AN ECONOMIC FEASIBILITY STUDY OF PHOVOLTAIC-UTILITY INTERACTIVE SYSTEM

By

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ABSTRACT

This study examines the economic feasibility of a photovoltaic-utility interactive system. This system is presently technologically feasible and environmentally sound. The major drawback, however, is the cost. The primary objective of this work is to examine a commercially available photovoltaic system and compare it with conventional systems, utility-grid systems. A life-cycle cost method is utilized and sensitivity analysis is performed on the results. Government incentive and its impact is also examined. A spreadsheet model is developed to assist the author in the calculation of the annual equivalent cost of the systems.

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CHAPTER I

INTRODUCTION

1.1 An Overview

The direct energy conversion of sunlight into electricity by solar cells or photovoltaic devices is one of the most promising renewable energy options to have emerged in recent years. In terms of its potential benefits to mankind, the invention in the early 1950s of this completely new way of generating electricity may come to rank in importance with Faraday's discovery of electromagnetic induction, which led to the development of rotary electric generators and motors.

If the present downward cost trend continues, as it is expected to do, photovoltaic generation offers a way of helping to meet the increasing worldwide demand for electricity without accelerating the depletion of finite resources of fossil fuels, adding to the contamination of the atmosphere or building hundreds of nuclear power stations. In the short run, there are many commercial applications for which solar power is already cost effective[13].

Early application of solar cells were in space beginning in 1958. Almost every long duration space mission undertaken by the United

States and the former Soviet Union was powered by photovoltaic cells. These include fly-by missions past Venus, Moon, Mars, and Jupiter, the early communication satellites and the Skylab manned space station.

On the other side, terrestrial use of photovoltaic cells has also been growing steadily. By 1983, 50,000,000 calculators with small amorphous silicon devices were in use world wide; 5,000 homes and over 200 water pumps were powered by photovoltaic cells in the United States alone; the one MW ARCO Solar central-station plant near Hesperia, California was in operation; and the 6.5 MW Carrisa Plains station, also in California, was in advanced stages of planning. Today, utility interest in photovoltaic cells is increasing [12].

Solar cells today are mostly made of silicon, one of the most common elements on earth. They do their job silently and there are no moving parts to wear out. They do not pollute the atmosphere and they leave behind no harmful waste products. Their mechanical simplicity means that they can be engineered to last reliably for many years, with little or no maintenance. In fact, many existing plants operate automatically and require no attendant operators. Solar cells work effectively even in cloudy weather and, unlike solar heaters, are more efficient at low temperatures. They also respond rapidly to the sudden changes of solar input which occur when cloud pass by. These properties are of particular importance in temperate climates, where a large proportion of solar energy comes in the form of diffuse radiation from cloudy skies. The crystalline silicon solar cell has the considerable advantage of being based on well-established semiconductor technology, which has been developed over many years for electronic components such diodes, transistors, and microchips.

Another important advantage of the photovoltaic generator is its modularity. Arrays of any size and voltage can be constructed from standard modules. There is no scale effect, the conversion efficiency being practically independent of output. The modules can be thoroughly type tested and mass produced under close quality control, thus ensuring a reliable product. Potential users of large generators can gain experience before hand with a smaller version. Systems can grow as more funds become available and demand increases. Repair is usually a matter of replacing a faulty module. One or modules can fail and the system continue to operate until replacements are installed[13].

Photovoltaic power plants can be built quickly and easily. The long lead times, commonly ten years or more, associated with the planning and construction of coal, oil or nuclear power stations can be avoided. Consequently, the investment can be delayed until a short period before the predicted load is realized, thus reducing the investment risk.

However, solar power should no be thought of solely in the context of central power stations and distribution grids. Perhaps its most important characteristic is that, because sunlight is a distributed energy source, the power can be generated as and where it is needed, thus saving the cost and avoiding the losses of transmission lines. It is therefore uniquely suited to on-site generation in the many parts of the world where there is no commercial supply and electricity has to be provided expensively by batteries or small diesel or gasoline generators. Because of this, photovoltaics have an important role to play in the developing countries. The other advantage of solar cells that is common to all renewable technologies is the absence of recurring fuel costs and uncertainty of escalation in conventional fuel costs.

However, there are some primary factors working against the widespread use of solar cells. Those are its costs (both cell/module cost and the balance of systems cost), the need for large collection areas, variability of the output (diurnal and seasonal), and the lack of demonstrated long-term (20-40 years) reliability of some components of the system. The diurnal nature of photovoltaic output may require, for some applications, an energy storage system or back-up energy supply such as a battery.

1.2 Objective of the Report

The primary objective of this report is to examine the economic feasibility of commercially available photovoltaic systems using life-cycle cost (LCC) analysis. To effectively do this an imaginative case study will be built. The case is designed to be especially "friendly" to photovoltaics. Then, sensitivity analysis will examine variation in the parameters.

LCC analysis is a method of calculating the total cost of ownership over the life span of the system. Initial cost and all subsequent expected costs of significance are included in the calculations as well as disposal value and any other quantifiable benefits to be derived.

The first step of evaluation of the systems will be made using present day costs. The second step will be to perform sensitivity analysis on various parameters of the economic model. Some parameters which will be altered are electricity prices, solar cells costs, interest rates, and solar cell efficiency. The rationale for examining future assumptions is that if photovoltaic system is not economically feasible at the present, there will conceivably be a time and condition in the future when it will be economically feasible.

A secondary objective of this report is to build a spreadsheet model which can be used to perform a LCC analysis of a photovoltaic system.

CHAPTER II

LITERATURE REVIEW ON

CURRENT STATUS OF PHOTOVOLTAIC SYSTEMS

Photovoltaic devices work by using an effect first discovered in 1839 by Becquerel but not used in commercial applications until the 1950s. These early applications were in the space industry. and development of photovoltaics for terrestrial use began only in the 1970s (see Chapter 1). In the last two decades, however, development of photovoltaics has been remarkable. This fact not only happens in the United States, but also in many other countries, such as Japan, Korea, Thailand, Indonesia, and so on. Currently, there are several programs or projects developed by these countries to promote the development of photovoltaic system. This chapter summarizes recent progress in these programs or projects.

Yukinori Kuwano[8] discusses the current status of photovoltaic systems in Japan. Recently Japan has opened the way toward interconnection of solar power generating systems. This system will feed surplus power back to the power system.

Figure 1 shows the actual results of generated power. The peak demand at noon is a problem in Japan.

As shown in Figure 1, this system generates maximum electricity around noon time, so, this system is very effective in cutting the peak demand. The total amount of electricity generated on June 10,1993 was about 8.1 kWh. Approximately 69% of this total, or 5.6 kWh of the electricity generated, was sold to the electric company. Therefore, sunlight which shines on a roof and verandah could be used effectively by installing a photovoltaic system.

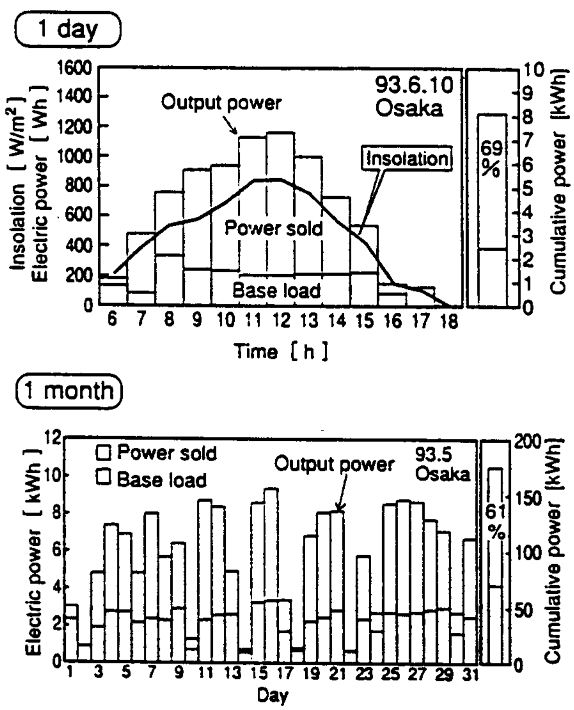

Figure 1: Operating Data of the PV System
Source: [8]

The Japanese government has supported 2/3 of the installation cost when regional public organizations install photovoltaic power generation systems. Using this subsidy in 1992 as a part of the Sunshine Project, a 25 kW system in Hyogo Prefecture as well the Sunshine Project, a 25 kW system in Hyogo Prefecture as well as 11 systems additional sites have completed installation, and more are expected in the future. According to Asahi[8], a plan is being drawn up in Japan for a program that will subsidize 1/2 of the installation costs for residential use starting in 1994. The first year of the plan calls for installation in about 700 households. This number will be gradually expanded to about 70,000 households by 2000. It will accelerate expanding solar power generation system in Japan.

Jinsoo Song[14] discusses recent progress in a national photovoltaic project in Korea. The National Photovoltaic Project with the long-term R&D plan from 1989 to 2001 in Korea was initiated to develop technologies for the generation of economically competitive electric power from photovoltaic systems. The ultimate goal of this project is to maximize photovoltaic technology utilization in Korea by the early 2000s. The plan will be conducted in 3 stages, and each stage has been divided into 3 steps with the nature of the research activity; basic research, technology development, and utilization and commercialization. Implementation of the National Photovoltaic Project is based on optimizing the mutually beneficial partnerships among government, research institutions, universities, private industries and electric utility. The government has responsibility for direction, operation, technical and budgetary allocations with the law and providing policy and budgetary allocations with the law and providing policy guidance. Universities and institutions play a major role in research and development, industries develop mass production technologies for commercialization, and the electric utility has a role in system demonstration by integration of developed products and technologies.

As a fruit of the efforts, remarkable progress has been achieved as follows during the first stage period:

- Development of mass production of single crystalline silicon cells with capacity of 300 kWp/year, which was raised to 700 kWp/year at the end of 1993.
- Performance improvement of inverters and lead-acid batteries for photovoltaic system.
- Establishment of application technology for stand-alone system for rural electrification.
- Development of technology for a-Si solar cell module and basic study on advanced materials such as $CuInSe_2$ and CdTe.

As a demonstration project using commercialized products and developed technologies, a stand-alone photovoltaic system, which consists of 90 kWp solar cell modules, lead-acid batteries, inverter, and a diesel generator as a back-up system, has been installed at Ho-Do island in the late 1992. Another photovoltaic-wind hybrid system which consists of a 30 kWp solar cell modules, and a 2 kW wind turbine, has been installed at the island of Wangdung-Do for demonstration purpose in the late 1993.

Jack L. Stone[15] discusses the development of photovoltaic system in the United States. The US Department of Energy (DOE), in collaboration with key stakeholders, initiated a strategy, named SOLAR 2000, to accelerate the adoption of phovoltaics, biomass electric and solar thermal electric technologies. There are estimates that nearly 600 GW of new generating capacity may be required worldwide entering the twenty-first century. Of this amount, nearly 500 GW will occur in the international marketplace, the rest in the United States. Developing countries will require 350 GW, with China and India accounting for one-half of that. Without a viable renewable energy option, about 45% of their generation will be coal-based. There are many emerging political, business, and environmental pressures that will favor solar electric technologies. The SOLAR 2000 strategy is aimed at accelerating their adoption.

SOLAR 2000 centers around three major elements that build upon the technological progress of the 1980s to address the growing energy needs of the 1990s. These elements are technology development and validation, market conditioning, and joint venture projects. SOLAR 2000 represents a new emphasis for DOE that, in the recent past, focused on technology R&D. Maturation of many of the PV technologies has focused the PV program on the of many of the PV technologies has focused the PV program on the next logical steps of manufacturing research, market development, and facilitation of commercialization.

The US DOE has established two important projects that support the goals of SOLAR 2000. Both build on the technical advances of the 1980s, and they represent the next logical steps in the development of PV technologies towards significant energy development in cost-effective applications.

Photovoltaic Manufacturing Technology Project (PVMaT)[15]

PVMaT is a government/industry R&D partnership whose immediate goal is to assist US industry in retaining and increasing its world leadership role in the manufacture and commercial development of PV components and systems. The projects that are funded under this program help industry to improve manufacturing processes, accelerate manufacturing cost reductions for PV modules, improve product performance, and lay the foundation for substantial scale-up of US-based PV manufacturing plant capacities. The program is being carried out in three phases. Phase 1 was a problem identification phase aimed at industry's needs and current status of the US PV industry. This phase was completed in 1991 and lasted approximately 3 months. Phase 2 is addressing process-specific problems of individual companies and is planned to last 5 years. The contracts are cost-shared with industry at about 50%. Only the winners of Phase 1 contracts were allowed to propose in the Phase 2 solicitation (PVMaT 2A). The allowed to propose in the Phase 2 solicitation (PVMaT 2A). The additional opportunity (PVMaT 2B) was established to allow all companies to "ramp on" and participate in the solution phase. Depending on the availability of funds, additional Phase 2 contracts may be available. A third phase, PVMaT Phase 3A, was established to allow participants to join forces to address generic problems in a teamed fashion. Additional Phase 3 contracts are planned, again pending availability of new funds.

Photovoltaic Building Opportunities in the US (PV: BONUS)[15]

Approximately two-thirds of the electricity generated in the United States is consumed in residential, commercial, and institutional buildings. Major uses of electricity includes lighting, air handling, air conditioning, pumping, and refrigeration. Photovoltaics has the potential of providing much of these requirements in such function as architectural, demand-side management, control, and a variety of hybrid functions. The PV: BONUS initiative is planned for three phases. A product conceptual design, a building conceptual design and testing, and a field demonstration and performance verification will be carried out over a 5-year period with heavily cost-shared subcontracts. It is expected that the PV: BONUS initiative will attract new participants to employ their expertise in developing these new applications. The new teams will involve architects, building engineers, utilities, state energy offices, regulatory agencies, and finance organizations. Utilities are recognizing agencies, and finance organizations. Utilities are recognizing the value of PV generation located on the building. Electrical generation close to the consumer avoids the costs associated with transmissions and distribution.

CHAPTER III

PHOTOVOLTAIC SYSTEMS

3.1 Components of the Systems

Several major components or parameters of a photovoltaic system are:

3.1.1 Incident Solar Radiation (Insolation)

Insolation is the input to a photovoltaic system. This energy is formed through a nuclear fusion process in the sun. The rate of energy radiated by the sun is 389 septillion (389×10^{24}) W, but on the average only 1,370 W/m^2 reached the outer atmosphere of the earth. Because of reflection and transmission losses, only about 1,000 W/m^2 of solar energy reached earth's surface on a clear afternoon near the equator. There are several factors that influence insolation level of a particular location. The major ones are: geographic location of the site, orientation, time of day, season of the year, sun-earth relative motion, and atmospheric condition[12].

3.1.2 Solar Cell

A solar cell basically is a specially-designed large-area *p-n* junction semiconductor diode, with the junction located very structure in the bottom - collect the minority carriers crossing the junction under irradiation and serve as the output terminals. Figure 2 illustrates one type of commercially available solar cells.

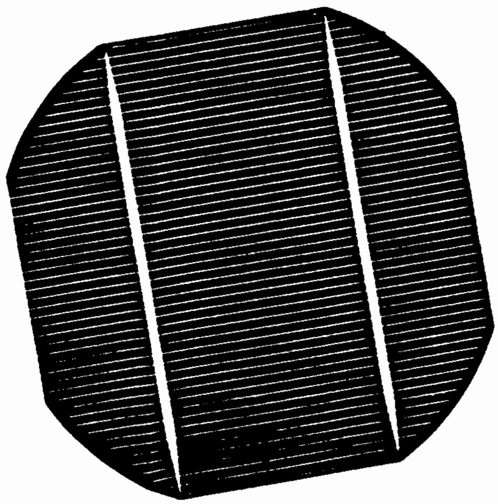

Figure 2: Siemens High-Efficiency PowerMAx Solar Cell
(Source: [23])

The output of an individual cell is rather low, about a watt or two at 0.5-0.6 V. Therefore, several cells must be connected in a series-parallel configuration to obtain practical outputs. Several cells (typically around 40-50) are connected in series-parallel to form a module. Many such modules are usually combined (again in a series-parallel arrangement) together to constitute an array (string). For larger industrial or utility installations a collection of several arrays are connected in a segment (or subfield). Today's large-scale plant or system will consist of several segments feeding into a bank of inverters, which convert the DC input into utility-grade AC, for injection into the grid. Examples of such application are one MW ARCO Solar central-station plant near Hesperia, California and 6.5 MW Carrisa Plains station, also in California[12].

Several fabrication stages exist between a laboratory cell and photovoltaic system. They are: production cells, production modules, operating array, and operating systems. At each stage, a certain decrease in efficiency is experienced. The overall efficiency of conversion of incident solar radiation (insolation) into electrical energy of a system could be as low as 60% of the efficiency of a laboratory cell[24]. Figures 3 and 4 illustrate the progress achieved in the efficiencies of solar cells and modules respectively in the recent past.

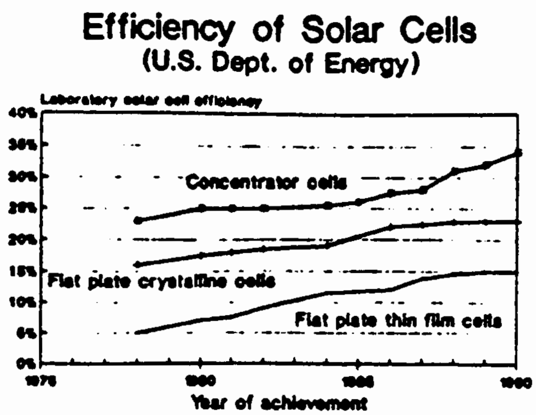

Fig. 3: Progress Achieved in Solar Cell Efficiencies (Source: [12])

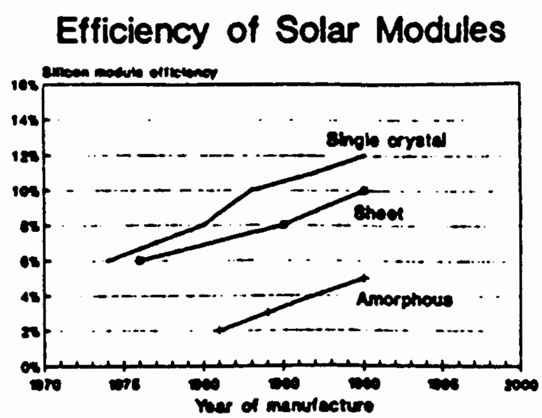

Fig. 4: Progress Achieved in PV Modules Efficiencies (Source: [12])

3.1.3 Charge Control/Regulator

It is important to provide some means of preventing excessive charging of system's batteries. If left connected directly to a battery, most solar panels would cause the voltage to rise to a point where gassing (electrolysis) would occur. This gassing, if excessive, causes water level loss and premature aging of the battery. Gassing scrubs the material off the sides of the plates decreasing its capacity and will cause excessive internal heating leading to shortened life. Small controlled amounts of gassing are, however, good for batteries as they cause a mixing of the battery's acid.

Charge regulators are used in PV power systems to allow maximum rates of charging up to the gassing point of the battery and then restrict the current so that a full charge can be approached gently. Figure 5 depicts a commercially available charge control/regulator.

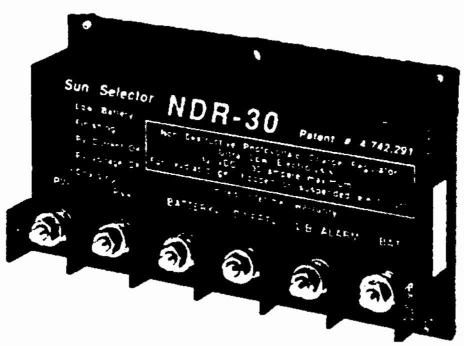

Figure 5: NDR-30 Charge Regulator
(Source: [21])

3.1.4 Battery

A battery is an electrical storage device that comes in many shapes, sizes, weights, and chemical compounds. They all have one thing in common, they store electrical energy.

There are many different types of storage batteries commercially available. Selection of a battery type for a particular solar electric system involves many considerations. Included among these are: voltage requirement, current requirement, operating schedule, ampere-hour capacity, operating temperature range, size and weight, required life, cost, and autonomy. By far the most common type of battery used in solar electric systems is the lead-acid battery. Figure 6 depicts an example of commercially available battery.

Figure 6: TROJAN J-185 Battery
(Source: [21])

To calculate the size of battery needed for a particular system, the battery sizing worksheet[21] is enclosed in appendix D.

3.1.5 Inverter

The photovoltaic array and battery produce DC current and voltage. If AC power is required by the loads, an inverter can be used to convert from DC to AC. Commonly available inverter can generate output in 1- or 3- phase, 50 or 60 hertz, and 117 or 220 volts, and can range in continuous output power from a few hundred watts to 10 kilowatts. Large utility scale inverters are made to generate output at 480 volts AC to capacities exceeding 1,000 kilowatts. Figure 7 depicts an example of commercially available inverter.

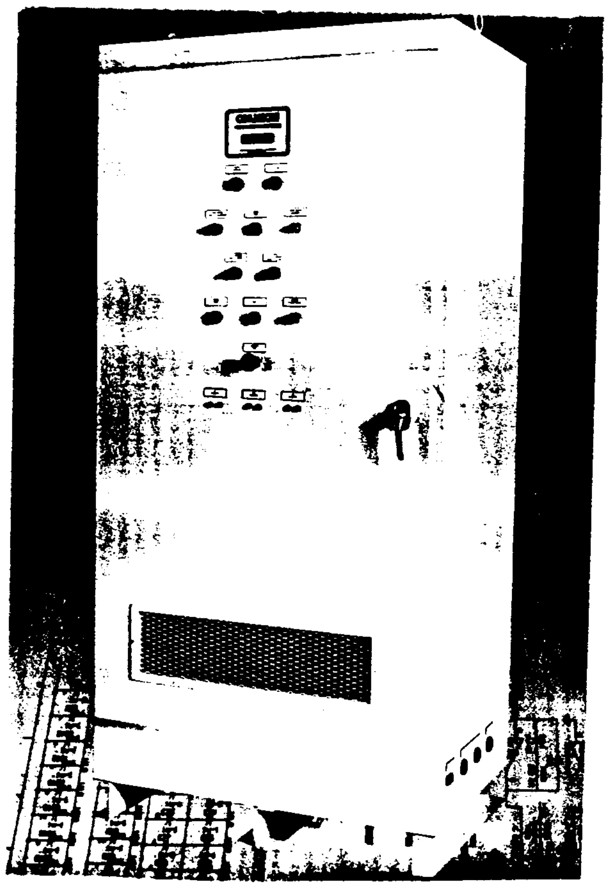

Figure 7: OMNION Series 3200, High Performance 3 Phase Photovoltaic Power Conversion (Source: OMNION Power Engineering Co. Product Literature)

3.2 Types of Systems

The modularity and flexibility of solar electricity allows users to choose a photovoltaic system tailored to the needs and preferences. Generally speaking, photovoltaic systems can be categorized into three primary types: stand-alone, hybrid back-up, and utility-integrated[21].

Stand-alone Systems

These systems are usually a utility substitute. They generally include photovoltaic modules, storage batteries and control/regulator. Ground mounted systems will require a special mounting structure, and if AC power is desired, an AC inverter will be required. Figure 8 depicts a configuration of a stand-alone AC/DC system.

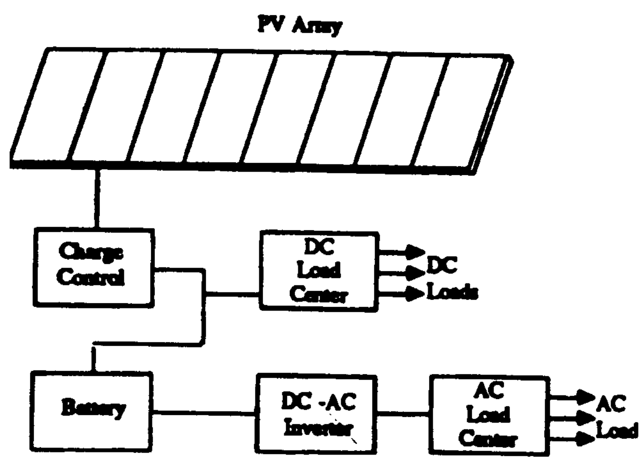

Figure 8: A Configuration of a Stand-alone AC/DC System (Source: [21])

The applications of stand-alone systems include remote communication repeaters and receivers, remote sensing stations, remote lighting systems, signals, including river and ocean navigational aids, and cathodic protection of remote bridges and pipelines. Such applications are too remote for regular maintenance or for fuel delivery.

Hybrid Back-up Systems

In these systems, a back-up system is added to photovoltaic system to increase reliability of the system. The most common back-up systems are diesel generators and wind systems. This back-up system will help a conventional photovoltaic system to meet the peak load demand during short periods, when there is a deficit of available energy to cover the load demand. Figure 9 depicts a configuration of a photovoltaic-generator combination system.

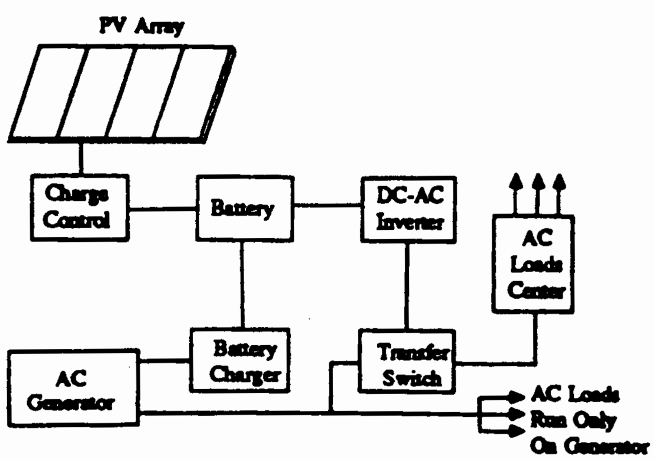

Figure 9: A Configuration of a PV-Generator Combination System
(Source: [21])

Utility Integrated Systems

These systems are generally designed to simply feed power back into the utility grid to help offset household utility bills. A typical system might include photovoltaic modules, a mounting structure, an AC inverter/controller, and an extra meter, for the power to be "fed back" into the utility grid. Figure 10 depicts a configuration of a utility interactive system.

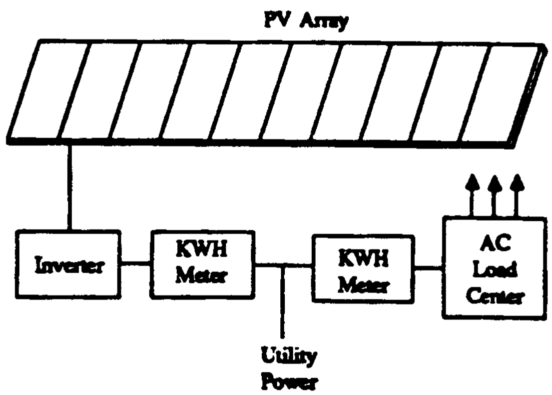

Figure 10: A Configuration of a Interactive System
(Source: [21])

These systems will most likely be the best option in the future. This is because technology and price of energy storage (i.e. battery) do not show a "positive" trend, diesel generators still need control of their operation and supply in fuel, and in the future the number of areas which are totally isolated/far from the utility-grid, will be very few.

3.3 Systems Sizing Procedure[4]

The step-by-step design procedure of a photovoltaic system is:

1. Determine the typical load electric energy demand on an average day for each month of the year (kWh/day). Establish a table of the energy demand (kWh/day) versus time of year (monthly).
2. Make a preliminary decision as to whether the photovoltaic array will be sized to satisfy the annual peak, average, or minimum energy demand shown in the graph drawn in step 1. If needed, calculate the annual average daily energy demand (kWh/day).
3. Determine the total solar energy available at the site under consideration on an appropriately tilted south-facing surface (kWh/day-m^2)[5]. Establish a table of daily solar energy versus month or season of year.
4. Make a preliminary decision as to whether the array is going to be sized according to the annual peak, average, or minimum solar energy. If needed, calculate the annual average daily solar energy per tilted square meter from the table compiled in step 3.
5. Complete a preliminary system design by choosing the type of power-conditioning equipment needed (i.e. utility-interactive, battery storage, maximum-power tracking, etc.).
6. Determine the approximate photovoltaic array size needed to meet the energy demand estimated in steps 1 and 2. Based on

the decisions made in steps 2 and 4, match up the annual peak, average, or minimum daily energy demand with the annual peak, average, or minimum daily solar energy received.

$$A = E_d/(S \times \eta_m \times f_t \times f_p \times \eta_p) \qquad \text{Eq. 3-1}$$

Where:

A = array area, m^2

E_d = daily load energy demand (kWh/day) based on the annual peak, average, or minimum

S = daily available solar energy at site, kWh/day-m^2, based on annual peak, average, or minimum

η_m = efficiency of the photovoltaic module at normal cell temperature; include packing factor

f_t = temperature correction factor for module efficiency (0.5%[1] decrease per ^0C rise above normal cell temp.)

= $[\eta_m$ - 0.5%(cell temp. ^0C - normal cell temp. $^0C)]/\eta_m$

f_p = packing factor for module or array

= module area/array area

η_p = power-conditioning efficiency for power-conditioning equipment such as AC/DC inverter, battery, or maximum-power tracker (≅ 90%)

[1] It depends on modules' characteristics (usually given at PV modules' specification sheet).

7. Calculate the peak power rating of the array sized in the step six.

$$P_p = A \times 1000\ W/m^2 \times \eta_m \times f_p \qquad \text{Eq. 3-2}$$

8. Choose particular modules available on the market and configure them into array composed of strings and branches that will meet the needed peak power and output voltage requirement (the module's rated power and voltage must be known). If the module's voltage and power output are not convenient value, a different module can be chosen or the array may have to be over or undersized.

9. Calculate the daily energy output of the proposed photovoltaic system by using the average daily insolation data for a tilted surface, develop in step 3, and the solar-cell array and system Equations 3-3.

$$P_E = S \times \eta_m \times f_t \times f_p \times S_F \times \eta_p \times A \qquad \text{Eq. 3-3}$$

Where:

P_E = photovoltaic energy for one day, kWh

S_F = soiling factor; the ratio of energy generated to energy that would be generated if the module cover glass were completely clean

Put the PV-system energy output versus time of day on the same table in step 1.

10. Examine the PV system output and load input in the table completed in step 9 and note the amount and times of PV-energy surplus and deficit throughout the year. If the surplus or deficit is excessive, change one or more of the design parameters and repeat some or all of steps 1 through 9.

11. Do life-cycle cost analysis to examine the feasibility of PV system. Life-cycle cost analysis includes both initial cost and all subsequent expected costs of significance in the calculations as well as disposal value and any other quantifiable benefits to be derived.

This step-by-step procedure, later, will be used as the basis to build Worksheet C: PV System Sizing.

CHAPTER IV

CASE STUDY: PHOTOVOLTAIC-UTILITY INTERACTIVE SYSTEMS INSTALLED AT AN INDUSTRIAL PLANT

4.1 General Information

The case study presented here is an "imaginative" case, but it reflects realistically a commercially available photovoltaic system in the market. This means the systems are technologically present[1], the electricity prices are the current Oklahoma Gas & Electricity Co. (OG&E) electricity rate schedule[19], and system costs are obtained from photovoltaic manufacturer and distributors[21],[22],[23].

