right] \\ & \left. + \bar{H} (\text{VF} + (1 - \text{VF}) \text{RF}) \right) \end{aligned}$$

Where:

$$\omega_s \text{ (sunset hour in radians)} = \arccos (-\tan \lambda \tan \delta)$$

$$\omega'_s \text{ (if less than } \omega_s) = \arccos (-\tan (\lambda - s) \tan \delta)$$

Table 4.6.1-B

PHOENIX

AVERAGE INSOLATION, TILT = LATITUDE

kWh/m²

1962

TIME	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	YEAR
0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	0.0	0.01	0.06	0.10	0.12	0.12	0.11	0.10	0.08	0.06	0.03	0.0	0.06
8	0.12	0.29	0.49	0.73	0.98	0.93	0.81	0.52	0.28	0.10	0.19	0.13	0.26
9	0.39	0.63	0.88	1.09	1.29	1.24	1.05	0.74	0.39	0.18	0.41	0.35	0.50
10	0.61	0.83	1.05	1.28	1.43	1.37	1.13	0.78	0.47	0.25	0.60	0.57	0.69
11	0.77	0.94	1.16	1.39	1.52	1.41	1.13	0.78	0.47	0.25	0.60	0.57	0.69
12	0.87	1.03	1.25	1.47	1.60	1.47	1.19	0.82	0.52	0.30	0.65	0.62	0.74
13	0.93	1.09	1.31	1.53	1.66	1.53	1.25	0.88	0.58	0.36	0.71	0.68	0.80
14	0.95	1.11	1.33	1.55	1.68	1.55	1.27	0.90	0.60	0.38	0.73	0.70	0.82
15	0.96	1.12	1.34	1.56	1.69	1.56	1.28	0.91	0.61	0.39	0.74	0.71	0.83
16	0.97	1.13	1.35	1.57	1.70	1.57	1.29	0.92	0.62	0.40	0.75	0.72	0.84
17	0.98	1.14	1.36	1.58	1.71	1.58	1.30	0.93	0.63	0.41	0.76	0.73	0.85
18	0.99	1.15	1.37	1.59	1.72	1.59	1.31	0.94	0.64	0.42	0.77	0.74	0.86
19	0.99	1.15	1.37	1.59	1.72	1.59	1.31	0.94	0.64	0.42	0.77	0.74	0.86
20	0.99	1.15	1.37	1.59	1.72	1.59	1.31	0.94	0.64	0.42	0.77	0.74	0.86
21	0.99	1.15	1.37	1.59	1.72	1.59	1.31	0.94	0.64	0.42	0.77	0.74	0.86
22	0.99	1.15	1.37	1.59	1.72	1.59	1.31	0.94	0.64	0.42	0.77	0.74	0.86
23	0.99	1.15	1.37	1.59	1.72	1.59	1.31	0.94	0.64	0.42	0.77	0.74	0.86
TOTAL	5.48	5.83	6.76	7.29	7.25	6.54	6.34	6.96	6.20	6.79	5.53	5.03	6.38

1963

TIME	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	YEAR
0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	0.10	0.24	0.34	0.35	0.35	0.36	0.31	0.22	0.31	0.27	0.19	0.19	0.28
9	0.42	0.49	0.61	0.53	0.57	0.56	0.52	0.51	0.57	0.53	0.44	0.45	0.52
10	0.62	0.71	0.82	0.77	0.76	0.75	0.69	0.67	0.75	0.73	0.67	0.63	0.72
11	0.77	0.85	0.95	0.92	0.87	0.85	0.80	0.79	0.89	0.87	0.83	0.83	0.86
12	0.86	0.90	0.99	0.97	0.95	0.92	0.87	0.85	0.94	0.93	0.93	0.92	0.92
13	0.84	0.88	0.96	0.97	0.92	0.92	0.86	0.85	0.94	0.94	0.92	0.92	0.91
14	0.77	0.84	0.88	0.89	0.87	0.87	0.80	0.77	0.87	0.82	0.79	0.83	0.83
15	0.61	0.69	0.72	0.75	0.71	0.74	0.69	0.62	0.70	0.66	0.61	0.65	0.63
16	0.43	0.47	0.52	0.55	0.52	0.56	0.52	0.48	0.49	0.46	0.42	0.42	0.43
17	0.16	0.24	0.27	0.31	0.31	0.34	0.31	0.27	0.27	0.22	0.16	0.13	0.23
18	0.03	0.03	0.05	0.10	0.11	0.12	0.11	0.08	0.07	0.03	0.03	0.0	0.06
19	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
20	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
21	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
22	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL	5.65	6.36	7.23	7.30	7.09	7.19	6.65	6.29	6.88	6.55	6.02	6.10	6.61

Table 4.6.1-C

RIVERSIDE

AVERAGE INSOLATION, TILT = LATITUDE

kWh/m²

1962

TIME	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	YEAR
0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	0.0	0.0	0.0	0.00	0.03	0.03	0.04	0.01	0.0	0.0	0.0	0.0	0.0
6	0.0	0.00	0.03	0.10	0.12	0.12	0.13	0.14	0.07	0.01	0.0	0.0	0.06
7	0.02	0.10	0.22	0.24	0.24	0.23	0.27	0.30	0.24	0.16	0.11	0.07	0.18
8	0.25	0.26	0.45	0.45	0.43	0.39	0.45	0.55	0.43	0.41	0.33	0.32	0.40
9	0.51	0.51	0.51	0.65	0.61	0.55	0.70	0.75	0.57	0.63	0.54	0.56	0.61
10	0.70	0.51	0.76	0.81	0.75	0.73	0.85	0.70	0.56	0.51	0.57	0.71	0.77
11	0.80	0.65	0.85	0.94	0.88	0.84	0.77	1.00	1.01	0.94	0.78	0.81	0.87
12	0.51	0.69	0.87	0.95	0.94	0.90	0.78	1.00	1.05	0.96	0.85	0.84	0.91
13	0.75	0.61	0.80	0.93	0.89	0.88	0.92	0.95	0.96	0.88	0.80	0.78	0.85
14	0.80	0.48	0.65	0.83	0.75	0.76	0.80	0.82	0.82	0.75	0.69	0.63	0.72
15	0.36	0.34	0.48	0.60	0.59	0.61	0.54	0.65	0.63	0.55	0.49	0.43	0.53
16	0.07	0.19	0.29	0.40	0.41	0.45	0.46	0.46	0.42	0.32	0.23	0.29	0.34
17	0.0	0.05	0.18	0.21	0.23	0.24	0.25	0.23	0.22	0.15	0.0	0.0	0.15
18	0.0	0.0	0.0	0.03	0.08	0.06	0.07	0.07	0.0	0.0	0.0	0.0	0.03
19	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
20	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
21	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
22	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL	4.87	4.50	6.18	7.13	6.99	6.78	7.58	7.82	7.40	6.60	5.56	5.43	6.42

1963

TIME	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	YEAR
0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	0.0	0.0	0.0	0.00	0.02	0.03	0.04	0.01	0.0	0.0	0.0	0.0	0.01
6	0.0	0.00	0.04	0.10	0.10	0.10	0.14	0.12	0.07	0.01	0.0	0.0	0.06
7	0.06	0.13	0.24	0.26	0.19	0.20	0.29	0.28	0.26	0.18	0.12	0.08	0.19
8	0.28	0.33	0.49	0.48	0.34	0.36	0.51	0.51	0.50	0.39	0.39	0.37	0.41
9	0.47	0.55	0.72	0.69	0.49	0.55	0.72	0.71	0.70	0.59	0.60	0.62	0.62
10	0.62	0.70	0.82	0.85	0.66	0.73	0.90	0.83	0.84	0.77	0.74	0.83	0.78
11	0.73	0.84	0.94	0.92	0.83	0.80	0.99	0.95	0.92	0.90	0.83	0.92	0.88
12	0.60	0.87	0.97	0.94	0.89	0.87	0.99	0.96	0.95	0.92	0.87	0.95	0.92
13	0.73	0.63	0.89	0.85	0.65	0.65	0.93	0.91	0.86	0.84	0.78	0.87	0.85
14	0.55	0.71	0.73	0.77	0.75	0.77	0.82	0.77	0.73	0.71	0.65	0.75	0.73
15	0.40	0.49	0.56	0.58	0.58	0.62	0.65	0.62	0.57	0.49	0.47	0.60	0.55
16	0.24	0.28	0.37	0.38	0.40	0.42	0.47	0.44	0.40	0.33	0.32	0.50	0.35
17	0.0	0.03	0.22	0.15	0.20	0.23	0.27	0.24	0.22	0.18	0.0	0.0	0.15
18	0.0	0.0	0.0	0.03	0.06	0.06	0.09	0.08	0.0	0.0	0.0	0.0	0.03
19	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
20	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
21	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
22	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL	4.90	5.77	7.00	7.04	6.35	6.60	7.31	7.43	7.03	6.32	5.76	6.50	6.55

