PHOTOVOLTAIC SYSTEMS CONCEPT STUDY

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MASTER

Spectrolab, Inc.
Sylmar, California

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FINAL REPORT
PHOTOVOLTAIC SYSTEMS CONCEPT STUDY

VOLUME IV OF V

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- Central Power Station Design
- Central Power Station Operation and Economic Analysis
- Institutional Factors Study Results

PREPARED FOR

U.S. ENERGY RESEARCH AND DEVELOPMENT ADMINISTRATION

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SPECTROLAB, INC.

A Subsidiary of Hughes Aircraft Company
12500 Gladstone Avenue
Sylmar, California 91342

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VOLUME IV

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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

7.0 CENTRAL POWER STATION DESIGN

7.1 SUMMARY DESCRIPTION

The conceptual design for the photovoltaic central station power plant is described in this section. Two design options, onsite storage and no storage, are considered. Section 7.1.1 presents the criteria used as a basis for the designs. A brief description of the plant is given in Section 7.1.2 in order to put ensuing detailed discussions into perspective. The sizing of the plant and its systems is discussed in Section 7.1.3. The remainder of Section 7.0 discusses the plant components in detail. Plant operation and economics are described in Section 8.0.

7.1.1 Design Criteria

ERDA's RFP number AT(11-1)-P-75-0011 required that the plant "be capable of meeting a demand of 50-1000 MWe of high voltage power from a conventional utility transmission/distribution grid that is fed also by other types of generating plants. The system must therefore meet the voltage, frequency, phasing, and synchronization requirements of the grid interface. The appropriate capacity of the electric storage sub-system will depend on the mode of operation of the photovoltaic power plant (baseload, intermediate, or peaking)." Additionally, the location of the site was specified as being in the Phoenix, Arizona area.

The arrays of solar cells to be used in the central station plant designs are specified by Spectrolab and are treated as system components with fixed specifications. Array specifications for the design effort were as follows:

- The weight of each array is 15 tons.
- Each array is 56 x 28.3 feet in plan.
- Each array has an aperture area of 208.1 m^2 (56 x 40 feet).
- Array spacing is 108 feet centerline to centerline N-S and E-W.

- Arrays will rotate about the center vertical axis to track the sun in azimuth.
- The power output of each array is 26 kW for insolation of 1 kW/m^2 and an array temperature of 28°C .
- The temperature of the array is 67°C above the ambient air temperature for isolation of 1 kW/m^2 .
- Silicon solar cells are used, with 15% efficiency under standard test conditions.
- Solar cell efficiency under operating conditions is obtained by adjusting standard-condition efficiency for variations in cell illumination and temperature.
- Array efficiency under operating conditions is obtained by multiplying cell efficiency by optical transfer efficiency of the array design, including optical reflection and shadowing losses.
- Array power is delivered to an output terminal by a center grounded dc system and operates at ± 600 volts to ground, $\pm 10\%$.
- The maximum array voltage is ± 750 volts to ground.
- A fused disconnect switch is included as part of each array.

7.1.2 Design Features

The photovoltaic central station power plant is comprised of 10,000 solar cell arrays used to generate power, and the systems needed to support and interface these arrays with the electric utility network. For purposes of Bechtel's design effort, the arrays are considered as system components with fixed specifications. These specifications include dimensions of 56 by 28.3 feet and centerline-to-centerline spacings of 108 feet in plan. This results in a site area of approximately 4 square miles for the plant, which has a rating of 200 MW. A site layout for the total plant is presented in Figure 7.1.2-A.

Figure 7.1.2-A PLANT LAYOUT

The dc outputs of 100 adjacent arrays are brought to the input of a power conditioning module by underground wiring. Each power conditioning module, nominally rated at 2.0 MW, is comprised of an energy storage battery (optional), a converter, and a controller as shown by the functional block diagram presented in Figure 7.1.2-B. The battery system, comprised of lithium/sulfur cells, is used to store electrical energy to provide for plant operation during absences of insolation. The converter changes the dc output of the arrays and battery into a 60 Hertz ac waveform compatible with the utility network. The converter can also be operated as a controlled rectifier, thus enabling the plant to store off-peak energy from the utility grid. For the no-storage option, the batteries are eliminated and the arrays are connected to a slightly modified converter.

The filtered ac outputs from the 100 power conditioning modules are collected and brought to the plant switchyard by a 34 kV overhead distribution system. At the switchyard, the voltage is stepped up to 230 kV for connection to the utility network by four 34/230 kV transformers. A section of 230 kV transmission line is included to bring power to the site boundary.

All switchgear necessary for proper operation of the above system is included. The plant also includes instrumentation and control systems and auxiliary systems (such as array drive power, battery cooling, etc.).

7.1.3 Plant Sizing

The design criteria listed in Section 7.1.1 specify that the power of the plant must be between 50 and 1000 MW. The logic for selection of a 200 MW rated power level in conceptual design, and for the selection of plant component sizes, is discussed in this section.

Arrays

Array characteristics and specifications are given in Section 7.1.1. The conceptual design is based on an array module capable of producing a maximum

power of 26 kW. For reasons discussed in Section 8.2, this design is de-rated to 20 kW per module to provide the optimum economic match to the converter.

It is further specified that the arrays operate at ± 600 volts to ground, $\pm 10\%$. Thus, the nominal operating current is 16.7 amperes (20 kW/1200 V); the maximum operating current is 24 amperes (26 kW/1080 V). It is assumed that the short circuit current available from the arrays is approximately 10% more than the current at maximum power (as is characteristic of the silicon cells used in the arrays) or about 26.5 amperes. Since fuse coordination to such precision is difficult and cells are not damaged by operating into a short circuit, wiring is sized on the basis of 26.5 amperes per array. Insulation is designed to accommodate the specified maximum voltage of ± 750 volts to ground.

Energy Storage

Transient cloud cover or gusts of wind that change the temperature of the arrays produce rapid and unpredictable variations in array power and add to the existing fluctuations in load power, typical of utility grids. If solar power represents even a moderate fraction of the utility system's generating mix, such added variations may be undesirable from the point of view of the utility system dispatcher. Therefore, sufficient energy storage is included as an option to permit leveling of such variations. Unlimited energy storage capacity would be desirable from an operational point of view, permitting the station to supply power when needed, even at night. However, the cost of a battery system precludes the installation of large amounts of storage. The cost of storing energy to permit full power operation of the plant during several consecutive days of low insolation is prohibitive.

Cloud cover in the Phoenix area in December results in a mean amount of possible sunshine of 76 percent, i.e., 8 out of 10.5 hours, (Ref. 2). Thus, to avoid shutting down the plant during periods of cloud cover or operating the plant at reduced output, a minimum storage capacity of 2.5 hours should be installed. However, insolation outages longer than 2.5 hours will occur, and

the storage system may be utilized to provide a portion of the energy to the grid during waning hours of sunshine. Off-peak energy from the utility may be used to supplement the solar energy.

Consideration of these factors, in conjunction with other factors such as available solar energy, the characteristics of utility daily load demand curves and the cost of storing energy in batteries (both in terms of invested capital and energy lost to battery efficiency), led to selecting a nominal 3-hour energy storage capacity.

Study efforts by Spectrolab have indicated that energy storage need not necessarily be physically located at the photovoltaic central plant site. Thus, no-storage (onsite) design option is also considered and costed.

Power Conditioning Modules

In the preliminary version of the conceptual design (Ref. 1), a dc power regulator was used to operate the arrays at the voltages and currents corresponding to the maximum power point for all temperatures and insolation levels. Calculations by Spectrolab indicated that the cost of the system was not justified by the amount of increase in energy output. Therefore, the dc regulator is not included in the final conceptual design, and the battery is floated on array/converter dc bus.

The number of power conditioning modules that could be used ranges from one per plant to one per array. One 200 MW power conditioning module for the entire plant would require that all arrays be connected together, likely in parallel, to avoid insulating arrays for impractical voltage levels. With this approach, the currents involved could not be handled by a single converter. Also, the power wiring cost would be relatively high. At the other extreme, each array could have an individual power conditioning module. Work conducted in preparation for the conceptual design showed that the cost of converter equipment in terms of \$/kW increases with decreasing power level (see Figure 3.2.3.2-E). Thus, individual power conditioning modules on each array would also lead to high costs.

The size of the power conditioning modules was determined by considering the sizes of converter equipment, battery and wire and the costs for both the dc and ac distribution systems. Converter equipment proposed for applications similar to this has been comprised of modules in the 1 to 2 MW range.

Generally, the lowest cost for transmitting power is achieved at low current and high voltage. The interaction of these and other factors led to the selection of 2.0 MW as the peak module power (100 modules for the 200 MW peak plant). The power rating of the converter is not completely straightforward, since maximum voltage and current in these devices do not occur simultaneously. This point is discussed further in Section 7.3.2. Each module is fed by 100 solar arrays connected in parallel. Each module's battery is capable of delivering 2 MW for 3 hours and is comprised of cells being proposed and developed for use in electric utility load leveling applications. Plant operation on battery power is discussed in detail in Section 8.0. A voltage of 34 kV was selected for the ac distribution bus. Further details on the voltages, currents, switchgear and wiring are discussed in Sections 7.3 and 7.4.

7.1.4 Total Plant Concept

For purposes of conceptualizing the photovoltaic central station power plant, a plant rating of 200 MW was selected. This is within the range of power specified, and a plant of this power level encompasses all elements of design that would be used for any size plant within the specified power level range.

The design of the 34 kV distribution bus and switchyard is such that any quadrant of the plant is capable of being operated independently. Thus, the 200 MW plant is essentially four 50 MW plants. This design approach offers several advantages:

- For a majority of scheduled maintenance, the entire plant need not be shut down.

- The nature of power conditioning modules and plant design are such that testing and turnup of portions of the plant may proceed before all of the construction is completed and may thereby improve cash flow during construction.
- Repetitive physical and electrical details tend to reduce engineering and construction costs. Also maintenance material and staff may be reduced.
- The power level for the proposed plant could be changed, up or down, without major impact on the basic design.
- Existing plans could be expanded to meet increasing load demand in small increments, thus minimizing capital expenditure for excess capacity.
- The basic performance of the entire proposed plant could be tested in a small pilot plant, using one of the 2.0 MW power conditioning modules and the associated arrays. A unit of this size may also find application in a distributed system of substations.

The selection of a 200 MW rating in conjunction with array and packing density specifications set the site requirement at approximately 4 square miles. The layout shown in Figure 7.1.2-A was used for purposes of the conceptual design effort. The layout of an actual plant would conform to the topography of a specific site, and need not have a square layout in plan. The array packing factor (array area divided by land area) is .19, resulting in shadowing losses of approximately 5%. Shadowing losses occur near sunrise and sunset.

7.2 ARRAY DESCRIPTION

7.2.1 General Characteristics

The conceptual design of the solar cell arrays, to include concentrating optics, in general is as follows: Each array has an aperture of 208.1 square meters (2240 square feet), with dimensions of 56 feet by 40 feet, and is 56 by 28.3 feet in plan. Front and rear views are shown in Figures 7.2.1-A and 7.2.1-B.

Figure 7.2.1-A. Model of 208 m^2 array showing fourteen concentrator modules and turntable track.

Figure 7.2.1-B. Rear view of array model showing support structure and central pivot.

The power output of each array is 26 kW with insolation of 1 kW/m^2 and a cell temperature of 28°C . Array power is delivered to a fused disconnect of a center grounded DC system and operates at ± 600 volts to ground, $\pm 10\%$, with a maximum array voltage of ± 750 volts to ground. With average wind conditions in the Phoenix area, approximately 2 m/s, the temperature of the cells will be approximately 67°C above ambient air temperature with 1 kW/m^2 insolation.

The concentrating optics will be a two-element design with a geometrical concentration of 20, and the system will be passively cooled for simplicity and reliability.

7.2.2 Optical Design and Features

The optical configuration to be used is a two-element, on-axis reflective type, utilizing a parabolic trough primary reflector in conjunction with a compound elliptical secondary concentrator which also incorporates cells, cell substrate, and heat sink assembly. The system will employ a geometric concentration ratio of 20, and will be passively cooled. Passive cooling generally decreases system complexity and increases overall reliability, eliminating the need for either forced air or circulated water cooling, and the attendant complexity and reliability problems associated with them.

The optical geometry of the two element optical system is shown in Figure 7.2.2-A. Details of the optical design are given in (6) and (7). The main reason for this optical configuration are relatively high concentration levels, plus the added advantage of a field of view significantly greater than that obtainable with a single-element system. Additionally, the compound elliptical secondary optics serves to produce a highly uniform intensity distribution across the width of the absorber (cells) which leads to significant improvements in overall cell efficiency. A view looking straight into the secondary concentrator unit is given in Figure 7.2.2-B. The field of view with a concentration of 20 is approximately 4° , which allows for mechanical tolerances in assembly and fabrication, tracking inaccuracies, and structural deflection under wind loads.

Figure 7.2.2 A. Optical Geometry of System, Showing Parabolic Trough in Conjunction with Compound Elliptical Concentrator.

Figure 7.2.2-B. Photo of model of secondary compound elliptical concentrator unit showing mirrored side surfaces, solar cells, and cooling fins.

The primary mirrors will have an aperture width of 4 feet and length of 40 feet, and will have a rim half-angle of 35° . They will be fabricated of 13 gauge cold rolled sheet steel, to which a reflective plastic tape, or perhaps silvered microsheet glass will be laminated. The primary mirrors will be anchored along their edges exclusively, with no lateral support ribs. This approach is taken to eliminate the problems of ripples in the mirror caused by lateral ribs. Such ripples create severe optical distortion, and cause areas of reduced illumination on individual cells in a series connected string. This will current limit the entire string, significantly reducing system output. A detailed view of the mirror edge support and mounting method is shown in Figure 7.2.2-C. The steel trough sections are attached to the steel joists using self-tapping metal screws, since the chord members of the steel joists are thin enough to permit their use. These screws are located using pre-punched holes in the edges of the sheet steel, which also serve to positively locate the reflector and insure proper alignment and rigid attachment along the edges.

The troughs are supported by steel joists, selected as the least expensive method of support available. The joists are supported by rectangular steel tubes, as are the secondary concentrator units.

The secondary optical element is a compound elliptical concentrator, which serves to further concentrate the light gathered by the primary mirror, to provide a highly uniform intensity distribution across the cells, and to provide an optical system with a relatively wide field of view. The reflecting surfaces will be formed as part of an aluminum extrusion on which the cells are mounted, and will be covered with either a reflective plastic tape or silvered microsheet glass. The extrusion also acts as a substrate for mounting the cells, and as a heat sink for dissipation of waste heat to the surroundings.

The secondary collector has an aperture of 4.8 inches, an absorber width of 2.4 inches (6 cm.), for a secondary concentration ratio of 2. The secondary unit is located with its aperture 3.44 feet from the chord drawn between the two rims of the 4 foot wide primary mirror.

Figure 7.2.2 C. Cutaway view showing method of attaching primary mirror edges to support structure.

All fourteen of the optical concentrating units are mounted on the same plane, and are tilted at a fixed angle of 45° to the horizontal, which is done to optimize energy collection in winter and give a more uniform yearly distribution of energy production.

7.2.3 Array Electrical Design and Performance Characteristics

Each array will produce a maximum power of 26 kW with an insolation of 1 kW/m^2 and a cell temperature of 28°C . The arrays will operate in a center-ground configuration, with voltages of ± 600 volts $\pm 10\%$. Open circuit array voltage will be ± 750 volts maximum.

The output current of each array is 16.7 amps (20 kW/1200 V), with a maximum operating current of 24 amps (26 kW/1080 V). The maximum short circuit current from each array will be 26.5 amps. To achieve the required operating voltages, double series strings of 1200 series connected cells will be required, with four of these series strings connected in parallel. System insulation is designed to accommodate the maximum open circuit voltage of ± 750 volts to ground. Nominal 15% efficient cells will be used in the arrays, and when operating under concentration, their efficiency can be expected to increase to 17% as demonstrated by experimental work recently performed at Spectrolab (8). The cell operating voltage decreases by $0.002 \text{ volts}/^{\circ}\text{C}$ as temperature increases, and the maximum operating temperature anticipated will be 67°C above ambient with a 1 m/sec wind and a system thermal conductivity coefficient of $0.3 \text{ kW/m}^2\text{-}^{\circ}\text{C}$. This figure can be obtained with interrupted aluminum fins and a thick anodized layer of aluminum oxide on the extruded absorber-substrate outer surface.

For the conceptual system design, the ± 600 volt center ground system was chosen, but by no means should be considered the optimum system voltage. There are a great many factors which influence the final choice of operating voltage, which include, but are not limited to: electrical insulation

reliability versus thermal conductivity; expense of matching very long series strings of cells; efficiency losses in long cell strings; optimizing system wiring to obtain maximum energy collection, and minimize losses due to adjacent array shading; costs of inverters as a function of operating voltage, and efficiency of converters as a function of voltage; system reliability with a larger number of parallel connected strings.

Each of the above factors has come bearing on each of the others, and careful tradeoff study would have to be undertaken during the detailed design of such a system to optimize the performance-cost characteristics with current state-of-the-art inputs going into the decision making process. Since the fine details of the projected system are not yet known, these factors must be held in abeyance until such a time as a system design is undertaken.

7.2.4 Array Mechanical Design and Drive System

The array mechanical support structure, as shown in Figure 7.2.4-A, consists of a top rectangular steel tube of 12 x 8 x 3/8 inch, with the 12 inch dimension vertical; the bottom tube is 10 x 6 x 3/8 inch, with the 10-inch dimension horizontal. Support for the top tube consists of four 6-inch schedule 40 pipes arranged as a "W". The trusses supporting the primary mirrors are attached to the top and bottom rectangular tubes, and the whole assembly is supported by four wheels rotating on a circular railroad-type track. Figure 7.2.4-B shows how the center pivot could be constructed, and Figure 7.2.4-C shows the center foundation design.

The turntable will be rotated by a fractional horsepower gearmotor located at one wheel. The motor will be a three-phase, three-wire delta-connected type, suitable for reversing duty and suited for exposed outdoor service conditions. The three phase motor system was selected to minimize maintenance costs as compared to single-phase capacitor and centrifugal switch-type motors.

The motor will be supplied with 480 volts AC, which will originate in the power conditioning module associated with that array which includes 34 kV/480

ELEVATIONS OF SUPPORT STRUCTURE
FOR PHOTOVOLTAIC ARRAY

Figure 7.2.4 A

Figure 7.2.4 B. Turntable center bearing detail.

Figure 7.2.4 C.
Turntable Center Foundation

volt stepdown transformer. All motors will be reversed simultaneously with a simple reversing contactor.

During normal operation, the primary source of avoidable rotation resistance envisioned for the turntable will be side slipping of the four wheels caused by minor misalignments during their installation and aging. Therefore it is felt that the connections at these wheels should be adjustable over a small range to permit field fine-tuning of the orientation of the wheel axes at the time of installation, and at whatever intervals deemed necessary.

7.3 POWER CONDITIONING MODULES

As indicated in Figure 7.3-A each power conditioning module consists of a battery, a converter and a controller plus needed auxiliaries, such as wiring and cooling. These components are described below.

7.3.1 Battery

A previous study by Bechtel (Ref. 3) concluded that batteries would be best suited to serve as the onsite energy storage element in a photovoltaic central station power plant. Since batteries (or any energy storage system for that matter) are less than 100-percent efficient, efforts to maximize the conversion of available solar energy to electric energy delivered to the utility should include minimizing the processing of energy. Therefore, as much of the available energy as practical should be delivered directly to the utility grid without going through a storage step. The cost of a battery system is proportional to the number of hours of installed storage capacity and thus provides further incentive to minimize storage. From the standpoint of photovoltaic plant capital cost alone, zero storage would be desirable. However, operation of this plant as part of a utility system may require that at least a minimal amount of storage should be used to prevent forced outages or large variations in plant output due to transient cloud cover. The importance of this factor increases in proportion to the number of solar power plants in a utility system's generating mix. Consideration of such

factors, in conjunction with available data on utility daily load curve and atmospheric conditions, led to setting the amount of storage time at a nominal 3 hours for this conceptual design.

Simply multiplying the desired storage time by the rated power can lead to a low estimate of the required battery capacity. Characteristically, batteries fail through a gradual degradation to a point where their capacity is diminished below a useful level. This decreasing capacity may accelerate as a battery approaches the end of its useful life. For the large number of cells comprising the type of battery required for this application, the end of life will have a statistical distribution in time, governed to some extent by manufacturing tolerances. Also, as with any mass produced item, there will be a small percentage of sudden failures before the normal projected end of life, thereby contributing to plant maintenance requirements. At present, the end of life for a lead-acid battery in cycling-type applications is defined as occurring when the battery's capacity reaches 80 percent of its initial capacity. For the moment, it is projected that this same definition will also apply to advanced battery systems (e.g., Li/S, Na/S). Therefore, to have a given amount of capacity throughout the useful life of the battery, the initially installed capacity must be 25 percent above the desired end-of-life capacity. In order to have a 3-hour storage capacity in the photovoltaic power plant for the entire life of the battery, 3.75 hours of initial battery storage capacity must be installed. Thus, each module contains a 7.5 MWh battery (at the 3-hour rate).

Any one of several battery types could meet the requirements of the solar power plant. Since this plant will be constructed at some time in the future, an advanced battery design was selected for purposes of this conceptual design effort. In general, the performance characteristics of such cells are projected to exceed those of currently available lead-acid cells and do so at a lower cost. Although the higher energy densities of advanced battery types are most important for electric vehicle applications, this characteristic is also important for a solar power plant, since it will reduce the amount (and cost) of building required to house the battery. The lithium/sulfur cell

being developed at Argonne National Laboratory (ANL) was selected as being representative of advanced battery designs. The level of effort at ANL has resulted in data that facilitated the conceptualization of a system for the photovoltaic plant. It is also likely that commercial versions of the cell will be available in time for use in solar power plants.

General battery and auxiliary systems design calculations were based on data generated by ANL for the Battery Energy Storage Test (BEST) facility and for load leveling application. The BEST program, under joint government/utility sponsorship, will comparatively test advanced battery systems under conditions representative of electric utility load leveling applications (Ref. 4). Cell voltage and current characteristics were based on data for a prototypical cell, R-7. Current designs for load leveling cells utilize an FeS positive, as opposed to FeS_2 which is being considered for electric vehicle applications. The negatives are Li-Al. A brief description of the electrochemistry and cell construction was presented in a previous Bechtel report (Ref. 3). Cell R-7 (and production versions) has a prismatic configuration instead of the cylindrical shape used for earlier engineering test cells. This permits higher packing density.

In a preliminary conceptual design (Ref. 1), a regulator, acting as a variable-ratio dc transformer, was used to track the arrays' maximum power point and assist in controlling power flow between the arrays, battery and converter. Consideration of array efficiency versus voltage and regulator cost led Spectrolab to eliminate the regulator and specify a design wherein the battery is floated across the array/converter dc bus (see Figure 7.3-A) as is currently done for lower power applications using solar arrays.

Figure 7.3-A POWER CONDITIONING MODULE
FUNCTIONAL BLOCK DIAGRAM

Test data for cell R-7 are illustrated in Figure 7.3.1-A, which shows voltages and currents during charge and discharge. The indicated open circuit voltage is 1.55 volts per cell. This voltage is divided into the array operating voltage of 1200 volts. Thus, the number of cells in the battery string should be 774. This value is changed to 780 to facilitate the packaging of cells into an integer number of submodules, as discussed below.

Future detailed design efforts would also take into account voltage drops in the dc wiring system between the arrays and converter; a small voltage drop on the bus between the converter and battery; voltage drops along the cell connectors; and the cutoff voltage set for production cells, plus some margin for error. ANL is currently working on an electronic system to preclude over-voltages on the cells. Detailed consideration of this system is beyond the scope of the present effort, although its proper operation is relied on to prevent damage in the event that the maximum array voltage appears across a fully charged battery when no power is being drawn by the converter.

The desired battery capacity (i.e., 7.5 MWh) must be obtained by paralleling cells. ANL has considered packaging paralleled cells into submodules as shown by Figure 7.3.1-B. In these submodules, cells are assembled in a manner that resembles the configuration of the plates in conventional lead-acid cells; although in this instance, the cells are separate and do not share a common electrolyte. Submodules with 6 to 24 cells have been considered. For the 10-hour discharge initially proposed for load leveling, each cell has a capacity of approximately 920 Wh to a discharge cutoff voltage of 1.0 volt per cell. At a C/3 rate, this capacity will decrease. Based on extrapolation of the data in Figure 7.3.1-A, a capacity of 675 Wh per cell at the 3-hour rate is assumed for purposes of this conceptual design.

Recent responses from the electric utility industry indicate that energy storage times for load leveling should be on the order of 3 to 5 hours. Future cell designs will likely take this into account, and the assumed value for capacity may be pessimistic. Detailed design would include consultation with manufacturers in an effort to optimize a cell design for the regime in a

Figure 7.3.1-A CHARGE/DISCHARGE CHARACTERISTICS OF PROTOTYPE CELL

Figure 7.3.1-B. ANL L1/S SIX-CELL SUBMODULE CONFIGURATION

solar power plant. A single series string of cells is used for each battery in order to mitigate any potential current sharing problem during charge. For the desired battery capacity of 7.5 MWh and 780 submodules connected in series, each submodule should have a capacity of 9.61 kWh and thus be comprised of 14 parallel cells. In the above calculations, numbers were rounded off to result in an integer number of cells. The 7.5 MWh (initially installed) capacity is for discharge at a 3-hour rate, when the battery is supplying the total power to the inverter. For operation where the battery and solar arrays both supply power to the inverter, the battery discharge current is less, and there is a corresponding increase in energy available from the battery.

Extrapolation of the depth dimension for the 6-cell submodule shown in Figure 7.3.1-B indicates that a "14-pack" submodule would be 14 inches tall, 12.5 inches wide, 14.5 inches thick and weigh approximately 200 pounds. Five submodules are stacked to form a module nominally 70 inches tall, 12.5 inches wide, 14.5 inches thick and weighing approximately 1000 pounds. The 156 modules (780/5) are arranged in a 6 by 26 array in an insulated container. The 8- by 35-foot structure is in turn contained within a 12- by 50-foot battery building, as shown in Figure 7.3.1-C. This building is steel frame, prefabricated construction with clad-steel siding and roof panels. The floor is a 6-inch thick reinforced concrete slab. The location of this building with respect to the arrays and converter is shown by Figure 7.3.1-D.

Connection of the battery to the regulator/inverter bus is made through a fused disconnect switch. Future detail design will include evaluations of the likelihood and expected frequency of inverter commutation failures and the possible need to replace the fused switch with a circuit breaker. To minimize the length of unprotected bus, this switch is mounted directly on the battery containment structure. A cooled section of bus is used to prevent heating of the switch by heat from the cell connectors within the battery.

The container provides the air duct system to maintain the cells at an operating temperature of 450°C. The container is insulated to reduce heat loss from the battery modules and to maintain a safe exterior surface temperature

Figure 7.3.1-C BATTERY BUILDING

Figure 7.3.1-D POWER CONDITIONING MODULE LAYOUT

of 32°C. Air is recirculated at approximately 375°C, with outside air mixed in to maintain the correct operating temperature. An insulated exhaust duct removes waste heat and discharges the high temperature air at some 20 feet above grade to preclude contact by facility personnel. As far as possible, the cooling is reduced and then stopped toward the end of the operating day, and the battery temperature is allowed to reach its safe maximum. The battery then cools slowly during the standby period and does not require heater power to maintain the cell temperature within the operating range. Electric heaters with a power of 100 kW are required to bring the battery to temperature in 3.5 days during startup operations. During startup (or when needed) the energy to heat the battery is derived from solar energy, from utility energy controlled through the converter operated as a phase-controlled rectifier or from the battery itself. Control system design prevents operation of the battery if it is not at temperature.

Battery modules are inserted and removed from the structure by means of a hand operated winch on a movable platform, as shown in Figure 7.3.1-C. Removable blocks of insulation allow access to the modules. Personnel working with cells at temperature would wear protective clothing. A 12-foot work area is provided in each 12- by 50-foot building to facilitate handling of the modules. This area also contains the cooling air fan, its motor controller, ductwork, dc bus and fused disconnect switch.

Determining the cost of the batteries is not entirely straightforward unless a manufacturer's quote has been obtained for a battery system design to perform specifically described functions. Cost goals for battery systems intended for load leveling service similar to what is required in a photovoltaic power plant have been given in terms of dollars per kWh by most advanced battery developers. However, this is usually for the energy capacity (kWh) at a 10-hour rate. The energy capacity at the 10-hour rate for the 10,920-cell (14 cells/submodule x 780 submodules) battery system in each power conditioning module described above is 10 MWh. A recent cost estimate by ANL indicates that the purchase price is approximately \$27 per kWh (10-hour

rate) in terms of late 1975 dollars. Thus, the cost of batteries for the total plant is \$27.1 million. The costs of shipping installation and auxiliary systems (e.g., cooling, housing etc.) must be added to the above cost figure.

The life goal for these cells is 1500 to 2500 deep discharge cycles. As details of plant operation become better defined in advancing from the present conceptual design and as the battery technology matures, battery developers should be consulted on the possibility and economics of extending cell life by not completely discharging the cells. For the moment, the higher life value of 2500 cycles is assumed. Thus, assuming battery operation on a 5-day-per-week basis for 50 weeks per year (leveling power variations caused by transient cloud cover, extending plant operating time or operation as a utility energy storage system), the batteries would be replaced every 10 years. The salvage value of the cells is relatively high. About 90 percent of the lithium is recoverable. Most of the electrolyte and some cell case material are also recoverable. The salvage value of the batteries is estimated to be \$5 per kWh or about \$5 million in terms of late 1975 dollars and current prices for the materials involved. This salvage value is used to offset labor costs of battery replacement.

Aside from the aforementioned replacement at the end of life and the occasional replacement of a failed cell, the battery systems are expected to be essentially maintenance free. A small amount of maintenance on the air cooling system fans and filters will be required. Onsite battery repair will be limited to replacement of defective submodules. Failed units will be returned to a manufacturing facility or disposed of as salvage.

Potential fire hazards due to the high temperature lithium (alloy) and other cell constituents are minimal, since these materials are contained within an iron cell casing that is further contained in submodules and the insulated containers. Also, the battery buildings are devoid of combustible materials. However, each battery house has a portable fire extinguisher charged with an oxygen barrier agent such as Met-L-X. The insulation on the structure

containing the cells and on the auxiliary air ducts of the cooling systems serves to keep these surfaces safe to the touch of facility personnel. Procedures will be established to protect personnel who handle cells at temperature during repair operations. As with any electrical system, only qualified personnel would be allowed access to areas containing the electrical circuits. At room temperature, the cells are electrically inert.

7.3.2 Converter

The converter equipment interfaces the dc solar array and battery systems with the 34 kV ac distribution system and, thereby, with the utility network. In addition to providing the proper waveshape, the converter matches voltage levels and strongly contributes to the plant's capacity to respond to utility stimuli. As discussed herein, the term converter is taken to mean a bidirectional inverter/rectifier system. Obviously, for the nostorage design option, only an inverter function would be needed.

Several types of converter systems were considered during the course of the conceptual design and preparatory study (Ref. 3).

One approach is to have no converter at the plant and to transmit the solar energy by a high voltage dc line with the converter located at the load center. However, insulating the arrays and batteries to the voltage levels required for direct transmission on a HVDC line would not be practical. Therefore, only in-plant converter systems were considered, with connection to the 230 kV ac transmission lines existing in the Phoenix area made through transformers.

Similarly, Bechtel's previous study effort led to the conclusion that many types of converter circuits currently in use at lower power levels are not practical for this application. Further, for reasons of efficiency, switching-type inverter circuits with SCRs as the switching elements, should be used. The study also showed that the cost of this type of equipment, in terms of dollars per kW, decreased with increasing power levels. However, at

high power levels (5 MW or more), most inverter equipment manufacturers combine the outputs of several lower power modules in order to achieve the desired rating. Combining the dc outputs of the solar arrays at ± 600 volts and busing the power to a central inverter would lead to high wiring costs and high I^2R losses. Since converters for the desired power level are modular in nature, it was decided that these modules should logically be located near the source and that power should be transmitted through the plant at a high voltage and low current. This factor is relatively important in reducing the wire costs for a plant as dispersed as the central station.

Both line and self-commutated converters were evaluated, and, as discussed in an earlier Bechtel report (Ref. 3), both types of circuits have advantages and disadvantages. With present day converter technology, most manufacturers believe self-commutated inverters to be slightly more costly due to a higher component content. If forced to have comparable performance characteristics (e.g., black start capability), the cost of a line-commutated inverter may exceed that of its self-commutated equivalent. For the present application, it is doubtful that the extra cost of a black start capability would be justified. Thus, the lower cost line-commutated circuit is favored. It is also favored in terms of operating cost because of a slightly higher efficiency, perhaps 95 percent versus 90 percent (Ref. 5). Line-commutated converters also have better efficiency at part load, but this is not of prime importance in the plant design. Consideration of these factors led to the selection of a line-commutated system. Future technological developments within the next decade could alter that selection.

A simplified schematic of a converter design is presented in Figure 7.3.2-A to illustrate the type of system considered for purposes of this conceptual design. Many variations and other types of converter circuits are available. Each power conditioning module has a converter system, which allows the module to operate either singly or in parallel. Since a line-commutator inverter is used, the inverter must be connected to a stiff ac bus for proper operation. A second set of SCRs has been added to the inverter to enable

charging of the battery with off-peak energy from the utility network. This energy is then used to supplement available solar energy or, in instances when there is a predictable, long-term insolation outage, allow the existing equipment to be operated as a load leveling energy storage plant.

