5105-21
Solar Thermal Power Systems Project
Parabolic Dish Power Systems
Applications Development

Economic Cost Goals for Parabolic Dish Systems: Electric Applications

Hamid Habib-agahi

March 1980

Prepared for
U.S. Department of Energy
Through an agreement with
National Aeronautics and Space Administration
by
Jet Propulsion Laboratory
California Institute of Technology
Pasadena, California

5105-21
Solar Thermal Power Systems Project
Parabolic Dish Power Systems
Applications Development

Economic Cost Goals for Parabolic Dish Systems: Electric Applications

Hamid Habib-agahi

March 1980

Prepared for
U.S. Department of Energy
Through an agreement with
National Aeronautics and Space Administration
by
Jet Propulsion Laboratory
California Institute of Technology
Pasadena, California

Prepared by the Jet Propulsion Laboratory, California Institute of Technology, for the U.S. Department of Energy by agreement with the National Aeronautics and Space Administration.

The JPL Solar Thermal Power Systems Project is sponsored by the U.S. Department of Energy and forms a part of the Solar Thermal Program to develop low-cost solar thermal and electric power plants.

FOREWORD

This paper determines the cost of energy produced by new power plants for different regions in the United States, for different sizes of coal plants and an 8 MW oil-fired diesel. It also estimates the cost of energy produced by parabolic dish electric power plants for first and second generation system technology. Comparing the levelized busbar energy cost of solar thermal with those of conventional power systems for the next 20 years, the production level necessary for solar thermal energy systems to compete with various forms of conventional energy was determined. As expected in this analysis, there are many uncertainties in estimating the cost of solar and conventional energy. In future work, the study should focus on regionalizing the solar thermal analysis and looking more closely at probabilistic cost ranges. No doubt the assessment of market potential for solar thermal systems and the impact of expected demand upon estimated supply is needed in order to arrive at more realistic cost goals. Also, the $\overline{\text{BBEC}}$ is an aggregate measure of the cost, thus a different methodology which could incorporate fuel displacement as well as capacity credits and social variables should be considered.

Despite these uncertainties, the initial results look promising for the development of solar thermal power systems for isolated regions in the near future and for grid connected utilities in regions with relatively high levels of insolation in the mid 1990s.

ACKNOWLEDGEMENT

I would like to take this opportunity to express my sincere thanks and appreciation to those who, at one time or another, contributed greatly to the development of this paper, especially Steven A. Bluhm, Sue C. Jones, and Thomas J. Kuehn for their great cooperation in the technical editing and production phases of this report. I would also like to thank E. S. Ab Davis, Katsuaki Terawawa and Vencent C. Truscello for their valuable review of this document. Finally, I am very grateful to Arlene M. Calvert and Jeanne Wadsworth who had the patience to prepare and type several versions of this report.

TABLE OF CONTENTS

TABLES

SECTION 1

INTRODUCTION

The aim of the Economic Cost Goals Analysis is to identify realistic cost goals for Point Focusing Distributed Receiver systems through a two-phase study. These goals will be stated in terms of mills/kWeh, in a particular region of the United States, in a given year at a production volume supported by market forces, and for a level of system performance commensurate with the degree of technological development.

This report is basically on Phase I. Preliminary cost goals have been determined for regions of the U.S. in given years, at selected levels of annual production, and for first and second generation parabolic dish technology. Phase II will match production volume to market demand and will refine technological assumptions, specifically those used in Phase I relating to parabolic dish system performance and efficiency.

The summary of the Phase I results and approach follows:

Estimates of the marginal cost of energy produced by new power plants, levelized busbar energy cost ($\overline{\text{BBEC}}$), for thirteen different regions in the United States, for three different sizes of coal plants (1000, 500, and 280 MW), and an 8 MW oil-fired diesel plant were obtained for both cooperative and municipal utilities. This analysis addressed conventional plant sizes far larger than those currently planned for parabolic dish system utilization. This was done to obtain an estimate of the cost of purchased power which may be available to small community utilities, in the case of the 1000 and 500 MW plants, and to estimate the cost of electricity from a joint venture with other small utilities in the case of the 280 MW plant. The results indicate that, as expected, as the size of the conventional power plant increases, the $\overline{\text{BBEC}}$ decreases. The small oil plants were costly enough to make solar thermal systems attractive within the next 5 to 10 years. The levelized busbar energy costs of the coal plants were bounded on the high side by a 280 MW plant in the West South Central Region II (Texas, Arkansas, and Louisiana), and on the low side by a 1000 MW plant in the West North Central Region (Kansas, Nebraska, N. Dakota, S. Dakota, Minnesota, Iowa, and Missouri).

Using the cost estimates for the General Electric low cost concentrator (Reference 5) and for a receiver and Brayton engine, all as illustrated in Section 3, and running SES II computer simulation program (Reference 9), the $\overline{\text{BBEC}}$ for both first and second generation system technology were developed.

Comparing the levelized busbar energy cost of dish electric power plants with those of conventional power plants for the next 20 years, the production level necessary for solar thermal energy systems to compete with various forms of conventional energy was determined. The preliminary analysis indicates:

* First Generation market: 1985-1990
    - Engine/generator efficiency of 25%
    - Compete with small oil-fired power plants especially in isolated regions
    - $\overline{\text{BBEC}}$ of 125-300 mills/kweh for parabolic dish systems
    - Annual production of 25,000 units in 1990 required in order to have a reasonable expectation of displacing 0.1 quad of energy by year 2000

* Second generation technology: 1990-1995
  - o Engine/generator efficiency of 40%
  - o Compete with intermediate size utility and industrial applications
  - o Annual production of 63,000 units in 1995
  - o Improved technology drops $\overline{\text{BBEC}}$ under 100 mills/kWeh for parabolic dish systems in regions with high insolation
* Maturing second generation technology: 1995-2000
  - o Solar thermal industry has reached high levels of system efficiency and mass production
  - o Competitive with all types of conventional energy sources and applications in regions with relatively high levels of insolation

Fuel price projections and other economic assumptions were based on Data Resources, Incorporated, "Energy Review," Summer 1979, with the exception of isolated (island) fuel prices. These were obtained from island utility representatives and escalated at rates projected by DRI for the Pacific region (California, Oregon, Washington, Alaska, and Hawaii). Coal plant performance and cost data were provided by the 1978 EPRI, "Technical Assessment Guide" and by Burns & McDonnell. Diesel generator performance and cost data were provided by Burns & McDonnell and from interviews with representatives of island utilities. All costs are in 1980 dollars.

SECTION II

ESTIMATION OF $\overline{\text{BBEC}}$ FOR CONVENTIONAL ELECTRIC POWER PLANTS

Introduction

Estimates were made of levelized busbar energy costs ($\overline{\text{BBEC}}$) for electric power plants within the United States at 5 year intervals from 1980 to 2000. The $\overline{\text{BBEC}}$ method was used to allow preliminary cost comparisons between different types of energy technologies. It essentially yields a present value of an annualized measure of total system-resultant costs divided by the constant annual energy output expected from the system*.

Each power plant for which $\overline{\text{BBEC}}$ estimates are made must be identified by 12 variables according to region, size, type of fuel, and ownership category. The thirteen regions within the United States are identified later. Size breakdowns are 1,000, 500, 280 and 8 MW plants. The type of fuel used is coal for the three larger sizes and diesel oil for the 8 MW plant. The plants are assumed to be owned by either a municipality or a rural cooperative. One additional case, defined as an isolated case, was examined for an 8 MW oil fired diesel power plant on the assumption that remote areas, such as islands, might provide early applications for solar thermal power.

Regional Classification

Data for economic variables and power plants were obtained both from Data Resources, Incorporated (DRI) and the Electric Power Research Institute (EPRI). Because DRI data are available in a finer regional breakdown than EPRI, the DRI regional definitions were used. Relevant EPRI regional data

---

* For a detailed explanation, see Reference 6.

(coal plant performance and capital cost) were then applied to the appropriate DRI region. The thirteen DRI regions identified by state are shown in Table 2-1. Table 2-2 defines the relationship between the EPRI regions and the DRI regions. Where DRI regional classification crosses EPRI borders, the EPRI data used was averaged for the relevant regions. Figure 2-1 shows the regional classiciations used.

Variable Definition

The variables required for calculating $\overline{BBEC}$ as described in Reference 6, and adapted for use in this study are defined as follows:

R_{00}	=	annual plant output
R_{01}	=	cost of capital
R_{02}	=	plant operating lifetime
R_{03}	=	annual rate of inflation for the years 1980 to 2000
R_{04}	=	capital escalation rate
R_{05}	=	escalation rate for operation, maintenance & fuel cost
R_{06}	=	year for which the $\overline{BBEC}$ is estimated
R_{07}	=	interest calculation factor over a construction period
R_{08}	=	capital cost
R_{09}	=	operation, maintenance and fuel cost
R_{10}	=	capital recovery factor
R_{11}	=	annual fixed charge rate

The calculations of these variables for 1000, 500, and 280 MW coal fired power plants, and for an 8 MW oil-fired diesel power plant are shown in the Appendix.

A total of 106 hypothetical power plants were thus described by identifying variables according to: 1) location, 2) size, 3) type of fuel,

TABLE 2-1

DRI REGIONAL DIVISION

	Region	States
1.	NEW ENGLAND	MA, ME, VT, RI, NH, CT
2.	MIDDLE ATLANTIC	PA, NJ, NY
3.	SOUTH ATLANTIC	DE, MD, DC, VA, WV, GA, FL, SC, NC
4.	EAST NORTH CENTRAL	OH, WI, IN, MI, IL
5.	WEST NORTH CENTRAL	KS, NE, ND, SD, MN, IA, MO
6.	EAST SOUTH CENTRAL I	KY, TN
7.	EAST SOUTH CENTRAL II	AL, MS
8.	WEST SOUTH CENTRAL I	OK
9.	WEST SOUTH CENTRAL II	TX, AR, LA
10.	MOUNTAIN I	NM
11.	MOUNTAIN II	MT, CO, WY, ID, UT
12.	MOUNTAIN III	NV, AZ
13.	PACIFIC	CA, OR, WA, AK, HI

TABLE 2-2.