Table 4.6.1-D

CLEVELAND

AVERAGE INSOLATION, TILT = LATITUDE

 kWh/m^2

1962

TIME	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	YEAR
0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	0.0	0.0	0.0	0.00	0.02	0.02	0.02	0.01	0.0	0.0	0.0	0.0	0.01
7	0.0	0.0	0.02	0.08	0.10	0.10	0.10	0.10	0.04	0.00	0.0	0.0	0.04
8	0.00	0.04	0.14	0.22	0.24	0.25	0.24	0.26	0.17	0.13	0.01	0.0	0.14
9	0.15	0.14	0.27	0.35	0.41	0.33	0.33	0.44	0.30	0.24	0.13	0.03	0.27
10	0.32	0.24	0.39	0.47	0.51	0.50	0.51	0.57	0.39	0.35	0.21	0.23	0.39
11	0.38	0.28	0.45	0.53	0.50	0.58	0.57	0.65	0.49	0.39	0.28	0.30	0.45
12	0.44	0.40	0.48	0.62	0.64	0.64	0.62	0.70	0.52	0.44	0.29	0.35	0.51
13	0.44	0.43	0.47	0.59	0.58	0.63	0.53	0.70	0.55	0.44	0.28	0.35	0.51
14	0.38	0.35	0.44	0.55	0.55	0.61	0.59	0.65	0.52	0.42	0.25	0.32	0.47
15	0.32	0.27	0.39	0.46	0.51	0.53	0.50	0.55	0.46	0.34	0.22	0.25	0.40
16	0.17	0.13	0.23	0.36	0.38	0.41	0.36	0.43	0.33	0.23	0.13	0.12	0.23
17	0.00	0.05	0.14	0.22	0.25	0.26	0.24	0.27	0.19	0.10	0.01	0.0	0.15
18	0.0	0.0	0.02	0.07	0.10	0.11	0.10	0.10	0.05	0.00	0.0	0.0	0.05
19	0.0	0.0	0.0	0.00	0.02	0.03	0.02	0.01	0.0	0.0	0.0	0.0	0.01
20	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
21	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
22	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL	2.60	2.39	3.50	4.52	4.91	5.05	4.97	5.43	4.00	3.09	1.81	2.01	3.69

1963

TIME	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	YEAR
0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	0.0	0.0	0.0	0.00	0.02	0.02	0.02	0.01	0.0	0.0	0.0	0.0	0.01
7	0.0	0.0	0.02	0.08	0.11	0.12	0.11	0.08	0.05	0.00	0.0	0.0	0.05
8	0.01	0.09	0.13	0.22	0.25	0.29	0.26	0.23	0.22	0.17	0.01	0.0	0.15
9	0.18	0.24	0.27	0.38	0.41	0.44	0.39	0.34	0.37	0.35	0.03	0.10	0.30
10	0.32	0.34	0.39	0.48	0.53	0.57	0.51	0.45	0.50	0.49	0.18	0.25	0.42
11	0.42	0.44	0.47	0.54	0.52	0.63	0.53	0.53	0.59	0.57	0.25	0.15	0.51
12	0.46	0.49	0.54	0.59	0.58	0.70	0.63	0.58	0.65	0.62	0.28	0.44	0.55
13	0.45	0.43	0.53	0.61	0.64	0.67	0.62	0.58	0.63	0.62	0.31	0.43	0.55
14	0.40	0.47	0.47	0.59	0.60	0.64	0.57	0.55	0.60	0.57	0.29	0.38	0.54
15	0.30	0.40	0.43	0.54	0.52	0.55	0.52	0.48	0.52	0.47	0.23	0.26	0.44
16	0.15	0.27	0.32	0.41	0.41	0.41	0.40	0.37	0.35	0.33	0.14	0.16	0.31
17	0.01	0.09	0.15	0.25	0.27	0.25	0.26	0.23	0.22	0.17	0.01	0.0	0.15
18	0.0	0.0	0.02	0.08	0.11	0.11	0.11	0.09	0.05	0.00	0.0	0.0	0.05
19	0.0	0.0	0.0	0.00	0.01	0.03	0.02	0.01	0.0	0.0	0.0	0.0	0.01
20	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
21	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
22	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL	2.69	3.30	3.73	4.78	5.17	5.43	5.00	4.51	4.79	4.35	1.79	2.41	4.60

Table 4.6.1-E

Washington

Latitude Tilt Array

Monthly Energy Totals

	<u>Insolation (kWh/m²)</u>	<u>Electricity Generated (kWh/m²)</u>
1962		
J	108.7	12.1
F	102.0	11.2
M	180.7	19.5
A	162.9	16.8
M	171.1	17.1
J	166.4	16.2
J	167.3	16.4
A	176.4	17.4
S	145.6	14.7
O	162.3	17.1
N	113.9	12.6
D	119.5	13.6
TOT	1776.9	182.5
J	134.0	15.5
F	134.6	15.4
M	162.5	17.4
A	187.5	19.5
M	189.7	19.2
J	179.5	18.3
J	192.1	18.6
A	189.0	18.6
S	163.1	16.8
O	183.1	19.2
N	118.1	12.6
D	101.4	11.5
TOT	1934.5	200.8

Figure 4.6.1-A: TRNSYS BLOCK DIAGRAM FOR ELECTRICAL SYSTEM

Table 4.6.1-F

PHOENIX

AVERAGE ELECTRICAL GENERATION

kWh/m²

1962

TIME	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	YEAR
0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.0	0.01
8	0.01	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.02	0.01	0.02
9	0.04	0.05	0.06	0.06	0.06	0.05	0.05	0.05	0.05	0.05	0.04	0.04	0.05
10	0.07	0.07	0.08	0.08	0.08	0.07	0.07	0.07	0.07	0.07	0.06	0.06	0.07
11	0.08	0.09	0.09	0.09	0.09	0.07	0.08	0.08	0.08	0.09	0.08	0.07	0.08
12	0.09	0.09	0.10	0.10	0.09	0.08	0.08	0.09	0.08	0.10	0.08	0.08	0.09
13	0.09	0.09	0.10	0.09	0.09	0.08	0.08	0.09	0.08	0.10	0.09	0.08	0.09
14	0.08	0.08	0.09	0.09	0.09	0.08	0.08	0.08	0.07	0.09	0.08	0.07	0.08
15	0.06	0.06	0.07	0.07	0.07	0.06	0.07	0.07	0.06	0.07	0.06	0.05	0.07
16	0.04	0.04	0.05	0.05	0.05	0.05	0.05	0.05	0.04	0.05	0.04	0.03	0.05
17	0.01	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.02	0.02	0.01	0.01	0.02
18	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.0	0.00
19	0.0	0.0	0.0	0.00	0.00	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.00
20	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
21	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
22	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL	0.57	0.61	0.70	0.72	0.71	0.61	0.64	0.65	0.59	0.67	0.56	0.51	0.63
η	.1040	.1046	.1036	.0986	.0979	.0933	.0936	.0934	.0952	.0987	.1013	.1014	.0987

1963

TIME	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	YEAR
0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	0.0	0.0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.00
7	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.0	0.01
8	0.02	0.02	0.03	0.04	0.03	0.03	0.03	0.03	0.03	0.03	0.02	0.02	0.03
9	0.04	0.05	0.06	0.06	0.06	0.06	0.05	0.05	0.06	0.05	0.04	0.05	0.05
10	0.07	0.07	0.09	0.08	0.08	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
11	0.08	0.09	0.10	0.10	0.09	0.08	0.08	0.08	0.09	0.09	0.09	0.09	0.09
12	0.09	0.09	0.10	0.10	0.09	0.09	0.08	0.08	0.09	0.09	0.10	0.10	0.09
13	0.09	0.09	0.10	0.10	0.09	0.09	0.08	0.08	0.09	0.09	0.10	0.10	0.09
14	0.08	0.09	0.09	0.09	0.08	0.09	0.08	0.07	0.08	0.08	0.08	0.09	0.08
15	0.06	0.07	0.07	0.08	0.07	0.07	0.07	0.06	0.07	0.06	0.06	0.07	0.07
16	0.04	0.05	0.05	0.05	0.05	0.05	0.05	0.04	0.04	0.04	0.04	0.04	0.05
17	0.02	0.02	0.02	0.03	0.03	0.03	0.03	0.02	0.02	0.02	0.02	0.02	0.02
18	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.0	0.00
19	0.0	0.0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.00
20	0.0	0.0	0.0	0.0	0.0	0.00	0.0	0.0	0.0	0.0	0.0	0.0	0.00
21	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
22	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL	0.59	0.65	0.74	0.74	0.69	0.69	0.62	0.60	0.66	0.64	0.61	0.64	0.66
η	.1044	.959	.1024	.1014	.0973	.0960	.0932	.0954	.0959	.0977	.1013	.1049	.0998

