ENERGY LABORATORY

**MASSACHUSETTS INSTITUTE
OF TECHNOLOGY**

COST GOALS FOR A RESIDENTIAL PHOTOVOLTAIC/THERMAL LIQUID COLLECTOR SYSTEM SET IN THREE NORTHERN LOCATIONS

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ABSTRACT

This study compares the allowable costs for a residential PV/T liquid collector system with those of both PV-only and side-by-side PV and thermal collector systems. Four types of conventional energy systems provide backup: all oil, all gas, all electric resistance, and electric resistance hot water with space heating by parallel heat pump. Electric space cooling is modeled, and the electric utility serves as backup for all electrical needs.

The analysis is separated into two parts. The first is a base case study using conservative market and financial parameters for comparing PV/T economics in three northern locations: Boston, Madison, and Omaha. All parameter estimates are for a privately purchased residence, newly constructed in 1986. Three measures are used for establishing allowable costs, including system breakeven capital cost, allowable levelized annual costs, and an allowable combined collector cost when compared directly with a side-by-side collector system. In the second portion of this study we examine the sensitivity of PV/T economics to pertinent physical, market, and financial variables. Here also we estimate the difference in economic outlook for PV/T in retrofit applications.

The results indicate that, for those northern locations modeled, the allowable cost for a combined collector system is roughly \$10-\$30/m^2 less than that of separate (side-by-side) collector systems, at total array areas between 40-80 m^2. Below this range, allowable costs diverge, benefiting optimally sized separate collector systems. All systems look best when operating against all-electric homes. Retrofit applications appear favorable over newly designed homes, although here there is need to assess alternative retrofit options such as conservation.

ACKNOWLEDGMENTS

Many thanks to Barbara Grossman, P. Raghuraman, and Miles C. Russell at M.I.T. Lincoln Laboratory for providing us with the collector system models used in this analysis.

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I. INTRODUCTION

I.1 Scope and Objectives

The specific focus of this study is to establish the cost goals required to make residential photovoltaic/thermal collector systems economically competetive with conventional and other non-conventional energy systems. Combined photovoltaic/thermal collectors, hereafter referred to as PV/T or combined collectors, are compared with separate PV and thermal collector systems set side by side, and with PV alone. Each system is evaluated against four alternative means for satisfying the thermal portion of the residence load: all oil, all gas, all electric resistance, and electric resistance hot water with space heating by parallel heat pump. In each case an electric vapor compression unit was modeled for summer space cooling.

This study develops a base case set of market and financial parameters with which to simulate the cash flows for a PV/T investment starting in 1986 in each of three northern locations: Boston, Madison, and Omaha. The base case analysis includes a newly constructed residence equipped with boiler and heater units having efficiencies anticipated for 1986. The PV/T collector is of a flat-plate, liquid cooled design. An optimally sized collector system is then chosen for Boston where sensitivity studies are performed to selected physical, market, and financial parameters. In this extended analysis, a retrofit application is characterized and compared with the results for a newly constructed home.

I.2 Study Rationale

Combining the functions of solar photovoltaic and thermal collectors into a single module design is conceptually attractive for many reasons. First, the cost of a combined collector module should be markedly less than for separate collectors when added, since many of the collector components, e.g. glazing, substrate materials, support structures, shipping and installation costs, etc., are common. Also, combining the two functions strives to maximize the energy output over the often limiting variable of rooftop area.

Although such a combination has the potential to displace significantly more conventional fuel as does an equivalent area of separate collectors, the latter is not necessarily equivalent to the objective of an economically rational invester. For this reason, recent studies have either challenged the Department of Energy's impetus in PV/T development (see Hoover, 9) or have severely qualified the realm of application (See Russell, 11). Specific problems identified as limiting the viability of PV/T systems include:

- deleterious interactive effects of combining the functions of the two collectors. Thermal collectors are designed to absorb and transport maximum quantities of heat with large discrepancies in seasonal demand. Photovoltaic output, on the other hand, is inversely correlated with temperature, and utilizable year-round. For this reason, combined collectors are generally less efficient and have larger parasitic electrical demands for heat rejection in summer months[1].

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[1] Hoover (9) reports that, in a southern location, roughly three quarters of the combined collector area is required by PV-only for an equivalent electrical output.

- the optimal size of the two collectors are usually different. Photovoltaic systems, especially when supported by high rates for utility buy back, are optimally sized for much larger areas than are required for thermal output. Northern locations, with larger proportional thermal loads, are expected to improve PV/T worth for this reason.

Furthermore, Russell (11) has reported that, of series and parallel heat pump options for auxiliary thermal energy, parallel systems prove more cost effective. He also points out that, excepting breakthroughs in storage technology costs, on-site electrical storage leads to sub-optimal designs. Dinwoodie (8) and Caskey (6) offer detailed analysis to support this latter point.

All of the above were considered when formulating the objective, scope, and system description of this study.

I.3 Caveats

We wish to stress from the start the limitations inherent to this analysis. To start, our results derive from the use of a model describing one liquid-cooled PV/T collector design. The extended analysis portion examines the impact of variations in single physical parameters such as electrical efficiency, thermal emissivity, and storage tank volume, however the basic system configuration is left unchanged. Our results, therefore, apply only to the collector system as described in the next section. Secondly, the individual components of the collector system, such as pumps, storage tank, heat exchangers, and so forth, have been sized with engineering optimizing objectives, and not according to any form of operational cost minimization formula. The latter objective would obviously lead to improved system worth.

With regards to the base case economic analysis, it was debated whether to estimate required cost goals based upon the unsubsidized merits of system worth, or to assume market conditions for 1986 as an investor would see them. This would include, in all likelihood, some form of investment tax credit. The decision was to not model the tax credit. Since we are using prices for electricity, gas, and oil at expected deregulated prices beginning in 1986, the figures in the base case analysis represent costs which must be met in order to be competitive and unsubsidized prices. Any reasonable value for investment tax credit would be reduced from its current (1980) offering of 40 percent or $4,000 (maximum). Solar tax credits tend to come in solar packages with maximum credits applicable to the sum of solar investment options. Thus the "marginal" credit to a PV/T or some combination of PV and T would be something less than the maximum, given credits for passive design, a solar greenhouse, or other investor options. Of all things one may be sure of, the tax credits scenario for 1986 will be unlike what we see now. A sensitivity study to this important parameter is conducted in the extended analysis.

The final caveat to be mentioned here regards the use of residential loads which are established without consideration of the impact of other technologies, especially load management, upon the load profile. In an analysis of the impact of time of day rates upon PV/T worth, this fact may be important.

II. STUDY METHODOLOGY

II.1 PV/T Physical System Description

The PV/T collector system evaluated here is depicted in Figure 2-1. Since this system is assumed to run parallel to each backup system considered, there is little complication in defining precisely those components included when establishing allowable initial costs. These components include:

- PV/T solar collector
- thermal storage tank
- pre-heat storage tank
- all pumps
- heat rejection equipment
- assembly
- all distributor and manufacturer markups
- installation costs
- warranty costs

These "initial" costs are included in the breakeven capital cost figure, as calculated in section II.5. The allowable levelized annual costs figure includes, in addition, all annual costs as follows:

- annual insurance
- operation
- maintenance

The performance models describing the operation of the PV/T collectors, in addition to the PV and thermal-only collectors, were developed by Raghuraman at Lincoln Laboratory. System integration utilizing TRNSYS components was accomplisyhed by Russell, also at Lincoln Laboratory. Implementation of these models on the Optional Energy Systems Simulator[2] (OESYS) was carried out by the authors.

Pertinent parameters describing system components are presented in Figure 2-2. Characteristics of the separate PV and thermal collectors are described in Figures 2-3 and 2-4, respectively.

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[2] Developed by T.L. Dinwoodie, while at the MIT Energy Laboratory (8).

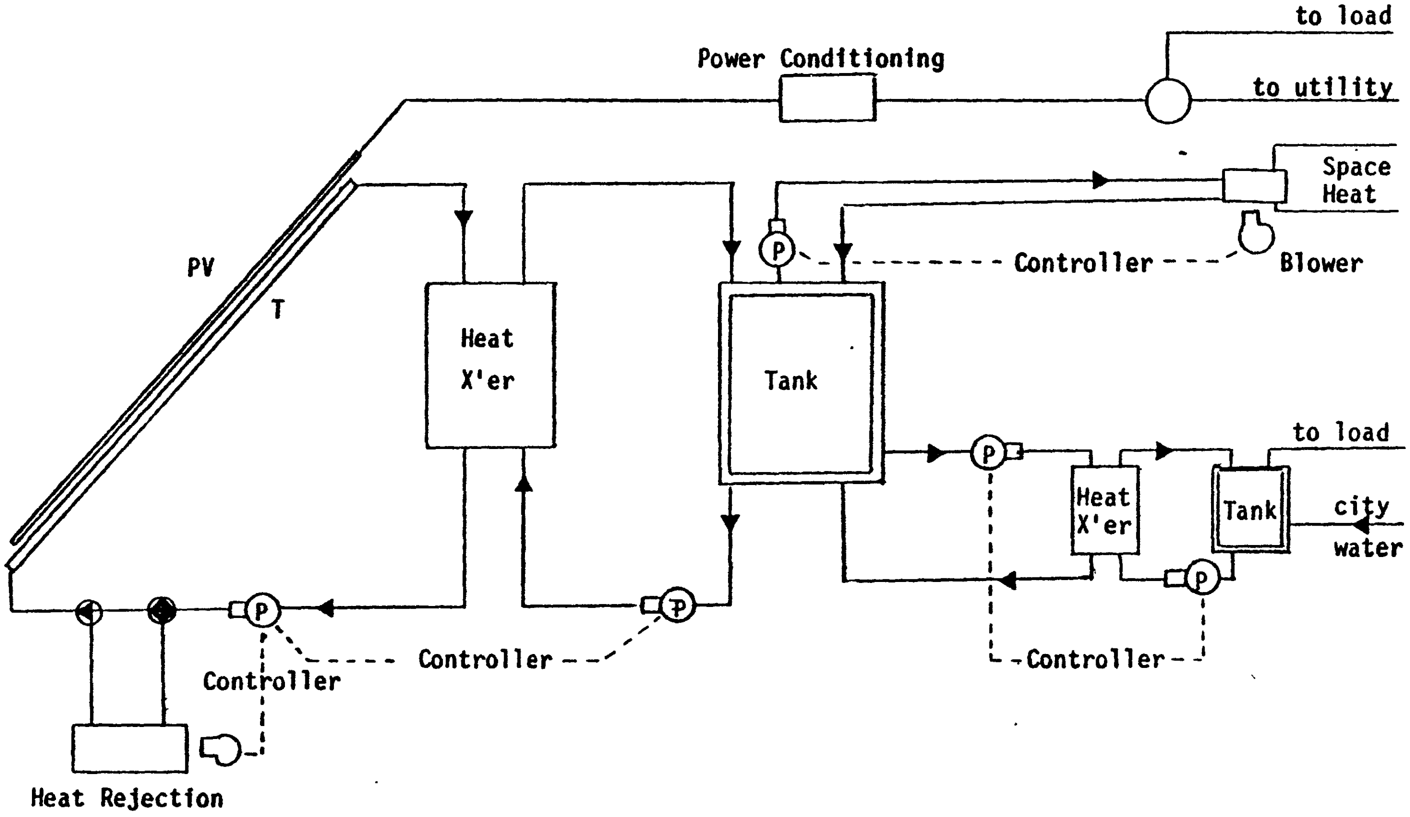

Figure 2-1

PV/T Collector System Description

Figure 2-2

PV/T Collector System Specifications

Collector Characteristics:

FLAT PLATE
non-concentrating
liquid-cooled
single-glazed
laminar tube flow

cell packing factor (total cell area/gross coll. area)	.90
cell envelope area/gross coll. area	.9
tilt angle (deg)	latitude + 5°
gap cell thickness (cm)	1.0
potant thickness (cm)	.05
Outer dia. of tube (cm)	1.6
Absorber plate thickness (cm)	.08
inner dia. of tube (cm)	1.27
potant conductivity (Wcm^{-1} °C^{-1})	.012
absorber plate conductivity (Wcm^{-1} °C^{-1})	2.0
cell emissivity	.10
cell IR absorptivity	.10
glass emissivity	.86
cell visible absorptivity	.89
glass transmissivity	.92
potant transmissivity	.85
absorber visible absorptivity	.95
cell reference efficiency	.135
cell efficiency temperature coefficient (°k^{-1})	.0045
cell efficiency reference temperature (°C)	28.
specific heat of liquid (Joules kg^{-1} °C^{-1})	4186.
length of cell envelope area (cm)	231.
number of tubes in collector	7.
thermal conductivity of liquid (Wcm^{-1} °C^{-1})	.0059

Storage Tank Characteristics

storage mass/collector area (kg/m^2)	50.
tank height 9m0	2.
specific heat (kJ/kg - °C)	4.186
fluid density (kg/m^3)	1000.
heat loss coefficient (kJ/hr-m^2 - °C)	1.5

Figure 2-3

PV-Only System Component Specifications

Glass thickness (cm)	.32
encapsulant thickness	.15
outermost substrate thickness (cm)	.10
conductivity of glass (w/cm°C)	.0105
conductivity of encapsulent (w/cm°C)	.00173
conductivity of substrate (W/cm°C)	.01
$\tau\alpha$ product of cell	.8
$\tau\alpha$ product between cells	.75
emissivity of glass	.88
emissivity of back surface	.9
packing factor (total cell area/gross cell area	.90
IR absorptivity of glass	.99
IR absorptivity of back surface	.9
visible absaorptivity of roof	.6
IR absorptivity of roof	.903
emissivity of roof	.903
reference cell efficiency	.135
Eff. charge coefficient	.0045
reference temperature for ref cell efficiency (°C)	28.
mounting angle from horizontal	latitude + 5°

Figure 2-4

Thermal-Only System Component Specifications

collector efficiency factor	.95
fluid thermal capacitance (kg/kg °C)	3.35
collector plate absorptance	.9
number of glass covers	1
collector plate emittance	.10
loss coefficient for bottom and edge losses	1.06
collector tilt angle (degrees)	latitude + 5°
transmittance	.9

II.2 Residence Description

The residence energy loads are divided into stochastic electrical and thermal (weather-dependent) loads. The stochastic load profile is a probabilistic description of household electrical appliance demand obtained from the Residential Electric Appliance Simulator (REAS).[3] The weather dependent loads were obtained from a General Electric model of a detached, northern climate, two-level single family house (See Scollon. 12). The weather data included a typical meteorological year in each location, and the solar technologies were modeled using hour by hour matching for the same weather year. A summary of station characteristics for each of the three loactions are presented in Figure 2-5.

Thermal energy demands for space heating and hot water were satisfied by several conventional sources while supplemented by the PV/T collector output. THe conventional backup alternatives modeled in this analysis include:

- gas space heating, vapor compression cooling, gas hot water heating
- oil heating, vapor compression cooling, oil hot water heating
- electric resistance heating, vapor compression cooling, electric hot water heating
- parallel connected heat pump for space heating and cooling, electric resistance hot water heating.

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[3] Developed at the M.I.T. Energy Laboratory by William A. Burns and described in (5).