CORRESPONDENCE BETWEEN DRI AND EPRI REGIONS

	DRI REGION	EPRI REGION WITHIN WHICH IT FALLS
1.	NEW ENGLAND	Northeast
2.	MIDDLE ATLANTIC	Northeast
3.	SOUTH ATLANTIC	1/2 in Northeast, 1/2 in Southeast
4.	EAST NORTH CENTRAL	East Central
5.	WEST NORTH CENTRAL	West Central
6.	EAST SOUTH CENTRAL I	1/2 in East Central, 1/2 in Southeast
7.	EAST SOUTH CENTRAL II	Southeast
8.	WEST SOUTH CENTRAL I	South Central
9.	WEST SOUTH CENTRAL II	South Central
10.	MOUNTAIN I	West
11.	MOUNTAIN II	West
12.	MOUNTAIN III	West
13.	PACIFIC	West

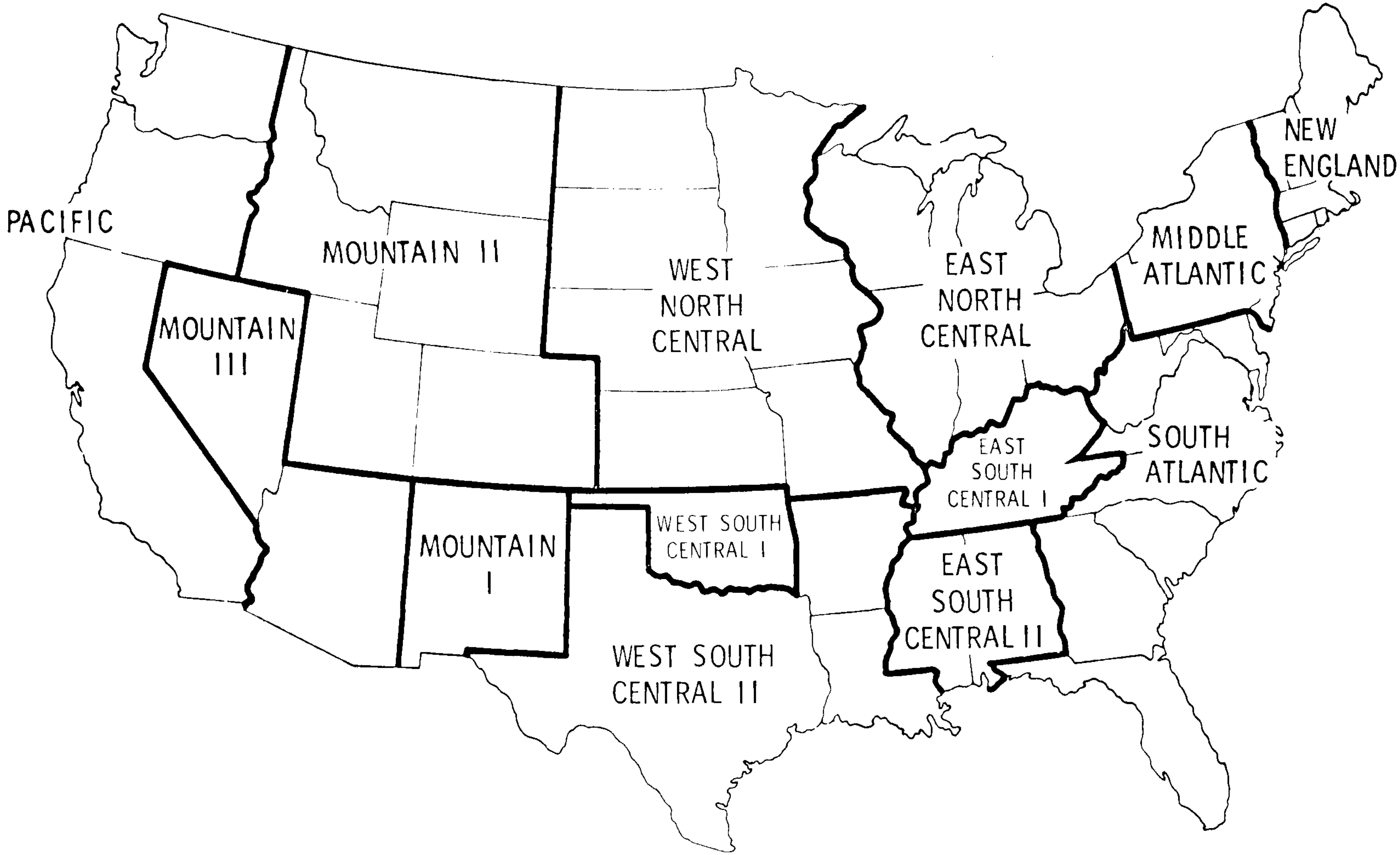

FIGURE 2.1 DRI REGIONAL CLASSIFICATION

and 4) ownership category. The analysis for these conventional power plants indicates that $\overline{\text{BBEC}}$ will vary with each of the four characteristics.

The size of the power plant affected the $\overline{\text{BBEC}}$ as economies of scale, reduced the per unit of output capital cost and operation, and maintenance cost as the plant size increased. Within any given region, the larger the power plant, the less will be the $\overline{\text{BBEC}}$. However, this was true only within regions, as the energy cost of a large plant in one region could be higher than the energy cost of a smaller plant in another region. The economy of scale effect leveled out within the range of the study as the gap between 280 MW coal power plants and 500 MW coal power plants was larger than the gap between $\overline{\text{BBEC}}$ for 500 MW and 1000 MW plants. All 8 MW oil-fired diesel power plants were more costly than the coal power plants investigated.

Regional differences in the $\overline{\text{BBEC}}$ occur due to the regional variations in the price of fuel supplied to the utility, the fixed and variable O&M costs, the heat rates, the capital costs, and the price escalation in the cost of fuel. The thirteen regions have been ranked according to $\overline{\text{BBEC}}$ in 1985, from lowest to highest, within a type of utility. Due to variations in the escalation rate of fuel costs, these rankings change during the time period investigated.

Tables 2-3, 2-4, 2-5, and 2-6 show the results of the $\overline{\text{BBEC}}$ for municipal power plants. The results obtained for cooperatives were so similar to the municipal results that only the municipal results are presented. The $\overline{\text{BBEC}}$ for cooperatives were slightly higher, but followed the same regional patterns as municipals, on a case by case basis. For coal plants in each size category, the West North Central region, composed of Kansas, Nebraska, North Dakota, South Dakota, Minnesota, Iowa, and Missouri, has the lowest $\overline{\text{BBEC}}$, while the highest cost region for 1985 varies between South Atlantic and West

TABLE 2-3

LEVELIZED BUSBAR ENERGY COSTS
MUNICIPAL COAL POWER PLANTS
Size: 1000 MW
Mills/kWh
(in 1980 $)

REGIONS	1985	1990	1995	2000
West North Central	61	69	79	89
Mountain 2	67	81	97	117
Mountain 3	68	81	96	114
Mountain 1	73	91	113	141
East South Central II	74	82	90	100
West South Central I	76	87	100	114
East South Central I	78	88	100	113
Pacific	81	98	118	142
Middle Atlantic	84	95	109	124
New England	88	99	111	125
West South Central II	88	107	131	160
East North Central	89	102	116	132
South Atlantic	92	105	121	140

TABLE 2-4

LEVELIZED BUSBAR ENERGY COSTS
MUNICIPAL COAL POWER PLANTS
Size: 500 MW
Mills/kWh
(in 1980 $)

REGIONS	1985	1990	1995	2000
West North Central	64	72	82	93
Mountain 2	69	83	100	121
Mountain 3	70	84	100	119
Mountain 1	75	93	116	145
East South Central II	76	84	93	103
West South Central I	78	89	102	117
East South Central I	80	91	102	116
Pacific	84	101	121	146
Middle Atlantic	86	98	111	127
New England	90	101	114	128
West South Central II	90	109	133	163
East North Central	91	104	118	136
South Atlantic	93	107	124	143

TABLE 2-5

LEVELIZED BUSBAR ENERGY COSTS
MUNICIPAL COAL POWER PLANTS
Size: 280 MW
Mills/kWh
(in 1980 $)

REGIONS	1985	1990	1995	2000
West North Central	78	88	100	114
East South Central II	83	92	102	114
East South Central I	86	98	111	126
Mountain 3	88	105	125	149
Mountain 2	89	106	128	154
West South Central I	91	104	119	136
Middle Atlantic	96	109	125	143
East North Central	96	110	126	144
Mountain 1	97	121	151	188
New England	100	113	127	143
South Atlantic	102	118	136	157
Pacific	103	124	150	180
West South Central II	105	128	156	190

TABLE 2-6

LEVELIZED BUSBAR ENERGY COSTS
MUNICIPAL OIL POWER PLANTS
Size: 8 MW
Mills/kWh
(in 1980 $)

REGIONS	1985	1990	1995	2000
East South Central II	156	185	218	258
West North Central	158	186	217	255
West South Central II	185	224	272	330
Mountain 2	188	229	279	341
West South Central I	194	236	288	351
New England	196	238	290	354
East South Central I	199	242	295	360
South Atlantic	199	242	295	360
Middle Atlantic	206	250	303	368
Mountain 3	207	252	307	375
Mountain 1	241	293	355	432
Pacific	241	293	355	432
East North Central	241	293	355	432
Catalina Island (Isolated Case)	294	360	442	542

South Central II. By the year 2000, the West South Central II region, Texas, Arkansas, and Louisiana, will be the most costly for all sizes of coal plant. The coal power plant $\overline{\text{BBEC}}$ are bounded on the low side by West North Central, 1000 MW plant, and on the high side by the West South Central II, 280 MW plant.

The 8 MW oil power plants showed fewer regional variations due to the data available to evaluate oil power plants. Regional differences occurred due to the variations in the cost of fuel to the utility and the escalation in the fuel cost. The 8 MW oil plant $\overline{\text{BBEC}}$ can be bounded by lowest cost in the West North Central region and highest cost in the Pacific region. Actually, there were several regions clustered at the high end.

Early applications of solar thermal energy systems are likely to occur in isolated areas, where the current cost of electricity makes alternative energy sources especially attractive. One "typical" isolated case, Catalina Island, was examined. The price of diesel oil at Catalina Island was provided by Southern California Edison in a September 1979 telephone report to JPL as \$28.50/bbl. This is \$4.89/10^6 Btu in 1979 dollars or \$5.28/10^6 Btu in 1980 dollars. All other variables for Catalina Island were held the same as for 8 MW oil power plants in the Pacific region because Catalina is off the coast of California. The $\overline{\text{BBEC}}$ for Catalina were significantly higher than those for the next most expensive region.

Figure 2-2 shows the $\overline{\text{BBEC}}$ for new conventional power plants. While only five results are shown, all for municipal utilities, it should be noted that there are 37 other cases between the two coal plant cost lines, and 11 between the two oil power plant $\overline{\text{BBEC}}$ lines. The leaps in costs occur between types of power plants studied.