As can be seen, the converter is principally composed of two parallel bridges feeding a common transformer. The two dc chokes provide smoothing and limit the rate of rise of current during a commutation failure. The high-speed static interrupters divert current flow during a commutation and supply reverse bias until a blocking condition is reestablished in the SCR bridges. The inverter bridges are shown as a simple Graetz-bridge configuration of SCRs. Actually, each SCR switch is comprised of SCRs in series to attain the need voltage rating with the use of commercially available SCRs. A voltage grading network and fuses are also included. A second set of SCRs form a phase-controlled rectifier bridge, which is used to charge the battery. Use of a second bridge, with the SCRs connected as shown, eliminates the need for polarity reversing switches, necessary if the line-commutated inverter firing angle were set to operate in a rectifier quadrant. The outputs of both inverter bridges are combined in a common transformer. Combining the outputs of the two 6-pulse inverter bridges with the wye-delta transformer windings results in a 12-pulse output, with the corresponding reduction in harmonic content. The SCR firing angles are appropriately phased. The harmonic content of the resulting output is brought to utility standards by the harmonic filters. Series filters for the 11th and 13th harmonics remove the majority of the remaining harmonic power, and a broad band filter traps higher frequency components to produce an acceptable waveshape. Although the filters contribute some reactive power, power factor capacitors are added to maintain the converter's minimum power factor above 0.9.

The converter control, instrumentation, SCR firing pulse generating system etc. are not shown in Figure 7.3.2-A, but are of course included as a part of the converter. In particular, ac voltage, current and phase angle transducers on the inverter output, in conjunction with the inverter's control logic,

serve to maintain the power output at the level set by the power conditioning module's controller over the range of dc input voltages. Similarly, a tie between converter and controller logic serves to coordinate bringing the inverter on line by increasing the inverter output voltage and synchronizing with the line before changing the output phase angle to deliver power to the utility.

The physical location of the converter is shown in Figure 7.3.1.D. The inverter bridges, dc inductors, dc disconnects and instrumentation (as well as the controller) are contained in a 10- by 27-foot enclosure. The power transformer, filters and power factor correction equipment are located in a small adjacent switchyard area. The weather-proof modules are factory assembled, shipped to the site and hoisted onto foundations. Standard construction techniques are used to mount the transformer, filters etc. and connect them to the module and associated power wiring. The modules contain an air cooling system. Exterior access is provided to enable disconnecting the 34 kV circuit and dc bus circuits. The battery bus can be disconnected and locked out in the adjacent battery house. A man-door permits interior access and enables maintenance or repair of smaller pieces of equipment. In the event of the failure of a large equipment item, access can be gained by unbolting wall panels of the weather-proof module. Normal maintenance is expected to be limited to replacement of filters on the air cooling system. Assigning a nameplate power rating to the converter is not entirely straightforward. As discussed previously (see Section 7.3.1), the battery delivers up to 2 MW at the end of discharge voltage of 780 volts. Thus, the maximum battery current is 2564 amperes ($2 \text{ MW}/780 \text{ V}$). When operating from the arrays, the nominal converter current is 1667 amperes at a voltage of 1200 volts (2.0 MW). Several ways of rating such converter equipment currently prevail in the converter industry to serve utility applications in this power range. Rather than assigning a fixed rating to the converter, it is stated that the equipment is capable of performing the functions described above; that is, accommodating the battery discharge of 2 MW at its end-of-discharge voltage or the 2.0 MW from the array at its nominal operating voltage range. The

converter is also capable of operating as a rectifier to permit charging the battery with energy from the utility grid.

The estimate of converter price has been reduced considerably from the value used in the preliminary conceptual design report. The majority of this change comes about from the use of mature production prices (as is done for the batteries) and not for units built today. Prices are in terms of January 1976 dollars. In arriving at these costs, information for similar equipment from several manufacturers was utilized. Costs, in terms of \$/kW, were analyzed and put on a common power basis. Prices were scaled upward to reflect a generally lower operating voltage limit and a wider operating voltage range. An equipment purchase price of \$13.4 million was arrived at for converter equipment to perform the desired functions and represents an average of the lower cost estimates for several designs. The cost of shipping and installation must of course be added to that figure.

For the no-storage design option, only an inverter function is needed. More importantly, the operating voltage range is less. Also, the fault protection is simpler. Again, equipment designs and comments from several manufacturers were used to obtain the inverter equipment purchase price of \$12.6 million. Estimates of shipping and installation cost are added to this figure to obtain the cost presented in Section 7.8.

7.3.3 Controllers

The power conditioning module controller consists of a microcomputer and associated sensor and input and output equipment. The major functions of the controller include:

- General control of the power conditioning module through internal programming and control room signals to operate as outlined in Section 8.0.
- Control of the position of the arrays.
- Processing and multiplexing of data for transmission to the plant's control room.

Basically, the microcomputer consists of a central processing unit (CPU), a programmable read-only memory (PROM), a random access memory (RAM), input/output interface modules and a communications modem. This system also includes auxiliaries, such as a power supply, wiring, enclosures etc. The CPU controls the operation of the microcomputer and, thereby, the power conditioning module. The CPU also performs arithmetic operations to process data. Instructions (i.e., the program) to direct the CPU in accomplishing these functions are stored in the PROM. The PROM is electrically nonvolatile; the program is not lost if power is lost. However, the PROM can be removed from the unit, erased and reprogrammed in the field, if necessary. Current values of data and other variables are stored in the RAM. This memory is volatile and in order not to lose data, such as the state of charge on the power conditioning module battery, a small battery is used to enable retention of data for up to a month.

Analog signals from thermocouples, angle encoders and current and potential transducers are input to the microcomputer through multiplexer modules and A/D converters. In this application, the signals are relatively slow varying, and input filters are used to eliminate noise. Multiplexing is accomplished through the use of flying capacitors, thus sensing circuits are never connected directly to the A/D converter. Eight-bit logic is used in the system. Contact closures and switch positions are input as digital data through isolating modules.

Output of analog signals (e.g., to set the regulator and inverter) is through D/A converters. Digital outputs in the form of switch closures are used for motor drive contactors etc.

Additionally, each microcomputer (located in the converter building) is connected to the control room computer by means of a communications modem. This modem converts the parallel signals internal to the microcomputer into serial form for transmission, and of course, incoming serial data are converted to parallel form. Transmission is over a single, shielded wire pair to a

similar modem in the plant's control room computer. This wire is mounted on the wood poles used for power distribution, although separated to eliminate induction of noise by the power circuits. Along this wiring route, microcomputer is individually addressable by the control room computer. Transmission of control and data by multiplexing is coming into increased industrial usage, and in view of the relatively large area occupied by the photovoltaic plant, this type of system can significantly reduce wiring costs. Each microcomputer power supply contains sufficient battery capacity to permit up to 8 hours of operation in the event that normal power is lost. Also, internal programming provides for continued safe operations and shutdown of each power conditioning module if tie to the control room is lost. A redundant transmission wire is not included, as it would be in more critical applications.

Operation of each power conditioning module in the modes described in Section 8.0 is controlled by means of the program stored in the microcomputer. Control room signals synchronize an internal clock and initiate power generating operations. A check of enabling switches is made. The position of the 100 associated solar arrays is read from angle encoders, and signals to the drive motor contactors bring the arrays to the correct position. The state of charge on the battery is read from memory, and, if it is less than full charge, operation in Mode 1 commences to charge the battery.

During operation, the current into (and out of) the battery is measured and integrated to track the battery's state of charge. A correction for efficiency is applied in the computation. Also, the enabling switches (e.g., battery temperature, converter function etc.) are continuously monitored. Control room supplied signals also cause updating of array positions.

As the day proceeds, stored programs enable operation in the several modes described in Section 8.0. If during initial operation in Mode 1 the battery becomes fully charged, the charging is stopped, and the plant control room operator is alerted. At this point, preset control room programming (with

operator override) directs the microcomputer to branch to other segments of the program and operate the power conditioning module in one of the routines described for terminating Mode 1 operation.

Similarly, operation in the other modes is controlled by the microcomputer program and control room signals. Enabling switches, battery state of charge and array positions are constantly monitored.

The above description of the microcomputer program is intended to provide a simplified insight into operation as conceived for the conceptual plant design. Discussions of intended plant operations and power equipment characteristics with computer manufacturers indicate that the one-time charge to develop software to accomplish the desired functions would amount to approximately \$20,000. The microcomputer system hardware to carry out these functions can be assembled with currently available, "off-the-shelf" components.

7.4 POWER WIRING

This wiring network brings power from the solar arrays to the plant site boundary and interconnects the major equipment items. The power wiring network consists of four major areas: dc buses, 34 kV distribution system, a switchyard and a 230 kV transmission line. Station power relay protection and grounding systems are also included.

7.4.1 Direct Current Bus

The dc bus systems included all wiring and components required for connection of the array power output terminals to the input terminals of the power conditioning module.

Array wiring brings the collective outputs of all solar cell panels of an individual array to a fused disconnect switch. From this switch, a short section of flexible cable brings the power to the array output terminal box

mounted on the central caisson about which the array revolves. The cable arrangement allows for the array's 180° (nominal) daily rotation. Power from the array is delivered to the output terminal box by a center grounded wiring system with a nominal operating voltage of ± 600 volts to ground. Each individual array is capable of producing a maximum voltage of ± 750 volts to ground (open circuit) and a maximum current of 26.5 amperes (short circuit). The dc power circuit wiring on each individual array to the output terminal box is a part of the array assembly and is not included or costed in this portion of the conceptual design.

The plant portion of the dc bus conceptual design consists of direct buried cable from the output terminal box of each of the individual arrays. The dc outputs from the arrays are collected in groups of five and brought to their respective power conditioning module along direct burial paths as shown in Figure 7.4.1-A. Twenty such dc power circuits for each 100 array group are brought back to each of the 100 power conditioning modules. The direct burial cable is 3/C, No. 1/0 AWG, type USE underground service cable. It is assumed that there will be no rodent or insect infestation that could result in damage to the underground cable. If conditions at an actual site invalidate this assumption, armored cable would have to be used, accompanied by an increase in cost.

Array drive power, control and instrumentation and ground cables will be installed in the same trenches and follow the same direct burial paths as the dc power circuits.

Station arresters are included at the dc terminals in each power conditioning module to provide for switching and lightning transients that could occur at the array output terminals and at the power conditioning module output terminals.

Figure 7.4.1-A 100-ARRAY GROUP WIRING LAYOUT

7.4.2 34 kV Distribution

The 34 kV, 60 Hertz ac, three-phase distribution system includes all wiring and components required for connection of each power conditioning module power output terminal to the 34/230 kV switchyard input terminals on the two 34 kV line dead-end terminus structures. Figure 7.4.2-A presents an electrical single-line diagram for the 34 kV distribution system and for the other ac electrical systems connected to it.

The 34 kV, 60 Hertz ac circuits, equipment and wiring within the power conditioning module are considered a part of the module assembly and are not included in this section. The filtered ac output of each power conditioning module is brought to a fused disconnect switch and lightning arrester terminal (part of the module) located in the module equipment yard and suitable for connection and continuation to the overhead 34 kV bare wire distribution circuit. At these 34 kV power output insulator terminals, each module is capable of producing a maximum voltage of 34 kV $\pm$ 2-1/2 percent and 38 amperes (2.0 MW @ 0.9 PF). The 34 kV output terminal is a wye-connected, resistance grounded system, at a nominal 0.9 PF. All lightning and surge arresters, R-L-C circuits for filtering and power factor improvements are included in the power conditioning modules.

Continuation from the 34 kV power output insulator terminals is by overhead distribution line, utilizing three 1/C, No. 2/0 AWG, ACSR wires on 45-foot wood poles on the 20 sections of north-south distribution lines. The four sections of east-west 34 kV overhead line, one from each quadrant, utilize 350 kcmils, ACSR for power distribution to the central switchyard dead-end structure terminus of 34 kV lines, as shown in the plant layout drawing in Figure 7.1-A. The route of the 34 kV distribution line follows the north-south maintenance roads to the arrays to minimize access requirements for initial construction and plant operations/maintenance functions.

7.4.3 34/230 kV Switchyard

The 34/230 kV, 60 Hertz ac switchyard includes all wiring, components and equipment required for connection of four 50 MW incoming (one from each quadrant) 34 kV overhead lines at two receiving dead-end structures and for connection of the output 200 MW, 230 kV transmission overhead lines from the same dead-end structures.

The layout for the switchyard 230 kV power transmission system, shown in Figure 7.4.3-A, is based on using standard industrial components in modular arrangement identified to the quadrants of solar arrays. Power received at 34 kV from each quadrant of the plant is stepped up to 230 kV transmission line potential through four 75 MVA power transformers. These power transformers are a delta 34 kV low voltage connection and a wye, neutral grounded, 230 kV high voltage connection. The primary and secondary sides of these two winding-type, outdoor, OA/FA/FOA 55/65°C rated power transformers provide bushing-type current transformers for supervision and protective relaying circuits. NEMA/ANSI standard accessories for oil temperature, pressure/vacuum instrumentation, impact loading, filter and drain connections etc. are provided. Current/potential transducers are provided for remote supervisory and control circuits from the central control room panels. Voltage regulation within a nominal range of $\pm 2\frac{1}{2}$ percent is anticipated for transmission line variations. Regulation in this range is provided by the converter modules.

The switchyard includes a standard breaker and a half-scheme on the 34 and 230 kV sides of the power transformers, as a means of avoiding shutdown during routine maintenance or system upsets. The short-time (8-12 hours) overload thermal maximum rating of the 75 MVA power transformers is used for periods when one of these transformers is down. The breaker arrangement, as shown in Figure 7.4.2-A, provides switching to enable routing the power from two quadrants through one 75 MVA transformer ($75 \text{ MVA} \times 175\% = 131 \text{ MVA}$).

The 34 kV and 230 kV power circuit breakers are outdoor-type with ratings suitable for the service and short circuit levels anticipated. For the

Figure 7.4.3-A SWITCHYARD AND BUILDING LAYOUT

purposes of this study, the available short circuit level from the utility system tie-in at the plant boundary has been considered to be 3000 MVA, symmetrical, at 230 kV. Therefore, the 230 kV breakers are rated at 230 kV, 2000 A, 3500 MVA for a 230 kV solid grounded neutral system service. The 34 kV system breakers are rated at 34 kV, 2000 A, 2500 MVA for a 34 kV resistance grounded neutral system service. The final short circuit ratings of these power circuit breakers, buses and transformers must be established by reference to actual values based on a definite utility tie-in and specific equipment parameters during detailed plant engineering.

7.4.4 230 kV Transmission Line

The 230 kV transmission line system includes all wiring, components and towers required for connection from the 34/230 kV switchyard dead-end structure 230 kV terminals to the 230 kV tower structure located on the plant boundary line, where continuation is by the utility. Nominal power factor is considered as 0.9.

A 1-mile 230 kV transmission line connects between the centrally located switchyard dead-end structure 230 kV terminals and a final tower structure at the boundary fence line. Prefabricated structural steel, octagonal cross section, tapered, double-circuit 6-arm statically and dynamically balanced, 100-foot towers (A.B. Chance Co. or equal) are provided.

The double-circuit power circuit conductors are six (total) 605 kcmils (Peacock) ACSR and 4/0 AWG static wires on top of the 100-foot mast. The ruling span will be 1080 feet for a total of five spans to the site boundary. Lightning arresters are provided at the termination point of the 230 kV line on the switchyard dead-end structure. Lightning rods will be provided at the top of each 100-foot transmission tower.

A communication/supervisory control circuit station-tube capacitor is provided for the power line carrier link between the utility dispatcher and the plant control room operator.

7.4.5 Station Power

The station power system includes all wiring and components required for connection of a double-ended 34 kV/480-volt substation with two three-phase 1000 kVA OA/FA (55/65°C) transformers to the 34 kV power circuit breakers and to the 480-volt switchgear and loads through switchgear and circuits from the control room. An emergency 500 kW diesel generator set and a 15 kVA uninterruptible power supply (UPS) are included for essential services on system upsets.

The 34 kV power circuit breakers and 1000 kVA transformers are located in the switchyard. Underground raceways are provided for connection to the indoor-type metal enclosed 480-volt switchgear located in the control room building. The 500 kW/480-volt emergency diesel generator set is located adjacent to the 480-volt switchgear. A 24-hour reserve diesel fuel tank is located outside the control room building below grade.

This 480-volt bus supplies all systems in the control building and maintenance building. A 480/34,000-volt, 250 kVA stepup transformer is included for service to each of the four quadrants for startup and system upsets. Each power conditioning module includes a 480/34,000-volt stepdown transformer for auxiliary services in the 100-array group (e.g., array drive power) and in the power conditioning module itself (e.g., cooling, microcomputer, etc.). During system upsets and startup, the 34 kV line to each quadrant would be energized through the transformers located in the switchyard. No additional power wiring between the control room substation and the plant proper is proposed. In the event that a section of 34 kV line is down for repair, the essential services for those power conditioning modules associated with a specific section of 34 kV line must be supplied through a portable trailer mounted diesel generator set. The 34 kV distribution lines and the 480-volt power system are planned for usage during the construction phase of this plant to minimize temporary construction power systems over the 4-square-mile plot.

Supervisory, control and protective relay systems are wired to the plant control room panels to provide operator remote control of the system.

7.4.6 Grounding

A ground mat system for the entire plant is provided by interconnecting the steel reinforcing bar assemblies in the array foundations with all power pole grounds, power conditioning module ground mats, the central switchyard and the 230 kV transmission line ground mat. All station arresters on the overhead lines are connected to this ground mat.

The ground mat system for a typical 100-array group is formed by connecting the circular steel running rail and the steel reinforcing bar cages in the foundation ring and central caisson of each array with a direct buried 1/C, No. 4 AWG, bare copper wire. The arrays are then connected in groups of five, and the No. 4 ground wire is brought to a common terminal point at the power conditioning module. All 20 grounding circuits utilize the same trenches and follow the same direct burial paths as the dc power circuits (see Figure 7.4.1-A).

All equipment at each power conditioning module is grounded to the ground mat, including the neutral grounding resistor of the 34 kV output transformer as well as the 20 array grounding circuits. This mat is formed by the reinforcing bars in the power conditioning module equipment foundations. Also, each of the 34 kV power poles is provided with a coiled bare copper ground wire. These wires are attached to the butt end of the poles, 6 feet below the ground surface, and are connected to all pole hardware, messenger and static wires on the poles.

At the 34/230 kV switchyard, all incoming 34 kV messenger and static wires and 230 kV system static wires are grounded to the switchyard ground grid mat along with all foundation reinforcing bar cages. A ground well connection is provided at each dead-end structure.

A 400-foot-high communication tower, adjacent to the central control room, is provided with lightning rods at the top, which are connected to the switchyard ground mat and ground well system.

7.4.7 Zones of Relay Protection

The power system relay overlapping zones of protection shown in Figure 7.4.7-A provide the essential features required for a safe and coordinated plan of equipment and personnel protection. The switchyard portion of this system is wired back directly to the system relaying, control and supervisory panels in the control room. A programmable controller with computer interface is included for supervision and control of all input/output lines, equipment, devices and circuits. Control logic would include elements of system capability in response to utility demands.

At each of the 20 sections of north-south 34 kV lines, a pole-mounted reclosure-type breaker is provided, complete with protective relaying and control package to isolate sections of line by selective control from the control room or by relay function on fault conditions. Current/potential transducers at each reclosure are wired back to the central control room for power system supervision, control and protective relay systems.

Power line carrier control logic is included to permit the utility to control the two 230 kV power circuit breakers that complete the tie-in between the solar facility and the 230 kV transmission line. Transmission line relaying unique to a specific utility system is not included and is provided by the utility.

The overlapping zones of protection include current and voltage transformers with the necessary relaying programmed for the individual and collective zones' power throughputs; capability limits of equipment; permissive and blocking equipment operation and isolation; shutdown for malfunction of circuit elements; and system supervision.

Figure 7.4.7-A ZONES OF RELAY PROTECTION

Zone 1 overlaps Zones 2 and 3. This permits the utility to monitor the sending and receiving end power throughputs and to isolate the 230 kV transmission line on fault conditions or as set by the utility system power dispatcher program. Transmission line isolation on fault conditions is accomplished by tripping 230 kV breakers 252-8 and 252-9 at the sending end and the utility network breakers at the transmission line receiving end. The transmission line impedance relaying and power line carrier control link will be by the utility to suit their established operating practice. The 230 kV switchyard end of the transmission line includes a capacitor line trap for the utility tie-in of the power line carrier control link. Breaker relaying includes overload, ground and phase fault, synchroverifier, differential and pilot wire. Commercial metering in Zone 1 is provided by the utility.

Zones 2 and 3 overlap Zone 1 on the utility tie-in and Zones 4, 5, 6 and 7 on the plant 75 MVA transformer throughput. Zones 2 and 3 include the collective output of the 75 MVA transformers at the 230 kV level for delivery to the utility. Breaker relaying includes overload, ground and phase fault, synchroverifier, differential and pilot wire. The throughputs of Zones 4, 5, 6 and 7 are metered individually and collectively for plant operating record purposes. All breakers in Zones 2 and 3 are under the direct control of the central control room operator and the system's programmed controller. A normally open breaker, 252-7, provides an alternate circuit for power flow when either breaker 252-8 or 252-9 is down for maintenance.

Zones 4, 5, 6 and 7 encompass the inputs and outputs of the four 60 MVA power stepup transformers. These zones overlap Zones 2 and 3 on the output 230 kV side and Zones 8, 9, 10 and 11 on input 34 kV side. Two normally open breakers 252-5 and 252-6 provide an alternate circuit for power flow when breakers 252-1, 252-2, 252-3 and 252-4 are down for maintenance. Breaker relaying includes transformer differential, overload, phase and ground fault.

Zones 8, 9, 10 and 11 each cover the collection and delivery of 65 MW (peak) to the central switchyard 34 kV input breaker associated with each quadrant of the plant. Eight 34 kV circuit breakers and 20 reclosures are included in these zones. In addition to breaker relaying noted above in Zones 4, 5, 6 and 7, these breakers are provided with a pilot wire differential relay system from transducers on the remote reclosures. A pilot wire system with transducers was selected owing to the distance involved between the switchyard and the remotely located reclosures. The power output from each of the five 34 kV reclosure- and lines in a quadrant is monitored individually and integrated collectively by the central control room computer.

Zones 12 through 31 each cover a 1-mile section of 34 kV distribution line with its tie-in reclosure at the output delivery end and the five inputs from power conditioning modules along the route of each of the twenty 1-mile sections of 34 kV line. This is a basic input-output differential relay scheme in which the reclosure is tripped and the 1-mile sections isolated on fault conditions. Due to the distance involved, a pilot wire system with transducers was selected.

Zones 32 through 132 each cover a power conditioning module through the 34 kV power output terminals and back to the array's power output terminals. These zones include current voltage and phase sensors with A/D converters for input into the local microcomputers and transmission to the central control room computer. The relaying system provides for on/off and programmed operating modes as required by the central control room power dispatcher. On component fault within a power conditioning module zone, the relaying and control will act to isolate the module zone until the condition is corrected.

All zones and the complete electrical generation, distribution and transmission system are monitored by and under the control of the central control room computer. The graphic display of the total system by a lighted mimic panel permits remote supervision and control of system elements, throughput and total plant output.

7.5 CONTROL AND INSTRUMENTATION

7.5.1 Central Control Room

The central control room includes all panelboards, displays, instrumentation and control elements necessary for data acquisition, supervision and control of the plant. A plan view of the control room (and building) is shown in Figure 7.5.1-A. The modular arrangement of the control room panel is provided with a mimic display bus of the plant power flow from the 100 power conditioning modules through the plant for power delivery to the utility at 230 kV. The operative condition of the system is indicated by backlighted signal lights that indicate normal or abnormal conditions of the system elements and subsystems. The elements and subsystems for each of the four quadrants will be displayed on a section of the control board for that quadrant, plus a central switchyard display. The elements and subsystems included on the mimic bus are:

- Power conditioning modules 1 through 100
- 34 kV reclosures 52-1 through 52-20
- 34 kV breakers 152-1 through 152-8
- 34 kV distribution lines
- 75 MVA power transformers T1 through T4
- 1 MVA auxiliary transformers T5 and T6
- 230 kV breakers 252-1 through 252-9
- 230 kV transmission line
- 230 kV utility delivery point
- 480-volt switchgear buses
- UPS system
- 500 kW emergency diesel generator set

Figure 7.5.1-A. CONTROL AND OFFICE BUILDING LAYOUT

A desk-type operator's console provides access to the control room computer and, thereby, the 100 power conditioning module microcomputers. Data is displayed on the console CRT by operator request and includes power flow configuration of selected elements, subsystem or the complete system with real and reactive power, voltage, current, phase values along with the position of the system breakers and disconnect switches. Electric power flow in a tabular form with individual throughputs and summations is included for the operator's control selections. The majority of the data is input by the 100 power conditioning module microcomputers to the central control room computer.

Control and instrumentation circuits in the power conditioning modules are described in preceding sections of the report. Included as part of the inverter equipment package are electronic and sensor equipment, which generate SCR firing pulses, provide internal control and maintain operation in accordance with simple control signal inputs from the module's controller. Similarly, operation of the battery (when onsite storage is included), its temperature control systems and alarm systems is provided for locally in each power conditioning module. Supervision and control of the power conditioning modules from the plant's central control room are accomplished by linking each module's microcomputer to the control room computer system. This enables the plant operators to set the operation of the modules as described in Section 8.0. Additionally, measurement data from sensors in each module are digitized, multiplexed and transmitted to the control room computer. These data include:

- dc bus voltage
- dc currents from each of the 20 dc power circuits in a 100-array group (see Figure 7.4.1-A)
- Battery voltage and current
- Battery state of charge

- Converter ac voltage, current, power and reactive power (This is the output during power generation and input during battery charging operation.)
- Status of internal control settings, interlocks, limit switches and alarms

Routine operation of the plant is by execution of programming stored in the central control room computer, with operator override to allow for coordination of available (or anticipated) insolation and of stored energy with utility system load demands. Changes to the program for plant operation or utility demands are entered by the operator at the operator's console. The computer in conjunction with the power conditioning module controllers sets the modes of operation for the plant. Also, control signals required for positioning of the solar arrays are generated by the computer.

A line printer is included to automatically print out a hard copy of conditions outside of operational set points or upset conditions. Visual and audio alarms accompany system upsets. The printer also provides a hard copy of data requested from the operator's console. Power for the central control room and its equipment is derived from the station power system. Connection of this system is further described in Section 7.4.5. The station power system includes an emergency generator, a 1000 Ah, 125-volt station battery, a 15 kVA uninterruptible power supply (UPS) and the normal and emergency 480/208-120 volt supply buses. The emergency 500 kVA diesel driven generator supplies the emergency 480-volt distribution bus. Some lighting, the rectifier for the station battery, the control panel and the UPS rectifier are connected to this bus. The UPS system supplies the computer and other critical control room systems.

The station battery 125-volt dc distribution panel provides circuits for each 230 kV and 34 kV power circuit breaker close and trip circuit, the breaker hydraulic operating pump driver and the protective relay circuits for the breaker system. The battery can also provide a limited backup for the loss of primary 480-volt power to the UPS.

7.5.2 Communications

Communication systems necessary for plant operation and maintenance are located in the central control room building. These systems include:

- 230 kV power line carrier interface link to the utility system
- VHF transmitter and receiver for plant field mobile units
- UHF transmitter and receiver for utility system tie backup
- Local telephone system line
- Meteorological data receiver
- TV cameras and displays

A 400-foot communication tower is provided adjacent to the control room building. All transmitter/receiver antennas are mounted on this tower. Aircraft warning light systems are provided as required for the selected site traffic patterns and FAA regulations. Maintenance of plant security is facilitated by the remote controlled TV cameras mounted on the tower. The cameras have zoom and pan features, with each camera able to scan 180°.

7.5.3 Array Drive

The array drive gear motors and wiring to the array output terminal box are considered as part of the array and are described in Section 7.2. However, all outgoing wiring from the terminal box mounted on the array foundation central caisson (for control, instrumentation and ac power) are included as a part of this plant conceptual design. The terminal box is divided into separate compartments. One compartment contains the motor contactor assembly, and other compartments are for instrumentation and dc power.

Array position is sensed by means of a resistive bridge element mounted at the centerline on the base of the array framework. This analog signal is read by the microcomputer in the corresponding power conditioning module. A signal

from the control room computer supplies each power conditioning module with current programmed data for all arrays in the plant. In turn, the microcomputer in each power conditioning module causes each of the 100 arrays associated with it to be brought to the proper position and track the sun. Each array is individually controlled. After each operating day, all arrays are rotated 180 degrees (nominal) back to the starting point, ready for the next day.

Power for the array drive motors will be supplied at 480 volts, three-phase, and will originate in the corresponding power conditioning module provided by the module's associated 34 kV/480-volt stepdown transformer. A single 3/C, No. 6 AWG, type USE underground service cable will supply a group of five arrays, and for each 100-array group, the 20 ac power feeders will be installed in the same trenches and follow the same direct burial paths as the dc power circuits (see Figure 7.4.1-A). A common reversing contactor, located in the power conditioning module, is used to reverse the voltage on the 20 ac power feeders for rotating the arrays back to the starting point at the end of each day. Each array is driven until proper positioning is achieved. During this process, the array position sensor is checked to assure that the proper position is being approached and to prevent overshooting the desired array alignment. In the event that an array is rotated beyond the point programmed for a specific time of day, the array drive will be operative until the next programmed rotation sequence, at which time the motor drive circuit is again energized to advance the array only for the degree of rotation required by the next programmed sequence. Misalignments in array position can be caused by wind force on the arrays.

The array gear motor (to be provided as part of each array) is planned as a three-phase, three-wire, delta-connected motor, suitable for reversing duty and sized for service conditions. A three-phase motor and system was selected to minimize maintenance costs as compared to single-phase capacitor and centrifugal switch-type motors.

7.6 CIVIL AND STRUCTURAL

7.6.1 Site

The site specified for purposes of this study is located near Phoenix, Arizona. Since this study is based on a general site location, no attempt has been made to coordinate layout with facilities beyond the site's exclusion area boundary. Site conditions, such as geology, hydrology, seismology and tornado and wind conditions, are based on data believed to be representative of the Phoenix area.

The Phoenix area is characterized by gently rolling sandy terrain. Only a nominal allowance is made for clearing, grubbing and grading operations. Also, it is assumed that the excavated material will be acceptable for backfill. Finish grading and landscaping are not included.

Site grading includes all contouring and ditching necessary to provide storm drainage. It is assumed that the site location is remote from local municipal storm drain systems. Therefore, storm runoff will be directed toward routes that have historically existed at the site. Further, site grading includes construction of an embankment around portions of the plant to divert flash floods that can occur at such locations. Although these precautions add to the cost of the plant, it appears they will be required in order to ensure reliable operation and to protect the large capital investment represented by the equipment installed at the site. A more precise evaluation of these requirements would normally be made after an actual site is selected.

7.6.2 Array Foundations

During this study, several alternative designs for the solar array foundations were evaluated from both a technical and an economic viewpoint. For the

80-foot array initially specified, the foundation design selected as optimum was a rail mounted on the array, supported by a system of roller assemblies mounted on eight concrete caissons (Ref. 1). The foundation design selected by Spectrolab for the 28- by 56-foot solar array now being considered is shown in Figure 7.6.1-A. With this design, rollers are mounted on the array and are supported by a rail mounted on a concrete ring. A central caisson takes the shear loads caused by wind impinging on the array. The rollers are fitted with "dogging" devices that form a captured rail system and thereby prevent the array from overturning (see Figure 7.6.1-B). The rail configuration takes no shear forces, but only the normal operating forces and uplift forces from high winds.

Standard structural theory and methods of design were used in designing the array foundations. The following manuals and codes of practice were used in developing the designs:

- The American Concrete Institute (ACI), ACI 318-71, "Building Code Requirements for Reinforced Concrete."
- The International Conference of Building Officials, "Uniform Building Code (UBC)," 1973 Edition.
- The American Society of Civil Engineers (ASCE), Paper No. 3269, "Wind Forces on Structures."
- The American Institute of Steel Construction (AISC), "Specifications for the Design, Fabrication and Erection of Structural Steel for Buildings," 7th Edition, 1970.

The following design loads were used in the structural design of the foundation:

- Dead Loads. These loads consist of the weights of photovoltaic panels, the superstructure framing to support the photovoltaic panels and all other devices mounted on the array framework. This was given as 15 tons.

Figure 7.6.1-A ARRAY FOUNDATION

Figure 7.6.1-B RAIL DETAIL

- Live Loads. These loads consist of all loads, except dead, seismic and wind loads. A live load of 15 psf was used in calculations.
- Seismic Load. The State of Arizona is designated as Zone 2 in the Seismic Risk Map of the Uniform Building Code. In Zone 2, moderate earthquake damage corresponding to intensity VII of the Modified Mercalli Scale could occur.
- Wind Load. The U.S. Climatic Atlas (Ref. 2) lists the fastest mile of wind at Phoenix as 75 mph for 24 years of measurement. From figures in ASCE Paper No. 3269, it is seen that the fastest mile of wind near Phoenix with 50-year period of recurrence is 80 mph, reduced to a height of 30 feet above the ground. The Uniform Building Code requires that structures in the Phoenix area, less than 30 feet in height, be designed to withstand a wind pressure of 15 pounds per square foot. For the estimated drag factor of the array design, this is equivalent to 67 mph. The array design was therefore based on a 15 psf wind load with a design safety factor adequate to withstand an 80 mph wind.

The following major structural materials were used in calculations for the foundation design.

- Concrete, cylinder strength f'_c — 4000 psi
- Reinforcing steel — ASTM Grade 40
- Hot rolled structural steel — ASTM Grade 36

The soil in the Phoenix area is generally comprised of alluvial fans of coarse-grained soil mixed with fine-grained materials, such as clay and silts. The allowable bearing capacity of this soil was assumed to be 3.0 ksf. The groundwater table in the area is too far below the surface to have an influence on the allowable bearing capacity.