Figure 2-5

Summary of Station Characteristics

```
**************************************************************************
            STATION:  BOSTON                          STATE:  MA
            ----------------------------------------  ----------
STATION NUMBER:  94701  LATITUDE:  4222N  LONGITUDE:   7102W  ELEVATION:        5
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                                        NORMAL DEGREE          TOTAL HEMISFHERIC
     NORMAL TEMPERATURE (DEG F)*           DAYS*          MEAN DAILY SOLAR RADIATION#

        DAILY     DAILY                BASE 65 DEG F
MONTH MAXIMUM   MINIMUM   MONTHLY   HEATING   COOLING      BTU/FT2     KJ/M2    LANGLEYS

 JAN    35.9      22.5      29.2      1110        0          475.5    5396.0     129.0
 FEB    37.5      23.3      30.4       969        0          709.6    8053.0     192.5
 MAR    44.6      31.5      38.1       834        0         1016.4   11535.0     275.7
 APR    56.3      40.8      48.6       492        0         1325.8   15046.0     359.6
 MAY    67.1      50.1      58.6       218       20         1620.5   18391.0     439.6
 JUN    76.6      59.3      68.0        27      117,        1817.1   20622.0     492.9
 JUL    81.4      65.1      73.3         0      260         1749.2   19852.0     474.5
 AUG    79.3      63.3      71.3         8      203         1486.5   16870.0     403.2
 SEP    72.2      56.7      64.5        76       61         1259.9   14293.0     341.7
 OCT    63.2      47.5      55.4       301        0          889.6   10096.0     241.3
 NOV    51.7      38.7      45.2       594        0          502.9    5707.0     136.4
 DEC    39.3      26.6      33.0       992        0          403.0    4574.0     109.3
 ANN    58.7      43.8      51.3      5621      661         1104.7   12537.0     299.6

* BASED ON 1941-1970 PERIOD                            # AS NOTED IN SOLMET VOLUME 1
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**************************************************************************
            STATION:  MADISON                         STATE:  WI
            ----------------------------------------  ----------
STATION NUMBER:  14837  LATITUDE:  4308N  LONGITUDE:   8920W  ELEVATION:      262
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                                        NORMAL DEGREE          TOTAL HEMISPHERIC
     NORMAL TEMPERATURE (DEG F)*           DAYS*          MEAN DAILY SOLAR RADIATION#

        DAILY     DAILY                BASE 65 DEG F
MONTH MAXIMUM   MINIMUM   MONTHLY   HEATING   COOLING      BTU/FT2     KJ/M2    LANGLEYS

 JAN    25.4       8.2      16.8      1494        0          515.2    5847.0     139.7
 FEB    29.5      11.1      20.3      1252        0          804.0    9125.0     218.1
 MAR    39.2      21.2      30.2      1079        0         1136.0   12892.0     308.1
 APR    56.0      34.6      45.3       591        0         1398.4   15870.0     379.3
 MAY    67.3      44.6      56.0       297       18         1743.2   19784.0     472.8
 JUN    76.9      54.6      65.8        72       96         1947.9   22107.0     528.4
 JUL    81.4      58.8      70.1        14      172         1934.4   21953.0     524.7
 AUG    80.0      57.3      68.7        39      154         1708.1   19385.0     463.3
 SEP    70.9      48.5      59.7       173       14         1299.4   14747.0     352.5
 OCT    60.9      38.9      49.9       474        6          910.9   10338.0     247.1
 NOV    43.0      26.4      34.7       909        0          504.2    5722.0     136.8
 DEC    29.8      14.0      21.9      1336        0          388.9    4414.0     105.5
 ANN    55.0      34.8      44.9      7730      460         1190.9   13515.0     323.0

* BASED ON 1941-1970 PERIOD                            # AS NOTED IN SOLMET VOLUME 1
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**************************************************************************
            STATION:  NORTH OMAHA                     STATE:  NE
            ----------------------------------------  ----------
STATION NUMBER:  94918  LATITUDE:  4122N  LONGITUDE:   9601W  ELEVATION:      404
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                                        NORMAL DEGREE          TOTAL HEMISPHERIC
     NORMAL TEMPERATURE (DEG F)*           DAYS*          MEAN DAILY SOLAR RADIATION#

        DAILY     DAILY                BASE 65 DEG F
MONTH MAXIMUM   MINIMUM   MONTHLY   HEATING   COOLING      BTU/FT2     KJ/M2    LANGLEYS

 JAN    29.1      11.2      20.2      1389        0          634.0    7195.0     172.0
 FEB    34.8      16.1      25.5      1106        0          892.1   10124.0     242.0