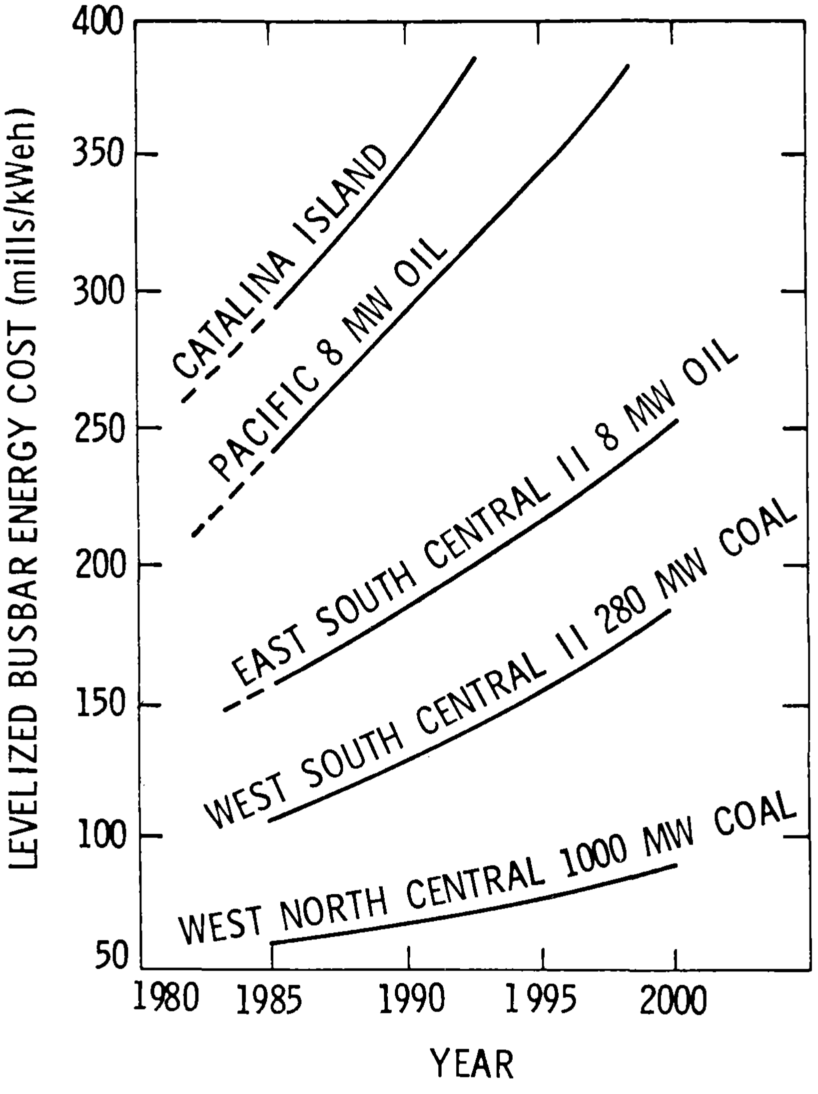

FIGURE 2-2. $\overline{\text{BBEC}}$ FOR NEW CONVENTIONAL POWER PLANTS

Due to the availability of data, specifically the cost of fuel to utilities and fuel cost escalation rates, all analysis was centered on utility costs. Consequently, when the results are compared with $\overline{\text{BBEC}}$ for solar thermal plants, the comparison will show at what point solar thermal becomes attractive to utilities. However, other sectors of the economy must be considered as potential solar thermal customers. Therefore, rough estimates were made showing how $\overline{\text{BBEC}}$, for isolated conventional applications and for industrial applications, relate to the utility cases analyzed. In a rough sense, $\overline{\text{BBEC}}$ costs for isolated applications fall above and below the Catalina Island analysis. Industrial $\overline{\text{BBEC}}$ are thought to fall generally in the range between the typical isolated case and the most costly coal power plant application. Utility applications fall basically between the high cost oil power plant and the low cost coal power plant. These ranges are shown in Figure 2-3.

The analysis of $\overline{\text{BBEC}}$ for conventional power plants indicates that $\overline{\text{BBEC}}$ are highest for small oil-fired diesel plants, especially in remote regions. The marginal cost of electricity, as indicated by $\overline{\text{BBEC}}$, drops as plant size increases, and fuel is switched from oil to the less expensive coal. The implication of the study of conventional $\overline{\text{BBEC}}$ is that alternative sources of energy may successfully compete with the conventional systems of small oil fired diesel, especially in isolated areas. Conversely, due to the low $\overline{\text{BBEC}}$ for 500 and 1000 MW coal power plants, alternative energy cost will have to be low enough to compete effectively or the cost of conventional energy will have to increase significantly. Both are possible, although not in the near future.

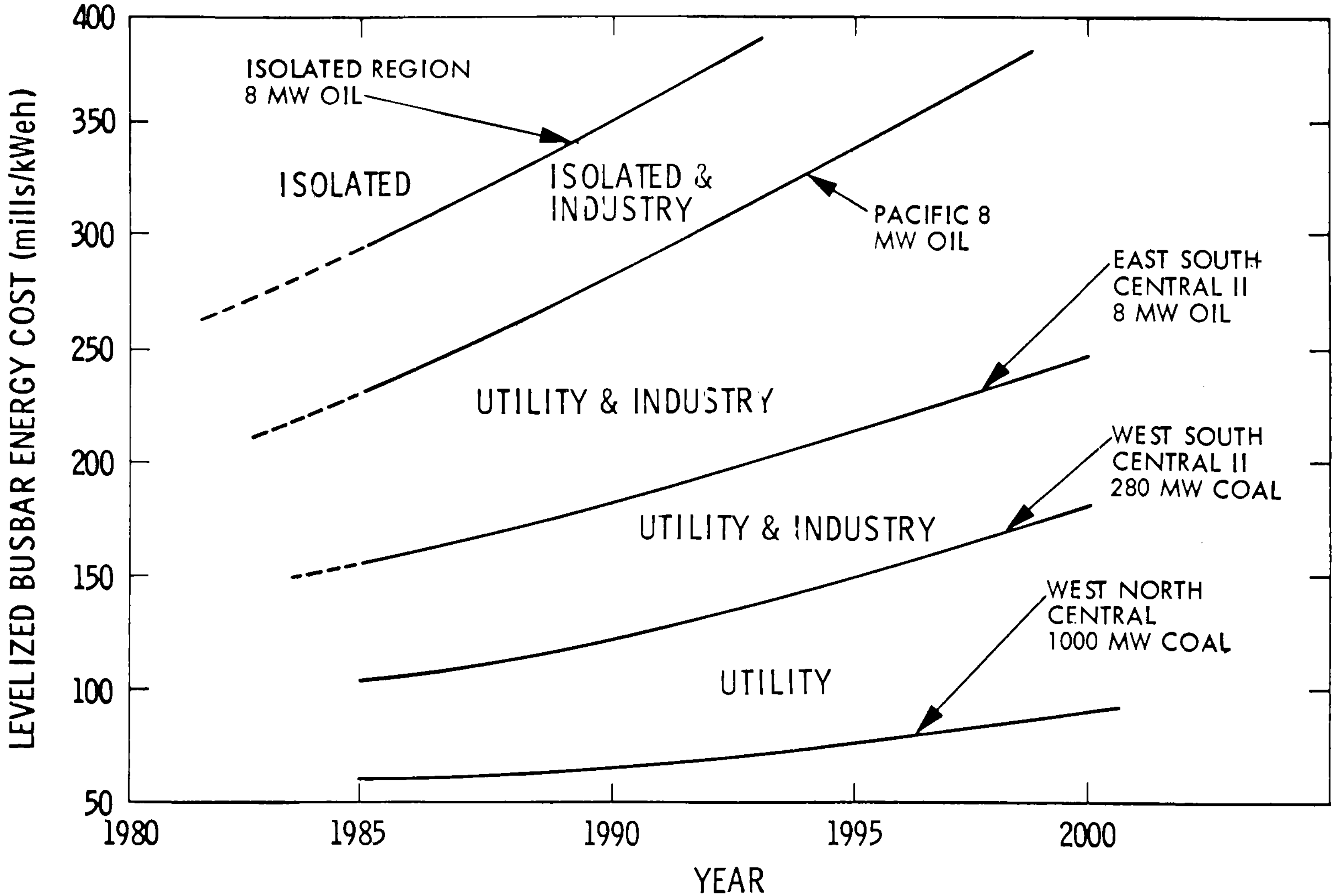

FIGURE 2-3. BBEC FOR NEW CONVENTIONAL POWER PLANTS BY SECTOR AND REGION

SECTION III

ESTIMATION OF $\overline{\text{BBEC}}$ FOR SOLAR THERMAL DISH ELECTRIC POWER PLANTS

The analysis of energy costs of dish electric power plants is heavily dependent on assumptions about production levels and industry technology. Much work has been done on estimating annual production levels necessary to meet solar thermal program goals, and estimating $\overline{\text{BBEC}}$ for given production levels (Reference 7). We have drawn heavily on this method in this phase of the cost analysis.

In a position paper prepared by Solar Thermal Industries Association, October 1979, "Creation of a Viable Solar Thermal Resource for the United States by the Year 2000," production plans for achieving 3 quad and 1 quad energy displacement by solar thermal energy sources were developed.

In this paper, is is assumed that by the year 2000, about 0.1 quad (10^{14} Btu) will be displaced by parabolic dish systems. The production assumptions used to obtain BBEC estimates are therefore based on the level of module production required to meet the 0.1 quad energy displacement goal. The production function is a modified version of that developed by STIA.

One factor which affects the energy output of a solar plant is the amount of energy input, or the insolation rate. An isolation rate of 1 kW/m^2 is considered a peak insolation rate, and will occur at noon on a cloudless day in an area with good isolation. The insolation rate at a given place will vary throughout the day and throughout the year. Insolation is also region dependent. Computer programs and data tapes have been developed to aid in analysis of solar insolation dependent functions and will be used to expand this analysis. However, 0.6 kW/m^2 can be taken as a national annual average insolation for the purpose of this analysis.

Assumptions must be made about the state of industry technology, specifically about the levels of efficiency achieved by the concentrator, receiver, and power conversion unit. At peak with 1 kW/m^2 insolation, each module is assumed to deliver 25 kWe, given an engine generator efficiency of 40% and a collector area of approximately $93m^2$ or about $1{,}000ft^2$. First generation technology, in operation from 1985-1990, however assumes an engine generator efficiency of 25%, while second generation technology will have an engine/generator efficiency of 40%. It is also assumed that there will not be significant changes in the efficiencies or costs of the other submodules, as improvements would not dramatically effect the overall system efficiency. Thus, the national average output per module would be:

$$\text{Second Generation:}\quad 25\text{ kWe} \times \left(\frac{.6\text{ kWe/m}^2}{1.0\text{ kWe/m}^2}\right) = 15\text{ kWe}$$

$$\text{First Generation:}\quad (15\text{ kWe}) \times \left(\frac{.25}{.40}\text{ efficiency ratio}\right) = 9.38\text{ kWe}$$

Assuming 5% of the energy needs met by parabolic dish systems will be supplied by first generation technology between 1985 and 1990, then the total collector area required by this technology is:

$$\left(\frac{.05 \times 10^{14}\text{Btu}}{3413\text{ Btu/kWh}}\right) \Big/ \left(\frac{9.38\text{ kW}}{1000\text{ft}^2} \times 3000\text{ hr}\right)$$

$$= .52 \times 10^8\text{ ft}^2$$

where 3000 hours is the number of hours of usable sunlight per year. Thus, by 1990, 52 million square feet of collector, or 52,000 modules will be installed and in operation.

Assuming the second generation of technology will be in operation from 1990 to 2000 and will supply 95% of the 10^{14} Btu energy goal by the year 2000, then the total collector area of second generation technology is:

$$\left(\frac{.95 \times 10^{14}\text{Btu}}{3413\ \text{Btu/kWh}}\right) \Big/ \left[\left(\frac{15\ \text{kW}}{1000\text{ft}^2}\right) \times (3000\ \text{hr})\right] = 6.18 \times 10^8\text{ft}^2.$$

Thus, the total collector area required by the year 2000 is $(.52 + 6.18) \times 10^8\text{ft}^2 = 670 \times 10^6\text{ft}^2$.

Figure 3-1 shows the production function in square feet of collector area needed to have 670 million square feet of collector, and associated engines and modules in operation by the year 2000. The size and growth necessary for the industry to meet yearly production levels to achieve this goal can be read from the figure.

Table 3-1 translates Figure 3-1 into yearly production levels in terms of the number of modules needed. It also shows installed dish electric power by year end for each year from 1985 through 2000.

Module costs are given as a function of the costs of concentrator, receiver, and power conversion unit, which are in turn functions of production rates, and of assumed balance of plant and O&M costs. Figures 3-2, 3-3, and 3-4 show the characteristics of receiver, low cost General Electric concentrator (11 meter diameter), and Brayton engine, respectively.