The array foundation selected by Spectrolab was designed under separate contract by INGENASU Associates. A review of that design indicates that a refinement of the design assumption that the rail takes all the uplift and the center caisson takes all the shear forces could be adjusted to allow for some shear to be taken by the rail system. Detailed consideration during

final design may result in the column being shortened. The central column cannot be completely eliminated, however. Because its action as a pivot point for array rotation is needed for system operation.

In designing and costing these foundations, it has been assumed that conditions at the site permit auguring and that no rock formations are encountered. After grading operations, the central column is drilled. A trenching machine is used to excavate the 40-foot-diameter ring. Preassembled reinforcing elements are placed into both the central column and the rail ring. Anchor bolts to hold the rail tiedown plates are installed at 15-degree intervals. A shear connection collar (part of the array) is placed on the concrete column as the concrete pour for that column approaches the embedment level of its holddown bolts. Concrete is poured, and, after it cures, sections of rail, precurved to a 40-foot radius, are installed by the anchor plate system (See Figure 7.6.1-B).

If soil conditions at the site preclude the use of an augur, or trencher, the basic design will remain valid, but a series of discrete footings may have to replace the continuous rail bed, and a larger mat may have to replace the caisson but retain the same shear resistance capability. This would likely result in increased cost.

Form work required for the concrete caisson and rail base will vary with site conditions. In certain soils, no forms will be required except for that portion of the concrete above the surface, while worst conditions could require some sort of form work for almost the entire foundation. For purposes of this study, the rail support system is assumed to require no form work except above the ground, while the central caisson requires a sleeve to follow the drill, with the sleeve extracted as concrete is poured, and a final form for the aboveground portion placed as the concrete approaches the surface.

The rail ring will require blockouts to allow for drainage of stormwater under the rail and for electrical wiring through the concrete. An alternative to storm water drainage blockouts would be to bring the entire center portion to grade with the caisson, but this alternative would be more expensive than blockouts and is therefore not used.

The use of "dogs" on the rail roller requires that the system stop tracking when the wind increases to a level that causes the "dogs" to engage. As the wind subsides, the friction force between the rail and dogs is eliminated and the array continues to track.

7.6.3 Buildings

The plant's office and control areas are in a 1400-square-foot building, located as shown in Figure 7.4.3-A. This building is prefabricated, with steel frame construction. The exterior walls and roof are double-sided, sheet steel panels filled with insulating polyurethane foam. The panels are prefinished and are sealed together during construction to form moisture-proof joints. A 6-inch thick concrete slab reinforced with steel mesh forms the base floor of the building, and concrete piers, reinforced with steel bars, are used at the bases of columns. As is typical, the floor of the control room is raised to allow for subfloor wiring to the elements of the control panels and equipment. Standard floor tile is used over the concrete in the remainder of the building. Interior walls are steel construction with a suitable decorative finish. A heating, ventilating and air conditioning (HVAC) system is included. Also included are other items required for a complete building, i.e., lighting, plumbing, lavatories, fire protection, etc.

Similarly, the maintenance and warehouse building is a prefabricated, steel frame, 1400-square-foot building with insulated steel panels. However, in this building, the concrete floor is reinforced with steel bars.

Also, this building is ventilated and heated but not air conditioned. In addition to standard fixtures, such as lighting, plumbing, lavatories, the building also includes an overhead crane, large equipment doors, work benches and equipment cribs.

In addition, there are 100 steel frame, prefabricated buildings used to house the batteries for the power conditioning modules. These buildings are simply weatherproof steel frame structures with uninsulated side and roof panels, as shown in Figure 7.3.1-C. Their cost is allocated to the battery auxiliaries in the power conditioning modules.

7.6.4 Roads

There are three classes of roads within the plant: main, access and maintenance. Their locations are indicated in Figure 7.1-A.

The main road connects the site boundary to the centrally located switchyard and the control building, a distance of about one mile. This road is 20 feet with 4-foot stabilized shoulders on either side and is of standard design. The road consists of a 12-inch-thick gravel base, covered by a 6-inch-thick concrete paving and topped with a 2-inch-thick asphalt wearing course.

Eight miles of access roads serve as a plant perimeter, and three 1-mile segments radiate to the perimeter from the central switchyard. These roads are 12 feet wide and are constructed with a 4-inch bituminous paving over a 12-inch gravel base.

There are approximately 20 miles of maintenance roads connecting the power conditioning modules and arrays to the access roads. These maintenance roads are 12 feet wide and consist of a gravel layer.

The parking area shown in Figure 7.4.3-A is paved with seal and chip topping over a gravel or crushed rock base.

Should the actual site selected have hard ground close to the surface (i.e., 2 to 4 inches), the above designs would be modified accordingly and would likely result in lower costs.

7.6.5 Other

It has been assumed that municipal water and sewage treatment facilities will not be available at the site. Accordingly, a well and pump system and a sewage treatment plant are planned to accommodate plant needs. The water system is nominally rated at 160 gallons per capita per day. The sewage system is sized to accommodate 95 percent of the output of the water system.

An 8-foot-high chain link fence, topped with barbed wire, surrounds the entire facility. Primary access is by the gate on the main road. This gate is electrically operated by a keylock at the roadside or from the control room. A television monitor and audio channel enable the control room operators to survey and communicate with people seeking access to the site. Locked gates are located at the outer termini of the three access roads. Capacitive probe systems (100) are connected to fence sections for intrusion detection and alarm.

7.7 SCHEDULE

The information shown in Figure 7.7-A includes sufficient lead time, based on information supplied by manufacturers or developers, to order and manufacture all major equipment items. No allowance is made for prototype development and testing, since it is a basic assumption that all necessary equipment will be commercially available by the start of the schedule. The schedule also assumes the existence of a commercial facility, capable of manufacturing lithium/sulfur cells at a rate of 5000 per day, and that batteries will be available as needed. Further, it is assumed that delivery and installation of the solar arrays can take place within the schedule shown, starting in the

Figure 7.7-A ENGINEERING AND CONSTRUCTION SCHEDULE

21st month and continuing as described. The schedule-limiting factors, or critical path, for the balance of plant are:

- Preliminary engineering and tentative approval of environmental report (concurrent)
- The time necessary to manufacture and deliver converters (estimated by the manufacturers to be about 18 months) and delivery time for circuit breakers (estimated at about 16 months)

The schedule assumes that construction will be planned for sequential startup of groups of arrays. The start dates of the site work, foundations, power lines, battery building construction and battery and array installation follow sequentially as overlapping activities but at sufficient intervals to avoid interference of work operations. The time allowed for the major construction activities is determined by the number of craftsmen likely to be hired for a project of this size.

The schedule shown in Figure 7.7-A applies to both the onsite storage and no-storage design options.

It should be noted for cash flow purposes that partial startup of about 10 percent capacity is possible. This is projected to occur 36 months after award of the engineering contract, with an additional 10 percent becoming available each month thereafter, subject to the delivery and installation of equipment, including solar arrays, as previously discussed.

The engineering and construction schedule developed during the previous design effort (Ref. 1) is still appropriate without modification, because the critical path items shown in Figure 7.7-A have not changed substantially. Further, construction work is also substantially unchanged, except for the construction of the array foundation, and, with a more intensive effort, the 10,000 array foundations can still be installed in 16 months.

7.8 CONSTRUCTION COST ESTIMATES

7.8.1 Estimate Scope

The cost estimates presented in this section are carefully derived estimates of design, material, and construction costs for the entire photovoltaic central station power plant. They include all equipment and structures necessary for production, storage (as indicated), conversion, and transmission of power to the site boundary of the power station.

Preliminary cost analyses were divided into sections and were made by several different organizations. Table 7.8.1-A gives an array cost breakdown. Tables 7.8.1-B and 7.8.1-C give cost estimates for two systems, one with storage and one without storage, both less arrays and foundations. Table 7.8.1-D combines the data from the preceding three tables and gives a cost comparison of various power plant types.

7.8.2 Estimate Basis

Estimates for the major array components were obtained from manufacturers using verbal quotes. Informal pricing information was obtained from various sources for the costs of excavation and forming for the foundations, price of steel erected in place, concrete, and cast-iron.

Estimate costs of the converters were obtained from manufacturers by verbal quotes and consideration of costs of similar equipment. The converter equipment required for the photovoltaic central station is not commercially available at present. Therefore, pricing of this system must rely on manufacturers' budgetary estimates as based on existing technology. Previous related work produced estimates ranging from \$150,000 to \$750,000 for the design charge associated with the first units. Design charges such as these are not included in the present cost estimate, since it is likely that converters similar to those required will be available by the time the plant construction.

Table 7.8.1-A

ARRAY COST BREAKDOWN

	<u>WT, KG</u>	<u>\$/MODULE</u>
SOLAR CELLS (\$182/m ²)	-	\$ 1,894
SECONDARY COLLECTOR (Alum. Extr.)	1,080	1,547
PRIMARY COLLECTOR (13 ga. Steel)	4,081	3,778
REFLECTIVE TAPE (Alum. Vinyl)	-	1,068
20H106 JOISTS	1,633	1,512
BRIDGING & SUPPORTS	493	456
TOP BEAM TS 12 x 8 x 3/8	1,195	1,106
BOTTOM BEAM - TS 10 x 6 x 3/8	935	866
REAR COLUMNS - 6" SCH. 40 PIPE	1,089	1,008
BOTTOM PANEL - W6 x 15.5	1,680	1,555
CENTER BEARING CASTING	64	45
WHEELS & DRIVE	750	2,028
FASTENERS	<u>382</u>	<u>353</u>
TOTAL, ROTATING ARRAY	13,163	\$17,216
PER m ² APERTURE	63.25	\$82.73
SUBSTRUCTURE		
RAIL	760	\$ 704
PINTLE CASTING	117	78
REINFORCING STEEL	2,671	1,721
CONCRETE & EXCAVATION	46,114	1,575
TOTAL PER ARRAY MODULE		\$21,294
PER m ² APERTURE		\$102.33
(208.1 m ² /MODULE)		

Table 7.8.1-B

COST ESTIMATE DETAIL
ONSITE STORAGE SYSTEM

<u>Major Component/System</u>	<u>Manhours (thousands)</u>	<u>Manhours (\$ thousands)</u>
Power Conditioning Modules		
Batteries	20	27,940
Battery Auxiliaries (buildings, cooling etc.)	100	2,390
Converter	50	13,680
Controllers	10	490
Other (wire, switchgear etc.)	<u>10</u>	<u>100</u>
Subtotal	190	44,600
Power Wiring		
DC Bus	57	3,320
DC Switchgear	20	620
34 kV Lines	16	120
34 kV Switchgear	7	520
Utility Poles	9	90
Switchyard	18	2,440
230 kV Line	4	100
Grounding System	<u>39</u>	<u>390</u>
Subtotal	170	7,600
Instrumentation and Control		
Computer and Control Panel	1	170
Control Cables	73	1,940
Communication Systems	5	170
Station Power	17	270
Array Drive Wiring, Switchgear	232	4,650
Other (TV, guard system etc.)	<u>2</u>	<u>200</u>
Subtotal	330	7,400
Civil and Structural		
Site Preparation	177	240
Array Foundations	333	28,424
Buildings (subcontracted)	-	180
Roads (subcontracted)	-	1,750
Other (well, sewage, fences etc.)	<u>10</u>	<u>420</u>
Subtotal	520	31,014

Table 7.8.1-C

COST ESTIMATE DETAIL
NO-STORAGE OPTION

<u>Major Component/System</u>	<u>Manhours (thousands)</u>	<u>Manhours (\$ thousands)</u>
Power Conditioning Modules		
Converters	50	12,910
Controllers	10	490
Other (wire, switchgear etc.)	<u>10</u>	<u>100</u>
Subtotal	70	13,500
Power Wiring		
DC Bus	57	3,320
DC Switchgear	20	420
34 kV Lines	16	120
34 kV Switchgear	7	520
Utility Poles	9	90
Switchyard	18	2,440
230 kV Line	4	100
Grounding System	<u>39</u>	<u>390</u>
Subtotal	170	7,400
Instrumentation and Control		
Computer and Control Panel	1	170
Control Cables	73	1,940
Communication Systems	5	170
Station Power	17	270
Array Drive Wiring, Switchgear	232	4,650
Other (TV, guard system etc.)	<u>2</u>	<u>200</u>
Subtotal	330	7,400
Civil and Structural		
Site Preparation	177	240
Array Foundations	333	28,424
Buildings (subcontracted)	-	180
Roads (subcontracted)	-	1,750
Other (well, sewage, fences etc.)	<u>10</u>	<u>420</u>
Subtotal	520	31,014

Table 7.8.1-D

Central-Power Station Cost Comparison
 200 MW Rated Capacity - 1990 Installation
 Costs in Millions of 1975 Dollars

<u>PHOTOVOLTAIC PLANT</u>	<u>No Stor.</u>	<u>3 Hr. Stor.</u>	<u>GT Suppl.</u>
Arrays and foundations	\$212.94	\$212.94	\$212.94
Site prep. and power wiring	19.67	19.67	19.67
Inverter and controls	31.75	32.52	31.75
Storage (incl. replacement)	-	69.84	-
Engineering, spares and contingency	<u>32.57</u>	<u>41.17</u>	<u>32.57</u>
Subtotal	\$296.93	\$376.14	\$296.93
Gas turbine plant (200 MW)	28.12	28.12	28.12
Present value - 30 years fuel	21.66	13.37	147.64
Present value - energy to charge storage	<u>-</u>	<u>43.63</u>	<u>-</u>
Total	\$346.71	\$461.26	\$472.69
Cost of plant - dollars/kW	\$1625	\$2021	\$1625
Cost of energy - mills/kWh levelized:			
Private ownership	91.7	91.9	82.6
Public ownership	59.7	60.7	57.5
Plant capacity factor	0.308	0.393	
<u>CONVENTIONAL PLANT</u>			
Plant cost (coal-fired intermediate-duty)	\$110.03		\$110.03
Present value - 30 years fuel	<u>112.00</u>		<u>142.90</u>
Total	\$222.03		\$252.93
Cost of energy - mills/kWh levelized:			
Private ownership	42.5		35.9
Public ownership	31.6		27.4

The purchase price of batteries was derived from cost estimates made by Argonne National Laboratories. Costs of minor equipment and bulk materials were obtained from current Bechtel data. All costs are in January 1976 dollars with no attempt to anticipate escalation.

An average wage rate for manual labor of \$15.50 per hour was used. This rate includes all fringe benefits and makes allowance for the expectation that the plant construction will require an unusually high portion of skilled craftsmen. Standard labor productivity has been assumed, and no allowance has been made for a possible change in productivity due to remoteness or unusual working conditions.

Distributable field costs were estimated at 75 percent of direct manual labor in accordance with experience gained from current Bechtel projects. This allowance covers construction costs such as temporary structures, construction equipment, field non-manual supervision and engineering, taxes and insurance.

Design engineering and other home office costs, including fee, were estimated at 8 percent of total field costs. This percentage is based on the assumption that the design of the balance of plant is relatively simple and is extremely repetitive in nature.

Since all areas of the plant design, exclusive of the batteries, converters and solar arrays, represent about one-third of the estimated plant field cost, relatively small cost impact will result from consideration of the individual items remaining. For instance, soil conditions at an actual site may require that a more expensive array foundation system be used. Similarly, topographical conditions at the site could alter the proposed plant layout and thereby produce an impact on the quantity of wiring needed and its cost.

A contingency allowance of 15 percent is based on the assumption that the balance-of-plant design and construction are relatively simple. The

contingency allowance is to cover materials and labor not anticipated at the conceptual level and is expected to be spent. It is not intended to cover changes in scope.

7.8.3 Estimate Exclusions

The following costs are not included in the estimate:

- Escalation beyond 1976
- Roads or utilities beyond the site boundary
- Energy transmission beyond the site boundary
- Utility relaying and metering
- Allowance for costs of special design of batteries and converters
- Maintenance equipment
- Client costs, such as interest during construction, land acquisition, licensing fees and environmental reports, landscaping and finish grading
- Contingency allowance on array costs
- Operation and maintenance costs

An overall cost estimate is given in Table 7.8.1-D. This table is identical to Table 8.3-A and is further explained in Section 8.3.

REFERENCES

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- (3) Bechtel Corporation, Energy Storage and Power Conditioning Aspects of Photovoltaic Solar Power Systems, prepared for Spectrolab, Inc., under Subcontract No. 66725, October 1975.
- (4) Bechtel Corporation, A Conceptual Design of a Battery Energy Storage Test (BEST) Facility, prepared for Argonne National Laboratory, under Contract No. 31-109-38-2962, June 1975.
- (5) Westinghouse Electric Corporation, AC/DC Power Conditioning and Control for Advanced Conversion and Storage Technology, prepared for the Electric Power Research Institute, under Contract RP 390-1-1.
- (6) Spectrolab, Inc., Preliminary Evaluation of Two-Element Concentrators For Use In Solar Photovoltaic Systems, Prepared under Contract No.: 31-109-38-3191, June, 1975.
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8.0 CENTRAL POWER STATION OPERATIONAL AND ECONOMIC ANALYSIS

8.1 OPERATIONAL ANALYSIS AND PLANT RATING

Solar electric generating plants generate electricity in proportion to the insolation falling on their collectors, while the level of output of conventional generating plants is controlled according to the demand for electricity imposed upon the utility. This is a basic difference between solar and conventional plants. Because of this difference, it is impossible to configure and operate a solar plant so that it is operationally identical to a conventional plant in the utility system. Since fossil fuels are a very convenient and presently inexpensive form of stored solar energy, a conventional plant can be considered as a solar plant with essentially infinite storage capacity, and a solar plant can be made to resemble a conventional plant as closely as may be desired by adding rechargeable storage capacity to the basic solar electric generating components. Alternatively, non-rechargeable storage (i.e., fossil fuel) can be used to substitute for the output of the solar plant when the level of demand requires operation of the plant and solar output is insufficient. The choice between these options is essentially a matter of economics.

The demand for electricity varies both diurnally and seasonally. Figure 8.1-A shows the diurnal demand profile for the Arizona Public Service System, a Phoenix area utility, for the 1974 peak day and for a typical winter day. It is evident that the demand for electricity remains at a near-peak level into the early evening hours, and that therefore the addition of a basic solar plant (without storage or supplemental generation) will not substantially reduce the peak demand which must be met by conventional generating plants, even under ideal weather conditions. Therefore, a basic solar plant can be said to provide little capacity displacement for the utility.

In order to meet demand, a utility will typically install a variety of generating plants of differing operational and economic characteristics. Figure 8.1-B shows the generation capability of the APS system in 1973. Generating

Figure 8.1-A. Arizona Public Service

Figure 8.1-B. ARIZONA PUBLIC SERVICE MONTHLY SYSTEM PEAKS, 1973.

plants are dispatched to meet load requirements according to incremental cost of generation; in the case of fossil-fuel and nuclear plants, incremental cost is predominantly fuel cost. More efficient plants using less expensive fuel are dispatched preferentially, and so operate most of the time; these are the base-load plants. Peaking requirements are filled by combustion turbines which have the highest fuel costs per kWh generated; older, less efficient steam plants fall into an intermediate category in terms of hours per year of operation. For fossil-fuel and nuclear plants, base-load plants will typically have the highest capital cost per kW rating, and peaking plants the lowest, with intermediate-duty plants in between.

Solar plants do not fit into this classification. Solar plants have a high capital cost and a very low incremental cost of generation, and therefore, will be dispatched preferentially. Because sunlight is available less than half the time, they will not have the high capacity factor (defined as annual energy output divided by the product of nameplate rating and 8760 hours/year) characteristic of base-load plants. Hydroelectric plants also do not fit into this classification. They also have high capital costs and very low incremental costs, but their annual energy output is limited by the availability of water. Where sufficient reservoir storage capacity exists, as in the case of the hydroelectric plants on the Colorado and Salt rivers, which serve the Phoenix area, they are dispatched to maximize the economic value of their energy output; i.e., during periods of peak load, when they can displace the highest incremental cost fossil-fuel capacity. The capacity factor of the Colorado river hydroelectric plants is between 0.30 and 0.35, which is comparable to the capacity factor of the basic solar plant described in Section 7 of this report.

When a basic solar plant is included in a utility system, the conventionally-generated energy displaced by solar energy is taken from the output of peaking, intermediate and base-load plants, in proportions depending on the time of day, season of year, and the fraction of the system generating capacity which is solar. Figure 8.1-C shows typical clear-day summer and winter load profiles for a basic solar photovoltaic plant (no storage) of $4.5 \times 10^6 \text{ m}^2$

Figure 8.1-C. Full Solar Utilization

array area (450 MW rating). These results are from an hourly simulation using 1962 solar data and 1970 load data from the Salt River Project. The 1970 peak load for SRP was 1055 MW; thus, this simulation represents about 37.5% solar penetration, into the 1970 SRP system. For this large penetration, solar generation at mid-day nearly equals system load in winter, and a substantial fraction of the solar energy displaces base-load energy in both summer and winter. There is also a substantial displacement of peaking energy during the summer peak load period, but very little reduction of peak conventional generating capacity required. Notice also the very rapid change in the output of the conventional plants at the beginning and end of the day.

These results, and also similar simulations of smaller solar plants in the 1970 SRP system, were discussed with systems planning and dispatching personnel of APS and SRP. Their reaction was that even the largest solar plant simulated did not appear to pose insuperable operational problems, and they saw no apparent reason to depart from the principles of economic dispatch, which would require the solar energy to be dispatched preferentially because of lowest incremental cost. They felt that, rather than reduce operating levels of base-load plants during the day, the excess energy could readily be sold in Los Angeles. Since the morning and evening transients could be predicted, they did not believe that operational adjustment would present severe problems, although the inclusion of storage capacity in the system to buffer these transients would be desirable if economic. Unpredictable transients of this magnitude would of course pose severe difficulties. However, this much solar capacity would certainly be built as several plants, widely dispersed, and accurate insolation forecasts one hour in advance would provide sufficient warning to bring up fossil-fuel plant capacity to take over the load. Even less warning would be required if the solar plant could be backed up by hydroelectric generation. Since suitable solar plant locations appear to exist to the north of Phoenix along the transmission lines connecting Phoenix with the Colorado River dams, we obtained data on the operation of the Colorado River hydroelectric plants in an attempt to determine if these facilities could be used to back up solar plants. The information obtained is given in Appendix M. Further study of this possibility appears to be desirable.

At this point in the study, we had thus reached the following tentative conclusions:

(1) Solar photovoltaic central power plants would be dispatched by the utility on an economic basis; i.e., on the basis of incremental cost of generation, which would essentially require that solar energy be supplied directly to the load whenever available;

(2) Adequate means for coping with transients, either through inclusion of buffer storage or by back-up with conventional plants, can be developed, with the choice to be made on an economic basis;

(3) Solar photovoltaic plants cannot be accurately characterized as base-load, intermediate or peaking plants; since if dispatched on an economic basis they could displace energy from all three classes of fossil-fuel conventional plants;

(4) No-storage solar plants, if economic, should not be ruled out of consideration even at high levels of penetration.

It is clear that the extent of the work performed during this study is insufficient to establish these conclusions firmly, and further study is suggested. We felt that the work to this point was sufficient to permit us to use these conclusions as the basis for the further investigations described below. A complete examination of the operational factors involved in integrating a solar photovoltaic plant with a utility system will require simulation of the entire system at a level of detail which is beyond the scope of this study.

8.2 COMPUTER SIMULATION RESULTS

Three sets of computer simulation calculations were made during the course of this study, to investigate the operation of the solar photovoltaic central power station design as a part of a utility system and to optimize performance/cost trade-offs. In each run the output of the photovoltaic plant was computed on an hourly basis, and hourly load data from a Phoenix utility was used. The

amount of storage and/or back-up generation included in the photovoltaic plant was varied, as was the operational mode.

In the first runs, 1962 weather data from Aerospace Corporation tapes was used with 1970 load data from Salt River Project. The 1970 peak hourly demand for SRP was 1055 MW. Four sizes of photovoltaic plants were simulated: Array aperture areas of 0.75, 1.5, 3.0, and $4.5 \times 10^6 \text{ m}^2$, approximately equivalent in rated output (as defined further on in this section) to 75, 150, 300, and 450 MW plants.

8.2.1 "Full Solar Utilization" and "Peaking" Modes of Operation

Two operational modes were simulated. In the first, called "Full Solar Utilization" on the charts, the plant did not include storage or back-up generation. Its output was fed directly to load whenever output was available. In the second mode, called "Peaking" on the charts, storage was included. Storage was modeled as battery storage on the DC side of the inverter. Storage loss was taken as 10% on charging and 10% on discharge, and inverter efficiency was taken as 90%. Array efficiency was computed hourly as a function of insolation and air temperature, using a constant K_e factor of 0.3 (K_e is the overall thermal conductance between cell and ambient air in units of $\text{kW/m}^2\text{-}^\circ\text{C}$, and equals the illumination level on the cells divided by the cell-to-ambient temperature difference).

In the "Peaking" mode, the load data for the early morning hours of each day was examined and the minimum load found. It was assumed that this level of demand was the boundary between "base-load" and "peaking" generation, and the output of the solar plant was constrained so that non-solar generation never was less than this value. Subject to this constraint, the preference for dispatch of power was as follows:

- (1) Solar direct to load. If solar output exceeded the available "peaking" load, as defined above, the excess was stored.
- (2) Stored solar energy, if available

(3) Conventional generation

Charging of storage from the grid was not permitted. Neither the storage capacity nor the inverter capacity was specified in advance. The program kept track of storage capacity and inverter capacity required, and of all energy flows.

Results of the first set of simulations are shown in Figures 8.2-A through 8.2-G. The first two figures are for the "Full Solar Utilization" mode. Figure 8.2-A is a "generation-duration" curve; it is similar to a load-duration curve. For example, it shows that inverter output to grid exceeded $.08 \text{ kW/m}^2$ of array aperture for 1400 hours/year. Figure 8.2-B shows a similar generation-duration curve for the non-solar part of the system. From this curve, it can be seen that the inclusion of the solar plant in the system displaces energy output from all classes of conventional plants. It also shows that, even for the largest solar plant, essentially no capacity displacement occurs.

Figure 8.2-C is a generation-duration curve similar to Figure 8.2-A, but this time for the "Peaking" mode of operation. Remember that in this simulation mode, storage was not limited; as much storage was provided as was necessary to avoid dumping of energy. The required amount, as determined from the calculation, was 0.6, 0.76, and 2.5 kWh/m^2 of array aperture for array sizes of 0.75, 1.5 and $3.0 \times 10^6 \text{ m}^2$. This corresponds to the capacity to deliver full rated power from storage for 5, 6, and 20 hours respectively. For the plant with $4.5 \times 10^6 \text{ m}^2$ array area, the first run showed an extremely large and obviously completely uneconomic storage requirement. Storage capacity was, therefore, limited to 6 kWh/m^2 (about 48 hours) and the simulation re-run.

Figure 8.2-C shows that the peak output of the plant is not significantly affected as the amount of array area and storage capacity is increased, but the generation-duration curve falls off sharply to a much lower plateau than was the case for the no-storage system of Figure 8.2-A. An increasing fraction of the solar-generated energy is passing through storage as array area

Figure 8.2-A. Full Solar Utilization

Figure 8.2-B. Full Solar Utilization Load - Duration Curves

Figure 8.2-C. "Peaking" Use

and storage capacity increase. Although the curves extend out to longer durations, the area under the curve (which is the amount of energy delivered) is smaller because of storage losses.

Figure 8.2-D is similar to Figure 8.2-B, and also shows non-solar generation. Since in the "Peaking" mode the base-load part of the conventional generation is not affected by the solar plant, Figure 8.2-D shows only the peaking part of the non-solar generation. It is clear that the inclusion of the solar plant in the system greatly reduces the energy output required of the non-solar peaking capacity, but it is also evident that the maximum power output required of the non-solar part of the system is not appreciably reduced. In other words, the "Peaking" mode of operation, despite the large amounts of storage used, exhibits no more capacity displacement than the no-storage system simulated previously.

An indication of why this is so can be obtained from Figure 8.2-E, which is a storage-duration curve. At the end of each day, at midnight, the level of stored energy in the system was determined. For the two smaller solar plants, this level was nearly always zero; i.e., all stored energy had been discharged to load by midnight. For the two larger plants, stored energy was present at midnight on a considerable fraction of the days of the year. Since there would be little demand for peaking energy after midnight, this energy would be carried over to the next day. For the largest system, most of the storage was operating on an annual cycle. In the winter, the system produced more energy than could be delivered to load, under the program constraint that conventional plant output could not at any time during the day be less than the minimum system hourly demand for that day. Since the storage was not limited in this mode, the excess energy accumulated in storage until summer. The summer load was high enough so that the storage was rapidly depleted. During the period from midsummer through fall, the storage was completely empty at nearly all times, because load demand was high enough so almost all solar generation could be fed directly to load. This is the period in which Phoenix utilities experience peak demand and also when thunderstorm activity produces days of low insolation. Consequently, despite the large amount of storage in the two larger systems, the instructions which set up this operational mode

Figure 8.2-D. "Peaking" Use Load - Duration Curves

Figure 8.2-E. "Peaking" Use

did not permit the storage to be effectively utilized. As the curve for the largest system shows, for about one-third of the year, storage was nearly always full and for the remainder, nearly always empty.

Figure 8.2-F shows annual electrical energy production for each of the four systems simulated in the "Peaking" mode. The non-solar base load in all cases supplies 75.3% of the annual energy requirement. As the size of the array increases, the fraction of the remaining energy requirement provided by the solar system increases, but not quite proportionately to array size. This is because a larger fraction of the total solar output passes through storage and incurs storage losses.

Table 8.2-A

Comparison of "Full Utilization" (no-storage) and "Peaking Modes

Percentage of Total Annual Energy:

<u>Aperture, m²</u>	<u>Direct</u>	<u>Thru Stor.</u>	<u>Total Solar</u>	<u>Total Solar</u>
0.75 x 10 ⁶	4.0	0.1	4.1	4.1
1.5 x 10 ⁶	7.5	0.5	8.0	8.2
3.0 x 10 ⁶	11.4	3.6	15.0	16.4
4.5 x 10 ⁶	13.6	6.7	20.3	24.6
	<u>"Peaking" Mode</u>			<u>No-Storage</u>

Finally, Figure 8.2-G is a bar chart showing a cost comparison of the various sized plants in the "Peaking" mode, with the energy cost for the no-storage, "Full Solar Utilization" mode indicated. The parameters used in the cost calculation are shown on the chart. They are not the final parameters used elsewhere in this report, but they are close enough for comparative purposes. It is clear that the energy cost from all of the systems with storage is higher than from the no-storage systems -- not a surprising conclusion since in this mode the addition of storage reduces system output (storage losses) and increases

Figure 8.2-F. "Peaking" Use

Figure 8.2-G. "Peaking" Use

system cost. The magnitude of the increase is large, and even reducing storage cost from \$50/kWh to \$15/kWh does not make it insignificant.

It was therefore apparent that the method of plant operation chosen in the "Peaking" mode was not a good choice. The storage was not providing the expected benefits of increased capacity displacement. Also, utility engineering personnel with whom these results were discussed found the division between base-load and peaking to be arbitrary and, as discussed above, not in accordance with the principles for electric power dispatch. We therefore modified the program to add a new mode of operation, called the "Capacity Reduction" mode on the following charts.

8.2.2 "Capacity Reduction" Mode of Operation

Figure 8.2-H illustrates the plant operation in this mode. At midnight of each day, the program looks ahead and computes the solar plant output during the next day. It also checks the level of energy in storage. From these values it computes two levels of operation for the conventional plant. The first level, applying during the early morning hours, is set to charge storage to a predetermined level. This level was set at 80% of storage capacity. The second level, applying during daylight and early evening hours, is set so that the sum of the solar-generated energy plus the energy available by discharging storage to 20% of capacity equals the area between the system demand curve and the chosen operating level. In this way the output of the conventional plants in the utility system is constrained to consist of two constant levels with smooth transitions in between. This mode was selected to manage stored energy in order to provide maximum capacity displacement. During the day, as solar output fluctuates with insolation, solar output is dispatched directly to load up to the point at which additional dispatch of solar energy would result in a change in the operating level of the conventional plant. Any excess solar output is stored, and any deficiency made up by releasing energy from storage, in order to maintain a constant operating level for the conventional plant.

SYSTEM OPERATION-
CAPACITY DISPLACEMENT MODE

Figure 8.2-H

For this mode, it is necessary to fix values for storage capacity. Several values, from 2 to 20 hours, were used in the second set of simulation runs. As was done previously, no specific value was set for inverter capacity; the program supplied whatever amount of inverter capacity was needed to avoid dumping of energy and to comply with the operational rules of this mode.

No results are shown for the second set of simulation runs, because upon inspection of the results it was clear that this mode also gave rise to an anomaly which made the mode an unsatisfactory choice. For the larger array areas, as storage capacity was increased capacity displacement first increased, then diminished. For the largest storage capacities used capacity displacement was actually negative. In these cases a very large amount of inverter capacity was required. It became apparent upon inspection of selected days that the problem was that the requirement for charging storage to 80% of capacity in the early morning hours was forcing the conventional plant to operate at a very high level at that time, if storage had been depleted as a result of low solar output during the preceding day. For large amounts of storage, the peak load on the conventional system at this time could exceed the peak load which it would see without solar output or storage, resulting in negative capacity displacement.

Final Choice of Mode of Operation

The "Capacity Reduction" mode was therefore modified to fix inverter capacity, thus preventing storage from being charged at an unrealistically high rate. Other changes which were made at this time were:

(a) Inverter efficiency was increased from 0.90 to 0.925, on the basis of new information from inverter manufacturers as to the efficiency which could be expected.

(b) 1963 load data for the Arizona Public Service systems was used together with 1963 insolation and weather data, in place of the 1970 Salt River Project load data and 1962 insolation data used previously.

(c) Solar output was always dispatched directly to load, to minimize the cost of solar energy by eliminating losses through storage.

(d) Storage was charged to 100% of capacity in the early morning, provided that this could be done without exceeding the specified inverter capacity (which was considered as bi-directional, providing rectification of grid energy for battery charging), and was allowed to discharge completely if required.