Table 4.6.1-G
RIVERSIDE
AVERAGE ELECTRICAL GENERATION

kWh/m²

1962

TIME	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	YEAR
0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
14	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
16	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
17	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
18	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
19	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
20	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
21	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
22	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL	0.50	0.46	0.63	0.71	0.70	0.66	0.74	0.75	0.72	0.65	0.55	0.55	0.54
η	.1027	.1022	.1019	.0989	.1001	.0973	.0976	.0959	.0973	.1	.1007	.1013	.0997

1963

TIME	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	YEAR
0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
14	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
16	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
17	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
18	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
19	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
20	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
21	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
22	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL	0.51	0.58	0.73	0.72	0.64	0.66	0.76	0.73	0.68	0.63	0.58	0.67	0.66
η	.1041	.1005	.1043	.1023	.1008	.1	.0973	.0976	.0967	.0997	.1007	.1031	.1008

Table 4.6.1-H

CLEVELAND

AVERAGE ELECTRICAL GENERATION

kWh/m²

1962

TIME	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	YEAR
0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	0.0	0.0	0.0	0.00	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
7	0.0	0.0	0.00	0.01	0.01	0.01	0.01	0.01	0.0	0.0	0.0	0.0	0.00
8	0.00	0.00	0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.00	0.0	0.0	0.00
9	0.02	0.01	0.03	0.04	0.04	0.04	0.04	0.04	0.03	0.02	0.01	0.01	0.01
10	0.04	0.03	0.04	0.05	0.05	0.05	0.05	0.06	0.04	0.04	0.02	0.02	0.03
11	0.04	0.03	0.05	0.06	0.06	0.06	0.06	0.06	0.04	0.04	0.03	0.03	0.04
12	0.05	0.04	0.05	0.07	0.07	0.06	0.06	0.07	0.05	0.04	0.03	0.04	0.05
13	0.05	0.05	0.05	0.06	0.06	0.06	0.06	0.07	0.05	0.04	0.03	0.04	0.05
14	0.04	0.04	0.05	0.06	0.05	0.06	0.05	0.06	0.05	0.04	0.03	0.04	0.05
15	0.04	0.03	0.04	0.05	0.05	0.05	0.05	0.05	0.05	0.03	0.02	0.03	0.04
16	0.02	0.02	0.03	0.04	0.04	0.04	0.03	0.04	0.03	0.02	0.01	0.01	0.03
17	0.00	0.00	0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.01	0.00	0.0	0.01
18	0.0	0.0	0.00	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.0	0.0	0.00
19	0.0	0.0	0.0	0.00	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.00
20	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00
21	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
22	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL	0.29	0.26	0.38	0.47	0.49	0.50	0.47	0.53	0.40	0.31	0.18	0.22	0.37

1963

TIME	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	YEAR
0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	0.0	0.0	0.0	0.00	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.00
7	0.0	0.0	0.00	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.0	0.0	0.00
8	0.00	0.01	0.01	0.02	0.02	0.03	0.02	0.02	0.02	0.02	0.00	0.0	0.00
9	0.02	0.03	0.03	0.04	0.04	0.04	0.04	0.03	0.04	0.04	0.01	0.01	0.01
10	0.04	0.04	0.04	0.05	0.05	0.06	0.05	0.04	0.05	0.05	0.02	0.03	0.03
11	0.05	0.05	0.05	0.06	0.07	0.07	0.06	0.05	0.06	0.06	0.03	0.05	0.05
12	0.05	0.06	0.06	0.06	0.07	0.07	0.06	0.06	0.07	0.06	0.03	0.05	0.05
13	0.05	0.06	0.06	0.06	0.07	0.07	0.06	0.06	0.06	0.06	0.03	0.05	0.05
14	0.05	0.05	0.05	0.06	0.06	0.06	0.06	0.06	0.06	0.05	0.03	0.04	0.05
15	0.03	0.04	0.05	0.06	0.05	0.06	0.05	0.05	0.05	0.05	0.02	0.03	0.04
16	0.02	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.04	0.03	0.01	0.02	0.03
17	0.00	0.01	0.01	0.02	0.03	0.02	0.02	0.02	0.02	0.02	0.00	0.0	0.01
18	0.0	0.0	0.00	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.0	0.0	0.00
19	0.0	0.0	0.0	0.00	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.00
20	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00
21	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
22	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
ADY TOTAL	0.30	0.37	0.39	0.50	0.53	0.54	0.49	0.44	0.48	0.44	0.18	0.27	0.41

TABLE 4.6.1-I
WASHINGTON
AVERAGE ELECTRICAL GENERATION, kWh/m²

TIME	1962												YEAR
	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	
0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	0.0	0.0	0.01	0.01	0.01	0.01	0.01	0.01	0.0	0.0	0.0	0.0	0.0
8	0.01	0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.01	0.01	0.02
9	0.02	0.02	0.05	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.02	0.03	0.04
10	0.04	0.04	0.07	0.06	0.06	0.05	0.05	0.06	0.06	0.06	0.04	0.04	0.05
11	0.05	0.06	0.09	0.07	0.07	0.06	0.07	0.07	0.07	0.07	0.05	0.06	0.07
12	0.06	0.06	0.09	0.07	0.07	0.07	0.07	0.07	0.07	0.08	0.06	0.07	0.07
13	0.06	0.06	0.09	0.08	0.07	0.07	0.07	0.07	0.07	0.08	0.07	0.07	0.07
14	0.06	0.06	0.08	0.07	0.07	0.07	0.07	0.08	0.06	0.07	0.06	0.06	0.07
15	0.04	0.05	0.07	0.06	0.06	0.06	0.06	0.06	0.05	0.06	0.05	0.05	0.05
16	0.03	0.03	0.05	0.04	0.04	0.04	0.04	0.04	0.03	0.04	0.03	0.03	0.04
17	0.01	0.01	0.02	0.02	0.02	0.02	0.02	0.03	0.02	0.02	0.01	0.02	0.02
18	0.0	0.0	0.0	0.01	0.01	0.01	0.01	0.01	0.0	0.0	0.0	0.0	0.0
19	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
20	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
21	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
22	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
24	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL	0.39	0.40	0.63	0.56	0.55	0.54	0.53	0.56	0.49	0.55	0.42	0.44	0.50

TIME	1963												YEAR
	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	
0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	0.0	0.0	0.0	0.01	0.01	0.01	0.01	0.01	0.0	0.0	0.0	0.0	0.0
8	0.01	0.02	0.02	0.03	0.03	0.03	0.03	0.02	0.02	0.02	0.01	0.01	0.02
9	0.03	0.04	0.04	0.05	0.05	0.05	0.05	0.05	0.04	0.04	0.03	0.02	0.04
10	0.05	0.06	0.06	0.07	0.06	0.06	0.07	0.06	0.06	0.06	0.05	0.05	0.07
11	0.06	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.07	0.08	0.06	0.05	0.07
12	0.08	0.09	0.08	0.09	0.09	0.09	0.08	0.08	0.08	0.09	0.07	0.06	0.08
13	0.08	0.08	0.08	0.09	0.08	0.08	0.08	0.08	0.07	0.09	0.06	0.05	0.07
14	0.07	0.07	0.07	0.08	0.08	0.07	0.07	0.08	0.07	0.09	0.06	0.05	0.07
15	0.06	0.06	0.06	0.07	0.07	0.05	0.06	0.06	0.06	0.07	0.04	0.04	0.05
16	0.03	0.04	0.04	0.05	0.05	0.04	0.04	0.05	0.04	0.05	0.03	0.02	0.04
17	0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.01	0.01	0.02
18	0.0	0.0	0.0	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.0	0.0	0.0
19	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
20	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
21	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
22	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
24	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL	0.50	0.55	0.56	0.65	0.62	0.59	0.60	0.60	0.56	0.62	0.42	0.37	0.55

4.6.2 Storage Performance

Solar generation and electrical demand in a residence do not match for three reasons. First, the solar generation and part of the electrical load varies from day to day due to weather and season. Second, residential demand has very sharp irregular peaks because loads are switched on and off through the day. Third, important parts of the residential load occur during the night and early morning.

On-site storage is one means of resolving these problems of non-coincidence. At present the most feasible way of storing electricity on site is by means of lead-acid batteries. These have a reasonable efficiency and cost, are known to homeowners because of their use in automobiles, and have a reasonably long lifetime.

For Phoenix and Riverside the fixity of weather patterns makes day to day storage of energy unattractive. For Cleveland and Washington, where weather patterns are more variable, some carry-over to the next day can be provided. Seasonal storage by means of batteries is unattractive. The seasonal match between load and generation can be improved in some cases by adjusting the array tilt angle. In cases where the winter heating load is substantial and sunlight is low, it appears to be better to use conventional heating methods or solar thermal systems which use solar energy more efficiently. For such areas solar energy could be stored for winter use in the form of hydrogen or some other combustible fuel, but this is very costly at present. Thus the only function of on-site storage as far as day-to-day variation of generation goes is to provide partially for daily fluctuations in regions of variable weather.