Estimates of $\overline{\text{BBEC}}$ for dish electric power plants have been made based on these collector and engine characteristics and costs. The results of these studies for different engine efficiencies are presented in Figure 3-5 as a function of the number of modules produced per year. As annual production increases, the $\overline{\text{BBEC}}$ decreases at a very fast rate at lower production levels, but tends to level out at higher output levels. Also, as expected, with increased engine efficiency, the $\overline{\text{BBEC}}$ will drop.

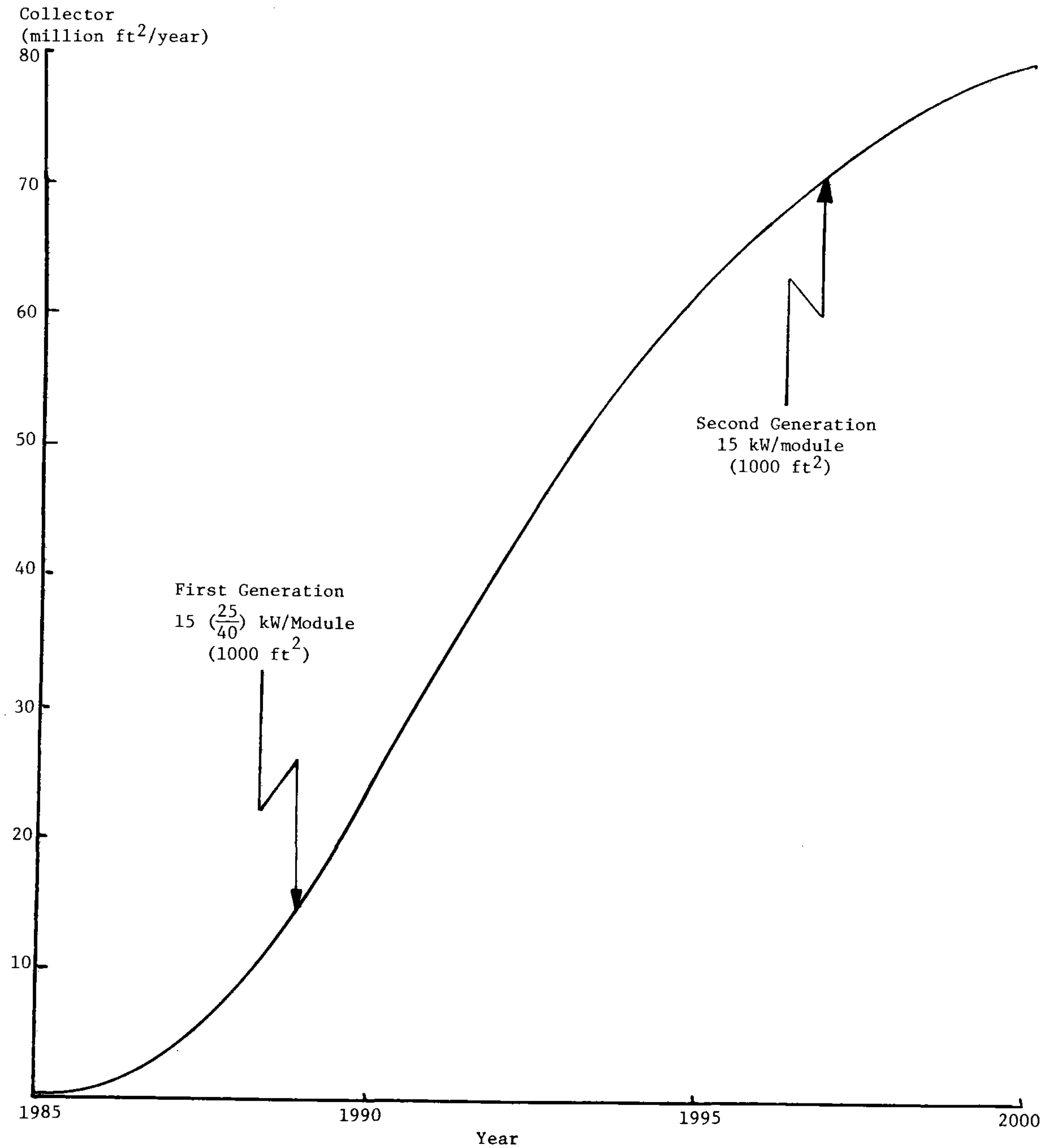

FIGURE 3-1. PARABOLIC DISH COLLECTOR SYSTEMS ANNUAL PRODUCTION GOALS (0.1 Quad by 2000)

TABLE 3-1

SOLAR THERMAL PARABOLIC DISH PRODUCTION GOAL

YEAR	YEARLY PRODUCTION OF MODULES	NO. OF MODULES IN PLACE	POWER GENERATED IN MW (AVERAGE/YEAR)
1985	100	100	0.9
1986	900	1,000	9.3
1987	3,000	4,000	37.5
1988	8,000	12,000	112.7
1989	15,000	27,000	253.7
1990	25,000	52,000	488.7
1991	33,000	85,000	983.7
1992	42,000	127,000	1,613.7
1993	49,000	176,000	2,348.7
1994	57,000	233,000	3,203.7
1995	63,000	296,000	4,148.7
1996	69,000	365,000	5,183.7
1997	72,000	437,000	6,263.7
1998	75,000	512,000	7,388.7
1999	78,000	590,000	8,558.7
2000	80,000	670,000	9,753.7

NOTE: The collector area for each module is 1000 ft^2.