As before, stored energy was released during the day and early evening to maintain conventional generation at a near-constant level and therefore to maximize capacity displacement.

In this mode as now modified, array area, storage capacity and inverter capacity were fixed at the beginning of the run. Most runs were made with the array area set at the economically optimum value for a no-storage system. This value was computed from the generation-duration curve as shown in Figure 8.2-I. The maximum output of the array at any time during 1963 was 0.13 kW/m^2 . Providing sufficient inverter capacity to handle this peak output would be uneconomic because the last increment of inverter capacity would be utilized only once per year. The inverter capacity was therefore reduced incrementally until the incremental value of the energy dumped just equalled the incremental saving on inverter cost. The economically optimum ratio of inverter capacity to array area was found to be 0.103 kW of inverter output capacity (0.111 kW of DC input capacity) per square meter of array aperture. At this ratio of inverter capacity to array area, less than 0.5% of the solar energy generated is dumped because of inverter capacity limitation.

For this final set of calculations inverter size was fixed at 50 or 200 MW, and storage capacity at 0, 2.5, 5, 10 or 15 hours. Capacity displacement was calculated in the following way. The peak hourly demand on the APS system in 1963 was 817 MW. When the solar plant (50 or 200 MW) was added to the system, an equal amount of conventional capacity was placed in reserve status. This reserve capacity was called upon only when system demand exceeded 767 or

Figure 8.2-I. Array Generation-Duration Characteristics. 1963 solar data, 1963 APS load data, Turntable with 45° tilted troughs, $K = 0.3 \text{ kW/m}^2\text{-}^\circ\text{C}$; Aper Area/Abs Area = 17.3, Cell packing factor=0.9, optical transmission = 80%, with end losses and shading calculations; $\eta = \eta(I, T)$

617 MW and direct solar generation plus release of stored energy was not sufficient to meet demand. The peak demand on the reserve plant and the total energy output of the reserve plant were calculated.

Table 8.2-B gives the results of these calculations. The upper part of the table shows the effect of increasing array size while holding inverter capacity constant. A larger than economically optimum array might be expected to reduce back-up requirements by providing full output under lower insolation. The results showed that back-up capacity required was not reduced at all, and there was only a small decrease in back-up energy, while the amount of energy dumped increased substantially. Therefore it appears that this approach to improving the reliability of the output of the solar plant is ineffective.

The lower part of the table shows the effect of the addition of storage capacity which in this mode is charged entirely from off-peak energy. For the 50 MW plant, no reduction in back-up capacity is obtained for 5 hours of storage or less. For the 200 MW plant, no reduction in back-up capacity is obtained for 15 hours of storage or less. Although the addition of storage capacity to the system reduces back-up energy requirements, the reduction is much smaller than the increase in energy output from the remainder of the conventional plant. The difference between these two numbers is the energy lost through storage.

The amount of generating capacity which would be required to meet the actual demand of 817 MW with the required loss-of-load probability was not calculated, but would be expected to be in the vicinity of 1000 MW. Thus the 50 and 200 MW solar plants simulated in these calculations correspond to 5% and 20% solar penetration. The capacity displacement for a 50 MW solar plant without storage was found to be 12 MW, or 24%. The capacity displacement for a 200 MW solar plant was also found to be 12 MW, or 6% in this case. In other words, above 5% penetration further addition of solar plant requires back-up on a one-for-one basis.

Although the capacity displacement was found to be small, the back-up energy requirement was also very small. For the 50 MW no-storage solar plant, the

Table 8.2-B

SUMMARY OF PLANT OPERATION CALCULATIONS

1963 Phoenix Weather Data

1963 APS Load Data

817 MW Peak Demand, 3.99×10^9 kWh to Load

EFFECT OF VARIATION OF ARRAY SIZE - NO STORAGE SYSTEMS

Inverter MW	Array 10^6 m^2	Solar to Load- 10^6 kWh	Solar Dumped % of Gen.	Back-Up Required	
				Cap. - MW	10^6 kWh
50	0.70	162	17.1	38	0.223
50	0.60	155	7.5	38	0.231
50	9.485*	135	0.5	38	0.299
50	0.10	28	0	42	1.23
200	3.00	656	21.7	188	22.0
200	1.94*	539	0.5	188	25.6

*Cost Optimum System

EFFECT OF ADDITION OF STORAGE CAPACITY CHARGED FROM GRID

Inverter MW	Array 10^6 m^2	Storage Hrs.	Non-Solar Gen- 10^6 kWh	Back-Up Required	
				Cap. - MW	10^6 kWh
50	0.485	0	3850	38	0.30
50	0.485	2.5	3870	38	0.29
50	0.485	5	3900	38	0.20
50	0.485	10	3900	18	0.03
50	0.485	15	3910	0	0
200	1.94	0	3430	188	25.6
200	1.94	2.5	3480	188	15.8
200	1.94	5	3520	188	9.3
200	1.94	10	3520	188	6.6
200	1.94	15	3520	188	6.4

back-up plant of 38 MW peak output is required to deliver only 299 MWh/year to make up for failure of the solar plant to deliver output when required. This corresponds to less than 8 hours of operation of the back-up plant at full capacity. For the 200 MW no-storage solar plant, 136 hours/year equivalent full-capacity operation of the back-up plant is required. These low numbers reflect the fact that operation of the solar plant is crucial to system reliability only when the demand on the system is very close to the peak.

The situation simulated here involves complete separation in the operation of the solar plant and the associated storage, since the storage is charged only from off-peak power from the grid, never from solar-generated power. Therefore the storage need not be co-located with the solar plant, and also need not have the same output rating as the solar plant, although that was assumed in these calculations. From the previous set of simulation computations some indication exists that the larger amounts of storage (10 and 15 hours) would be more effective if the storage capacity could be charged at a higher rate than it was discharged.

In any case, we believe that these computations are sufficient to establish that economically viable amounts of storage added to a solar plant do not substantially reduce back-up capacity requirements. This logically follows from the fact that solar plant operation is critical to system reliability only when the system is operating near peak demand. Since this is a relatively infrequent situation, the most cost-effective approach to dealing with the back-up requirement is the approach with the lowest capital cost. In the 50 MW case, it would probably be adequate to rely on operation of conventional plants above their nameplate ratings and on interconnections with other utility systems to meet the very infrequent need for back-up. In the 200 MW case the need for back-up occurs more frequently and low-cost gas turbine generation appears to be the most cost-effective form of back-up. Although the inclusion of storage makes the solar plant conceptually more like a conventional plant in that its output can be controlled to meet demand without dumping energy, and therefore it may be instinctively more attractive to

utility engineers, our computations indicate that the no-storage plant backed up with gas turbine capacity is the more effective alternative.

The values obtained for capacity displacement in our calculations are lower than those obtained by others who have proceeded to model a solar plant in a suitable way for inclusion in a standard loss-of-load probability calculation. Although the probabilistic approach should give results which agree with the deterministic method used in this study, provided that an accurate probabilistic model of solar plant output is used, the development of such a model poses some difficulties. For a conventional plant, the assumption of a forced outage rate which is entirely independent of load is probably valid. For a solar plant, loss of output due to lack of insolation is obviously highly correlated with time of day and weather conditions, and system load is also correlated with these parameters. Therefore the equivalent "forced outage rate" for a solar plant is not independent of load. The effect of these correlations is to make a probabilistic calculation excessively optimistic if they are not taken into account.

8.3 ECONOMIC ANALYSIS

Based on the computer simulations described in the preceding section, we have concluded that the use of back-up generation is preferable to storage in order to achieve the same level of reliability in a solar plant as in a conventional plant. It certainly should be conceded that the combination of a 200 MW solar plant without storage plus 200 MW of gas turbine back-up is superior in reliability to any conventional 200 MW intermediate-duty plant. Both the solar and the gas-turbine back-up plant are highly modular and therefore equipment failure would affect only a small part of capacity. It should also be conceded that, with 100% back-up, the solar plant can be controlled to meet demand in the same way as a conventional plant; in fact, the combination of solar plus gas turbine back-up offers considerably more flexibility than a conventional intermediate-duty plant since as much as 400 MW output is available under certain circumstances. Therefore a cost comparison of these plants cannot be considered as biased in favor of solar generation.

Plant costs for intermediate-duty coal-fired plants and gas turbine peaking plants were taken from Table 18, page 139, Volume II of the Aerospace Corporation Final Report: Mission Analysis of Photovoltaic Solar Energy Systems, December 1975. In 1990 dollars Table 18 gives cost estimates of \$857.1/kW for a 250 MW coal-fired intermediate-duty plant and \$219.1/kW for a 100 MW gas turbine peaking plant. These costs, restated in 1975 dollars using the cost escalation factors used by Aerospace, are \$550.1/kW and \$140.6/kW respectively. 1975 fuel costs of \$1.00/MMBTU and \$3.00/MMBTU were assumed for coal and low sulfur distillate oil, respectively, and these costs were assumed to escalate in the future at a rate (6%) which is 1% larger than the average rate of escalation of all prices (5%), in accordance with the suggestion on page III-13 of the JPL/ERDA/EPRI document "The Cost of Energy from Utility-Owned Solar Electric Systems." In constant 1975 dollars, the cost of coal is therefore assumed to be \$1.16/MMBTU in 1990, the year assumed to be the year of initial operation of the plant, and \$1.565/MMBTU in 2020, at the end of plant life. Utility cost of capital (8%) and appropriate fixed charge ratios for privately-owned (14.83%) and publicly-owned (9.51%) are the "nominal" values given in the JPL/ERDA/EPRI document.

The assumed cost of coal can be compared with actual 1975 costs as reported by the Federal Energy Administration. The cost of coal delivered to electric utility plants averaged \$0.81/MMBTU nationwide in 1975, but was lower in the Pacific region (\$0.58) and still lower in the Mountain region (\$0.32). A coal-fired plant serving Phoenix might be located in either region. Nationwide, the price of coal to utilities averaged \$16/ton on long-term contracts and \$23/ton for spot deliveries. Since the cost of fuel as reported by utilities does not include amortization of capital expenditures made in connection with mine development and transportation facilities, it was felt that the spot price more accurately reflected the true cost of providing fuel to a new plant. The national average spot price for coal was very nearly \$1.00/MMBTU, the value assumed in this cost analysis. Although prices for coal in the Southwest may presently be somewhat lower than the national average, upward pressure on coal prices may be greater in this area over the

next 15 years because of the present almost exclusive reliance on gas and oil.

Table 8.3-A presents the results of the economic analysis. Costs are given for three versions of the photovoltaic plant: the basic version without storage, which is computed to have a plant capacity factor of 0.308; a version with three hours of storage in advanced lithium-sulfur batteries, which is computed to have a plant capacity factor of 0.393 assuming the storage is cycled 250 times/year; and the basic version without storage in which the plant capacity factor is increased to 0.393 by running the gas turbines an additional 745 hours/year. The comparison is to the intermediate-duty coal-fired plant operated at either a plant capacity factor of 0.308 or 0.393.

Cost detail for the components of the photovoltaic plant is given in Section 7.8. Storage cost includes battery replacement after 10 and 20 years of operation; battery costs are expected to escalate at the general inflation rate (5%) and their salvage value is assumed to equal the cost of labor in replacement. Off-peak energy for charging storage is assumed to cost 9 mills/kWh (1975 dollars) in 1990 and to escalate at the same rate as fuel costs. Under these assumptions, the initial cost of the no-storage versions is \$1625/kW and of the version with storage, \$2021/kW, compared to a capital cost of \$550/kW for the coal plant.

Table 8.3-A indicates two ways of comparing solar and conventional plants. The first method is to compute the present value of fuel costs. This method converts the original stream of annual costs into a one-time capital cost. It is equivalent to calculating the amount of capital which, if placed at interest at 8%, would yield the annual sums required to by fuel. The other method uses the levelized fixed charge ratio to convert capital costs into annual capital charges, to which are added the levelized annual fuel costs. The assumptions made in calculations for both methods are identical, but the methods give a somewhat different ratio of costs between solar and conventional plant.

Table 8.3-A

Central Power Station Cost Comparison
 200 MW Rated Capacity - 1990 Installation
 Costs in Millions of 1975 Dollars

<u>PHOTOVOLTAIC PLANT</u>	<u>No Stor.</u>	<u>3 Hr. Stor.</u>	<u>GT Suppl.</u>
Arrays and foundations	\$212.94	\$212.94	\$212.94
Site prep. and power wiring	19.67	19.67	19.67
Inverter and controls	31.75	32.52	31.75
Storage (incl. replacement)	-	69.84	-
Engineering, spares and contingency	<u>32.57</u>	<u>41.17</u>	<u>32.57</u>
Subtotal	\$296.93	\$376.14	\$296.93
Gas turbine plant (200 MW)	28.12	28.12	28.12
Present value - 30 years fuel	21.66	13.37	147.64
Present value - energy to charge storage	<u>-</u>	<u>43.63</u>	<u>-</u>
Total	\$346.71	\$461.26	\$472.69
Cost of plant - dollars/kW	\$1625	\$2021	\$1625
Cost of energy - mills/kWh levelized:			
Private ownership (FCR = .1483)	91.7	91.9	82.6
Public ownership (FCR = .0951)	59.7	60.7	57.5
Plant capacity factor	0.308	0.393	
<u>CONVENTIONAL PLANT</u>			
Plant cost (coal-fired intermediate-duty)	\$110.03	\$110.03	
Present value - 30 years fuel	<u>112.00</u>	<u>142.90</u>	
Total	\$222.03	\$252.93	
Cost of energy - mills/kWh levelized:			
Private ownership	42.5	35.9	
Public ownership	31.6	27.4	

When a utility finances a capital expenditure with a combination of debt and equity, it must pay income tax on the money paid out in dividends on equity. The present value method used here assumes that the capital equivalent of fuel costs is financed in the same way as other capital items. Thus a tax liability is imputed to fuel costs, which results in a somewhat more favorable comparison for a solar plant. In actuality, fuel costs will be paid from revenues as operating costs and will not involve tax liability. From the point of view of an accountant, the fixed charge ratio method is thus more realistic. An economist, however, might prefer the present value method, reasoning that unmined fuel is a "capital asset" to society. As a practical approach to resolving this difference, there is a discussion in Section 9 of this report on the merits of the government rebating to owners of solar energy systems the additional income tax owed as a result of their decision to substitute solar collectors for fossil fuel. If such a change was made in the tax law, the present value method would provide a more appropriate comparison.

It is clear from these figures that storage is not an attractive option, even though an advanced battery was chosen at a projected cost of one-half to one-third estimates for current-technology storage batteries. The comparison might be more favorable to the storage system if it were assumed to be located at the load center, since certain credits might then be taken for reducing peak transmission line loads. Since estimating the magnitude of these credits involves detailed analysis of a particular utility system, they were not included.

From these figures it can be concluded that the photovoltaic central power station design detailed in Section 7 will produce energy at about twice the cost of a competitive conventional plant. In our judgement, this comparison is remarkably encouraging with respect to the solar plant. To review the basis for this design and cost comparison:

- (1) The design is based on the performance characteristics of 1975 components; no future technical breakthroughs are assumed.

(2) While solar cell prices are projected at levels well below present prices, the projected prices are believed to be attainable within the limits of 1975 processing technology. They are well above ERDA 1975 goals, and in any case solar cell costs are a relatively small item in this concentrator design.

(3) The concentrator itself is the major cost item; had more time been available, it is likely that refinement of the design would result in a substantial cost reduction.

(4) The operational comparison was deliberately structured to assure that the solar plant was capable of at least equivalent performance to a conventional plant.

(5) Economic comparisons were made on the basis of present capital costs and tax laws, although considerable societal credit can realistically be assigned to the solar plant as discussed in Section 9.

We therefore feel that this comparison can best be viewed as a benchmark which indicates the status of solar photovoltaic system as of 1975, for the application of utility power generation.

8.4 CONCLUSIONS

The following conclusions were reached as a result of the calculations described in this chapter:

The most economical way to dispatch power from photovoltaic plants into the utility system is to dispatch it directly as generated, without passing it through storage.

Although it is necessary to add some means of back-up to the basic solar photovoltaic plant in order to make meaningful cost comparison with a conventional plant, it by no means follows that these additional components

will be required in a utility system. At low levels of penetration existing conventional plants and inter-utility interconnections should be capable of providing back-up.

At high levels of penetration additional back-up will be required. Back-up with fossil-fuel generating capability should in most cases be preferred to back-up with storage, on economic grounds.

Although at high levels of penetration back-up requirements approach 100%, a capacity displacement credit is still earned by the solar plant since the very low back-up energy requirement permits back-up to be furnished by low cost gas turbine equipment.

It appears that the design of a photovoltaic central power station plant, using 1975 technology, can come within a factor of two of equalling the bus-bar energy cost of a conventional plant using 1975 technology.

9.0 INSTITUTIONAL FACTORS STUDY RESULTS

9.1 INTRODUCTION

The first part of this section provides background for the analyses presented in this report. The second part lists the major conclusions of the report, while the final part describes how the section is organized.

9.1.1 Background

This section discusses the analysis performed by Midwest Research Institute (MRI) under subcontract No. 68494 to Spectrolab, Inc. The role of MRI was to examine the technoeconomic, social and institutional factors related to conceptual designs of three photovoltaic electric power systems (PEPS). Under Contract No. E(11-1)-2748, Spectrolab, Inc., developed three detailed conceptual PEPS designs for the Photovoltaics Branch of the U.S. Energy Research and Development Administration (ERDA). The three conceptual designs were: (1) an on-site PEPS to supply electricity to residences, (2) an on-site PEPS to supply a commercial shopping center, and (3) a central power station PEPS tied into the electric utility generating network.

Preliminary construction cost estimates indicated that of the three designs, the central power station design offered the greatest potential for cost effectiveness as well as the greatest potential for providing significant quantities of energy in the future. Therefore, the analysis performed by MRI concentrated on the central power station PEPS. Since ERDA directed that PEPS installations for all three applications should be treated as utility-owned equipment, and since the analysis in this report basically compares total costs for PEPS against total costs to a utility for conventional generating capacity, the conclusions reached in this report are broadly applicable to the other applications as well.

9.1.2 Major Conclusions

As a result of the analyses performed, several conclusions were reached. The major conclusions are listed here without supporting discussion. (Both major and minor conclusions are discussed in Section 9.8.) The first conclusion presented below is the single, most significant conclusion of this study.

- PEPS will become a viable option for electric utilities if appropriate combinations of the following occur:

- a. Reductions in system cost result from RD&D.
- b. Fuel costs continue to rise.
- c. Identifiable social benefits of PEPS are incorporated into the utility design making process.

- In most plausible U.S. energy futures, an abandonment of ERDA Research, Development and Demonstration (RD&D) photovoltaics program in the 1970's would prevent PEPS from contributing to the U.S. energy supply by 2000. The private sector would not develop PEPS independently of the government unless major electricity shortages persisted.

- Many parallels between PEPS and nuclear technologies exist. The experience gained in supporting the development of nuclear energy may be useful to PEPS development.

- The likely social benefits of PEPS range from \$50 to \$350 per installed kilowatt. However, these benefits could exceed \$3,000 per installed kilowatt if severe energy shortages were to develop.

- If conventional fuel prices are expected to equal a levelized amount of 10 to 15 mills/kW-hr (in real terms), government RD&D would have to reduce PEPS cost by \$120 to \$340 from the estimated cost of \$1,286/kW per installed kilowatt to justify permanent government subsidies.

- To achieve the required reduction in PEPS cost for planar (non-concentrating) systems, drastic reductions in cell cost are required. For concentrating systems, improvements in cell efficiency and reductions in structural costs of concentrators are far more effective in reducing system costs.

- An adjustment of RD&D priorities to place greater emphasis on cost reduction of concentrating systems appears to be desirable.

- Regional subsidy programs and variations in state and local taxes may have a greater impact upon penetration than will regional variations in insolation.

9.1.3 How the Section is Organized

Section 9.2 discusses the methodology used for economic analysis and compares the estimated cost of PEPS to the allowable price of PEPS. Section 9.3 identifies both technical and social factors which will influence the

development of PEPS. Section 9.4 specifies research, development and demonstration (RD&D) goals derived from the technical factors identified in Section 9.3. Section 9.5 examines the social benefits of PEPS. Section 9.6 estimates the appropriate magnitude of government expenditures on PEPS based on the estimated social benefits. Section 9.7 examines potential elements of a commercial subsidy for PEPS. Section 9.8 concludes the report by enumerating the major and minor conclusions derived from the analyses which are discussed throughout the report.

Estimated costs of PEPS, utility cost of capital and discount rates, as used in the calculations in this report, are taken from preliminary versions of the PEPS design reports and from a preliminary version of the JPL/ERDA economic analysis methodology. They differ slightly from the final cost estimates, as given in Section 8.0 of this report, and from the recommended baseline values of economic parameters given in the final version of the economic analysis methodology report¹. The differences involved are numerically small and have qualitatively insignificant effect on the conclusions reached in this study.

¹/ The Cost of Energy from Utility-Owned Solar Electric Systems: A Required Revenue Methodology for ERDA/EPRI Evaluations; JPL Report 5040-29, June 1976.

9.2 ECONOMIC ANALYSIS OF PEPS

This section discusses the approach used in the economic analysis of PEPS. The discussion covers the objectives of economic analysis, assumptions used, the details of the methodology, and the results of the cost model. Finally, the maximum allowable price of PEPS from the cost model is compared to the estimated cost of PEPS.

9.2.1 Approach

If photovoltaic electric power systems are to provide a significant portion of our future energy needs, they must be accepted and integrated into the electric utility industry. However, the rate at which photovoltaic electric power systems (PEPS) are integrated into the electric utility generating mix will depend upon many factors. The electric utility industry is regulated by both state and federal organizations. In an analysis of the economic viability of PEPS within the electric utility industry, the regulating process as well as the internal capital budgeting procedure of the utility should be considered.

The project team began by investigating the interrelationship between the utility and the regulatory agencies. (Appendix A applies economic theory to this relationship and concludes that regulation, as it is now practiced, may not achieve its intended purpose of providing energy to the consumer at the lowest price.) Initial efforts by the project team to develop a comprehensive model of the investment-decision process of the regulated utility indicated that such a task was beyond the scope of this subcontract. Therefore, the analysis was directed at only the major factors which affect the utility's investment-decision process, with the assumption of no changes in the regulatory process.

The major after-tax benefits of PEPS to the utility are (1) cost savings resulting from displacement of costly fuels, and (2) a possible displacement of conventional generating capacity. The maximum justifiable investment by a utility in a PEPS is equal to or less than the discounted present value of these benefits. The objective of economic analysis is to estimate the value of the maximum justifiable investment and the key variables that may influence the investment decision in the future.

To achieve the objectives of economic analysis, a computer cost model was developed which calculates the maximum dollar amount that a utility would invest in a central photovoltaic power plant as a function of levelized fuel costs. A discussion of the model is contained in the Paragraphs which follow.

Objectives of economic analysis: The objectives of economic analysis are (a) to identify the maximum acceptable price a utility would pay for PEPS, and (b) to compare the maximum acceptable price to the estimated cost of PEPS.

The maximum allowable price (dollars per kilowatt) of PEPS is derived from the value of displacing variable costs plus the value of displacing conventional capacity that would occur by adding PEPS to the utility system. In this study, the investment analysis of PEPS is examined from an electric utility viewpoint rather than that of a consumer-owner. This approach eliminates the uncertainties associated with allocating the cost of backup capacity provided by the utility to the consumer-owner. The utility has the option of adding several types of capacity to meet additional demand. Thus, the PEPS can be integrated into a utility mix and assessed on the value of costs that are displaced relative to the cost of conventional power-generating alternatives. Another aspect which favors a utility ownership point of view involves the economies of scale in electric power production which makes utility ownership more attractive than consumer ownership.

Assumptions: The utility-investment decision process is complex and affected by a variety of factors which are unique to each utility. Thus, several simplifications were required in completing the analysis of PEPS from an electric utility viewpoint. These simplifications are outlined below.

- PEPS combined with battery storage is not cost-effective. The addition of battery storage to a PEPS is extremely expensive. This increase in cost is due to high inverter (\$231/kw vs. \$141/kw without storage) and storage battery costs (\$68/kw-hr). If storage was sufficiently cost-effective to be added to PEPS to meet required reliability and thus displace capacity, the same storage without PEPS would also allow capacity to be displaced. For example, storage could be charged during off-peak time by idle low-cost base capacity. Thus, the advantage of PEPS plus storage, as a capacity displacer, could be achieved with the addition of storage to the existing conventional system. However, this argument does not mean that in all cases PEPS becomes uneconomical because storage charged by off-peak base capacity is more attractive. It simply indicates that PEPS plus storage turns out to be too expensive as a reliable capacity addition for electric utilities. Since PEPS plus storage appears too costly, PEPS plus conventional backup alternatives may result in a more cost-effective combination.

- The combination of PEPS plus gas turbines for backup creates generating capacity which has nearly the same performance and reliability aspects as an intermediate coal-fired plant. Since the gas turbine, at \$125 to \$150 per installed kilowatt, is less expensive than the coal-fired plant at \$400 to \$600 per installed kilowatt, a credit should be allowed to the PEPS gas turbine combination for the difference in these costs:

$$\left[\begin{array}{l} \text{credit to} \\ \text{PEPS and} \\ \text{gas turbine} \end{array} \right] = \left[\begin{array}{l} \text{intermediate coal-} \\ \text{fired capacity cost} \\ \text{\$/kw} \end{array} \right] - \left[\begin{array}{l} \text{gas-turbine} \\ \text{backup capacity} \\ \text{costs (\$/kw)} \end{array} \right]$$

● A major portion of the value of the PEPS to the electric utility is the reduction in variable operating costs (mostly fuel). This value of PEPS can be expressed by a single-valued levelized* cost expressed in mills per kilowatt-hour. The amount and value of the fuel displaced by PEPS are complex functions of insolation patterns, the load duration curve, the generation mix, and the dispatch schedule for each individual utility. Also, the number, size, and type of generating units will change with time as a utility adjusts to expected long-term changes in fuel prices and availability. We have chosen to simplify this complex situation by assuming that the value of all fuels displaced by PEPS can be expressed by a single-valued function which is representative of the levelized, weighted average value of the reduced operating costs. Expressing the value of PEPS in this manner greatly simplifies the analysis, yet allows valuable information to be generated.

● The revenues to the owner of the PEPS are always sufficient to allow the full advantage of all tax benefits associated with the PEPS. We have chosen not to consider the effects of the investment in PEPS upon rate base, rate adjustments, and the fuel adjustment factor for utilities. These factors, which affect revenues, could be affected by the investment in PEPS and are recognized as being extremely important. However, for the sake of simplicity, these factors were assumed constant, and thus did not enter the analysis.

● The tax structure does not change over the useful life of the PEPS.

● Sufficient financing is available to the investor in the form of debt or equity. (The rate of return required by both debt and equity remains constant over the life of the investment, as does the ratio of debt financing to equity financing.) It is recognized, however, that financing the future investment in new generating capacity will likely be a major problem to the electric utility industry.

● Fuel is always available at the assumed price. The added value of the energy from a PEPS during periods of fuel shortage is not considered in this analysis.

Method of analysis: Because PEPS with gas-turbine backup is a fuel displacer as well as a capacity displacer, two factors provide value to the electric utility. One factor is the net after-tax benefit of the fuel

* Levelizing changes a non-constant stream of cash flows to a constant stream of cash flows, with the same present value.

saved over the life of the PEPS, while the other factor is the difference between the total present value of the cost of coal and gas-turbine generating capacity. The difference between capacity costs is derived from subtracting the total present value cost of gas-turbine backup capacity from the total present value cost of the coal capacity (each cost adjusted for the tax effects on capital costs). The total value of PEPS to the utility can therefore be expressed as:

$$\begin{aligned} & \left[\begin{array}{c} \text{Maximum} \\ \text{Acceptable Price} \\ \text{of PEPS (\$/kw)} \end{array} \right] = \left[\begin{array}{c} \text{Present Value of} \\ \text{Displaced Variable} \\ \text{Operating Costs (\$/kw)} \end{array} \right] \\ & - \left[\begin{array}{c} \text{Present Value} \\ \text{of Operating and} \\ \text{Maintenance Costs} \end{array} \right] + \left[\begin{array}{c} \text{Intermediate} \\ \text{Coal Capacity} \\ \text{(Capital) Costs (\$/kw)} \end{array} \right] - \left[\begin{array}{c} \text{Gas-Turbine} \\ \text{Backup Capacity} \\ \text{(Capital) Costs (\$/kw)} \end{array} \right] \end{aligned}$$

Thus, the maximum acceptable price for PEPS is equal to the total present value of the fuel displaced by a PEPS, less operating and maintenance costs of PEPS, plus the capital cost savings of the gas-turbine backup over intermediate coal capacity.

The economic model used in this study is based on an economic model originally designed to determine the effective life-cycle cost of various on-site solar electric systems. The earlier form of the model is discussed in detail in Appendix B, "Evaluating the Total Cost of an On-Site Solar Energy System." This methodology is nearly identical to the more recent methodology^{1/} developed for ERDA by Doane of the Jet Propulsion Laboratory (JPL), California Institute of Technology. In fact, the developers of the methodology used in this study assisted in the development of the ERDA/JPL methodology. The derivation of the cost model methodology is contained in Appendix C, "Derivation of PEPS Cost Model."

From Appendix C, it can be seen that the maximum justifiable investment in a PEPS is equal to the sum of the net capacity credit and the after-tax value of fuel saving, less after-tax operating and maintenance costs associated with the PEPS. This net savings is adjusted on a per-dollar-of-investment basis for the after-tax cost of financing, insurance and state and local taxes, less the tax benefits of depreciation and the investment tax credit.

^{1/} The Cost of Energy from Utility-Owned Solar Electric Systems: A Required Revenue Methodology for ERDA/EPRI Evaluations; JPL Report 5040-29, June 1976.

Cost model: For the sake of convenience, the equation for the maximum acceptable price for PEPS as derived in Appendix C, was computerized to allow sensitivity analyses to be performed. Of particular interest was the effect of fuel cost and various tax incentives on the maximum allowable price of a PEPS.

The output of the PEPS economic analysis model is shown in Table 9.2.1-A and Fig. 9.2.1-A. The output is expressed as the acceptable price in dollars per installed kilowatt of PEPS, as a function of the levelized variable operating cost and the capacity factor. For example, at a levelized fuel cost of 30 mills/kw-hr and with a plant capacity factor of 0.308 (representative of Phoenix), the utility would accept a cost of approximately \$1,220/kw of PEPS capacity. The remainder of this section develops the specific details of the economic model.

The PEPS system can be owned by either a private or a public utility. Each type of ownership requires unique input parameters that are representative of the owner's particular economic framework. The weighted cost of capital, fixed charge rate and capital recovery factor are calculated as a function of the economic input parameters (refer to Appendix D for a detailed flow chart and listing of the model). The capacity factor was determined by researchers at Arizona State University utilizing hourly simulation of a 200 mw PEPS interfaced with a load model of the Arizona Public Service grid. The resulting capacity factor for a plant located in Phoenix was 0.308. This capacity factor was multiplied by the ratio of direct radiation for Cleveland and Phoenix to arrive at a capacity factor of 0.194 for Cleveland. Each of these values depicts the likely extremes for PEPS operations. The value of the fuel displaced by a PEPS is a function of the fuel price. The model converts value of fuel displaced, in levelized mills per kilowatt-hour, to dollars per installed kilowatt of PEPS by means of the following relationship:

$$\frac{\$}{\text{kw}} = \frac{\text{mills}}{\text{kw-hr}} \times 8760 \text{ hr/year} \times 0.001 \text{ dollar/mills} \times \text{CF where:}$$

$$\frac{\$}{\text{kw}} = \text{levelized annual dollars per kilowatt of PEPS}$$

$$\frac{\text{mills}}{\text{kw-hr}} = \frac{\text{levelized value of fuel displaced by PEPS in mills per kilowatt-hour}}{\text{kw-hr}}$$

$$\text{CF} = \text{capacity factor} = \frac{\text{annual power production (mw hr)}}{\text{nameplate capacity (mw)} \times 8760 \text{ hr/year}}$$

The levelized $\frac{\$}{\text{kw}}$, which can be thought of as the maximum yearly payment a utility would make per kilowatt of PEPS capacity, can be converted to present value ($\frac{\$}{\text{kw}_{\text{pv}}}$) form by dividing by the capital recovery factor, CRF.

TABLE 9.2.1-A

SUMMARY OF ECONOMIC ANALYSIS

MAXIMUM INVESTMENT PER INSTALLED KW OF PEPS (1976 DOLLARS)

CASE = 100

VARIABLE PORTION OF OVERALL UTILITY OPERATING COST (*)
(LEVELIZED MILLS/KWH)

CAPACITY FACTOR OF PEPS	5.0	10.0	15.0	20.0	25.0	30.0	35.0	40.0	45.0	50.0
.194 (CLEVELAND)	\$ 269.53	\$ 381.03	\$ 492.53	\$ 604.03	\$ 715.54	\$ 827.04	\$ 938.54	\$1050.04	\$1161.54	\$1273.04
.308 (PHOENIX)	\$ 335.05	\$ 512.07	\$ 689.10	\$ 866.12	\$1043.14	\$1220.17	\$1397.19	\$1574.21	\$1751.24	\$1928.26

(*) VARIABLE PORTION OF OVERALL UTILITY OPERATING COSTS IS PRIMARILY FUEL COSTS

Figure 9.2.1-A - Maximum Acceptable Price of PEPS vs. Levelized Fuel Cost

$$\$/\text{kw}_{\text{pv}} = \$/\text{kw}/\text{CRF}$$

$$\text{CRF} = \frac{r}{1 - \frac{1}{(1+r)^n}}$$

where r = weighted cost of capital

n = life of system

The above procedure determines the present value of PEPS, in $\$/\text{kw}$, based on the levelized cost of displaced fuel over the life of the PEPS installation (30 years).