The system chosen is a photovoltaic-utility interactive system which is intended to supply electricity needs for an industrial plant located in Oklahoma City, Oklahoma. The reasons behind the choice are: photovoltaic-utility interactive system is technologically feasible at the present and it will become the "best" option for a photovoltaic system in the future[24]. Based on Statistical Abstract of the United States 1994[3], the industrial sector was the biggest user of electricity in US from 1970 to 1992. In 1992, thirty-six percent of electricity produced was sold to the industrial sector. Figure 11 shows how the United States electricity consumption is distributed among the sectors.

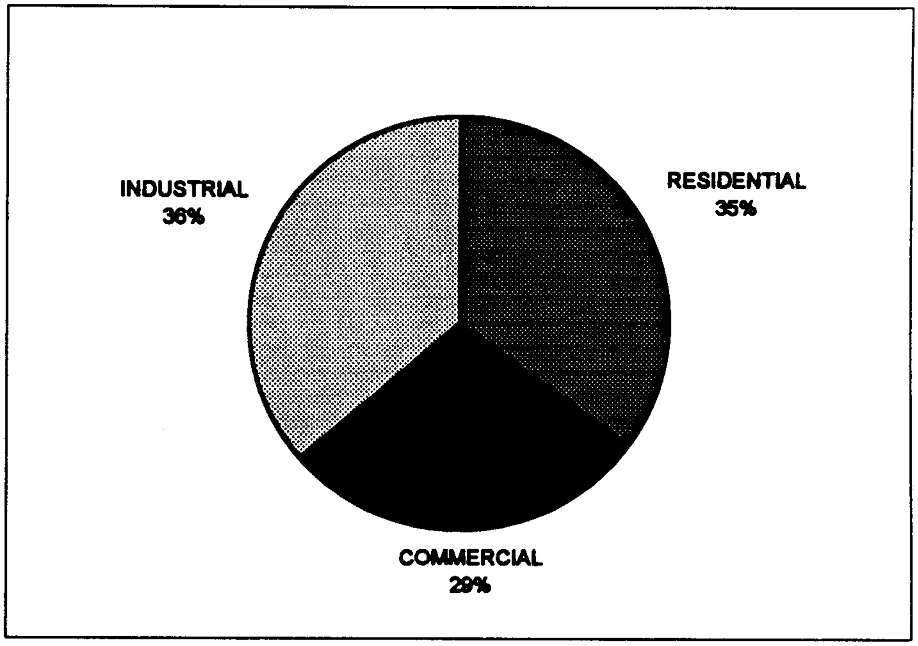

Figure 11: 1992 US Electricity Consumption by Sectors
(Source: US Dept. of Commerce, Statistical Abstract of the US 1994)

Thus, if the utilization of photovoltaic system in industry can be justified economically, the dollar savings will be significant.

4.2 Systems Sample Data

The sample system chosen is an industrial plant, located in Oklahoma City, Oklahoma at a latitude of $35^0 04'$N and a longitude of $97^0 36'$W[20].

This plant utilizes three-phase electricity at voltage of 480 V AC. The load profile and hours of operation are chosen to reflect an ideal scenario for the PV systems. To supply its processes, this plant needs power of 100 kW with no variation. Operating hours are assumed to be when the sun is shinning. Thus, no battery costs are incurred and the PV array is 100% utilized. The annual operation hours of the plant is 2,912 hours/year (8 hours/day, 7 days/week, and 52 weeks/year). Thus, based on the power requirement and the operation hours of the plant, energy consumption per day of the plant is 800 kWh/day. This load information is very critical, since PV system must be sized to meet the energy requirements (measured in kWh), not power (measured in kW), of the system (see again Section 3.3). The insolation and weather data is shown in Table 1.

Table 1: Insolation and Weather Data of Oklahoma City (Lat.: 35°04'N;Long.:97°36'W)

MONTH	Daily Insolation Clear Day On Horizontal Surface (MJ/m^2)	Daily Insolation Clear Day On Tilted Surface (MJ/m^2)	Mean Percentage Possible Sunshine (%)	Daily Maximum Temperature (°C)
January	9.09	13.30	50	8.67
February	11.97	16.05	52	11.44
March	15.89	18.28	54	15.44
April	19.58	19.78	55	22.00
May	21.77	20.47	54	15.94
June	24.34	22.13	59	30.56
July	24.16	22.28	59	33.67
August	22.14	21.74	59	33.61
September	17.64	19.15	56	29.28
October	13.99	17.28	56	23.44
November	10.22	13.67	53	16.06
December	8.23	11.61	50	10.39

Source:

- Insolation and Percentage Possible Sunshine Data are obtained from reference[5]
- Maximum Temperature Data is obtained from reference [20]

The procedure to calculate insolation on tilted surface is attached in Appendix A[2].

4.3 Photovoltaic Systems Data

The PV system used is Photovoltaic-Utility Interactive System (Figure 12 illustrates the schematic of the system).

Description of the System:

- Photovoltaic array converts sunlight into electricity. This array is mounted on the roof-top of the plant, thus eliminating the need for empty land. The array is faced south and has tilt angle of 30^0. This tilt angle is determined based on tilt angle "rule of thumb". The optimum tilt angle is $\pm\ 10^0$ of location's latitude[7].
- The electrical output is a DC current. Therefore, to fulfill the load requirement (see Section 4.2) an inverter is installed to convert DC current into AC current.

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[2] An example of calculation of insolation on tilted surface is detailed below for January.

- The first step is to find H_d/H,

$$H_d/H = 1.391 - 3.560K_T + 4.189K_T^2 - 2.137\ K_T^3$$
$$= 0.45$$

- Next step is to find R_b,

$$R_b = \frac{\cos(\phi-\beta)\cos\delta\sin\omega_s' + (\pi/180)\omega_s'\sin(\phi-\beta)\sin\delta}{\cos\phi\cos\delta\sin\omega_s' + (\pi/180)\omega_s'\sin\phi\sin\delta}$$
$$= 1.817$$

- Then insolation on tilted surface (= H_T) can be solved,

$$H_T = H(1 - H_d/H)R_b + H_d[(1+\cos\beta)/2] + H\rho_g[(1-\cos\beta)/2]$$
$$= 13.30\ \text{MJ/m}^2\text{-day}$$

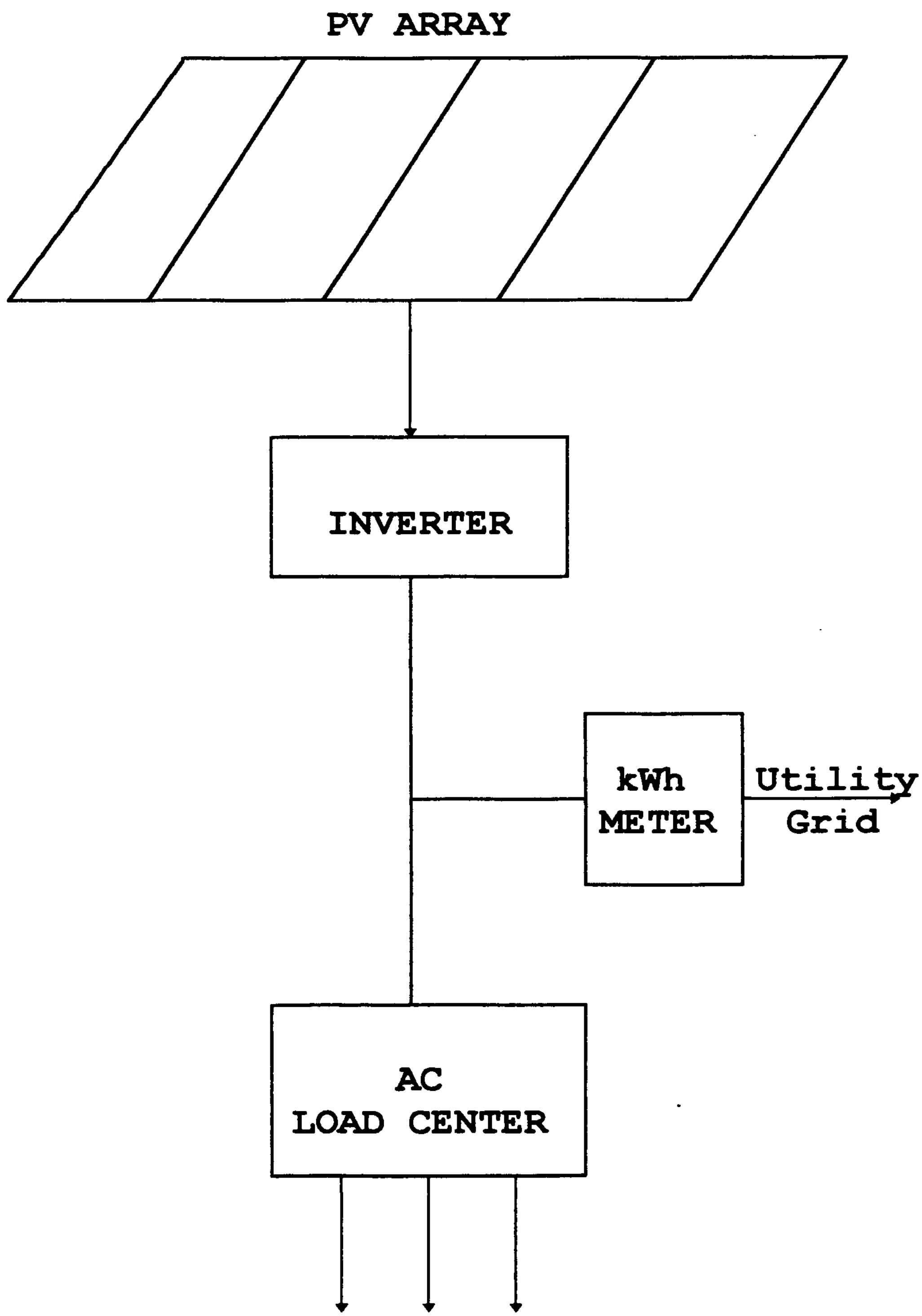


Figure 12: Photovoltaic-Utility Interactive System

- This photovoltaic system is designed to supply the highest monthly energy consumption of the plant.
- If there is excess on the output of PV, the system will feed the excess into the grid. Thus, this system requires a meter to measure how much electricity fed into the utility grid during the solar day.

Major Components of the PV System:

1. Photovoltaic Modules:

   SOLAREX MSX-83 photovoltaic modules are used. These modules use the latest technology in polycrystalline silicon photovoltaics which contain the largest solar cells in commercial production: 11.4 cm x 15.2 cm. These features give the MSX-83 the highest power and charging current of any of the 36 cell PV modules on the market today.

   One of many reasons behind the choice is with more power per module, fewer modules are needed lowering Balance of System (BOS) costs. Figure 13 illustrates the most important PV module characteristic (i.e. I-V curve) of SOLAREX MSX-83.

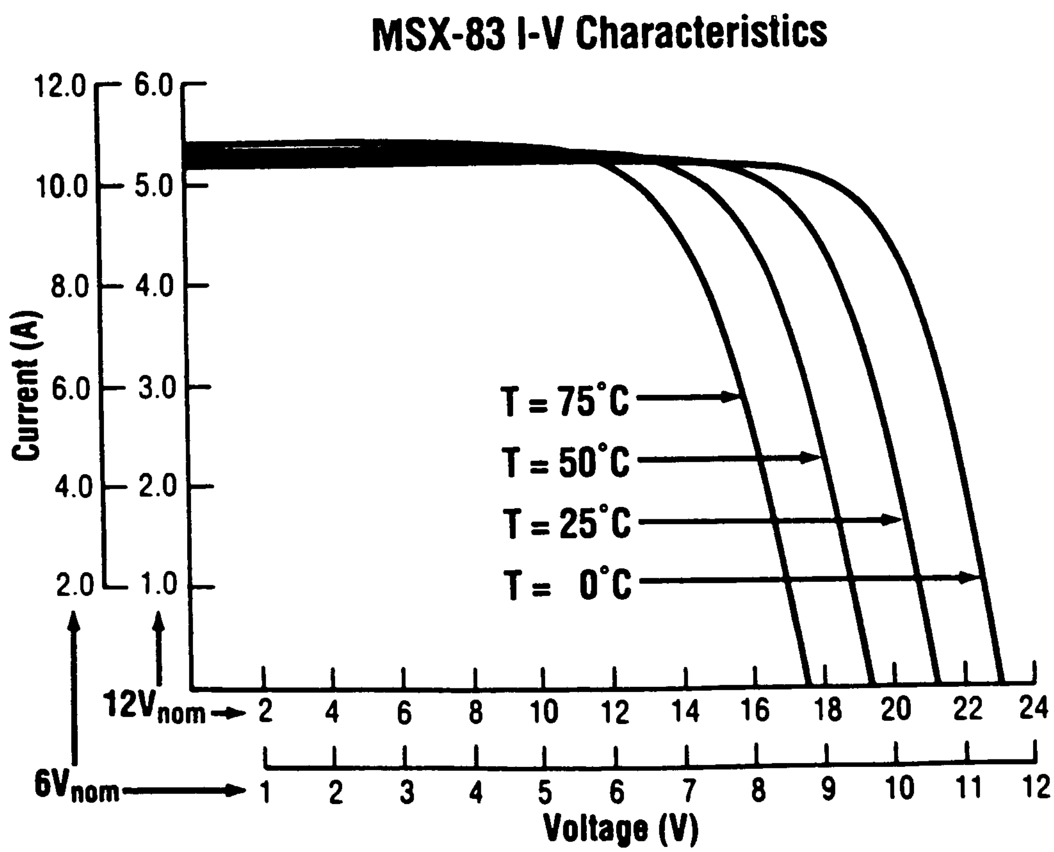


Figure 13: MSX-83 I-V Characteristics
(Source: Solar Electric Specialties Co. Product Literature)

A complete product literature is attached in Appendix D.

2. Inverter:

An OMNION Series 3200 - High Performance Three Phase Photovoltaic Power Conversion is used. The Series 3200 sophisticated microprocessor control provides automatic system start-up and shut-down, maximum power tracking and utility protection with a minimum number of components. The efficiency of this unit is 95%. Picture and Specifications of OMNION Series 3200 are attached in Appendix D.

3. Meter:

The meter is assumed to have 100% efficiency.

4.4 Boundaries of the Study

In order to avoid an unmanageable project, certain limitations have to be placed on the study. One of these is to limit PV system being examined to PV-Utility Interactive system only.

The location is certainly a limitation in that it makes the study very regionalized. Cost data such as electricity and labor, and the actual system design would also vary with different weather patterns and climatological data. However, this is partially overcome by the use of sensitivity analysis.

In addition, a spreadsheet model is developed so that cost data from any locale or other system could easily be inputted and evaluated.

CHAPTER V

SYSTEMS ANALYSIS

5.1 Evaluation Criteria and Assumptions

There are two criteria used in the evaluation of the systems. The main one was Annual Equivalent Cost (AEC), and the second criteria was Electricity (Energy) Cost.

By amortizing the initial investment over the life of the photovoltaic system, the AEC could be considered as a principal payment, interest payment, the annual electricity cost and other annual expenses. While, electricity (energy) Cost, is calculated by dividing AEC of the system with annual electricity consumption which would include purchased as well as produced electricity. A system with lower AEC or energy cost indicates a more economical system. The annual equivalent cost was calculated based on After-Tax Cash Flow of the System.

Evaluation in this study used 1994 as the basis year. The reason behind this choice is the availability of data. Since 1995 just started, most of 1995 data needed to do this study, such as fuel escalation rate and system costs, is not available yet.

The life's span of PV system used in this study is 30 years. This represents the expected life of commercially available PV modules.

The initial interest rate (i.e. combined interest rate) used for the evaluation was composed of an inflation rate of 5.3% and a real interest rate of 4.5%. Projected electricity price indices in Table 5.1 were used for electricity rate increases. The inflation rate was determined based on Annual Data of Percent Change of 1994 US City Average Consumer Price Index[18], while the real interest rate was based on the rate used by Federal Agency for public investment and regulatory analyses with project's maturity of 30 years[11]. Consideration was also given to the fact that electricity costs will be steadily changing over the next 30 years. The projected electricity price indices from 1994 to 2023 for industrial sector is given in Table 2 in the next page.

Table 2: Projected Electricity Price Indices

Year	Projected Electricity Price Indices (excluding Inflation Rate)	Projected Electricity Price Indices (including Inflation Rate of 5.3%)
1994	1.01	1.06
1995	1.01	1.12
1996	1.01	1.18
1997	1.02	1.25
1998	1.02	1.32
1999	1.04	1.42
2000	1.05	1.51
2001	1.05	1.59
2002	1.06	1.69
2003	1.08	1.81
2004	1.08	1.91
2005	1.09	2.03
2006	1.09	2.13
2007	1.09	2.25
2008	1.09	2.37
2009	1.09	2.49
2010	1.10	2.65
2011	1.10	2.79
2012	1.10	2.93
2013	1.11	3.12
2014	1.11	3.28
2015	1.12	3.49
2016	1.12	3.67
2017	1.12	3.87
2018	1.13	4.11
2019	1.13	4.33
2020	1.14	4.60
2021	1.14	4.84
2022	1.14	5.10
2023	1.15	5.41

Source: This data is obtained from reference [11]
Note:

- **This data is prepared for US Department of Energy, Office of the Assistant Secretary for Conservation and Renewable Energy-Federal Energy Management Program**

The electricity is assumed purchased from Oklahoma Gas and Electricity Company. There are two kinds of rate schedule used in this evaluation, one rate schedule which has demand (measured in kW)and energy (measured in kWh) charge, and the one that only has energy charge. Since the system voltage requirement is 480 V AC (refer to Section 4.2), the service level falls into category 5. The two rate schedules used in this project are summarized as follows:

POWER AND LIGHT RATE

SECONDARY (Service Level 5):

Customer Charge: $151.00 per bill per month.

Capacity Charge:

Summer Season: $15.54 per kW of Billing Demand per month
Winter Season: $ 5.63 per kW of Billing Demand per month

Energy Charge:
First 2,000,000 kWh per month: 2.93 cents per kWh.
All additional kWh per month: 2.52 cents per kWh.

GENERAL SERVICE RATE

SECONDARY (Service Level 5):

Customer Charge: $12.00 per bill per month.

Energy Charge:

Summer Season: The five OG&E Revenue Months of June through October.
All kWh per month: 10.61 cents per kWh.

Winter Season: The seven OG&E Revenue Months of November through May of the succeeding year.
First 1,000 kWh per month: 8.74 cents per kWh.
All additional kWh per month: 4.77 cents per kWh.

The original rate schedules are attached in Appendix C.

The evaluation was performed on two systems, present system: utility grid line, and proposed system: PV-utility interactive system.

5.2 Evaluation of the Present Systems

The initial step in the analysis of the present system was the calculation of annual electricity costs. Using projected electricity price indices (Table 2), the annual cost of electricity over 30 years were obtained. Then, AEC of the present system was obtained, and lastly, electricity (energy) cost of the system was determined. The step-by-step procedure of calculating the AEC of the present system is flowcharted in Figure 14.

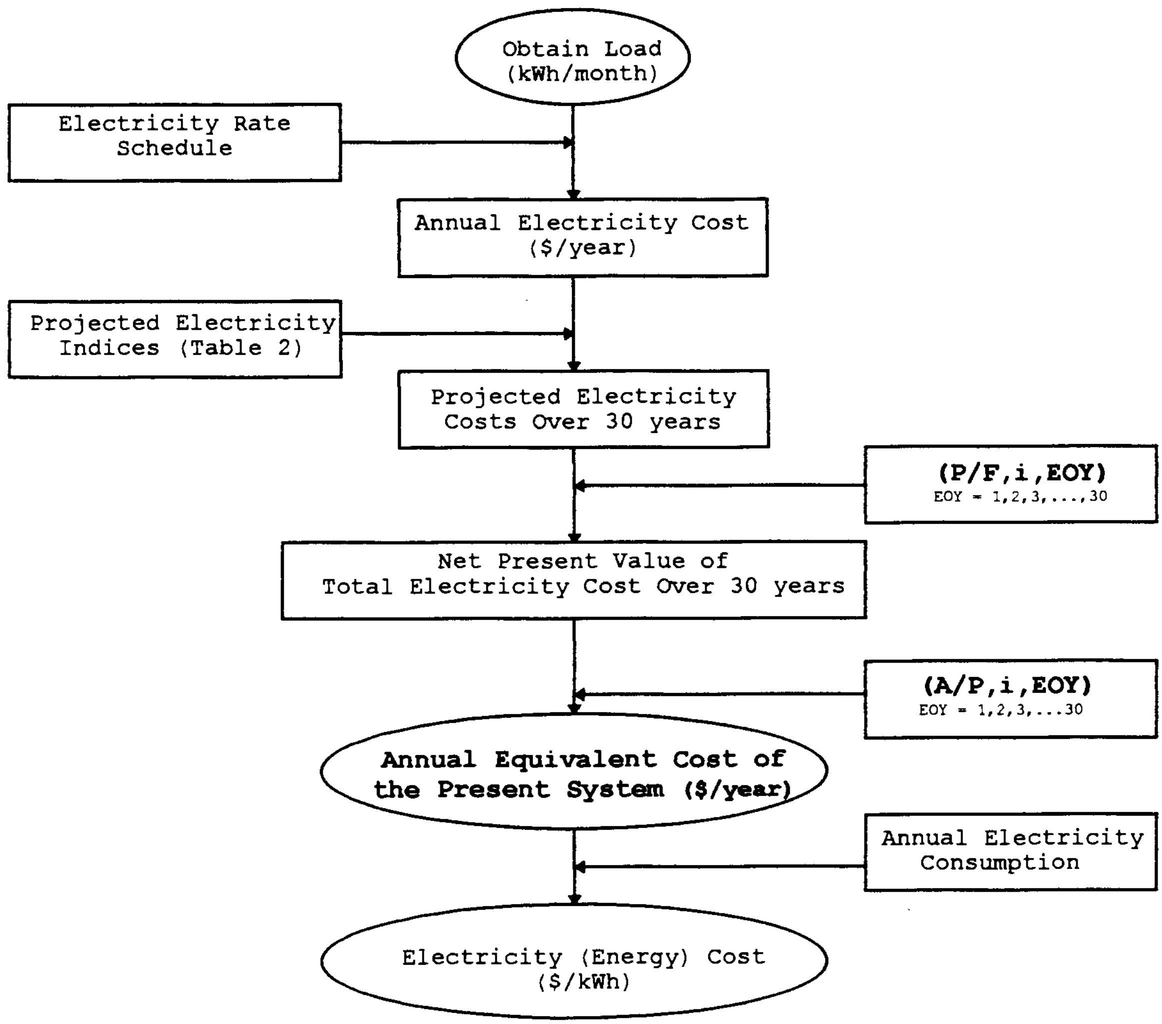


Figure 14: Flowchart of Step-by-Step Evaluation of the Present System

The author has generated a set of spreadsheets or worksheets to assist the evaluation. The following formula was utilized to calculate AEC of the present system.

$$AEC = [\sum_{EOY=1}^{n}(\text{Present Annual Electricity Cost})(PEPI)_{EOY}(P/F,i,EOY)](A/P,i,n) \qquad \text{Eq. 5-1}$$

Where,

AEC = Annual Equivalent Cost of the Present System

PEPI = Projected Electricity Price Indices (including Inflation Rate of 5.3%), obtained from Table 2

$(A/P,i,n) = [i(1+i)^n]/[(1+i)^n - 1]$

$(P/F,i,EOY) = 1/[(1+i)^{EOY}]$

i = Combined Interest Rate

$= ((1+j)(1+d))-1$

j = Inflation Rate

d = Real Interest Rate

n = Life of the study (in this case 30 years)

EOY = 1,2,3,...,n

To calculate the electricity (energy) cost of the present system, the following formula was utilized.

$$\text{Energy Cost} = (AEC)/(\text{Annual Electricity Consumption}) \qquad \text{Eq. 5-2}$$

Where:

Energy Cost = measured in $/kWh

AEC = calculated using Equation 5-1 ($/year)

Annual Electricity Consumption = measured in kWh/year

Worksheet A[3] was used to calculate the annual electricity cost. This worksheet is shown in the next page. Outcomes of this worksheet is shown in Table 3 below.

Table 3: Outcomes of Worksheet A: Annual Electricity Cost & Present Electricity Cost

	Annual Electricity Cost ($/year)	Present Energy Cost ($/kWh)
P&L Rate	$ 24,148.47	$ 0.083
GS Rate	$ 23,356.44	$ 0.080

Worksheet B[3] was generated to calculate the annual equivalent cost and electricity (energy) cost of the present system. This worksheet is shown in page 44. Worksheet B used annual electricity cost calculated in worksheet A to generate the projected electricity costs over 30 years. Net present value of those projected costs was, then, calculated. Next, annual equivalent cost of the present system was determined. And, lastly energy cost of the present system was obtained. In computing

[3] The procedure to use this spread sheet is attached in Appendix B.

WORKSHEET A: ANNUAL ELECTRICITY COST

OG&E POWER AND LIGHT RATE (P&L Rate) - Service Level 5

(charged by electricity demand and consumption)

Month	Electricity Demand		Electricity Consumption		Total Costs
	kW	$	kWh	$	$
Jan	100	$ 563.00	24,800	$ 726.64	$ 1,440.64
Feb	100	$ 563.00	22,400	$ 656.32	$ 1,370.32
Mar	100	$ 563.00	24,800	$ 726.64	$ 1,440.64
Apr	100	$ 563.00	24,000	$ 703.20	$ 1,417.20
May	100	$ 563.00	24,800	$ 726.64	$ 1,440.64
Jun	100	$ 1,554.00	24,000	$ 703.20	$ 2,408.20
Jul	100	$ 1,554.00	24,800	$ 726.64	$ 2,431.64
Aug	100	$ 1,554.00	24,800	$ 726.64	$ 2,431.64
Sep	100	$ 1,554.00	24,000	$ 703.20	$ 2,408.20
Oct	100	$ 1,554.00	24,800	$ 726.64	$ 2,431.64
Nov	100	$ 563.00	24,000	$ 703.20	$ 1,417.20
Dec	100	$ 563.00	24,800	$ 726.64	$ 1,440.64
Annual			292,000		$ 22,078.60

INPUT:

Customer Charge = $ 151.00 per Month

OUTPUT:

Annual Electricity Consumption = 292,000 kWh

Annual Electricity Cost =

Without Taxes = $ 22,078.60 per Year

With Taxes = $ 24,148.47 per Year

ADDITIONAL OUTPUT:

Present Electricity (Energy) Cost = 0.083 ($/kWh)

NOTE:

Taxes are composed from:

- Franchise payment =	1.000%
- State sales tax =	4.500%
- City sales tax =	3.875%
Total Taxes =	9.375%

OG&E GENERAL SERVICE RATE(GS Rate) - Service Level 5

(charged by electricity consumption)

Month	Electricity Consumption		Total Costs
	kWh	$	$
Jan	24,800	$ 1,222.66	$ 1,222.66
Feb	22,400	$ 1,108.18	$ 1,108.18
Mar	24,800	$ 1,222.66	$ 1,222.66
Apr	24,000	$ 1,184.50	$ 1,184.50
May	24,800	$ 1,222.66	$ 1,222.66
Jun	24,000	$ 2,546.40	$ 2,546.40
Jul	24,800	$ 2,631.28	$ 2,631.28
Aug	24,800	$ 2,631.28	$ 2,631.28
Sep	24,000	$ 2,546.40	$ 2,546.40
Oct	24,800	$ 2,631.28	$ 2,631.28
Nov	24,000	$ 1,184.50	$ 1,184.50
Dec	24,800	$ 1,222.66	$ 1,222.66
Annual	292,000		$21,354.46

INPUT:

Customer Charge = $ 12.00 per Month

OUTPUT:

Annual Electricity Consumption = 292,000 kWh

Annual Electricity Cost =

Without Taxes = $21,354.46 per Year

With Taxes = $23,356.44 per Year

ADDITIONAL OUTPUT:

Present Electricity (Energy) Cost = 0.080 ($/kWh)

NOTE:

Taxes are composed from:

- Franchise payment =	1.000%
- State sales tax =	4.500%
- City sales tax =	3.875%
Total Taxes =	9.375%

WORKSHEET B: ANNUAL EQUIVALENT COST OF THE PRESENT SYSTEM

N	EOY	(PEPI)	PEPI [(PEPI)*(1+j)^n]	PEC ($/year)
0	1993	1.00	1.00	
1	1994	1.01	1.06	$ 24,840.28
2	1995	1.01	1.12	$ 26,156.81
3	1996	1.01	1.18	$ 27,543.12
4	1997	1.02	1.25	$ 29,290.06
5	1998	1.02	1.32	$ 30,842.44
6	1999	1.04	1.42	$ 33,113.89
7	2000	1.05	1.51	$ 35,204.21
8	2001	1.05	1.59	$ 37,070.03
9	2002	1.06	1.69	$ 39,406.50
10	2003	1.08	1.81	$ 42,277.97
11	2004	1.08	1.91	$ 44,518.70
12	2005	1.09	2.03	$ 47,312.25
13	2006	1.09	2.13	$ 49,819.80
14	2007	1.09	2.25	$ 52,460.25
15	2008	1.09	2.37	$ 55,240.64
16	2009	1.09	2.49	$ 58,168.40
17	2010	1.10	2.65	$ 61,813.26
18	2011	1.10	2.79	$ 65,089.36
19	2012	1.10	2.93	$ 68,539.10
20	2013	1.11	3.12	$ 72,827.78
21	2014	1.11	3.28	$ 76,687.65
22	2015	1.12	3.49	$ 81,479.59
23	2016	1.12	3.67	$ 85,798.01
24	2017	1.12	3.87	$ 90,345.31
25	2018	1.13	4.11	$ 95,983.01
26	2019	1.13	4.33	$ 101,070.11
27	2020	1.14	4.60	$ 107,368.66
28	2021	1.14	4.84	$ 113,059.20
29	2022	1.14	5.10	$ 119,051.34
30	2023	1.15	5.41	$ 126,460.72

INPUT:

Inflation Rate (= j) =	5.30%	
Real Interest Rate (= d) =	4.50%	
Annual Electricity Cost (outcome of Spreadsheet A) =	$ 23,356.44	per Year

LIFE-CYCLE COST ANALYSIS OUTPUT:

Net Present Value of Electricity Costs Over 30 Years =	$407,330.95	
Annual Equivalent Cost of Electricity =	$43,348.20	per Year

Annual Equivalent Cost of the Present System = $ 43,348.20 per Year

Electricity (Energy) Cost of the Present System = $ 0.15 per kWh

Note:

(PEPI) = Projected Electricity Price Indices (for Industrial sector, **excluding** general inflation)

PEPI = Projected Electricity Price Indices (for Industrial sector, **including** general inflation)

PEC = Projected Electricity Costs (after **escalated** and **inflated**) these AECs and energy costs, it was assumed that the tax rates will be stable over the project's span. The outcomes of this worksheet are shown in Table 4 below.

Table 4: Outcomes of Worksheet B: Annual Equivalent and Electricity (Energy) Costs of the Present Systems

	Annual Equivalent Cost ($/year)	Electricity (Energy) Cost ($/kWh)
P&L Rate	$ 44,818.15	$ 0.15
GS Rate	$ 43,348.20	$ 0.15

In the evaluation of the present system, the only pertinent cost was annual electricity cost. Thus, annual equivalent cost of the present system yields the sama results as annual equivalent cost of electricity consumption.