 MAR    44.1      25.1      34.6       942        0         1222.5   13874.0     331.6
 APR    61.0      38.9      50.0       456        6         1558.4   17686.0     422.7
 MAY    71.4      50.4      60.9       186       59         1872.6   21252.0     507.9
 JUN    80.2      60.2      70.2        33      189         2122.5   24088.0     575.7
 JUL    85.4      64.8      75.1         7      320         2106.5   23906.0     571.4
 AUG    84.0      63.4      73.7        10      280         1858.5   21092.0     504.1
 SEP    75.2      53.6      64.4        99       81         1373.2   15584.0     372.5
 OCT    65.9      42.8      54.4       342       14         1049.8   11914.0     284.8
 NOV    47.4      28.3      37.9       813        0          644.1    7310.0     174.7
 DEC    34.3      17.0      25.7      1218        0          511.2    5802.0     138.7
 ANN    59.4      39.3      49.4      6601      949         1320.5   14936.0     358.2

* BASED ON 1941-1970 PERIOD                            # AS NOTED IN SOLMET VOLUME 1
**************************************************************************
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The boiler and heater efficiencies used in this analysis were derived from telephone conversations and literature research directed at unit efficiencies likely available for 1986 installation. These efficiencies, in terms of overall average fuel use, are depicted in Figure 2-6. Sensitivity runs were performed on these parameters in the extended analysis.

Figure 2-6

Average Fuel Use Efficiencies
for
Domestic Boilers and Hot Water Heaters

1986 Technology

TYPE	Average Fuel Use Efficiency	Efficiency Range
	Boilers	
OIL*	81%	70-90%
GAS**	69%	60-80%
Electric Resistance	100%	
	Hot Water	
OIL	60%	45-65%
GAS	60%	50-70%
Electric	86%	80-90%

*taken from the upper range of currently available efficiencies as listed in (13).

**telephone conversation with Charles Steats, Bradford Wright Corp. 7/29/80 these numbers were confirmed as reasonable by others in the field.

II.3 The Finance Simulation Method

Finance modeling was carried out on the Optional Energy Systems Simulator (OESYS)[4] using a cash flow analysis of a standard homeowner mortgage. The method used is depicted in Figure 2-7. Here, we compute the system breakeven capital cost by determining that initial cost, I, where the net benefits just equal zero. Simulating annual cash flows differs from closed form solutions in its accountability of time varying inflation, fuel escalation, and tax rates, in the treatment of investment tax credits, and in determining tax benefits due to time-varying interest charges. Comparison and assessment of the various homeowner finance models currently being applied to photovoltaic investments is discussed by Cox (3).

II.4 Base Case Market/Financial Parameters

Those parameters which are independent of the solar investment but which directly impact the prospects for that investment are listed here as market parameters. These include fuel and electricity prices for backup service, time-varying escalation rates applied to these prices, the general inflation rate, and others. The values assumed for these parameters are listed in Figures 2-8 through 2-10.

Figure 2-10 also presents a conservative set of base case parameters effecting project finance. The zero value assumed for an investment tax credit in 1986 allows an unsibsidized allowable cost to be computed. A discussion of this is found in section I.3. Figure 2-10 also presents system annual costs used in the breakeven capital cost analysis. The breakeven capital cost figure represents the *initial* allowable system cost only.

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[4] Developed by T.L. Dinwoodie at the MIT Energy Laboratory.

Figure 2-7

Mortgage Finance Method

$$NB = \sum_{t=1}^{L} \frac{\alpha^{y-yb} \cdot \gamma_j^{y-yb} \cdot B_{tj} - \alpha^{y-yb} \cdot OM_t + G_t - T_t}{(1+r)^t \cdot \alpha^{y-yb}}$$

$$- \beta \cdot I \cdot D - \sum_{t=1}^{\Gamma} \frac{P_t - (1 - TR_t)\, F_t}{(1+r)^t \cdot \alpha^{y-yb}} .$$

where,

$NB =$ net benefits to accrue to the project over its operating life

$\alpha^{y-yb} =$ general inflation multiplier computed for the current calendar year y with respect to some base year yb.

$\beta =$ capital escalator computed for the construction year with respect to some base year.

$\gamma_j^{y-yb} =$ real price escalator applied to displaced conventional energy j (different rates applied to electricity, oil, gas, etc.) during the current calendar year y with respect to some base year y_b

$B_{tj} =$ returns to the project in year t in terms of the value of displacing conventional energy of type j.

$D =$ percent down payment/100.