The peakiness of the daily residential load for a single residence is smoothed somewhat by any battery capacity. However, in an AC system, the inverter size limits the size of the peak which can be served by solar electricity.

A substantial part of the residential load does not coincide with daylight hours. The cooling solar load lags insolation because of thermal storage

by the house. The heating load is concentrated during the late night and early morning hours. Residential loads for the morning-breakfast and dinner periods occur when there is little or no solar generation from a fixed collector. After dark, the TV and lighting loads are significant. The major function of storage in a residential system with utility backup is to keep solar energy generated during the day for nighttime use.

There is some question about whether solar energy should be stored at all and, if so, whether it should be stored on site. Utilities when faced with peak loads which can be leveled by storage have in many cases chosen to install extra peak generating capacity instead. However, up to now utilities have only had to deal with scheduable or constant output generating equipment. Terrestrial solar energy has no flexibility in time and is unavailable for a significant part of the time except with storage.

Solar energy generated on houses could be used for commercial or manufacturing purposes during the day rather than stored, but institutional barriers to this approach are many. Using a single system for several residences would level the daytime load but without storage would leave the night load untouched. This night load would have to be met by a large capacity backup system which would be unutilized on clear days. Cost calculations for a single residence show that storage batteries should be attractive for a wide range of battery to array price ratios, and for systems which supply various fractions of the residential load.

Battery Model

A battery model was used to examine the dependence of battery efficiency on the size of the array and battery. This model was also used to help evaluate array efficiency variations due to changes in the operating voltage (see Section 4.6.3). For a system not equipped with a control system forcing the array to operate at its maximum power point, the battery terminal voltage establishes the operating voltage. This voltage varies with the state of charge, rate of discharge or charge relative to storage capacity, and to a lesser extent with battery temperature.

The model used for battery voltage gives a good fit to the tables in the Standard Handbook for Electrical Engineers for voltage across a lead acid cell. This model is expressed by the following equation:

$$V = 1.965 + .045(I/I_8) + .075F + .17S \\ + \max(0, F \cdot \max(S - .8, 0)) + .5 \min(0, F \cdot \max(.2 - S, 0))$$

V = cell potential

I = current in amperes (+ charge, - discharge)

I_8 = charging current at 8 hour rate ($C_8/8$)

S = level of charge/capacity

F = flat +1 charge
-1 discharge

Here 1.965 is the basic cell voltage, and the second term represents cell resistance. Although the resistance increases as the cell nears complete charge or discharge, this effect is ignored. The coefficient of F in the third term is half of the polarization potential. The coefficient of S in the fourth term reflects the effect of concentration changes. The last two terms correct for the higher/lower cell potential as complete charge/discharge is reached.

Using this model, an eight hour rate charge-discharge cycle between 10% and 90% of capacity yields a voltage efficiency of .84. If the ampere efficiency is .93, the battery efficiency would be .78.

If the battery discharge limit is set at 1.85 volts, the currents which cause the inverter to turn off are shown in the following figure as a function of the state of charge of the battery. Variations in the battery temperature were not taken into account. If the battery is not in a protected environment, temperature adjustments of the voltage set points are necessary.

To evaluate the effect of array and battery size on battery efficiency a 5 day simulation was performed using the Phoenix heat pump residence. In this simulation a 3.5 kW inverter (see Section 4.6.5 on inverter sizing) and a battery ampere efficiency of .9 were used. The results are shown below:

Battery Efficiency vs. Battery and Array Size

Battery kWh	Array Size	
	35 m ²	65 m ²
5	.741 - .754	.745 - .765
20	.806 - .818	.760 - .813

The efficiencies increase with battery size because charges and discharges are smaller in relation to battery capacity. The effect of array size is not clear. For the system optimization studies reported on in subsequent sections a fixed battery efficiency of .78 was used, and battery cycles were assumed to be limited to 80% of rated capacity.

4.6.3 Array Operating Voltage

In the residential system the voltage across the array is determined by the battery voltage. Hence the array operating voltage will seldom correspond to the maximum power point voltage of the array. The problem of establishing the array design to reduce the maximum power loss is complicated by several factors. They include:

a) The panel voltage characteristics are primarily established by the number of series connected solar cells. The resulting EI (voltage-current) characteristics are also a function of the cell temperature and insolation level. If too few cells are selected for the series connected cell strings making up an array, the battery voltage may on warm days or days of low insolation cause panel operation at a voltage approaching open circuit voltage. This condition would significantly reduce the panel current and hence output power.

b) The battery voltage varies with its state of charge, rate of charge or discharge and to a lesser extent with temperature.

The characteristic of a typical solar cell, sketched below, illustrates the problem. Its maximum power voltage varies with temperature by $-.0022 \text{ V}/^{\circ}\text{C}$ as a result of similar changes in the open circuit voltage. In a flat array under $1 \text{ kW}/\text{m}^2$ insolation, cell temperature variation from 0°C to 80°C would

induce a change in open circuit voltage (.6 volts for cells at 28°C and under $1 \text{ kW}/\text{m}^2$ insolation) from .66 to .49 volts, and in maximum power voltage from about .57 to .4 volts.

A sketch of cell efficiency relative to maximum power efficiency versus voltage shows how the cell (or an array) characteristic may be matched to the battery voltage. Typically the relative efficiency of a flat array remains high under low temperature conditions even when the array voltage

is high enough to avoid loss of power for high temperatures. This was confirmed by one-month TRNSYS simulations which showed that maximum power losses are less than 1% when array voltage is established according to weather conditions for that month.

A design rule for good year round performance for flat arrays tilted at latitude angle is that the calculated maximum power voltage at an insolation of 749 watts/m^2 , an ambient temperature equal to the average of daily maximum temperatures over the year, and a wind velocity equal to the yearly average be set equal to the nominal battery voltage at full charge. The insolation value is the AM2 value given by NASA-Lewis in their Interim Solar Cell Testing Procedures for Terrestrial Applications. With this design rule the effect of varying battery voltage with the state of charge can be determined for different weather conditions from the array characteristic and the array thermal models. The effect on array efficiency is shown in Figure 4.6.3-A. In the figure, low temperature conditions are defined as 500 W/m^2 insolation, lowest of month-by-month average daily maximum temperatures, and average wind velocity. High temperature conditions are 1000 W/m^2

ARRAY EFFICIENCY RELATIVE TO MAXIMUM POWER EFFICIENCY

Figure 4.6.3-A

insolation, highest average daily maximum temperature, and average wind velocity. We conclude that the direct connection of the storage battery across the array results (for non-concentrating arrays) in a loss of less than 5% of the maximum collected energy over the year. In subsequent system optimization calculations a constant loss of 2.5% was assumed.

4.6.4 Seasonal Load/Supply Relations

The seasonal coincidence between solar electrical availability and the residential load can be examined by calculation of the ratios of average monthly residential loads to average monthly insolation (LIR's). A level LIR profile for the year indicates that a large part of the load can be met efficiently with solar, while a peaked profile shows that a system with enough solar generating capacity for the whole load would dump solar energy during part of the year.

Data based on monthly averages do not show the fluctuations of solar output and of the load. The fluctuations lead to dumping energy on days when solar generation exceeds the load. This effect can be minimized by matching the monthly solar availability to the load as well as possible. For example, if the monthly availability always averages 70% of the load, on those days when availability is above average there still may not be much dumping. However, during a month when the average available energy is 100% of the load, there will be days when dumping must occur.

Figures 4.6.4-A through C show load-insolation ratios for Phoenix, Riverside and Cleveland for 1962. The space conditioning loads are the computer generated loads which are tabulated in Section 4.4.2. To these were added the fixed appliance and lighting loads of either 20 kWh/day or 11.85 kWh/day (Section 4.4.1). Insolation was derived from monthly horizontal and direct normal insolation from the Aerospace tapes using the third formula in Table 4.6.1-A.

The baseline system, with the 20 kWh/day fixed load, Supreme Aire heat pump and resistance heating, gives unbalanced LIR's in Phoenix. The largest LIR

Figure 4.6.4-A. PHOENIX 1962 LOAD-INSOLATION RATIOS

Figure 4.6.4-B. RIVERSIDE 1962 LOAD-INSOLATION RATIOS, ARRAY INCLINED AT LATITUDE ANGLE

Figure 4.6.4-C. CLEVELAND, 1962 LOAD-INSOLATION RATIOS, ARRAY INCLINED AT LATITUDE ANGLE

is more than twice as great as the smallest. The dotted curve in Figure 4.6.4-A shows that decreasing the array tilt levels the LIR profile somewhat. Despite the high summer LIR it is shown in Section 4.6.5 that a large solar fraction can be provided, because a large part of the summer cooling load can be met directly, without storage losses. The Phoenix summer LIR is effectively reduced in the alternate system by the use of an evaporative cooler. This system uses gas for heating and some appliances so the electrical load is much smaller.