5.3 Evaluation of the Proposed Systems: PV-Utility Interactive Systems

The initial step in the analysis of this system was the development of the system itself. This was done by utilizing step-by-step procedure in section 4.3. Spread sheet C[4] (shown in the next page) was developed to assist the author in the

[4] The procedure to use this spread sheet is attached in Appendix B.

WORKSHEET C: PV SYSTEM SIZING
(INPUT SHEET)

INPUT:

Month	Daily Insolation Clear Day (kWh/m²-day)	% Possible Sunshine	Daily Insolation (kWh/m²-day)	Daily Maximum Temperature (°C)	Cell Temp. (°C)
Jan	3.69	0.44	1.63	8.67	28.67
Feb	4.46	0.49	2.18	11.44	31.44
Mar	5.08	0.50	2.54	15.44	35.44
Apr	5.49	0.47	2.58	22.00	42.00
May	5.69	0.50	2.84	25.94	45.94
Jun	6.15	0.53	3.26	30.56	50.56
Jul	6.19	0.54	3.34	33.67	53.67
Aug	6.04	0.54	3.26	33.61	53.61
Sep	5.32	0.51	2.71	29.28	49.28
Oct	4.80	0.50	2.40	23.44	43.44
Nov	3.80	0.39	1.48	16.06	36.06
Dec	3.22	0.37	1.19	10.39	30.39

PV System Requirements:

Daily Load Requirement =	800 kWh/day
System Voltage Requirement =	480 V AC

PV Module Data:

Nominal Operation Cell Temperature =	49 °C
Temperature Effect On Power =	0.38%
Module Peak Power (Pp) =	83 W
Voltage @ Peak Power (Vpp) =	17.1 V
Current @ Peak Power (Ipp) =	4.85 A

Power Conditioning Unit Data:

Average Efficiency of Power Conditioning Unit =	95%
Array Nominal Operating Voltage =	360 V DC

Estimated:

Soiling Factor =	98%
Module Packing Factor =	95%

Calculated Based On Above Input:

Temperature Correction Factor =	84%
PV Modules Efficiency (include Packing Factor) =	11%

WORKSHEET C: PV SYSTEM SIZING
(OUTPUT SHEET)

OUTPUT:

Area of PV array needed:

Scenario 1 =	7,764.63	m^2
Scenario 2 =	3,778.90	m^2
Scenario 3 =	2,772.61	m^2

Peak Power Rating of the Array:

Scenario 1 =	742,897.47	Watt
Scenario 2 =	361,553.86	Watt
Scenario 3 =	265,275.41	Watt

Number of Modules Needed:

Scenario 1:

Theoritical Number of Modules =	8,951	Modules
Number of Modules Wired in Series =	21	Modules
Number of Strings Wired in Parallel =	426	Modules
Practical Number of Modules =	8,946	Modules
Array Peak Power =	742.52	kW
Array Area =	6,547.18	m^2

Scenario 2:

Theoritical Number of Modules =	4,356	Modules
Number of Modules Wired in Series =	21	Modules
Number of Strings Wired in Parallel =	207	Modules
Practical Number of Modules =	4,347	Modules
Array Peak Power =	360.80	kW
Array Area =	3,181.37	m^2

Scenario 3:

Theoritical Number of Modules =	3,196	Modules
Number of Modules Wired in Series =	21	Modules
Number of Strings Wired in Parallel =	152	Modules
Practical Number of Modules =	3,192	Modules
Array Peak Power =	264.94	kW
Array Area =	2,336.08	m^2

Month	Monthly Load Requirement (kWh/month)	PV Output			Load Supplied by Utility		
		Scenario 1 (kWh/month)	Scenario 2 (kWh/month)	Scenario 3 (kWh/month)	Scenario 1 (kWh/month)	Scenario 2 (kWh/month)	Scenario 3 (kWh/month)
Jan	24,800	33,085.84	16,076.92	11,805.28	(8,285.84)	8,723.08	12,994.72
Feb	22,400	40,165.53	19,517.05	14,331.36	(17,765.53)	2,882.95	8,068.64
Mar	24,800	51,679.43	25,111.84	18,439.61	(26,879.43)	(311.84)	6,360.39
Apr	24,000	50,878.47	24,722.64	18,153.82	(26,878.47)	(722.64)	5,846.18
May	24,800	57,875.01	28,122.36	20,650.24	(33,075.01)	(3,322.36)	4,149.76
Jun	24,000	60,833.89	29,560.13	21,705.99	(36,833.89)	(5,560.13)	2,294.01
Jul	24,800	57,390.86	27,887.11	20,477.49	(32,590.86)	(3,087.11)	4,322.51
Aug	24,800	56,132.39	27,275.60	20,028.46	(31,332.39)	(2,475.60)	4,771.54
Sep	24,000	52,953.40	25,730.88	18,894.17	(28,953.40)	(1,730.88)	5,105.83
Oct	24,800	48,864.78	23,744.16	17,435.32	(24,064.78)	1,055.84	7,364.68
Nov	24,000	29,172.20	14,175.22	10,408.86	(5,172.20)	9,824.78	13,591.14
Dec	24,800	24,291.59	11,803.66	8,667.42	508.41	12,996.34	16,132.58
		563,323.39	273,727.56	200,998.02	(271,323.39)	18,272.44	91,001.98
		Annual PV Output			Annual Electricity Consumption Supplied by Utility		

Note:

Numbers in brackets indicate excessive outputs which are fed into utility determination of the PV system size. There were three scenarios used in this project in the development of system size. The first one was, system was sized based on annual minimum daily insolation (in December, 3.22 kWh/m^2-day, see Table 1), the second one was based on annual average daily insolation (4.99 kWh/m^2-day), and the last scenario was based on annual maximum or peak daily insolation (in July, 6.19 kWh/m^2-day, see Table 1). Information on module's characteristics, such as efficiency, nominal operating cell temperature, temperature effect on power, and so on were obtained from manufacturer data sheet. The other factors, such as module packing factor, soiling factor were assumed based on common numbers used in the references[4]. The outcomes of Worksheet C are shown in Table 5 below.

Table 5: Outcomes of Worksheet C: PV Systems Size

	Scenario 1	Scenario 2	Scenario 3
Number of Modules	8,946	4,347	3,192
Array Peak Power (kW)	742.52	360.80	264.94
Array Area (m^2)	6,547.18	3,181.37	2,336.08

The second step in the evaluation of the proposed system was the calculation of the Annual Equivalent Cost of the system. Worksheet D[5] (shown in the next page) was designed to do this calculation.

[5] The procedure to use this spread sheet is attached in Appendix B.

WORKSHEET D: ANNUAL EQUIVALENT COST OF THE PROPOSED SYSTEM

(INPUT SHEET)

GENERAL INFORMATION:

PV Module Price =	$	467	per Module
Operation & Maintenance Cost =	$	0.01	per kWh
Mounting Support Price =	$	229	per 4 Modules
Corporate Income Tax =		34%	

INPUT:

Initial Costs ($):

PV Modules =	$	1,490,664.00
Inverter =	$	100,000.00
Mounting Support =	$	182,742.00
Miscellaneous Costs# =	$	88,670.30
Total Initial Costs =	$	1,862,076

Annual Costs ($/year):

Operation & Maintenance =	$	2,009.98	per Year
Annual Equivalent Cost of Electricity =	**see Input Sheet - Continue (i.e. PEC)**		

Note:

#: Miscellaneous Costs consists of Cable & Wire Cost, Meter Cost, Installation Cost and any other costs and are assumed to be 5.0% of the sum of the other inital costs.

WORKSHEET D: ANNUAL ELECTRICITY COST OF THE PROPOSED SYSTEM

(INPUT SHEET - CONTINUE)

N	EOY	(PEPI)	PEPI	PEC ($/year)
0	1993	1.00	1.00	
1	1994	1.01	1.06	$ 7,160.92
2	1995	1.01	1.12	$ 7,540.45
3	1996	1.01	1.18	$ 7,940.09
4	1997	1.02	1.25	$ 8,443.70
5	1998	1.02	1.32	$ 8,891.22
6	1999	1.04	1.42	$ 9,546.03
7	2000	1.05	1.51	$ 10,148.62
8	2001	1.05	1.59	$ 10,686.50
9	2002	1.06	1.69	$ 11,360.05
10	2003	1.08	1.81	$ 12,187.84
11	2004	1.08	1.91	$ 12,833.79
12	2005	1.09	2.03	$ 13,639.11
13	2006	1.09	2.13	$ 14,361.99
14	2007	1.09	2.25	$ 15,123.17
15	2008	1.09	2.37	$ 15,924.70
16	2009	1.09	2.49	$ 16,768.71
17	2010	1.10	2.65	$ 17,819.44
18	2011	1.10	2.79	$ 18,763.87
19	2012	1.10	2.93	$ 19,758.36
20	2013	1.11	3.12	$ 20,994.69
21	2014	1.11	3.28	$ 22,107.41
22	2015	1.12	3.49	$ 23,488.83
23	2016	1.12	3.67	$ 24,733.74
24	2017	1.12	3.87	$ 26,044.62
25	2018	1.13	4.11	$ 27,669.85
26	2019	1.13	4.33	$ 29,136.36
27	2020	1.14	4.60	$ 30,952.09
28	2021	1.14	4.84	$ 32,592.55
29	2022	1.14	5.10	$ 34,319.96
30	2023	1.15	5.41	$ 36,455.93

INPUT:

Annual Electricity Cost ($/year):

	P&L Rate	GS Rate
Scenario 1 =	(6,097.41)	(24,058.80)
Scenario 2 =	6,730.26	442.57
Scenario 3 =	17,707.11	6,733.16

Note:

(PEPI) = Projected Electricity Price Indices (for Industrial sector, **excluding** general inflation)

PEPI = Projected Electricity Price Indices (for Industrial sector, **including** general inflation)

PEC = Projected Electricity Costs

WORKSHEET D: ANNUAL EQUIVALENT COST
OF THE PROPOSED SYSTEM
(OUTPUT SHEET)

N	EOY	Before-Tax Cash Flow	MACRS %	Depreciation	Taxable Income	Taxes	After-Tax Cash Flow
0	1993	$ (1,862,076)					$ (1,862,076)
1	1994	$ (9,170.90)	5.00%	$ 93,103.82	$ (102,274.72)	$ (34,773.40)	$ 25,602.50
2	1995	$ (9,550.43)	9.50%	$ 176,897.25	$ (186,447.68)	$ (63,392.21)	$ 53,841.78
3	1996	$ (9,950.07)	8.55%	$ 159,207.52	$ (169,157.60)	$ (57,513.58)	$ 47,563.51
4	1997	$ (10,453.68)	7.70%	$ 143,379.88	$ (153,833.56)	$ (52,303.41)	$ 41,849.73
5	1998	$ (10,901.20)	6.93%	$ 129,041.89	$ (139,943.08)	$ (47,580.65)	$ 36,679.45
6	1999	$ (11,556.01)	6.23%	$ 116,007.35	$ (127,563.36)	$ (43,371.54)	$ 31,815.53
7	2000	$ (12,158.60)	5.90%	$ 109,862.50	$ (122,021.10)	$ (41,487.18)	$ 29,328.57
8	2001	$ (12,696.48)	5.90%	$ 109,862.50	$ (122,558.98)	$ (41,670.05)	$ 28,973.57
9	2002	$ (13,370.03)	5.91%	$ 110,048.71	$ (123,418.74)	$ (41,962.37)	$ 28,592.34
10	2003	$ (14,197.82)	5.90%	$ 109,862.50	$ (124,060.32)	$ (42,180.51)	$ 27,982.69
11	2004	$ (14,843.77)	5.91%	$ 110,048.71	$ (124,892.48)	$ (42,463.44)	$ 27,619.67
12	2005	$ (15,649.09)	5.90%	$ 109,862.50	$ (125,511.59)	$ (42,673.94)	$ 27,024.85
13	2006	$ (16,371.97)	5.91%	$ 110,048.71	$ (126,420.67)	$ (42,983.03)	$ 26,611.06
14	2007	$ (17,133.15)	5.90%	$ 109,862.50	$ (126,995.65)	$ (43,178.52)	$ 26,045.37
15	2008	$ (17,934.68)	5.91%	$ 110,048.71	$ (127,983.39)	$ (43,514.35)	$ 25,579.67
16	2009	$ (18,778.69)	2.95%	$ 54,931.25	$ (73,709.94)	$ (25,061.38)	$ 6,282.69
17	2010	$ (19,829.42)	0.00%	$ -	$ (19,829.42)	$ (6,742.00)	$ (13,087.42)
18	2011	$ (20,773.85)	0.00%	$ -	$ (20,773.85)	$ (7,063.11)	$ (13,710.74)
19	2012	$ (21,768.34)	0.00%	$ -	$ (21,768.34)	$ (7,401.24)	$ (14,367.10)
20	2013	$ (23,004.67)	0.00%	$ -	$ (23,004.67)	$ (7,821.59)	$ (15,183.09)
21	2014	$ (24,117.39)	0.00%	$ -	$ (24,117.39)	$ (8,199.91)	$ (15,917.48)
22	2015	$ (25,498.81)	0.00%	$ -	$ (25,498.81)	$ (8,669.59)	$ (16,829.21)
23	2016	$ (26,743.72)	0.00%	$ -	$ (26,743.72)	$ (9,092.86)	$ (17,650.85)
24	2017	$ (28,054.60)	0.00%	$ -	$ (28,054.60)	$ (9,538.57)	$ (18,516.04)
25	2018	$ (29,679.83)	0.00%	$ -	$ (29,679.83)	$ (10,091.14)	$ (19,588.69)
26	2019	$ (31,146.34)	0.00%	$ -	$ (31,146.34)	$ (10,589.75)	$ (20,556.58)
27	2020	$ (32,962.07)	0.00%	$ -	$ (32,962.07)	$ (11,207.10)	$ (21,754.97)
28	2021	$ (34,602.53)	0.00%	$ -	$ (34,602.53)	$ (11,764.86)	$ (22,837.67)
29	2022	$ (36,329.94)	0.00%	$ -	$ (36,329.94)	$ (12,352.18)	$ (23,977.76)
30	2023	$ (38,465.91)	0.00%	$ -	$ (38,465.91)	$ (13,078.41)	$ (25,387.50)

NOTE: In the above table, cost is presented as negative/bracketed number

OUTPUT:

Net Present Value of the Proposed System Over 30 Years = $1,625,201.49

Annual Equivalent Cost of the Proposed System = $ 172,954.09 per Year

Electricity (Energy) Cost of the Proposed System = $ 0.59 per kWh

The following formula was utilized to compute the AEC of the proposed system.

$$AEC = \{(\text{Initial Cost})+\{[[\sum_{EOY=1}^{n}(\text{Present Annual Electricity Cost})(PEPI)_{EOY} + (O\&M)_{EOY}](1-r) + r(DEPR)_{EOY}](P/F,i,EOY)\}\}(A/P,i,n) \qquad \text{Eq. 5-3}$$

Where,

AEC = Annual Equivalent Cost of the Proposed System ($/year)

PEPI = Projected Electricity Price Indices (including Inflation Rate of 5.3%), obtained from Table 2

$(A/P,i,n) = [i(1+i)^n]/[(1+i)^n -1]$

$(P/F,i,n) = 1/[(1+i)^n]$

i = Combined Interest Rate

$= ((1+j)(1+d))-1$

j = Inflation Rate

d = Real Interest Rate

n = Life of the study (in this case 30 years)

EOY = 1,2,3,...,n

r = Corporate Income Tax Rate

The costs involved in this AEC calculation can be divided into two categories:

<u>The Initial Cost</u>

There are four major components of the initial cost,

- PV Modules cost
- Mounting Support cost
- Inverter cost
- Miscellaneous costs (i.e. cable cost, installation cost, and so on)

The amount of the initial cost, especially PV module and mounting support costs, depends highly on the size of the PV system developed in Worksheet C.

The Annual Cost

The components of this cost are,

- **Operation and Maintenance Cost**

  This cost was determined based on the average O&M costs (measured in $/kWh) of several reference projects[2], and was assumed to be constant over 30 years.

- **Electricity Cost**

  This cost depends on the output of PV system calculated in worksheet C and was calculated using worksheet A.

  This cost is positive when there is excess of PV output which will be sold to the utility company. It was assumed that the "buy-back ratio" was one[6]. This means that the utility will buy the excess output from the PV system with the same price as its selling price. Worksheet B

[6] This is a naive assumption, since the utility usually pays less than its selling price. But it was found that in one country the utility pays surplus output of PV systems the same price as its selling rate. Thus, an assumption of buy-back ratio of one was used in this study. However, the utility only pays for electricity consumption, not demand.

was utilized to calculate the AEC of this electricity cost.

The other important information needed to calculate AEC of the proposed system is salvage value, depreciation method, and income tax. Salvage value was assumed to be zero, due to technology obsolescence or assumed to be equal to the book value year 30 under MACRS. Depreciation method used was MACRS with 15-Year Property Class[17]. Corporate Income Tax was assumed to be 34%, based on the weighted average Federal Income Tax rates for corporations[17]. This rate was assumed to be stable over project's life span.

The last step in the evaluation of the proposed system was calculation of its electricity (energy) cost. This calculation was also done in Worksheet D. Formula 5-2 was utilized to calculate energy cost of the proposed system. The outcomes of Worksheet D are summarized in Table 6 below.

Table 6: Outcomes of Worksheet D: Annual Equivalent and Electricity (Energy) Costs of the Proposed Systems

Scenario	Annual Equivalent Cost ($/year)		Electricity (Energy) Cost ($/kWh)	
	P&L Rate	GS Rate	P&L Rate	GS Rate
1	437,535.52	415,534.23	1.50	1.42
2	229,214.71	221,512.77	0.78	0.76
3	189,396.31	172,954.09	0.64	0.59

5.4 Initial Analysis

Given initial combined interest rate of 10% and projected electricity prices indices from reference[11], the annual equivalent cost and electricity (energy) cost of the present and proposed systems are shown in Table 7. The present system has two scenarios, that is, being charged for the electricity consumption only (General Service Rate/GS) and for both electricity consumption and demand (Power and Light Rate/P&L). The proposed system, on the other side, has six scenarios.

Table 7: Annual Equivalent Cost and Energy Cost of the Present and Proposed Systems

	Present System		Proposed System					
	P&L Rate	GS Rate	P&L Rate			GS Rate		
			Scenario 1	Scenario 2	Scenario 3	Scenario 1	Scenario 2	Scenario 3
AEC ($/year)	$ 44,818.15	$ 43,348.20	437,535.52	229,214.71	189,396.31	415,534.23	221,512.77	172,954.09
Electricity (Energy) Cost ($/kWh)	0.15	0.15	1.50	0.78	0.64	1.42	0.76	0.59

NOTE:

= The Lowest Annual Equivalent Cost of the Proposed System

= The Lowest Electricity (Energy) Cost of the Proposed System

It can be seen clearly, that with existing conditions, PV systems can not compete economically with conventional systems. It should be pointed again that the comparison was made using Combined Interest Rate of 10% and Projected Electricity Price Indiees determined by Federal Government[11]. However, this result can be changed by varying initial conditions (i.e. present electricity price, interest rate, PV module cost, projected electricity price factor, and solar cell efficiency). This matter will be discussed in the next chapter on sensitivity analysis.

The results also showed that the PV system which operates under GS rate and was sized based on Scenario 3 (i.e. based on annual maximum/peak daily insolation), gave the lowest annual equivalent cost and electricity (energy) cost among the PV systems. Based on this implication the remainder of the study will focus on this system. However, this occurs because of the nature of the load which was chosen as the "most friendly" to adoption of PV systems (flat demand daylight hours only). Thus, GS rate with energy charges only, becomes the cheaper.

CHAPTER VI

SENSITIVITY ANALYSIS

Chapter 5 dealt strictly with conditions as they exist at the present. Electricity cost was based on current price and was escalated throughout the life of PV system using indices developed by the Energy Information Administration of the US Department of Energy[11]. The real interest rate used was the current rate used for evaluating federal project, and the inflation rate was determined based on Annual Data of Percent Change of 1994 US City Average Consumer Price Index. The module cost and the other initial costs reflected the price of today's market.

This chapter will address itself to the investigation of the sensitivity of the results. For example, what would happen if certain cost components behaved in a different manner or if electricity cost increased at a higher rate? Various components will be altered and varied with the purpose of viewing how and if the changes result in significant deviation in the initial conclusions.

6.1 Module Cost

The initial analysis of the PV system was performed with module cost of $467 per module. Recently, a new method to manufacture PV module was found[16]. This new method, in the future, can lower 80% of today's PV module production cost. In any event, because PV modules comprise a larger percentage of the overall system cost than any other component, an examination of how PV module cost variances affect the economic feasibility of the PV system should be undertaken.

Two charts plotting annual equivalent cost as a function of the PV module cost were created and are presented as Figure 15 and Figure 16. The first chart is indicative of present conditions, i.e. 5.3% inflation, 4.5% real interest, current projected electricity price indices, and present electricity cost of $0.08/kWh. The second chart indicates the same conditions as the first one's, accepts it used present electricity cost of $0.16/kWh.

The curve for the present system is simply a horizontal line intersecting the y-axis at the value of its AEC. Three scenarios of the proposed system were plotted. However, Scenario 3 is the benchmark to which the others should be compared because it represents the best scenario among the other scenarios.

Examining the first chart (Figure 15), it can be seen, that all scenarios of the proposed system break-even with the present system at points close to each other. Scenario 3 system will become the most economical system when PV module cost goes down approximately to $27/module, Scenario 2 system beats the present system at $23/module, while Scenario 1 system will be more economical than the present system at PV module cost of $18/module. The other important point can be concluded is that these all three points, where the proposed systems turn out to be more economical systems than the present system, are quite impossible to achieve with present manufacturing technology of solar cell.

However, when the present electricity cost goes to $0.16/kWh (i.e. twice of current present electricity cost), the Scenario 3 system will become the most economical system at PV module cost of $147/module. At approximately $128/module the Scenario 2 will be more economical than the present system, and Scenario 1 system will beat the present system approximately at $105/module. Figure 15 and 16 also illustrate how PV systems' optimality is quite sensitive to the value of PV module and present electricity cost.

Another noteworthy point from Figure 16 is that when PV module cost goes down to $87/module, Scenario 1 system will take the lead to be the most economical system compared with the other two proposed systems. This could happen because high surplus output

Figure 15: PV Module Cost Sensitivity Analysis Chart
(w/ Present Electricity Cost of $0.08/kWh)

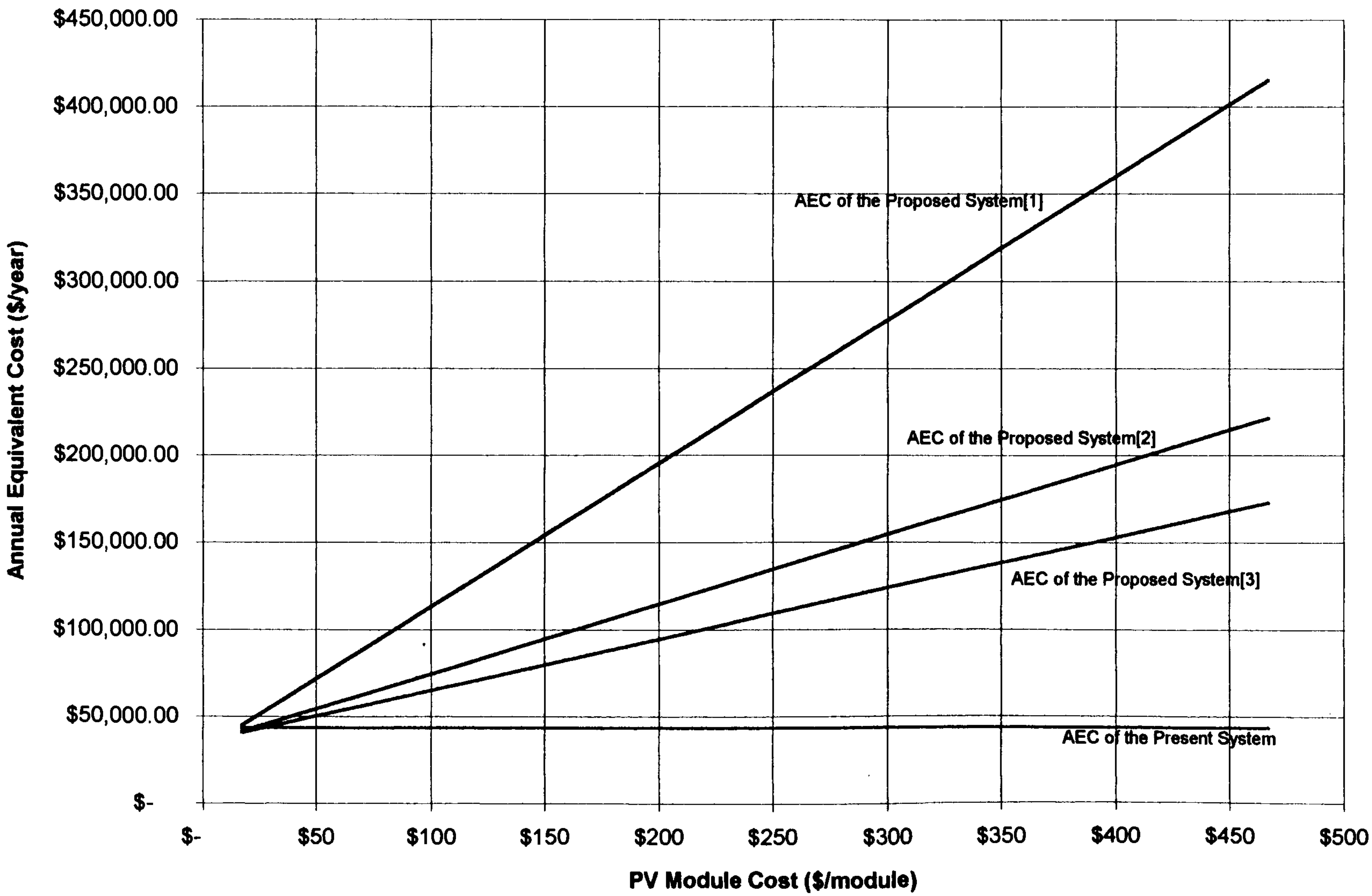
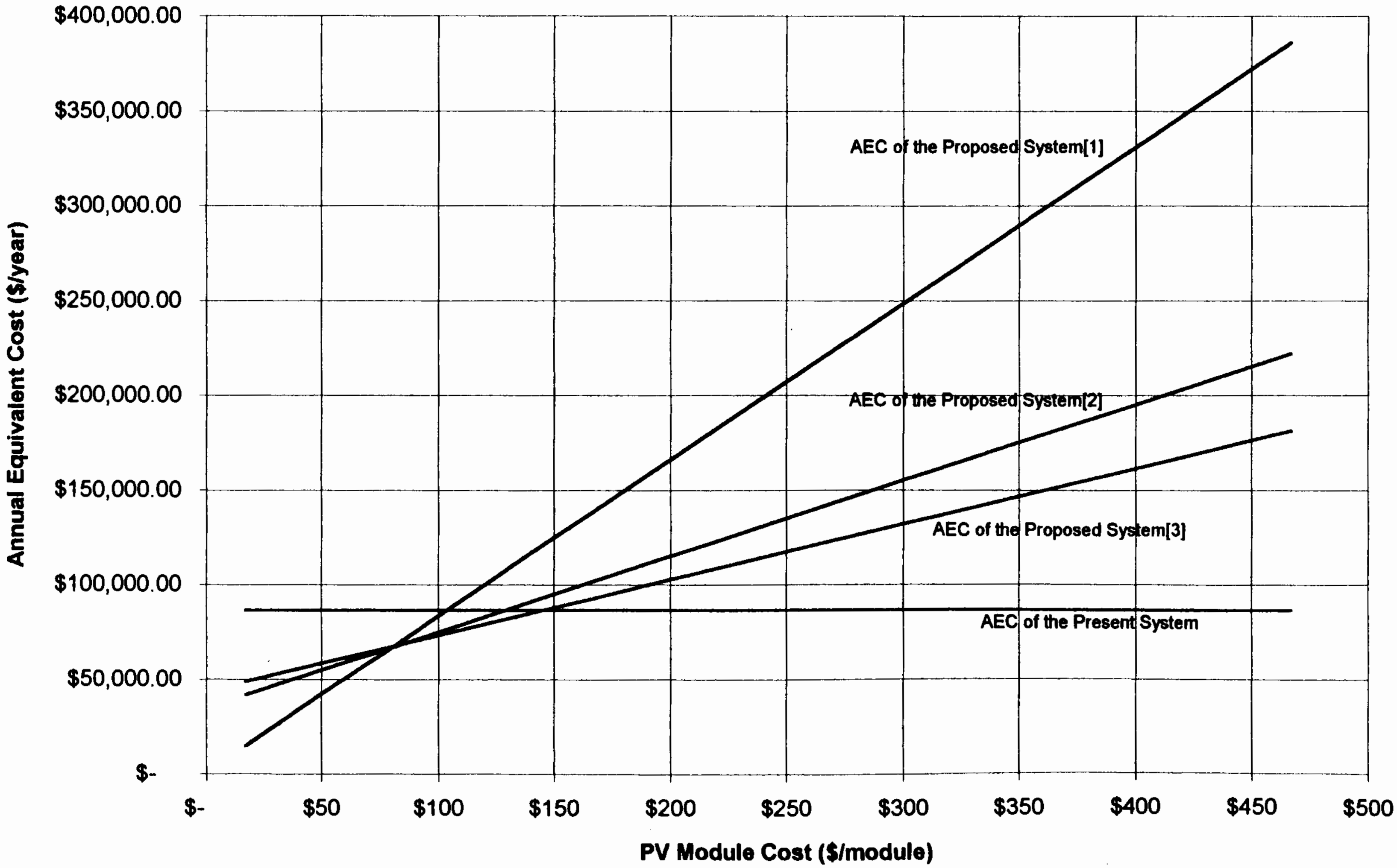


Figure 16: PV Module Cost Sensistivity Analysis
(assumed Present Electricity Cost of $0.16/kWh)



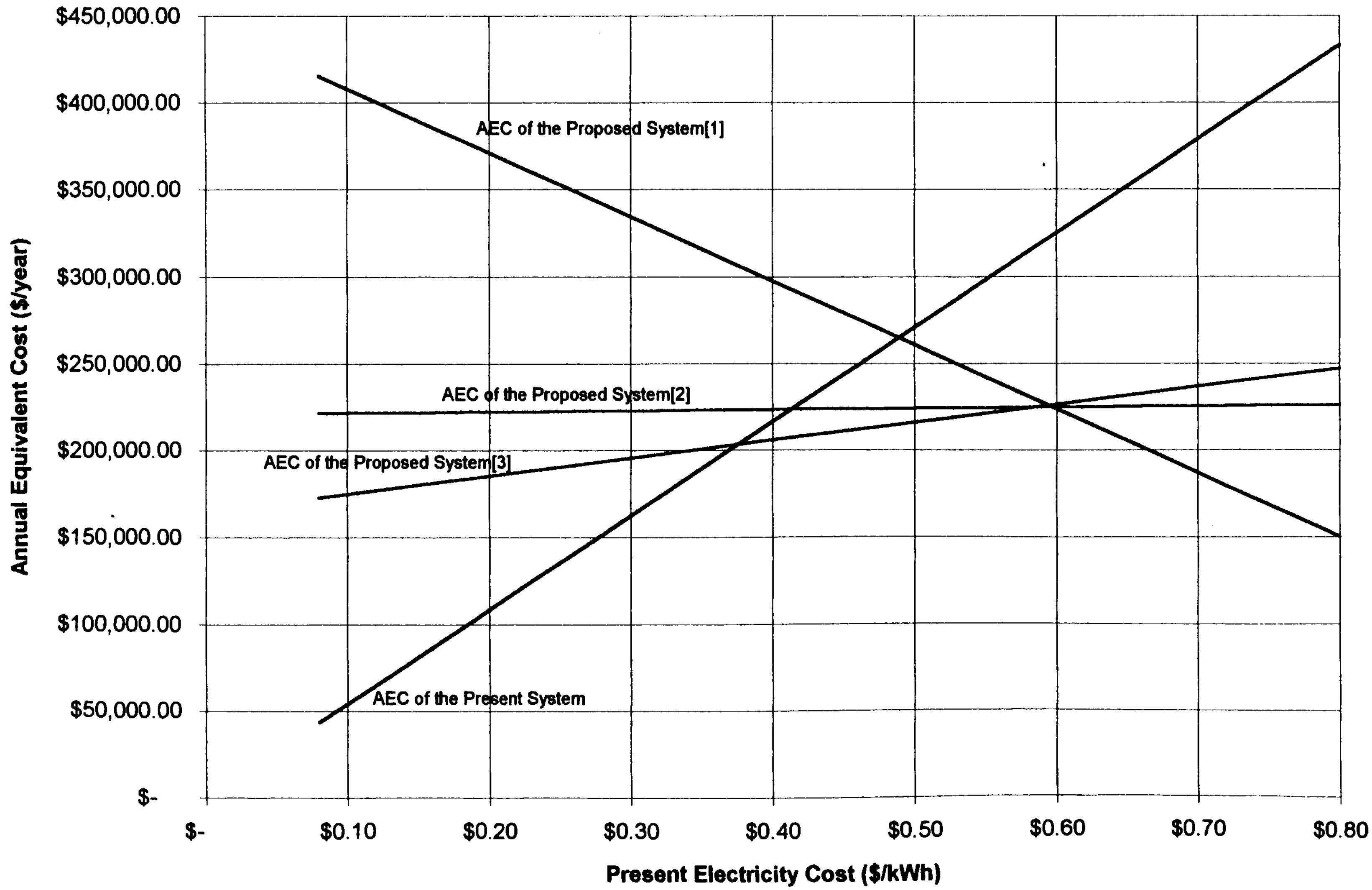
of Scenario 1 gives "positive" impact on its AEC (i.e. reduce the AEC). Thus, when PV module cost goes down low enough (approximately at $87/module), additional income from surplus output will affect its AEC more heavily than the cost of PV module.