$G_t =$ investment tax credit allowed in year t

$I =$ initial capital cost

$j =$ denotes type of energy diplaced (electricity, gas, oil)

$\Gamma =$ mortgage life

$L =$ project life

$OM_t =$ annual (in year t) operating and maintenance costs including insurance costs.

Figure 2-7 (cont'd)

r = homeowners discount rate

t = project year

T_t = sum of taxes in year t

TR_t = homeowner's tax rate in year t

F_t = mortgage interest charge in year t computed as

$F_t = A - P_t$, where;

A = annual mortgage payment, given by

$A = I\ .\ (1 - D)\ .\ (i/[1 - 1/(1 + i))^N])$

i = annual mortgage rate

P_t = payment required on the balance of principle in year t, from

$P_t = i\ .\ BAL_t$, where

$BAL_t = A\ [1 - 1/\ (1 + i)^{N-t+1}]\ /i$

Figure 2-8

Average Residential Fuel Prices
for the First Quarter, 1980

	Heating Oil[*] (cents per gallon)		Natural Gas[#] (dollars per million BTU's)	
	1980 Price	1986[#] Adjusted Price (1980 $)	1980 Price	1986[+] Adjusted Price (1980 $)
NEW ENGLAND (Boston)	96.7	116.04	4.92	8.12
EAST NORTH CENTRAL (Madison)	93.5	112.20	3.16	6.32
WEST NORTH CENTRAL (Omaha)	93.6	112.20	2.79	5.58

[+] The 1986 price is the 1980 price adjusted for deregulation. For oil this is given by a 20% increase over the 1980 price. For natural gas, this is given by either price doubling or the cost of gas at an equivalent BTU content of oil at the adjusted price, whichever is minimum. Estimates for deregulation of gas prices suggest these prices will double, but it is unlikely that they will exceed the cost of deregulated oil on an equivalent energy content basis.

[*] Source: Energy Data Report DOE/EIA - 0013(80/03)

[#] Source: American Gas Association

Figure 2-9

Base Case
Residential Electricity Rates by Region*
(Based on Average 600 kwh/month Usage)

Boston

Fixed Charge	$1.17/month
per kwh/charge	3.95¢/kwh
fuel adjustment	3.905¢/kwh
	7.86¢/kwh

Madison

Fixed charge	$2.50/month
per kwh/charge	4.14¢/kwh
fuel adjustment	$ .52¢/kwh
	4.66¢/kwh

Omaha

Fixed charge	$3.95/month
per kwh/charge	3.64¢/kwh
fuel adjustment	.208¢/kwh
	$3.85¢/kwh

* Source: Correspondence with the electric utility in each respective region

Figure 2-10

Base Case Market/Financial Parameters and Annualized Costs

Market Parameters	
Escalation in Home Heating Oil Prices (real)	2%/year
Escalation in Gas Prices (real)	2%/year
Escalation in Electricity Prices (real)	1%/year
General Inflation Rate	12% in 1980, declining linearly to 6% in 1986, 6%/year thereafter
Utility Buyback Rate	.80

Finance Parameters	
System Installation Date	1986
System Lifetime	20 years
Homeowner Discount Rate (real)	5%
Homeowner Tax Rate	35%
Mortgage interest rate (real)	3%
Down payment	10%
Investment tax credit	0
Property taxes	0

Annualized Costs	
Cleaning and Inspection	(Annual Cost)
PV-only system*	$\$25 + \$1.00/\mathrm{m}^2$
PV + T side by side#	$\$25 + \$1.00/\mathrm{m}^2$
Combined Collector#	$\$25 + \$1.00/\mathrm{m}^2$
Maintenance	(Present value at 5% discounting)
PV-only System	$\$13.00/\mathrm{m}^2$
PV + T Side by Side#+	$\$13/\mathrm{m}^2\mathrm{PV} + \$62 + 5.00/\mathrm{m}^2\mathrm{T}$
Combined Collector#	$\$62 + \$18/\mathrm{m}^2$
Insurance	(Annual Cost)
All systems	\$30 for first 5K of system cost; \$2/1k each additional 1k

* See Cox (7).

\# Obtained from telephone conversations with solar-thermal installers. Most influential was Lou Boyd, Solar Solutions, Inc., Natick, MA. Maintenance costs were broken down into annual checkup and expected (1986) component failure probabilities coupled with the probability of the cost of repair.

\+ The $\$62.00 + \$5.00/\mathrm{m}2_T$ is attributable to the thermal system.

II.5 Description and Derivation of the Performance Evaluation Parameters

Three figures of merit are utilized in this analysis, each of which assesses an allowable system cost. These include an allowable combined collector cost for comparison with side by side collectors, a breakeven capital cost, and an allowable levelized annual cost. They are taken in order here.

Side by Side Collector Comparison

This analysis follows directly from a study conducted by Hoover(9) addressing those conditions under which a flat plate PV/T collector can compete with separate photovoltaic and thermal collectors. This method determines the allowable combined collector cost given 1) the cost of PV and thermal collectors, and 2) the separate PV and thermal array areas required to produce electrical and thermal output equivalent to the combined collector. Derivation of allowable combined collector cost is given by the following example