In Riverside, the same equipment sets were adopted as for Phoenix. Both systems have level LIR profiles. For the baseline system in Cleveland the largest LIR is seven times as big as the smallest. It is clearly impractical to meet this large heating load with solar electricity. The alternate system uses gas for heating and some appliances, and a heat pump for cooling. Its LIR profile is much more level. Removing the heating load from the electrical system leaves the problem of heating the house during a period of low solar availability. It was thought that conventional fuels are a more suitable way of storing energy for the winter than storage batteries.

The monthly load insolation ratios can be used to estimate an efficient array size. One can choose an array which according to average data would just satisfy the load during the month with the smallest load insolation ratio. A larger array would have to dump energy during part of the year. Dividing the smallest monthly LIR by a system efficiency of 7% gives the following array sizes for arrays inclined at the latitude angle.

	<u>Baseline System</u>	<u>Alternate System</u>
Phoenix	68 m ²	26 m ²
Riverside	71 m ²	27 m ²
Cleveland	72 m ²	43 m ²

It can be seen from Figure 4.6.4-A that adjusting the tilt angle of the array can help to level the LIR profile. While it is desirable to make this profile as flat as possible, inclination angles which entail a large loss of insolation should be avoided. Accordingly, tilt angles were selected for each system which minimized the following criterion.

$$\varphi = \frac{\frac{1}{12} \cdot (LIR - \overline{LIR})^2 (I_i/\overline{I})^2}{\overline{I}^2}$$

$$= \frac{\frac{1}{12} (L_i - (\overline{LIR}) I_i)^2}{\overline{I}}$$

Here I_i , L_i , LIR_i are monthly insolation, load and load insolation ratio and bars denote averages of monthly quantities. Insolation for various tilt angles were calculated from the third formula in Table 4.6.1-A. Table 4.6.4-A shows the tilt angle which maximizes insolation, the array inclination which minimizes the above criterion for various systems, and the percent of insolation lost by using an array tilted at the latter angle instead of at the former. The tilt angles which minimize φ were used in the two-year solar fraction calculations except for Washington and the Cleveland alternate system, where the latitude angle was used. For the Phoenix heat pump system two year hourly computer calculations were done for photovoltaic systems with 35 m² of array and no battery and 70 m² of array and a 20 kWh battery with both a latitude tilted array and an array tilted at 13.43°. Although the latter array received 2.8% less insolation, 2.2% more solar electricity was used by the load for the systems with flatter arrays. Two year calculations for the Cleveland alternate system, however, showed that the loss of insolation for an array tilted at 58.4° was not offset by the better load insolation match, and solar utilization declined. It appears that in most cases the criterion above helps in selecting a tilt angle, but that the resulting gain is not very large.

Table 4.6.4-A
ARRAY INCLINATION ANGLES

System	For Maximum Insolation	Minimum φ	Percent Insolation Loss
Riverside (33.95°N)			
Heat Pump	25.95°	38.95°	1.1%
Evaporative Cooler	25.95°	40.95°	1.8%
Phoenix (33.43°N)			
Heat Pump	29.43°	13.43°	3.0%
Evaporative Cooler	29.43°	21.43°	1.0%
Cleveland (41.4°N)			
Heat Pump	28.4°	38.4°	1.3%
Heat Pump plus gas heat	28.4°	58.4°	11.0%

4.6.5 Inverter Sizing

Solar cells and batteries are DC devices, while utility power is AC. The form in which power is to be used for the load and the way that the two power sources are integrated must be decided. An AC load system was chosen for analysis.

If loads are AC, all solar power must be inverted before it can be used. In Section 3.2 the operational cost of the inverter and interface are discussed in detail. For the interface chosen (Bechtel's Interface C) the solar output is in parallel with the utility. Solar power to the load is limited by the inverter capacity, with the peaks thrown on the utility. The inverter used in this system can be of moderate quality, because the waveform can be improved by the utility transformers. Costs of \$200/kW for the inverter and \$140 for the interface were used for calculations. The selected utility interface allows solar and utility power to operate in parallel. When the residential load exceeds the rating of the inverter the extra load is met by utility power. A small inverter thus decreases the load seen by the solar system, lowering the solar fraction which can be achieved. However, in addition to being expensive, a large inverter would operate at low efficiency most of the time.

To determine the effect of inverter size on efficiency and solar fractions, hourly simulations were run with different inverter sizes for the Washington heat pump system with a 48.3 square meter array and a 23.5 kilowatt hour battery. Instead of the constant efficiency assumed in other solar fraction calculations, the function shown in Table 4.6.5-A was used to model the inverter. Figure 4.6.5-A presents the results of the computer calculation. The inverter efficiency decreases by ten percent as the size of the inverter increases from .5 to 6 kW (These inverter sizes are .35 and 4.17 times the average load). The ratio of annual energy supplied by the solar system to total annual energy used, denoted as solar fraction, increases with inverter size because the solar system sees more of the load with a larger inverter. However, for inverters larger than 4.5 kW the lower inverter efficiency causes a decrease in the solar fraction.

Table 4.6.5-A. Inverter Performance

<u>Load/Rating</u>	<u>Efficiency</u>
.1	.691
.2	.817
.4	.899
.6	.928
.8	.934
1.0	.920
1.2	.884

Figure 4.6.5-A Washington Heat Pump System

The inverter calculation assumes that the HVAC load is distributed equally to each quarter hour and that when the load exceeds the inverter capacity it is met by utility power, as shown above. The results of this calculation are shown in Figure 4.6.5-B, where the fraction (f_{ex}) of the load shifted to the utility is plotted against the ratio (r) of inverter size to average load. The curves for these systems lie close to the fitted curve $f_{ex} = e^{-.8r}$. The inverter sizes chosen for the eight systems analyzed excluded 9.9% to 20.5% of the load from the solar system. The ratio of the selected inverter sizes to the load ranged from 1.85 to 2.95.

A criterion for optimizing the inverter size follows: the increase in solar system output from an additional dollar spent for the array is the same as the increase in output from an additional dollar spent for an inverter which produces

$$\frac{1}{P_i} \cdot K_i \left(- \frac{L_{ex}}{I} \right)$$

more output. (P_i is the price of the inverter, $\frac{L_{ex}}{I}$ is the change in the load excluded per unit change in inverter size, and K_i is a factor showing the proportion of the additional load seen by the solar system which is actually met by the solar system.) The additional dollar for array produces

$$\frac{1}{P_a} \cdot K_a \cdot g$$

more output. (P_a is the array size price, g is the electrical output per square meter of array, and K_a is the proportion of additional generated energy which is used.) Preliminary calculations indicated that $K_i = .2$, $K_a = .7$ are reasonable values near the optimum. The cost assumptions of the study were that $P_i = \$200/\text{kW}$ and $P_a = \$100/\text{m}^2$. The optimization criterion is thus summarized by the following equation:

$$\frac{1}{P_i} K_i \left(- \frac{L_{ex}}{I} \right) = \frac{1}{P_a} \cdot K_a \cdot g$$

or

$$- \frac{L_{ex}}{I} \cdot \frac{1}{g} = \frac{P_i}{P_a} \frac{K_a}{K_i} = 7 \frac{\text{m}^2}{\text{kW}}$$

Figure 4.6.5-B. Effect of Inverter - Residential Systems

In detailed calculations for the Phoenix heat pump system, for five days, the following inverter efficiencies were obtained.

<u>Inverter Efficiency</u>		
Array Size-m ² :	35	65
Battery Size kWh		
5	.78 - .91	.83 - .92
20	.81 - .92	.83 - .92

There is some improvement in efficiency with increased array size and battery size. Subsequent system studies assumed a constant inverter efficiency of .87.

To select an inverter size for each system, the fraction of each electrical load that would be shifted to the utility by different sizes of inverters was calculated. The load was input to the calculation as a quarter hourly appliance and lighting load which repeated everyday and a HVAC load in the form of the electrical power drawn by the heat pump, fan, etc., and the fraction of the hour that the appliance was on. The relationship between inverter size and utility load is illustrated below.

Values of $-\frac{L_{ex}}{I} \cdot \frac{1}{g}$ for the selected inverter sizes range from 4.5 to 9.9 $\frac{m^2}{kW}$.

The inverter sizes selected for each of the eight systems studied are shown in Table 4.6.5-B.

The last figure (4.6.5-C) examines the effect of the inverter on the demand for utility power. It shows number of days per year that any fraction of the 6 AM to 12 midnight ("peak-time") is excluded by the inverter. For most of the systems 40% or less of the average peak load is shifted to the utility by the inverter. However, for both Cleveland systems the inverter shifts more than 120% of the average peak-time load to the utility for a few days of the year. For the heat pump system this occurs on very cold days when the major loads are the heat pump (2.5 kW) and resistance heating (5 kW).