6.2 Present Electricity Cost

A sensitivity analysis chart for the present electricity cost was constructed at a module cost of $467/module and at the current rate of real interest, inflation, and projected electricity price indices. The present electricity price was varied from $0.08/kWh (i.e. current price) to $0.80/kWh in $0.08/kWh increments.

Examining the chart (Figure 17), it can be seen that the present system remains more economical than any proposed systems until present electricity cost reaches $0.37/kWh, where Scenario 3 system will be the most economical system. AEC of the Scenario 1 system will be lower than AEC of the present system at $0.49/kWh. AEC of the Scenario 2 curve is quite flat over the span of investigation, meaning that its AEC doesn't vary much with changing on the present electricity price. Scenario 2 system will be more economical than the present system approximately at present electricity cost of $0.42/kWh.

Figure 17: Present Electricity Cost Sensitivity Analysis Chart



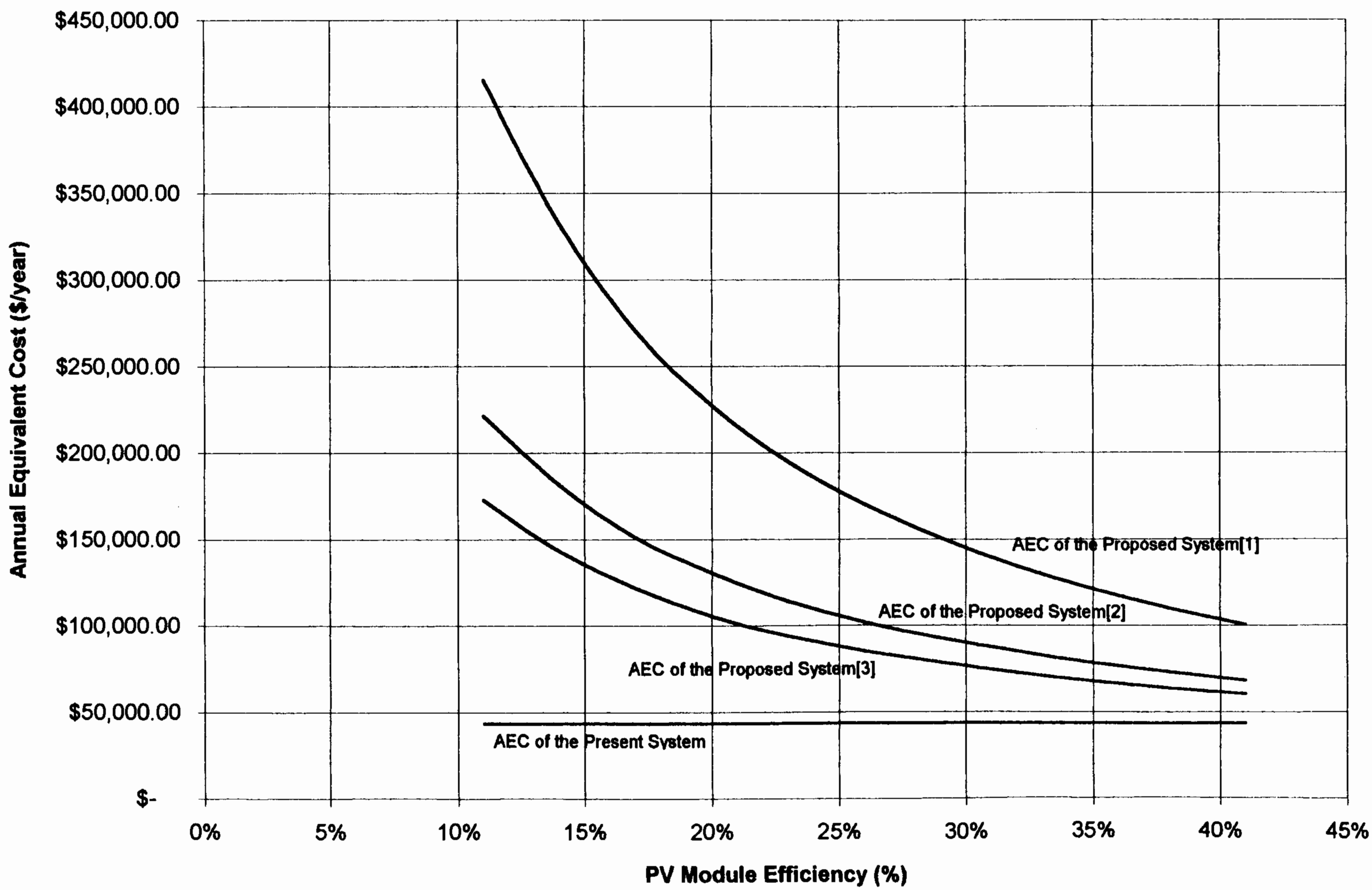
Another noteworthy point is that the AEC of Scenario 3, 2, and present systems increase (in different rates) as the present electricity cost increases, while the Scenario 1 system's AEC decreases as the present electricity cost increases, meaning that Scenario 1's surplus output affects more the AEC of that system than the other two proposed systems.

6.3 PV Module Efficiency

The next item investigated was the PV module efficiency. The efficiency of PV module was varied from 11% to 41% with 3% increments. This 41% efficiency represents the highest possible efficiency of "laboratory tandem solar cell". A chart plotting the Annual Equivalent Cost of present and proposed systems was created and is presented as Figure 18.

Examining the chart, it can be seen that the AEC of the present system is simply horizontal line intersecting y-axis at its AEC. It can be seen also, neither scenarios of the proposed system can "beat" economically the present system with any possible efficiency of PV module as long as the other parameters remain at existing levels. Another important point is that AECs of the proposed systems decrease at slower rate after PV module efficiency reaches approximately 30%.

Figure 18: PV Module Efficiency Sensitivity Analysis Chart



6.4 Projected Electricity Price Indices

In the initial analysis, Projected Electricity Price Indices determined by Energy Information Administration of the US DOE were used (see Table 2). A sensitivity analysis was done by varying projected electricity price indices (PEPI). This was done by escalating the existing PEPI (shown in Figure 19) from 100% to 900% with 100% increments.

Examining the chart (see Figure 20), it can be seen that the present system remains as the most economical system until PEPI was escalated to 370%, where Scenario 3 system turns out to be the most economical system. Scenario 2 system will be more economical than the present system approximately at escalation of 415%, and Scenario 1 will beat the present system approximately at 510% escalation.

Another important point is the curves in this chart behave similarly as the curves in present electricity cost sensitivity analysis chart (see Figure 17).

6.5 Inflation Rate

The next item examined was inflation rate. A sensitivity analysis chart for interest rate was constructed and is presented as Figure 21. The inflation rate was varied from 0.1% to 6% with 0.5% increments, and the resulting AECs were plotted. The chart

Figure 19: Current Projected Electricity Price Indices

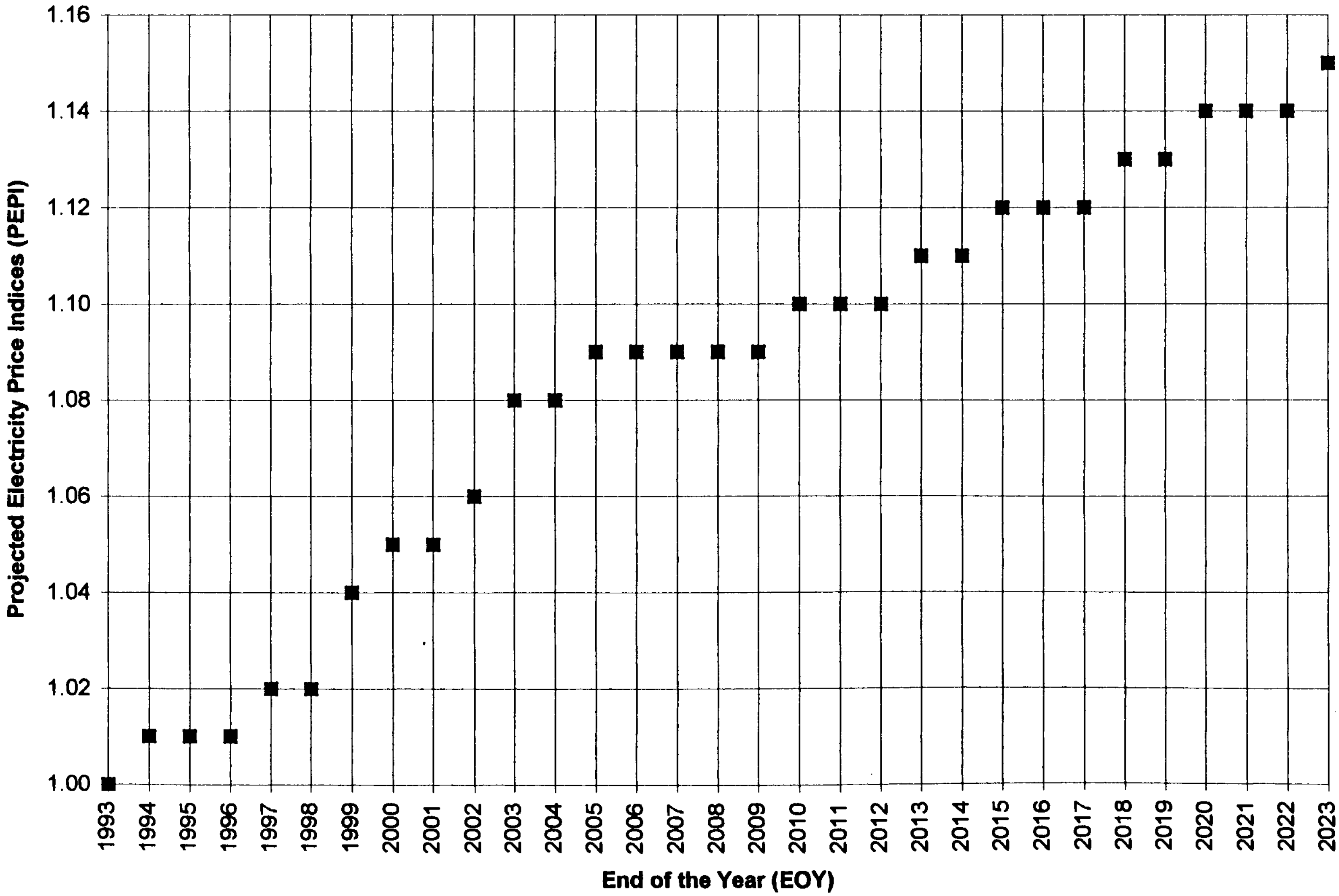


Figure 20: Projected Electricity Price Indices Sensitivity Analysis Chart

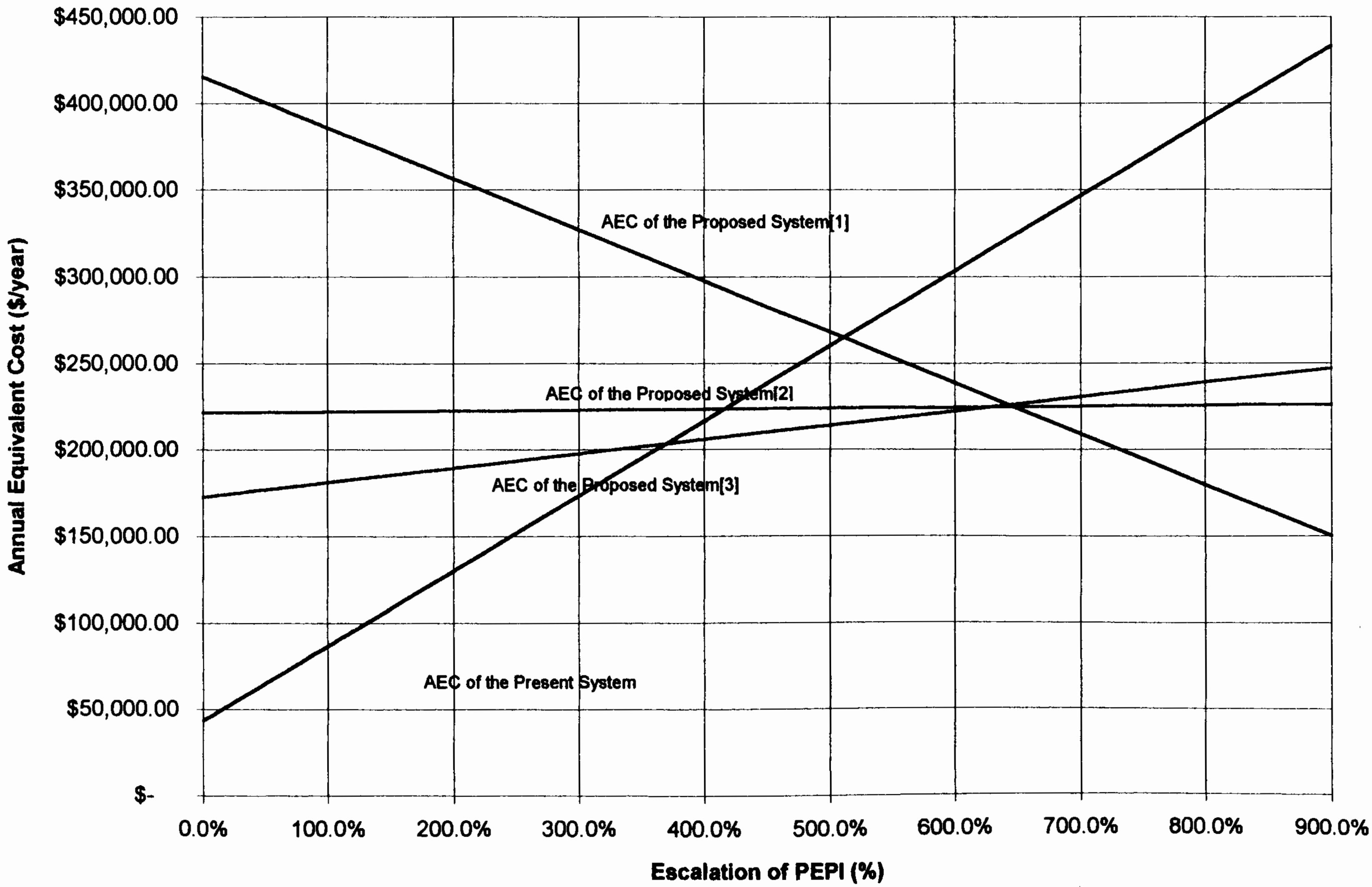
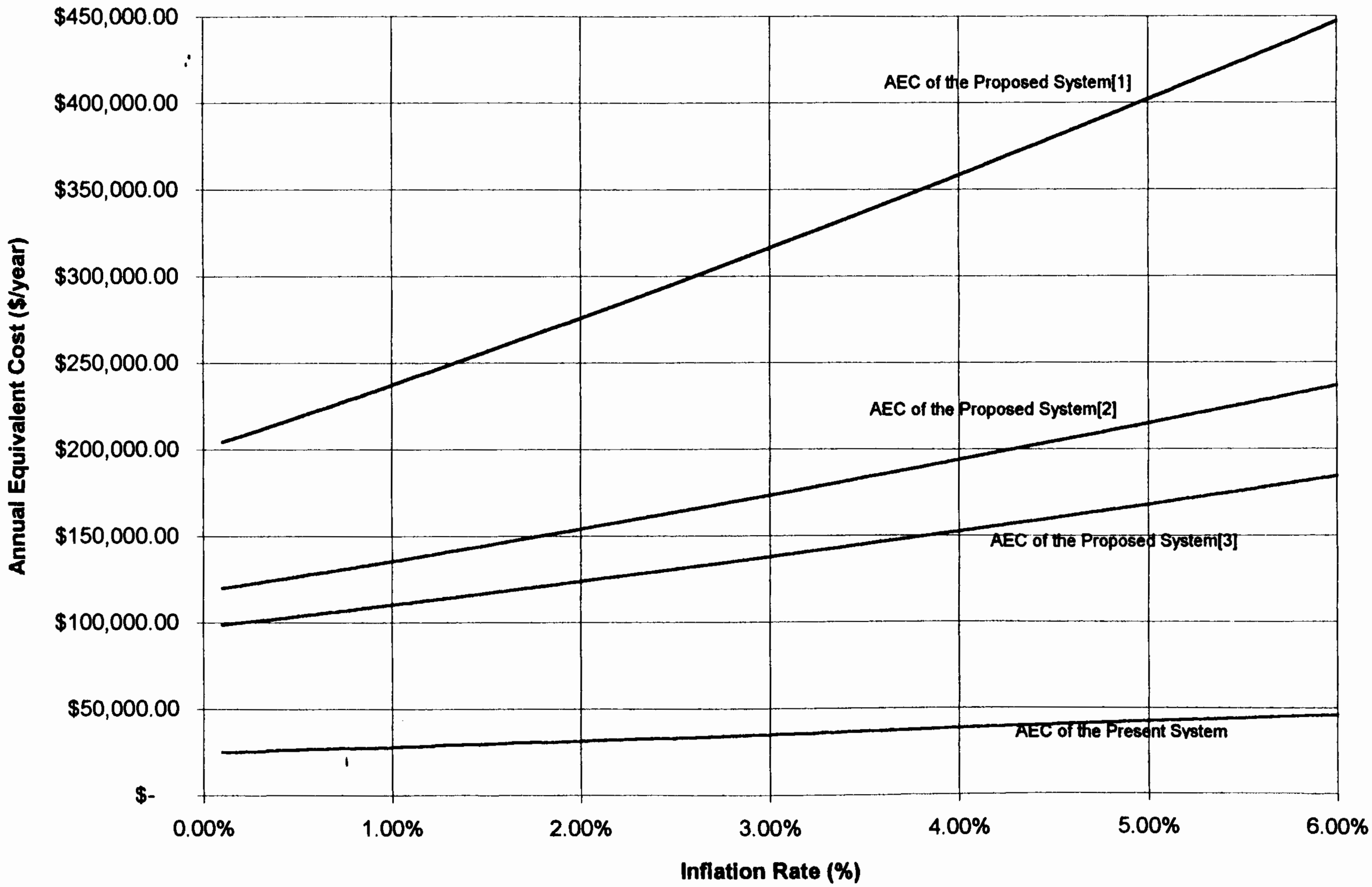


Figure 21: Inflation Rate Sensitivity Analysis Chart



reveals that the AEC of the various systems is relatively insensitive to the inflation rate which can be seen from the fact that neither scenarios of the proposed system can beat the present system over the span of investigation.

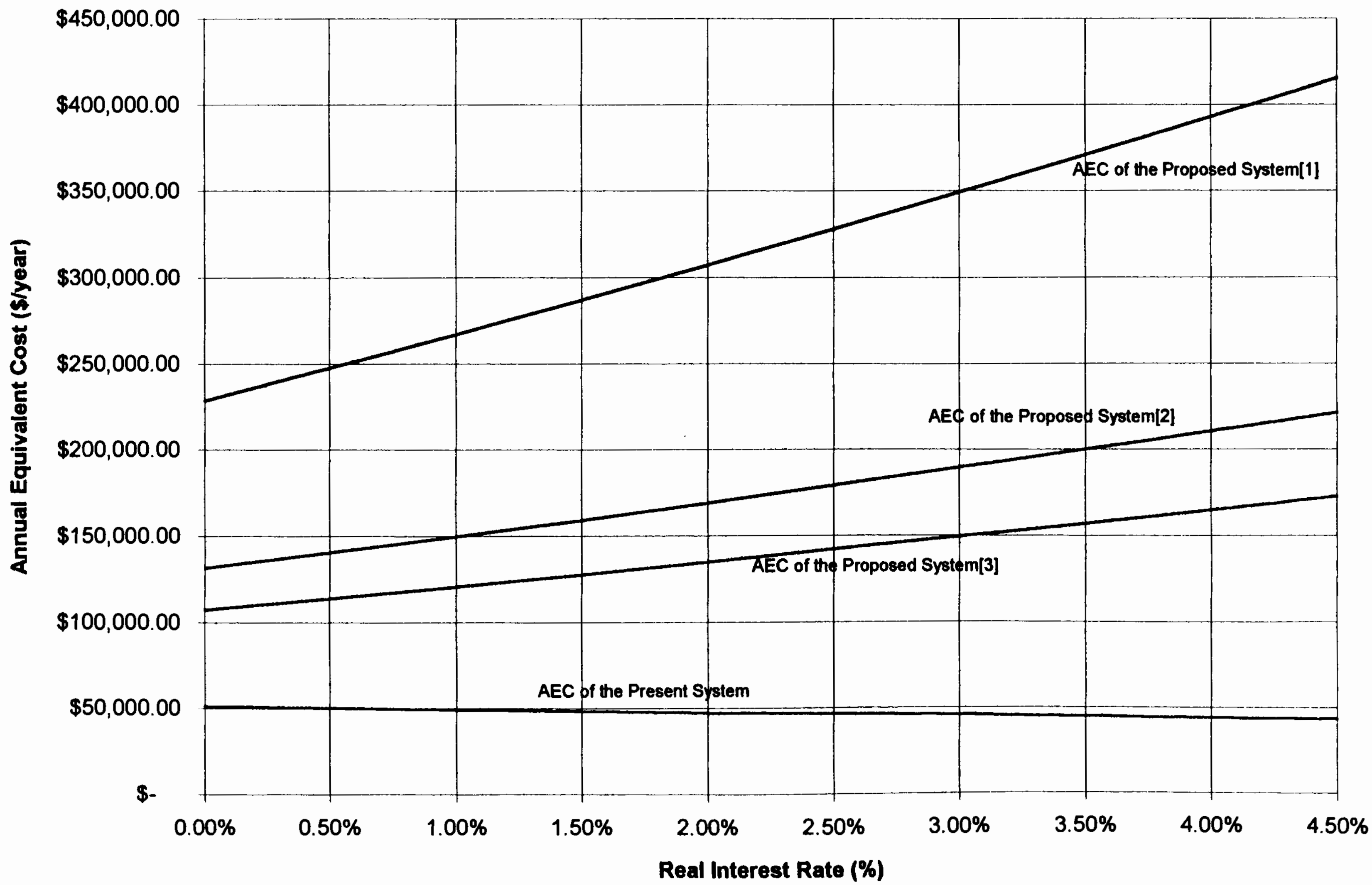
Another noteworthy point is that the proposed system cost curves increase at much higher rate than the present system cost as inflation rate increases. This points out the impact the initial cost has on the AEC of the proposed system.

6.6 Real Interest Rate

A sensitivity analysis chart for the real interest rate was constructed at a inflation rate of 5.3% - the present estimate. The real interest rate was varied from 0.0% to 4.5% in 0.5% increments, and the resulting AECs were plotted. The chart (Figure 22) reveals that the AEC of the various systems is relatively insensitive to the real interest rate. The curves of the proposed systems never break-even with the present system's, meaning that the AEC of the systems vary only slightly over the range of the study.

Another important point is that the conventional system cost curves decreases as the real interest rate increases, while the PV systems costs curves increase with the interest rate. This points out the impact the large initial cost has on the AEC of

Figure 22: Real Interest Rate Sensitivity Analysis Chart



the PV system. The investment cost is weighed heavily while the annual electricity savings are weighed much less so as money increases in value.

6.7 Investment Tax Credit (ITC)

It can be seen from the above analysis, with stated present conditions, photovoltaic systems do not compete well with conventional systems. There are some actions that could be initiated by the government to help spur on the acceptance of photovoltaic system by the public. This section investigated the effect of Investment Tax Credit, one of many governmental incentives, on the economic feasibility of photovoltaic system. The Investment Tax Credit (ITC) is designed to stimulate investment by providing reduced taxation in the year in which an asset is placed in service[17].

Since, currently there are no existing ITC rules for photovoltaic system, the author has generated a scenario of ITC rules which were based on the Tax Reform Act of 1986[17]. The credit allowable was 10% of the eligible investment. The amount of eligible investment was 100%. If the full ITC was taken, half the amount of the ITC be used to reduce the cost basis of the asset, thereby lessening the allowable cost recovery. Thus, if the 10% ITC was claimed, the cost basis of the asset was to be reduced immediately by 5%.

Table 8 in the next page summarizes the cash flow calculations, while Table 9 below displays the proposed system's AEC, before and after ITC.

Table 9: Comparisons of Proposed System'AECs, Before and After ITC

	Scenario 1		Scenario 2		Scenario 3	
	$/kWh	$/year	$/kWh	$/year	$/kWh	($/year)
Proposed System Without ITC	1.42	415,534.23	0.76	221,512.77	0.59	172,954.09
Proposed System With ITC	1.27	371,591.02	0.68	199,688.47	0.54	156,684.76

It can be seen from Table 9 that, although all AECs of the proposed system are still greater than the AEC of the present system (= $43,348.20), the ITC can be a major economic factor for justifying feasibility of photovoltaic system.

To investigate how "sensitive" the AEC of the proposed system is to the changing on the investment tax credit, a sensitivity analysis chart was constructed and is presented as Figure 23. The investment tax credit was varied from 10% to 90% with 10% increments. The other purpose of doing this is to determine how much credit should be given by government to make investment on phovoltaic system attractive.