The thermal performances of a combined collector and two thermal collectors are shown in Figure 2-11. This figure suggests that 13 m^2 of a thermal collector with 10 percent infrared emittance, the same emittance modeled for the combined collector, yields a solar fraction equivalent to 40 m^2 of combined collectors. Emissivities characteristic of non-selective surface thermal collectors are around 80 percent, which requires roughly 26 m^2 for equivalent output. Figure 2-12 presents the electrical output characteristics of photovoltaics-only verses that of a combined collector. Output from the latter has been reduced by the parasitic electrical requirements of the collector pump and of the heat rejection unit.

Figure 2-11

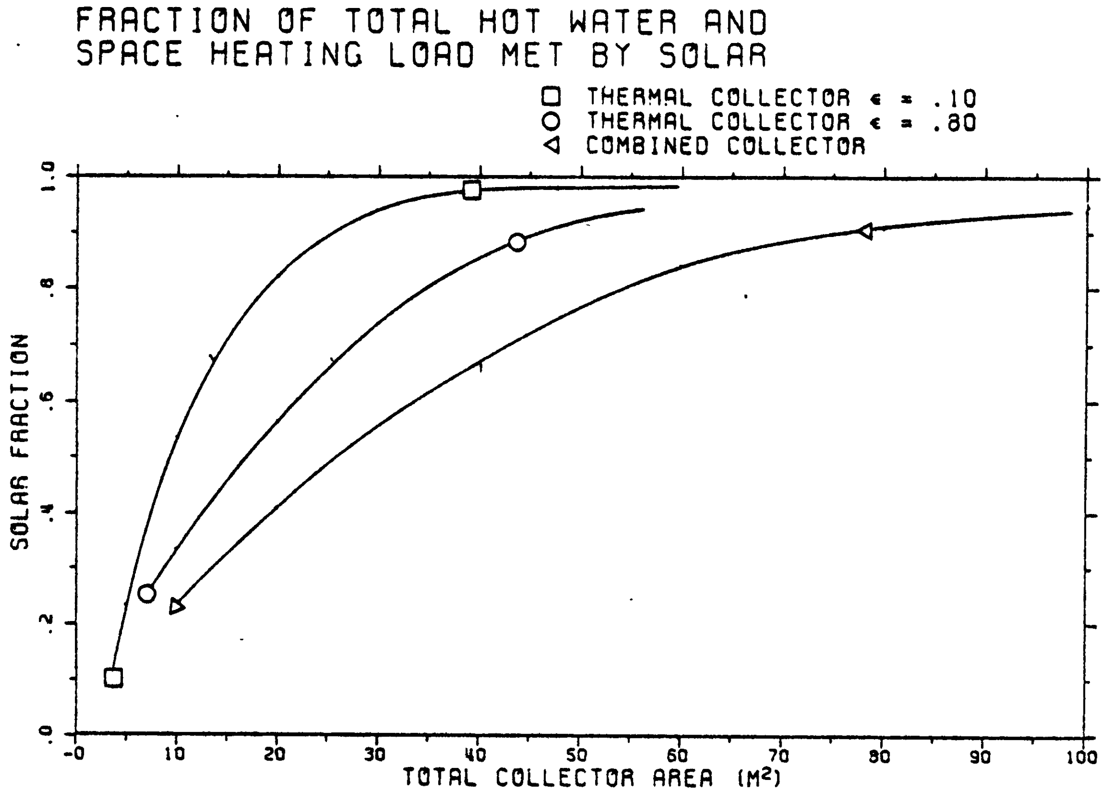


Figure 2-12

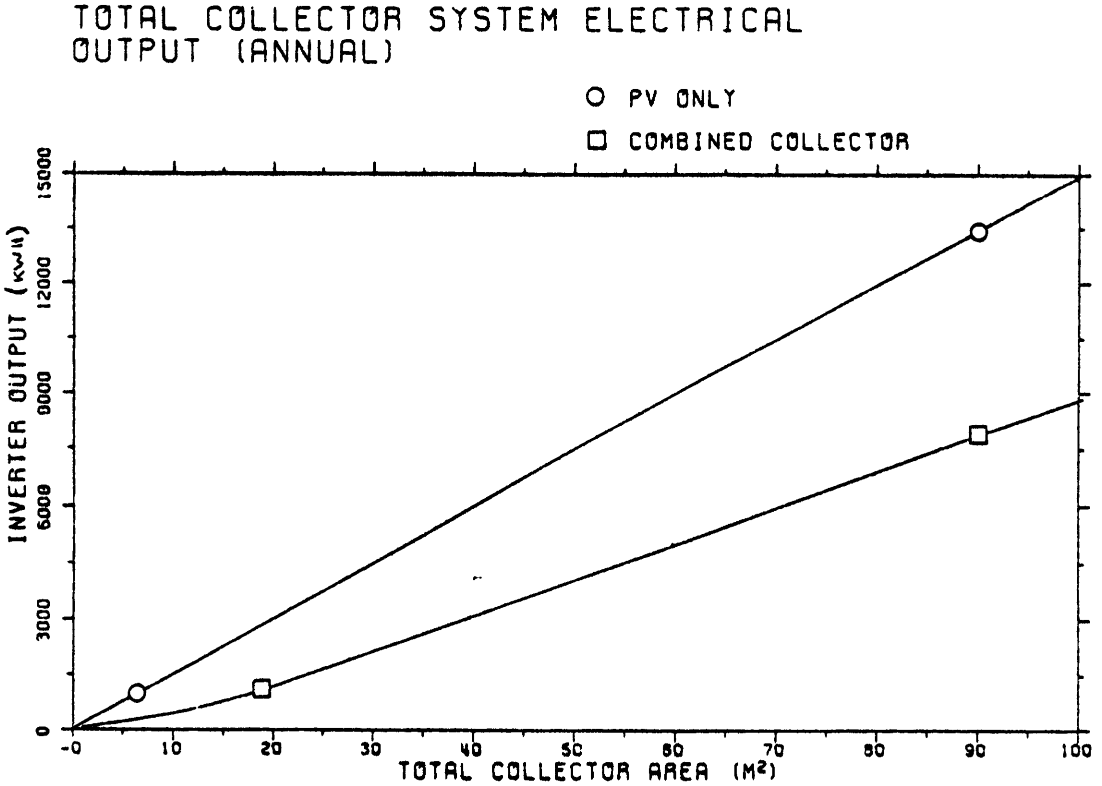


Figure 2-13 next illustrates the parasitic electrical demand placed by the various collectors. The difference in parasitic demand between 40 m^2 of combined collector and an "equivalent" area of thermal collector (ε = .80 at 26 m^2) is 1000 kwh. Adding this to the combined collector output of Figure 2-12 is necessary in order to compare directly with the net output of an equivalent side by side PV and thermal system. (Equivalently, this difference in parasitic demand is <u>subtracted</u> from the gross output of a PV-only system to reflect that energy which went toward satisfying the parasitic demand of an accompanying thermal system.)

Thus, if we add 1000 kWh to the net annual electrical output of the combined collector (on Figure 2-12), we find that the equivalent PV-only is roughly 27 m^2. Assuming a cost for both a photovoltaic module and thermal collector allows computation of the maximum allowable combined collector cost by the following relationship:

$$AC_{CC} = \frac{A_{PV}}{A_{CC}} \quad C_{PV} + \frac{A_{TC}}{A_{CC}} \quad C_T$$

where

AC_{CC} = allowable cost for the combined collector, \$/m^2

A_{PV} = equivalent PV collector area, m^2

A_{CC} = combined collector area, m^2

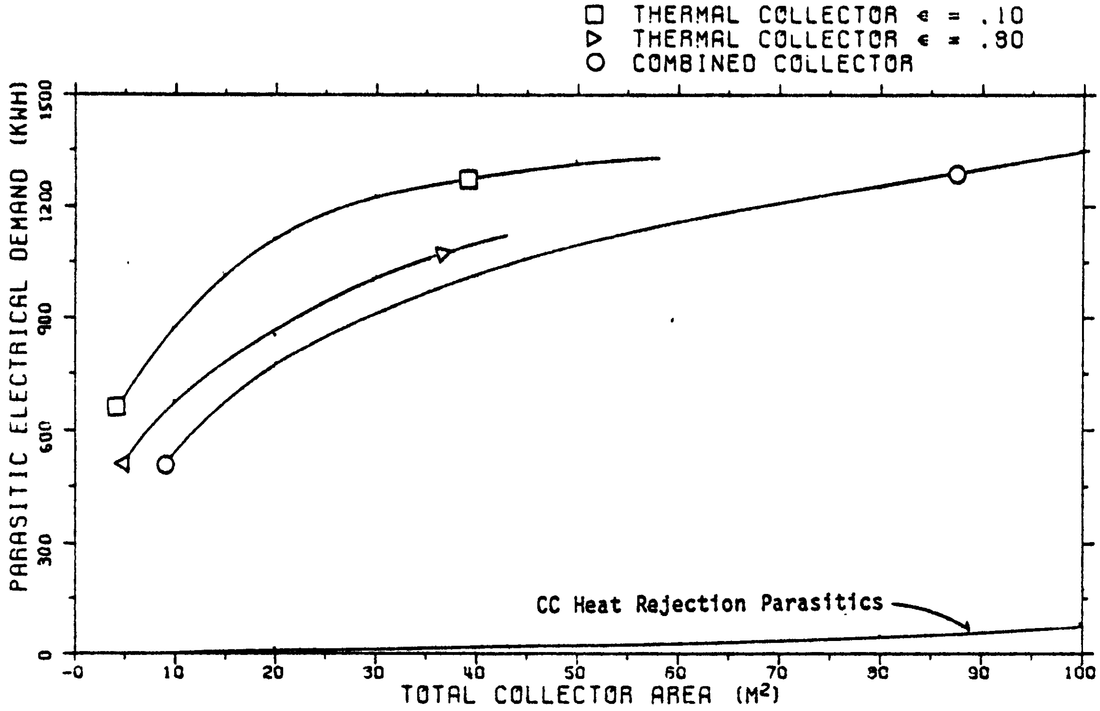
A_{TC} = equivalent thermal collector area, m^2

C_{PV} = PV module cost, \$/m^2

C_T = Thermal collector cost, \$/m^2

Figure 2-13

PARASITIC ELECTRICAL REQUIREMENTS



For our example, we fix the PV cost at \$70/m^2 and, in Figure 2-14, plot the allowable combined collector cost as a function of thermal collector cost. We see that for a selective surface thermal collector cost of \$100/m^2 and PV module at \$70/m^2, the allowable cost for the combined collector is \$90/m^2. By assuming that the thermal collector portion of the combined collector costs the same to manufacture as a separate thermal-only system, we can determine the allowable incremental cost for adding PV cells to the thermal collector. This is accomplished in Figure 2-15 by subtracting a line of slope 1 from the lines of Figure 2-14. For thermal collector costs above \$160/m^2 we could not afford to pay anything for the addition of PV cells.

The latter methodology, leading to Figures 2-14 and 2-15, are taken directly from Hoover's analysis and utilized in this report when comparing PV/T with side by side collectors. It is important to note the

Figure 2-14

ALLOWABLE COMBINED COLLECTOR COST WHEN COMPARING SIDE BY SIDE PV AND T COLLECTORS

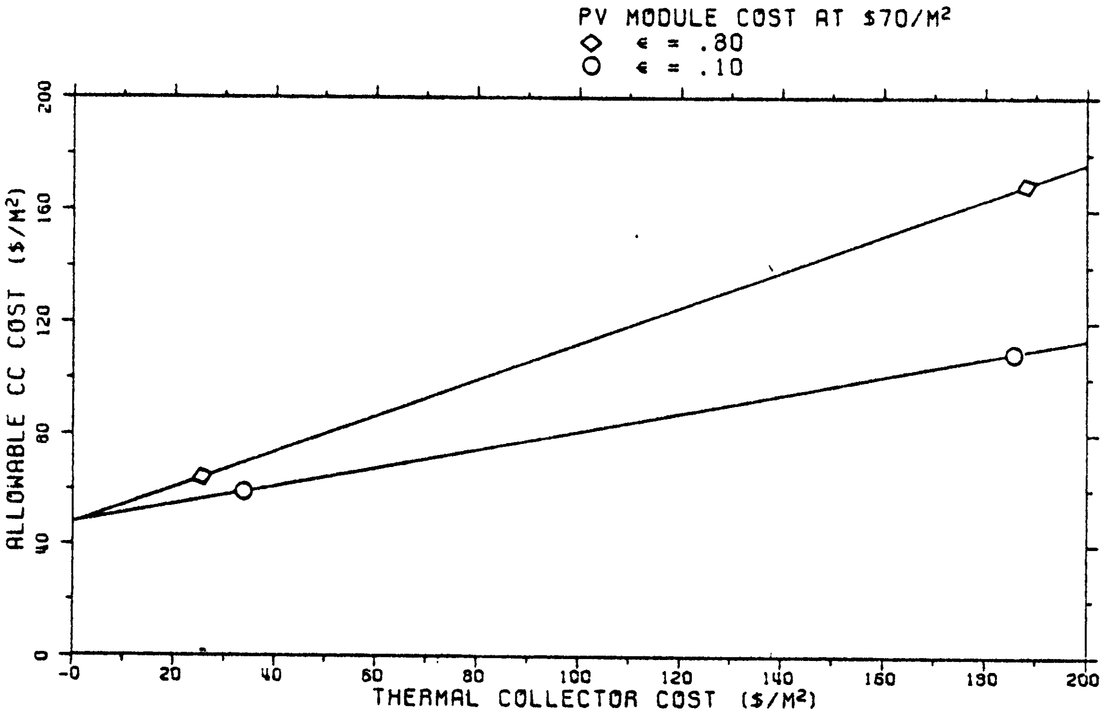
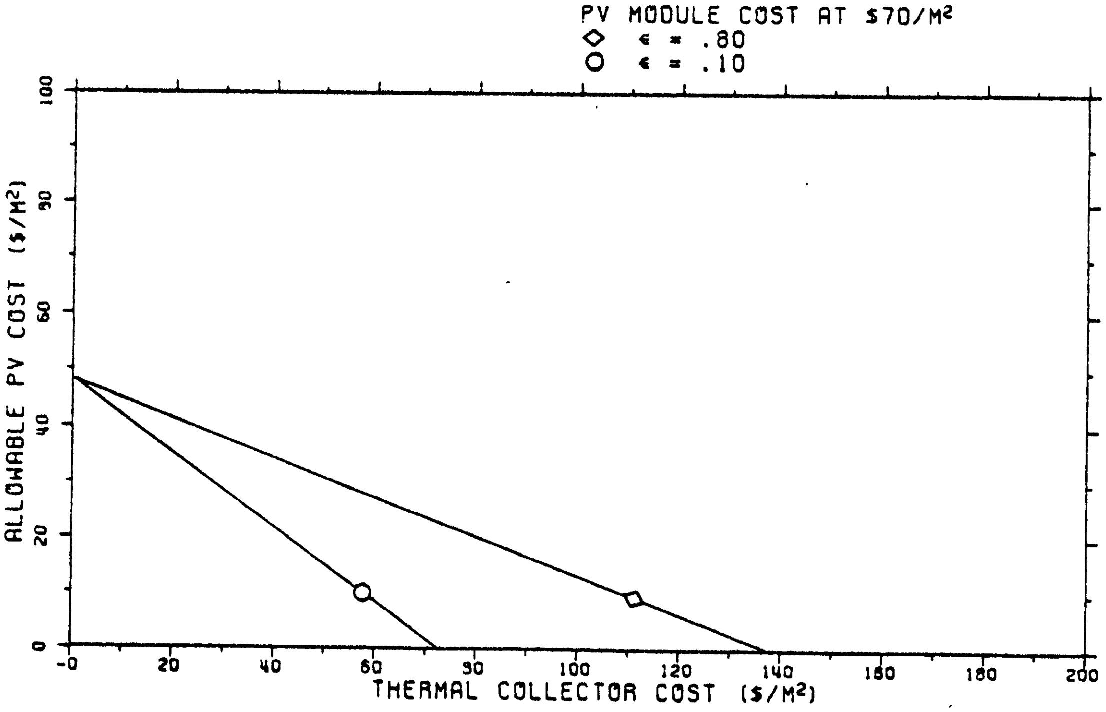


Figure 2-15

INCREMENTAL ALLOWABLE PV COST FOR COMBINED COLLECTOR



shortcomings of this method, many of which are outlined by Hoover (9). First, this technique holds that the proportional electrical vs: thermal output of a combined collector is maintained by side by side collectors. In fact, the optimum relative areas of separate PV and thermal collectors may be quite different from the "equivalent" areas, and hence the separate collector system may prove significantly more attractive than the computed "allowable" PV/T costs suggests. We attempt to resolve this problem by including varying PV and thermal collector area ratios when comparing side by side with combined collectors in the breakeven cost analysis.

Furthermore, this analysis does not consider the cost of a heat rejection unit required by the combined collector system, and the size of the thermal system components, especially collector pumps, piping, and the storage tank, would be less than for the combined collector system. These costs may or may not be offset by the reduced cost of installation of a single collector system.

Breakeven Capital Cost

The method used to compute the collector system breakeven capital cost was presented in Section II.3. Figure 2-16 illustrates how this quantity is depicted in this analysis. Since our base case analysis uses a 5 percent homeowner discount rate, multiplication of all figures shown by .0802, the capital recovery factor for a 20-year life at 5 percent, yields an equivalent allowable levelized annual cost under the given financing conditions.