For the gas heating system, this occurs on very hot days when the heat pump cooling load of 3.2 kW exceeds the inverter capacity of 1.75 kW. In the Cleveland gas heating system a 3 kW inverter would be needed to keep daily utility use due to the inverter down to 50% of the average load, for the other Cleveland system a 9 kW inverter would do this.

Table 4.6.5-B. Selected Inverter Sizes

Location	System	Inverter Size (kW)	$r = I/L$	f_{ex}	$-\frac{L_{ex}}{I} \cdot \frac{1}{g}$
					(m ² /kW)
Cleveland	Heat Pump	4.5	2.4	.172	7.4
	Gas Heat	1.75	2.8	.157	5.7
Phoenix	Heat Pump	3.5	1.85	.175	9.9
	Evap Cool	1.5	2.4	.099	4.5
Washington	Heat Pump	3.5	2.4	.154	6.7
	Rock Bed	3.0	2.95	.205	5.0
Riverside	Heat Pump	3.5	2.25	.153	6.8
	Evap Cool	1.25	2.35	.146	5.2

Figure 4.6.5-C. Number of Days Per Year That Any Relative Peak-Time Utility Load is Exceeded Due to Inverter

4.6.6 Array-Storage Sizing

The performance of a residential solar power system can be rated in terms of the utility energy that it displaces annually. When a particular load is specified, performance can be measured by the solar fraction or the ratio of displaced energy to the load. The same level of performance can be achieved with different sizes of array and storage. Relative prices of the components determine the size combination of array and storage which can produce a given solar fraction at lowest cost.

The array-storage trade-off was examined for each of the eight systems studied (baseline and alternate systems in four locations). First, computer calculations of solar fractions for various combinations of array and storage sizes were made using 1962-63 hourly electrical generation and electrical space-conditioning load files derived from the Aerospace weather tapes. Curves of equal solar fractions were interpolated from this data. Least cost points on each curve were found giving a locus of optimal array-storage combinations.

The solar fraction calculation assumed that the electrical load is met with solar energy whenever it is available, and that supplemental power is drawn directly from the utility line. No off-peak charging is done. All loads are AC. The operational assumptions made in the program are as follows. If solar electricity is generated during an hour it is used to meet the load up to the capacity of the inverter. If solar availability exceeds the load, energy is stored in the battery, which has an overall efficiency of .78, unless the battery is full, in which case energy is dumped. If generated electricity is less than the load, it is supplemented by energy from the battery, which cycles to 80% of its capacity, unless the battery is low, in which case solar electricity is supplemented by utility energy. When no solar electricity is being generated, energy to meet the load up to the capacity of the inverter is withdrawn from the battery until it is low, after which the load is met directly from the utility. Loads in excess of the inverter capacity (approximately twice the average load - see Section 4.6.5)

are met by the utility at all times. All solar power, whether from the array or battery is inverted for the AC house loads with an efficiency of 87%. Battery costs of \$114/kWh and installed array costs of \$100/m² were used.

Figure 4.6.6-A shows the solar fractions that were calculated for the Phoenix heat pump system. Figures 4.6.6-B1 thru B8 contain array-storage trade-off charts for the eight systems in the study. Curves of equal solar fractions are shown, along with isocost lines which have slopes numerically equal to the ratio of battery cost to array cost or P_b/P_a . Points of tangency locate least-cost systems. Table 4.6.6-A lists component sizes for these systems. Clearly different price ratios would lead to the selection of different component sizes. For the optimized systems, the ratio of storage to array size is about .4 kWh/m² in many cases. The economic performance characteristics of these optimized systems are reviewed in Section 4.8.

16-7

Figure 4.6.6-A. PHOENIX HEAT PUMP SYSTEM SOLAR FRACTIONS

Figure 4.6.6-B1. PHOENIX HEAT PUMP SYSTEM ARRAY STORAGE TRADE-OFF.

Array
Size, m²

Figure 4.6.6-B2. PHOENIX EVAPORATIVE COOLING ARRAY STORAGE TRADE-OFF.

Figure 4.6.6-B3. RIVERSIDE HEAT PUMP SYSTEM ARRAY STORAGE TRADE-OFF.

Figure 4.6.6-B4. RIVERSIDE EVAPORATIVE COOLER SYSTEM ARRAY STORAGE TRADE-OFF.

Figure 4.6.6-B5. WASHINGTON SUPREME AIRE HEAT PUMP ARRAY STORAGE TRADE-OFF.

Figure 4.6.6-B6. WASHINGTON SOLAR AIR HEATING WITH PARALLEL SUPREME AIR HEAT PUMP BACKUP, ARRAY STORAGE TRADE-OFF.

Figure 4.6.6-B7. CLEVELAND HEAT PUMP SYSTEM ARRAY STORAGE TRADE-OFF.

Figure 4.6.6-B8. CLEVELAND GAS HEATING ARRAY STORAGE TRADE-OFF.

Table 4.6.6-A

Optimized Array-Storage Combination

Baseline Systems

Location	Phoenix		Riverside		Washington		Cleveland	
Average Load	45.3 kWh/day		37.4 kWh/day		34.5 kWh/day		45.3 kWh/day	
Inverter Size	3.5 kW		3 kW		3.5 kW		4.5 kW	
<u>Solar Fraction</u>	<u>Array</u>	<u>Storage</u>	<u>Array</u>	<u>Storage</u>	<u>Array</u>	<u>Storage</u>	<u>Array</u>	<u>Storage</u>
.2	23.0 m ²	0.kWh	21.8	0.	16.0	6.5	31.	10.
.3	35.2	0.	26.3	6.2	27.4	10.0	51.	14.
.4	40.0	9.	32.2	12.2	36.4	16.5	67.	25.
.5	50.2	14.2	42.3	15.8	48.3	23.5	97.	39.
.6	60.5	22.0	50.2	22.0	62.3	34.0	151.	65.
.7	74.0	28.0	61.2	28.2	89.0	51.5	228.	106.

Alternate Systems

901-7	Location	Phoenix		Riverside		Washington		Cleveland	
	Average Load	14.8 kWh/day		12.7 kWh/day		24.4 kWh/day		14.8 kWh/day	
	Inverter Size	1.5 kW		1.25 kW		3.0 kW		1.75 kW	
	<u>Solar Fraction</u>	<u>Array</u>	<u>Storage</u>	<u>Array</u>	<u>Storage</u>	<u>Array</u>	<u>Storage</u>	<u>Array</u>	<u>Storage</u>
	.2	7. m ²	0.kWh	6.6	0	12.6	2.5	11.7	1.8
	.3	14.8	0	8.5	2.2	19.2	6.2	15.0	4.5
	.4	12.8	4.8	11.0	3.9	26.4	10.5	21.6	6.8
	.5	16.8	6.9	13.7	5.5	34.1	15.5	27.0	9.0
	.6	19.5	8.8	17.4	7.4	41.9	19.5	33.3	12.5
	.7	23.8	10.2	22.0	9.2	57.9	25.5	42.0	17.0
	.8	29.0	14.2	25.5	13.2				

From the description of the electrical space conditioning and appliance loads it is clear that the residential utility load, even without solar generation, is strongly dependent on the electrical equipment set of the house. With on-site solar power systems it is claimed that the pattern of utility demand would become even more dependent on weather, that the peak to average ratio would worsen, and that utility backup capacity would be required for the whole residential load. On the other hand, because solar energy is available during the day and during sunny summer days when the overall utility load is highest, it has also been claimed that solar energy can help level utility loads.

From our analysis it appears that with increased market penetration of residential photovoltaic power systems, a favorable impact on the load distribution of summer peaking utilities in areas of good insolation can be anticipated. In areas of variable insolation, however, backup would have to be provided for a large part of the load. Utility winter peaks would be increased to some extent, particularly if the winter heating load is to be met by electricity. Figure 4.7-A shows the number of days in the year for which the 6 AM to 12 midnight ("peak-time") utility load exceeds any fraction of the average "peak-time" load. The Riverside alternate system has the steadiest utility load, which is the most favorable pattern. The poorest utility load comes from the Cleveland base-line system, which requires very little utility power during half of the year, but a large amount on a few days. It should be noted, however, that the Cleveland heat pump load is extremely uneven to begin with.

The impact of solar generation on utilities is affected by the method of operation of the solar system. The pattern of utility displacement is more level when power generated on-site is not fed back into the utility lines but stored for use at night. A "smart" control strategy which kept the little electricity generated during cloudy days for the most crucial time and which also charged the battery off peak in anticipation of cloudy days would help to minimize the effect of weather on utility demand, except for

Figure 4.7-A. Number of Days per Year that any Relative Peak-Time Utility Load is Exceeded. Solar Fraction = 0.5

extreme winter peaking loads. If weather prediction is not used, backup for bad weather would entail extra storage capacity at the residential or utility level, extra generating capacity, or load reduction during cloudy days.