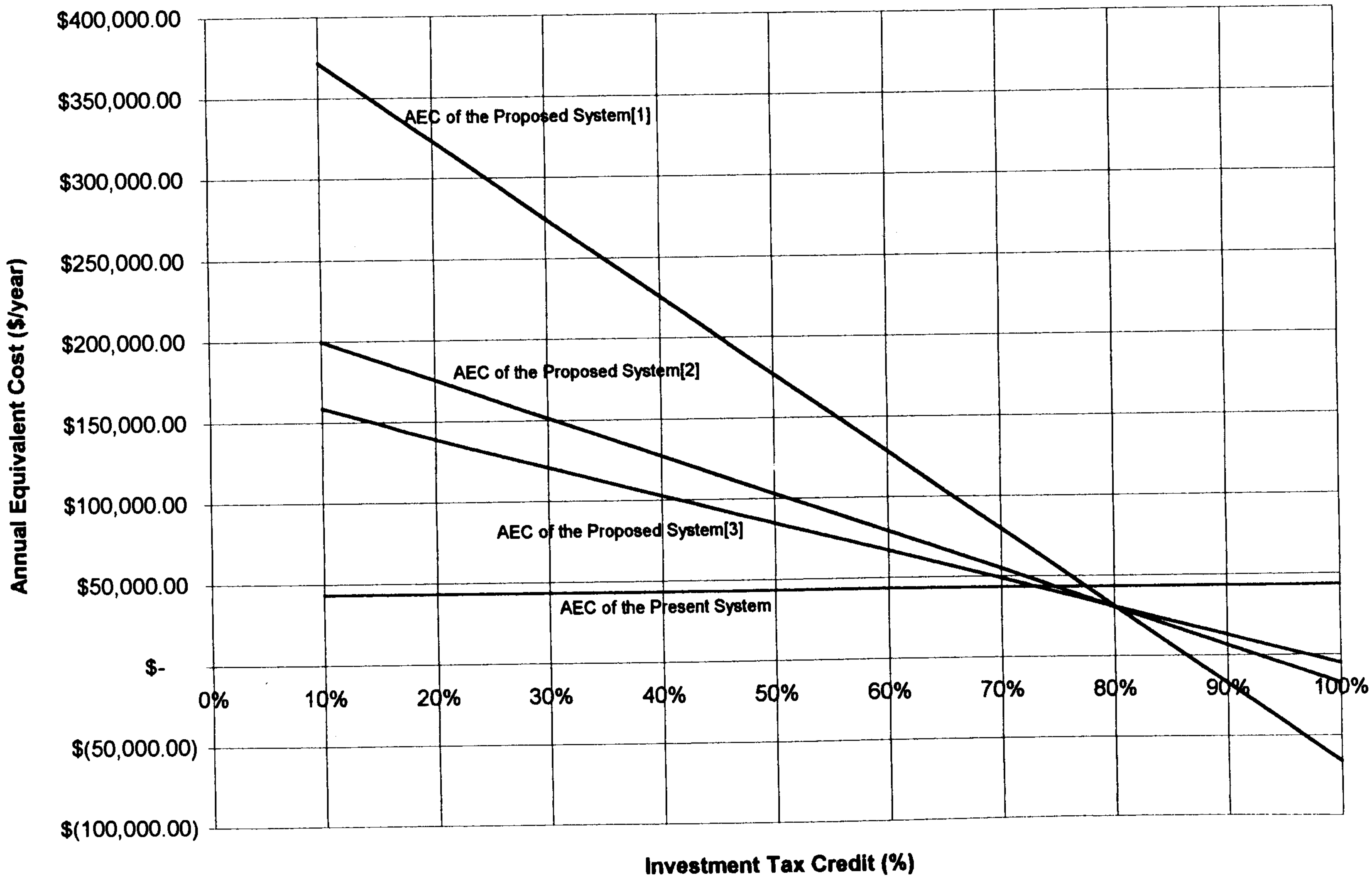
Examining the chart, it can be seen that the AECs of the proposed systems are relatively sensitive to the investment tax credit. It can be seen also that Scenario 3 system becomes the most

Table 8: After-Tax Cash Flows Using Investment Tax Credit

N A	EOY B	Before-Tax Cash Flow C	MACRS % D	Depreciation E	Taxable Income (C-E) F	Taxes (F*0.34) G	Investment Tax Credit H	After-Tax Cash Flow (C-G+H) I
0	1993	$(1,862,076)						$ (1,862,076.30)
1	1994	$ (9,170.90)	5.00%	$ 88,448.62	$ (97,619.53)	$ (33,190.64)	$ 186,207.63	$ 210,227.37
2	1995	$ (9,550.43)	9.50%	$ 168,052.39	$ (177,602.82)	$ (60,384.96)	$ -	$ 50,834.53
3	1996	$ (9,950.07)	8.55%	$ 151,247.15	$ (161,197.22)	$ (54,807.06)	$ -	$ 44,856.98
4	1997	$(10,453.68)	7.70%	$ 136,210.88	$ (146,664.56)	$ (49,865.95)	$ -	$ 39,412.27
5	1998	$(10,901.20)	6.93%	$ 122,589.79	$ (133,490.99)	$ (45,386.94)	$ -	$ 34,485.74
6	1999	$(11,556.01)	6.23%	$ 110,206.99	$ (121,762.99)	$ (41,399.42)	$ -	$ 29,843.41
7	2000	$(12,158.60)	5.90%	$ 104,369.38	$ (116,527.98)	$ (39,619.51)	$ -	$ 27,460.91
8	2001	$(12,696.48)	5.90%	$ 104,369.38	$ (117,065.86)	$ (39,802.39)	$ -	$ 27,105.91
9	2002	$(13,370.03)	5.91%	$ 104,546.27	$ (117,916.31)	$ (40,091.54)	$ -	$ 26,721.51
10	2003	$(14,197.82)	5.90%	$ 104,369.38	$ (118,567.19)	$ (40,312.85)	$ -	$ 26,115.03
11	2004	$(14,843.77)	5.91%	$ 104,546.27	$ (119,390.05)	$ (40,592.62)	$ -	$ 25,748.84
12	2005	$(15,649.09)	5.90%	$ 104,369.38	$ (120,018.47)	$ (40,806.28)	$ -	$ 25,157.19
13	2006	$(16,371.97)	5.91%	$ 104,546.27	$ (120,918.24)	$ (41,112.20)	$ -	$ 24,740.24
14	2007	$(17,133.15)	5.90%	$ 104,369.38	$ (121,502.53)	$ (41,310.86)	$ -	$ 24,177.71
15	2008	$(17,934.68)	5.91%	$ 104,546.27	$ (122,480.95)	$ (41,643.52)	$ -	$ 23,708.85
16	2009	$(18,778.69)	2.95%	$ 52,184.69	$ (70,963.38)	$ (24,127.55)	$ -	$ 5,348.86
17	2010	$(19,829.42)	0.00%	$ -	$ (19,829.42)	$ (6,742.00)	$ -	$ (13,087.42)
18	2011	$(20,773.85)	0.00%	$ -	$ (20,773.85)	$ (7,063.11)	$ -	$ (13,710.74)
19	2012	$(21,768.34)	0.00%	$ -	$ (21,768.34)	$ (7,401.24)	$ -	$ (14,367.10)
20	2013	$(23,004.67)	0.00%	$ -	$ (23,004.67)	$ (7,821.59)	$ -	$ (15,183.09)
21	2014	$(24,117.39)	0.00%	$ -	$ (24,117.39)	$ (8,199.91)	$ -	$ (15,917.48)
22	2015	$(25,498.81)	0.00%	$ -	$ (25,498.81)	$ (8,669.59)	$ -	$ (16,829.21)
23	2016	$(26,743.72)	0.00%	$ -	$ (26,743.72)	$ (9,092.86)	$ -	$ (17,650.85)
24	2017	$(28,054.60)	0.00%	$ -	$ (28,054.60)	$ (9,538.57)	$ -	$ (18,516.04)
25	2018	$(29,679.83)	0.00%	$ -	$ (29,679.83)	$ (10,091.14)	$ -	$ (19,588.69)
26	2019	$(31,146.34)	0.00%	$ -	$ (31,146.34)	$ (10,589.75)	$ -	$ (20,556.58)
27	2020	$(32,962.07)	0.00%	$ -	$ (32,962.07)	$ (11,207.10)	$ -	$ (21,754.97)
28	2021	$(34,602.53)	0.00%	$ -	$ (34,602.53)	$ (11,764.86)	$ -	$ (22,837.67)
29	2022	$(36,329.94)	0.00%	$ -	$ (36,329.94)	$ (12,352.18)	$ -	$ (23,977.76)
30	2023	$(38,465.91)	0.00%	$ -	$ (38,465.91)	$ (13,078.41)	$ -	$ (25,387.50)

NOTE: In the above table, cost is presented as negative/bracketed number

Figure 23: Investment Tax Credit Sensitivity Analysis Chart



economical system when ITC is increased approximately to 73%. The AEC of Scenario 2 system will be lower than that of present system at 75% ITC, while Scenario 3 system beats present system approximately at 78% ITC.

Another noteworthy point is at 80% ITC, Scenario 1 system becomes the most economical system. This happens because AEC of the Scenario 3 system decreases at much higher rate than the other two proposed systems, as ITC increases. This higher rate can be explained with high excess output of Scenario 1 system compared with the other two scenarios.

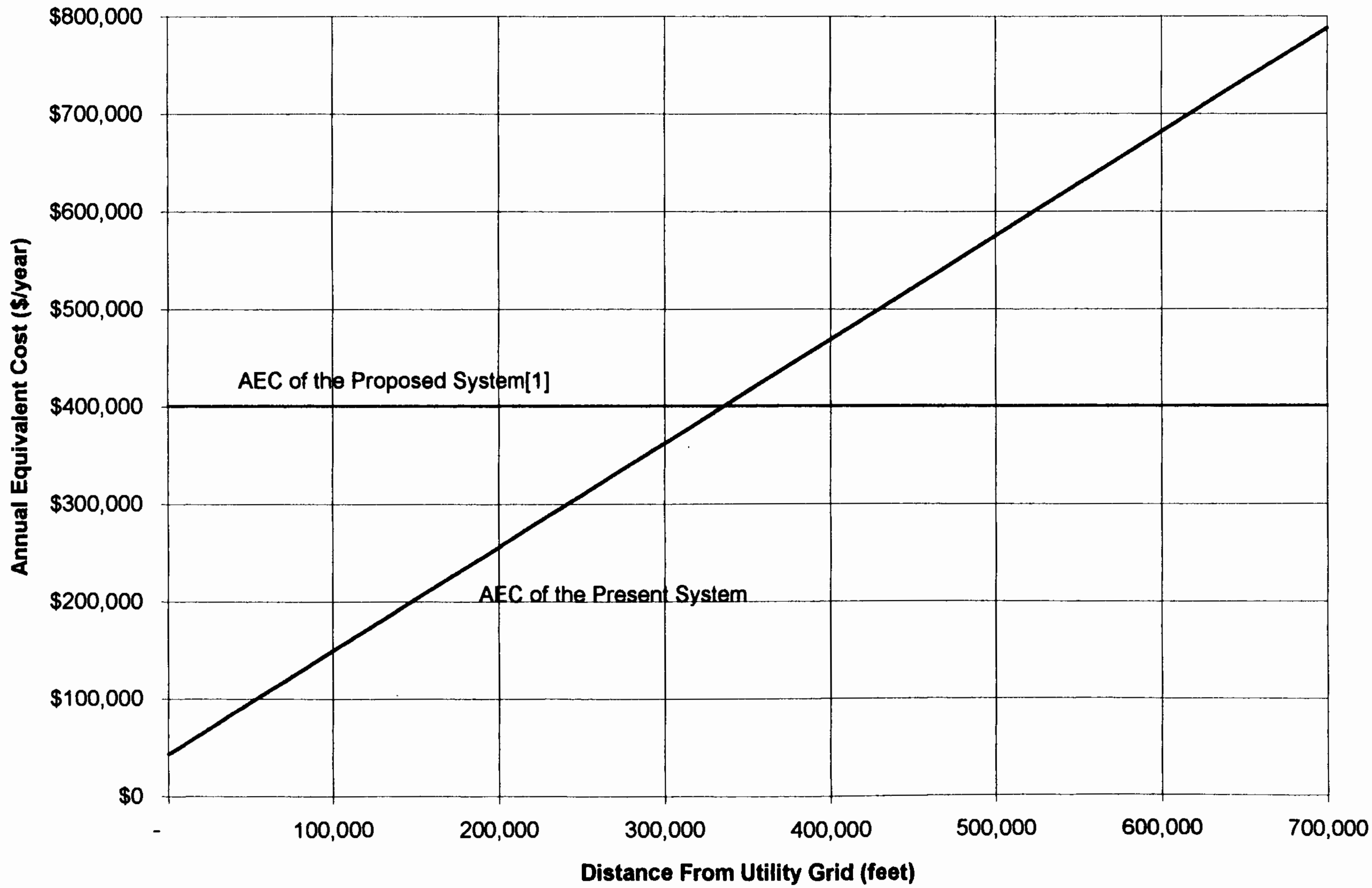
6.8 Remoteness Costs

One of the most attractive points of PV systems is the remoteness issue. To some points, an utilization of PV systems will be more economical than distribution line extensions. The purpose of this section is to find the optimum distance to remote areas where PV systems become cost-effective.

This remoteness analysis will only concentrate on Scenario 1 systems, since this system is the only system which can independently supply the electricity needs of the plant, thus eliminates the needs of utility grid. The AEC of Scenario 1 system was calculated based on following conditions: excess output from the system is negligible and there is 10% ITC. This study assumed that the cost of distribution line extensions is \$10/ft[26]. This extensions cost will be integrated into the cost of electricity of the conventional systems. The results of this analysis are presented in Figure 24 in the next page.

It can be seen from the figure that distribution line extensions of approximately more than 360,000 feet for 100 kW loads will be less economical than applying PV-utility interactive systems. Note, this is almost 70 miles. Yet, the load is quite small. Larger loads would payback quicker and \$10 per linear foor is quite conservative. This analysis was also very conservative since the assumption was made that excess electricity cannot be sold (i.e. there is no utility grid).

Figure 24: Remoteness Distance Sensitivity Analysis Chart



CHAPTER VII

SUMMARY

7.1 General Information

An imaginative case study on an industrial plant was developed to determine the economic feasibility of photovoltaic (PV) systems. Oklahoma City, Oklahoma was chosen as the location and weather data is pertinent to the location. The PV systems chosen in this study was "a photovoltaic-utility interactive system". The load profile and hours of operation were chosen to reflect an ideal scenario. Some other assumptions were made to simplify the evaluation.

In order to examine all consumer aspects of a PV systems investment, as many of the associated costs as possible were included in the cost model. Electricity cost was obtained from local utility and sales taxes were included. Estimates for initial and annual costs were obtained from several PV distributors in the US. Depreciation and investment tax credit effects were included in the AEC calculations. Photovoltaic information, as regards basic knowledge and design, was obtained through lectures and literature.

Annual equivalent cost (AEC) was used as the primary decision criteria, with electricity (energy) cost used as the second criteria. All costs and rates used in this study were relevant with the study basis year conditions. A set of spreadsheets was developed as an aid in computation and evaluation.

To investigate how the AEC of the systems behave to the changing on various parameters, several sensitivity analysis were made, and several sensitivity analysis charts were constructed. PV module and present electricity costs were varied to determine how much PV module cost should go down or how much present electricity cost should go up, to make an investment on photovoltaic systems attractive. Various level of projected electricity price indices, inflation, and real interest rates were investigated to determine their effect on the study. The effect of one of many governmental incentives, Investment Tax Credit (ITC), was also studied.

7.2 Conclusions

The results of the annual equivalent cost and electricity (energy) cost at the present conditions of 5.3% inflation rate, 4.5% real interest rate, and current projected electricity price indices (see Table 2) are shown in Table 10. It can be seen that three scenarios of photovoltaic systems are presently not competitive with the present systems. Even with governmental incentive from 10% Investment Tax Credit, the present system is still the most economical.

Table 10: Annual Equivalent Cost and Energy Cost of the Present and Proposed Systems

	Present System	Proposed Systems					
		Without ITC			With ITC		
		Scenario 1	Scenario 2	Scenario 3	Scenario 1	Scenario 2	Scenario 3
AEC ($/year)	$ 43,348.20	$ 415,534.23	$ 221,512.77	$ 172,954.09	$ 371,591.02	$ 199,688.47	$ 156,684.76
Electricity (Energy) Cost ($/kWh)	$ 0.15	$ 1.42	$ 0.76	$ 0.59	$ 1.27	$ 0.68	$ 0.54

NOTE:

[box] = The Lowest Annual Equivalent Cost of the Proposed System

[shaded] = The Lowest Electricity (Energy) Cost of the Proposed System

However, at different parameters, these conclusions are altered. With present electricity cost of $0.08/kWh, the photovoltaic system (Scenario 3) will be more economical than the present system at PV module cost of $27/module. If the present electricity price goes to $0.16/kWh, at PV module cost of $147/module, the photovoltaic systems (Scenario 3) will take over the place of the most economical systems. Since AEC of Scenario 1 system decreases with much higher rate as PV module cost increases, at cost of $87/module Scenario 1 system turns out to be the most economical systems.

Present electricity price, obviously, impacts the economic justification of photovoltaic systems. Present electricity price should go up to $0.37/kWh, in order to make photovoltaic systems (Scenario 3) attractive. Because of high surplus output of

Scenario 1 systems, the AEC of this systems decreases as the present electricity price increases. Thereby, approximately at present electricity cost of $0.60/kWh, Scenario 1 is considered to be the most economical systems.

There is an evidence that one utility in New Mexico has electricity price of $0.12/kWh[26]. On the other hand the price of PV modules has gone down over 500% in 22 years[2]. These facts prove that in the near future, photovoltaic systems can be cost-effective.

PV module efficiency also alters the initial conclusions, but not as drastically as might be believed. Even with the highest possible efficiency, photovoltaic system still cannot compete with the conventional systems. This result, to some point, supports the fact that today's R&D on photovoltaic system is more directed to find the way to reduce PV manufacturing costs, rather than to increase solar cell efficiency (read Chapter 2).

Projected electricity price indices (PEPI) variation gave similar results to present electricity price analysis. PEPI was escalated to 370% to make the proposed system (Scenario 3) turns out to be the most attractive systems. Sensitivity analysis also showed that AECs of the systems are relatively insensitive to inflation and real interest rates.

Government can play important role in the development of photovoltaic systems. Investment tax credit sensitivity analysis showed that if ITC is increased to 73%, photovoltaic system (Scenario 3) can become more attractive investment compared with the conventional systems. When ITC goes up to 80%, photovoltaic system (Scenario 1) will be the most economical system among the other systems.

In the author's opinion, the AEC of photovoltaic systems above, can be lowered if the study included the other components of cost. This components of cost can be summarized as follows,

- *Environmental Cost.* In this study, environmental costs of fossil fuels are not reflected in today's market prices. Consequently, the discussions of the market penetration of photovoltaic systems based on prices alone understate the total potential value of photovoltaic, when nonmarket environmental damages are included[25].
- *Indirect energy conservation effect cost.* This cost is expected to incur in decentralized systems of PV[7] because users of this systems are expected to become more cost conscious and judicious in consuming electricity. This will result in a reduction in demand[6].
- *Remoteness cost.* The smaller the load and the farther it is from an existing distribution line, the more likely that a PV

[7] System in this case study can be categorized as decentralized systems

- system would be cost-effective, for any application. A study by EPRI found that as general rule, distribution line extensions of more than 500 feet for low-power loads will be less than applying PV[10]. Some examples of PV application in remote area are microwave repeaters, remote weather stations, water pumping, cathodic protection, and remote lighting.

A photovoltaic system is an environmentally sound energy source, and as long as the sun continues to rise, it will be available for use free of charge. It is certainly worth considering as the most potential energy systems in the future.

7.3 Suggestions for Further Study

This study only investigated one type of PV system, photovoltaic-utility interactive systems. There are other systems which likely be alternative systems to this utility interactive systems, such as wind-PV hybrid systems, diesel generator-PV hybrid systems, and utility interactive systems with battery storage. Economic feasibility of these systems needs to be justified as well.

Electricity load, in this study, was modeled to be the best scenario for PV systems. To reflect more realistically condition in the real situation, different scenarios of electricity loads must be used, for example fluctuating demand or demand occurred outside sunshine periods.

This study only investigated "tangible" costs of PV systems (e.g. PV module cost, inverter cost, installation cost, electricity cost, and so on). Studies by Reinhard Haas[6] and US DOE[25] discuss the importance to integrate "intangible" costs into analysis on renewable energy systems. Examples of intangible costs are environmental costs, indirect energy conservation effect costs, and remoteness costs. These "hidden" costs which usually are neglected in the evaluation of renewable energy technologies, make conventional systems look better than proposed systems.

WE LIVE FOR THE FUTURE

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APPENDICES

APPENDIX A

STEP-BY-STEP PROCEDURE TO FIND MONTHLY INSOLATION ON TILTED SURFACE[5]

- Based on location latitude, obtain monthly insolation (solar radiation) on horizontal surface (= H) from meteorological data[5], measured in J/m^2 or W/m^2. Obtain also monthly average clearness index (= K_T) and monthly ground reflectance (= ρ_g) data of location.
- Calculate monthly fraction of diffuse[8] insolation to total insolation (= H_d/H) using this following equation,

For $\omega_s \leq 81.4^0$ and $0.3 \leq K_T \leq 0.8$

$$H_d/H = 1.391 - 3.560K_T + 4.189K_T^2 - 2.137\ K_T^3 \qquad \text{Eq. A-1}$$

For $\omega_s > 81.4^0$ and $0.3 \leq K_T \leq 0.8$

$$H_d/H = 1.311 - 3.022K_T + 3.427K_T^2 - 1.821\ K_T^3 \qquad \text{Eq. A-2}$$

<u>or</u> Figure 25 in the next page.

[8] Insolation has two components, diffuse and beam.

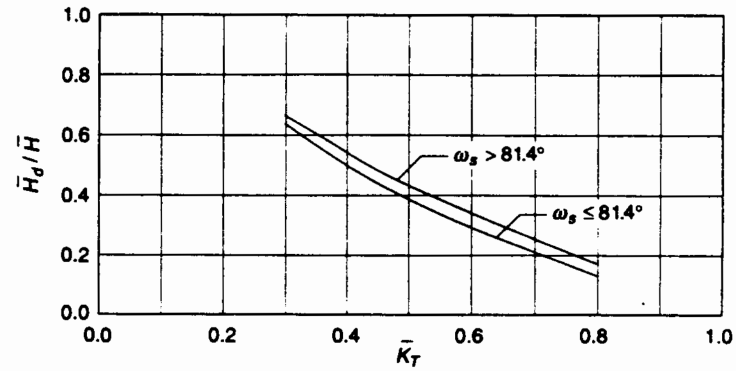

Figure 25: Suggested correlation of H_d/H vs. KT and ω_s. Adapted from Erbs et al.(1982)

Where,

ω_s = sunset hour angle on horizontal surface, the angular displacement of the sun west of the local meridian due to rotation of the earth on its axis at 15^0 per hour, afternoon positive

$$= \cos^{-1} (-\tan \phi \tan \delta) \qquad \text{Eq. A-3}$$

ϕ = latitude, the angular location north or south of the equator, north positive; $-90^0 \leq \phi \leq 90^0$

δ = declination, the angular position of the sun at solar noon (i.e. when the sun is on the local meridian) with respect to the plane of the equator, north positive; $-23.45^0 \leq \delta \leq 23.45^0$, its value for each month can be obtained from Table A-1,

Table 11: Recommended Average Days for Months and Values of n by Months. Adapted from Klein (1977)

Month	*n* for *i*th Day of Month	For the Average Day of the Month		
		Date	*n*, Day of Year	δ, Declination
January	*i*	17	17	–20.9
February	31 + *i*	16	47	–13.0
March	59 + *i*	16	75	–2.4
April	90 + *i*	15	105	9.4
May	120 + *i*	15	135	18.8
June	151 + *i*	11	162	23.1
July	181 + *i*	17	198	21.2
August	212 + *i*	16	228	13.5
September	243 + *i*	15	258	2.2
October	273 + *i*	15	288	–9.6
November	304 + *i*	14	318	–18.9
December	334 + *i*	10	344	–23.0

[a] From Klein (1977)

- Next step, calculate the ratio of the average daily beam radiation on the tilted surface to that on a horizontal surface for the month (= $R_b = H_{bT}/H_b$), using this following equation.

$$Rb = \frac{[\cos(\phi-\beta)\cos\delta\sin\omega_s' + (\pi/180)\omega_s'\sin(\phi-\beta)\sin\delta]}{[\cos\phi\cos\delta\sin\omega_s' + (\pi/180)\omega_s'\sin\phi\sin\delta]} \qquad \text{Eq. A-4}$$

Where,

ω_s' = the sunset hour angle for the tilted surface for the mean day of the month

$= \min[\cos^{-1}(-\tan\phi\tan\delta)\ ,\ \cos^{-1}(-\tan(\phi-\beta)\tan\delta)]$

- Finally, calculate monthly mean insolation (solar radiation) on an unshaded tilted surface (= H_T), using this following equation.

$$H_T = H(1 - H_d/H)R_b + H_d[(1+\cos\beta)/2] + H\rho_g[(1-\cos\beta)/2]$$

Eq. A-5

Where,

β = surface tilt angle (slope), the angle between the plane of the surface in question and the horizontal; $0 \leq \beta \leq 180^0$ ($\beta > 90^0$ means that the surface has a downward facing component)

APPENDIX B

USER'S MANUAL TO
THE ANNUAL EQUIVALENT COST
CALCULATION WORKSHEETS

GENERAL INFORMATION

The users of this manual are assumed to have basic knowledge on Windows and any spreadsheet software (knowledge on Microsoft Excel is preferred). These worksheets were designed using Microsoft Excel Version 5.0 software. To call up the worksheets into the current work-window, insert disk into drive a:, then from "File Manager" select and open file "AEC.XLS". This action should bring up the entire set of system evaluation worksheets on the screen.

This workbook (i.e. AEC.XLS) consists of seven worksheets which can be divided into two groups based on their functions. Worksheet 1, 2, 3, and 4 are categorized as Main Worksheet, while worksheet 5 and 6 are referred as Support Worksheet. Basically, most of the time users will work in main worksheet. The main function of support worksheet is to provide additional data to main worksheet. The structure of workbook "AEC.XLS" can be summarized as follows.

WORKBOOK "AEC.XLS"

- → **Main worksheet**
  - → Worksheet A: Annual Electricity Cost (SHEET1)
  - → Worksheet B: Annual Equivalent Cost of the Present System (SHEET2)
  - → Worksheet C: PV System Sizing (SHEET3)
  - → Worksheet D: Annual Equivalent Cost of the Proposed System (SHEET4)
- → **Support worksheet**

Continue

- Worksheet S-1: Discrete Compound Interest Factor Table (SHEET5)

- Worksheet S-2: Insolation (Solar Radiation) on Tilted Surface (SHEET6)

WORKSHEET A

The main function of worksheet A is to calculate annual electricity cost of the system. This worksheet is designed to calculate the cost based on two current rate schedules of OG&E, Power & Light - Service Level 5 Rate (P&L Rate) and General Service - Service Level 5 Rate (GS Rate). Thereby, if users use another rate schedules, cells E10-E21, G10-G21, N10-N21, G28, and O27 must be modified. Outputs of this worksheet can be seen in cell G34 for P&L Rate and cell O34 for GS Rate. A hard copy of worksheet A is shown in the next page.

WORKSHEET A: ANNUAL ELECTRICITY COST

OG&E POWER AND LIGHT RATE (P&L Rate) - Service Level 5

(charged by electricity demand and consumption)

Month	Electricity Demand		Electricity Consumption		Total Costs
	kW	$	kWh	$	$
Jan	100	$ 563.00	24,800	$ 726.64	$ 1,440.64
Feb	100	$ 563.00	22,400	$ 656.32	$ 1,370.32
Mar	100	$ 563.00	24,800	$ 726.64	$ 1,440.64
Apr	100	$ 563.00	24,000	$ 703.20	$ 1,417.20
May	100	$ 563.00	24,800	$ 726.64	$ 1,440.64
Jun	100	$ 1,554.00	24,000	$ 703.20	$ 2,408.20
Jul	100	$ 1,554.00	24,800	$ 726.64	$ 2,431.64
Aug	100	$ 1,554.00	24,800	$ 726.64	$ 2,431.64
Sep	100	$ 1,554.00	24,000	$ 703.20	$ 2,408.20
Oct	100	$ 1,554.00	24,800	$ 726.64	$ 2,431.64
Nov	100	$ 563.00	24,000	$ 703.20	$ 1,417.20
Dec	100	$ 563.00	24,800	$ 726.64	$ 1,440.64
Annual			292,000		$ 22,078.60

INPUT:

Customer Charge =	$ 151.00	per Month

OUTPUT:

Annual Electricity Consumption =	292,000	kWh
Annual Electricity Cost =		
Without Taxes =	$ 22,078.60	per Year
With Taxes =	$ 24,148.47	per Year

ADDITIONAL OUTPUT:

Present Electricity (Energy) Cost =	0.083	($/kWh)

NOTE:

Taxes are composed from:

- Franchise payment =	1.000%
- State sales tax =	4.500%
- City sales tax =	3.875%
Total Taxes =	9.375%

OG&E GENERAL SERVICE RATE(GS Rate) - Service Level 5

(charged by electricity consumption)

Month	Electricity Consumption		Total Costs
	kWh	$	$
Jan	24,800	$ 1,222.66	$ 1,222.66
Feb	22,400	$ 1,108.18	$ 1,108.18
Mar	24,800	$ 1,222.66	$ 1,222.66
Apr	24,000	$ 1,184.50	$ 1,184.50
May	24,800	$ 1,222.66	$ 1,222.66
Jun	24,000	$ 2,546.40	$ 2,546.40
Jul	24,800	$ 2,631.28	$ 2,631.28
Aug	24,800	$ 2,631.28	$ 2,631.28
Sep	24,000	$ 2,546.40	$ 2,546.40
Oct	24,800	$ 2,631.28	$ 2,631.28
Nov	24,000	$ 1,184.50	$ 1,184.50
Dec	24,800	$ 1,222.66	$ 1,222.66
Annual	292,000		$ 21,354.46

INPUT:

Customer Charge =	$ 12.00	per Month

OUTPUT:

Annual Electricity Consumption =	292,000	kWh
Annual Electricity Cost =		
Without Taxes =	$ 21,354.46	per Year
With Taxes =	$ 23,356.44	per Year

ADDITIONAL OUTPUT:

Present Electricity (Energy) Cost =	0.080	($/kWh)

NOTE:

Taxes are composed from:

- Franchise payment =	1.000%
- State sales tax =	4.500%
- City sales tax =	3.875%
Total Taxes =	9.375%

WORKSHEET B

Worksheet B is designed to assist calculation of annual equivalent cost (AEC) the present system. Since the pertinent cost in the present system is only annual electricity cost, this worksheet can also be utilized to calculate AEC of annual electricity cost of any systems (not limited to the present system).

This worksheet needs several inputs. The first parameters need to inputted are projected electricity price indices, excluding general inflation, in cells E7 through E37. The second input is inflation rate at cell H40, and real interest rate at H41. These rates are entered as a percentage, that is, a interest rate of 10% per year will be entered as 0.10. Another input need to be entered is annual electricity cost of the system. This parameter is the output of worksheet A. Once this information is entered or updated, the annual equivalent cost of annual electricity cost of a system will change to reflect the new information. This worksheet is supported by support worksheet S-1 which provide (A/P,i,n) factor for calculation of AEC.

The primary output of this worksheet, AEC of the Present System, can be seen in cell H48, while cell H51 contains the second output of the worksheet, electricity (energy) cost. This worksheet can be seen in the next page.

	B	C	D	E	F	G	H	I
1	**WORKSHEET B: ANNUAL EQUIVALENT COST**							
2				**OF THE PRESENT SYSTEM**				
3								
4								
5		N	EOY	(PEPI)	PEPI	PEC		
6					[(PEPI)*(1+j)^n]	($/year)		
7		0	1993	1.00	1.00			
8		1	1994	1.01	1.06	$ 24,840.28		
9		2	1995	1.01	1.12	$ 26,156.81		
10		3	1996	1.01	1.18	$ 27,543.12		
11		4	1997	1.02	1.25	$ 29,290.06		
12		5	1998	1.02	1.32	$ 30,842.44		
13		6	1999	1.04	1.42	$ 33,113.89		
14		7	2000	1.05	1.51	$ 35,204.21		
15		8	2001	1.05	1.59	$ 37,070.03		
16		9	2002	1.06	1.69	$ 39,406.50		
17		10	2003	1.08	1.81	$ 42,277.97		
18		11	2004	1.08	1.91	$ 44,518.70		
19		12	2005	1.09	2.03	$ 47,312.25		
20		13	2006	1.09	2.13	$ 49,819.80		
21		14	2007	1.09	2.25	$ 52,460.25		
22		15	2008	1.09	2.37	$ 55,240.64		
23		16	2009	1.09	2.49	$ 58,168.40		
24		17	2010	1.10	2.65	$ 61,813.26		
25		18	2011	1.10	2.79	$ 65,089.36		
26		19	2012	1.10	2.93	$ 68,539.10		
27		20	2013	1.11	3.12	$ 72,827.78		
28		21	2014	1.11	3.28	$ 76,687.65		
29		22	2015	1.12	3.49	$ 81,479.59		
30		23	2016	1.12	3.67	$ 85,798.01		
31		24	2017	1.12	3.87	$ 90,345.31		
32		25	2018	1.13	4.11	$ 95,983.01		
33		26	2019	1.13	4.33	$ 101,070.11		
34		27	2020	1.14	4.60	$ 107,368.66		
35		28	2021	1.14	4.84	$ 113,059.20		
36		29	2022	1.14	5.10	$ 119,051.34		
37		30	2023	1.15	5.41	$ 126,460.72		
38								
39	**INPUT:**							
40	Inflation Rate (= j) =						5.30%	
41	Real Interest Rate (= d) =						4.50%	
42	Annual Electricity Cost (outcome of Spreadsheet A) =						$ 23,356.44	per Year
43								
44	**LIFE-CYCLE COST ANALYSIS OUTPUT:**							
45	Net Present Value of Electricity Costs Over 30 Years =						$407,330.95	
46	Annual Equivalent Cost of Electricity =						$43,348.20	per Year
47								
48	**Annual Equivalent Cost of the Present System =**						**$ 43,348.20**	**per Year**
49								
50								
51	**Electricity (Energy) Cost of the Present System =**						**$ 0.15**	**per kWh**
52								
53	**Note:**							
54	(PEPI) =	Projected Electricity Price Indices (for Industrial sector, **excluding** general inflation)						
55	PEPI =	Projected Electricity Price Indices (for Industrial sector, **including** general inflation)						
56	PEC =	Projected Electricity Costs (after **escalated** and **inflated**)						

WORKSHEET C

This worksheet is designed as a tool to size a PV system. Since PV sizing process involves a lot of parameters, this worksheet is divided into two parts, input and output sheet. The first parameters need to be inputted are daily insolation on tilted surface in cells D7 through D18. These parameters are calculated using support worksheet S-2. The second input is monthly percent possible sunshine data of the location in cells E7 through E18. This data is obtained from meteorological data of the location. Next, daily maximum temperature experienced by the location is inputted in cells G7 through G18. This temperature data is obtained from weather data of the location.