To arrive at the familiar $/Wp, the vertical axis can be divided by the overall array efficiency times 1000 W/m^2 standard peak insolation. The overall array efficiency is the average cell efficiency times the array packing factor times the front panel reflectance. For our base case analysis, this figure is .014, so that the total divisor is 104.

Allowable Levelized Annual Cost

This figure is arrived at as a function of collector area but independent of all financial parameters excepting the investors discount rate and the rate of inflation. It is calculated as the equivalent annual payment which results from applying a capital recovery factor to the sum of discounted yearly payments. The conventional manner for computing capital recovery factor is given by

$$CRF = \frac{r'(1 + r')^N}{(1 + r')^N - 1} .$$

In order to arrive at a capital recovery factor in constant (base year) dollars, as opposed to current year (nominal) dollars, we calculate the discount rate r' to be the real (or inflation adjusted) discount rate, defined as

$$r' = \frac{1 + r}{1 + g} - 1$$

where g is the general inflation rate.

Estimation of this relationship is depicted in Figure 2-17. Curve A is the levelized annual cost to the homeowner of satisfying all residence energy demand by conventional means, in this case, all oil. It is the levelized annual cost of all heating oil and electricity as billed by the utility. Curve B is the same levelized annual cost as presented by utility bills, but with a solar system supplementing. The difference between these two curves, Curve C, is that levelized annual cost which a homeowner may be willing to pay for that solar system. Since the

Figure 2-16

SYSTEM BREAKEVEN CAPITAL COSTS COMPARISON OF ALTERNATIVE COLLECTOR SYSTEMS

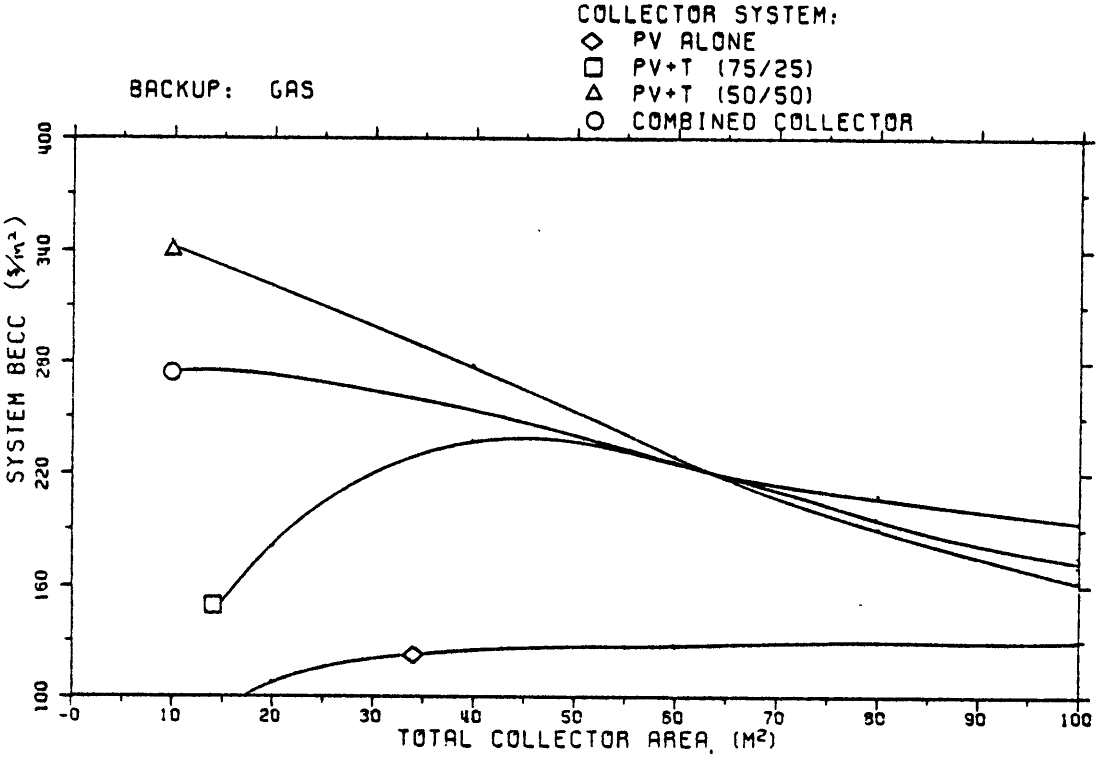
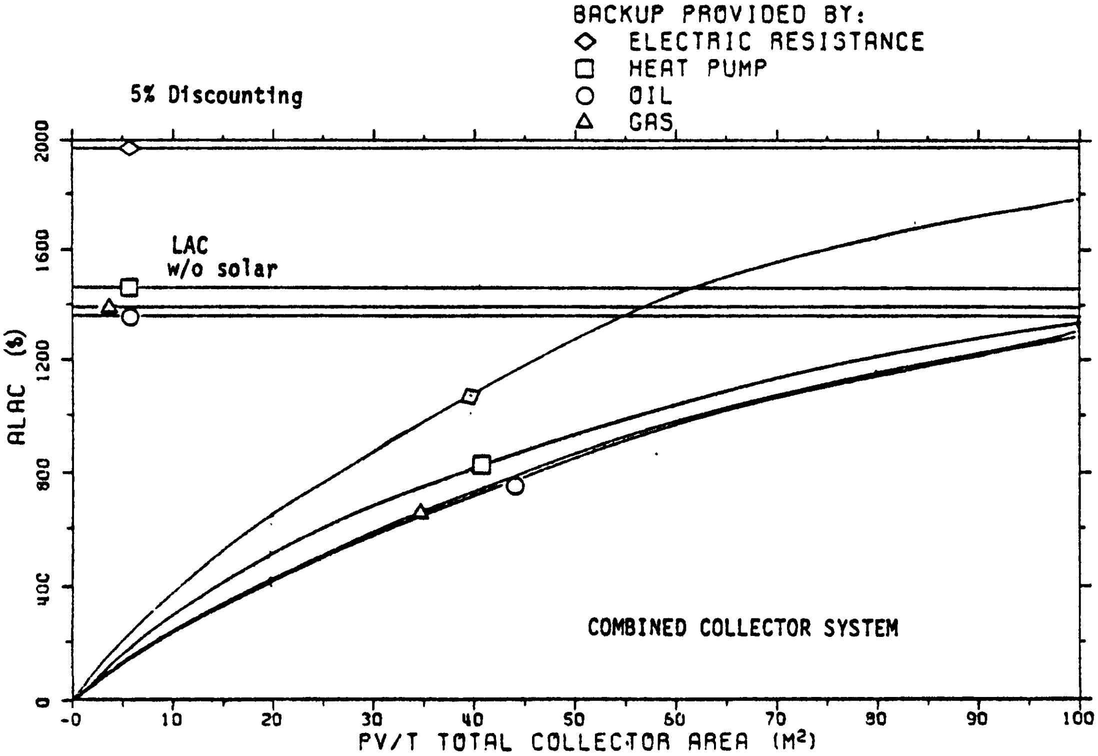


Figure 2-17

ALLOWABLE LEVELIZED ANNUAL COST ANALYSIS



homeowner is assumed to pay monthly energy bills out of hand (not by borrowing), only his/her rate of discount of future cash payments enters into the investment decision. However, computation of the solar system levelized annual cost, for comparison with this allowable costs figure, must account for the effects of borrowing.

There is an important distinction to be made between the system breakeven capital cost and the allowable levelized energy cost as presented here. First, those costs which these figures take account of differ, as described in section II.1. The system BECC only accounts for all first-year costs, not annual costs. Second, the system BECC takes into account financing, and for the base case financial parameters assumed, this figure yields a higher levelized annual cost than the ALAC method. There are two reasons for this. First, setting the discount rate higher than the mortgage interest rate results in having acquired a loan with a positive net value to the borrower. Second, the tax effects of borrowing improve system worth by offering deductions on the interest payments. If, in the system BECC formulation, the tax rate is set to zero and the discount and interest rates set equal, application of the capital recovery factor to the total system BECC should result in the ALAC computed by the alternative method. Since in our formulation of the BECC we subtract out all annual (O and M plus insurance) payments, our levelized annual cost computed from the BECC is lower than the ALAC by just the equivalent levelized annual O and M costs assumed. This has provided an important check on our results.

The allowable LAC curve represents costs below which the levelized annual costs must lie, however they may be financed. This is the attractive feature of the ALAC formulation. One is free to choose his or her own finance parameters (down payment, tax credit, interest rate, etc.), remaining consistent only with the discount rate and utility price escalation rates assumed.

III. BASE CASE STUDY

III.1 Boston Residence

Typical annual meteorological conditions were depicted for Boston in Figure 2-5. These conditions translate into the following annual house loads:

Space Heating:	33.285 MBtu's
Space Cooling:	4.012 MBtu's
Hot Water Heating:	16.776 MBtu's

In addition, the residence had a non-weather-related stochastic electricl load which summed to 5886 kWh for the year. This latter figure does not include the parasitic electrical demand of the solar collector system.

System Performance