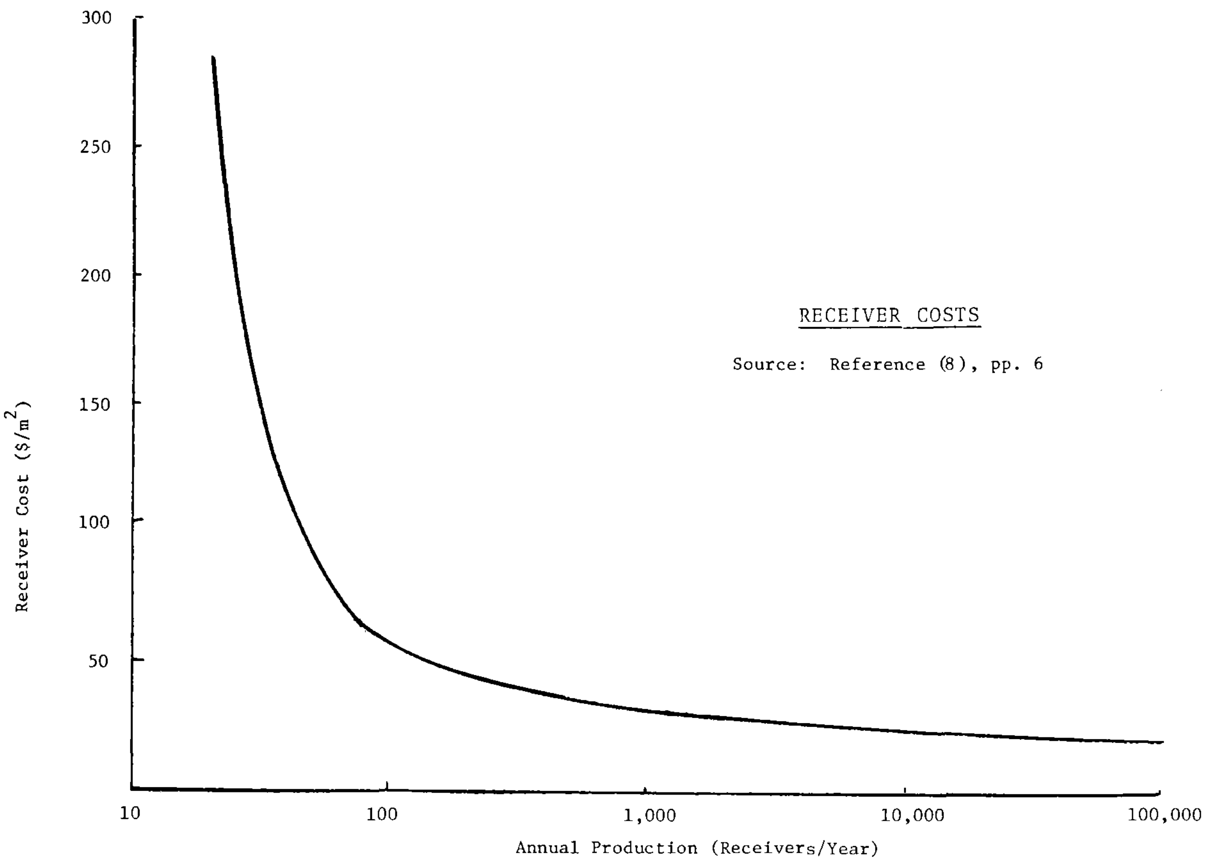

FIGURE 3-2. RECEIVER COSTS
Source: Reference 8, pp. 6

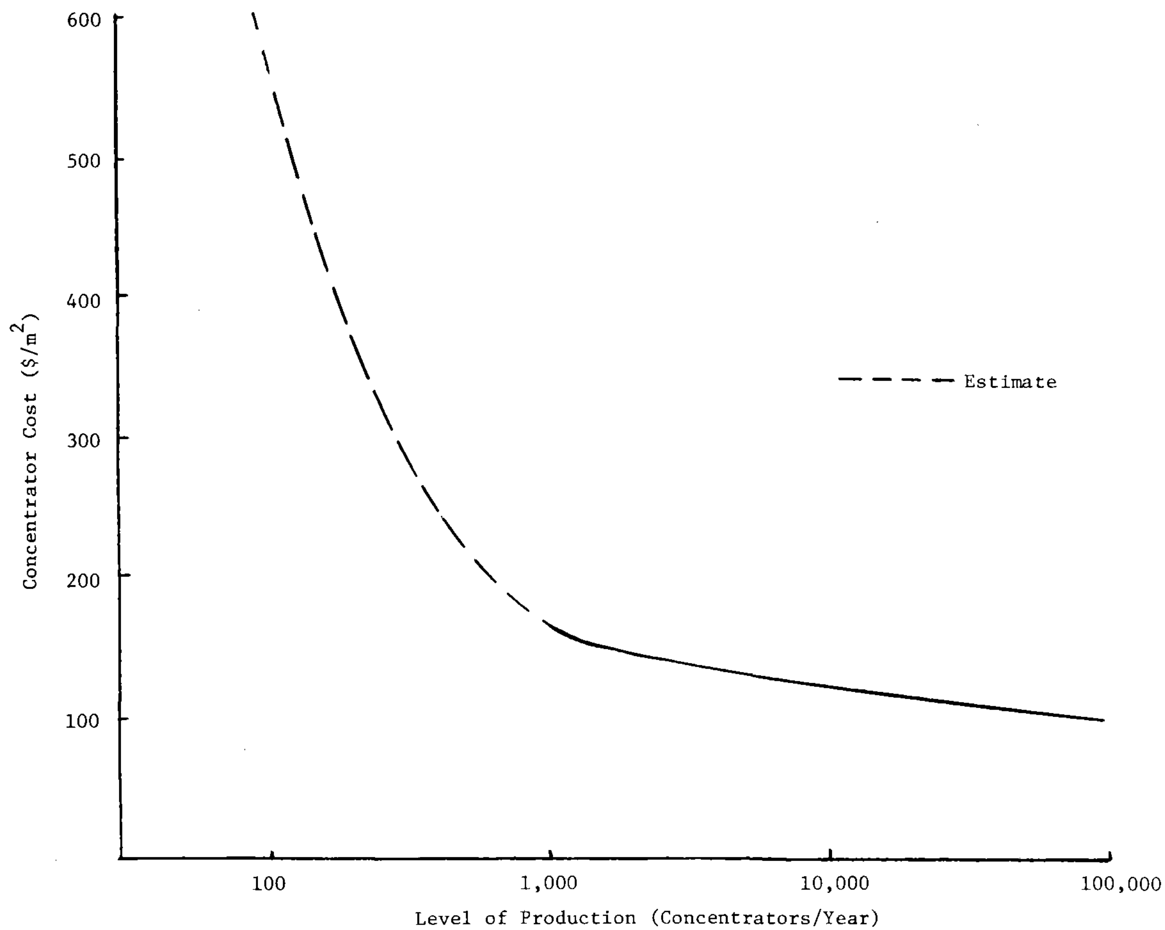

FIGURE 3-3. CONCENTRATOR COSTS
Source: Reference 5

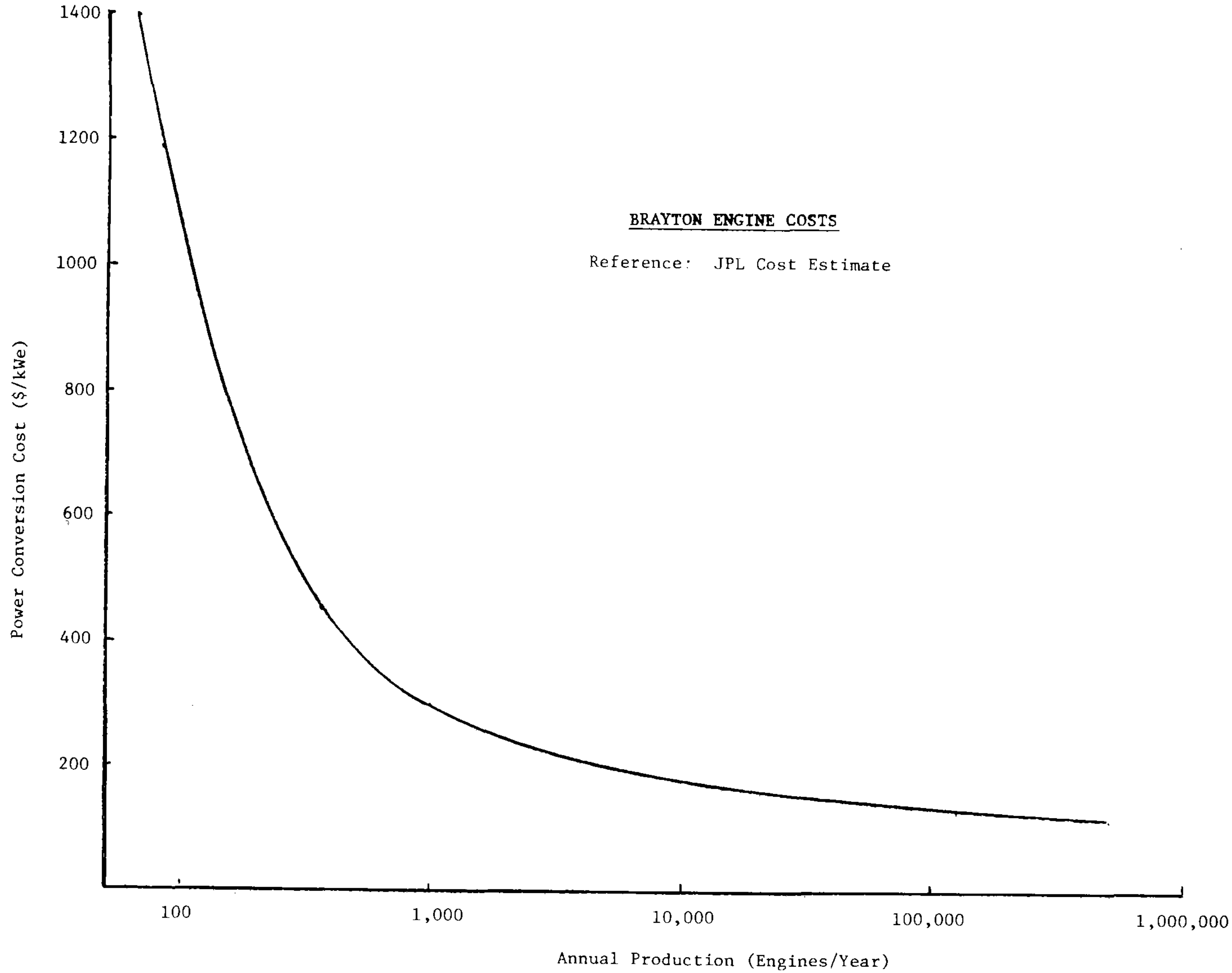

FIGURE 3-4. BRAYTON ENGINE COSTS
Reference: JPL Cost Estimate

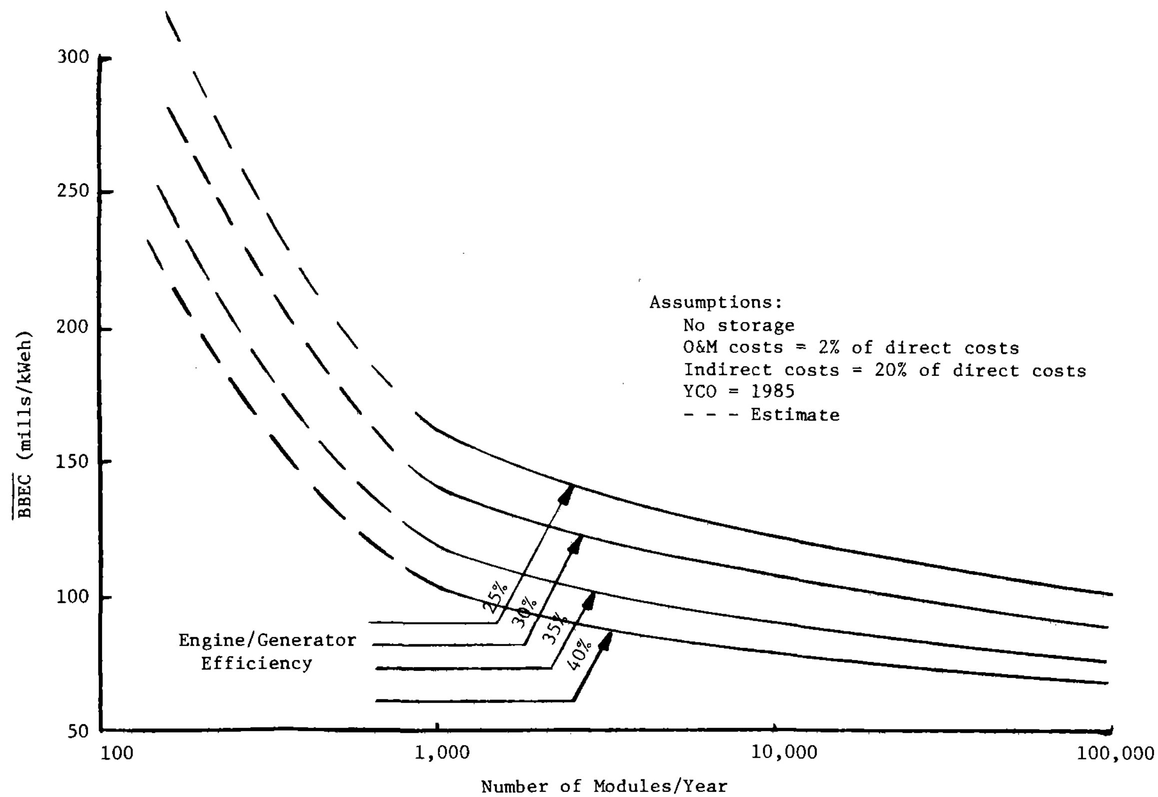

FIGURE 3-5. SOLAR THERMAL PARABOLIC DISH SYSTEM $\overline{\text{BBEC}}$
(in 1979 Dollars)

This study has been confined to two generations of technology, a first generation engine/generator efficiency of 25%, and a second generation engine/generator efficiency of 40%. The $\overline{\text{BBEC}}$ estimates for these two engine efficiencies are shown in Figure 3-6 as a function of production levels. Because production levels were defined earlier for each year from 1985 through 2000, the $\overline{\text{BBEC}}$ estimates can be read as estimates for each year as well as for production level. All $\overline{\text{BBEC}}$ estimates are in 1980 dollars. Using the first generation of technology with an engine/generator efficiency of 25% and assuming no storage, the $\overline{\text{BBEC}}$ for 1000 units would be 175 mills/kWeh and would occur in 1987. For the same technology, at 25,000 units, costs will drop to 120 mills/kWeh. We have assumed that this level of production will occur in 1990, the last year for the first generation technology. The $\overline{\text{BBEC}}$ for power plants using second generation dish technology is estimated to be 126 mills/kWeh for a 1000 unit production level, 90 mills/kWeh for 25,000 units, and 80 mills/kWeh at 100,000 units of production, beyond the year 2000.

Figure 3-7 combines the schedule developed in Table 3-1 for yearly production levels with the $\overline{\text{BBEC}}$ for various production levels developed in Figure 3-6. This gives estimated $\overline{\text{BBEC}}$ for each year. The next section compares the $\overline{\text{BBEC}}$ for solar thermal with those for conventional power sources, as projected for the next 20 years. The production levels necessary for solar thermal to successfully compete with various forms of conventional energy, and the year at which breakeven costs will occur, can then be determined.