Two other measures which would have a small positive effect on the pattern of utility demand are using an array tilt angle which improves the LIR profile, and using more array and less storage to produce a given solar fraction. (See Figure 4.7-B.) A large array makes more energy available on days when the load is large relative to insolation. The three peaks in the lower part of Figure 4.7-B are due to appliance loads. Much of the daytime space conditioning load is met by solar energy as can be seen from the low average load from 11 a.m. to 4 p.m.

Figure 4.7-B Phoenix Heat Pump System
Solar Fraction = 0.5

4.8 SYSTEM ECONOMIC PERFORMANCE

In this section the economic performance and cost competitiveness of the residential photovoltaic systems as sized in Section 4.6 are presented.

4.8.1 System Cost Elements

The photovoltaic systems for their respective loads and locations were sized using array module costs of \$500/kW peak for fixed nonconcentrating modules. For these modules, the cost exclusive of cells was estimated to be \$67.96 per .914m x 2.43m (3' x 8') module, or \$30.48/m². We have assumed the use of round silicon cells with an efficiency (1 kW/m² insolation, 28°C cell temperature) of 15% and a packing factor of 0.74. The module therefore generates 111 watts/m² peak and costs \$55.50/m².

To satisfy the \$500/kW_p for the module the cells must cost \$25.02/m² of module area. This is equivalent to \$33.81/m² of cell area or \$225 per kilowatt of peak output. The cell costs are based upon satisfying the \$500/kW_p uninstalled module costs and are not based upon a cost projection for a specific cell manufacturing process. The cell costs do however, fall within the long range ERDA cost goals.

The cost projection for the module exclusive of cells is based on a specific design and manufacturing process, and the cost estimate was obtained with the assistance of a company with experience in the high-volume manufacture of similar items.

All other component costs are based on specific component designs and specifications and on price projections from manufacturers of these components, assuming high-volume manufacture. Installation costs are based on cost estimates from contractors experienced in similar work, and have been adjusted (with their help) to reflect cost reductions likely to be realized through experience.

Array costs are thus calculated at \$100/m², of which \$55/m² is for the module itself, and \$45/m² is for installation on the roof, including wiring. Batteries

are assumed to cost \$50/kWh and to need replacement every ten years. Using the spread of 3% between capital costs and the inflation rate, the present value of batteries and their replacement is \$114.9/kWh. A battery shed to hold the batteries and interface components is assumed to cost \$300 installed. Additional costs are \$200/kW for the inverter/interface and \$140 for its installation.

4.8.2 Economic Analysis

Two methods are used to determine the cost-competitiveness of residential photovoltaic systems depending on whether the system is to be owned and financed by an investor-owned utility company or the homeowner. Figures for the case of utility ownership are based on the methods and model calculations in JPL's study for ERDA/EPRI of the cost of solar electricity from utility owned systems. For the residential ownership case, the cost of the system is compared to the present value of electricity displaced.

A utility which finances a project through debt and equity must receive enough income from the resulting product stream (electrical output) to retire the financial obligations, to pay its taxes, and to pay overhead and maintenance expenses. The required revenue per unit of output can be found by multiplying the cost of the system per unit of output per year by a fixed charge ratio.

The fixed charge rate (FCR) is defined as the factor by which the initial value of the capital investment must be multiplied to obtain a uniform contribution of capital investment to the annual cost over the life of the system. This annual cost when included with a uniform annual contribution covering total life cycle maintenance and operating costs represents a total uniform or "Levelized Annual Cost" for the system life. This represents an annuity with a present value equal to the life cycle costs of the system.

This annualized cost divided by the average annual energy delivered establishes a "levelized energy cost" in \$/kWh or mills/kWh. This levelized energy cost represents a yearly energy cost that is constant. It is important to note however, that the real value, or purchasing power of this annual amount is not constant. Inflationary pressure results in a cost of energy the initial year that is far more expensive in real dollars than in the energy produced toward the end of life when using the FCR concept.

An alternate but equivalent approach is to establish an annuity whose annual cost is constant in terms of purchasing power and whose present value is also equal to the life cycle costs of the system. This approach is discussed in Appendix D of reference 16. A charge rate analogous to the FCR can be called a "Constant Value Charge Rate" which would increase each year of the system life.

For a cost of capital of 8%, a general escalation rate of 5% and a system lifetime of 30 years a FCR of a "typical" investor owned utility is approximately .1483. The first year charge rate of the alternate "Constant Value Charge Rate" is only .0836. We believe this latter constant value computation, although equivalent to the levelized charge, gives a truer picture of the cost of energy generation.

From a homeowner's standpoint the present value of his solar energy system is his purchase price plus the present value of maintenance and replacement costs over the life of the system. Now, the question is, what does he get back for his investment? The solar system displaces an average annual amount of utility power which he would otherwise have to pay for. This energy cost savings over the life of his system has a present value which at some utility rate would equal the present value of the system.

The energy cost savings to the homeowner will escalate over the life of the system at a rate probably higher than the general inflation rate. Upon estimating this escalation rate it is necessary to evaluate the present value of the stream of annual savings of increasing dollars. If we let g equal a constant rate of energy cost escalation per year and k the cost of money, we can establish the present value (X_{pv}) of the energy cost savings over the life of the system using the following equations:

$$X_{pv} = X_o \left(\frac{1+g}{k-g} \right) \left[1 - \left(\frac{1+g}{1+k} \right)^N \right] \quad \text{if } k \neq g$$

$$X_{pv} = X_o N$$

$$\text{if } k = g$$

where X_o represents the first year cost savings and N the life of the system in years. If $g = 5\%$ and $K = 8\%$, the present value is equal to 19.97 times the first year's cost savings. If the present value of the system is denoted as S a breakeven point for the homeowner is obtained when

$$S = 19.97 X_o$$

The first year's savings to break even must therefore equal

$$X_o = \frac{S}{19.97} = (.050) (S)$$

Or conversely, the actual first year's savings divided by the annual energy displacement equals the cost of energy delivered by the solar system.

It is noted that the .050 coefficient is analogous to a first year constant value charge rate.

4.8.3 System Evaluation

In evaluating the systems tabulated in Table 4.6.6-A the first year's cost of energy in \$/kWh is computed using the homeowner charge rate of .050 determined above. The energy costs computed can be interpreted as the break even first year utility rates or as the cost of the energy produced. Curves of these energy costs are plotted as a function of the fraction of utility power displaced in Figure 4.8.3-A based upon the following assumptions:

Component	Value
Array	\$100/m ² (installed)
Battery	\$115/kWh + 300 (includes installation and replacement)
Inverter/interface costs	\$200/kW + 140 installation
Lifetime	30 years
Cost of money	8%
Escalation rate of energy costs	5%
Inverter efficiency	.87
Cell efficiency	.15
Battery efficiency	.78
Variation from Max Power	.975
Cell packing factor	.74

Figure 4.8.3-A. Price of Solar Electricity Optimized Systems

The minimum price and minimum cost fraction differs according to the location and load. For particular loads the curves are quite flat, indicating that in most cases a range of solar fractions can be achieved at close to the minimum price of energy. Overall system efficiency of the minimum energy cost systems was about 7%.

Table 4.8.3-A contains economic cost and performance data for the eight photovoltaic systems which supply half of the electrical load (solar fraction = .5). The explanation of this table is given below:

Column 1) This column denotes the type system and location. The first letter denotes the location: R - Riverside; W - Washington, D.C.; P - Phoenix; and C - Cleveland. The second letter refers to either the base-line system (B) or the alternate system (A). The definition of these systems is given in Section 4.1.

Column 2) This column provides the total electrical load per year for the various systems.

Column 3) This column provides the nominal utility rates that a homeowner would pay for electrical energy in the respective locations. These rates⁽¹⁷⁾ correspond to those existing on January 1, 1974, about the time of the oil embargo.