The operation and maintenance (O&M) cost of PEPS is assumed to be \$5.00 per year per installed kilowatt. This assumption is based upon the fact that O&M costs for conventional power plants generally range from 0.6 mill/kw-hr to 1.0 mill/kw-hr^{1/} (\$3.90/kw to \$6.60/kw/year at a 0.75 capacity factor). Because operating and maintenance costs are deductible expenses, they are adjusted to include tax effects.

The maximum acceptable price for PEPS is also adjusted for the tax effect on the following factors: financing costs, depreciation, investment tax credit, and state and local taxes. Each of these factors either increases or decreases the dollar value of PEPS.

PEPS capacity may be combined with an equal amount of gas-turbine capacity. This combination can displace an equal amount of conventional (probably coal) intermediate capacity. The investment in PEPS can therefore be given a credit equal to the difference between the present value of the cost of coal-fired intermediate capacity and the cheaper gas-turbine capacity. A nominal cost (not including interest during construction) of \$413/kw for coal and \$129/kw for gas-turbine capacity was assumed.^{2/}

The model calculates the maximum allowable price for PEPS by merely adding the present value of fuel savings and allowable credit for displacing conventional capacity.

In order for the results of the economic analysis to be more useful, it is desirable to translate the actual price of the fuel (cents per million Btu) into variable operating cost (mills/kw-hr). The fuel price can then be estimated as a function of region of the country. The utility, knowing its generation mix and fuel prices, can determine whether or not the allowable expense for PEPS is justified within a reasonable time frame.

^{1/} Comparative Risk-Cost-Benefit Study of Alternative Sources of Electrical Energy, (Wash.-1224), December 1974.

^{2/} "Changing Electric Utility Economics and the Role of Combustion Turbines," R. A. Brown, D. R. Jones, J. J. Meyer, Proceeding of the American Power Conference, 1975.

9.2.2 Analysis

Table 9.2.2-A presents the plant heat rates used in this analysis. The plant-heat rate is dependent on how the plant is dispatched (base, intermediate, or peaking), and on the presence of pollution control equipment. The base load heat rates were taken from a report by Hittman Associates.^{1/} Power plants which are characteristic of intermediate plants tend to be older, less efficient facilities. Therefore, the heat rate for intermediate plants was somewhat arbitrarily increased by 10% over the base load.

Gas- (and oil-) fired peaking units have heat rates which reflect the necessity of maintaining in a standby condition. The 1974 survey of gas-turbine capacity in U.S. utilities was presented in the March/April and May/June 1976 issues of Gas Turbine International. Based on this survey, a value of 16,000 Btu/kw-hr was found to be representative of gas-turbine peaking units.

The use of pumped hydro for peaking applications is of increasing interest to many utilities. The heat rate for these types of units was determined by assuming a 75% efficiency for the pumped storage. The results allowed the heat rate of the base load plants to be adjusted to include pumped storage for peaking applications.

Once the plant heat rate is established, the following relationship allows the determination of the cost per kilowatt-hour.

$$\left[\begin{array}{c} \text{Levelized} \\ \text{Variable} \\ \text{Operating Cost} \end{array} \right] = \left[\begin{array}{c} \text{Plant} \\ \text{Heat Rate} \end{array} \right] \times \left[\begin{array}{c} \text{Levelized} \\ \text{Fuel Cost} \end{array} \right]$$

Figure 9.2.2-A presents the results of using this relationship with the plant heat rates given in Table 9.2.2-A. For example, a variable operating cost of 30 mills/kw-hr in conjunction with a base load nuclear plant (see Figure 9.2.2-A), results in a fuel cost of \$2.72 per million Btu.

The preceding calculations should next be combined with the anticipated cost of fuel as a function of time for the utility considering investing in PEPS. This combination results in a levelized fuel cost over the life of the PEPS.

Although it is possible to generate fuel-cost curves as a function of time into the future, this has not been done for the present analysis. The primary reason for not pursuing this course of action is that each individual utility has a unique combination of generation mix, fuel costs, and plant capacity factors. However, since each utility has a forecast of its

^{1/} "Environmental Impacts Efficiency and Cost of Energy Supply and End Use: Final Report, (HIT-593), November 1974.

TABLE 9.2.2-A

PLANT HEAT RATES (Btu/kw-hr)

	<u>Base Load</u>	<u>Intermediate Load</u>	<u>Peaking</u>
Nuclear	11,010	--	--
Gas-fired	8,982	9,880	16,000
Nuclear/pumped hydro	--	--	14,680*
<u>Without Pollution Control Equipment</u>			
Coal-fired	8,982	9,880	--
Oil-fired	8,982	9,880	16,000
Coal/pumped hydro	--	--	11,976*
<u>With Pollution Control Equipment</u>			
Coal-fired	9,224	10,146	--
Oil-fired	9,053	9,958	16,000
Coal/pumped hydro	--	--	12,299*

* 75% efficient pumped storage system.

Figure 9.2.2-A - Variable Operating Cost as a Function of Fuel Cost for Several Types of Power Plants

generation facilities in future years, it will be possible for each utility to apply the results of this analysis to its system.

As an example of the methodology, the prices for primary fuels used by electric utilities in July 1975 are presented in Table 9.2.2-B by region of the U.S. These statistics are taken from information prepared by the Federal Energy Administration. Choosing a generation mix which might be "typical" for the South Atlantic region of the U.S., and the "typical" price paid for fuels in that region, leads to the results presented in Table 9.2.2-B.

Figure 9.2.2-B illustrates the effect of a constant growth over 30 years at a discount rate of 0.049. This graph may be utilized by the reader to estimate the appropriate levelized fuel cost in mills per kilowatt-hour for his expectations of real (without inflation) growth in fuel cost. Obviously, the levelized fuel cost is highly dependent upon expected growth rates for fuel costs. The generation percentages for all fuels in each region are presented in Table 9.2.2-C column (1). Column (2) is the price ($\text{¢}/10^6$ Btu) for the corresponding fuel. The operating cost, in mills per kilowatt-hour, column (3), is calculated for each fuel as a function of the applicable plant heat rate and type of load (Table 9.2.2-A). Using the above relationship, the operating cost of coal in the South Atlantic region can be calculated as follows:

$$(99.5 \text{ ¢}/10^6 \text{ Btu}) \times (9224 \text{ Btu/kw-hr}) \times (10 \text{ mills/1¢}) = 9.21 \text{ mills/kw-hr}$$

The 9.21 mills/kw-hr is then multiplied by the generation percentage to derive the weighted mills per kilowatt-hour for coal. The same procedure is followed for each of the remaining fuels, utilizing their applicable heat rate presented in Table 9.2.2-A.

If a constant value in real terms for the operating (fuel) cost is assumed over the 30-year life of the PEPS plant, and the capital recovery factor is 0.0646 (see output of model), then the levelized operating cost will be the same as the weighted cost calculated in Table 9.2.2-C. However, if fuel prices increase at a rate of 3% per year, then the levelized operating cost is 15.69 mills/kw-hr (see Table 9.2.2-D).

One interesting sidelight of this analysis is the opportunity to examine the ranges of costs which correspond to the high and low prices paid for the various fuels in the nine regions of the U.S. Table 9.2.2-E gives the ranges of levelized operating costs (fuel only) for the various fuels both at a constant fuel price and at a 3% growth rate for the price of fuels.

Table 9.2.2-F presents the results of utilizing these levelized operating costs in the cost model. The range of costs per kilowatt of installed generating capacity which can be expended for a PEPS is shown for each fuel type, both with constant fuel prices and with a 3% inflation in the price of fuels.

TABLE 9.2.2-B

PERCENT CONTRIBUTION FROM EACH FUEL BY
REGION AND FUEL PRICE

	Generation Mix* 1974 (%)	Approximate Fuel Price** 1975 (mills/kwh)
<u>New England</u>		
Coal	7.4	10-12
Oil/Gas***	61.3	20-30/11-16
Nuclear****	24.4	3-6
Hydro	6.9	--
Other	--	--
<u>Middle Atlantic</u>		
Coal	42.7	9-10
Oil/Gas	36.2	20-30/10-15
Nuclear	8.5	3-6
Hydro	12.6	--
Other	--	--
<u>East North Central</u>		
Coal	82.0	8-10
Oil/Gas	8.7	16-25/10-15
Nuclear	8.3	3-6
Hydro	1.0	--
Other	--	--
<u>West North Central</u>		
Coal	54.4	5-6
Oil/Gas	27.2	16-25/5-8
Nuclear	7.7	3-6
Hydro	10.7	--
Other	--	--
<u>South Atlantic</u>		
Coal	54.9	9-10
Oil/Gas	32.5	18-28/7-11
Nuclear	7.4	3-6
Hydro	5.2	--
Other	--	--

TABLE 9.2.2-B (Continued)

	Generation Mix* 1974 (%)	Approximate Fuel Price** 1975 (mills/kwh)
<u>East South Central</u>		
Coal	76.5	8-10
Oil/Gas	5.4	16-25/9-14
Nuclear	3.6	3-6
Hydro	14.5	--
Other	--	--
<u>West South Central</u>		
Coal	3.0	2-3
Oil/Gas	92.6	18-28/7-11
Nuclear	0.2	3-6
Hydro	4.2	--
Other	--	--
<u>Mountain</u>		
Coal	46.3	3-4
Oil/Gas	23.2	19-29/7-11
Nuclear	--	3-6
Hydro	30.5	--
Other	--	--
<u>Pacific</u>		
Coal	1.7	5-6
Oil/Gas	27.8	23-40/10-15
Nuclear	2.8	3-6
Hydro	66.7	--
Other	1.0	--

* FEA, Energy Outlook, 1975.

** Six-month average of delivered fuel price ($\$/10^6$ Btu) divided by typical plant heat rate (10^6 Btu/kwh) Source of fuel prices: FEA, December 1975, Monthly Energy Review.

*** Residual fuel oil (No. 6)/natural gas.

**** Nuclear fuel cost is an MRI estimate based on consultations with a consulting engineering firm.

Figure 9.2.2-B - Levelized Fuel Costs as a Function of Rates of Escalations.

TABLE 9.2.2-C

WEIGHTED OPERATING COST (FUEL ONLY) FOR UTILITIES
IN THE SOUTH ATLANTIC REGION

<u>Fuel</u>	(1) <u>Generation</u> <u>(percent)</u>	(2) <u>Fuel Price</u> <u>(¢/10⁶ Btu)</u>	(3) <u>Operating Cost</u> <u>(mills/kw-hr)</u>	(4) <u>Weighted</u> <u>(mills/kw-hr)</u>
Coal	54.4	99.5	9.2	4.993
Oil	26.4*	185.8	16.8	4.441
Gas	6.6*	69.1	6.2	0.410
Nuclear	7.4	40.0	4.4	0.326
Hydro	5.2	--	--	--
Total	100.0			10.169

* Actual statistics combined oil and gas - for this analysis gas was assumed to be 20% of the total of oil and gas.

TABLE 9.2.2-D

LEVELIZED OPERATING COST (WEIGHTED) FOR UTILITIES
IN THE SOUTH ATLANTIC REGION

<u>Year</u>	<u>Weighted*</u> <u>Operating Cost</u> <u>(mills/kw-hr)</u>	<u>Present</u> <u>Value Factor</u> <u>(4.9% discount rate)</u>	<u>Present Value</u> <u>of Operating Cost</u> <u>(mills/kw-hr)</u>
0	10.169	1.000000	10.169
1	10.474	0.953289	9.985
2	10.788	0.908760	9.804
3	11.112	0.866310	9.626
4	11.445	0.825844	9.452
5	11.789	0.787268	9.281
6	12.142	0.750494	9.112
7	12.506	0.715437	8.947
8	12.882	0.682018	8.786
9	13.268	0.650161	8.626
10	13.666	0.619791	8.470
11	14.076	0.590840	8.317
12	14.498	0.563241	8.166
13	14.933	0.536931	8.018
14	15.381	0.511851	7.873
15	15.843	0.487941	7.730
16	16.318	0.465149	7.590
17	16.808	0.443421	7.453
18	17.312	0.422709	7.318
19	17.831	0.402964	7.185
20	18.366	0.384141	7.055
21	18.917	0.366197	6.927
22	19.485	0.349091	6.802
23	20.069	0.332785	6.679
24	20.671	0.317240	6.558
25	21.291	0.302422	6.439
26	21.930	0.288295	6.322
27	22.588	0.274829	6.208
28	23.266	0.261991	6.095
29	23.964	0.249753	5.985
30	24.683	0.238087	5.877
			242.855

Capital recovery factor = 0.0646

Levelized operating cost (fuel only) = $242.86 \times 0.0646 = 15.69$ mills/kw-hr

* Fuel costs are assumed to increase at 3% per year.

TABLE 9.2.2-E

RANGES OF LEVELIZED OPERATING COST
(FUEL ONLY) IN MILLS/KW-HR

<u>Fuel</u>	<u>Constant Fuel Price</u>		<u>Fuel Price at a 3% Growth Rate</u>	
	<u>High Value</u>	<u>Low Value</u>	<u>High Value</u>	<u>Low Value</u>
Coal	11.48	1.97	17.72	3.05
Oil	22.25	15.04	34.33	23.10
Gas	10.13	4.74	15.63	7.32
Nuclear	4.40	4.40	6.79	6.79

TABLE 9.2.2-F

RANGES OF INDIFFERENCE COSTS PER KILOWATT OF INSTALLED
GENERATING CAPACITY FOR PEPS UNITS
 (Capacity Factor = 0.308)

<u>Fuel</u>	<u>Constant Fuel Price</u>		<u>Fuel Price at a 3% Growth Rate</u>	
	<u>High Value</u>	<u>Low Value</u>	<u>High Value</u>	<u>Low Value</u>
Coal	\$564.48	\$227.78	\$ 785.40	\$266.01
Oil	945.79	660.52	1,373.48	970.93
Gas	516.68	325.85	711.41	417.19
Nuclear	313.81	313.81	398.43	398.43

Although current fuel costs range as high as 40 mills/kw-hr (oil-fired peaking turbines in the Pacific region), typical costs range from approximately 5 to 10 mills/kw-hr for coal and 15 to 20 mills/kw-hr for oil. In the future, when gas and oil are not allowed as boiler fuels PEPS will probably displace mostly coal for intermediate plants. Therefore, PEPS would be attractive today at a cost of approximately \$300 to \$800 per installed kilowatt.¹ Figure 9.2.2-C illustrates this relationship between current fuel costs and the maximum acceptable price for PEPS.

9.2.3 Results

This chapter has discussed both the methodology and the results of an analysis of the maximum allowable price that the utility industry would pay for PEPS. This price is compared on a per kilowatt basis in Figure 9.2.3-A to the estimated cost (between \$120 and \$1400/kw) of building a 200 mw_e PEPS. The major conclusion which can be drawn from Figure 9.2.3-A is that a significant gap exists between the maximum allowable price of PEPS and the estimated costs of PEPS.

At today's fuel prices, the maximum allowable price that a utility would pay for PEPS is in the range of \$200 to \$900 per installed kilowatt, depending upon insolation and fuel costs. The estimated costs of a PEPS with 100% back-up gas turbine is \$1,286 per installed kwe (\$1,157 for PEPS, \$129 for gas turbine backup). Thus, a gap of \$386 to \$1,086 exists. This gap could be reduced or eliminated by any single factor, or a combination of the factors in the following list:

- Escalation of fuel prices at a rate greater than the general inflation rate.
- Reduction of PEPS component costs through R&D and mass production.
- Inclusion of the social benefits of PEPS in the maximum allowable price of PEPS.

These factors are discussed in greater detail in Section 9.3.

^{1/} A nearly identical estimate of the value of a solar generating plant to an investor-owned utility has been reached in a study by Southern California Edison Co. under ERDA sponsorship (G. Braun, private communication).

Figure 9.2.2-C - Comparison of Maximum Acceptable Price of PEPS Compared to Current Fuel Prices

Figure 9.2.3-A - Comparison of Cost of PEPS to Maximum Acceptable Price of PEPS

An exercise in scenario writing was conducted to complement the economic analysis presented in Section 9.2, and help identify major factors that will affect the level of penetration of PEPS in the year 2000. These factors are discussed below in two groups, technical and social. Factors influencing the development of PEPS that became apparent in the economic analysis of PEPS are also discussed in this section. It is unlikely that any one of these factors will change sufficiently to cause PEPS to become an attractive investment to the utility industry. However, a combination of these factors could shift the economics from unfavorable to favorable.

Different combinations of future events will result in alternative levels of PEPS market penetration. The eight scenarios developed in this project were constructed to bracket the range of plausible penetration levels. The scenarios, with the expected level of market penetration in 2000, are listed in Table 9.3-A (details of the individual scenarios appear in Appendix E). The scenarios are not intended to discuss all possible (or even probable) futures or all the reasons for any particular event described in a scenario. They are also not intended to provide explicit details regarding the rate of PEPS penetration, required government action, levels of funding, etc.

In the scenarios, particular attention was given to the role of ERDA in the photovoltaic market. The scenarios attempt to (1) determine what conditions would warrant ERDA support of the market even if PEPS is not economically viable, and (2) what impacts variation in the extent, nature, and timing of ERDA involvement will have on the future development of PEPS.

Section 9.3.1 discusses the technical factors influencing the development of PEPS while Section 9.3.2 discusses the social factors. Section 9.3.3 of this chapter discusses the findings of an investigation into the similarities between the factors influencing the development of PEPS and nuclear technologies (the complete investigation is contained in Appendix F). Given the similarities between the problems confronting these two technologies, and the 25-year experience of the nuclear industry, this comparison provides some insight into the type of government support that the successful development of a PEPS industry might require.

TABLE 9.3-A

SUMMARY OF SCENARIOS

<u>Scenario</u>	<u>Relevant General Conditions</u>	<u>PEPS Market Events, Especially 1976-1985</u>	<u>Penetration in 2000 AD (in quads)</u>
1	Baseline future	No further government involvement in PEPS	minimal (less than 0.5)
2	Wide variety of electricity technologies become commercially viable	Current ERDA Plan	minimal (less than 0.5)
3	Baseline future	Current ERDA Plan	small (0.5 to 2)
4	Major strides in conservation	Government subsidies to industry and consumers	small (0.5 to 2)
5	Major increase in U.S. dependence on electric energy	Current ERDA Plan	significant (1 to 5)
6	Baseline future	Government subsidies to industry and consumers	significant (1 to 5)
7	Limited nuclear power	Current ERDA Plan	highly significant (2 to 10)
8	Major increase in U.S. dependence on electric energy	Government subsidies to industry and consumers	highly significant (2 to 10)

9.3.1 Technical Factors

The technical factors influencing the development of PEPS include (1) escalation of fuel prices, (2) reduction in the cost of PEPS, and (3) changes in the cost of competing technologies.

Escalation of fuel prices: If conventional fuel prices were to escalate such that the levelized cost of fuels displaced by PEPS is equal to or greater than approximately 33 to 49 mills/kw-hr, PEPS would be an attractive investment to the utilities.

Figure 9.2.2-B in Chapter 9.2 shows the levelized mills/kilowatt as a function of the annual real growth rate for fuel costs over 30 years. A horizontal line added at 33 mills/kw-hr represents the baseline cost estimate for PEPS with a 0.308 capacity factor, representative of Phoenix (refer to model output).

This line intersects the oil price range at 3% and again at 5% annual real growth rate for 30 years. The 3% to 5% range of growth rates is very close to the historical real annual growth rate, for the period from 1960 to 1972, of 2.5%.* However, it is questionable whether oil will be allowed as a boiler fuel in the next 10 to 20 years.

The 0.308 capacity factor line also intersects the coal price range of 7% real annual growth rate. However, there has been a decline in the real price of coal, from 1960 to 1972, of slightly less than 1% per year. Figure 9.2.2-B indicates that the coal prices would have to grow at a real rate of 7% per year over the next 30 years starting with the 1976 price range of 21.4¢ per 10⁶ Btu and 124.5¢ per 10⁶ Btu (refer to Table 9.2.2-B). Although escalation of such magnitude might occur during the next 5 to 10 years, such a large real growth rate over a 30-year period is not likely to occur in the next 30 to 50 years because of the vastness of our coal reserves.

A horizontal line added at 46 mills/kw-hr is representative of a PEPS having a capacity factor of 0.194, representative of Cleveland. This line intersects the oil price range at 5.5% and 8% real growth rate and the coal price range at 10% real growth rate.

* Calculated using the price deflator for fuels and related products and power taken from the 1973 Statistical Supplement to the Survey of Current Business Products and Power; and oil prices from World Oil, February 1975, pg. 74.

This analysis indicates that oil and coal prices would have to escalate at real rates greater than are likely to occur under a "no surprises" future if PEPS are to be competitive. Also, based on the scenarios examined, it can be concluded that the level of PEPS market penetration depends heavily on the general trends in fuel price between 1976 and 2000.

2. Reduction of the component cost of PEPS: The conceptual design presented in this report resulted in a cost estimate of \$1,157 per installed kilowatt of focusing photovoltaic capacity (this estimate does not include \$129 per installed kilowatt-electric of capacity of backup gas turbine). This cost estimate was based upon cell costs of \$182/m² and a 200 mw plant having no storage capacity. The individual components of the total cost of the 200 mw plant are itemized for both the focusing system and a similar planar system in Table 9.3.1-A. The cost information in Table 9.3.1-A is plotted versus cell cost in Figures 9.3.1-A and 9.3.1-B for the focusing and planar systems respectively. These plots illustrate the relative magnitude of the components of total cost as well as the sensitivity of total system cost to photovoltaic cell cost.

At \$182/m², photovoltaic cells account for only slightly more than 5% of the total focusing system cost. The concentration structure and the primary mirror respectively account for 33.8% and 22.0% of the total focusing system cost. At the same cell cost (\$182/m²), cells account for 76.8% of the total cost (\$2,536 per installed kilowatt-electric) of the planar system, while the structure accounts for only 7.7% of total system cost.

If one assumes a cell efficiency of 15%, the cell cost in dollars per square meter can be converted to dollars per peak watt by dividing by 150. For example, a cell cost of \$182/m² is equivalent to \$1.21 per peak watt. ERDA milestones, as reported in ERDA-49,* call for a reduction from the present level of approximately \$20.00 per peak watt to \$5.00 per peak watt in the late 1970's and \$4.00 per peak watt in the mid-1980's, with an ultimate goal of cell costs in the \$0.10 to \$0.30 per peak watt range. Focusing and planar system costs are equal at a cell cost of approximately \$50/m² (\$0.30 per peak watt at 15% efficiency). From the above figures, it is apparent that focusing PEPS are likely to be competitive with planar systems, especially if concentration costs can be reduced. Some worthwhile, yet perhaps obvious, conclusions may be drawn from Figures 9.3.1-A and 9.3.1-B.

● Focusing photovoltaic systems will derive little benefit from reduction in cell costs, while planar photovoltaic systems must rely almost entirely upon reductions in cell cost for economic viability.

* ERDA-49, Definition Report, National Solar Energy Research and Development Program, June 1975.

TABLE 9.3.1-A

COMPONENTS OF THE TOTAL COST OF 200 MW PHOTOVOLTAIC
PLANT WITH NO STORAGE

	Cost (\$/kw)	
	<u>Focusing System</u>	<u>Planar System</u>
Site Preparation, Roads, Security	39	39
Substrate and Heat Rejection	6	--
Array Foundations	72	72
Engineering and Contingencies	86	86
D.C. Wiring	56	56
Array Structure	391	196*
Tracking Drives	50	--
Primary Mirror	254	--
Inversion Equipment (inverters, A.C. wiring, switchgear, controls)	141	141
Backup Gas Turbine	129	129
Photovoltaic Cells	<u>0.3451 P**</u>	<u>10.70 P**</u>
Total Cost (\$/kw)	1223 + 0.3451 P	718 + 10.70 P

* Assumes the cost of the array structure for non-focusing system is 50% the cost of the array structures for the focusing system.

** P is the price of photovoltaic cells in dollars per square meter of cell. Note all costs are in 1976 dollars.

Figure 9.3.1-A - Focusing Photovoltaic System Cost vs Photovoltaic Cell Cost

Figure 9.3.1-B - Planar Photovoltaic System Cost vs Photovoltaic Cell Cost

- Focusing systems are likely to benefit much more from reductions in mirror and structure costs than from reductions in cell costs.

- All cost components with the exception of inversion equipment will vary approximately linearly with array area. Thus, an increase in cell efficiency which reduces the necessary array area will result in a proportionate decrease in system cost.

- Reductions in the cost of the following components are not likely to occur because they do not reflect new technology or a new industry:

- Controls
- AC Wiring
- Switch Gear
- Site Preparation
- Roads
- Security
- Array Foundations
- Engineering and Contingencies

These relatively inflexible components account for approximately \$350 per installed kilowatt or about 30% of system cost.

- If cell costs drop to \$0.20 per peak watt without reductions in the cost of other components, the system cost will still be high (\$800/kw to \$1,000/kw). In fact, if cell costs were zero, PEPS might not be cost effective without significant reductions in other system component costs.

Component costs can be influenced by both research and development activities and economies from large-scale commercialization. This influence is evidenced by a comparison of scenarios 1, 3 and 6, which predict the impact of differing levels of government support for PEPS. Government support of PEPS is discussed below.

Success of competing technologies: The cost and availability of competing electrical energy technologies and the extent to which conservation technologies are used will have a major impact on the market penetration of PEPS. An examination of scenarios 2, 3, 4, 5 and 7 indicates that:

- Rapid reductions in the cost of other new energy technologies would seriously reduce the potential penetrations of PEPS.

- Limitations on a major electrical fuel source, such as nuclear, would require PEPS to play a significant role in the national energy supply by 2000.

- Decreased electrical demand due to effective conservation programs would lower private sector interest in PEPS for 5 to 15 years. However, the conservation programs may help foster PEPS penetration after that time.

- If U.S. electrical energy problems worsen significantly, the private sector will probably play an important role in PEPS development.

9.3.2 Social Factors

Government support of PEPS: Comparison of the penetration levels of the scenarios that assume different amounts of government support for PEPS demonstrates that the government will be a major factor in the future of PEPS. Based on the scenarios, it can be concluded that:

- In most plausible U.S. energy futures, an abandonment of the ERDA RD&D photovoltaics program in the 1970's would prevent PEPS from contributing to the U.S. energy supply by 2000. The private sector would not develop PEPS independently of the government unless major electricity shortages persisted.

- A government RD&D program, such as the current ERDA plan, may have a substantial impact on the penetration of PEPS in 2000.

- An extensive government subsidy aimed at commercially available PEPS would have a major impact on PEPS penetration by 2000 under most U.S. energy futures.

Level of dependence on electric energy: The U.S. demand for electric energy was identified as a major factor affecting the future of PEPS. The scenarios indicated that:

- A decreased electrical demand due to conservation will reduce the penetration of PEPS for 5 to 15 years.

- A major increase in the U.S. dependence on electrical energy will substantially increase the penetration of PEPS in 2000.

Concern for environment and resource availability: PEPS provides a minimal insult to the environment compared to other energy sources. Also, solar energy is a non-depletable form of energy. Therefore, PEPS should provide benefits to society that are not included in the direct benefits of PEPS to the utility of fuel and capacity displacement. The social benefits of PEPS can be added to the direct benefits realized by

the utility through a variety of government policies and incentives. Chapter 9.5 discusses the characteristics and magnitudes of the social benefits of PEPS. The appropriate magnitude of government expenditures based upon several factors including the social benefits of PEPS is discussed in Chapter 9.6.

Concern for the environment has the potential of increasing the penetration level of PEPS in 2000. The desire for independence from imported energy sources will also increase the PEPS penetration level. Both of these factors will have little impact unless they are translated into government action in the form of increased support for PEPS, or more stringent environment controls and controls on energy imports. From scenario 1, and from the economic analysis, it can be concluded that:

- If the social benefits of PEPS were equal to or greater than \$386/kwe to \$1,086/kwe, and these benefits were realized by the utility industry through incentives, PEPS would be considered attractive by the utility industry.

- The social benefits of environmental preservation, conservation of finite energy resources, and insurance against foreign control of U.S. energy supplies warrant the cost of continuing the current ERDA RD&D program in photovoltaics under most possible energy futures.

9.3.3 A Case Study: Factors Which Influenced the Development of Nuclear Technology

Many of the factors influencing the development of PEPS may be similar to those influencing the development of other energy sources. One of these factors will be the amount of subsidization provided by the federal government. (This aspect of the PEPS program is covered in greater detail in Chapters 9.4 and 9.5.) In this context, it is instructive to examine the similarities between the development potential and problems of PEPS and the other energy industries. This comparison will be useful in attempting to determine additional major factors influencing the development of PEPS technology.

Conventional energy sources for the generation of electric power include coal, oil, natural gas, and nuclear power. Government participation in the development of nuclear energy has been large and recent, compared to other conventional energy sources. Therefore, nuclear energy will be examined in more detail.

If government support of PEPS technology is determined to be in the national interest, the most striking similarity between the two energy sources could be the level of subsidization. Even if PEPS is pursued less vigorously than nuclear, as implied in many of the scenarios, the pattern of outlays and the resulting rate of market penetration may be similar.

A large number of diverse RD&D programs and direct subsidies to the nuclear industry are examined in Appendix E. However, the magnitude of the support is more surprising than its diversity. Figure 9.3.3-A presents the cumulative dollar amount of federal subsidies to nuclear energy per industry kilowatt of installed capacity from 1960 to 1985 (projected). All subsidies are expressed in constant 1975 dollars. The government support has been separated into two categories. The first is research and development expenditures while the second represents more direct subsidies such as the procurement of raw materials, enrichment, plant construction and capital equipment.

Figure 9.3.3-A indicates that in the early years of nuclear energy development, government outlays were extremely large relative to the amount of installed nuclear capacity. As the industry matured, annual government outlays for RD&D programs remained relatively constant. However, direct subsidies, such as plant construction, decreased and installed nuclear capacity expanded rapidly (especially after 1970). The net effect is a decrease in the dollar subsidy per kilowatt of installed nuclear capacity. From almost \$100,000/kwe in 1960, the subsidy represents about \$875/kwe in 1976. By 1985, the cumulative subsidy will be reduced to approximately \$356/kwe.

To relate the nuclear program more directly to PEPS, the cumulative subsidy was also related to cumulative kilowatt-hour of electricity produced by U.S. nuclear plants. The results are presented in Figure 9.3.3-B. As expected, the shape of the subsidy over time changes very little. In 1960, the cumulative nuclear subsidy represented almost \$1.00/kw-hr of electricity. By 1976, the cumulative subsidy had been reduced to 50.5 mills/kw-hr, R&D programs accounted 28.7 mills/kw-hr and direct subsidies equal 21.8 mills/kw-hr. This subsidy is several times larger than the normally quoted busbar cost of nuclear power.

The U.S. nuclear program is similar to the PEPS programs outlined in scenarios 4, 6 and 8 for several reasons. First, both R&D and direct subsidies play an integral role in the technology's development. Second, government investment in the technology was massive and continued after the technology became commercialized. Third, subsidies reduced the private cost of the technology by considerably more than 50%. Fourth, neither technology would reach commercialization without government support. A number of other similarities between the development of PEPS and nuclear technologies can be drawn. They include:

Figure 9.3.3-A - Cumulative Federal Subsidies to the Nuclear Power Industry Distributed Over the Cumulative Installed Nuclear Generating Capacity as a Function of Time

Figure 9.3.3-B - Cumulative Federal Subsidies to the Nuclear Power Industry Distributed over the Cumulative Energy Generated by Nuclear Power Plants as a Function of Time.

1. The primary goal of both PEPS and nuclear power is to provide a significant amount of electric power within a reasonable time frame. While the term "reasonable time frame" is somewhat speculative, the annual production of electricity from nuclear reactors in the U.S. is expected to be slightly over 240 billion kw-hr by the end of 1976.* In contrast to this, ERDA-48** predicts about 1 billion kw-hr/year from PEPS in 1985 and about 200 billion kw-hr/year by the year 2000. This amount of electricity would be generated by the equivalent 0.1 to 0.3 billion kw of installed PEPS having a load factor of 0.6 in 1985, and the equivalent of 30 to 60 billion kw of capacity having a load factor of 0.7 in 2000. By comparison, 46 billion kw of installed nuclear generating capacity is expected to be in service by the end of 1976.

In other words, the development of PEPS is expected to closely parallel that of the nuclear power industry. After 25 years, both industries would have almost identical installed capacity and power generated.

2. There is a need to develop both PEPS and nuclear power from essentially a zero level. Although a few nuclear reactors were in operation by 1955, these were primarily naval or research reactors. Similarly, PEPS that are operational in 1976 are primarily for space applications or remote applications. Both PEPS and nuclear power were required to develop from this small base capacity.

3. In order for any new energy source to become a viable alternative for the generation of electricity, it is essential to gain widespread acceptance by the utility industry. The ERDA goal of 30 to 60 billion kw of installed PEPS by the year 2000 will probably be accomplished primarily through utilities. Although PEPS has some advantage over nuclear power in that it can be installed in small modules at diverse locations, the on-site generation of electricity is not expected to dominate the market.

As in any speculative venture of this type, utilities will naturally be cautious in the beginning. In the case of nuclear power, the promise of large base-load units operation with a significantly lower fuel cost was used to overcome the initial resistance to investing in a new energy source. In contrast, PEPS will have to be appealing as an intermediate or peaking facility.

* "Statistical Year Book of the Electric Utility Industry for 1973," Edison Electric Institute.

** "A National Plan for Energy Research, Development, and Demonstrations: Creating Energy Choices for the Future," ERDA-48, Volume 2: Program Implementation.

4. Both PEPS and nuclear power must be integrated into existing utility networks. This did not present significant problems for nuclear power because nuclear reactors had the potential to be large basic plants (1,000 mwe) operating at a high capacity factor (original estimates were in excess of 80%). PEPS will not have the advantage of being an extremely reliable power source. However, the basic issue of integrating the PEPS into the existing utility network must be accomplished, as it was for nuclear power, if the predicted generating capacity is to be realized.