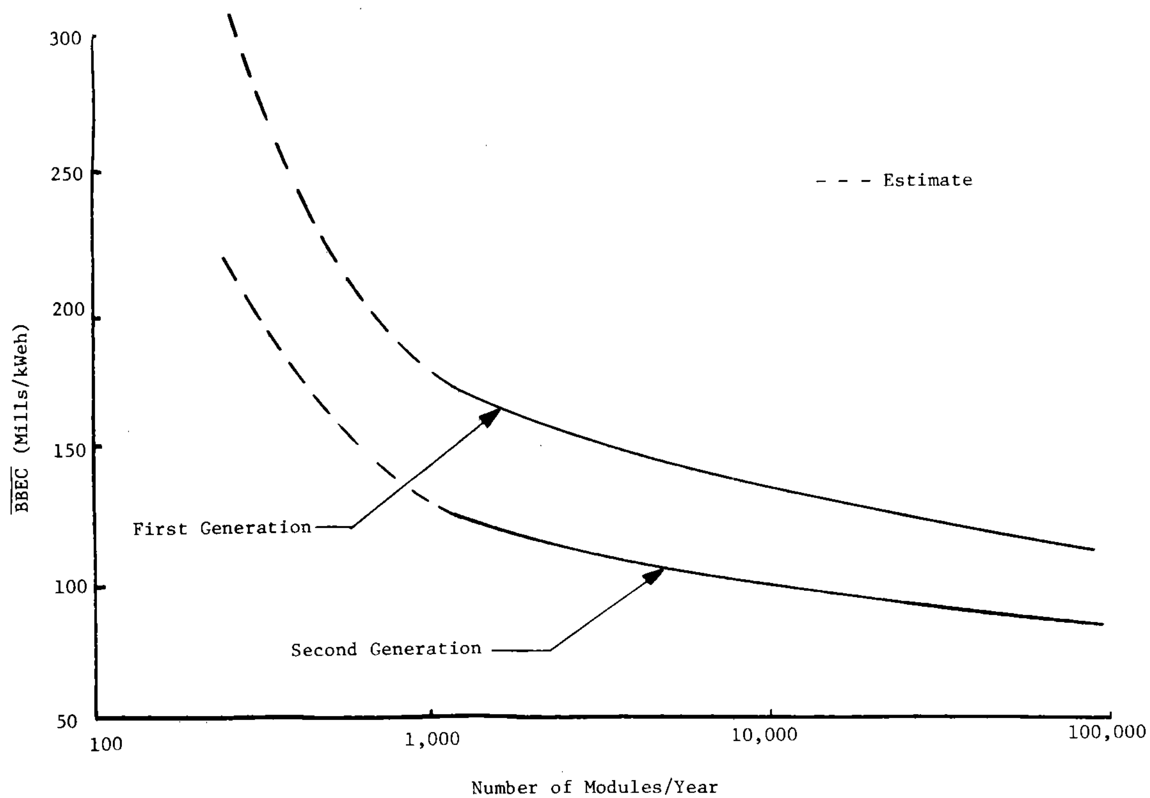

FIGURE 3-6. SOLAR THERMAL PARABOLIC DISH SYSTEM $\overline{\text{BBEC}}$
First Generation and Second Generation
(in 1980 Dollars)

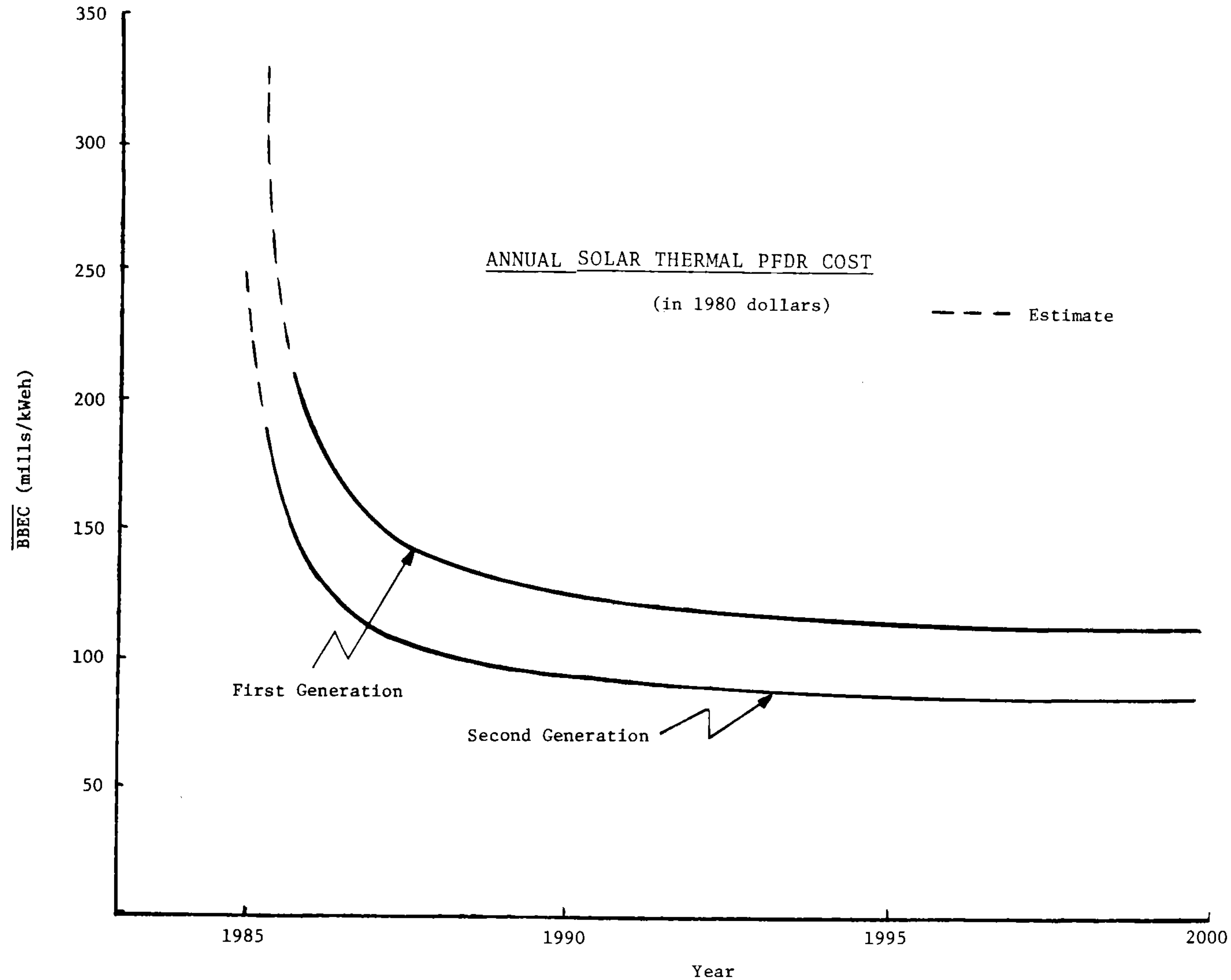

FIGURE 3-7. ANNUAL SOLAR THERMAL PARABOLIC DISH SYSTEM COST (in 1980 Dollars)

DISH-ELECTRIC POWER PLANT

COSTS AND CHARACTERISTICS

* Balance of plant costs = $230/kWe

* O&M costs = 2% of direct costs

* Indirect costs = 20% of direct costs

* Plant size = 5 MWe

* Capacity factor = .296

* Capital recovery factor = .0939

* Engine cost includes alternator cost

* O&M escalation = 7% per year

* Capital cost escalation = 6% per year

* General escalation = 6% per year

* Submodule costs are the same for the first and second generation of dish technology

SECTION IV

BREAKEVEN COST

The ability to achieve the production cost levels by the specific years indicated by this analysis is uncertain. As the solar thermal production figures indicate, the achievement of the 0.1 quad energy displacement goal by the year 2000 depends on the rate of production for the next ten years, specifically on the rate of growth in production. If these goals are achieved and the annual level of production reaches 25,000 modules by 1990, and 80,000 modules by 2000, then the cost of solar thermal energy would be competitive with the cost of conventional energy. The analysis indicates that as the costs of solar thermal energy are coming down, the costs of conventional energy are increasing. The strategy applied to developing a solar thermal industry will rely on identifying those applications where the conventional $\overline{\text{BBEC}}$ are highest. It is those applications where solar thermal will potentially be competitive earliest.

The analysis of $\overline{\text{BBEC}}$ for new conventional power plants, described in Section II, shows that in a given region within the range tested, the larger the size of the power plant, the less will be the $\overline{\text{BBEC}}$. As shown in Figure 2-3, the $\overline{\text{BBEC}}$ is highest in isolated applications where the power plants are small and fuel costs high, followed by industrial, then utility applications, with the large utilities having the lowest cost of the conventional energy systems.

In Section III, the $\overline{\text{BBEC}}$ for first and second generaton dish electric power plants were developed. Figure 3-7 indicates as the production of modules increases, the $\overline{\text{BBEC}}$ drops from 300 mills/kWeh for first generation system technology in 1985 to less than 90 mills/kWeh in the year 2000. Both improved engine/generator efficiency and increased production levels account for this drop in $\overline{\text{BBEC}}$.

The $\overline{\text{BBEC}}$ by year for conventional power plants, shown in Figure 2-3, and that for dish electric power plants, Figure 3-7, have been combined in Figure 4-1. This comparison allows the various production levels required for solar thermal to compete with conventional energy systems to be determined. During the period of first generation technology, 1985 to 1990, as costs drop from 300 mills/kWeh to 125 mills/kWeh, solar thermal energy systems will be competitive with conventional energy systems in isolated applications, and some industrial applications. The solar thermal power plants will also be cost competitive with small oil-fired diesel utility power plants.

As second generation engine generator efficiency is introduced in 1990, $\overline{\text{BBEC}}$ drop becomes less sensitive to the level of production. By 1995, as the $\overline{\text{BBEC}}$ for solar thermal drops to about 90 mills/kWeh, and production reaches 63,000 modules, dish electric power plants will compete with medium sized coal power plants, in both industrial and grid connected utility applications. Beyond 1995, when solar thermal $\overline{\text{BBEC}}$ drops below 90 mills/kWeh, dish electric power plants will be competitive with most types of conventional power, and will definitely permit penetration of the grid connected utility market. As the cost of solar thermal energy continues to drop, and the cost of conventional energy rises, by the year 2000 solar thermal power systems will have attained high levels of mass production, high system efficiency and be highly competitive with all types of conventional energy, in regions with relatively high levels of insolation.

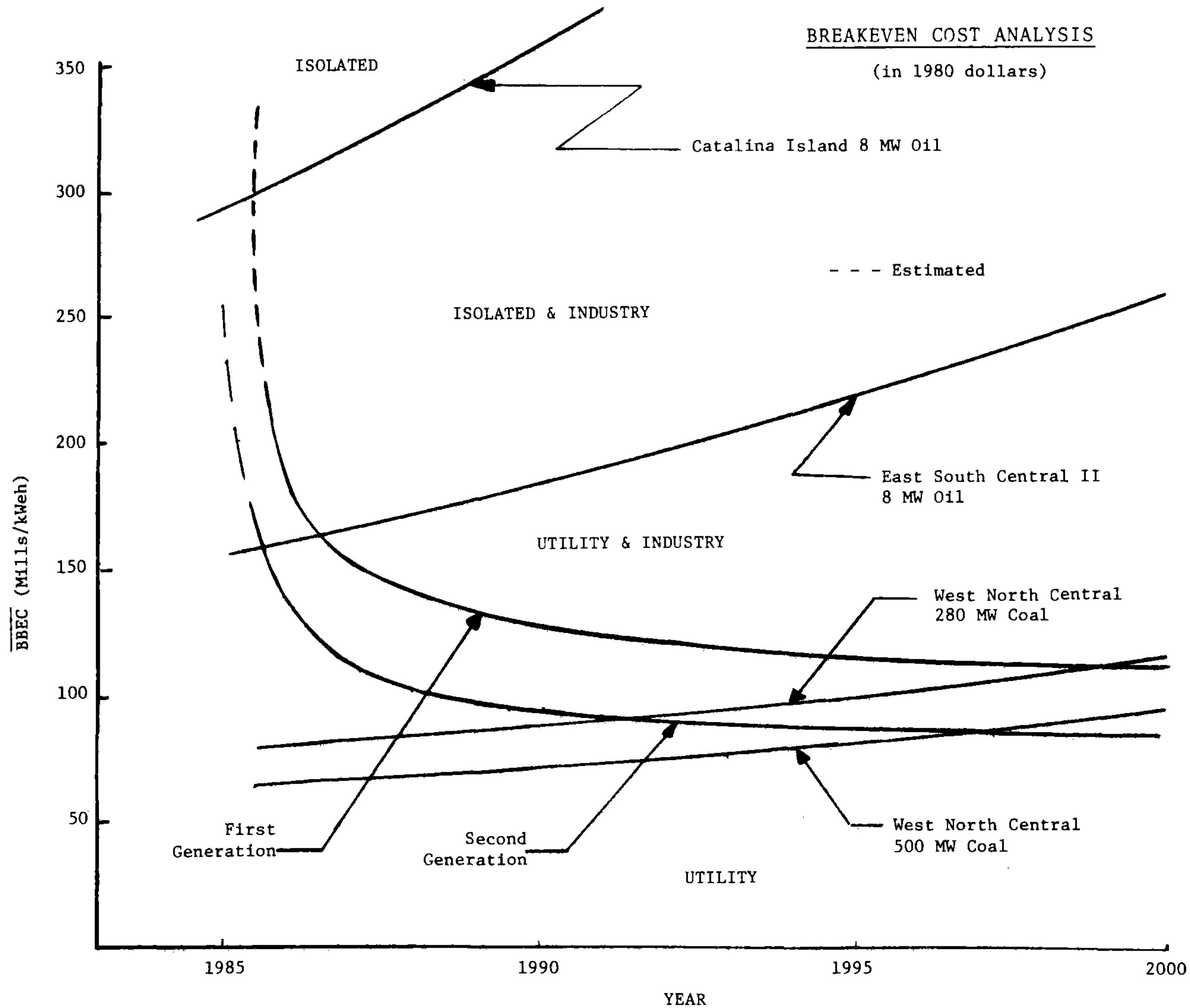

FIGURE 4-1. BREAKEVEN COST ANALYSIS
(in 1980 Dollars)