Column 4) The present value of the stream of annual savings of the homeowner or conversely the loss of revenue by the utility is based upon an energy cost escalation rate of 5%, interest rate of 8%, and a system life of 30 years. From Section 4.8.2 the present value was found to be equal to 19.97 times the first year's energy cost savings. Hence the present value is computed as

$$\begin{aligned} \text{Present Value} = & 19.97 \times (\text{Total load kWh/yr}) \\ & \times (\text{Solar fraction}) \\ & \times (1^{\text{st}} \text{ yr utility rate \$/kWh}) \end{aligned}$$

Table 4.8.3-A

Economic Analysis of Photovoltaic Systems

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
Syst	Total kWh/yr	Util. Rate Mills/kWh	Pres. Val. Disp. Util. Energy	Array m ²	Stor kWh	Inv. kW	Syst. Cost	Competitive Utility Levelized	Cost-Energy Utility Initial	Mills/kWh Owner (8)(3)/(4)
PE	16537	25.9	\$4277	50.2	14.3	3.5	\$ 7803	140.0	78.9	47.3
PA	5393	25.9	1395	16.8	6.9	1.5	3213	176.7	99.6	59.7
RB	13635	22.3	3036	42.3	15.8	3.5	7185	156.3	88.1	52.8
RA	4652	24.1	1119	13.7	5.5	1.25	2692	171.6	96.7	58.0
WB	12598	23.7	2981	48.3	23.5	3.5	8670	204.1	115.1	68.9
WA	8896	23.7	2105	34.1	15.5	3.0	6231	207.8	117.1	70.2
CB	16522	17.8	2937	97.0	39.0	4.5	15521	278.6	157.1	94.1
CA	5396	17.0	916	27.0	9.0	1.75	4524	248.7	140.2	84.0

NOTES:

Cost of capital = 8% escalation rate = 5%

Levelized Fixed Charge Ratio = .1483 (used in Column 9)

Constant Value Charge Ratio (first year) = .0836 (used in Column 10)

Array = \$55/m² price + \$45/m² installation

Storage = \$50/kWh price + 50 (1.03⁻¹⁰ + 1.03⁻²⁰) replacement + \$300 installation

Inverter = \$200/kW + \$140 installation

System cost = 100 (5) + 114.9 (6) + 200 (7) + 140 + 300

Columns 5, 6, 7 and 8) These columns give the system array, storage and inverter sizes which lead to the total system costs where

$$\begin{aligned} \text{System cost} = & \left[\text{Array area m}^2 \right] \$100/\text{m}^2 \text{ (installed array costs)} \\ & + \left[\text{Storage kWh} \right] \$114.9/\text{kWh} + \$300 \text{ (installed battery costs including replacements)} \\ & + \left[\text{Inverter size kW} \right] \$200/\text{kW} + \$140 \text{ (installed inverter and interface costs)} \end{aligned}$$

Operation and maintenance costs have not been estimated and therefore are not included.

Columns 9, 10, 11) In these columns the competitive cost of energy (mills/kWh) are given for the three methods of computation reviewed in the previous section.

Column 9 is based on use of a levelized energy cost which will be of little interest to the homeowner. For this case the competitive cost of energy is computed by the following:

$$\text{Cost of Energy} = \frac{(\text{FCR}) (\text{System Cost})}{\text{Energy Savings (kWh/yr)}}$$

where

$$\text{FCR} = .1483$$

$$\text{System Cost} = \text{Column (8)}$$

$$\text{Energy Savings} = \text{Column (2)} \times .5$$

Column 10 gives the first year competitive energy costs computed by replacing the FCR with a constant value charge rate of .0836*. Again this competitive cost of energy in mills/kWh would have significance only for utility ownership of the system.

In column 11 the competitive cost of energy (1st year) that would result in a breakeven situation for the homeowner is given. This is computed as follows:

$$\text{Cost of Energy} = \text{Current Utility Rate} \frac{\text{System Cost}}{\text{Present value of displaced energy}}$$

$$\text{where: current utility rate} = \text{Column 3}$$

$$\text{present value of displaced energy} = \text{Column 4}$$

*The relationship between these two charge rates is given in Equation D-12 of Reference 16.

Columns 9 and 10 may be compared to the cost of alternate energy generation when computed using the same charge rates. For the homeowner who owns his own system, Column 11 may be compared to the present utility rates (Column 3). This is equivalent to comparing the present value of displaced utility energy in Column 4 to the System Cost in Column 8. The system costs include the discounted costs of two replacement batteries. (Battery lifetime is taken as ten years.) Comparison of system costs with present values show that it would cost a homeowner twice as much in Phoenix and Riverside, three times as much in Washington, D.C., or five times as much in Cleveland to own a photovoltaic system as to buy electricity from the utility.

Figures 4.8.3-B to 4.8.E present a detailed breakdown of the system costs given in Table 4.8.1 for the eight residential systems. These are compared to present value of the utility electricity displaced. The array cost without installation is comparable with the present value of utility electricity, but so is the sum of battery and inverter costs, or the cost of installation.

Since the "normal" inflation rate is expected by many to be approximately 5% per year over the long term the cost of utility power could be expected to escalate at a slightly higher rate. To evaluate this effect the present value of the energy displaced is calculated for the Phoenix baseline system for a range of escalation rates.

g Energy Escalation Rate %	k Cost of Money %	Present Value of Displaced Energy	System Cost
5	8	\$4277	\$7803
6	8	4872	7803
7	8	5528	7803
8	8	6425	7803
9	8	7434	7803

Figure 4.8.3-B. Phoenix Residential System Cost Comparison
Solar Fraction = 0.5

Figure 4.8.3-C. Riverside Residential System Cost Comparison
Solar Fraction = 0.5

Figure 4.8.3-D. Washington Residential System Cost Comparison
Solar Fraction = 0.5

Figure 4.8.3-E. Cleveland Residential System Cost Comparison
Solar Fraction = 0.5

From the above table it is seen that the impact of higher escalation rates of energy costs would make the economics of on-site residential photovoltaic systems more attractive than at present.

In summary, for the component cost assumptions made here, the cost of a photovoltaic system while small enough to be afforded by a homeowner, is more than the cost of buying electricity from the utility at today's utility rates. Utility companies which own on-site photovoltaic systems would have to get at least three times as much as they now do for electricity to cover their costs in constructing such systems. Should utility rates double (in addition to price escalation at the general inflation rate), photovoltaic systems will begin to look attractive economically. Potential benefits to the environment and in saving exhaustible resources as reviewed in Section 9 have to be weighed with these economic considerations.

4.9 CONCLUSIONS

The economic competitiveness of on-site photovoltaic power systems has been evaluated for systems in four geographical locations. Two systems were sized and evaluated for each of these sites. In performing this conceptual design study many observations have been made associated with house design; photovoltaic system design; and economic performance characteristics. The more salient observations and conclusions are presented below.

Residence Loads

1. The size and seasonal variability of residential electrical loads are extremely dependent on the space conditioning system selected, the thermal design, and the climate.
2. Residential electrical loads can be reduced by good thermal design and by the use of efficient space conditioning equipment.
3. Evaporative coolers provide an energy-efficient means of meeting the cooling load in hot, dry locations like Phoenix and Riverside. They entail only a small reduction in comfort if well maintained.

4. In comparison with conventionally designed houses, thermally well designed homes equipped with photovoltaic systems would not create major problems with the utility system load if they do not feed power into the grid.

Photovoltaic System Design

5. The use of tilt angles other than the latitude angle for fixed solar arrays, in order that monthly solar generation can better match the energy demand, was found to improve solar system performance by two percent at best. The load can be adjusted to the availability of solar energy by the choice of the system.
6. For nonconcentrating arrays it is not necessary to provide maximum power tracking devices, because proper matching of array output characteristics and battery voltage will limit maximum power losses to less than five percent.
7. The results of the space conditioning array-storage tradeoff studies depend on the various assumptions made for loads, component efficiencies and costs for residential systems. We observe the following:
 - a. For systems with storage, a ratio of approximately one square meter of array to .4 kWh of battery was observed for optimal systems. After correcting the battery figure for cycle depth and efficiency this gives 2.5 kilowatt-hours of battery output capacity per kilowatt of array (standard conditions). For systems with the above ratio of array to battery, battery output capacity would be 43% of average daily array output in Phoenix and Riverside, 53% of it in Washington and 70% of array output in Cleveland.
 - b. The overall system efficiency of use of solar energy was seven percent (10% for conversion and 70% for power conditioning, storage and utilization).

8. The problem of handling electrical loads when solar electricity is not available due to weather or for winter heating may be handled by a variety of methods at the utility or residential level and involves considerations separate from those of designing a solar electrical system for a particular load.

Economic

9. The cost per unit of solar energy provided is nearly constant for systems which provide from thirty to sixty percent of electrical demand (except for the one Cleveland system with a very large winter heating load).
10. Small systems without storage are attractive in Phoenix and Riverside.
11. The economics of intermediate size residential photovoltaic systems (fractions from .3 to .6) for a given location is only slightly affected by the type and size of the residential load, except for those with very large heating loads.
12. It is uneconomical to use on-site solar electrical systems to supply energy for large, unbalanced winter heating loads. Solar thermal systems, conventional fuels used on-site, or other methods should be used to meet these loads.
13. Assuming array costs of \$500/kW for photovoltaic modules, the cost of an on-site photovoltaic system which provides half the electricity used in a home is within the financial capability of most homeowners.
14. Under the economic assumptions used in this section, the cost of on-site photovoltaic electricity to a residential owner is 80 to 400 percent higher than that utility supplied electricity.
15. The cost of ownership of a residential photovoltaic system is about 66% percent more for a private utility than for the homeowner.

SECTION 4

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