5. Both PEPS and nuclear power benefited from a "head start" in the development of commercial systems. PEPS is certainly further advanced because of the space photovoltaic program, just as nuclear power was from the naval program and the nuclear weapons program.

6. Statistics compiled by the Edison Electric Institute* show that nuclear power provided 0.07% of the total U.S. generation in 1960, 0.35% in 1965, 1.42% in 1970, and about 8.5% in 1975. It was only after 25 years of intensive efforts by government and industry that a significant impact was realized in the amount of electricity generated by nuclear power.

PEPS has some advantage over nuclear power in that it is less complex, has fewer moving parts, is less hazardous, can be modularized, etc. For these reasons, there is an expectation that PEPS should require less time than did nuclear power to make a meaningful impact on the power generation mix.

7. Both PEPS and nuclear power are extremely capital intensive. Despite the best efforts of government, manufacturers, and the utility industry, the cost of nuclear power today is approaching \$1,000/kw of installed capacity. PEPS may face similar problems in attaining cost reductions.

8. One parallel that exists between PEPS and nuclear power is applicable to any emerging technology. Almost invariably the new technology appears simple and straightforward, but problems occur during the developing years that were not anticipated earlier. As an example, the demonstration of the feasibility of nuclear power for generating electricity was essentially complete by 1965. However, the many additional problems associated with nuclear energy are still emerging. Areas such as safety, thermal pollution, reprocessing of spent fuel, uranium supply, plutonium recycle, waste disposal, financing, etc., have emerged in recent years. It is reasonable to expect that a group of unforeseen problems will plague the development of PEPS.

* "Statistical Year Book of the Electric Utility Industry for 1973,"
Edison Electric Institute.

9. Any new technology will have stringent requirements to minimize risk to the general public. This is true for both PEPS and nuclear power. As previously discussed, the Price-Anderson provisions of the Atomic Energy Act of 1954, with amendments, provided insurance against the risks of nuclear power.

It seems prudent for the federal government to at least study the insurance problem as it applies to PEPS. Because PEPS appears to have considerably lower risks than nuclear power, the liability of the government should be much less than the \$560 million limit for each claim against nuclear accidents. There is a possibility that private insurance pools will be able to handle the entire coverage.

10. There is some concern in the industry because ERDA has apparently decided to emphasize single-crystal silicon cells for PEPS. Manufacturers and proponents of gallium arsenide or cadmium sulfide and other thin-film cells are not convinced that this emphasis is completely justified. A striking parallel exists with the nuclear reactor industry.

Although many varieties of nuclear reactors were experimented with in the beginning, the AEC decided to support the BWR and PWR as the primary reactor types. One result of this action is evident in the case of the HTGR. After trying to develop this concept for many years, General Atomic recently announced that it was terminating all sales of these reactors and began "buying out" contracts already signed. If the HTGR received the enormous subsidy provided to the BWR and PWR, the concept might have survived.

A similar situation exists with the breeder reactor programs. Although such concepts as the molten salt breeder reactor and the gas cooled fast breeder reactor are technically comparable, the decision was made to pursue primarily the liquid metal fast breeder reactor. Critics of this decision argue that it is not the best policy to sink all of the funds in only one concept without more research and data. The same criticism may apply to the PEPS silicon cell decision.

11. Neither PEPS nor nuclear power was cost competitive in the initial stages of development, so government subsidy efforts will probably also have to play an important role in the PEPS development program. The potential of each of these industries has been demonstrated, but the cost of the system is much greater than utilities can afford to pay.

The cumulative governmental subsidy to the nuclear power program stands near \$25 billion at the present time. This includes both R&D and direct costs incurred by the federal government. It is fairly certain that the utility industry could not have begun to invest money at that rate on a somewhat speculative source of energy. A similar reluctance of utilities to undertake R&D also exists in the case of PEPS.

In addition to the similarities between PEPS and nuclear power, there are some noticeable dissimilarities. Some of the issues which are not parallel between the two industries are presented in the following discussion.

1. There probably will be no defense aspects associated with PEPS. The government has been forced to operate uranium enrichment facilities for defense reasons. The government is also heavily involved with the back end of the nuclear fuel cycle, i.e., spent fuel reprocessing and waste storage.

2. PEPS has no fuel cycle to support. There will be no mining or milling industry to support, and no fuel reprocessing or waste storage. PEPS technology may therefore face fewer technical and institutional problems than nuclear power.

3. Nuclear power has the advantage of being primarily a "base-load" source of electric energy, in contrast to PEPS which has a highly variable availability. This fact implies that PEPS without backup may not displace conventional generating capacity--only energy. The availability of PEPS can be increased to displace capacity if it is combined with gas turbine capacity. The PEPS then becomes similar to intermediate load plants.

4. Public acceptance of PEPS should be easier than for nuclear power. So far at least, public criticism of solar energy has not been prevalent. Opposition to PEPS may increase as the full impact of the land area required becomes better defined. However, it is not expected that PEPS will face the opposition that nuclear power has had to overcome.

5. In order to overcome the myriad of problems that beset the emerging nuclear power industry, the AEC used a multifaceted subsidy program. All phases of the industry were subsidized in some form. This included the fuel cycle, reactor development, demonstration reactors, etc.

In contrast, the PEPS subsidy program to date has been aimed primarily at research. However, as the factors which influence the development of PEPS are identified, supporting programs will probably evolve in a manner similar to the evolution of the nuclear program.

9.4 GOALS FOR RESEARCH DEVELOPMENT AND DEMONSTRATION (RD&D) PROGRAM

One of the most fundamental findings of this assessment is that essentially no commercial utilization of PEPS technology will likely occur before the year 2000 without substantial action by the federal government. This finding gives rise to the issue of how much government involvement in the commercial development of a technology is justified. What is an acceptable boundary between government intervention which overcomes deficiencies in the free enterprise system, and government intervention which constrains the desirable features of that market system? To develop answers to this basic question of governmental theory is a task far beyond the intentions or capabilities of this assessment. Indeed, it can be reasonably claimed that well-defined answers do not exist. Nonetheless, preliminary comments regarding the possible role of government in the commercial development of solar energy technology have a legitimate place in this analysis.

Financial support of Research, Development and Demonstration (RD&D) has long been regarded as acceptable involvement of government in business, particularly if the development of the technology is judged to be in the public interest and would not occur without government involvement. This concept has been increasingly applied to other business activities until government has become a central influence in many aspects of the marketplace through taxation, subsidies, and regulation. It is unlikely that such trends will be reversed. But recent failures and excesses of government have called its role into question. These inadequacies are particularly evident in the history of regulation of energy supplies and prices to support an ad hoc national policy of cheap energy. Now, however, amidst considerable sentiment to remove regulatory constraints currently applied to the energy industry, elements of the business community are calling for increased federal involvement to facilitate commercial development of solar energy. They are asking not only for support of research and development, but also financial assistance for business development.

Specifically, it appears that the role of the government in PEPS-related RD&D should be directed at two goals. The first goal should be to reduce the cost of delivered electricity from a PEPS installation. This means that all costs associated with the entire system must be considered and efforts made to reduce these costs where possible. The second goal of government-supported research should be to examine, in detail, the social benefits (and possible disbenefits) associated with the development of PEPS technology. The results of such a detailed assessment will provide guidance as to the appropriate levels and objectives of incremental governmental funding of RD&D activities or incentive programs.

An RD&D program by the federal government can reduce the cost of PEPS in three general areas:

- Improvements in the efficiency of photovoltaic cells.
- Reduction in the cost of concentrator devices and related hardware.
- Reduction in cell costs.

Each of these three areas of potential cost reduction is discussed in the following paragraphs, in light of the information gained in this conceptual design study.

9.4.1 Improvement in the Efficiency of Photovoltaic Cells

An increase in the efficiency of photovoltaic cells reduces the number of cells required to deliver a given amount of energy. If the increase in efficiency is obtained without a proportionate increase in cost, a reduction in the total cost of cells will result. However, examination of the effect of improvements in cell efficiency upon system costs reveals additional savings beyond the direct savings in cell costs. Many of the PEPS component costs are directly proportional to the aperture area of the photovoltaic array. Thus, the reduction in aperture area resulting from increased cell efficiency will result in a proportional reduction in total cost. Table 9.4.1-A lists the estimated cost of those area-related components at \$869/kwe and \$363/kwe respectively for focusing and non-focusing systems. If we assume an initial cell efficiency of 15%, an improvement in cell efficiency to 18% would result in a system cost reduction (not including savings in cell cost) of \$145/kwe and \$61/kwe respectively for focusing and planar systems. This has the same effect upon total system cost as reducing cell cost by \$420/m² for the focusing system and by \$6/m² for the planar system. Thus, minor improvements in cell efficiency can have a sizeable effect upon the total system cost. This effect is especially pronounced on focusing systems. Because of this sensitivity of system cost to cell efficiency, R&D directed at improving cell efficiency should be encouraged. In fact, for focusing systems, R&D to increase cell efficiency should be given higher priority than RD&D to reduce cell costs.

System cost can still be reduced, even if improvements in cell efficiency result in higher cell costs (\$/m²). Figures 9.4.1-A and 9.4.1-B illustrate the trade-off that exists between improvements in efficiency and increases in cell costs for focusing and planar systems, respectively. An efficiency improvement factor (the ratio of resulting efficiency η to the initial efficiency η_0) is the vertical axis, while the cell cost factor (the ratio of resulting cell cost P to initial cell cost P_0) is the horizontal axis of Figures 9.4.1-A and 9.4.1-B.

TABLE 9.4.1-A

COMPONENTS OF PEPS COST WHICH ARE PROPORTIONAL
TO ARRAY APERTURE AREA*

	<u>Focusing System</u> (\$/kw)	<u>Planar System</u> (\$/kw)
Site Preparation, Roads, Security	39	39
Array Foundations	72	72
D. C. Wiring	56	56
Array Structure	391	196
Substrate and Heat Rejection	6	----
Tracking Drives	50	----
Primary Mirror	<u>254</u>	<u>----</u>
Total	\$869/kw _e	\$363/kw _e

* Does not include cell costs

Figure 9.4.1-A - Trade-off Between Improvements in Cell Efficiency, Increases in Cell Cost, and Reductions in System Cost for a Focusing PEPS.

Figure 9.4.1-B - Trade-off Between Improvements in Cell Efficiency, Increases in Cell Cost, and Reductions in System Cost for a Planar PEPS.

Lines of constant system cost are plotted on these two graphs. As an example, from Figure 9.4.1-A an improvement in cell efficiency by a factor of 1.20 ($\eta/\eta_0 = 1.20$) would reduce system cost from \$1,157/kwe to approximately \$1,000/kwe, if cell cost did not change. The same reduction in system cost could also be obtained at twice the cell cost ($P/P_0 = 2.0$) if cell efficiency were improved by a factor of 1.29 rather than 1.20. A similar, though less dramatic, trade-off exists with planar systems, as illustrated in Figure 9.4.1-B.

9.4.2 Reduction in the Cost of the Concentrator Subassembly

The cost advantage of focusing over planar photovoltaic systems results from trading lower cost concentrator sub-systems for higher cost cells. Based upon the 200 mw central station design presented in this study, focusing systems are more cost-effective than planar systems at cell costs greater than approximately \$48/m². RD&D activities directed at reducing the cost of the concentrator sub-system could reduce the cell cost beyond which concentrators are most cost effective.

The concentrator sub-system consists of the concentrator structure (\$391/kw), the primary mirror (\$254/kw) and the tracking drives (\$50/kw). The total cost of the concentrator sub-system equals \$695/kw or 60% of the total PEPS cost of \$1,157/kw. Thus, reductions in the cost of the concentrator sub-system will result in significant reductions in the total system cost. Figure 9.4.2-A illustrates the effect of 10, 20 and 30% reduction in the concentrator subsystem. Table 9.4.2-A indicates the effect of reduction in the cost of the concentrator subassembly on the total system cost and the cell cost above which concentrator systems are more cost-effective.

TABLE 9.4.2-A

THE EFFECT OF REDUCTIONS IN CONCENTRATOR SUB-ASSUMBLY COST ON SYSTEM COST

<u>Reduction In Concentrator Cost</u> (%)	<u>Total System Cost</u> (\$/kw)	<u>Cell Cost Above Which Concentrating Systems Are More Cost Effective</u>	
		(\$/m ²)	(\$/peak watt, $\eta=15\%$)
0	1157	49	0.33
10	1088	42	0.28
20	1018	35	0.23
30	949	29	0.19

Figure 9.4.2-A - Total System Cost vs Cell Cost for Different Levels of Reduction in Concentrator Subsystems Cost.

From Figure 9.4.2-A and Table 9.4.2-A, it can be seen that reductions in the cost of the concentrator subassembly can produce significant reductions in the total system cost. Therefore, RD&D activities directed toward reducing the cost of concentrators are justified. Such activities might include:

- R&D to improve reflectivity of surfaces;
- Systems analyses to optimize efficiency of supporting structure;
- Design analyses to reduce the cost of tracking drives;
- Detailed evaluations of cost reduction potential of high volume production techniques; and
- Competitive RFP's for design and fabrication of low-cost concentrator modules.

9.4.3 Reduction in Cell Cost

The major objective of ERDA photovoltaic RD&D has been the reduction of the cost of planar non-concentrating arrays by means of reduction in cell manufacturing cost. It is clear that very large cost reductions must be achieved to bring the cost of planar arrays into a competitive range, and the achievement of the required cost reductions implies major technical advances in photovoltaic technology and dramatic expansion and re-structuring of the photovoltaic industry. Both the technical and economic problems involved in this approach are clearly formidable.

Concentrating arrays may be more limited than planar arrays in their range of applications, but they appear to be equally (or in some cases better) suited to utility central station and larger on-site applications. As discussed above, reductions in cell cost are not a particularly powerful approach to achieving cost reductions of concentrating arrays, especially if lower cell efficiency is a consequence of cost reductions. More powerful approaches are increasing cell efficiency and reducing concentrator cost. Increased RD&D support in these areas should be given a high priority, because the required improvements over existing technology are much more modest than the cell cost improvement required to make planar arrays cost-competitive, and the industrial implementation of the resulting technology is likely to involve fewer problems.

9.4.4 Summary of Relative Payoffs of Three Areas of RD&D

The purpose of this section is to compare the relative payoff likely to result from the three RD&D areas which have been identified. This comparison could be made at any of several nominal values of cell cost. It seems appropriate to select a cell cost representative of a level that can be achieved relatively easily without major breakthroughs but with improved production techniques and the other economic benefits of volume production. A cell cost of \$500/m² (\$3.33 per peak watt, $\eta = 15\%$) is an appropriate cell cost. Table 9.4.4-A presents the necessary results from each of the three RD&D areas to reduce the cost of PEPS by 10%.

TABLE 9.4.4-A

RELATIVE EFFECTIVENESS OF THREE AREAS OF RD&D

Total System Cost (\$/kw)	% Reduction in System Cost	Required Results of RD&D Efforts		
		% Increase in Cell Efficiency	% Reduction in Concentrator Cost	% Reduction in Cell Cost
1269	0	--	--	--
1142	10	14%	18%	308%

From Table 9.4.4-A, it is obvious that improvements in cell efficiencies have the greatest effect on system cost, while reduction in concentrator costs is nearly as effective. Reductions in cell costs, on the other hand, must be approximately 20 times greater to provide the same reductions in system cost.

9.5 THE SOCIAL BENEFITS OF PEPS

9.5.1 The Social Justification for Government Expenditures on PEPS

The economic analysis conducted in Section 9.2 indicates that at the present time PEPS cannot effectively compete with conventional energy sources in the private sector marketplace. However, the value of PEPS as perceived by a corporation may be significantly less than their value to the nation as a whole. External social costs associated with conventional energy sources include pollution, national security and the depletion of fossil energy resources. These costs of conventional energy sources (or benefits to the PEPS) increase the value of PEPS to the society as a whole.

Government decisions must be based on the broadest interests of society. RD&D expenditures and various other subsidies are considered a national investment in the future. In the area of photovoltaics, this investment is made in a future renewable energy source that is part of the long-term solution to the nation's energy problems. The return on such a national investment may not begin until 10 to 25 years from its inception as evidenced by the nuclear program. The federal government takes a larger time frame into account than individuals or corporations. It is probably the only organization that would be willing to invest in a venture with so many years before payoff. The exact time frame appropriate for government investments, however, is under considerable debate among economists, political scientists and members of numerous other professions.

The debate over appropriate time frames for government investments is best reflected in the controversy over social discount rates. The discount rate is applied to future costs and benefits of a project to account for the investment opportunities which are foregone by spending funds in the present. The discount rate should reflect the value of time to the decision-maker. Subsequently, the social discount rate should reflect the value that society places on time.

A wide variety of social discount rates have been used by economists. These rates vary from zero to almost 15%.^{1/} A social discount rate of zero implies that the future is valued as much as the present, and that there is a

^{1/} A variety of discount rates used by economists is summarized in "Our R&D Economics and the Space Shuttle" by Klaus Heiss (Astronautics and Aeronautics, October 1971) p. 57.

one to one tradeoff between present and future cost.* This is an unconventional value for the discount rate because it implies that time has no value. In other words, receiving a sum of money 10 years from today is exactly equivalent to receiving the same sum today. No account is taken of investment opportunities that are given up today by not receiving the sum until the future.

The real social rate of discount used throughout most of this study will be 5%. The economic literature provides as many agreements as disagreements with this choice. Therefore, the 5% assumption will be subjected to some sensitivity analyses.

Although the time horizon for government investment is questionable, there is some agreement among economists that the expenditures should yield a positive return in the future. The return on the government investment does not necessarily have to be monetary, and it does not have to be received directly by the government. The return may be non-monetary in nature, and could be received by any group or groups within the society.**

If the investment yields a positive social return, using some pre-specified social rate of discount, the nation will be better off than before the program. The phrase "better off" is a value judgement that requires further clarification. The value judgement assumed for this analysis is that more goods and services are preferred to less.

The cost-benefit approach is used in this analysis. It assumes that the satisfaction lost by an individual who bears \$1.00 of the cost of a project is equal to the satisfaction gained by the individual receiving a dollar in benefit. In other words, it assumes that the marginal utility of all individuals in the society is constant. This assumption can lead to many types of misconceptions about the tradeoff between social cost and benefits. Impacts on the distribution of income will be especially misrepresented. Although this drawback of cost-benefit analysis is realized, no acceptable way of avoiding it has been formulated. Therefore, the reader is cautioned that income distribution considerations are not included in the analyses that follow.

* Some individuals hold that resources for future generations should be valued higher than the present generation. This argument would support the use of a negative social discount rate.

** Those sectors receiving these social benefits may not be the same sectors that paid for the investment. However, the problem of equitable distribution of social wealth between groups within the nation will not be addressed extensively in this analysis.

In summary, research, development and demonstration expenditures and even permanent subsidies can be regarded as societal investments. These investments should yield some societal benefit in the future. The benefit must be at least large enough to recoup the initial investment, cover the cost of time between the outlay and the payoff (expressed by the social rate of discount), and pay society for the risks of the investment. Any benefit above this minimum will make the society better off than before the investment. RD&D programs for PEPS and other energy technologies will be compared in this study from a societal investment viewpoint. Social costs and benefits that are external to private sector decision makers will be of special interest in the remainder of this chapter.

9.5.2 The Social Benefits of PEPS Investments

The social justification for a national investment in research, development and demonstration of PEPS will have to be based on the following factors:

1. Social value of not polluting the environment as a byproduct of electricity production.
2. Social value of not depleting finite energy resources in the production of electricity.
3. Social value of insurance against foreign energy curtailments, restrictions or price increases.
4. Social value of the technology for exportation to other nations.
5. Social value of information gained that could be transferred to other energy problems (e.g., the development of practical energy storage systems).
6. Any improvement in national employment or economic conditions due to the RD&D program or the growth of a new industry.

The future value of each of these factors depends on a large variety of events. For example, if conservation and the discovery of new domestic energy reserves occur before the year 2000, the need for energy imports may be eliminated. Therefore, the value of a PEPS research program as national insurance against foreign energy curtailments would become negligible. Conversely, a nuclear moratorium before 1985 would dramatically increase the value of a PEPS research development and demonstration program. Under these circumstances, the social benefits of national insurance, non-depletion of domestic energy sources, and pollution abatement become very high.

Each of the major social benefits associated with a photovoltaic RD&D program will be discussed in more detail below. Major national and international events that could affect these benefits are also examined.

1. The social benefits of PEPS related to pollution, health, and safety: A large amount of literature has evolved that deals with the social cost of pollution created from the generation of electricity.^{1/} Most of these studies also investigate the social costs incurred by increases in health and safety hazards. Social cost estimates have been derived for coal, nuclear, natural gas and oil-fired generating plants. Using photovoltaics for the production of electricity avoids the pollution created by these alternative generating facilities. Therefore, society receives the benefit of a less polluted environment as a result of PEPS use.

Avoidance of pollution by PEPS is not adequately considered by private sector investors. The benefits of a cleaner environment do not accrue only to the PEPS investor. Since the investor can receive no monetary reward for a cleaner environment, he will not be willing to pay an additional amount for this benefit of PEPS. However, the society does receive the benefits of a cleaner environment and should, therefore, bear the additional cost.

Although the private investor does not consider the social benefit of reduced pollution in the purchase of PEPS, he partially considers the pollution effects of alternative electricity sources. Environmental standards require that the investor add pollution control equipment to most conventional electricity plants. The cost of pollution control forces the investor to bear a portion of the cost (or internalize some of the cost) of degrading the environment. That is, through pollution control equipment expense, the investor bears part of the social cost of pollution. The percentage of the social cost not reflected in the private cost of control equipment still does not enter the private-sector decision. A similar argument can be made for the social benefits due to any reduction in health and safety hazards.

It is generally agreed that a clean, safe and healthy environment has value to the society. However, it is extremely hard to obtain estimates of that value. One of the most complete estimates of pollution, safety and health damage is contained in the Atomic Energy Commission (AEC) Report

^{1/} Representative works in the field include (1) Comparative Risk-Cost-Benefit Study of Alternative Sources of Electrical Energy, U.S. Atomic Energy Commission, December 1974, U.S. Government Printing Office, 1974, and (2) Social Costs for Alternate Means of Electrical Power Generation for 1980 and 1990, Argonne National Laboratory (USAEC Technical Information Center, 1973).

(Wash. 1224).^{1/} The AEC report is also one of the few sources of estimates of the economic value of these social costs. Reluctance by most authors to make such estimates is understandable. Any estimates of the values of pollution, health or safety will be vigorously attacked by at least one group in the society.

Table 9.5.2-A presents the AEC estimates of safety, health and environmental costs associated with coal, oil, gas and LWR power plants having a capacity of 1,000 mw and a capacity factor of 0.75. The most striking aspect of the AEC estimates is their insignificance compared to the private (or market) costs of the power plants. The total human (both health and safety) and environmental costs equal between 3% and 5% of the market cost of power plants.^{2/}

One might expect that a study conducted for the Atomic Energy Commission would underestimate the social costs of pollution, safety, and health. One way of underestimating these social costs is by expressing them as a constant cost per unit of installed generating capacity. The constant cost estimate breaks down because the effect of pollution is often cumulative.

In addition, the societal response to these social costs is non-linear and is not necessarily related to any cost estimate. When air pollution affected only a very small segment of society, its social costs were borne by those affected. As air quality in major urban areas declined to the point that the effects of air pollution were clearly felt by a large part of the population, societal pressure resulted in the mandating of air pollution control regulations. One result of these regulations is that the cost of required air pollution control equipment for a fossil fuel generating plant has now become a significant item in plant cost, and this item is easily 100 times larger than the annual social cost of pollution as estimated by the AEC.

One can only speculate on the impact on the cost of nuclear power which would result from a major accident at a nuclear generating plant, affecting a considerable part of the neighboring population. In any case, it is clear that the social costs of electrical generation by conventional means, as perceived by society and expressed through the political process, bear no necessary relation to economists estimates. Society may well be willing to pay much more than the costs estimated in Table 9.5.2-A in order to avoid these adverse effects.

1/ Comparative Risk-Cost-Benefit Study of Alternative Sources of Electrical Energy, United States Atomic Energy Commission (Wash. 1224, December 1974).

2/ Ibid., p. 1-19.

TABLE 9.5.2-A

ATOMIC ENERGY COMMISSION ESTIMATES OF POLLUTION, HEALTH
AND SAFETY COSTS OF VARIOUS ELECTRIC POWER PLANTS ^{f/}
(EXPRESSED IN 1980 DOLLARS)

	<u>Coal</u>	<u>Oil</u>	<u>Gas</u>	<u>LWR</u>
Safety (\$10 ⁶ /yr)				
Occupational ^{a/}	0.46	0.086	0.039	0.05
Public ^{b/}	<u>0.18</u>	<u>u</u>	<u>u</u>	<u>0.003</u>
Subtotal	0.64	>.086	>0.039	0.053
Health (\$10 ⁶ /yr)				
Occupational	0.03 ^{c/}	u	u	0.024 ^{d/}
Public	<u>u</u>	<u>u</u>	<u>u</u>	<u>0.01^{e/}</u>
Subtotal	>0.03	u	u	0.034
Environmental Effects (\$10 ⁶ /yr)				
Water Base	0.4	0.4	0.4	0.6
Air Base	0.8	0.6	0.1	s
Land Base	<u>0.2</u>	<u>s</u>	<u>s</u>	<u>s</u>
Subtotal	1.4	1.0	0.5	0.6
Total Safety, Health and Environ- mental Effects (\$10 ⁶ /yr)	>2.1	>1.1	0.5	0.7

Key: u = unevaluated, s = small

- Footnotes: (a) Conventional injuries in routine industrial accidents, including fatal and non-fatal injuries; 1 death = 6,000 MDL = \$300,000
- (b) Conventional injuries in accidents in transportation of fuels; 1 death = 6,000 MDL = \$300,000
- (c) Coal workers' pneumoconiosis (CWP)
- (d) Radiological health effects, including lung cancers among uranium miners.
- (e) Radiological health effects from routine emissions
- (f) Assumes 1000 MW plant having a capacity factor of 0.75.

Source: Comparative Risk-Cost-Benefit Study of Alternative Sources of Electrical Energy, United States Atomic Energy Commission (December 1974), pp 1-18 and 1-19.

Although these problems are important, it is outside the scope of this study to try to improve the estimates of the social cost of pollution; health or safety made by previous investigators. However, it is possible to conduct a sensitivity analysis on these social cost estimates to examine the effect of such variations on the societal benefits attributable to PEPS.

The social cost estimates presented in Table 9.5.2-A can be interpreted as social benefits of PEPS. Table 9.5.2-B presents estimates of these social benefits in equivalent dollars per kilowatt of PEPS capacity.

TABLE 9.5.2-B

THE SOCIAL VALUE OF PEPS AS A NON-POLLUTING ENERGY SOURCE

Power Plant being Replaced by PEPS	1980 Dollar Cost of Pollution, Safety and Health Per Year \$10 ⁶ /yr	Present Value of Cost Over 30 Yr at 10% \$10 ⁶	Present Value of Cost Per kw \$/kw	Social Value of Displacement by PEPS ^{a/} \$/kw of PEPS
Coal	>2.1	19.80	19.80	5.28
Oil	>1.1	10.37	10.37	2.76
Gas	>0.5	4.71	4.71	1.26
LWR	0.7	6.60	6.60	1.76

^{a/} Assumes a capacity factor of 0.20 for PEPS and 0.75 for all conventional alternatives.

Columns 1 and 2 of Table 9.5.2-B present the results of the AEC report.^{1/} Column 3 uses a 10% discount rate to translate the dollar cost per year to a present value figure for 30 years. The present value of the cost per kilowatt is expressed in Column 4. The last column presents the social value of displacement by PEPS. To express the value per kilowatt, a capacity factor of 0.20 was assumed for the PEPS and 0.75 for all the

^{1/} Ibid.

alternatives. These dollar values assume that the PEPS creates no environmental degradation and does not harm the health or safety of humans in any way. In spite of this rather extreme assumption about PEPS, the dollar value of these benefits barely exceed \$5.00/kw. The PEPS market or private cost estimates obtained in this study average \$1,000/kw to \$1,700/kw.^{1/} The social value of PEPS amounts to 0.3% to 0.5% of the private costs. Therefore, one can conclude, using the AEC estimates, that the social value of PEPS in avoiding pollution, health and safety hazards is not large enough to justify any government support.

The estimates in Table 9.5.2-B vary with changes in the assumptions. Table 9.5.2-C shows the effect of the discount rate on the value of the pollution, health and safety benefits.

TABLE 9.5.2-C

THE EFFECT OF DISCOUNTING ON THE SOCIAL VALUE
OF PEPS AS A MEANS OF POLLUTION ABATEMENT

<u>Social Discount Rate</u>	<u>Present Value of Cost of Pollution, Health and Safety^{a/} (over 30 yr) \$10⁶</u>	<u>Social Value of PEPS as Means of Pollution Abatement^{b/} \$/kw of PEPS</u>
0%	63.00	16.80
5%	32.28	8.61
10%	19.80	5.28
15%	13.79	3.68

Source: Atomic Energy Commission, op.cit.

a/ Assuming a cost of \$2.1 x 10⁶/yr for pollution, and reductions in health and safety occurring in the operation of a 1,000 mw coal fired plant operating at 0.75 capacity factor.

b/ Assuming a PEPS capacity factor of 0.20 and assuming the PEPS has no negative effects on the environment or the health and safety of humans.

Although discounting changes the social value of PEPS, the change is not enough to warrant significant government investment. Even with a zero discount rate, the value of PEPS as pollution control is only \$16.80/kw--less than 2% of the estimated private cost of PEPS.

1/ See Chapter 9.2, Economic Analysis of PEPS.

Table 9.5.2-D examines how possible inaccuracies in the AEC estimates would affect the social value of PEPS as a means of pollution abatement. The effect of possible inaccuracies is not large when compared to a market price of PEPS of \$1,000 to \$1,700/kw. Table 9.5.2-D was constructed to show how higher pollution, health and safety costs may influence the social benefit of PEPS. It does not imply that the AEC report was inaccurate or that it purposely underestimated these social costs. The alternative costs shown in Table 9.5.2-D have not been proven empirically superior to the AEC estimates.

TABLE 9.5.2-D

THE EFFECT OF ALTERNATIVE POLLUTION COST ESTIMATES ON THE
SOCIAL VALUE OF PEPS AS POLLUTION CONTROL

<u>Dollar Cost of Pollution, Safety and Health^{b/} \$10⁶/yr</u>	<u>Present Value of Cost (30 yr at 10%) \$10⁶</u>	<u>Social Value of Displacement by PEPS \$/kw of PEPS</u>
2.1 ^{a/}	19.80	5.00
4.2	39.60	10.56
6.3	59.40	15.84
12.6	118.80	31.68

a/ \$2.1 x 10⁶/yr represents the AEC estimate (Wash 1224). It includes the cost of health and safety degradation, as well as pollution costs.

b/ Associated with a coal-fired 1,000 mw power plant operating at 0.75 capacity factor.

In summary, it appears that under most conditions, and if one assumes that a PEPS would eliminate all health and safety problems of a comparable conventional system the value of photovoltaic technology as a form of pollution control is not large, especially when compared to the estimated market price of the system. Given a liberal estimation of the costs of pollution (or given low discount rates), the social benefits of PEPS as a means of pollution, health and safety control is between \$5.00 and \$20.00/kw of PEPS capacity. However, if environmental degradation becomes significantly worse, this value may increase substantially. Similarly, its value may increase if health and safety problems associated with nuclear and coal power become severe in the future.

2. Conservation of domestic energy resources: Another potential social benefit of PEPS is the conservation of domestic energy resources for

future generations. The value of this social benefit is not considered by private sector decision makers if the market price of conventional energy is not at its competitive equilibrium level. Conventional economic price theory holds that, under conditions of perfect competition, the equilibrium price of a resource reflects current market conditions and expectations of its future value. In this perfectly competitive world, the value of the resource to future generations would be reflected in current prices. Therefore, the social benefit of conserving the resource would not have to be estimated separately.

In addition to arguments about competitive pricing, economists have attempted to relate the availability of natural resources to long-term economic growth. In fact, the scarcity of natural resources (or capital) has been a key element of most economic growth theory. Growth theory, although algebraically complex, fails to offer many significant conclusions about how the availability of a specific energy resource influences economic growth. Some examples from classical growth theory will serve to illustrate this point.

The first example is a simplified society in which no technological progress occurs.^{1/} All natural resources are homogeneous and available without limit. The condition is labeled "Utopia" by the authors.^{2/} Labor inputs grow according to the population growth and capital accumulates to keep the ratio of labor to capital constant. Growth continues restricted only by population growth while resource availability exerts no influence. Returns on capital do not charge overtime.

The second example places restrictions on the quantity of resources available. In this case, termed Mathematician scarcity,^{3/} growth continues as in the first case until resource limits are reached. At that point the labor to capital ratio increases, marginal returns decrease, and growth slows.

The third example further assumes that resources are not homogeneous in physical characteristics or location. As growth continues, resources with different characteristics are pressed into productive uses. If it is further assumed that the society uses these resources in order of increasing costs, then cost per unit of output increases as resource limits are approached.

1/ Scarcity and Growth; The Economics of Natural Resource Availability
H. Barnett and C. Morse, John Hopkins Press, Baltimore, Maryland,
1979), pp. 1-11.

2/ Ibid.

3/ Ibid., p. 2.

These three cases illustrate some basic characteristics of natural resources and economic growth. However, considerable questions arise when the impact of more than a single resource is assessed. A number of crucial conditions of existing in a society are ignored in the foregoing examples. Those conditions include:^{1/} (1) the stock of resources is not constant; (2) substitutions in resource inputs can stop the depletion of almost any resource; (3) there are possibilities for increasing returns per unit of input due to changes in production organization; (4) resources may not necessarily be used in order of decreasing quality; (5) technological innovations occur continuously; and (6) new technology makes previously unvalued resources valuable and once valuable resources unnecessary.