The next inputs are grouped as the PV system requirements. The first one is daily load requirement which is entered in cell G21, and the second input is system voltage requirement, entered in cell G22. The next input group is PV module data, which are entered in cells G25 through G32. The other parameters are obtained from power conditioning unit data and entered in cells G35 and G36. There are some data which need to estimated, those are inputted in cells G39 and G40. The last category of input is input which is calculated automatically based on the input entered in the previous step, those parameters can be seen in cells G43 and G44.

Output sheet contains all output of this worksheet. Those outputs can be seen in cells H52 through H81 and table following these those results. This worksheet is presented in the next page.

	C	D	E	F	G	H
1	**WORKSHEET C: PV SYSTEM SIZING**					
2	**(INPUT SHEET)**					
3	**INPUT:**					
4	Month	Daily Insolation	% Possible	Daily Insolation	Daily Maximum	Cell Temp.
5		Clear Day	Sunshine		Temperature	
6		(kWh/m^2-day)		(kWh/m^2-day)	(^0C)	(^0C)
7	Jan	3.69	0.44	1.63	8.67	28.67
8	Feb	4.46	0.49	2.18	11.44	31.44
9	Mar	5.08	0.50	2.54	15.44	35.44
10	Apr	5.49	0.47	2.58	22.00	42.00
11	May	5.69	0.50	2.84	25.94	45.94
12	Jun	6.15	0.53	3.26	30.56	50.56
13	Jul	6.19	0.54	3.34	33.67	53.67
14	Aug	6.04	0.54	3.26	33.61	53.61
15	Sep	5.32	0.51	2.71	29.28	49.28
16	Oct	4.80	0.50	2.40	23.44	43.44
17	Nov	3.80	0.39	1.48	16.06	36.06
18	Dec	3.22	0.37	1.19	10.39	30.39
19						
20	**PV System Requirements:**					
21	Daily Load Requirement =				800	kWh/day
22	System Voltage Requirement =				480	V AC
23						
24	**PV Module Data:**					
25	Nominal Operation Cell Temperature =				49	^0C
26	Temperature Effect On Power =				0.38%	
27	Module Peak Power (Pp) =				83	W
28	Voltage @ Peak Power (Vpp) =				17.1	V
29	Current @ Peak Power (Ipp) =				4.85	A
30	Dimension =					
31		Length =			0.6604	m
32		Width =			1.1082	m
33						
34	**Power Conditioning Unit Data:**					
35	Average Efficiency of Power Conditioning Unit =				95%	
36	Array Nominal Operating Voltage =				360	V DC
37						
38	**Estimated:**					
39	Soiling Factor =				98%	
40	Module Packing Factor =				95%	
41						
42	**Calculated Based On Above Input:**					
43	Temperature Correction Factor =				84%	
44	PV Modules Efficiency (include Packing Factor) =				11.34%	

	C	D	E	F	G	H	I	J
47	**WORKSHEET C: PV SYSTEM SIZING**							
48		**(OUTPUT SHEET)**						
49								
50	**OUTPUT:**							
51	Area of PV array needed:							
52		Scenario 1 =				7,764.63	m^2	
53		Scenario 2 =				3,778.90	m^2	
54		Scenario 3 =				2,772.61	m^2	
55	Peak Power Rating of the Array:							
56		Scenario 1 =				742,897.47	Watt	
57		Scenario 2 =				361,553.86	Watt	
58		Scenario 3 =				265,275.41	Watt	
59	Number of Modules Needed:							
60								
61		Scenario 1:						
62			Theoritical Number of Modules =			8,951	Modules	
63			Number of Modules Wired in Series =			21	Modules	
64			Number of Strings Wired in Parallel =			426	Modules	
65			Practical Number of Modules =			8,946	Modules	
66			Array Peak Power =			742.52	kW	
67			Array Area =			6,547.18	m^2	
68		Scenario 2:						
69			Theoritical Number of Modules =			4,356	Modules	
70			Number of Modules Wired in Series =			21	Modules	
71			Number of Strings Wired in Parallel =			207	Modules	
72			Practical Number of Modules =			4,347	Modules	
73			Array Peak Power =			360.80	kW	
74			Array Area =			3,181.37	m^2	
75		Scenario 3:						
76			Theoritical Number of Modules =			3,196	Modules	
77			Number of Modules Wired in Series =			21	Modules	
78			Number of Strings Wired in Parallel =			152	Modules	
79			Practical Number of Modules =			3,192	Modules	
80			Array Peak Power =			264.94	kW	
81			Array Area =			2,336.08	m^2	
82								
83	Month	Monthly Load		PV Output		Load Supplied by Utility		
84		Requirement	Scenario 1	Scenario 2	Scenario 3	Scenario 1	Scenario 2	Scenario 3
85		(kWh/month)	(kWh/month)	(kWh/month)	(kWh/month)	(kWh/month)	(kWh/month)	(kWh/month)
86	Jan	24,800	33,085.84	16,076.92	11,805.28	(8,285.84)	8,723.08	12,994.72
87	Feb	22,400	40,165.53	19,517.05	14,331.36	(17,765.53)	2,882.95	8,068.64
88	Mar	24,800	51,679.43	25,111.84	18,439.61	(26,879.43)	(311.84)	6,360.39
89	Apr	24,000	50,878.47	24,722.64	18,153.82	(26,878.47)	(722.64)	5,846.18
90	May	24,800	57,875.01	28,122.36	20,650.24	(33,075.01)	(3,322.36)	4,149.76
91	Jun	24,000	60,833.89	29,560.13	21,705.99	(36,833.89)	(5,560.13)	2,294.01
92	Jul	24,800	57,390.86	27,887.11	20,477.49	(32,590.86)	(3,087.11)	4,322.51
93	Aug	24,800	56,132.39	27,275.60	20,028.46	(31,332.39)	(2,475.60)	4,771.54
94	Sep	24,000	52,953.40	25,730.88	18,894.17	(28,953.40)	(1,730.88)	5,105.83
95	Oct	24,800	48,864.78	23,744.16	17,435.32	(24,064.78)	1,055.84	7,364.68
96	Nov	24,000	29,172.20	14,175.22	10,408.86	(5,172.20)	9,824.78	13,591.14
97	Dec	24,800	24,291.59	11,803.66	8,667.42	508.41	12,996.34	16,132.58
98								
99			563,323.39	273,727.56	200,998.02	(271,323.39)	18,272.44	91,001.98
100				Annual PV Output			Annual Electricity Consumption	
101							Supplied by Utility	
102								
103	**Note:**							
104	Numbers in brackets indicate excessive outputs which are fed into utility							

WORKSHEET D

Worksheet D is utilized as an aid to calculate the annual equivalent cost of the proposed system. The costs of components of the system must be entered in cells G6 through G9 and G15. The main output of this worksheet can be obtained in cell AC44, while the second output is placed in cell AC48. This worksheet is shown in the next page.

	B	C	D	E	F	G	H	I	J
1	**WORKSHEET D: ANNUAL EQUIVALENT COST**								
2				**OF THE PROPOSED SYSTEM**					
3					**(INPUT SHEET)**				
4									
5	**GENERAL INFORMATION:**								
6	PV Module Price =					$ 467	per Module		
7	Operation & Maintenance Cost =					$ 0.01	per kWh		
8	Mounting Support Price =					$ 229	per 4 Modules		
9	Corporate Income Tax =					34%			
10									
11									
12	**INPUT:**								
13	**Initial Costs ($):**								
14		PV Modules =				$ 1,490,664.00			
15		Inverter =				$ 100,000.00			
16		Mounting Support =				$ 182,742.00			
17		Miscellaneous Costs[#] =				$ 88,670.30			
18									
19									
20				Total Initial Costs =		$ 1,862,076			
21									
22									
23									
24									
25	**Annual Costs ($/year):**								
26		Operation & Maintenance =				$ 2,009.98	per Year		
27		Annual Equivalent Cost of Electricity =				**see Input Sheet - Continue (i.e. PEC)**			

	K	L	M	N	O	P	Q	R
1		**WORKSHEET D: ANNUAL ELECTRICITY**						
2		**COST OF THE PROPOSED SYSTEM**						
3		**(INPUT SHEET - CONTINUE)**						
4								
5		N	EOY	(PEPI)	PEPI	PEC		
6						($/year)		
7								
8		0	1993	1.00	1.00			
9		1	1994	1.01	1.06	$ 7,160.92		
10		2	1995	1.01	1.12	$ 7,540.45		
11		3	1996	1.01	1.18	$ 7,940.09		
12		4	1997	1.02	1.25	$ 8,443.70		
13		5	1998	1.02	1.32	$ 8,891.22		
14		6	1999	1.04	1.42	$ 9,546.03		
15		7	2000	1.05	1.51	$10,148.62		
16		8	2001	1.05	1.59	$10,686.50		
17		9	2002	1.06	1.69	$11,360.05		
18		10	2003	1.08	1.81	$12,187.84		
19		11	2004	1.08	1.91	$12,833.79		
20		12	2005	1.09	2.03	$13,639.11		
21		13	2006	1.09	2.13	$14,361.99		
22		14	2007	1.09	2.25	$15,123.17		
23		15	2008	1.09	2.37	$15,924.70		
24		16	2009	1.09	2.49	$16,768.71		
25		17	2010	1.10	2.65	$17,819.44		
26		18	2011	1.10	2.79	$18,763.87		
27		19	2012	1.10	2.93	$19,758.36		
28		20	2013	1.11	3.12	$20,994.69		
29		21	2014	1.11	3.28	$22,107.41		
30		22	2015	1.12	3.49	$23,488.83		
31		23	2016	1.12	3.67	$24,733.74		
32		24	2017	1.12	3.87	$26,044.62		
33		25	2018	1.13	4.11	$27,669.85		
34		26	2019	1.13	4.33	$29,136.36		
35		27	2020	1.14	4.60	$30,952.09		
36		28	2021	1.14	4.84	$32,592.55		
37		29	2022	1.14	5.10	$34,319.96		
38		30	2023	1.15	5.41	$36,455.93		
39								
40								
41	**INPUT:**							
42	Annual Electricity Cost ($/year):							
43							P&L Rate	GS Rate
44		Scenario 1 =					(6,097.41)	(24,058.80)
45		Scenario 2 =					6,730.26	442.57
46		Scenario 3 =					17,707.11	6,733.16
47								
48								
49								
50								
51								
52								
53	**Note:**							
54	(PEPI) =	Projected Electricity Price Indices (for industrial sector, **excluding** general inflation)						
55	PEPI =	Projected Electricity Price Indices (for industrial sector, **including** general inflation)						
56	PEC =	Projected Electricity Costs						

	U	V	W	X	Y	Z	AA	AB	AC	AD	AE
1	**WORKSHEET D: ANNUAL EQUIVALENT COST**										
2					**OF THE PROPOSED SYSTEM**						
3							**(OUTPUT SHEET)**				
4											
5			Before-Tax					After-Tax			
6	N	EOY	Cash Flow	MACRS %	Depreciation	Taxable Income	Taxes	Cash Flow			
7											
8	0	1993	$ (1,862,076)					$ (1,862,076)			
9	1	1994	$ (9,170.90)	5.00%	$ 93,103.82	$ (102,274.72)	$ (34,773.40)	$ 25,602.50			
10	2	1995	$ (9,550.43)	9.50%	$ 176,897.25	$ (186,447.68)	$ (63,392.21)	$ 53,841.78			
11	3	1996	$ (9,950.07)	8.55%	$ 159,207.52	$ (169,157.60)	$ (57,513.58)	$ 47,563.51			
12	4	1997	$ (10,453.68)	7.70%	$ 143,379.88	$ (153,833.56)	$ (52,303.41)	$ 41,849.73			
13	5	1998	$ (10,901.20)	6.93%	$ 129,041.89	$ (139,943.08)	$ (47,580.65)	$ 36,679.45			
14	6	1999	$ (11,556.01)	6.23%	$ 116,007.35	$ (127,563.36)	$ (43,371.54)	$ 31,815.53			
15	7	2000	$ (12,158.60)	5.90%	$ 109,862.50	$ (122,021.10)	$ (41,487.18)	$ 29,328.57			
16	8	2001	$ (12,696.48)	5.90%	$ 109,862.50	$ (122,558.98)	$ (41,670.05)	$ 28,973.57			
17	9	2002	$ (13,370.03)	5.91%	$ 110,048.71	$ (123,418.74)	$ (41,962.37)	$ 28,592.34			
18	10	2003	$ (14,197.82)	5.90%	$ 109,862.50	$ (124,060.32)	$ (42,180.51)	$ 27,982.69			
19	11	2004	$ (14,843.77)	5.91%	$ 110,048.71	$ (124,892.48)	$ (42,463.44)	$ 27,619.67			
20	12	2005	$ (15,649.09)	5.90%	$ 109,862.50	$ (125,511.59)	$ (42,673.94)	$ 27,024.85			
21	13	2006	$ (16,371.97)	5.91%	$ 110,048.71	$ (126,420.67)	$ (42,983.03)	$ 26,611.06			
22	14	2007	$ (17,133.15)	5.90%	$ 109,862.50	$ (126,995.65)	$ (43,178.52)	$ 26,045.37			
23	15	2008	$ (17,934.68)	5.91%	$ 110,048.71	$ (127,983.39)	$ (43,514.35)	$ 25,579.67			
24	16	2009	$ (18,778.69)	2.95%	$ 54,931.25	$ (73,709.94)	$ (25,061.38)	$ 6,282.69			
25	17	2010	$ (19,829.42)	0.00%	$ -	$ (19,829.42)	$ (6,742.00)	$ (13,087.42)			
26	18	2011	$ (20,773.85)	0.00%	$ -	$ (20,773.85)	$ (7,063.11)	$ (13,710.74)			
27	19	2012	$ (21,768.34)	0.00%	$ -	$ (21,768.34)	$ (7,401.24)	$ (14,367.10)			
28	20	2013	$ (23,004.67)	0.00%	$ -	$ (23,004.67)	$ (7,821.59)	$ (15,183.09)			
29	21	2014	$ (24,117.39)	0.00%	$ -	$ (24,117.39)	$ (8,199.91)	$ (15,917.48)			
30	22	2015	$ (25,498.81)	0.00%	$ -	$ (25,498.81)	$ (8,669.59)	$ (16,829.21)			
31	23	2016	$ (26,743.72)	0.00%	$ -	$ (26,743.72)	$ (9,092.86)	$ (17,650.85)			
32	24	2017	$ (28,054.60)	0.00%	$ -	$ (28,054.60)	$ (9,538.57)	$ (18,516.04)			
33	25	2018	$ (29,679.83)	0.00%	$ -	$ (29,679.83)	$ (10,091.14)	$ (19,588.69)			
34	26	2019	$ (31,146.34)	0.00%	$ -	$ (31,146.34)	$ (10,589.75)	$ (20,556.58)			
35	27	2020	$ (32,962.07)	0.00%	$ -	$ (32,962.07)	$ (11,207.10)	$ (21,754.97)			
36	28	2021	$ (34,602.53)	0.00%	$ -	$ (34,602.53)	$ (11,764.86)	$ (22,837.67)			
37	29	2022	$ (36,329.94)	0.00%	$ -	$ (36,329.94)	$ (12,352.18)	$ (23,977.76)			
38	30	2023	$ (38,465.91)	0.00%	$ -	$ (38,465.91)	$ (13,078.41)	$ (25,387.50)			
39	NOTE:	In the above table, cost is presented as negative/bracketed number									
40											
41	OUTPUT:										
42	Net Present Value of the Proposed System Over 30 Years =								$1,625,201.49		
43											
44	**Annual Equivalent Cost of the Proposed System =**								**$ 172,954.09**	**per Year**	
45											
46											
47											
48	**Electricity (Energy) Cost of the Proposed System =**								**$ 0.59**	**per kWh**	

SUPPORT WORKSHEETS

WORKSHEET S-1:

10.04% INTEREST FACTORS FOR DISCRETE COMPOUNDING PERIODS

	N	F/P,i,n	P/F,i,n	F/A,i,n	A/F,i,n	P/A,i,n	A/P,i,n
7	1	1.100	0.9088	1.0000	1.0000	0.9088	1.1004
8	2	1.211	0.8259	2.1004	0.4761	1.7346	0.5765
9	3	1.332	0.7505	3.3112	0.3020	2.4852	0.4024
10	4	1.466	0.6821	4.6436	0.2153	3.1672	0.3157
11	5	1.613	0.6198	6.1098	0.1637	3.7871	0.2641
12	6	1.775	0.5633	7.7231	0.1295	4.3504	0.2299
13	7	1.953	0.5119	9.4984	0.1053	4.8623	0.2057
14	8	2.150	0.4652	11.4519	0.0873	5.3275	0.1877
15	9	2.365	0.4228	13.6015	0.0735	5.7502	0.1739
16	10	2.603	0.3842	15.9669	0.0626	6.1344	0.1630
17	11	2.864	0.3491	18.5697	0.0539	6.4836	0.1542
18	12	3.152	0.3173	21.4338	0.0467	6.8009	0.1470
19	13	3.468	0.2883	24.5855	0.0407	7.0892	0.1411
20	14	3.816	0.2620	28.0535	0.0356	7.3513	0.1360
21	15	4.199	0.2381	31.8696	0.0314	7.5894	0.1318
22	16	4.621	0.2164	36.0689	0.0277	7.8058	0.1281
23	17	5.085	0.1967	40.6896	0.0246	8.0025	0.1250
24	18	5.595	0.1787	45.7743	0.0218	8.1812	0.1222
25	19	6.157	0.1624	51.3693	0.0195	8.3436	0.1199
26	20	6.775	0.1476	57.5260	0.0174	8.4912	0.1178
27	21	7.455	0.1341	64.3008	0.0156	8.6254	0.1159
28	22	8.203	0.1219	71.7556	0.0139	8.7473	0.1143
29	23	9.027	0.1108	79.9588	0.0125	8.8581	0.1129
30	24	9.933	0.1007	88.9854	0.0112	8.9587	0.1116
31	25	10.930	0.0915	98.9183	0.0101	9.0502	0.1105
32	26	12.027	0.0831	109.8482	0.0091	9.1334	0.1095
33	27	13.234	0.0756	121.8753	0.0082	9.2089	0.1086
34	28	14.563	0.0687	135.1097	0.0074	9.2776	0.1078
35	29	16.025	0.0624	149.6727	0.0067	9.3400	0.1071
36	30	17.634	0.0567	165.6976	0.0060	9.3967	0.1064

WORKSHEET S-2: INSOLATION ON TILTED SURFACE (H_T)

	B	C	D	G	H	I	J	K	L	M
2	WORKSHEET S-2: INSOLATION ON TILTED SURFACE (H_T)									
3										
4										
5	Month	n	delta	omega(s)	Rb	H	K_T	Rho(g)	Hd/H	H_T
6										
7	Jan	17	-20.9	74.5	1.817	9.09	0.44	0.7	0.45	13.30
8	Feb	47	-13.0	80.7	1.535	11.97	0.49	0.7	0.40	16.05
9	Mar	75	-2.4	88.3	1.267	15.89	0.50	0.4	0.43	18.28
10	Apr	105	9.4	90.8	1.051	19.58	0.47	0.2	0.46	19.78
11	May	135	18.8	91.7	0.922	21.77	0.50	0.2	0.43	20.47
12	Jun	162	23.1	92.1	0.871	24.34	0.53	0.2	0.40	22.13
13	Jul	198	21.2	91.9	0.893	24.16	0.54	0.2	0.39	22.28
14	Aug	228	13.5	91.2	0.991	22.14	0.54	0.2	0.39	21.74
15	Sep	258	2.2	90.2	1.173	17.64	0.51	0.2	0.42	19.15
16	Oct	288	-9.6	83.2	1.439	13.99	0.50	0.2	0.43	17.28
17	Nov	318	-18.9	76.1	1.736	10.22	0.39	0.2	0.51	13.67
18	Dec	344	-23.0	72.7	1.911	8.23	0.37	0.4	0.54	11.61
19										
20	**NOTE:** Step-by-step procedure to find insolation on tilted surface is attached in Appendix A									
21										
22										
23	**INPUT:**									
24	Phi (= Location Latitude) =	35								
25	Beta (= Tilt Angle) =	30								
26										

APPENDIX C

OKLAHOMA GAS & ELECTRIC RATE SCHEDULE

POWER AND LIGHT RATE
(Service Level 5)

OKLAHOMA GAS AND ELECTRIC COMPANY
P. O. Box 321
Oklahoma City, Oklahoma 73101

SHEET NO. 20.0
DATE ISSUED 3-3-94

STANDARD RATE SCHEDULE PL-1 — **STATE OF OKLAHOMA**
POWER AND LIGHT RATE — **Code No. 39**

EFFECTIVE IN: All territory served.

AVAILABILITY: Power and light service. Alternating current. Service will be rendered at one location at one voltage. No resale, breakdown, auxiliary or supplementary service permitted.

RATE:

TRANSMISSION (Service Level 1):

Customer Charge: $637.00 per bill per month.

Capacity Charge:

Summer Season: $ 12.35 per kW of Billing Demand per month.
Winter Season: $ 4.48 per kW of Billing Demand per month.

Energy Charge:

First 2,000,000 kWh per month: 2.70¢ per kWh.
All additional kWh per month: 2.36¢ per kWh.

DISTRIBUTION SUBSTATION (Service Level 2):

Customer Charge: $637.00 per bill per month.

Capacity Charge:

Summer Season: $ 13.99 per kW of Billing Demand per month.
Winter Season: $ 5.08 per kW of Billing Demand per month.

Energy Charge:

First 2,000,000 kWh per month: 2.74¢ per kWh.
All additional kWh per month: 2.39¢ per kWh.

Continued

Effective 3 March 1994

Rates Authorized
by 380443 PUD 001055 25 February 1994
(Order No.) (Cause/Docket No.) (Date of Order)

Issued by [signature] Chairman of the Board and President
(Name of Officer) (Title)

APPROVED
MAR 03 1994
DIRECTOR OF
PUBLIC UTILITIES

OKLAHOMA GAS AND ELECTRIC COMPANY
P. O. Box 321
Oklahoma City, Oklahoma 73101

SHEET NO. 20.1
DATE ISSUED 3-3-94

STANDARD RATE SCHEDULE PL-1 — STATE OF OKLAHOMA

POWER AND LIGHT RATE — Code No. 39

Continued

DISTRIBUTION (Service Levels 3 and 4):

Customer Charge: $269.00 per bill per month.

Capacity Charge:

Summer Season: $14.30 per kW of Billing Demand per month.
Winter Season: $ 5.19 per kW of Billing Demand per month.

Energy Charge:

First 2,000,000 kWh per month: 2.86¢ per kWh.
All additional kWh per month: 2.43¢ per kWh.

SECONDARY (Service Level 5):

Customer Charge: $151.00 per bill per month.

Capacity Charge:

Summer Season: $15.54 per kW of Billing Demand per month.
Winter Season: $ 5.63 per kW of Billing Demand per month.

Energy Charge:

First 2,000,000 kWh per month: 2.93¢ per kWh.
All additional kWh per month: 2.52¢ per kWh.

DEFINITION OF SEASON:

SUMMER SEASON: The five OG&E Revenue Months of June through October.

WINTER SEASON: The seven OG&E Revenue Months of November through May of the succeeding year.

Continued

Effective 3 March 1994

Rates Authorized
by 380443 PUD 001055 25 February 1994
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Issued by [signature] Chairman of the Board and President
(Name of Officer) (Title)

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DIRECTOR OF
PUBLIC UTILITIES

Continued

DETERMINATION OF MAXIMUM DEMAND: The customer's Maximum Demand shall be the maximum rate at which energy is used for any period of 15 consecutive minutes of the month for which the bill is rendered as shown by the Company's demand meter. In the event a customer taking service under this rate has a demand meter with an interval greater than 15 minutes, the Company shall have a reasonable time to change the metering device.

DETERMINATION OF BILLING DEMAND: The Billing Demand upon which the capacity charge is based shall be the Maximum Demand as determined above corrected for power factor, set forth under Power Factor Clause; provided that no Billing Demand shall be considered as less than 65 percent of the highest Summer Season Maximum Demand corrected for power factor previously determined during the 12 months ending with the current month.

POWER FACTOR CLAUSE: The customer shall at all times take and use power in such manner that the power factor shall be as nearly 100 percent as possible, but when the average power factor, as determined by continuous measurement of lagging reactive kilovoltampere hours is less than 80 percent, the Billing Demand shall be determined by multiplying the Maximum Demand, shown by the demand meter for the billing period, by 80 and dividing the product thus obtained by the actual average power factor expressed in percent. The Company may, at its option, use for adjustment, the power factor as determined by test during periods of normal operation of the customer's equipment instead of the average power factor.

SERVICE LEVELS: For purposes of this rate, the following shall apply:

Service Level 1: Shall mean service at any nominal standard voltage of the Company above 50 kV where service is rendered through a direct tap to the Company's prevailing transmission source.

Service Level 2: Shall mean service at any nominal standard voltage of the Company between 2 kV and 50 kV, both inclusive, where service is rendered through a Company Substation which has a transmission voltage source and the point of delivery is at the load side of the substation or from a circuit dedicated to the customer.

Continued

Continued

Service Level 3: Shall mean service at any nominal standard voltage of the Company between 2 kV and 50 kV, both inclusive, by a direct tap to the Company's prevailing distribution source from a circuit not dedicated to the customer.

Service Level 4: Shall mean service at any nominal standard voltage of the Company between 2 kV and 50 kV, both inclusive, where service is rendered through transformation from a Company prevailing distribution voltage source (2 kV to 50 kV) to a lower distribution voltage with metering at distribution voltage.

Service Level 5: Shall mean service at any nominal standard voltage of the Company less than 2,000 volts with metering at less than 2,000 volts.

If the Company chooses to install its metering equipment on the load side of the customers's transformers, the kWh billed shall be increased by the amount of the transformer losses calculated as follows:

Service Level 1: 0.50 percent of the total kVA rating of the customer's transformers times 730 hours.

Service Level 3: 0.60 percent of the total kVA rating of the customer's transformers times 730 hours.

LATE PAYMENT CHARGE: A late payment charge in an amount equal to 1.5 percent of the total balance for services and charges remaining unpaid on the due date stated on the bill shall be added to the amount due. The due date as stated on the bill shall be 20 days after the bill is mailed.

MINIMUM BILL: The minimum monthly bill shall be the Customer Charge, plus the applicable Capacity Charge as computed under the above schedule. The Company shall specify a larger minimum monthly bill, calculated in accordance with the Company's Allowable Expenditure Formula in its Terms and Conditions of Service on file with and approved by the Commission, when necessary to justify the investment required to provide service.

FRANCHISE PAYMENT: The above stated rates do not include any amount for franchise payments levied upon the Company by a municipality.

Continued

Effective 3 March 1994

Rates Authorized
by 380443 PUD 001055 25 February 1994
(Order No.) (Cause/Docket No.) (Date of Order)

Issued by [signature] Chairman of the Board and President
(Name of Officer) (Title)

APPROVED
MAR 03 1994
DIRECTOR OF
PUBLIC UTILITIES

Continued

When a municipality, by a franchise or other ordinance approved by the qualified electors of the municipality, levies or imposes upon the Company franchise payments or fees (based upon a percent of gross revenues) to be paid by the Company to the municipality, such franchise payment will be added as a percentage of charges for electric service to the bills of all customers receiving service from the Company within the corporate limits of the municipality exacting said payment.

ANNUAL PUBLIC UTILITY ASSESSMENT FEE: See Rider for Annual Public Utility Assessment Fee - APUAF.

FUEL COST ADJUSTMENT: See Rider for Fuel Cost Adjustment - FCA.

TERM: The Company, at its option, may require a written contract for a year or longer, subject also to special minimum guarantees, which may be necessary in cases warranted by special circumstances or unusually large investments by the Company. Such special minimum guarantees shall be calculated in accordance with the Company's Allowable Expenditure Formula in its Terms and Conditions of Service on file with and approved by the Commission.

Customers who request to be changed to the Power and Light Rate from another rate will remain on the Power and Light Rate or the Power and Light Time-of-Use rate for one year before being permitted to change rates again unless they demonstrate a permanent change in electric consumption.

Effective 3 March 1994

Rates Authorized
by 380443 PUD 001055 25 February 1994
(Order No.) (Cause/Docket No.) (Date of Order)

Issued by [signature] Chairman of the Board and President
(Name of Officer) (Title)

APPROVED
MAR 03 1994
DIRECTOR OF
PUBLIC UTILITIES

Continued

When a municipality, by a franchise or other ordinance approved by the qualified electors of the municipality, levies or imposes upon the Company franchise payments or fees (based upon a percent of gross revenues) to be paid by the Company to the municipality, such franchise payment will be added as a percentage of charges for electric service to the bills of all customers receiving service from the Company within the corporate limits of the municipality exacting said payment.

ANNUAL PUBLIC UTILITY ASSESSMENT FEE: See Rider for Annual Public Utility Assessment Fee - APUAF.

FUEL COST ADJUSTMENT: See Rider for Fuel Cost Adjustment - FCA.

TERM: The Company, at its option, may require a written contract for a year or longer, subject also to special minimum guarantees, which may be necessary in cases warranted by special circumstances or unusually large investments by the Company. Such special minimum guarantees shall be calculated in accordance with the Company's Allowable Expenditure Formula in its Terms and Conditions of Service on file with and approved by the Commission.

Customers who request to be changed to the Power and Light Rate from another rate will remain on the Power and Light Rate or the Power and Light Time-of-Use rate for one year before being permitted to change rates again unless they demonstrate a permanent change in electric consumption.

GENERAL SERVICE RATE
(Service Level 5)

OKLAHOMA GAS AND ELECTRIC COMPANY
P. O. Box 321
Oklahoma City, Oklahoma 73101

SHEET NO. 10.0
DATE ISSUED 3-3-94

STANDARD RATE SCHEDULE GS-1 — STATE OF OKLAHOMA

GENERAL SERVICE RATE — Code No. 06

EFFECTIVE IN: All territory served.

AVAILABILITY: Alternating current for use other than a residential dwelling unit. Service will be rendered at one location at one voltage. Not available for service at transmission voltage (Service Level 1).

No resale, breakdown, auxiliary, or supplementary service permitted. Where commercial and residential services are served through one meter, the General Service Rate shall apply to the entire load.