There are many uncertainties in the analysis. These uncertainties are involved in both the cost of conventional energy, and the development of solar thermal. Future refinements to the analysis presented will center on regionalizing the solar thermal analysis, investigating new generation technology, and looking at probabilistic cost ranges. In future work, the assessment of market potential for solar thermal systems and the impact of expected demand upon the estimated supply is required in order to arrive at more realistic cost goals. No doubt the $\overline{\text{BBEC}}$ is an aggregate measure of the cost, thus a different methodology incorporating other economic and social variables should be investigated. Then, perhaps most importantly, the competitive effect of the development of other alternative energy technologies needs to be considered. Despite these uncertainties, the initial results look promising for the development of a solar thermal power industry for isolated regions in the near future and for grid-connected utilities in regions with high levels of insolation during 1990-2000.

APPENDIX

The appendix shows the calculation of the 12 variables needed to estimate $\overline{BBEC}$ for conventional power plants.

APPENDIX

1000 MW Coal Power Plant

R_{00} = Annual plant output = (plant size) x (CF) x (number of hours/year) where CF is the annual attained capacity factor. For all plants assume that CF = 0.70. Hence, for a 1000 MW plant, R_{00} = 1000 MW x 0.70 x 8760hr/yr = 6,132,000 MWh/yr.

R_{01} = k = cost of capital to a "typical utility." In the case of municipal utilities, k = 0.07, and in the case of cooperatives, k = 0.09 for all plant sizes.

R_{02} = Plant operating lifetime = 30 years for all plants

R_{03} = Average annual inflation rate for the years 1980-2000 = 6%/year

R_{04} = g_c = capital escalation rate = 4% above the rate of inflation for coal power plants and 2.4% above inflation for diesel plants. (Source: Reference 3, p. 54.)

R_{05} = $g_{O\&M + fuel}$ = escalation in operation and maintenance and fuel cost. This escalation rate was represented by the escalation in the price of coal. The cost of coal to electric utilities was obtained by region in $/million Btu from Reference 2. The DRI figures were changed into 1980 dollars, determined the average annual price escalation in real terms from 1980 to 2000, then added 6% general inflation to obtain R_{05} (See Table A-1).

R_{06} = The year for which $\overline{BBEC}$ were estimated, input as the number of years from the base year. $R_{06} = Y_t - Y_o$ when Y_o = 1980 and Y_t = 1985, 1990, 1995, and 2000.

R_{07} = Interest calculation factor during the construction period. A 4 year construction time is assumed, consequently R_{07} = -1.5.

R_{08} = Capital cost = (1000 MW) x (capitalized plant cost in \$/kW). The capitalized plant costs by region were obtained from Reference 4, section XII, p. 6. EPRI capital cost figures were adjusted from 1977 dollars to 1980 dollars using a 25.6% increase in general inflation during the 1977-1980 period plus a 5% increase in capital costs over the rate of inflation for those years. The inflation figures are from Reference 2. Table A-2 shows the adjusted capital cost figures by region. The capital cost for the West region includes the environmental costs.

R_{09} = Operations & Maintenance plus Fuel Cost. O&M = fixed + variable costs = (fixed cost/year/MW) x (plant size) + (variable cost/kWh) x (annual plant output). Variable cost per kWh is the sum of variable operation and maintenance cost and consumable cost where consumable cost is the cost of lime, sludge and ash disposal. Both fixed and variable cost estimates were obtained from Reference 4, and are shown in Table A-2. The EPRI figures have been escalated from 1977 to 1980 dollars by a 25.6% inflation factor. Fuel Cost = (heat rate) x (price of coal to electric utilities) x (annual plant output). The heat rate in Btu/kWh for each region was obtained from Reference 4, and is shown in Table A-2. The heat rate is defined as the amount of energy in Btu's required to produce a unit of electricity in kWh. The price comparison of coal to electric utilities in 1980 was obtained by region from Reference 2, and is reproduced as Table A-1. Annual output for a 1000 MW coal power plant is 6,132,000 MWh.

R_{10} = Capital recovery factor = CRF = $\frac{k}{1-(1+k)^{-n}}$ which is equal to .0806 for municipal power plants and 0.0973 in the case of cooperative coal power plants.

R_{11} = Annual fixed charge rate = FCR = CRF + $\beta_1 + \beta_2$ where $\beta_1 + \beta_2$ represent non-income taxes and insurance, and equal 0.0225. FCR = 0.1031 for municipal power plants, and 0.1198 for cooperative coal power plants. Municipal utilities do not ordinarily pay property taxes. They do, however, make payment in lieu of taxes. For evaluation of FCR and estimated β_1 and β_2 see Reference 6, section III, pp. 6-10.

TABLE A-1

PRICE OF COAL TO ELECTRIC UTILITIES

($/Million Btu)

	CURRENT $					1980 $					R_{05}
	1980	1985	1990	1995	2000	1980	1985	1990	1995	2000	
NEW ENGLAND	1.8	2.8	4.0	5.9	8.8	1.8	2.1	2.2	2.5	2.7	8.0%
MIDDLE ATLANTIC	1.5	2.5	3.6	5.3	7.8	1.5	1.9	2.0	2.2	2.4	8.4%
SOUTH ATLANTIC	1.6	2.6	4.1	6.1	8.9	1.6	1.9	2.3	2.6	2.8	8.8%
E.N. CENTRAL	1.5	2.4	3.6	5.3	7.8	1.5	1.8	2.0	2.2	2.4	8.5%
W.N. CENTRAL	1.1	1.7	2.5	3.6	5.3	1.1	1.3	1.4	1.5	1.7	8.1%
E.S. CENTRAL 1	1.4	2.3	3.3	4.8	7.0	1.4	1.7	1.8	2.0	2.2	8.2%
E.S. CENTRAL 2	1.6	2.4	3.3	4.8	7.0	1.6	1.8	1.8	2.0	2.2	7.6%
W.S. CENTRAL 1	1.3	2.1	3.2	4.7	6.8	1.3	1.6	1.8	2.0	2.1	8.5%
W.S. CENTRAL 2	1.0	1.9	3.3	5.2	7.6	1.0	1.4	1.8	2.2	2.4	10.4%
MOUNTAIN 1	.6	1.3	2.3	3.6	5.2	.6	1.0	1.3	1.5	1.6	11.1%
MOUNTAIN 2	.7	1.3	2.2	3.4	4.9	.7	1.0	1.2	1.4	1.5	10.0%
MOUNTAIN 3	.8	1.5	2.4	3.6	5.2	.8	1.1	1.3	1.5	1.6	9.6%
PACIFIC	1.0	1.9	3.2	4.8	7.0	1.0	1.4	1.8	2.0	2.2	10.0%

SOURCE: "DRI Energy Review," Data Resources, Incorporated, Lexington, Massachusetts, Summer 1979.

TABLE A-2

REGIONAL COAL POWER PLANT CHARACTERISTICS

REGION	CAPITALIZED PLANT COST $/kW	OPERATIONS & MAINTENANCE FIXED $/kW/yr	OPERATIONS & MAINTENANCE VARIABLE(2) Mills/kWh	AVG. ANNUAL HEAT RATE Btu/kWh
NORTHEAST	961	3.35	3.97	10100
SOUTHEAST	784	2.73	3.99	10150
EAST CENTRAL	915	3.18	5.23	10200
WEST CENTRAL	903	3.14	2.01	10400
SOUTH CENTRAL	923(1)	2.90	2.83(3)	10700
WEST	1121	3.24	2.06	10400

NOTE: All dollar figures are in 1980 dollars.

(1) An additional $83/kW is included to account for the additional transmission associated with mine mouth power stations typical of plants planned for this region.

(2) Includes cost of lime plus sludge and ash disposal.

(3) An additional 0.33 mills/kWh is added to account for additional transmission energy losses.

SOURCE: Technical Assessment Guide, EPRI PS-866-SR, Electric Power Research Institute, Palo Alto, California, June 1978, section XII, p. 6.

500 MW COAL POWER PLANTS

All variables for a 500 MW plant in a given region remain the same as those for the 1000 MW plant in that region, with the exception of R_{00}, R_{08}, and R_{09}. These are annual plant output, capital cost in \$/kW times plant size, and the operation and maintenance plus fuel cost.

R_{00} = Annual plant output = (plant size) x (CF) x (number of hours/year) = 500 MW x 0.70 x 8760hr/yr = 3066,000 MWhr/yr.

R_{08} = Capital cost = $\frac{\text{(Capital cost of 1000 MW plant by region)}}{2} \times 1.11$.

In general, $C = C_o \times \left(\frac{MW_o}{MW}\right)^{0.15}$ where C and C_o are the cost/kW of the new and 1000 MW plants, respectively and MW and MW_o are the new and original 1000 MW unit size, respectively. The exponential factor applies only to units between 500 and 1000 MW in size. In the case of 500 MW unit, $\left(\frac{MW_o}{MW}\right)^{0.15} = \left(\frac{1000}{500}\right)^{0.15} = 1.11$. For further information see Reference 4, section XII, p. 2.

R_{09} = Operation & Maintenance, and fuel cost. The fixed cost per kW and the variable cost per kWh are assumed to be the same as for the 1000 MW plant. Because the annual plant output of a 500 MW plant is half that of a 1000 MW plant, the O&M + fuel cost for 500 MW is half that for 1000 MW for each region.

280 MW COAL POWER PLANT

As for the 500 MW coal power plant, all variables for a 280 MW plant are assumed to be the same as those for a 1000 MW plant in a given region, with the exception of R_{00}, R_{08}, and R_{09}.

R_{00} = annual plant output in MW hours = (plant size) x (CF) x (number of hours per year) = 280 MW x 0.70 x 8760h/yr = 1,716,960 MWh/yr.