Technological advances, substitutions in resource inputs, and changes in societal tastes are extremely important to the future value of a society's resources. These changes also place the value of conserving resources in question. According to Barnett and Morse:

"The reservation of particular resources for later use, therefore, may contribute little to the welfare of future generations. The social heritage consists far more of knowledge, equipment, institutions, and far less of natural resources, than it once did. Resource reservation, by limiting output, and thereby research, education and investment, might even diminish the value of the social heritage."^{2/}

Based on this argument, it is unlikely that any social benefits can be assigned to the conservation of domestic energy supplies other than those benefits incorporated in the private-sector price.

3. Insurance against foreign energy curtailments: One of the major objectives of recent U.S. energy policy has been to reduce the U.S. dependence on foreign energy supplies. This national objective implies that reduced foreign energy dependence is valuable to the nation. The nation, through the federal government, has demonstrated that it is willing to pay to achieve this objective. Therefore, any technology or action which reduces our foreign energy dependence has a value to society greater than its private cost.

Photovoltaic technology reduces U.S. dependence on foreign energy because it utilizes the sun's radiation rather than imported fuels. Electricity produced from PEPS instead of from conventional means, especially oil-fired plants, offers a societal advantage not reflected in the price. The development of PEPS technology can be viewed, in part, as insurance against foreign curtailment and price manipulation of fuels for electricity. The nation should be willing to pay a premium for this type of insurance. The appropriate dollar amount of this premium, or the value of this insurance, is investigated below.

^{1/} Ibid., pp. 4-11.

^{2/} Ibid., pp. 11-12.

One method of estimating the value of PEPS as national energy insurance is to use an alternative technology to estimate the cost of insuring the nation. One available alternative is the stockpiling of petroleum. An MIT Energy Laboratory study has investigated petroleum stockpiles.^{1/}

The MIT study states that, although the U.S. maintains reserves of metals and other natural resources, no crude oil stockpiles (above normal inventories) are held. Stockpiling could allow the U.S. to avoid foreign curtailments and take maximum advantage of fluctuating crude oil prices. The U.S. could fill stockpiles after a decrease in world crude oil prices or before an announced increase in prices. The size of the stockpile will depend on "the magnitude of the expected interruptions and on the volume of imports permitted."^{2/} For a given level of imports, the larger the stockpile, the longer the U.S. can withstand curtailments without serious domestic impacts.

The MIT study estimated the cost to the U.S. of stockpiling at two levels. The lower stockpile contains 730 million barrels of crude oil. Assuming that a mix of above-ground and below-ground storage facilities is used, they estimate the cost of the facilities to be \$3.00/barrel. The purchase price of the oil is \$8.00/barrel, and annual operating cost is \$0.10/barrel. If we assume a 15% interest and depreciation for the facilities and 10% interest on the oil, the report estimates the carrying cost to be \$1.35/barrel/year. The annual cost of stockpiling 730 million barrels would be \$990 million.^{3/} The cost of constructing the facilities would be \$2.2 billion.

The larger stockpile would contain 4.4 billion barrels of oil and cost the U.S. approximately \$5.9 billion/year. According to the study, the stockpile would add \$1.50/barrel to the cost of oil in the U.S. In spite of these large costs, the MIT study concludes, "The cost of the high stockpile compares favorably with the alternative of eliminating dependence on impacts."^{4/}

^{1/} Energy Self-Sufficiency, An Economic Evaluation, by MIT Energy Laboratory Policy Study Group (American Enterprise Institute for Public Policy Research, Washington, D.C., 1974) pp. 69-71.

^{2/} Ibid., p. 69.

^{3/} All the above price estimates are taken from the MIT report cited above, p. 69.

^{4/} Ibid., p. 71.

Let us assume stockpiling represents an alternative technique for insuring against foreign energy (at least oil) curtailments. The value of similar insurance from a PEPS program should be reflected in the cost of stockpiling.

As discussed previously, the MIT study estimates the cost of stockpiling at \$1.35 barrel/year for the smaller stockpile (730 million barrels). By using a 10% discount rate, the present value of that cost over 30 years is \$12.72 barrels or $\$2.31/10^6 \text{ Btu}$. In other words, the U.S. is willing to pay $\$2.31/10^6 \text{ Btu}$ of stockpiled oil for insurance against foreign oil curtailments.

A PEPS program by the U.S. government would act as insurance against foreign curtailment of electricity fuels. One would expect the value of national insurance for crude oil to be higher than the value of insurance against foreign curtailments of fuels for electricity. There are two major reasons for the difference. First, there are more domestic fuels (such as coal) that can be used in electricity generation than can be substituted for crude oil. Second, oil is a more versatile energy source. It can be used in transportation or feedstock production, in addition to producing electricity. There is no information on how large the difference should be between the values of these two types of national insurance. For this study, we will arbitrarily assume that the U.S. is willing to pay half as much to guarantee the availability of fuels for electricity as for crude oil insurance. Therefore, the value (or premium) of national insurance against curtailment of fuel for electricity would be approximately $\$1.16/\text{Btu}$. However, as the U.S. converts from an oil-based to an electricity-based economy, this difference may become less pronounced.

The next question that arises is, how does the value of this insurance relate to the cost of PEPS capacity? By assuming the PEPS facility operates at 0.2 capacity factor, 1 kw of PEPS produces approximately 1,752 kw-hr or $5.98 \times 10^6 \text{ Btu/year}$. At an average of 0.35 as the conversion efficiency for fossil fuel to electricity, this output is equivalent to $17.1 \times 10^6 \text{ Btu}$ of conventional fuel. The value of this fuel displacement as national insurance is $\$19.84/\text{kw/year}$, $(17.1 \times 10^6 \text{ Btu} \times \$1.16/10^6 \text{ Btu})$. If a PEPS facility remains in operation for 30 years, the present value of this national insurance (at a 10% discount) is $\$187.00/\text{kw}$. In other words, the social value of a PEPS installation as insurance against foreign curtailment of fuels for electricity is approximately $\$190.00/\text{kw}$ of installed PEPS capacity. Therefore, if national insurance were the only social benefit of PEPS, the market or private price of PEPS could be $\$190.00/\text{kw}$ above the market price of conventional power plants and still be economically feasible from a social perspective.

A very crude estimate of the value of this type of national insurance is \$190.00/kW. The value will change considerably with alternative crude oil import prices, social discount rates and different assumptions about the value of electricity fuel insurance relative to crude oil insurance. Tables 9.5.2-E, 9.5.2-F and 9.5.2-G present alternative values for these three key assumptions and their corresponding effect on the results.

Table 9.5.2-E shows that the purchase price of crude oil will have pile carrying cost increases because interest charges are higher on the more highly valued oil. The social value of PEPS as national insurance increases with the price of crude oil. The movement is expected because the relationship between the carrying cost of the stockpile is assumed to be proportional to the value of PEPS insurance. The value of PEPS as electricity fuel insurance varies from approximately \$200 to \$300.

Table 9.5.2-F deals directly with the relationship between the value of a crude oil stockpile and a PEPS insurance program. The original estimate assumed that the PEPS insurance was half as valuable as crude oil insurance. In Table 9.5.2-F the insurance is evaluated at one-fourth and one-eighth the value of crude oil insurance. The total value of the electricity fuel insurance from PEPS declines from \$187.00/kw (at one-half the value of oil insurance) to \$47.00/kw (at one-eighth the value of oil insurance).

The effect of discounting on the value of PEPS insurance is illustrated in Table 9.5.2-G. The discount rate is used to account for the value of time and also to calculate the interest charges on the stockpiled oil. As the interest rate increases, the carrying cost of the oil stockpile (per barrel/year) also increases. However, the present value of this carrying cost over 30 years decreases with larger discount rate. The decline occurs because higher discount rates result in a much lower valued future.

Discounting the future more heavily reduces the dollar value of PEPS (per kilowatt) as fuels for electricity insurance. A 3% discount rate yields an insurance value of PEPS of about \$400.00/kw while a 15% discount rate implies the insurance is only worth about \$100.00/kw.

In summary, the value of PEPS as national insurance against foreign curtailment of fuel for electricity cannot be precisely estimated. However, the preceding analysis indicates that the insurance value of PEPS is probably in the range of \$100.00 to \$300.00/kw. The nation should be willing to pay between \$100.00 to \$300.00/kw more for PEPS than for a conventional power plant that uses imported energy sources. Furthermore, the government should be willing to subsidize PEPS owners or producers for this social benefit.

TABLE 9.5.2-E

THE EFFECT OF CRUDE OIL PRICES ON THE VALUE OF PEPS AS NATIONAL INSURANCE

<u>Cost of Crude Oil \$/bbl</u>	<u>Carrying Cost of Stockpile^{a/} \$/yr/bbl</u>	<u>Present Value of Carrying Cost (30 yrs at 10%) \$/mmBtu (\$/bbl)</u>	<u>Value of PEPS as Insurance^{b/} \$/kw/yr</u>	<u>Total Present Value of PEPS as Insurance (over 30 yrs) \$/kw</u>
8.00	1.35	2.31 (12.73)	19.84	187.00
13.00	1.85	3.17 (17.44)	27.02	255.00
16.00	2.15	3.69 (20.27)	31.46	297.00

^{a/} The MIT Study assumes capital, operation and maintenance costs are \$0.55/yr/bbl and interest on stored oil is 10%/yr of its price and 730 mmBtu of crude are stockpiled.

^{b/} The value of national insurance against curtailments of fuels for electricity is assumed to be half the cost of crude oil curtailment insurance. The conversion from \$/mmBtu (Column 4) to \$/Kw/yr (Column 5) assumes a PEPS capacity factor of 0.20 and a 0.35 conversion efficiency of conventional fuels to electricity.

TABLE 9.5.2-F

SENSIVITY OF PEPS INSURANCE TO VALUATION FACTOR^{a/}

<u>Cost of Crude Oil \$/bbl</u>	<u>Present Value of Carrying Cost of Oil Stockpile (30 yrs at 10%) \$/mmBtu</u>	<u>Valuation Factor^{a/}</u>	<u>Value of PEPS as Insurance \$/kw/hr</u>	<u>Total Present Value PEPS as Insurance (30 yrs) \$/kw</u>
8.00	2.31	0.50	19.84	187.00
8.00	2.31	0.25	9.91	93.00
8.00	2.31	0.125	4.96	47.00

^{a/} The valuation factor is the value of electricity fuels insurance expressed as a present of the value of crude oil insurance.

TABLE 9.5.2-G

THE EFFECT OF DISCOUNT RATES ON THE VALUE OF PEPS AS INSURANCE

Social Discount Rate ^{a/} (%)	Carrying Cost of Oil Stockpile ^{b/} \$/bbl	Present Value of Carrying Cost \$/mmBtu (\$/bbl)	Value of PEPS as Insurance ^{c/} \$/mmBtu	Value of PEPS as Insurance \$/kw/yr	Total Present Value of PEPS as Insurance (over 30 yr) \$/kw
3	.79	2.81 (15.48)	1.40	23.94	389.00
5	.95	2.65 (14.60)	1.32	22.57	347.00
10	1.35	2.31 (12.73)	1.16	19.84	187.00
15	1.75	2.09 (11.49)	1.04	17.78	117.00

a/ Also the rate used as interest on oil stockpile.

b/ Assumes 730 mmb of crude are stockpiled at a purchase price of \$8.00/bbl. Operation, depreciation, and maintenance costs are \$0.55/bbl and interest on the stockpile is calculated using the social discount rate.

c/ The value of national insurance against curtailments of fuels for electricity is assumed to be half the cost of crude oil curtailment insurance.

4. Export value of PEPS technology: The potential development of PEPS technology may influence United States foreign policy and relationships in several ways. First, it provides direct opportunities to provide technological assistance to nations possessing sufficient solar insolation to use PEPS, but lacking the required technical skills to develop it. Secondly, the demand for alternative sources of energy will be affected to the degree PEPS can be substituted for these other energy sources. Eventually, as the market penetration of PEPS expands, the prices of alternative energy sources will be affected.

a. Technological assistance: Those nations possessing high levels of solar isolation required for efficient PEPS utilization can be divided into two groups. The first contains the world's most important oil-producing nations (e.g., Iran, Iraq, Saudi Arabia, Indonesia, Venezuela). The remaining countries are usually classified as the underdeveloped, third-world nations possessing few natural resources.

To those nations already possessing abundant natural energy resources, the potential impact of the export of PEPS technology may be small. For them, PEPS will merely serve as a supplement for existing production capacity. In those nations lacking alternative energy resources, the commercial development of PEPS technology may present a key tool required for economic development.

The circumstances under which PEPS technology could be exported may differ between the two groups of nations, but both represent potential markets. The probable form of the export of U.S. PEPS technology will include both software and hardware. Through the export of this technology special relationships between the exporter of the technology (the United States) and the eventual importers may evolve.

b. Impact on U.S. energy trade: Increasing use of PEPS technology to produce electricity will have an impact on the demand for non-renewable energy resources. The need to import energy resources to produce electricity will diminish as PEPS is substituted for nonrenewable fuels. Major consequences attributable to increased use of PEPS include:

(1) Altering the import-export ratio or balance of trade for those nations utilizing PEPS by decreasing the amounts of imported energy resources that would be required.

(2) The export of PEPS technology (both hardware and software) would serve as a national income source, improving the balance of trade.

(3) The increased energy supplies would encourage competition among the world's energy suppliers.

For example, one ERDA forecast contained in ERDA-48 assumes the United States may use PEPS to produce as much as 2 quadrillion (10¹⁵) Btus of electrical energy by the year 2000. This generation level could annually displace over 1 billion barrels of imported oil or 250 million short tons of coal (assuming they were used to generate electricity). The current (1975) cost to purchase this quantity of imported oil would be approximately \$14 billion. The revenue gained by the export of this quantity of coal would be \$5 billion. The value of either number is increased several times when considering the "multiplier effect" that accompanies any addition to national income derived from domestically produced goods and services.

The major value of PEPS as an exportable technology may not be a direct increase in the economic health of the United States. Rather, its value may lie in political ramifications due to changes in the balance of trade.

5. Value of transferable knowledge: Most frequently, an energy technology's value (e.g., PEPS) is measured only in very tangible terms including cents per million Btus, dollars per installed kilowatt, etc. But the technology's value can also be measured by assessing less tangible factors. One of these significant but less tangible by-products of PEPS may be the increase in scientific knowledge transferable to other activities.

Predicting the exact nature and value of all the potential additions to the nation's inventory of technological knowledge attributable to PEPS is an extremely difficult task. Yet, this additional knowledge will have value, as will the value of PEPS measured in terms of increased energy production capacity.

The new knowledge gained from the further development of PEPS may result in the commercial development of new innovative products and components. New markets created for these products may involve power conditioning systems, tracking systems for focusing collectors, electrical storage batteries, system controls and others.

For example, advancements in PEPS technology may be utilized by the building industry leading to modifications in home-construction technology. It could stimulate increased emphasis on energy considerations in building design and construction. It may also stimulate the creation of new building trade skills to complement any modifications to current building construction technology.

New knowledge attributable to advances in PEPS development may affect more than just business conditions. The new knowledge may be used by consumers, consumer protection organizations, financial institutions, organized labor and congressional and federal agencies involved with energy RD&D and its by-products.

Ultimately, the transfer of PEPS technology to other areas may contain added benefits in relation to its environmental and conservation attributes. It may give rise to new industries, create new employment opportunities, or influence the nation's income and spending patterns. PEPS development will undoubtedly influence the direction of government expenditures to support research, development and demonstration activities in other areas, as it may change consumer buying habits.

The value of transferable knowledge derived from advancement in PEPS technology can only be speculated. Any estimate of its future value is clouded with uncertainty, and not quantifiable. Therefore, estimates of these benefits are not included in the analyses that follow (Section 9.6).

6. Improvement in general economic conditions: Economic conditions existing at the national, regional and local levels will be influenced by the future development of PEPS technology. Initially, each PEPS induced change will be local or regional in nature. Each change to one regional economic factor will induce other changes. Through a series of substitution effects, national economic conditions will be eventually affected in a diluted and often time-lagged manner. While PEPS economic impacts will be local or regional in scope, their total impact on the demand for financing, materials and labor will be of national significance.

a. National economic impacts: The assessment of how PEPS technology will influence general economic conditions is dependent upon which future scenario is selected. Generally, an analytical framework forecasting the future overall energy supply-demand situation must also be related to national economic indicators. By assuming alternative market penetration levels for PEPS, a structured approach was used to forecast the associated economic consequences. Each new increment of PEPS energy was assumed to be an addition to the nation's energy supply. The forecasting procedure related growth in Gross National Product (GNP)* to different levels of PEPS market penetration.

* Historically, a high positive correlation has existed between GNP growth and energy consumption ($R^2 = 0.987$).

The GNP value associated with different market penetration levels for PEPS can be derived using a regression equation relating growth in GNP and electrical energy consumption over time. The equation below was generated for the years 1947 through 1973 using these parameters.

$$\text{Model Equation: } \frac{1}{\text{Kw-hr}_t} = a + b (\text{real GNP})_t$$

$$1947-73 \text{ Kw-hr}_t = 727 + 3.167 (\text{real GNP})_t$$

(Note: Kw-hr = billion kilowatt hours; real GNP = billion 1958 dollars.)

This equation is used in Table 9.5.2-H below to simulate possible alternative effects PEPS technology may have on GNP, assuming different levels of market penetration and assuming an energy capacity limited economy.

These calculations approximate the marginal effect of PEPS technology on GNP. If one assumes that real GNP grows linearly over time, energy provided from PEPS would have little impact on 1985 GNP. By 2000 PEPS could increase GNP from \$33 to \$68 billion (0.6-1.6%) if no lower cost alternative means of generating electricity were available and no changes in production technique occurred that would allow economic growth without increased electricity consumption. However, the probability of this set of events occurring is remote.

b. Regional economic impacts: The economic impact of PEPS development at the regional level will be much greater. If the structural relationship between energy and GNP continues, the regional availability of energy from PEPS can help promote economic growth while preventing energy shortages. For example, California has encountered numerous nuclear power plant siting problems, and an alternative source of electrical energy would make it easier to fulfill demand for electricity and maintain economic growth. Some rural areas (especially in the mountain states) are on the fringes of the power network, and may be increasingly subject to intermittent electrical outages. The availability and reliability of service could be improved in these areas by a local PEPS unit.

PEPS development may also impact overall regional employment level through its salutary influence on energy availability, maintenance of economic growth, and attraction of new or expanded industries.

c. Summary of social benefits of PEPS: Table 9.5.2-I summarizes the value of the social benefits of PEPS as estimated in this chapter. The total value of the social benefits of PEPS is estimated to be between \$55 and \$330 per installed kilowatt of PEPS capacity. Section 9.6 discusses the appropriate magnitude of government expenditures on PEPS based on this estimate.

^{1/} M. F. Searl, Significance of Zero Power Growth in 1974, Electric Power Research Institute (September, 1975).

TABLE 9.5.2-H

POSSIBLE NATIONAL ECONOMIC IMPACT OF PEPS

	1985		2000	
	Low Est. ^{d/}	High Est.	Low Est.	High Est.
Equivalent PEPS Capacity ^{a/}	0.1 Gwe	0.3 Gwe	30.0 Gwe	60.0 Gwe
Load Factor ^{a/}	0.6	0.6	0.7	0.7
Net Electricity Generated (in 10 ⁹ kw-hr)				
--Total	3,147.3 ^{b/}	3,960.0 ^{c/}	6,720.6 ^{b/}	8,650.0 ^{c/}
--PEPS	0.5-1.6	0.5-1.6	184.0-367.9	184.0-367.9
PEPS Market Penetration	--	--	2.7-5.5%	2.1-4.3%
GNP Value of PEPS (in billions)				
--1958 dollars	--	--	\$52-104	\$53-106
--1975 dollars	--	--	\$95-193	\$98-197
\$ GNP/mmBtu (1975 dollars)	--	--	\$153	\$157
\$ GNP/kw (1975 dollars)	--	--	\$3,210	\$3,300

a/ ERDA-48, p 33.

b/ Edison Electric Institute, Electrical Work Forecast contained in the "26th Annual Electrical Industry Forecast." Electrical World, September 15, 1975.

c/ Walter G. Dupree and John S. Corsentino, U.S. Energy Through the Year 2000 (revised), Bureau of Mines, U.S. Department of Interior, December 1975.

d/ Estimates given in gigawatts per year (GW_e = 10⁹ watts).

TABLE 9.5.2-I

ESTIMATES OF THE EXTERNAL SOCIAL BENEFITS OF PEPS

	<u>Low Estimate</u>	<u>High Estimate</u>
Social benefit/kw of PEPS as:		
Insurance against foreign energy curtailment	\$50.00	\$300.00
Pollution, Health and Safety Control	5.00	30.00
Conservation of Domestic Resources	0	small
Export value of technology	0	small
Value of transferable knowledge	NE ^{a/}	NE ^{a/}
Positive impact on national economy	<u>small</u>	<u>--b/</u>
Total	\$55.00	\$330.00

a/ NE - not estimated.

b/ This benefit could be large under certain futures.

Government expenditures on all aspects of photovoltaic energy should be justified based on resulting social benefits. The magnitude of these expenditures should also be limited by the size of these social benefits. The difference between the social benefits of the PEPS (over some long period of time) and the social costs of producing the system is the maximum amount the technology should be subsidized.

A social benefit-cost approach was used to estimate the appropriate amount of government support to PEPS. The social costs of PEPS include:

1. the private market price (i.e., the private-sector costs of production);
2. government subsidies to PEPS; and
3. any other external social costs (external to the private sector price mechanism).

The first element of the social cost of PEPS reflects the private sector valuation of the materials, labor and capital expended in the production of PEPS. Technological advances in production techniques and economies of scale due to expanded demand will alter this cost element over time.

The second cost element is government subsidies to PEPS. The purpose of this analysis is to estimate the magnitude of these subsidies. Therefore, the magnitude of the subsidy is a dependent variable in the analysis.

Any other external social costs are included in the third element of the social cost. These external costs include any environmental damage, negative impacts on national security, or significant health and safety hazards. These negative effects are considered small by the project team, and are assumed to be zero for the following analysis.

The social benefits of PEPS are also divided into three parts. The total social benefits of PEPS include:

1. value of the energy from PEPS to the private sector;
2. any subsidies on displaced conventional energy; and
3. any other social benefits of PEPS.

The economic model described in Section 9.2 is used to estimate the first part of social benefits. The private market value of energy from PEPS represents what a private-sector decision-maker would be willing to pay. The current tax structure and subsidies to competing technologies affect this decision, and are therefore included. Within the private sector environment, the value of PEPS critically depends on the market price of competing energy. This relationship is considered in the analysis presented below.

The second social benefit element is subsidies on displaced conventional energy. Subsidies on conventional energy systems reduce the percentages of social cost that enter the private sector decision. This market distortion due to subsidies should be eliminated from a social cost analysis. An investigation into the history of subsidies to conventional energy sources was conducted by the project team in order to better understand the purpose and extent of these subsidies. The results of this investigation are contained in Appendix F. The amount of subsidies to displaced energy sources is added to the social benefits of PEPS.

The final element of social benefits includes those benefits external to the private sector and not currently affected by subsidies. The value of pollution abatement, health and safety, conservation of energy resources, insurance against foreign energy curtailments, exports, transferable knowledge, and improvements in economic conditions are included. The magnitude of these benefits has been discussed in Section 9.5.

Two critical areas must be addressed before the benefit/cost estimates can be made. First, an appropriate time frame must be chosen. Second, the benefits and costs must be expressed in common units. A time frame of 30 years was chosen for several reasons. The estimated useful life of a PEPS is assumed to be 30 years. Estimation of the private sector cost was accomplished on a 30-year life-cycle basis. Secondly, the social benefits discussed in Chapter III also were calculated over the life of a PEPS system. Third, the 30-year time frame allows the costs and benefits to be expressed in a common unit (i.e., dollars per kilowatt of installed PEPS capacity). The \$/kw unit was chosen to avoid problems of estimating (1) the future penetration of PEPS, and (2) the cash flow of subsidies in the future. The uncertainty of these two factors and their interdependence makes any estimation of total costs and benefits over time highly subjective. Expressing benefits and costs as dollars per kilowatt of installed PEPS capacity allows the use of an incremental (or marginal cost approach.

One major drawback of this approach is that government support is also expressed in \$/kw and therefore, abstracted from time. This approach is appropriate when direct subsidies to commercialized PEPS are considered. However, RD&D expenses and/or other temporary government supports will not

necessarily be proportionate to installed kilowatts of PEPS capacity. In fact, RD&D expenses will probably be largest before a significant number of PEPS facilities are installed. As market penetration grows, RD&D expenditures will probably decline. However, for simplicity in this analysis, government subsidies will be expressed in \$/kw and should be considered permanent subsidies to PEPS when it is in the commercial stage of its development.

Figure 9.6-A presents the marginal social costs and benefits of PEPS in an insolation region represented by Phoenix (i.e., the PEPS has a capacity factor of 0.308). As expected, the private sector value of PEPS (in \$/kw) is an increasing function of the cost of conventional fuels. The social value of subsidies on displaced conventional energy also increases with the price of conventional energy. The most easily measurable subsidy is the tax-deduction for variable operating costs (mostly fuel). This deduction becomes more valuable (i.e., the subsidy increases) as the price of conventional fuel rises. Other subsidies to competing energy sources are not as readily available and are not included in Figure 9.6-A. Inclusion of these other subsidies would tend to increase the social benefits of PEPS.

The economic model was utilized to obtain the dollar value of the tax deductions for conventional fuels. Some representative values of this subsidy are shown in Table 9.6-A.

TABLE 9.6-A

SOCIAL VALUE OF TAX DEDUCTIONS FOR CONVENTIONAL FUELS

	<u>Mills/kw-hr (Conventional Energy)</u>			
	10	15	20	30
Value of tax deduction per kw of installed PEPS:				
Cleveland	\$127	\$189	\$253	\$379
Phoenix	200	301	401	601

The external social benefits of PEPS for national insurance, pollution, safety and health, exports, domestic resource conservation, etc. are also presented in Figure 9.6-A. These benefits do not vary with the price of conventional fuels and add a constant amount to the social benefits of PEPS. As the analysis in Section 9.5 indicated, the estimation of these external benefits is very imprecise. The benefits are also extremely dependent on a large variety of future events. Table 9.6-B summarized the range of estimates obtained in Section 9.5.

Figure 9.6-A - Social Costs and Benefits of PEPS in Phoenix

TABLE 9.6-B

ESTIMATES OF THE EXTERNAL SOCIAL BENEFITS OF PEPS

	Low Estimate	High Estimate
Social benefit/kw of PEPS as:		
Insurance against foreign energy curtailment	≈\$50.00	≈\$300.00
Pollution, Health and Safety Control	≈ 5.00	≈ 30.00
Conservation of Domestic Resources	0	small
Export value of technology	0	small
Value of transferable knowledge	NE ^{a/}	NE ^{a/}
Positive impact on national economy	<u>small</u>	<u>- ^{b/}</u>
Total	≈\$55.00	≈\$330.00

a/ NE = not estimated.

b/ This benefit could be large under certain futures (see Chapter III).

The sum of the external social PEPS benefits, the value of tax deductions for competing energy sources, and the private sector value of PEPS form the marginal social benefit of PEPS. The estimated private cost of PEPS is given by the horizontal band in Figure 9.6-A. The external social costs of PEPS are assumed to be zero so the private and social costs are equal. Furthermore, it is assumed that the production of PEPS does not require enough energy as input to be affected by changes in the cost of conventional fuels. The cost estimate is comprised of a cost of PEPS (in 1976 dollars) equal to \$1,157/kw and a gas turbine for backup at \$129.00/kw.^{1/}

Point A in Figure 9.6-A represents the mills/kilowatt-hour at which the marginal social cost of PEPS equals the marginal social benefit (using the high estimate). A' represents the same intersection using the low estimate of external social benefits. Point B represents the mills/kilowatt-hour at which the private sector benefits equal the private sector costs. In other

1/ See Section 9.2 for data sources.

words, the private sector would be willing to purchase PEPS if the levelized price of conventional fuels ranged between 30 and 35 mills/kw-hr. If conventional fuel costs average less than 18 mills/kw-hr, government subsidy to PEPS would not be justified. Below 18 mills/kw-hr, the social benefit/cost ratio is less than one. The social benefit/cost ratio approximates one between 18 and 25 mills/kw-hr. Above 25 mills/kw-hr, the benefit/cost ratio is greater than one.

The level of government subsidy warranted for PEPS is zero if the social benefit/cost ratio is less than one. As conventional fuel costs approach 18 mills/kw-hr, subsidies become justifiable. At Point A the appropriate government support is the distance between Point A and Point C in Figure 9.6-A or approximately \$500/kw of PEPS. The subsidy would sway private-sector decision-makers to invest in PEPS by reducing the private cost \$500. The cost reduction would be large enough to equate private sector costs to private benefits. The social benefits would be realized by the entire society and paid for by the society through the \$500/kw subsidy.

If A' more closely represented the true social benefits of PEPS, no subsidy would be warranted unless fuel prices approached 25 mills/kw-hr. At 25 mills/kw-hr the appropriate subsidy would be the distance from C' to A', or \$300/kw. A smaller subsidy is more appropriate at A' than A because the value of the societal benefits of PEPS is estimated to be less. However, the subsidy of \$300/kw would reduce private sector costs enough to equal private sector benefits at 25 mills/kw-hr for conventional fuel.

The fuel cost at which a subsidy is justified will reduce as system cost is reduced through RD&D activities. For example, if system cost was reduced from \$1,286/kw to \$1,000/kw, the threshold fuel cost would reduce from 18 mills/kw-hr to 12 mills/kw-hr.

To put these fuel prices in perspective, current fuel prices range from 2 mills/kw-hr to 22 mills/kw-hr. Levelized fuel prices over the next 30 years (using a 5% discount rate) assuming a 3% real (non-inflated) growth in fuel prices range from 3 mills/kw-hr to 35 mills/kw-hr. However, only oil prices exceed 20 mills/kw-hr in either case. Of course, larger percentage increases in the price of these conventional fuels could result in coal, gas and nuclear prices above 20 mills/kw-hr.

The first conclusion to be drawn from Figure 9.6-A is that significant increases in conventional fuel prices (or expectations of such increases) will have to occur to warrant commercial subsidies to photovoltaic technology. However, improvements in PEPS production techniques must also be considered. Production advances would significantly lower both the private and social costs of PEPS. The social cost reduction would lower the levelized fuel price at which a PEPS subsidy would be warranted.

Many of the current ERDA efforts in RD&D are specifically aimed at improving PEPS production techniques. Figure 9.6-A indicates how much costs will have to be reduced by these RD&D efforts. By assuming conventional fuel prices are expected to equal a levelized amount of 10 to 15 mills/kw-hr (in non-inflated dollar terms), and by using the high estimate of the social benefit of PEPS, the RD&D effort must reduce the total life-cycle cost of PEPS by the equivalent of \$120/kw to \$340/kw in order to justify further government support of PEPS. If the RD&D program successfully reaches these goals, there will be social justification to initiate a commercial subsidy program. That subsidy should not exceed \$250/kw to \$520/kw (depending on which social benefit estimate is used). In fact, the present value of the RD&D costs should be subtracted from the commercial subsidy that is offered. The combination of a successful RD&D program and a commercial subsidy program would then stimulate private sector investors to purchase PEPS in geographic areas similar to Phoenix.

Figure 9.6-B presents the social costs and benefits of a PEPS located in an insolation area similar to Cleveland, Ohio. The lower average solar insolation in Cleveland results in the production of less energy per kilowatt of installed capacity. Therefore, the private sector benefits of PEPS increase considerably slower with fuel prices in Cleveland than in Phoenix. The social value of tax deductions for competing fuel costs is equivalent in both Phoenix and Cleveland. The external social benefits are of similar magnitude in both cities. By ignoring possible transportation cost differences, the costs of producing the PEPS are also assumed to be equal in both cities.

Point A in Figure 9.6-B again represents the point at which the social costs and benefits of PEPS (using the high estimate) are equal. Conventional fuel prices would have to equal 25 to 30 mills/kw-hr for a government investment in PEPS to be justified. If fuel prices increased to 30 mills/kw-hr, the government would have to subsidize PEPS about \$460/kw to stimulate private investment (Point C). By using the low estimate of external social benefits, social benefits and costs would be equal at levelized fuel prices of 35 to 40 mills/kw-hr. The appropriate subsidy under these circumstances would amount to no more than \$200 to \$250/kw of PEPS.

As one would expect, fuel prices would have to rise much faster (or be expected to rise faster) in regions having low insolation (Cleveland) than in regions having high insolation (Phoenix). Alternatively, an RD&D program aimed at PEPS system costs would have to be more successful to stimulate private sector interest in low rather than higher insolation regions. If levelized fuel costs equaled 10 to 15 mills/kw-hr, an RD&D program would have to lower PEPS costs to \$850/kw to \$990/kw to equate social cost and benefits in Cleveland. In Phoenix, similar fuel prices result in RD&D cost goals of \$950/kw to \$1,200/kw. In both cases, further commercial subsidies would still be required even if the RD&D cost goals are attained.

Figure 9.6-B - Social Costs and Benefits of PEPS in Cleveland

9.7 ELEMENTS OF A PEPS COMMERCIAL SUBSIDY PROGRAM

The analysis in Sections 9.5 and 9.6 indicated that the social benefits of PEPS technology warrant government support. The magnitude of this support depends on the cost of competing energy fuels. Given a set of expectations about future fuel prices, the appropriate magnitude of government support for PEPS can be estimated.

The next question that arises is what is the best way to provide this government support. The best policy to stimulate PEPS is the one which reduces the private cost of PEPS by the largest amount with the smallest government outlay. All alternative policies should be examined by these criteria. However, significant problems arise when the cost of administration of alternative policies is considered. Therefore, the policies presented below are compared on the basis of how they affect private sector costs.