RATE:

DISTRIBUTION SUBSTATION (Service Level 2):

Customer Charge: $180.00 per bill per month.

Energy Charge:

Summer Season: The five OG&E Revenue Months of June through October.

All kWh per month: 10.04¢ per kWh.

Winter Season: The seven OG&E Revenue Months of November through May of the succeeding year.

First 1,000 kWh per month: 8.24¢ per kWh.
All additional kWh per month: 4.47¢ per kWh.

Continued

Effective 3 March 1994

Rates Authorized by 380443 (Order No.) PUD 001055 (Cause/Docket No.) 25 February 1994 (Date of Order)

Issued by [signature] (Name of Officer) — Chairman of the Board and President (Title)

APPROVED
MAR 03 1994
DIRECTOR OF PUBLIC UTILITIES

OKLAHOMA GAS AND ELECTRIC COMPANY
P. O. Box 321
Oklahoma City, Oklahoma 73101

SHEET NO. 10.1
DATE ISSUED 3-3-94

STANDARD RATE SCHEDULE GS-1 — STATE OF OKLAHOMA
GENERAL SERVICE RATE — Code No. 06

Continued

DISTRIBUTION (Service Levels 3 and 4):

Customer Charge: $50.00 per bill per month.

Energy Charge:

Summer Season: The five OG&E Revenue Months of June through October.

All kWh per month: 10.04¢ per kWh.

Winter Season: The seven OG&E Revenue Months of November through May of the succeeding year.

First 1,000 kWh per month: 8.24¢ per kWh.
All additional kWh per month: 4.47¢ per kWh.

SECONDARY (Service Level 5):

Customer Charge: $12.00 per bill per month.

Energy Charge:

Summer Season: The five OG&E Revenue Months of June through October.

All kWh per month: 10.61¢ per kWh.

Winter Season: The seven OG&E Revenue Months of November through May of the succeeding year.

First 1,000 kWh per month: 8.74¢ per kWh.
All additional kWh per month: 4.77¢ per kWh.

Continued

Effective 3 March 1994

Rates Authorized
by 380443 PUD 001055 25 February 1994
(Order No.) (Cause/Docket No.) (Date of Order)

Issued
by [signature] Chairman of the Board and President
(Name of Officer) (Title)

APPROVED
MAR 03 1994
DIRECTOR OF PUBLIC UTILITIES

Continued

SERVICE LEVELS: For purposes of this rate, the following shall apply:

Service Level 2: Shall mean service at any nominal standard voltage of the Company between 2 kV and 50 kV, both inclusive, where service is rendered through a Company Substation which has a transmission voltage source and the point of delivery is at the load side of the substation or from a circuit dedicated to the customer.

Service Level 3: Shall mean service at any nominal standard voltage of the Company between 2 kV and 50 kV, both inclusive, by a direct tap to the Company's prevailing distribution source from a circuit not dedicated to the customer.

Service Level 4: Shall mean service at any nominal standard voltage of the Company between 2 kV and 50 kV, both inclusive, where service is rendered through transformation from a Company prevailing distribution voltage source (2 kV to 50 kV) to a lower distribution voltage with metering at distribution voltage.

Service Level 5: Shall mean service at any nominal standard voltage of the Company less than 2,000 volts with metering at less than 2,000 volts.

If the Company chooses to install its metering equipment on the load side of the customer's transformers, the kWh billed shall be increased by the amount of the transformer losses calculated as follows:

Service Level 3: 0.60 percent of the total kVA rating of the customer's transformers times 730 hours.

LATE PAYMENT CHARGE: A late payment charge in an amount equal to 1.5 percent of the total balance for services and charges remaining unpaid on the due date stated on the bill shall be added to the amount due. The due date as stated on the bill shall be 20 days after the bill is mailed.

Continued

Effective 3 March 1994

Rates Authorized by 380443 PUD 001055 25 February 1994
(Order No.) (Cause/Docket No.) (Date of Order)

Issued by (Name of Officer) Chairman of the Board and President (Title)

APPROVED
MAR 03 1994
DIRECTOR OF PUBLIC UTILITIES

OKLAHOMA GAS AND ELECTRIC COMPANY
P. O. Box 321
Oklahoma City, Oklahoma 73101

SHEET NO. 10.3
DATE ISSUED 3-3-94

STANDARD RATE SCHEDULE GS-1 — STATE OF OKLAHOMA

GENERAL SERVICE RATE — Code No. 06

Continued

MINIMUM BILL: The minimum monthly bill shall be the Customer Charge. The Company shall specify a larger minimum monthly bill, calculated in accordance with the Company's Allowable Expenditure Formula in its Terms and Conditions of Service on file with and approved by the Commission, when necessary to justify the investment required to provide service.

FRANCHISE PAYMENT: The above stated rates do not include any amount for franchise payments levied upon the Company by a municipality.

When a municipality, by a franchise or other ordinance approved by the qualified electors of the municipality, levies or imposes upon the Company franchise payments or fees (based upon a percent of gross revenues) to be paid by the Company to the municipality, such franchise payment will be added as a percentage of charges for electric service to the bills of all customers receiving service from the Company within the corporate limits of the municipality exacting said payment.

ANNUAL PUBLIC UTILITY ASSESSMENT FEE: See Rider for Annual Public Utility Assessment Fee - APUAF.

FUEL COST ADJUSTMENT: See Rider for Fuel Cost Adjustment - FCA.

TERM: The Company, at its option, may require a written contract for a year or longer, subject also to special minimum guarantees, which may be necessary in cases warranted by special circumstances or unusually large investments by the company. Such special minimum guarantees shall be calculated in accordance with the Company's Allowable Expenditure Formula in its Terms and Conditions of Service filed with and approved by the Commission.

Customers who request to the changed to the General Service Rate from another rate will remain on the General Service Rate or the General Service Time-of-Use Rate for one year before being permitted to change rates again unless they demonstrate a permanent change in electric consumption.

Effective 3 March 1994

Rates Authorized
by 380443 PUD 001055 25 February 1994
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Issued by [signature] Chairman of the Board and President
(Name of Officer) (Title)

APPROVED
MAR 03 1994
DIRECTOR OF PUBLIC UTILITIES

APPENDIX D

PRODUCTS LITERATURE

PV MODULE

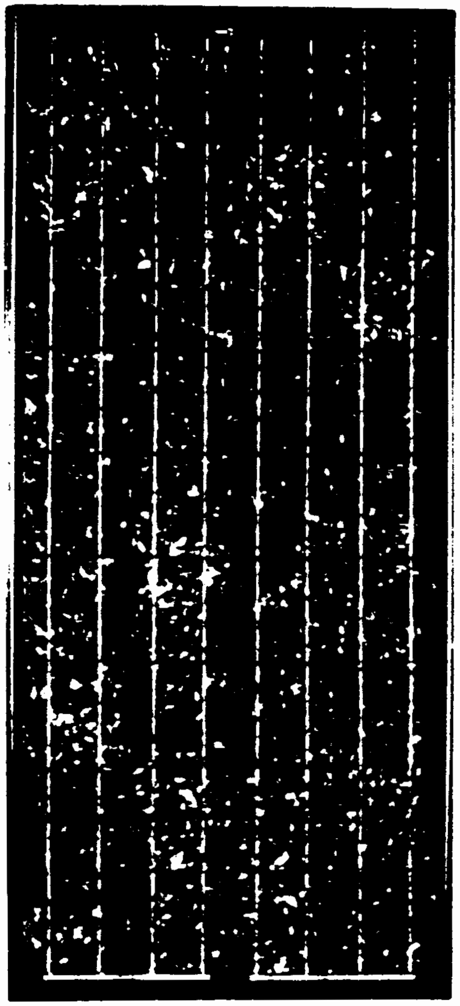
Module Warranty*

All of the high power modules in Solar Electric Specialties' P Series are covered by our industry-leading ten-year limited warranty. This warranty guarantees:

- that no module will generate less than its guaranteed minimum power when purchased
- continued power (at least 90% of guranteed minimum) for ten years

Details are available from your SES representative or any SES sales office.

Module Features and Characteristics



Highest power standard size module commercially available

Large area (11.4cm x 11.4cm) MSX semi-crystalline cells coated with patented titanium dioxide anti-reflective material

Dual voltage capability (12 or 6 volt nominal output)

Large, versatile, easy to use, weatherproof junction box located at one end of the module for all connections

Rugged and weatherproof: cells laminated between ethylene vinyl acetate and tempered glass, with a tough Tedlar® backsheet

Self-cleaning, impact resistant tempered glass superstrate

Strong, rugged frame of corrosion-resistant, bronze-anodized aluminum: compatible with SES and a wide variety of other mounting structures

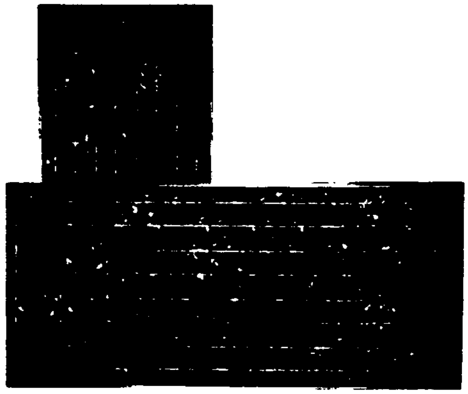
Meet or exceed all Jet Propulsion Laboratory Block V test criteria including temperature cycling, relative humidity, wind loading and hailstone impact

Safety approved by Factory Mutual Research for use in NEC Class 1, Division 2, Group D hazardous locations

10 year limited warranty on power output*

SES SOLAR ELECTRIC SPECIALTIES CO.
P.O. Box 537 Willits, CA 95490
(707) 459-9496 FAX: (707) 459-5132

HIGH-POWER MODULES



TYPICAL APPLICATIONS:
Telecommunications, water pumping, residential, cathodic protection, utility, navigation, lighting

SES-P40 Power Specifications*		Physical Description	
Typical Peak Power**	40 watts	Length	30.1 inches / 765 mm
Voltage at Peak Power	17.1 volts	Width	19.8 inches / 502 mm
Current at Peak Power	2.34 amps	Depth	2.0 inches / 50 mm
Short-Circuit Current (Isc)	2.53 amps	Weight	11.8 pounds / 5.4 kg
Open-Circuit Voltage (Voc)	21.1 volts		
SES-P60 Power Specifications*		**Physical Description**	
Typical Peak Power**	60 watts	Length	43.8 inches / 1113 mm
Voltage at Peak Power	17.1 volts	Width	19.8 inches / 502 mm
Current at Peak Power	3.50 amps	Depth	2.0 inches / 50 mm
Short-Circuit Current (Isc)	3.80 amps	Weight	15.9 pounds / 7.2 kg
Open-Circuit Voltage (Voc)	21.1 volts		
SES-P64 Power Specifications*		**Physical Description**	
Typical Peak Power**	64 watts	Length	43.8 inches / 1113 mm
Voltage at Peak Power	17.5 volts	Width	19.8 inches / 502 mm
Current at Peak Power	3.66 amps	Depth	2.0 inches / 50 mm
Short-Circuit Current (Isc)	4.00 amps	Weight	15.9 pounds / 7.2 kg
Open-Circuit Voltage (Voc)	21.3 volts		
SES-P77 Power Specifications*		**Physical Description**	
Typical Peak Power**	77 watts	Length	43.6 inches / 1108 mm
Voltage at Peak Power	16.9 volts	Width	26.0 inches / 660 mm
Current at Peak Power	4.56 amps	Depth	2.0 inches / 50 mm
Short-Circuit Current (Isc)	5.00 amps	Weight	20.9 pounds /9.5 kg
Open-Circuit Voltage (Voc)	21.0 volts		
SES-P83 Power Specifications*		**Physical Description**	
Typical Peak Power**	83 watts	Length	43.6 inches / 1108 mm
Voltage at Peak Power	17.1 volts	Width	26.0 inches / 660 mm
Current at Peak Power	4.85 amps	Depth	2.0 inches / 50 mm
Short-Circuit Current (Isc)	5.27 amps	Weight	20.9 pounds / 9.5 kg
Open-Circuit Voltage (Voc)	21.2 volts		

OPTIONS (SES-P40, -P60, -P64, -P77, -P83)
- SES charge controller
- Mounting support structures
- Module interconnection wiring
- 6-volt output
- Blocking and/or bypass diodes
- Protective aluminum backplate
- Marine environment junction box

* Power specifications are for standard 12-volt shipping configurations.

** Peak power is defined as the maximum amount of power available from the module under Standard Test Conditions (STC) which are:
- Illumination of 1 kW/meter^2 (1 sun) at spectral distribution of AM 1.5; - Cell temperature of 25°C.

SOLAR ELECTRIC SPECIALTIES CO.
A DIVISION OF E. A. PADULA LUMBER CO. INC.
P O BOX 537 WILLITS, CA 95490 707 459-9496 1 800-344-2003
FAX 707 459-5132 TELEX 5106012219 SES WLLT UO

SES P-SERIES

POLY-CRYSTALLINE PHOTOVOLTAIC MODULES

Authorized Wholesale Price List

Effective 07/01/93

Large High Power Photovoltaic Modules							
Stock Number	Model Number	Description Output	Watts Rated	Wholesale Price			Suggested List
					1 to 11	12 +	
M-2012	SES-P83	17.1V, 4.85A	83		$498	$467	$830
M-2011	SES-P77	16.9V, 4.56A	77		$462	$434	$770
M-2010	SES-P64	17.5V, 3.75A	64		$384	$359	$640
M-2009	SES-P60	17.1V, 3.50A	60		$359	$339	$598
M-2006	SES-P40	17.2V, 2.34A	40		$276	$239	$460
Mid-Range Power Photovoltaic Modules				1 to 4	5 to 23	24 +	
M-2005	SES-P30	17.8V, 1.68A	30	$244	$221	$210	$406
M-2004	SES-P18	17.8V, 1.06A	18.5	$197	$178	$169	$328
M-2003	SES-P10	17.5V, .57A	10	$114	$103	$97	$190
M-2001	SES-P5	16.8V, .27A	4.5	$86	$80	$76	$143
Light (Marine) Photovoltaic Modules				1 to 4	5 to 23	24 +	
M-2028	SM-30	17.8V, 1.68A	30	$244	$221	$210	$406
M-2027	SM-18	17.5V, 1.06A	18.5	$197	$178	$169	$328
M-2026	SM-10	17.5V, .57A	10	$114	$103	$97	$190
M-2025	SM-5	17.5V, .26A	4.5	$86	$80	$76	$143
Low Power Photovoltaic Modules				Wholesale			List
Amorphous Silicon					1 to 10	11 to 49	
M-2037	SA-5	17.5V, .290A	5.3		$60	$56	$99
M-2036	SA-2	7.5V, .290A	2.4		$42	$39	$69
M-2035	SA-1	17.5V, .080A	1.75		$35	$33	$59
M-2034	SA-2/12	15.0V, .145A	2.2		$44	$41	$73
					1 to 11	12 to 49	
M-2045	SA-1	Battery Mate	1.75		$35	$32	$58
M-2044	SA-2/12V	Battery Mate II	2.2		$65	$58	$89
M-2038	MSA-5 /6V	6 Volt	4.5		$75	$69	$125
M-2039	MSA-5 /12V	12 Volt	5.3		$73	$67	$122
M-2041	MSA-5 /24V	24 Volt	4.5		$77	$71	$128

Prices, specifications, terms and conditions are subject to change by SES without notice.

Modules on this page may be mixed to qualify for quantity discounts.

Prices are FOB, Willits, Ca.

Call for quotes on quantities of 50 or more.

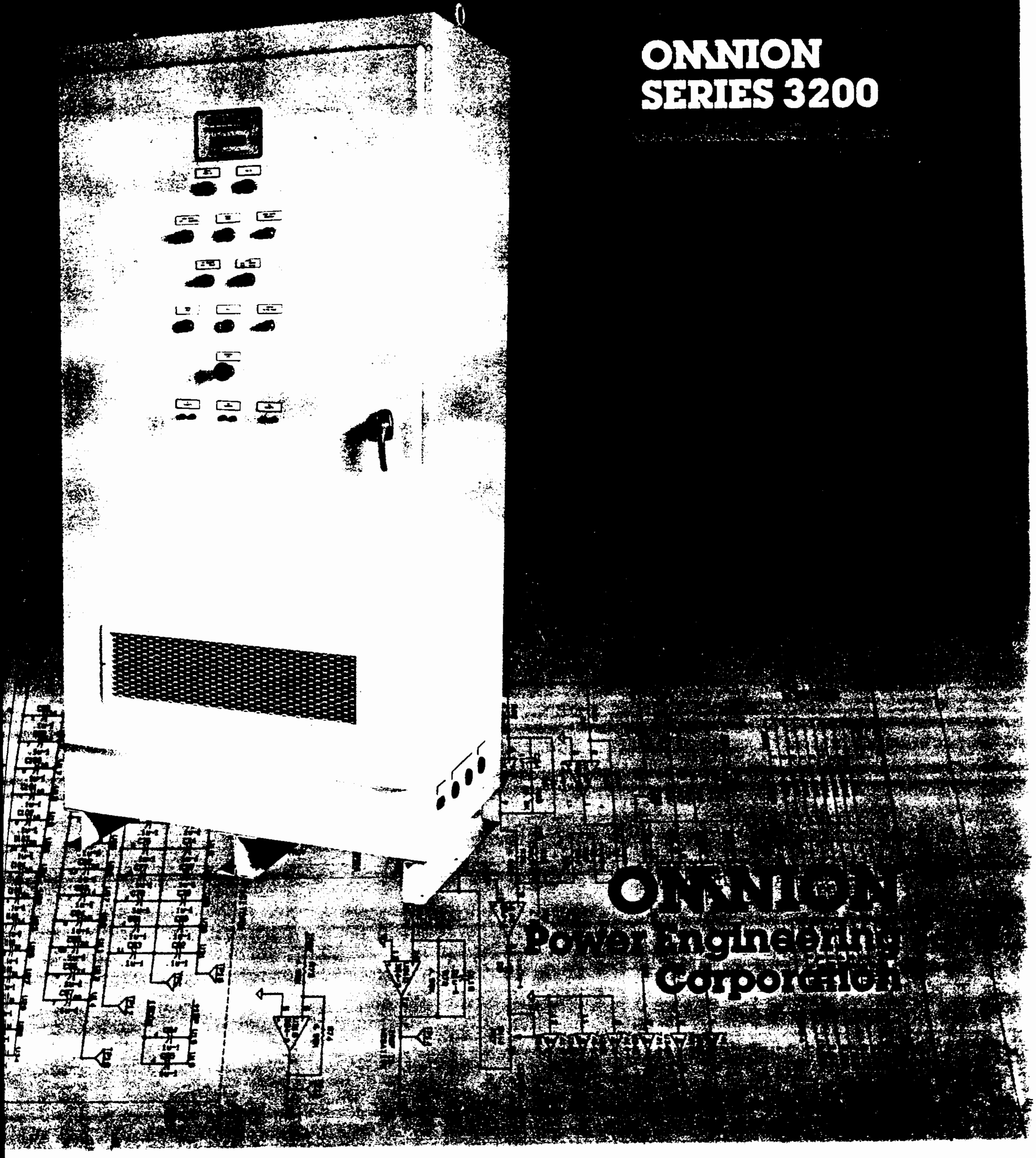
Solarex Dlr

Regional Offices: ☐ 232 Anacapa St., Santa Barbara, CA 93101, (805) 963-9667, Fax (805) 963-9929
☐ P.O. Box 609, Elk Grove, CA 95759, (916) 686-4898, Fax (916) 685-4117

INVERTER/POWER CONVERTER

High Performance
Three Phase
Photovoltaic
Power Conversion

OMNION SERIES 3200



Realize the Full Potential of Your Photovoltaic Array

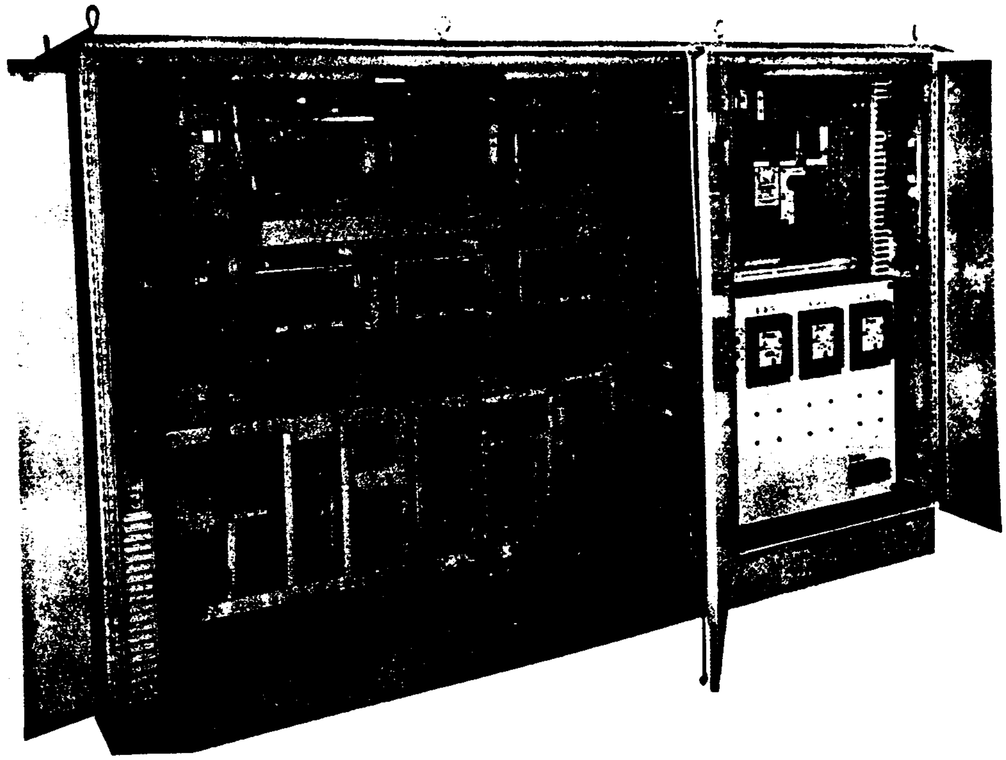
If you've been looking for a three-phase utility-interconnected converter to maximize the output of your photovoltaic array, look no further than the Omnion Series 3200.

Employing the same revolutionary technology introduced in our single-phase Series 2200 converters, the Series 3200 provides you with both high performance and high reliability.

Insulated gate bi-polar transistors (IGBTs), the most advanced high-power switch technology commercially available, and sophisticated microprocessor controls make the Series 3200 the logical solution.

Series 3200 converters are modular in construction. Based on our nominal 50 kilowatt three phase bridge, multiple bridges are paralleled to provide capacities up to 1 megawatt. Multiple 1 megawatt units can, in turn, be paralleled to achieve still higher system capacities.

Modular Capacity To One MW



300 KW Converter for PG&E's Kerman substation project.

High Performance Re-defined

Omnion's Series 3200 power conversion systems have peak efficiencies over 96% for the converter alone and overall efficiencies including transformer losses in excess of 94%.

Total current harmonic distortion, on the other hand, is limited to less than 5% through the use of high-frequency switching techniques unique to Omnion's Series 3200 controls. Single frequency current harmonic distortions are limited to less than 3%.

Power factor for standard units is unity. However, as an option, power factor can be varied automatically or manually to source or sink VARs whenever the array is not using the converter's full capacity. This feature allows the PCS to assist in regulating the AC line voltage, providing yet another benefit to the user and to the interconnecting utility.

Smart Controls

Series 3200 controls are microprocessor-based with sophisticated self-diagnostics. Performance and operating status are continually updated on a liquid crystal display. Gone are the days of guessing what is happening — this equipment tells you.

ONMNION Series 3200

Field Proven Technology

System Protective Features

The Series 3200 power conversion system includes self-protective and self-diagnostic features to safe-guard both the converter and the PV array from damage in the event of component failure or input parameters beyond the safe operating range of the equipment.

The Series 3200 control incorporates over/under voltage detection on all three phases of the utility service. The Series 3200 will shut down within 30 cycles anytime the utility voltage exceeds ± 10% of nominal. Over/under frequency detection will cause the equipment to shut down within 30 cycles anytime the frequency exceeds 61 Hz or falls below 59 Hz.

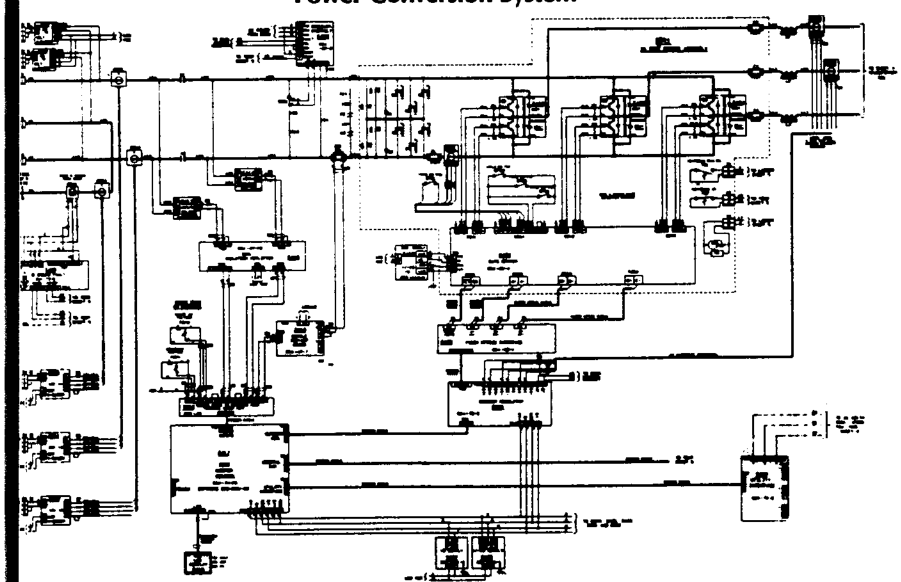
A digital phase-locked-loop (PLL) circuit is implemented in the microprocessor control to prevent "islanding" or self-excitation of the converter in the event of a utility outage. The free-running frequency of the PLL is set at a value below the nominal operating frequency. In the absence of a reset signal from the zero-crossing pulses, the PLL circuit will cause the output frequency of the converter to drop below the nominal frequency at which time an under-frequency condition will be detected and the converter will shut itself down within 5 cycles.

Voltage and frequency tolerances as well as delay periods prior to system shut-down are programmed in software and can be modified within certain limits to accommodate specific utility operating practices.

Additional Features

Omnion offers source circuit combining circuitry, ground fault detection, and AC and DC disconnects as options for use in conjunction with its standard converters. This additional hardware can be supplied in a separate enclosure or incorporated into the converter enclosure. Both indoor and outdoor enclosures are available. Data acquisition sensors and transducers can be provided as well for display and recording system performance. System controls as well as performance monitoring can be configured for both local and remote operation.

20 KW Series 3200
Power Conversion System



Factory Testing

Each Omnion Series 3200 PCS is tested to demonstrate operation of its control systems and its ability to be automatically synchronized and connected in parallel with a utility service prior to shipment.

Operation of all control, protective and instrumentation circuits are demonstrated by direct test if feasible or by simulating operating conditions for parameters that cannot be directly tested.

Testing includes measurements of phase currents, efficiencies, harmonic content and power factor. Tests are performed at 25%, 50%, 75%, and 100% of nominal power output to the fullest extent permitted by Omnion's test facilities.

The Cost-effective Choice

Developed in conjunction with the Department of Energy, Sandia National Laboratores, and leading US utilities, the Series 3200 power conversion technology was designed with cost-effectiveness in mind as well as high performance and high reliability.

Our objective: a converter that can do its part in making photovoltaic power plants cost-competitive with conventional energy sources.

Specifications

OMNION Series 3200

Array (DC) Input

Nominal operating voltage: ± 360 VDC
Minimum operating voltage: ± 320 VDC
Max power tracking window: ± 320-400 VDC
Max open circuit voltage: ± 600 VDC
Operating current: 100 ADC per module
Max ripple voltage: 5% peak-to-peak
Array is center-grounded to utility neutral

Utility (AC) Output

Operating voltage: 480 ± 10% VAC
Operating current: 70 AAC per bridge
Capacity: 50 KW per bridge
Number of phases: Three
Power factor: Unity or controllable
Frequency: 60 Hz ± 1 Hz (50 Hz optional)
Harmonic current distortion: Less than 5% RMS above 5% of rated power

System

Tare losses: Less than 30 watts (exclusive of transformer if used)
Efficiency: 96% peak (exclusive of transformer if used)
Ambient operating temperature: 0-40° C
Humidity: 0-100% non-condensing
Enclosure: Indoor (Outdoor optional)

Fully automatic operation, including:

- Maximum power tracking
- Start-up/shut-down
- Over/Under voltage protection
- Over/Under frequency protection

Display

Two-line, 20-character liquid crystal display (LCD) provides converter operating status, performance and system fault information

For more information, please call or write.

Distributed By:

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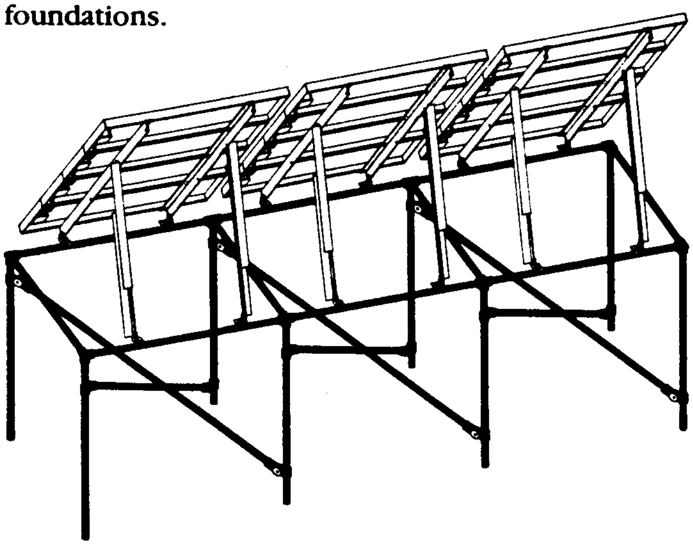
MOUNTING SUPPORT

Solarex IntegraSystem™ Photovoltaic Array Support Systems

SOLAREX
An Amoco Company

This publication describes Solarex's IntegraSystem photovoltaic array support hardware. This hardware is offered in a range of types, capable of mounting arrays as small as one module and as large as several dozen kilowatts to buildings, poles, and ground-based foundations.



IntegraSystem hardware is adaptable, reliable, easy to use, and uses a standardized complement of well-tested components. Its modular design allows it to precisely match your array support requirements and the characteristics of your site. It meets stringent specifications in any of its approved configurations.

Complete Integrated Kits

IntegraSystem hardware kits are complete and fully compatible with Solarex modules, panels and wiring kits. The interfaces between each kit and other array components are clearly identified in this brochure.

A Pre-engineered Support System

IntegraSystem kits are fully documented, easy to assemble, and compatible with other indicated Solarex products. Assembled arrays will withstand winds in excess of 125 mph (200 km/hr).

Engineered for Severe Environments

All kit materials are selected for corrosion resistance in severe climates. The largest mounting kit, the HPF1 rack structure, uses galvanized steel structural members. The structural members of smaller kits are fabricated from corrosion-resistant aluminum alloys and assembled with stainless steel fasteners.