R_{08} = Capital Cost. The only estimate of capital available for a 280 MW coal plant was conducted by Burns and McDonnell (Reference 1) for the state of Wisconsin. Since EPRI figures and Burns and McDonnell figures would have to be combined, other Burns and McDonnell estimates for Wisconsin were compared with EPRI estimates for the East Central region. According to EPRI (Reference 4), the capital cost for a 600 MW power plant in 1977 dollars is: $700 \times \left(\frac{1000}{600}\right)^{0.15} = 755$ \$/kWh. Using the DRI GNP inflation rate plus the 5% inflation in capital costs, the above capital cost in 1980 dollars would be 987\$/kW. But the Burns and McDonnell capital cost estimate for a 600 MW coal power plant in Wisconsin is 690\$/kWh in 1980 dollars. In other words, the EPRI estimate of capital cost is 43% higher than that of Burns and McDonnell. To maintain consistency and input data in line with the EPRI estimates, the 877\$/kW estimate for 280 MW power plants by Burns and McDonnell has been raised by 43% so the capital cost for a 280 MW coal power plant in East Central is 1254\$/kW (in 1980 dollars). To evaluate the 280 MW capital cost for different regions, the ratio of the capital cost for a 1000 MW plant in that region to a 1000 MW plant in the East Central region given by EPRI is assumed to be consistent with 280 MW plants (see Table A-3).

TABLE A-3

CAPITAL COST OF A 280 MW COAL POWER PLANT*

REGION	REGIONAL CAPITAL COST RATIO**	CAPITAL COST 280 MW EAST CENTRAL $/kW	CAPITALIZED 280 MW PLANT COST $/kW	TOTAL CAPITALIZED PLANT COST (MILLIONS $)
NORTHEAST	961/915	1254	1317	368.8
SOUTHEAST	784/915	1254	1074	300.7
EAST CENTRAL	915/915	1254	1254	351.1
WEST CENTRAL	903/915	1254	1238	346.6
SOUTH CENTRAL	923/915	1254	1265	354.2
WEST	1121/915	1254	1536	430.1

* All figures are in 1980 dollars.

** Ratio of the regional capital cost per kW of a 1000 MW power plant to the capital cost per kW in the East Central region.

R_{09} = Operation and Maintenance + fuel cost. The O&M and fuel cost estimates for 280 MW coal plants are derived in a different way from 500 and 1000 MW coal plants. Fuel cost = (heat rate) x (price of coal to electric utilities) x (annual plant output). The heat rate is derived as follows:

1) The average net heat rate for 280 MW plants = 10,650 Btu/kWh, from Burns & McDonnell (Reference 1) for Wisconsin.

2) Heat rates by region for 1000 MW plants are taken from Table XII-A of EPRI (Reference 4) and are shown in Table A-2.

These are used to estimate relative regional heat rate differences, with the East Central region as the base. Let

HR_i = estimated heat rate for 280 MW plants in region i (Btu/kWh)

hr_i = average annual heat rate for 1000 MW plants in region i (Btu/kWh) (Reference 4).

HR_{EC} = 10,650 average net rate for 280 MW plants (Btu/kWh) in Wisconsin.

hr_{EC} = 10,200 average annual heat rate for 1000 MW plants in the East Central region (Btu/kWh) (Reference 4).

then

$$HR_i = \frac{hr_i}{hr_{EC}} \times HR_{EC} = hr_i \times \frac{10,650}{10,200} .$$

The price of coal to electric utilities by region is the same as for 1000 MW coal power plants. Annual plant output is variable R_{00}, defined above.

Operation & Maintenance = (fixed cost in $/kWyr) x (1 year) x (280,000 kW) + (variable cost in mills/kWh) x (annual plant output in kWh) x ($\$1/10^3$mills) which, after cancellation, gives O&M cost for region i of (FC_i) x (280,000 kW) + (VC_i) x (1,716,960 MWh). The fixed cost estimate is derived similarly to the heat rate estimate:

Let

FC_i = estimated fixed cost per kW/yr in 1980$ for a 280 MW coal plant in region i.

fc_i = fixed cost per kW/yr in 1977$ of a plant in region i from Table XII-A in Reference 4.

FC_{EC} = \$14.92 average fixed cost per kW/yr in 1980\$ for 280 MW coal power plants for Wisconsin (Reference 1).

fc_{EC} = \$2.53 fixed cost per kW/yr in 1977\$ of a plant in the East Central region, from Table XII-A in Reference 4.

Then

$$FC_i = \frac{fc_i}{fc_{EC}} \times \$14.92 = fc_i \times \frac{\$14.92}{\$2.53}$$

See Table A-4 for heat rate and fixed cost estimates. The variable cost was assumed to be constant over regions for 280 MW coal power plants and equal to 2.7 mills/kWh (Reference 1).

TABLE A-4

HEAT RATE
OPERATION & MAINTENANCE COST
280 MW COAL POWER PLANT

REGION	HEAT RATE Btu/kWh	OPERATIONS & MAINTENANCE FIXED COST \$/kW/yr
NORTHEAST	10,546	15.75
SOUTHEAST	10,598	12.80
EAST CENTRAL	10,650	14.92
WEST CENTRAL	10,859	14.74
SOUTH CENTRAL	11,172	13.62
WEST	10,859	15.21

8 MW OIL-FIRED DIESEL POWER PLANTS

The $\overline{BBEC}$ for 8 MW oil-fired diesel plants were estimated for municipal power plants only. This is because the difference between municipal and cooperative utilities at the level of detail which are being investigated is not significant.

Despite the difference in magnitude between a 1000 MW plant and an 8 MW plant, several input variables remain the same. Those which do not are R_{00}, R_{04}, R_{05}, R_{07}, R_{08}, and R_{09}. Details of these variables follow.

R_{00} = Annual plant output = 8 MW x 0.7 x 8,760hr/yr = 49,056 MWh, assuming 70% capacity utilization.

R_{04} = The capital cost escalation is projected to average 2% above the general rate of inflation, g_c = 8%.

R_{05} = O&M and fuel cost escalation. The same procedure was followed as for coal plants. The real rate of change in the price of oil was determined by region, then added to the general rate of inflation. Table A-5 shows the ratio of price of oil to electric utilities for the next 20 years (Reference 2).

R_{07} = Interest during construction, assuming a 2 year construction time is a factor of -0.5.

R_{08} = Capital cost = (8000 kW) x (641 \$/kW) = \$5.13 x 10^6. The capital cost per kW was obtained from Reference 1, and is assumed to be constant across all regions.

R_{09} = O&M + fuel cost. Fuel cost = (heat rate) x (price of oil to electric utilities) x (annual plant output). Heat rate = 9600 Btu/kWh (Reference 1). The price of oil to electric utilities by region was obtained from Reference 2, and is shown in Table A-5. Plant annual output = R_{00} = 49,056 MWh.

O&M = (fixed cost $/kWyr) x (plant size) + (variable cost mills/kWh) x (annual plant output). Average fixed and variable costs were 5.63 $/kWyr and 3.81 mills/kWh respectively for Wisconsin (Reference 1). It is assumed that costs are the same for all regions except the North Eastern region which is 10% higher.

TABLE A-5

COST OF OIL TO ELECTRIC UTILITIES
($/Million Btu)

	CURRENT $					1980 $					R_{05}
	1980	1985	1990	1995	2000	1980	1985	1990	1995	2000	
NEW ENGLAND	3.3	7.0	10.9	16.8	25.5	3.3	5.2	5.8	7.0	7.9	10.4%
MIDDLE ATLANTIC	3.6	7.4	11.6	17.8	27.1	3.6	5.5	6.5	7.4	8.5	10.3%
SOUTH ATLANTIC	3.4	7.0	11.1	17.0	25.8	3.4	5.2	6.2	7.1	8.1	10.4%
E. N. CENTRAL	4.4	9.0	14.1	21.6	32.8	4.4	6.7	7.8	9.0	10.2	10.3%
W. N. CENTRAL	3.2	6.6	10.4	16.0	24.2	3.2	4.9	5.8	6.7	7.5	9.5%
E. S. CENTRAL 1	3.4	7.1	11.2	17.2	26.1	3.4	5.3	6.2	7.1	8.1	10.4%
E. S. CENTRAL 2	3.0	6.3	9.9	15.3	23.1	3.0	4.7	5.5	6.4	7.2	9.7%
W. S. CENTRAL 1	3.2	6.7	10.5	16.2	24.5	3.2	5.0	5.8	6.7	7.6	10.4%
W. S. CENTRAL 2	3.2	6.6	10.4	16.0	24.2	3.2	4.9	5.8	6.7	7.5	10.3%
MOUNTAIN 1	4.4	8.9	14.0	21.5	32.6	4.4	6.6	7.8	8.9	10.2	10.3%
MOUNTAIN 2	3.2	6.7	10.5	16.1	24.4	3.2	5.0	5.9	6.7	7.6	10.4%
MOUNTAIN 3	3.6	7.5	11.8	18.1	27.4	3.6	5.6	6.6	7.5	8.5	10.4%
PACIFIC	4.4	9.0	14.1	21.6	32.8	4.4	6.7	7.9	9.0	10.2	10.3%

SOURCE: "DRI Energy Review," Data Resources, Incorporated, Lexington, Massachusetts, Summer 1979.

TABLE A-6

SUMMARY TABLE

	1000 MW	500 MW	280 MW	8 MW
R_{00}	6,132,00 MWh	3,066,000 MWh	1,716,960 MWh	49,056 MWh
R_{01}	7% municipal	---	---	7% municipal
	9% cooperative	---	---	
R_{02}	30 years	---	---	---
R_{03}	6%	---	---	---
R_{04}	10%	---	---	8%
R_{05}	region specific	---	---	region specific
R_{06}	5,10,15,20 years	---	---	---
R_{07}	-1.5,*	---	---	-0.5
R_{08}	region specific	region specific	region specific	region specific
R_{09}	region specific	region specific	region specific	region specific
R_{10}	0.0806 municipal	---	---	---
	0.0973 cooperative	---	---	
R_{11}	0.1031 municipal	---	---	---
	0.1198 cooperative	---	---	

--- The same as 1000 MW

* Assuming 4 years construction period. In the case of a 6 year construction time interval, $R_{07} = -2.5$.

REFERENCES

1. Burns and McDonnell, "Power Plant Capital Cost," report to JPL, September 1979.

2. Data Resources, Incorporated "Energy Review," Lexington, Massachusetts, Summer 1979.

3. Data Resources, Incorporated "Energy Review," Lexington, Massachusetts, Spring 1979.

4. Electric Power Research Institute, Technical Assessment Guide, PS-866-SR, Palo Alto, California, June 1978.

5. General Electric Corporation, Low Cost Point Focus Solar Concentrator, Final Study Report, pp. 12-12, March 16, 1979.

6. Jet Propulsion Laboratory, The Cost of Energy from Utility Owned Solar Electric Systems, JPL document no. 5040-29, Pasadena, California, June 1976.

7. Solar Thermal Industries Association, Creation of a Viable Solar Thermal Resource for the United States by the Year 2000, position paper, October 1979.

8. Truscello, Vincent C. and A. Nash Williams, "Heat and Electricity from the Sun Using Parabolic Dish Collector Systems," Jet Propulsion Laboratory, Pasadena, California, September 1979.

9. Rosenberg, L. S., "Continued Development of the Solar Energy Simulation Model (SES II)," JPL IOM 311.3-245, January 7, 1980.