The government supports considered in this chapter are grouped into non-tax subsidies and tax subsidies. The non-tax subsidies include:

- . Capital cost subsidies
- . Operating and maintenance subsidies
- . Government-furnished equipment
- . Low-interest and interest-free loans
- . Public utility ownership of PEPS

The tax subsidies include:

- . Property tax subsidies
- . Investment tax credits
- . Accelerated depreciation allowance
- . Policies affecting fossil fuel tax deduction
- . Fossil fuel displacement as a tax deduction

Each of these policies is examined separately below and later compared.

9.7.1 Non-Tax Subsidies

1. Capital cost subsidies: One of the major drawbacks to investing in PEPS is the large initial capital outlay that is required. Capital outlays, plus the financing expenses, constitute the largest component of the PEPS cost. The large capital requirement creates problems for the investor concerning finding the funds to finance the outlay, obtaining these funds at a minimum interest rate, and the risk of not realizing a fair return in a reasonable length of time. The important role of capital in PEPS costs gives government subsidies the potential to strongly influence their economic competitiveness.

To determine the policy potential of government subsidies, two separate cases are analyzed. The first assumes a subsidy of 25% is instituted for all PEPS capital equipment. The second expands the subsidy to 50%. Figure 9.7.1-A presents the results.

The 25% capital subsidy reduces the nominal cost of PEPS from \$1,286/kw to \$965/kw. As a result, investors in Phoenix would be willing to purchase PEPS if levelized conventional fuel costs equaled 23 mills/kw-hr (Point B in Figure 9.7.1-A rather than 32 mills/kw-hr (Point A in Figure 9.7.1-A.

The 50% capital subsidy reduces the nominal cost of PEPS to \$643/kw. Investors in Phoenix would then be willing to invest in PEPS if levelized fuel costs equaled 13 to 14 mills/kw-hr (Point C in Figure 9.7.1-A. The investors in areas similar to Cleveland would invest in PEPS if levelized fuel costs equaled 22 mills/kw-hr, if a 50% capital subsidy was in effect (Point D in Figure 9.7.1-A

2. Operation and maintenance cost subsidies: A great deal of uncertainty surrounds the future magnitude of PEPS operation and maintenance costs. If operation and maintenance costs are excessive, PEPS will not develop on a large-scale commercial basis. If they are equal to or less than the cost of operating and maintaining a conventional fossil system, the outlook for PEPS would be enhanced.

One alternative for overcoming the uncertainty of operation and maintenance costs lies in a government subsidy. However, the exact size of the subsidy will depend on the importance of these expenses relative to the cost of the whole system. The best estimate of operation and maintenance costs derived in this study is contained in the cost model presented in Section 9.2. To analyze the effect of the subsidy on PEPS, a 50% and 100% subsidy was applied to the assumptions of the cost model.

Exercising the cost model with a 50% subsidy on operation and maintenance cost has very little impact on the maximum acceptable price of PEPS. The maximum acceptable price for PEPS does not increase by more than 10% over

Figure 9.7.1-A - The Effect of Capital Cost Subsidies on the Private Cost of PEPS

the base case. This 10% estimate cannot be considered a significant amount, given the degree of accuracy of the other assumptions of the cost model. The 100% operation and maintenance cost subsidy raised the maximum acceptable price of PEPS by not more than 15% to 20%.

In summary, subsidies for operation and maintenance costs have only a marginal impact on the cost competitiveness of PEPS. However, two other important factors that enter the investor's decision process must also be examined.

First, the subsidy would be more important if operation and maintenance costs were significantly larger than those assumed in the cost model. In this case, the subsidy could make the technology appealing to investors who would normally reject it solely on the basis of operation and maintenance costs.

Secondly, the subsidy decreases the uncertainty of operation and maintenance costs. Under the 50% subsidy, the investor is assured that he only has to bear half of these expenses no matter how large they become. Even if operation and maintenance costs are similar to those assumed in the cost model, the reduced risk resulting from the subsidy adds to the attractiveness of the PEPS. Operation and maintenance cost subsidies have a positive impact on the uncertainty of a PEPS investment even though they would probably have only a marginal impact on life-cycle costs.

3. Government-furnished equipment: The impact of government-furnished equipment on the economic viability of PEPS is similar to the impact of the capital cost subsidies discussed earlier. However, government-furnished equipment tends to be a more selective subsidy.

The components of the PEPS capital costs are presented in Section 9.2 as a function of cell costs. The relative importance of these components is presented in Table 9.7.1-A for two alternative estimates of cell costs.

If only photovoltaic cells were furnished by the government, the PEPS concentrating system (not including gas turbine backup) would be reduced from \$1,157/kw (at \$182/m² cell costs) to \$1,095/kw. However, the PEPS using a planar array declines from \$2,537/kw (at \$182/m² cell costs) to \$590/kw. The planar array would always be preferred to a concentrating array under this subsidy. The high cost of focusing is only warranted by the resulting lower total cost for cells. If cells are free, no cost savings can accrue due to concentration.

TABLE 9.7.1-A

CAPITAL COST COMPONENTS OF PEPS

	<u>Concentrating PEPS</u>		<u>Planar Array</u>	
Cell Cost: (\$/m ²)	\$50	\$182	\$50	\$182
Capital Cost Components:*				
Cells	2%	5%	48%	77%
Primary Mirror	23%	22%	0	0
Tracking Drives	4%	4%	0	0
Concentrator Structure	35%	34%	0	0
Planar Structure	0	0	17%	8%
D.C. Wiring	5%	5%	5%	2%
Engineering & Contingencies	8%	7%	8%	3%
Inversion Equipment	13%	12%	13%	6%
Array Foundations	6%	6%	7%	3%
Site Preparation, Roads, Security, etc.	4%	4%	3%	2%

* Expressed as a percent of total capital cost.

Figure 9.7.1-B demonstrates how government-furnished cells would affect private investment decisions concerning focusing PEPS. Little change would occur in investor's behavior if only concentrating PEPS were considered.

Government programs do not have to be limited to cell cost alone. A more potent alternative would be to furnish cells, tracking devices, concentrators and array supports. Under this program, the investors would only have to pay for DC wiring, inversion equipment, engineering and contingencies, and site preparations, roads, security, etc. The cost, without backup, of a concentrating PEPS to the investor would be about \$325/kw. Although these costs would be appealing to the private investor, the society would still bear the entire cost. Furthermore, additional costs could be incurred by the government in purchasing, handling and distributing the necessary equipment. However, if the social benefits of PEPS warranted government support of this magnitude, a government-furnished equipment program would provide a rather direct means of accomplishing that end.

4. Low-interest and interest-free loans to PEPS: Government lending policies are one of the most potent policy instruments available to promote PEPS because of the highly capital-intensive nature of the systems. Capital costs (including financing) can amount to more than 75% of the total life-cycle cost of a PEPS. Since interest is a major contributor to the capital cost, any measures which reduce interest will have a significant impact on total system costs.

Figure 9.7.1-B • The Effect of Government-Furnished Cells on Economic Feasibility of PEPS

The role of interest in capital financing can be more important than the repayment of the principal, from a life-cycle cost perspective. A corporation or utility that issues long-term debt is often obliged to pay interest on the entire principal over the life of the loan. The principal is then repaid in full in the last period. The cost model used in this analysis assumes that the corporation finances the capital outlays over the entire useful life of the energy system (assumed to be 30 years). Discounting the repayment of the principal 30 years into the future significantly reduces its impact. For example, if the principal was \$100,000, the discount rate was 5%, and it was repaid in 30 years, its present value would be \$23,137, only 23% of its nominal value. If the same calculation was made using a 10% discount rate, the present value of the \$100,000 is \$5,730, or 6% of its nominal value. At a 15% discount rate, the present value of the principal repayment is only 1-1/2% of its nominal value.

The present value of the interest on debt is much more significant. If the corporation pays a 5% interest rate on the debt and also uses a 5% discount rate, the present value of all the interest payments over 30 years is \$76,862 or 77% of the amount borrowed. As interest rates increase, the percentage of total capital cost which is interest becomes more important. For example, a 10% interest rate on the loan and a corporate discount rate of 5% yield interest payments equal to 78% of the total effective capital cost. The only factor reducing the interest is its tax status. Interest paid on debt can be deducted from corporate taxable income. The tax benefit of this deduction decreases the effective cost of the PEPS.

The first policy alternative examined is granting low-interest loans to corporations or utilities purchasing a PEPS. For this analysis, a 2% real rate of interest on all PEPS equipment is assumed. No changes are assumed in the other costs, tax structures, or the firm's weighted cost of capital. The impact of the low-interest loans is illustrated in Figure 9.7.1-C.

As expected, the low-interest loans significantly raise the maximum acceptable price of PEPS to investors. At conventional fuel costs of 15 mills/kw-hr, the maximum acceptable price of PEPS rises 115% in Phoenix and 101% in Cleveland. At \$1,286/kw, Phoenix investors would purchase PEPS at fuel costs of 13 mills/kw-hr. Cleveland investors would consider PEPS at 20 mills/kw-hr. The policy is so potent that investors in Cleveland would pay more for the PEPS with the low-interest loan than Phoenix investors would without the policy (i.e., under the base case conditions). In other words, if the low-interest loan program was instituted on a regional basis, PEPS performance differences due to insolation variances could be completely overcome. In fact, areas with lower average insolation may purchase PEPS before more technically advantageous areas because of regional low-interest loan incentives.

Figure 9.7.1-C - The Effect of Low-Interest Loan Policies on the Economic Feasibility of PEPS

An interest-free loan program was also examined with the use of the cost model. As with the low-interest loan program, it is assumed that the corporation or utility finances the entire PEPS purchase with the lower cost debt but continues to discount the future with its average weighted cost of capital (assumed to be 5% in real terms). The results of the interest-free loan program are also presented in Figure 9.7.1-C. PEPS (at \$1,286/kw) is attractive at levelized fuel costs of 9 mills/kw-hr in Cleveland and 6 mills/kw-hr in Phoenix.* Both of these fuel costs are within the present range of conventional fuel prices. The maximum acceptable price of PEPS with interest free loans becomes negative for fuel costs below approximately 1 mill/kw-hr. This is because the benefits of full savings are less than the disbenefits of insurance, and operating and maintenance costs. Thus, the utility would require payment to accept a PEPS and be no worse off as a result. However, fuel prices are unlikely to be below 1 mill/kw-hr where this problem occurs.

In summary, low-interest and interest-free loans have a large impact on the cost competitiveness of PEPS. The interest-free loan program, together with existing tax benefits, could make PEPS competitive in the very near future.

5. Public utility ownership of PEPS: The most probable future owners of PEPS are the existing utilities. There are many possible variations in the exact form of utility ownership and procedures for charging customers for the service. The analysis that follows deals with how public utility ownership will affect the costs of the system (in terms of the utility rather than its customer), and compares them with costs realized by investor-owned utilities.

The investor-owned utilities currently produce 77% of the industry's output.^{1/} These utilities have financing options corresponding to privately owned non-utility corporations. As illustrated in Chapter II, they can issue common and preferred stock and debt. Investor-owned utilities are also subject to federal and local taxes similar to those levied on most corporations.

The public-owned utility, on the other hand, is subject to costs and taxes that are significantly different from those of an investor-owned utility. Most nonfederal public utilities finance capital expenditures through internally generated funds and tax-exempt debt issues.^{2/} The federal public utilities finance mostly through congressional appropriations. The Tennessee Valley Authority has the additional option of entering the private

* The PEPS cost of \$1,286/kw is a focusing system and assumes cell costs of \$182/m².

^{1/} A good discussion of investor-owned utilities is contained in Financing the Energy Industry, by J. Hass, E. Mitchell, and B. Stone (Ballinger Publishing Company, 1974), pp. 51-75.

^{2/} Ibid., p. 53.

capital market. In addition, most public-owned utilities do not pay income taxes or ad valorem taxes, although many municipal utilities make payments to local governments in lieu of taxes. The cost of PEPS will therefore be somewhat different when viewed by a public utility versus an investor-owned utility. Figure 9.7.1-D presents the maximum acceptable price of PEPS from the perspective of both public and private utilities.

The lack of most of the tax deductions available to a private utility increases the maximum acceptable price of PEPS to a public utility.* The benefit of lower interest rates due to the tax exempt status of long-term bonds acts to reduce these differences. The interest rate on debt is assumed to be 4%.

The results indicate that, in Phoenix, public utilities would purchase PEPS at \$1,286/kw when levelized fuel costs equaled 25 mills/kw-hr. Investor-owned utilities would not invest in PEPS until fuel costs reached 32 mills/kw-hr. A similar phenomenon occurs in Cleveland at much higher levelized fuel costs. Public utilities are more willing to purchase PEPS because these organizations bear a higher percentage of the true social cost of generating electricity than their investor-owned counterparts.

The most pressing problem facing the public utility industry, however, is not the cost of individual energy systems. The industry as a whole is currently facing serious earnings and financing problems. According to the Project Independence Report, "The most pressing financial problem in the energy sector pertains to public utilities. This is true in terms of its immediacy, its size, and its impact on future energy supply.^{1/} These problems will have to be resolved before any serious consideration is given to public utility participation in the PEPS market.

9.7.2 Tax Subsidies

1. Property tax subsidies: All the policy analyses contained in this chapter deal entirely with programs administered by the national government. This does not imply that state and local governments have no policy options available. In fact, most tax subsidy programs are as easily adaptable to state and local income tax alterations as they are to federal taxes.

* The analysis deals with the acceptable price of a single PEPS. No conclusions concerning the income and expenses of either utility are implied. In addition, no conclusions concerning profitability are addressed.

^{1/} Project Independence Report (Federal Energy Administration, Nov. 1974), p. 283.

Figure 9.7.1-D - The Effect of Public and Private Utility Ownership of PEPS Feasibility

Lending policies, as well as research and development programs, can also be instituted at the state and/or local government levels.

One additional policy tool open exclusively to state and local government is the property tax. Property taxes enter the investor's cost calculation through the impact of PEPS on assessed valuation or possible PEPS requirements for acquisition of additional land. Corporations and some investor-owned utilities are taxed on the increased valuations and/or through other types of taxes on physical assets.

State and local property taxes appear to play a minor role in the PEPS investment decision. Joseph A. Pechman states that "effective property tax rates are below 3% in all states; in 1962, the median state effective rate was 1.1%, and only eight states had average rates in excess of 2%.^{1/} It is unlikely that effective property tax rates have risen dramatically between 1962 and 1976.

The effect of property taxes on the maximum acceptable price of PEPS is estimated with the use of the cost model. A 100% property tax subsidy for PEPS (i.e., PEPS are excluded from property taxes) was analyzed with the model. Property taxes on gas-turbine backup capacity were not altered. The results of the subsidy are presented in Figure 9.7.2-A. At 15 mills/kw-hr, the subsidy increases the maximum acceptable price of PEPS (i.e., decreases the life-cycle cost) 4% and 15% in Cleveland and Phoenix, respectively. As expected, the dollar value of the subsidy increases as the maximum acceptable price of PEPS increases.

2. The investment tax credit: Two types of policies can be instituted which affect the investment tax credit. First, the overall rate can be altered. Without changes in the structure of the credit, non-solar energy sources would also receive additional benefits. However, the capital-intensive nature of PEPS (as well as other solar energy systems) would result in relatively larger benefits per kilowatt from the increased tax credit. Previous work by MRI has indicated that this differential impact does occur but has an insignificant effect on the cost competitiveness of PEPS.^{2/}

The second type of policy is a change in the structure of the tax credit. The most often discussed change in the structure is a larger credit applied only to PEPS equipment. To examine the impact of this type of change, special tax credits of 14% and 25% were entered in the cost model. These special credits apply only to the nominal cost of PEPS capital equipment. Backup capacity is excluded. The results are presented in Figure 9.7.2-B.

1/ Joseph Pechman Federal Tax Policy (The Brookings Institution, Washington, D.C., 1966), p. 207.

2/ Technology Assessment of On-Site Solar Electricity for the U.S. Congress, Office of Technology Assessment (Midwest Research Institute, Kansas City, Missouri, August 1975), pp. 7-15 to 7-18.

Figure 9.7.2-A - The Effect of Property Tax Subsidies on the Economic Feasibility of PEPS

Figure 9.7.2-B - Investment Tax Credits and PEPS Economic Feasibility

At 15 mills/kw-hr for conventional fuels, increasing the tax credit from 3% (assumed in the base case) to 14% raises the maximum acceptable price of PEPS approximately 11% in both Phoenix and Cleveland. Under the same conditions, the 25% credit results in a 35% rise in the maximum acceptable price of PEPS in Phoenix and a 23% rise in Cleveland.

The impact of the 25% special tax credit is not insignificant. However, the projected cost of PEPS of \$1,286/kw (including backup and cell costs of \$182/m²) is too high, given current fuel prices, to be overcome solely by the change in the investment tax credit. Private investors in Phoenix would purchase PEPS under the base case at \$1,286/kw (assuming no uncertainty) if levelized fuel costs were 30 to 35 mills/kw-hr. With the addition of the special 25% tax credit, investors in Phoenix would purchase PEPS at levelized fuel costs of about 22 mills/kw-hr. Nonetheless, only a few projections of oil prices include sustained levels at or above 22 mills/kw-hr for 30 years.

3. Accelerated depreciation allowances: One of the many hazards facing a utility or corporation investing in PEPS is the risk of an unproven and rapidly developing technology. Depreciating the system at an accelerated pace for tax purposes is one way of offsetting some of this risk.* Accelerated depreciation is of value because it reduces the corporation's taxable income and tax burden in the early years of the system's life. The resulting increased cash flow from accelerated depreciation reduces the losses which might occur if premature scrapping the system was required.

The useful life of each PEPS is assumed to be 30 years in the cost model. Each system is depreciated over that period using a "double-declining balance" method and switching to "straight-line" when it is more advantageous.

Two alternative accelerated depreciation schemes were addressed with the use of the cost model. First, it was assumed that the PEPS could be fully depreciated for tax purposes after 10 years of operation. Only a straight-line method was used in the analysis. However, over such a short period, the use of a double-declining balance method would make very little difference in the results. Gas-turbine backup capacity was assumed to be precluded from the accelerated depreciation policy.

The second scheme allowed the PEPS to be fully depreciated in 5 years. The results of the 5-year depreciation scheme are presented in Figure 9.7.2-C.

* This assumes that the Congress and/or the Internal Revenue Service allows the firm to utilize an accelerated depreciation method for tax purposes.

Figure 9.7.2-C - The Effect of Accelerated Depreciation Allowances on PEPS Economic Feasibility

Accelerated depreciation policies raise the maximum acceptable price that investors would be willing to pay for PEPS. If levelized conventional fuel prices equaled 15 mills/kw-hr, a 5-year PEPS depreciation policy would raise the maximum acceptable price of PEPS by 24% in Cleveland and 31% in Phoenix. The 10-year depreciation scheme had half as large an impact as the 5-year policy.

The impact of accelerated depreciation increases with higher conventional fuel costs and would significantly improve the outlook for PEPS especially if fuel prices increase to above 22 mills/kw-hr.

4. Policies affecting fossil fuel tax deductions: Current tax law allows corporations and utilities to include the cost of fossil fuels as part of deductible operating expenses. Consequently, the effective after-tax cost of the fuel to the firm is significantly less than the market price. In the analysis that follows, the tax deduction for fossil fuel costs is eliminated. Therefore the firm bears the full cost of all fossil fuels consumed.

Figure 9.7.2-D presents the changes in cost resulting from the elimination of the tax deduction. The figure illustrates the potency of this policy option. In Phoenix, the maximum acceptable price investors would pay for PEPS (if levelized fuel price equaled 15 mills/kw-hr) increases 71% with the elimination of the tax deduction. In Cleveland, the increase amounts to 63%.

The results can also be expressed by relating the policy to the expected cost of PEPS (i.e., \$1,157/kw for PEPS plus \$129/kw for backup). If PEPS and backup costs were \$1,286/kw, Phoenix investors would purchase PEPS when levelized conventional fuel cost equaled 17 mills/kw-hr. Before the policy, PEPS would not be considered by these investors until fuel cost reached almost 32 mills/kw-hr. Cleveland investors would consider PEPS at levelized fuel costs of 26 mills/kw-hr after the policy is enacted. Under the existing tax structure, Cleveland investors would not consider PEPS until fuel prices reached approximately 50 mills/kw-hr.

In spite of the potency of this policy, it is unlikely that eliminating the fossil fuel tax deduction alone will make PEPS economically feasible. However, coupled with an effective RD&D program, the policy could insure PEPS economic viability. If an RD&D program reduced PEPS costs from \$1,286/kw to \$1,179/kw and the fossil fuel tax deduction was eliminated, Phoenix investors would consider PEPS at fuel prices at 15 mills/kw-hr (well within the range of probable future fuel prices). In Cleveland, the same PEPS cost reduction would make PEPS competitive at fuel costs of 22 to 23 mills/kw-hr.

In spite of its potency, eliminating fossil fuel tax deductions may be one of the most difficult solar energy policies to institute. Fuels comprise almost 80% of the total production expenses of investor-owned utilities

Figure 9.7.2-D - The Effect on the Economic Feasibility of PEPS of Eliminating Fossil Fuels as a Tax Deduction

using steam power, and approximately 65% of the production costs for nuclear plants.^{1/} A quick and/or unexpected elimination of the fossil fuel deduction would have a crippling effect on the already troubled utility industry. The elimination would have its largest impact on the cost of conventional fossil systems. Current regulation controls utility profits and revenues through price and rate of return constraints. The large increase in cost without a change in utility revenue constraints would make many utilities insolvent and force them out of the industry.

One possible compromise would be to eliminate the tax deduction in phases. Changes in revenue and profit-related regulations would have to occur simultaneously. By using this plan, it would be possible to eliminate the deduction over a number of years without eliminating the utility industry in the process. The consequences of such an action would be widespread. One would expect a general increase in utility rates to customers. However, the increased tax revenue gained from utilities would reduce some of the tax burden on other taxpayers. The situation can be conceived as a transfer of costs from all taxpayers to just utility customers. Currently all taxpayers are subsidizing utilities by paying additional taxes to offset the tax deduction granted to utilities. The elimination of this deduction better aligns the social cost of producing energy with the retail or private cost realized by the customer. A better alignment of social and private costs leads to a better allocation of the nation's scarce resources. However, the resulting redistribution of income may increase or decrease the society's welfare. Holding to conventional economic practice, we will not attempt to estimate the direction of the change.

The elimination of the deduction will also have an impact on utility company financial behavior. If all the additional tax burden is passed on to the consumer, the utility would undergo no change in profits. However, as net taxable income increases, utilities may choose to increase capital investments to regain some of the lost tax advantages. The result could be more efficient electricity production and increased energy availability. On the other hand, such action could result in plants that are unnecessarily large and overly capital intensive.^{2/} Additional research is needed in this area before policy steps are taken toward elimination of fossil fuel tax deductions.

^{1/} These averages were generated from Statistics of Privately-Owned Electric Utilities in the United States, 1971 (Federal Power Commission FPC-S-226) p. XVII.

^{2/} Some important conclusions concerning the effects of regulation on capital investment are contained in "Behavior of the Firm Under Regulatory Constraint," by J. Stein and G. Borts, The American Economic Review, December 1972, pp. 964-970.

5. Fossil fuel displacement as a tax deduction^{1/}: One of the major tax advantages of owning a conventional fossil energy system is the opportunity to deduct fossil fuel expenses from taxable income. Policies that change this deduction are both powerful and highly controversial (see discussion in Section 4 above). Utility companies would be extremely hard pressed to remain profitable if the deduction were eliminated. In order to eliminate the deduction without jeopardizing most of the utility industry, a program extending over a number of years would be required. The time necessary to institute the policy is another drawback to its effectiveness.

One innovative way to eliminate the problems associated with the fossil fuel tax deduction while retaining its power as a policy tool is to allow a tax deduction for fossil fuel displaced by PEPS. The present tax status of fossil fuels would not have to be altered. All that is required is provisions to allow PEPS investors to retain the tax benefits of the fossil fuel deductions.

To calculate the deduction, the amount of fossil fuel used as back-up for the PEPS is first subtracted from the average amount used in a conventional fossil system of comparable size and operational characteristics. The difference equals the fossil fuel displaced by PEPS. The dollar value of the displaced fuel is then subtracted from taxable income just as if the fuel had been actually purchased. As a result, the PEPS owner avoids most of the expense of actually buying fuel, but retains the tax savings that accompany the purchase.

The effect of this policy on the cost competitive position of PEPS is exactly the same as the elimination of the fossil fuel tax deduction shown in Figure 9.7.2-D. The maximum acceptable price of PEPS rises considerably because of the displacement of fossil fuels without the loss in the accompanying tax deductions. In addition, the policy has the ability to be instituted quickly because it does not adversely affect the existing tax status of competing energy sources. These factors combine to make the tax deduction for displaced fuels one of the more promising policy tools investigated.

9.7.3 Comparison of Subsidy Options

As discussed in Section 9.6 a value can be calculated for the amount of government subsidy of PEPS which is economically justifiable. A government subsidy is economically justifiable (under certain circumstances as given in Section 9.6 because the installation of PEPS rather than a conventional

^{1/} This policy innovation was first conceived in the Technology Assessment of On-Site Solar Electricity (op. cit.) by Midwest Research Institute.

generating plant avoids certain social costs which would otherwise be incurred by government or society generally, and also generates additional tax revenue to the government because of the larger capital investment in PEPS. In this chapter, we have examined a number of methods which might be chosen to implement this subsidy, and have shown that means exist for implementing the subsidy which are flexible enough to cover the range of subsidy which might be found to be economically justifiable and also which have minimal complications in other respects.

The most desirable type of subsidy is the option which provides the greatest ratio of benefit to the PEPS owner to cost incurred by the government. While the cost to the government can be calculated fairly precisely, the benefit to the utility is not so easily quantified. In particular, in comparing a capital-intensive PEPS plant with a conventional fuel-fired plant, consideration should be given to the present difficulties experienced by utilities in raising capital, and also to the uncertainties and risks associated with an unconventional technology.

The subsidy options which are likely to be most effective in attracting utility investment in PEPS are therefore those which reduce the amount of capital which the utility must raise through normal commercial channels, and which shift to the government a portion of the risks incurred as a result of the limited experience with PEPS technology.

Of the options considered, capital cost subsidies, government-furnished equipment, low-interest loans, and investment tax credits all reduce the amount of capital raised through normal commercial channels by the utility. Of these options, low-interest loans appear to have the greatest potency and the lowest administrative costs. If the loan agreement provides for repayment of the loan from revenues generated by the PEPS installation, the risks are also borne in part by the lender. This method of subsidy is commonly employed in similar situations at present. For example, pollution control facilities required by EPA regulations for processing industrial wastes are often financed by municipal revenue bonds.

In the discussion of low-interest loans in this chapter, interest rates are given in constant dollars; that is, the actual interest rate assumed is the sum of the anticipated general inflation rate and the true interest rate quoted. A true interest rate of 2% is approximately the rate historically paid by the U.S. Treasury on borrowings; a true interest rate of 0% is approximately the rate historically paid on tax-exempt municipal bonds. Therefore, federal financing of PEPS installations at a true interest rate of 2%, or state or municipal financing at a true interest rate of 9%, would not result in an out-of-pocket loss to the government.

A final advantage of this option is that it can be structured to permit a degree of local control over the level of subsidy to be granted in a particular case. Since the long-term societal benefits of PEPS (see Section 9.5) are so difficult to quantify and vary so much depending on future circumstances, it would seem advantageous to choose an option which would permit the citizens who would be directly affected to participate in the decision via the normal political processes.

Of the remaining options, the last one discussed (fossil fuel displacement as a tax deduction) is attractive because of its potency and flexibility, and also because an impressive argument can be made for it on grounds of equity. In effect, instituting this option would place a utility choosing PEPS in a similar tax situation as a utility choosing a fuel-fired plant. Without this option, the utility choosing PEPS pays higher taxes than the utility choosing a fuel-fired plant, because the cost of fuel is deductible from before-tax income while a part of the equivalent portion of the cost of PEPS (the part financed by stock) is financed from after-tax income. This option returns these excess taxes to the utility. The amount of this subsidy increases as the cost of fuel increases, which enhances the value of PEPS to a utility as "insurance" against future increases in fuel costs. This may be considered as an offset to the techno-economic risks associated with an investment in PEPS technology.

Although this particular option is novel, the principle involved can clearly be discerned in the nuclear power program. As with solar, nuclear power achieves low cost because of low fuel costs, but the achievement of low fuel costs required substantial technological development and massive investment in uranium enrichment facilities. The federal government not only financed both the development and the facilities required, but also guaranteed a low fuel cost to the utility industry by setting a ceiling price on fuel enrichment, and provided important assistance in financing the cost of nuclear fuel inventories by leasing nuclear materials. As detailed in Appendix F, the expenditures by the AEC to assure low nuclear fuel prices to the utility industry have constituted a very substantial subsidy.

If ERDA goals for the implementation of solar energy are to be met, it will be necessary for utilities to commit to the purchase of solar power plants long before the operating economics of such plants can be reasonably assured by operating experience. It does not seem unreasonable that the utility industry should request the government to assume a portion of the risk inherent in this commitment. By proper structuring of a subsidy program, it appears that the risk and financial burden of utility investment in PEPS can be substantially reduced, while the cost to the government does not exceed the economic value of the social benefits obtained.

9.8 CONCLUSIONS AND RECOMMENDED GOALS FOR FUTURE PROGRAMS

The analyses discussed in Section 9.0 have produced many results and conclusions which shed new light on the problems of transferring photovoltaic technology from the laboratory to energy consumers. The purpose of Section 9.8 is to highlight these conclusions--both major and minor--and provide guidelines for possible changes in the current national research and development activities related to PEPS. The conclusions and guidelines are organized by section and are listed in order of significance, as perceived by the authors.

Section 9.2- Economic Analysis of PEPS

- No significant penetration of PEPS will occur by the year 2000 without large increases in fuel costs and/or reductions in PEPS system cost and/or additional government support of PEPS technology.

Section 9.3 - Identification of Factors Influencing the Development of PEPS

- PEPS can become a viable option for electric utilities if appropriate combinations of the following occur:

- a. Reductions in system cost result from RD&D.
- b. Fuel costs continue to rise.
- c. Identifiable social benefits of PEPS are incorporated into the utility decision making process.

- Many parallels between PEPS and nuclear technologies exist. The experience gained in supporting the development of nuclear energy will be useful to the development of PEPS.

In most plausible U.S. energy futures, an abandonment of the ERDA Research, Development and Demonstration (RD&D) photovoltaics program in the 1970's would prevent PEPS from contributing to the U.S. energy supply by 2000. The private sector would not develop PEPS independent of government support unless major electricity shortages persisted.

- An extensive government subsidy aimed at commercially available PEPS would have a major impact on PEPS penetration by 2000 under most U.S. energy futures.

- The level of PEPS market penetration associated with current ERDA plans depends heavily on general energy trends between 1976 and 2000.

- An effective subsidy or commercial incentive program aimed at PEPS would substantially increase PEPS market penetration. Many of the potential markets for other new electric technologies would then be absorbed by PEPS.

- Regional variations in fuel costs may be more important than regional variations in insolation in determining the economic feasibility of PEPS.

- Limitations on a major electrical fuel source such as nuclear, or a rapid increase in the nation's demand for electricity in the 1980's, would require PEPS to play a significant role in the national energy supply by 2000.

- If U.S. electrical energy conditions deteriorate significantly, the private sector will probably play the leading role in PEPS development.

- Decreased electrical demand due to effective conservation programs would lower private sector interest in PEPS for 5 to 15 years. However, the conservation programs may help to foster PEPS penetration after that time.

- Rapid reductions in the cost of other new electric energy technologies would seriously reduce the potential penetration of PEPS.

- A deterioration in the national energy outlook coupled with a PEPS subsidy program could place strain on PEPS production capabilities.

Section 9.4 - Goals for Research, Development and Demonstration (RD&D) Program

- PEPS system cost can be reduced by RD&D efforts directed at:
(a) improving the efficiency of photovoltaic cells, (b) reducing the cost of the concentrator subassembly, and (c) reducing the cost of photovoltaic cells.

- RD&D priorities should be adjusted to increase emphasis on efforts in the area of improving cell efficiency.

- RD&D efforts to reduce concentration subassembly costs should begin immediately and should be given emphasis equal to efforts to improve cell efficiency.

- Present RD&D activities directed at reducing cell costs should be re-evaluated in light of the potential benefits from improvements in cell efficiency and reduction in concentrator subassembly costs.

Section 9.5- Social Value of Government Expenditures on PEPS

- The social benefits of environmental preservation, conservation of finite energy resources, and insurance against foreign control of U.S. energy supplies warrant the cost of continuing the current ERDA RD&D program in photovoltaics under most possible energy futures.

- The likely social benefits of PEPS range from \$50 to \$350 per installed kilowatt. However, these benefits could exceed \$3,000 per installed kilowatt if severe energy shortages were to develop.

- The social benefits of reduction in pollution levels resulting from PEPS probably will be minimal.

- Other social benefits of PEPS, which are difficult to quantify, include: export value, value as transferable knowledge, positive economic impacts.

Section 9.6- Estimation of Appropriate Magnitude of Government Expenditures on PEPS

- A reduction in the cost of PEPS or an increase in fuel prices may justify on-going government subsidies based upon the social benefits of PEPS.

- If conventional fuel prices are expected to equal a levelized amount of 10 to 15 mills/kw-hr (in real terms), government RD&D would have to reduce PEPS cost by \$120 to \$340 from the estimated cost of \$1,286/kw per installed kilowatt to justify permanent government subsidies.

Section 9.7 - Elements of a PEPS Commercial Subsidy Program

- Allowing the value of the fuel displaced by a PEPS as a tax deduction is a powerful incentive which will have minimal effect on the existing tax structure.

- Low-interest loans are one of the most potent forms of government support to PEPS.

- Because public utilities now bear a higher fraction of the social costs of energy production, PEPS may be more attractive to public than investor-owned utilities.

- Regional subsidy programs and variations in state and local taxes may have a greater impact upon penetration than will regional variations in insolation.