Tested in the Real World

Twenty years of real-world testing and design development means IntegraSystem array hardware performs well anywhere. Solarex' rigorous material specifications ensure consistent quality.

Adjustable for Any Latitude

Integrasystem kits allow arrays to be adjusted to and securely fixed at the optimum tilt angle for sites at any latitude. The tilt angle range (in degrees of variance from horizontal) is shown in the kit specifications which follow.

The IntegraSystem Concept

The key to the IntegraSystem™ concept is pre-engineering. Every IntegraSystem PV component or subsystem is electrically and mechanically pre-engineered for reliability, compatibility with other IntegraSystem components, ease of installation and compliance with code and safety requirements. This pre-engineering process includes:

- *identifying the subsystem's interfaces with other components and ensuring compatibility;*
- *applying design and selection criteria that assure compliance with NEC requirements and efficient, safe, reliable system operation;*
- *applying economies of scale to the process of system design and component selection and procurement.*

IntegraSystem enables a customer to select PV components with confidence that they will assemble easily into an efficient, reliable, cost-effective power system.

630 Solarex Court, Frederick, Maryland 21701 USA • PHONE (301) 698-4200• FAX (301) 698-4201

GENERAL SPECIFICATIONS

Wind loading	Minimum 125 mph (200 km/hr)
Materials	Hot-dip galvanized Schedule 40 steel pipe
	5052 or 6061 (as appropriate) clear anodized structural aluminum alloy
	Type 316 stainless steel fasteners

SINGLE-MODULE MOUNTING HARDWARE

IntegraSystem kits are available for mounting single modules to cylindrical or square poles or masts and horizontal, vertical or sloping structural surfaces. These kits include all necessary hardware and fasteners with the exception of the fasteners that attach the completed assembly to the mounting surface; fasteners required for this function vary greatly since mounting surfaces vary greatly. The kits include complete installation instructions and recommendations for attachment hardware (e.g., hose clamps, U-bolts, lag screws, etc.) for use on common surfaces.

Universal

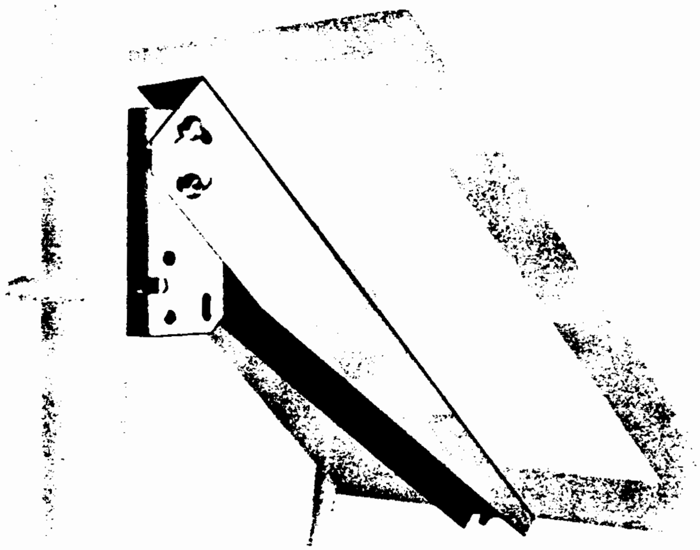
Multimount

Some of Solarex's small PV modules are available with two styles of frame: the "Universal" frame and the Multimount™ frame. Mounting kits for each frame style are available.

Mounting Kits for Small Module with Universal Frame

These kits consist of a mounting bracket, a module bracket and required assembly fasteners. They mount one MSX-10, -18, -30 or -40 with universal frame to a vertical pole (cylindrical or square) or a flat structural surface.

- Continuous adjustment of module tilt angle from 0° to 90°.
- Heavy-duty aluminum alloy brackets with clear anodized finish.
- Fits poles with outside diameter 2-7/8" to 12" using hose clamps, 1" to 4" using U-bolts.

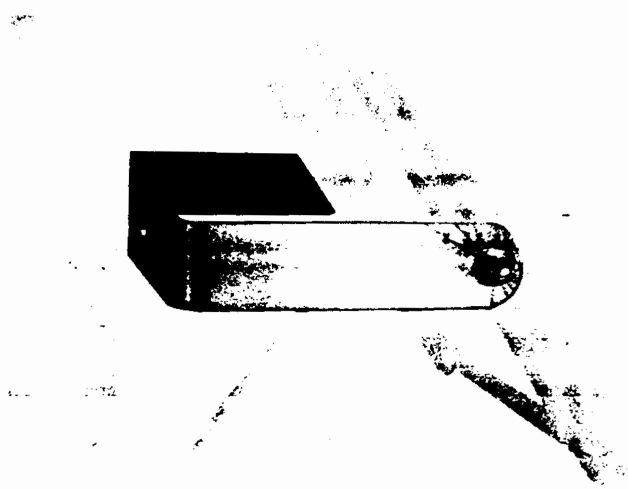


Module	Mounting Kit
MSX-18, -30, and -40	HPM18-30
MSX-10	HPM10U

Mounting Kit for Small Module with Multimount Frame

These kits mount one MSX-5, -10, -18, or -30 with Multimount™ frame to a vertical pole (cylindrical or square) or a flat structural surface.

- Continuous adjustment of module to any desired tilt; tilt angles are imprinted on the bracket.
- Fits poles with outside diameter 1" to 4"

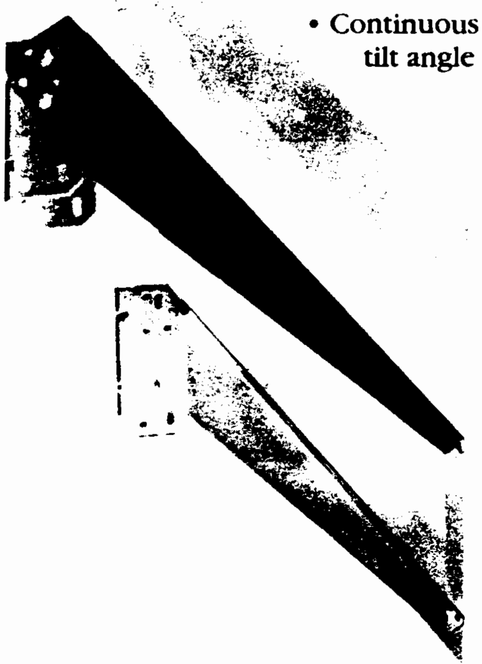


Module	Mounting Kit
MSX-18 and 30	HPM18-30M
MSX-5 and 10	HPM5-10

Large Module Flat-surface Mounting Kits

These kits attach a single large module to a horizontal, vertical, or sloping flat surface. Each kit consists of two heavy-duty type aluminum alloy brackets, two aluminum alloy angle brackets, and assembly fasteners.

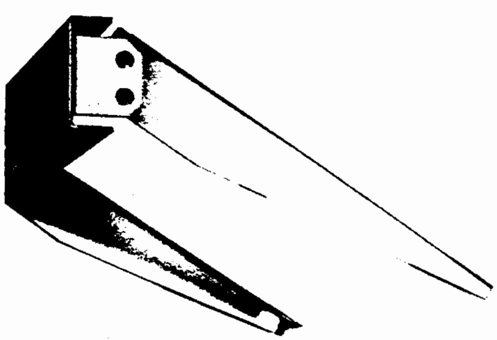
- Continuous adjustment of tilt angle from 0° to 90°



Module	Mounting Kit
MSX-50, -53, -56, -60, and -64	HFMH60
MSX-77, -83	HFMH80

Mounting Kits for Large Module with Long Axis Horizontal

These kits consist of a crossarm bracket, two feet, two angle brackets, and required fasteners. They mount a single large Solarex module to a vertical pole or other flat vertical, horizontal or sloping surface, supporting the module with its long axis horizontal.



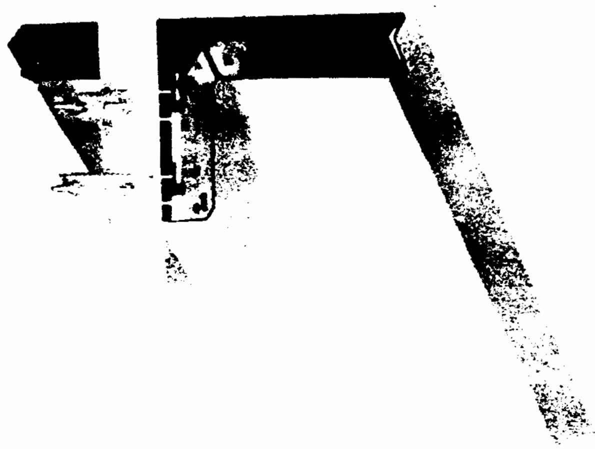
- Continuous adjustment of tilt angle from 0° to 90°
- Fits poles with outside diameter 2" to 12-3/4"

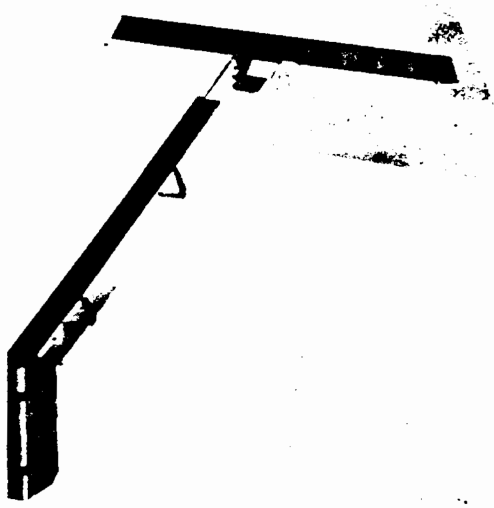
Module	Mounting Kit
MSX-50, -53, -56, -60, and -64	HPMH53-60
MSX-77, -83	HPMH80

Mounting Kit for Large Module with Long Axis Vertical, Item HPMV53-60

This kit consists of six brackets, a two-section adjustable leg assembly, and assembly fasteners. It mounts a single large Solarex module to a vertical pole or other flat vertical surface, supporting the module with its long axis vertical.

- Applicability: Single MSX-50, -53, -56, -60 or -64 module
- Incremental adjustment of tilt angle from 15° to 70°.
- Fits poles with outside diameter 1" to 4"

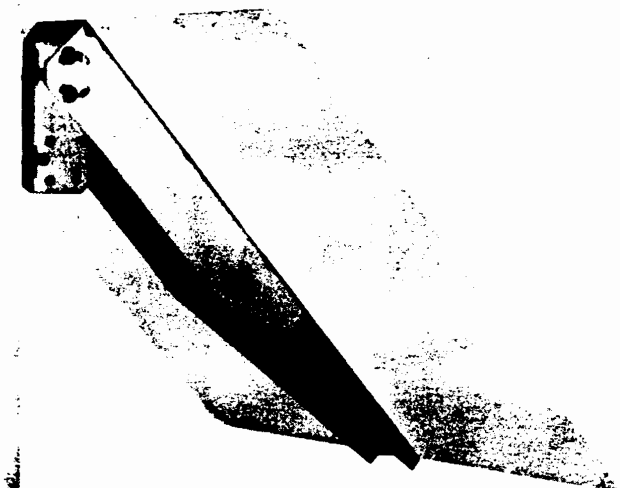




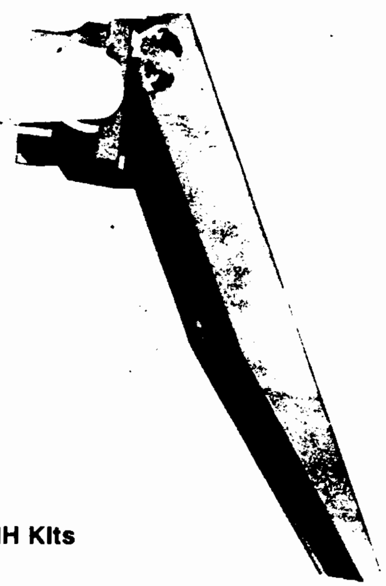
Mounting Kit for Marine Modules

These kits consist of two brackets and assembly hardware, and mount an MSX-20MM or -38 MM to a vertical or horizontal beam or a flat structural surface.

- Continuous adjustment of tilt angle from 0° to 90°.
- Fits poles with outside diameter 1" to 2-1/2"



HPMV Kits



HPMH Kits

Module	Mounting Kit	
	Vertical Beam	Horizontal Beam
MSX-20MM	HPMV20MM	HPMH20MM
MSX-38MM	HPMV38MM	HPMH38MM

MOUNTING HARDWARE FOR MULTIPLE-MODULE ARRAYS

The IntegraSystem modular approach to mounting a multiple-module array considers the support system as three subassemblies, which are described in the remainder of this brochure. When ordering IntegraSystem hardware for a site, ensure that *all three hardware categories* are considered in your design.

Panel assembly kits which combine modules into panels ranging in size from 1 module (a 1X panel) to 6 modules (a 6X panel).

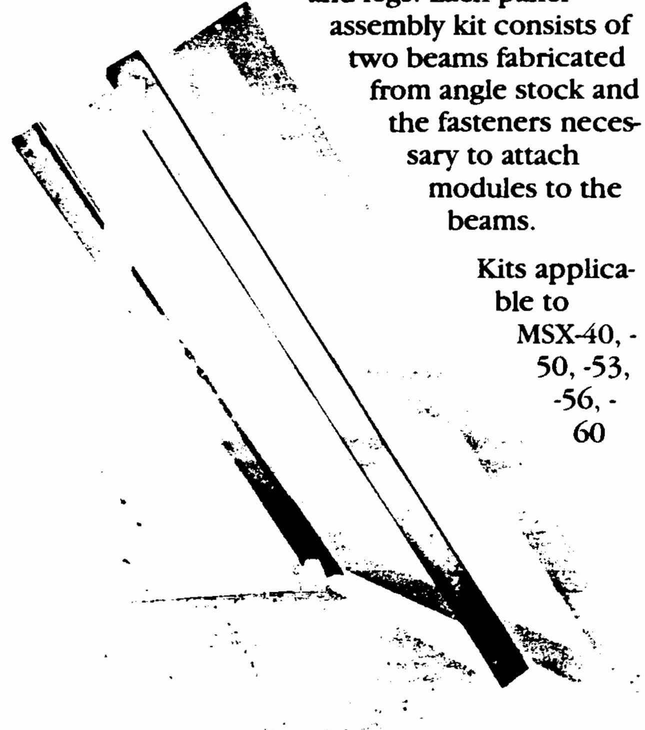
Leg kits which hold panels at the appropriate tilt angle

Site structural interface. This must accept the mounting feet of the leg kits and be able to withstand mechanical loading transferred by the array. It may be provided by Solarex or the Customer. Typical Customer-furnished interfaces include poured concrete pads, roof-mounted external beams, and horizontal or vertical poles.

Panel Assembly Kits, Items HPK

IntegraSystem panel assembly kits assemble multiple modules into panels, using longitudinal beams which mechanically integrate the modules, add rigidity to the panel, and accept mounting feet and legs. Each panel assembly kit consists of two beams fabricated from angle stock and the fasteners necessary to attach modules to the beams.

Kits applicable to MSX-40, -50, -53, -56, -60



HPK Kits

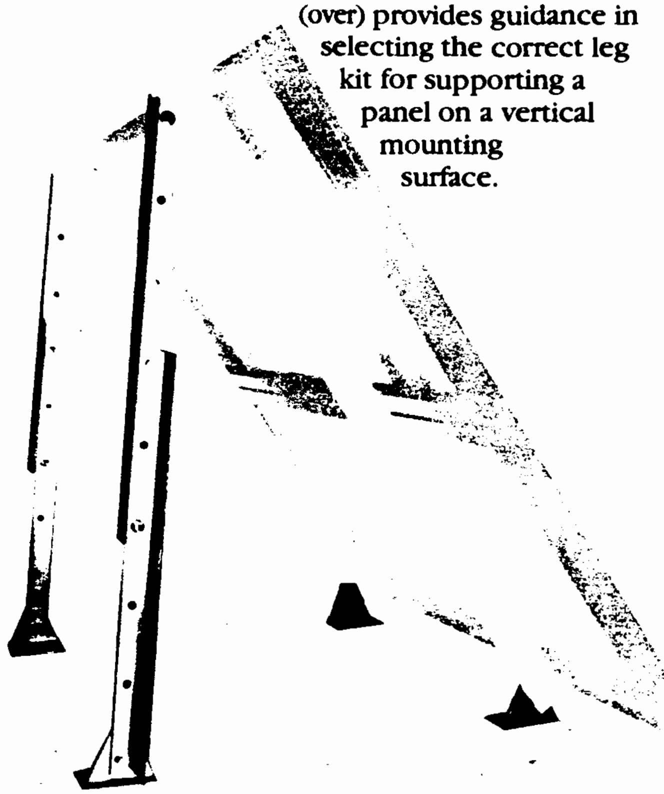
and -64 modules are identified by item numbers ranging from HPK2X (for a 2-module panel) through HPK6X (for a 6-module panel). The item numbers of most kits for MSX-77, -83, and -120 modules include a module designator suffix, as shown in Table 1.

Table 1
HPK Panel Assembly Kits for MSX-77, -83 and -120 Modules

Panel Configuration	HPK Item Number
2 MSX-77 or -83 modules	HPK2X-80
4 MSX-77 or -83 modules	HPK4X-80
1 MSX-120 module	HPK1X-120
2 MSX-120 modules	HPK4X
3 MSX-120 modules	HPK3X-120

Adjustable Leg kits, Items HAFMS

Each leg kit consists of two adjustable two-section legs (adjustable in 4-inch increments), four "feet", and required assembly hardware. The kits securely support a panel at the desired tilt angle on horizontal, vertical and sloping surfaces. Table 2 provides guidance in selecting the correct leg kit for supporting a panel on a Customer-supplied horizontal foundation or mounting surface. Table 3 (over) provides guidance in selecting the correct leg kit for supporting a panel on a vertical mounting surface.



HAFMS Kits

Note that these kits do not include hardware for attaching the feet to the supporting surface.

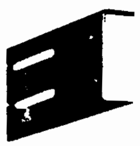
Table 2
Selecting HAFMS Leg Kits for Mounting Panels on Horizontal Surfaces

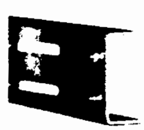
Panel Configuration	Leg Kit	Tilt Range
2 or 3 MSX-40, -50, -60 (series) modules	HAFMS12	12° to 30°
2 MSX-77 or -83 modules	HAFMS20	24° to 63°
1 MSX-120 module	HAFMS28	35° to 88°
4 MSX-40, -50, -60 (series) modules 2 MSX-120 modules	HAFMS12	10° to 22°
	HAFMS20	19° to 42°
	HAFMS28	28° to 68°
	HAFMS36	36° to 89°
5 or 6 MSX-40, -50, -60 (series) modules 4 MSX-77 or -83 modules 3 MSX-120 modules	HAFMS12	7° to 14°
	HAFMS20	8° to 26°
	HAFMS28	10° to 38°
	HAFMS36	19° to 50°
	HAFMS36 plus 36" extension	43° to 77°

Panel pole mounting kit, Item HPMA

A panel pole mounting kit consists of two crossarm brackets which, in conjunction with the appropriate leg kit and panel kits, support a panel on a vertical pole or flat vertical surface. This kit does not include hardware for attaching the brackets to the supporting surface, since surfaces and appropriate fasteners vary widely.

- Supports panels of two, three or four MSX-50, -53, -56, -60 or -64 modules; two MSX-77 or -83 modules; or one MSX-120 module.





- Incremental adjustment of tilt angle is provided by the separately ordered HAFMS leg kit. Table 3 provides guidance in selecting the leg kit needed for various angles.
- Fits poles with outside diameter 2" to 12-3/4"

Array Support Rack Structure, Items HPF1

The IntegraSystem rack structure is a modular galvanized steel rack which provides a stable elevated base for a PV array. Used in conjunction with the appropriate HAFMS leg kit, it supports panels at any desired tilt angle. The starting point for any rack structure is the HPF101, a single-bay rack which supports one panel consisting of one or more modules. The rack is expanded by adding HPF1E1 extension bays, each of which support an additional panel.

Solarex recommends that each rack structure not be extended beyond a total of ten bays. If the array is larger than ten bays, it should be divided into two subarrays.

- Includes precut Schedule 40 galvanized steel pipe and all required fittings.
- Fittings assemble to pipe with socket-head Allen (hex) screws. Allen wrench is included.
- See Table 4 for guidance in selecting correct HAFMS leg kit.
- Optional HSK support kit available for mounting equipment on rack uprights

Table 3
Selecting HAFMS Leg Kits for Mounting Panels on Vertical Surfaces

Panel Configuration	Leg Kit	Tilt Range
2 or 3 MSX-40, -50, -60 (series) modules 2 MSX-77 or -83 modules 1 MSX-120 module	HAFMS28 HAFMS20 HAFMS12	10° to 55° 25° to 65° 60° to 75°
4 MSX-40, -50, -60 (series) modules 2 MSX-120 modules	HAFMS36 HAFMS28 HAFMS20 HAFMS12	10° to 55° 25° to 65° 50° to 75° 75° to 80°

Array Support Rack Structure

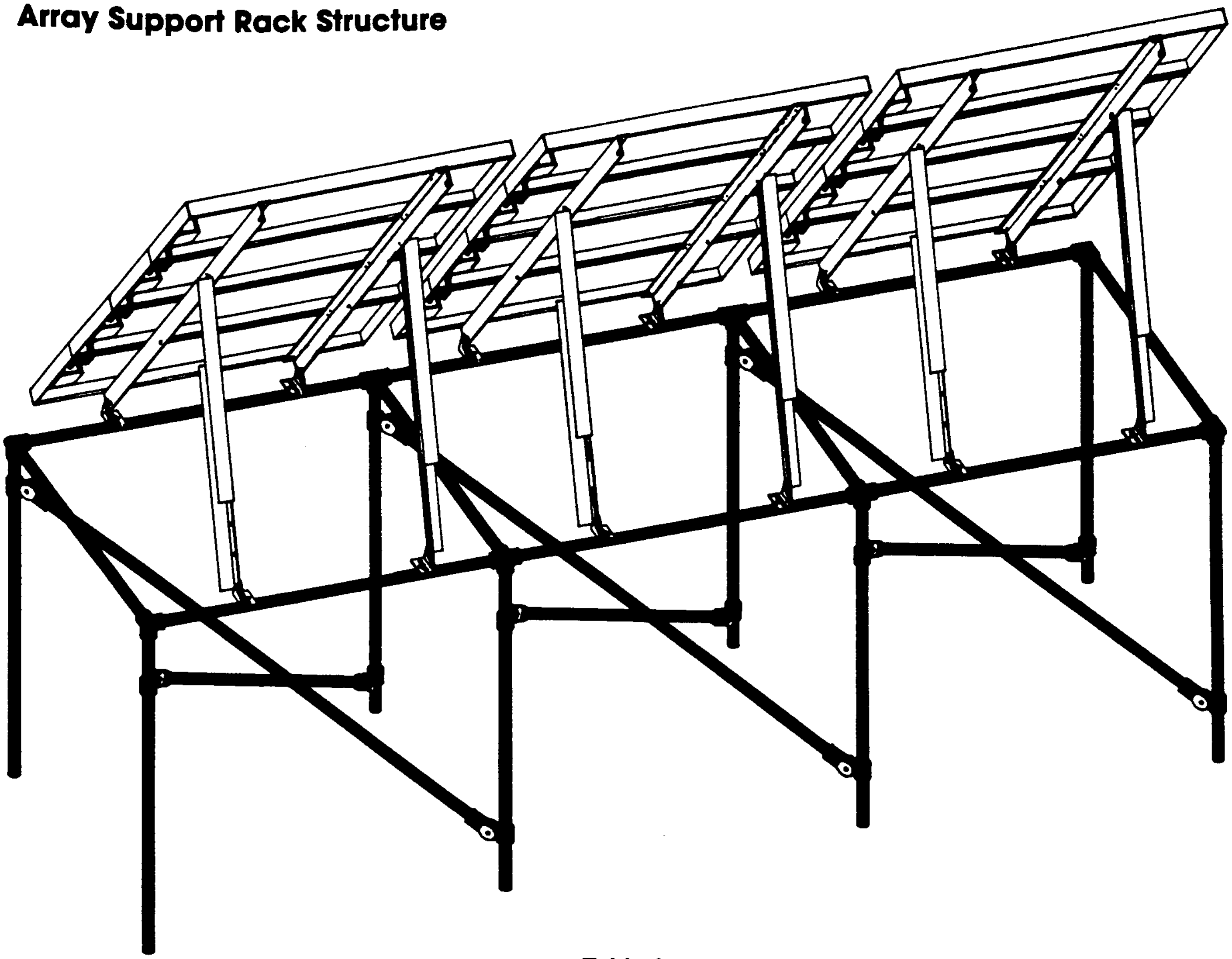
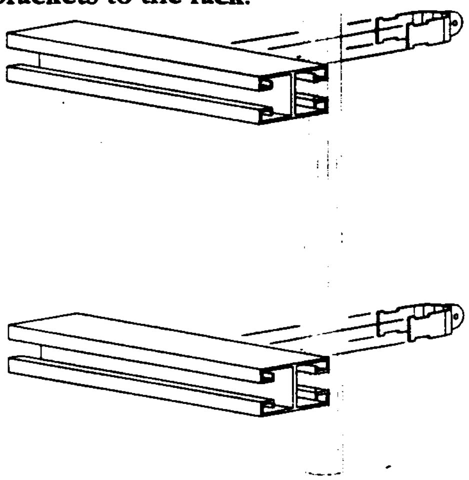


Table 4
Selecting HAFMS Leg Kits for Mounting Panels on Rack

Panel Configuration	Leg Kit	Tilt Range
3 MSX-40, -50, -60 (series) modules	HAFMS12	14° to 22°
2 MSX-77 or -83 modules	HAFMS20	22° to 38°
1 MSX-120 module	HAFMS28	30° to 54°
	HAFMS12	15° to 23°
4 MSX-40, -50, -60 (series) modules	HAFMS20	23° to 40°
2 MSX-120 modules	HAFMS28	32° to 57°
	HAFMS36	40° to 76°
5 or 6 MSX-40, -50, -60 (series) modules	HAFMS12	13° to 21°
4 MSX-77 or -83 modules	HAFMS20	21° to 37°
3 MSX-120 modules	HAFMS28	29° to 54°
	HAFMS36	37° to 72°

HSK Enclosure Attachment Kits

HSK attachment kits are designed to support equipment (typically an enclosure containing switchgear or a controller) on a vertical member of the HPF rack base. Each kit consists of two channel brackets, clamps and other hardware to mount the brackets to the rack.



The HSK12 kit includes channel brackets 12" long; the HSK24 kit includes 24" channel brackets.

Selecting a Fixed Tilt Angle

The angle at which an array is tilted affects its ability to collect solar energy. Some arrays are continuously or periodically adjusted to account for the sun's daily or seasonal movement, but at remote sites it is usually more cost-effective for the array to be installed at a fixed angle. This angle varies with site latitude, load characteristics and other factors, and must be known to enable ordering some of the support hardware in this publication.

Accurate design of a PV power system is a complex process, requiring a computer simulation of the on-site interaction between the load and the power system. The optimum array tilt angle is one product of this process, which can be performed by Solarex representatives.

Table 5 provides approximate tilt angle recommendations, by site latitude, for typical installations. These recommendations are based on certain assumptions, most importantly that the electrical load on the system is the same every day of the year. This table is not intended to replace a comprehensive system design process.

Tilt angle is not critical: variations of up to 5° usually make little difference in an array's ability to support a given load.

If modules are not cleaned regularly, it is recommended that they not be mounted at an angle flatter than 15°. Flatter angles cannot take full advantage of the cleansing action of rainfall.

Table 5
Approximate Array Tilt for Loads with Consistent Daily Energy Requirements

Latitude of Site	Recommended Tilt Angle
0-4°	10°
5-20°	Add 5° to local latitude
21-45°	Add 10° to local latitude
46-65°	Add 15° to local latitude
66-75°	80°

For more information, contact:

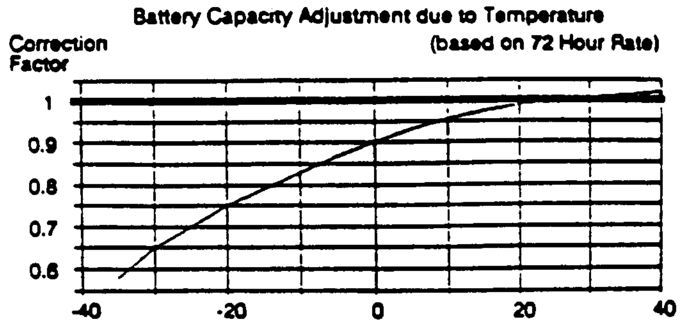
BATTERY SIZING WORKSHEET

BATTERY SIZING WORKSHEET

BATTERY BANK SIZING

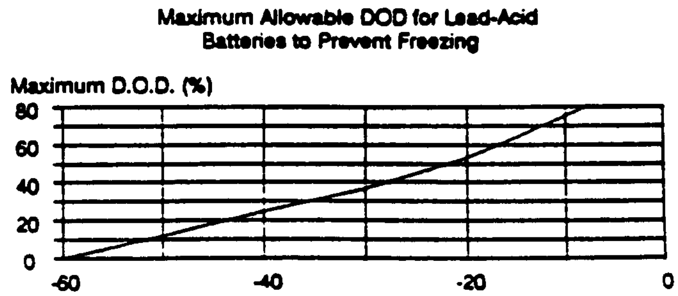
1. Accounting for low temperature:

Coldest 24-hour temperature = ________ deg. C.



Capacity Correction Factor = ______

Maximum Allowable Depth of Discharge to prevent freezing (use only if coldest 24-hour temperataure is LESS than -8 deg.C.) = ______



Manufacturer's Recommended Maximum Allowable Depth of Discharge (from literature, usually 0.8) = ______

Maximum D.O.D. (choose smallest of above two values) = ______

2. Capacity for Autonomy

Number of Days Autonomy desired = ______ days

Required Battery Capacity = $\dfrac{\text{\#Days Autonomy X Total Avg. Daily Load (Ah/day)}}{\text{Maximum D.O.D. X Capacity Correction Factor}}$

= $\dfrac{(\quad\quad) \text{ X } (\quad\quad)}{(\quad\quad) \text{ X } (\quad\quad)}$ = ☐

3. Average rate of discharge

Time for Total Discharge at room temperature = $\dfrac{\text{\# Days Autonomy X 24 hours}}{\text{Maximum D.O.D. X Capacity Correction Factor}}$

= $\dfrac{(\quad\quad) \text{ X 24}}{(\quad\quad) \text{ X } (\quad\quad)}$ = hours

4. Parallel Batteries

Individual Battery Capacity = __________ Ah Name: ______________________________

NBp = $\dfrac{\text{Required Battery Capacity}}{\text{Individual Capacity}}$ = $\dfrac{(\quad\quad)}{(\quad\quad)}$ = ( ) rounded to ☐

5. Series Batteries

NBs = $\dfrac{\text{nominal system voltage}}{\text{nominal battery voltage}}$ = $\dfrac{(\quad\quad)}{(\quad\quad)}$ = ☐

6. Total Batteries

Total Batteries = NBs X NBp = ( ) X ( ) = ☐