Figure 2-18 compares collector system thermal performance characteristics. The vertical axis is the fraction of solar system supplied hot water and space heating load over the total house space heating and hot water load. Figure 2-19 presents the electrical output characteritics of both a PV-only and PV/T collector system. The PV/T system output is shown reduced by its parasitic electrical requirement. Parasitic electrical requirements for both thermal and combined collector systems are plotted as a function of collector area in Figure 2-20.

The various economic figures of merit utilized in performance evaluation were described in section II.5. They are examined here in order.

Figure 2-18

FRACTION OF TOTAL HOT WATER AND SPACE HEATING LOAD MET BY SOLAR

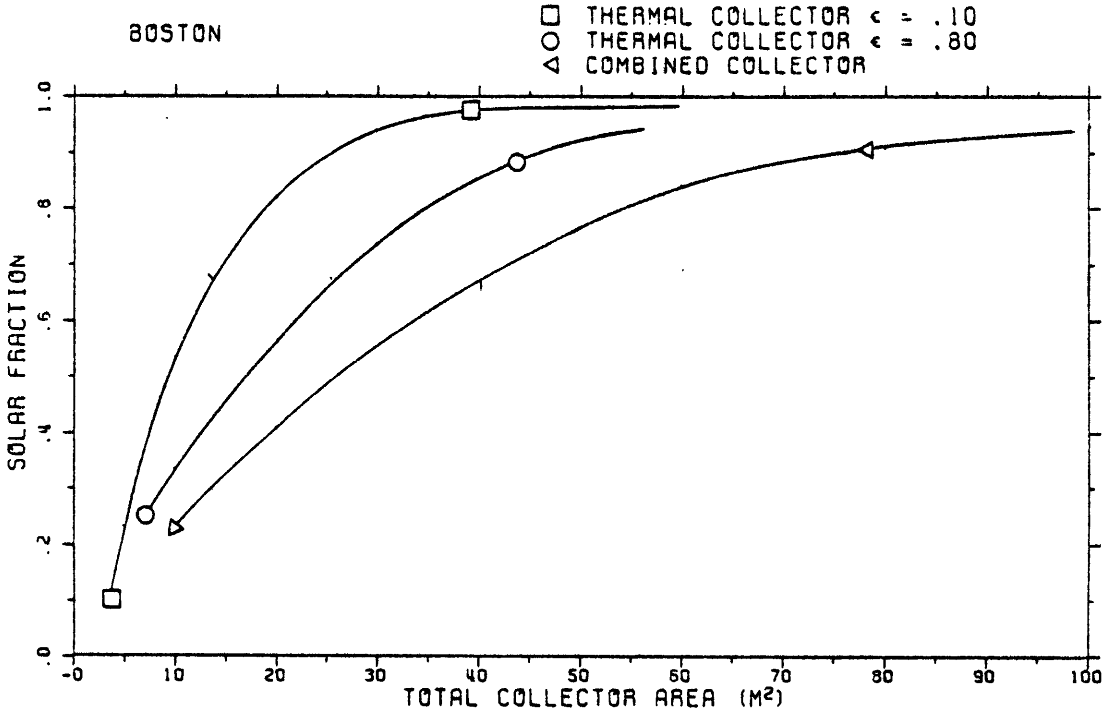


Figure 2-19

TOTAL COLLECTOR SYSTEM ELECTRICAL OUTPUT (ANNUAL)

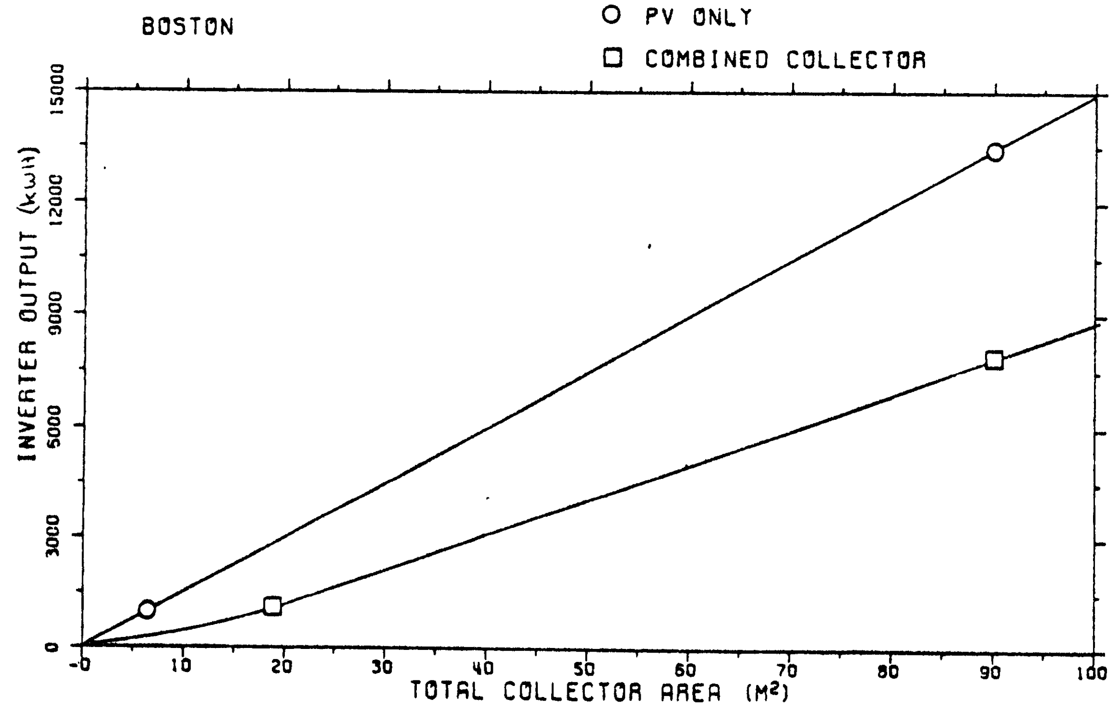
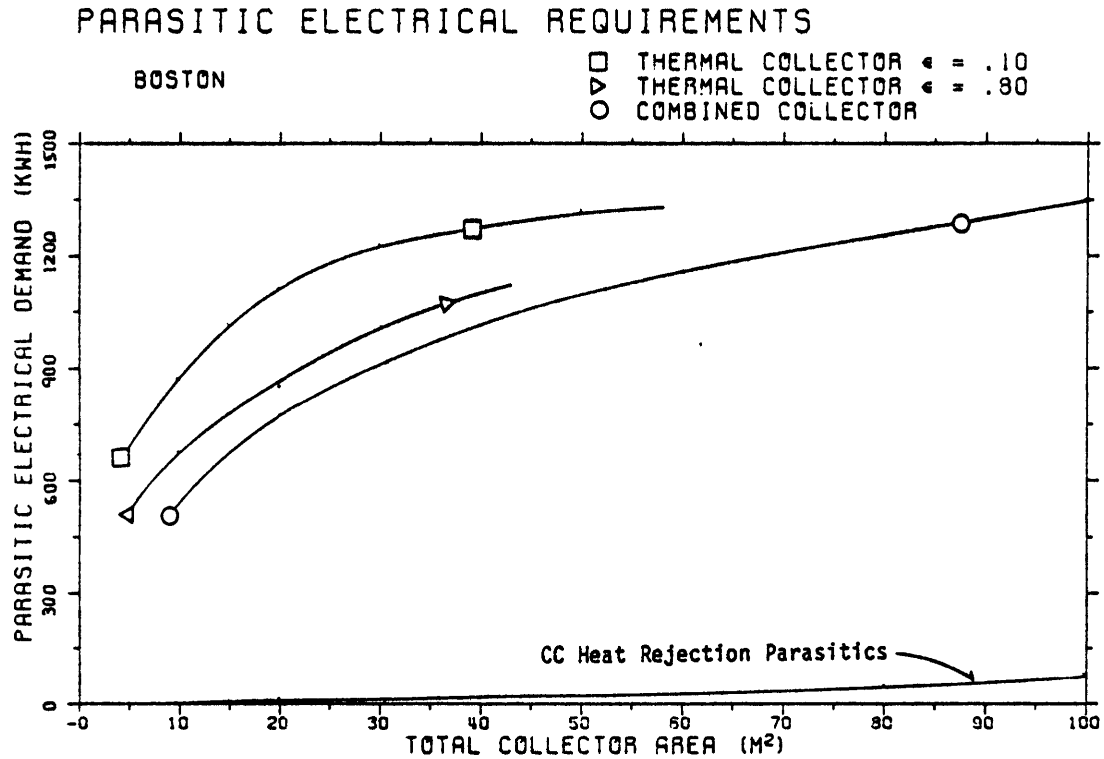


Figure 2-20



Side-by-Side Collector Comparison

Allowable combined collector costs, as defined in section II.5, are shown plotted in Figure 2-21. Figure 2-22 depicts the incremental allowable combined collector cost. We find that we could afford to pay zero dollars for inclusion of the solar cells if the thermal collector costs were greater than $\$80/m^2$, when comparing with side-by-side systems having selective surface absorbers. Since flat-plat selective surface collector costs range typically from $\$80$-$\$150/m^2$, this analysis does not appear to favor combined collector systems for Boston.

Cost Effectiveness with Alternative Backup Systems

The combined photovoltaic/thermal collector system is modeled in tandem with each of the four types of conventional backup systems and a breakeven cost analysis is made as performed in Figure 2-23. Figures 2-24 through 2-28 allow comparison of PV/T with PV-only and side-by-side collector systems, again for each backup type. Careful attention should be paid to the vertical axis divisions, as these change on each graph. Breakeven costs are nearly identical when modeling oil and gas backup systems since the cost of these fuels was set equal on a Btu-equivalent basis (see Figure 2-8). This is not found to be true for the Madison and Omaha runs, where gas prices tend to be lower. The high electric rates in Boston (double those of the other two cities) prove PV-only systems twice as attractive as in the other cities, and cause all collector systems to be most attractive when electric resistance is the only means of space heating available. These plots clearly portray that the thermal collection portion is optimally sized to an area smaller than the optimal electrical portion.

The system breakeven costs curve for the combined collector system is always below that of at least one of the side-by-side collector systems for the range of total collector areas modeled. Thus, one would always be able to pay some additional amount over the PV/T allowable cost in order to receive the energy benefits of some side-by-side configuration. On the other hand, if the savings in assembly and installation costs for the combined collector are significant, they may override the effects of poorer operational performance. The best opportunity for this is in the 40-80 m^2 range for the PV/T system.

Finally, Figure 2-28 portrays the allowable collector costs, again as defined in section II.5. The levelized annual costs of heating by oil, gas, or heat pump are remarkably close.

Figure 2-21

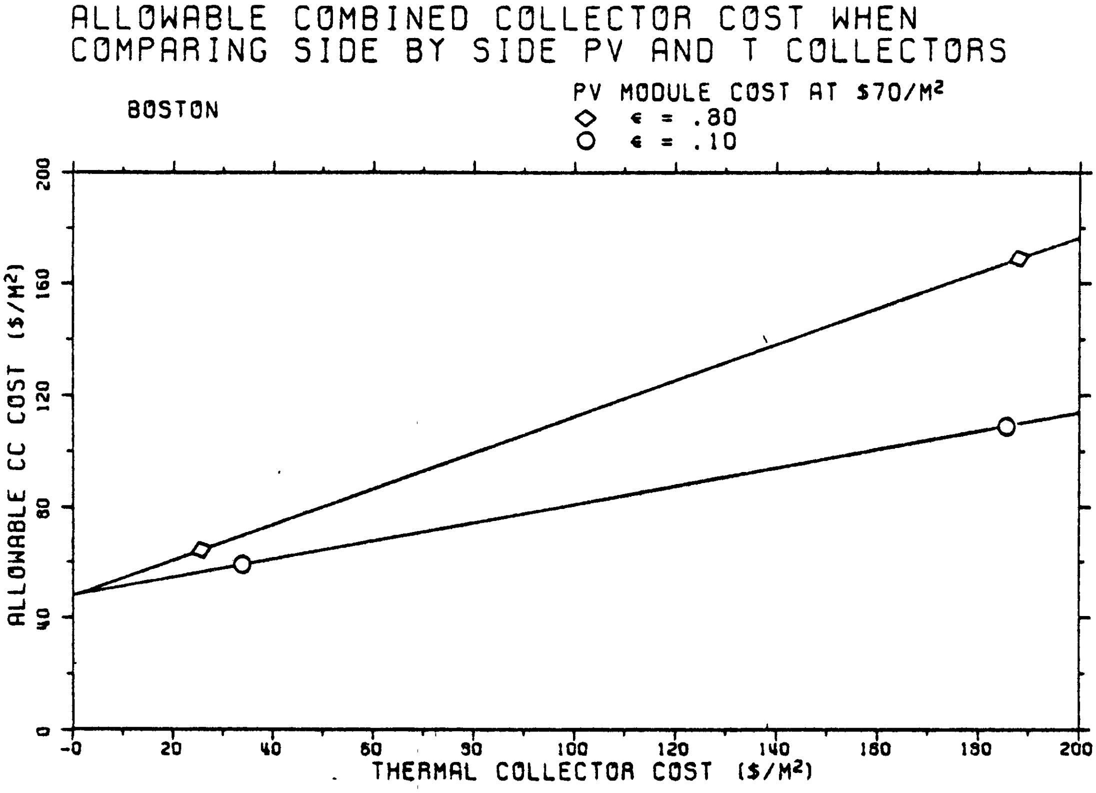


Figure 2-22

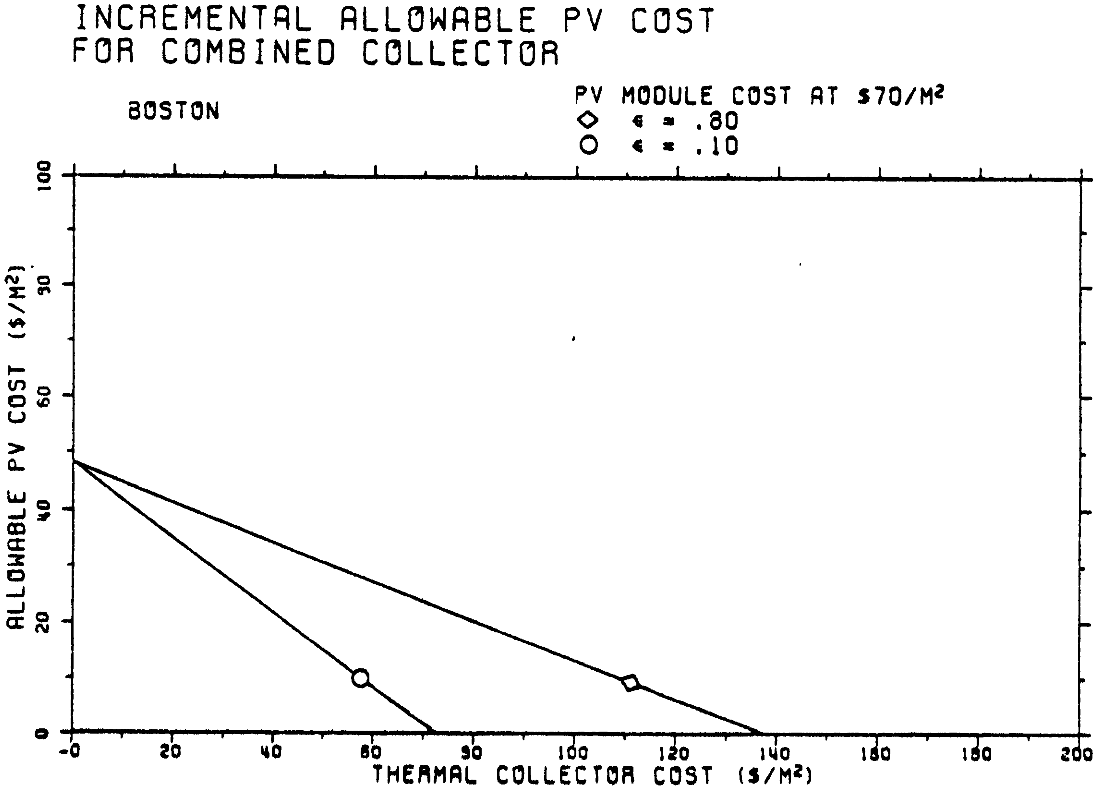


Figure 2-23

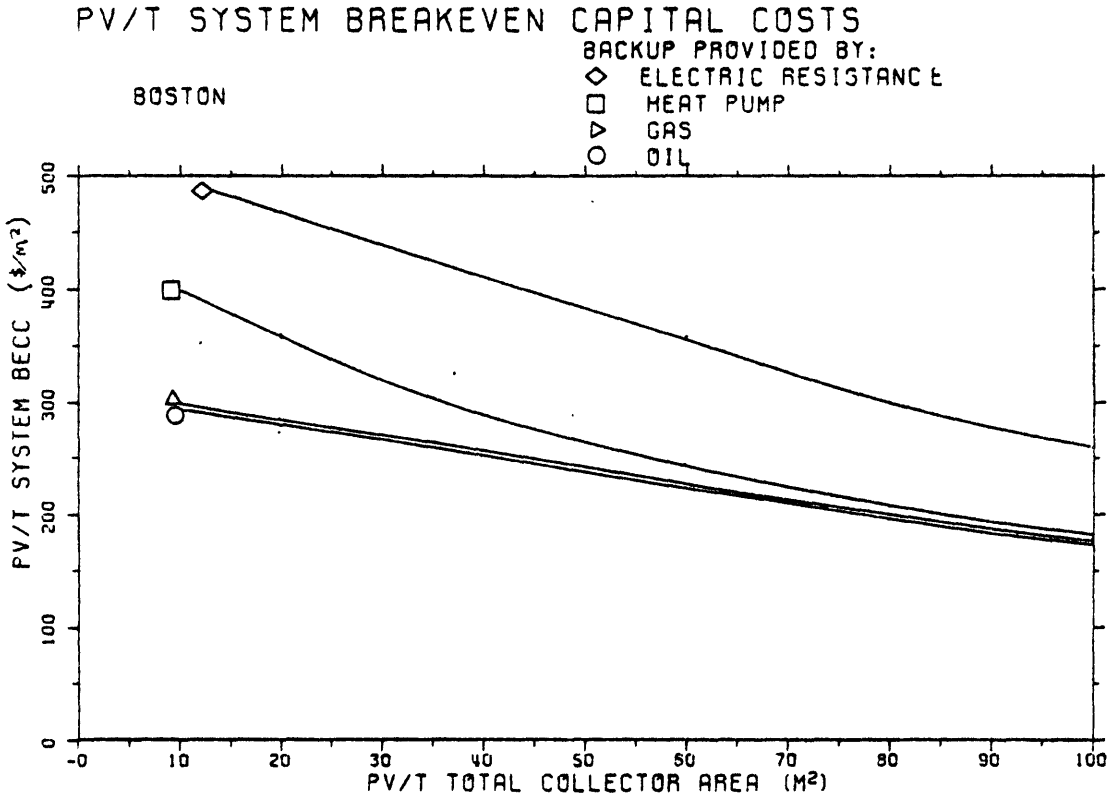


Figure 2-24

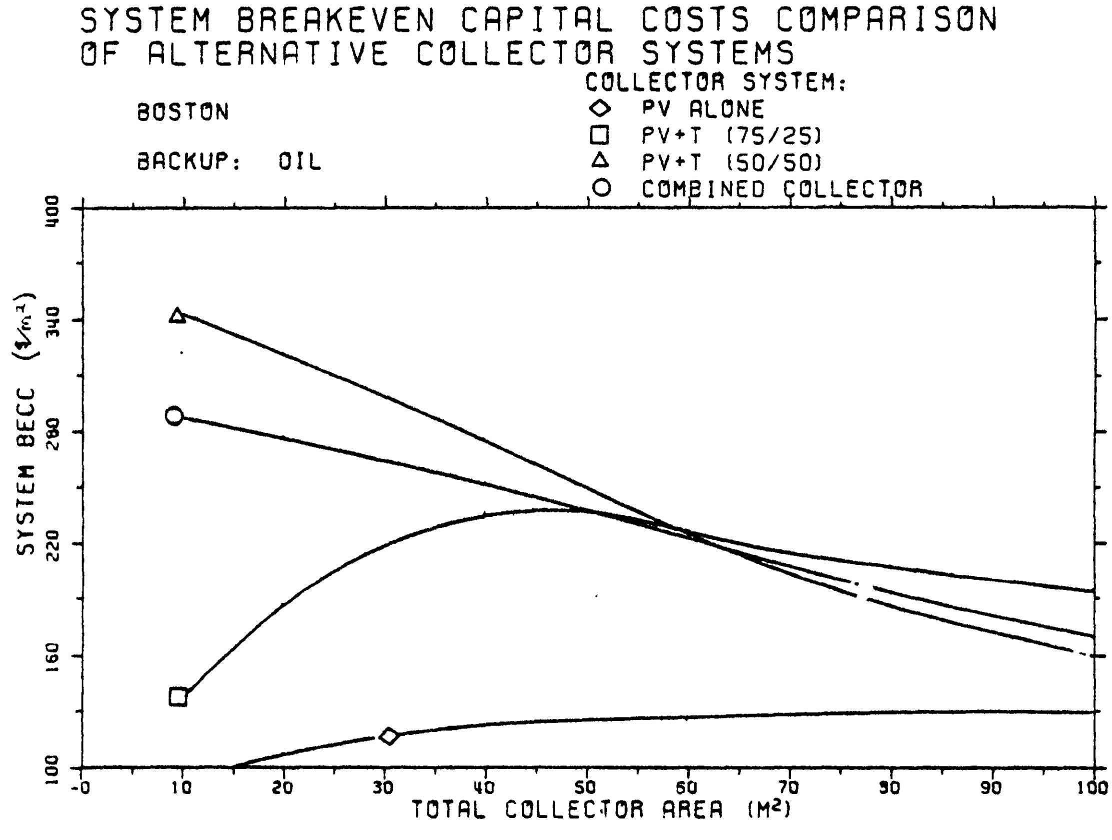
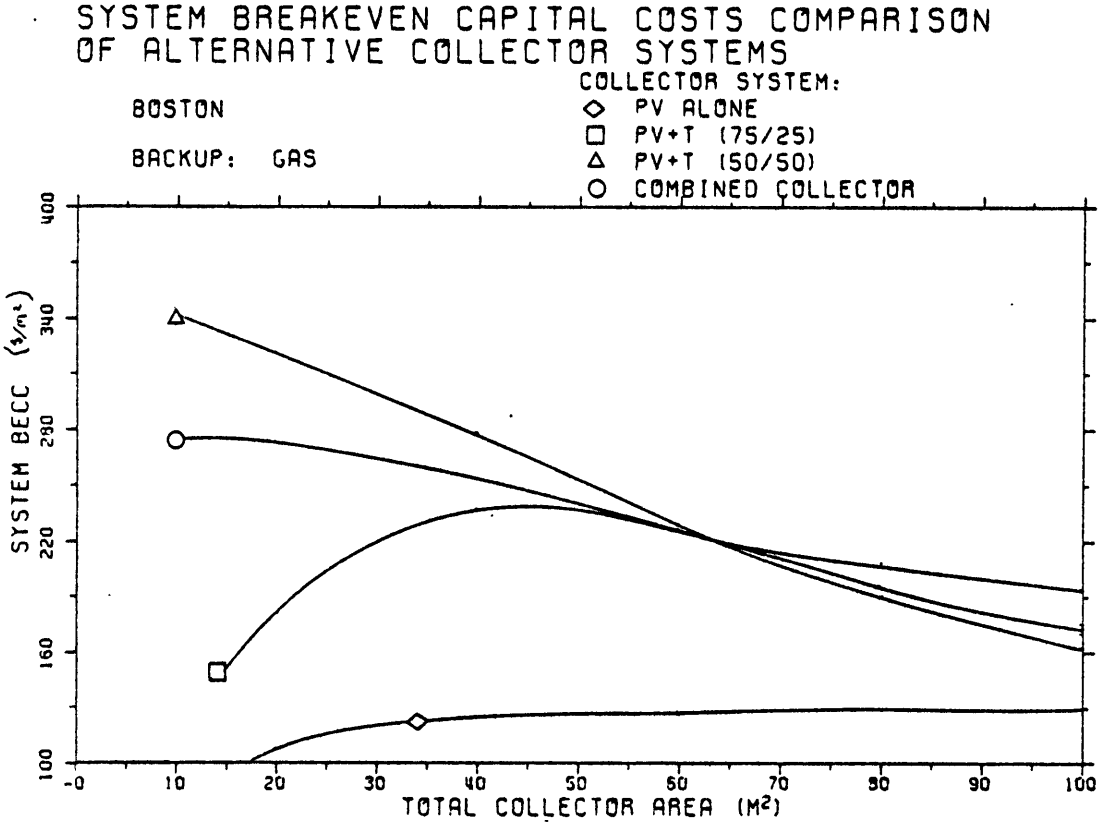
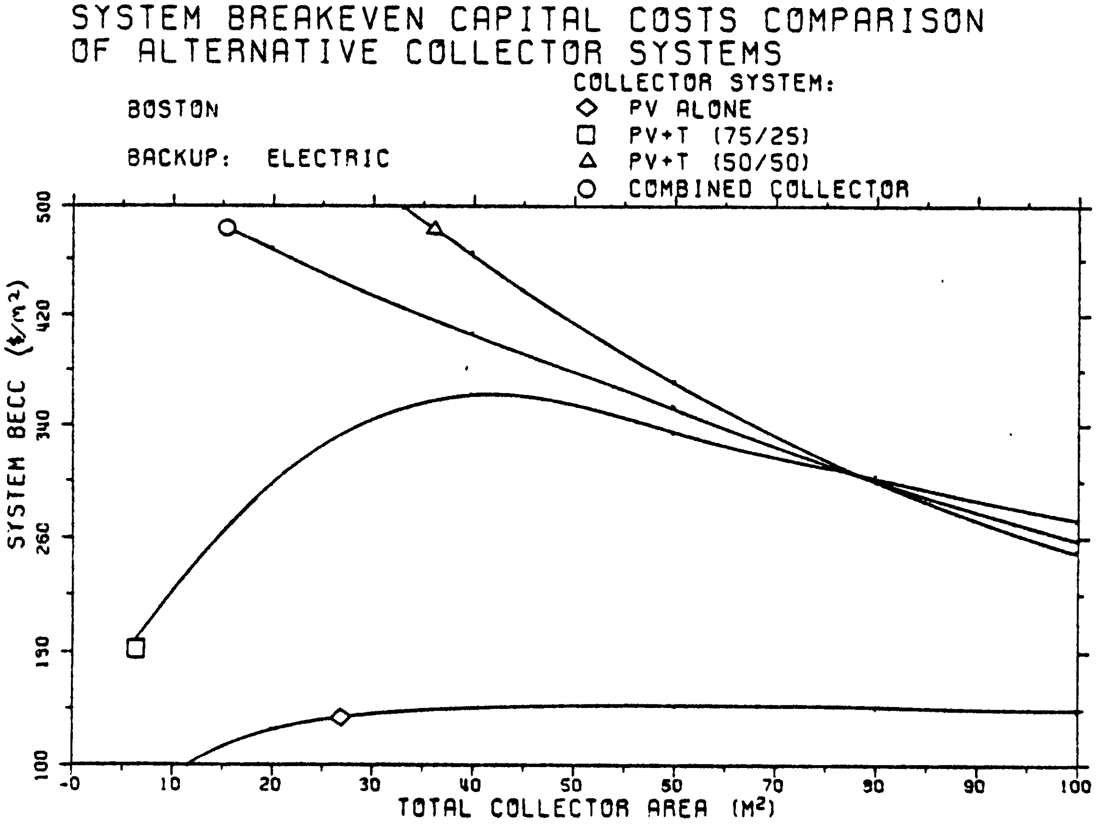


Figure 2-25



SYSTEM BREAKEVEN CAPITAL COSTS COMPARISON OF ALTERNATIVE COLLECTOR SYSTEMS

Figure 2-26



SYSTEM BREAKEVEN CAPITAL COSTS COMPARISON OF ALTERNATIVE COLLECTOR SYSTEMS

Figure 2-27

SYSTEM BREAKEVEN CAPITAL COSTS COMPARISON OF ALTERNATIVE COLLECTOR SYSTEMS

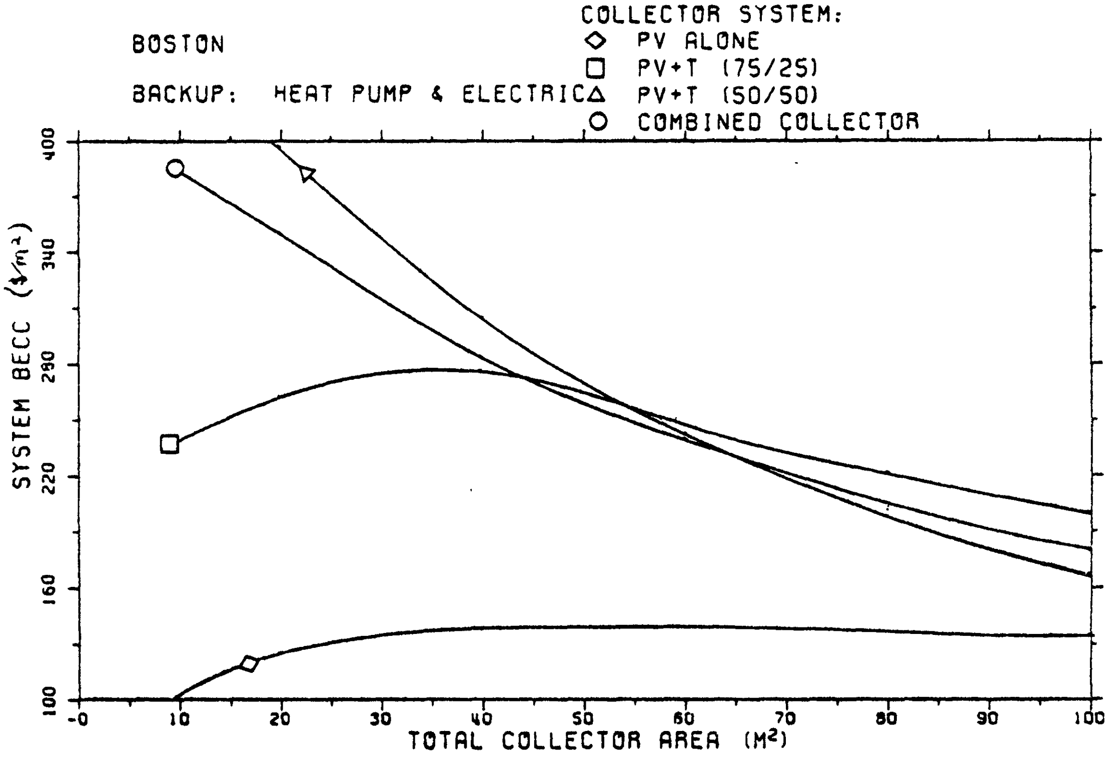
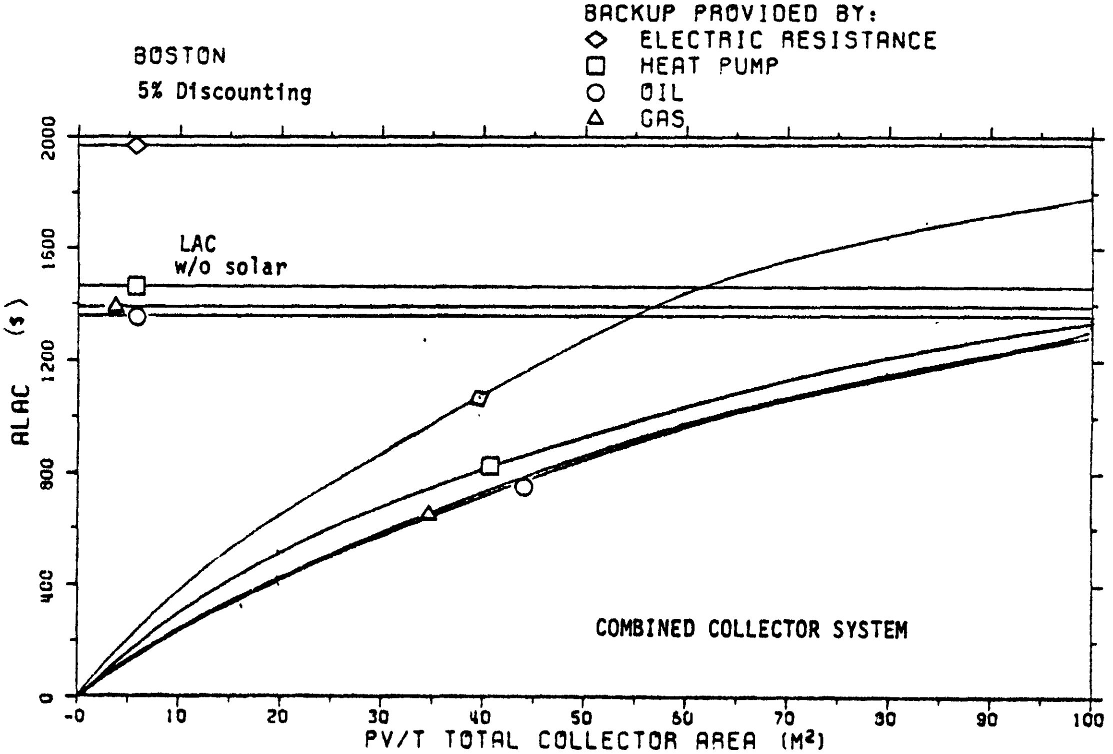


Figure 2-28

ALLOWABLE LEVELIZED ANNUAL COST ANALYSIS



III.2 Madison Residence

Figures 2-29 through 2-39 present results analogous to Figures 2-18 through 2-28 for the Boston residence. Discussion of these graphs will not be repeated here, but will be dealt with in the conclusions of section V. Again, pay careful attention to the vertical axis divisions of Figures 2-35 through 2-38. The Madison residence thermal loads are summarized as follows:

Space Heating:	44.562 MBtu's
Space Cooling:	3.683 MBtu's
Hot Water Heating:	16.776 MBtu's

Figure 2-29

FRACTION OF TOTAL HOT WATER AND SPACE HEATING LOAD MET BY SOLAR

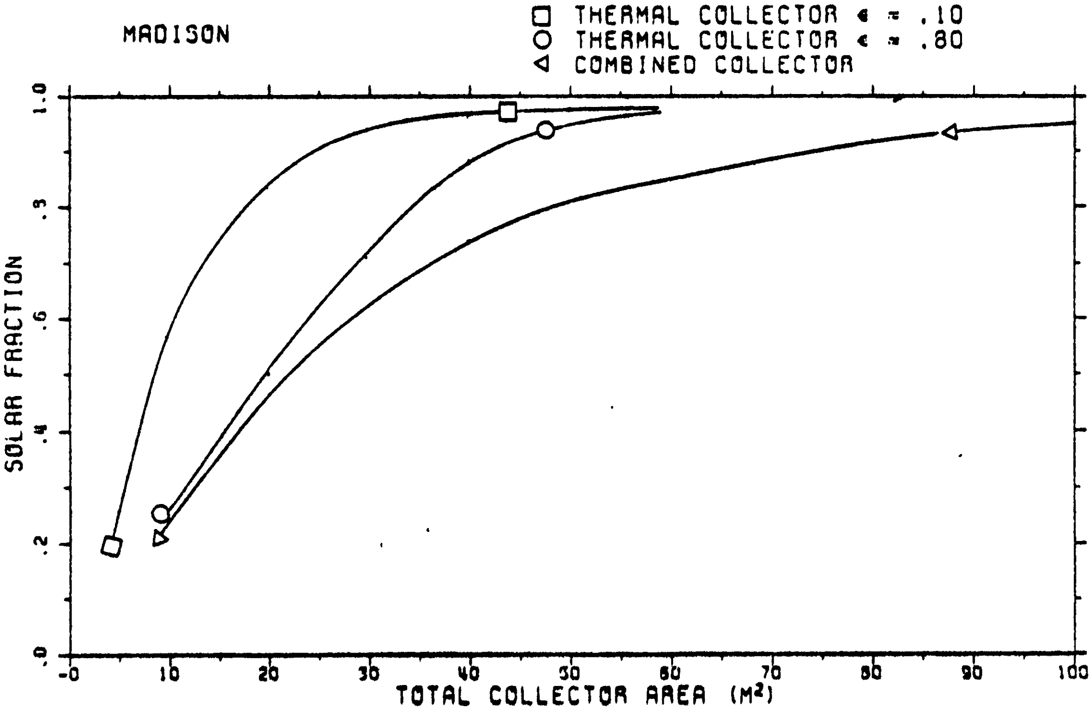


Figure 2-30

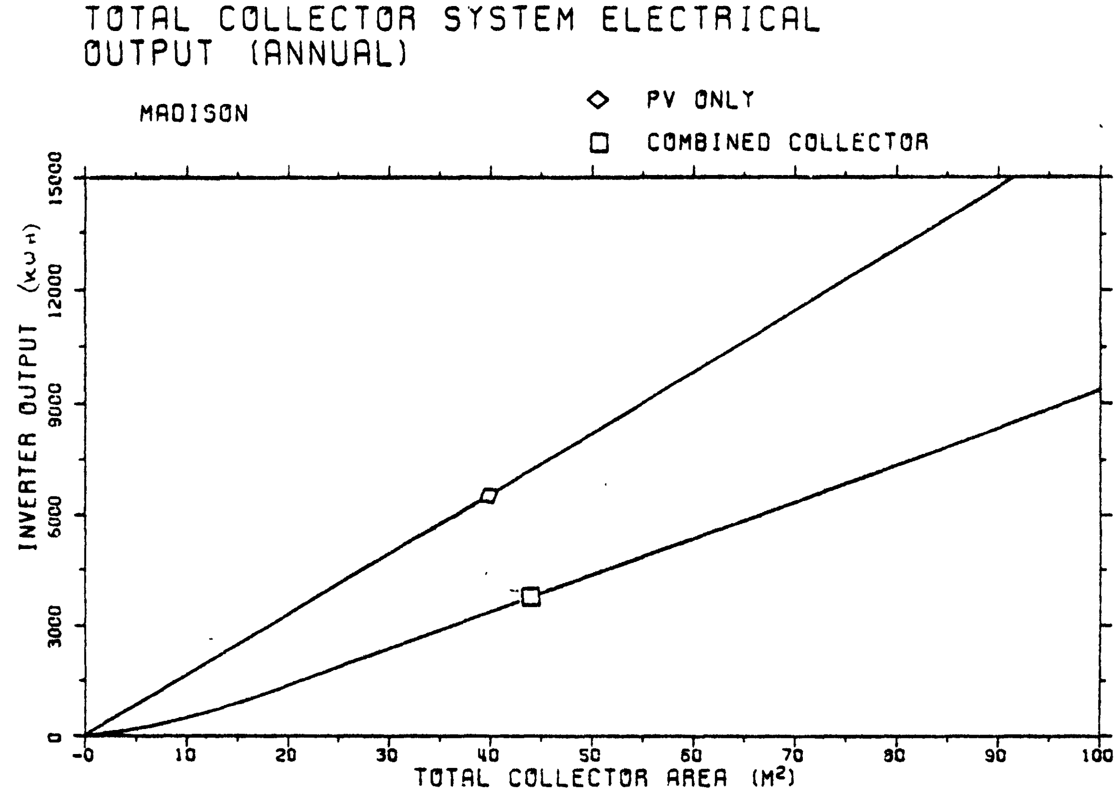


Figure 2-31

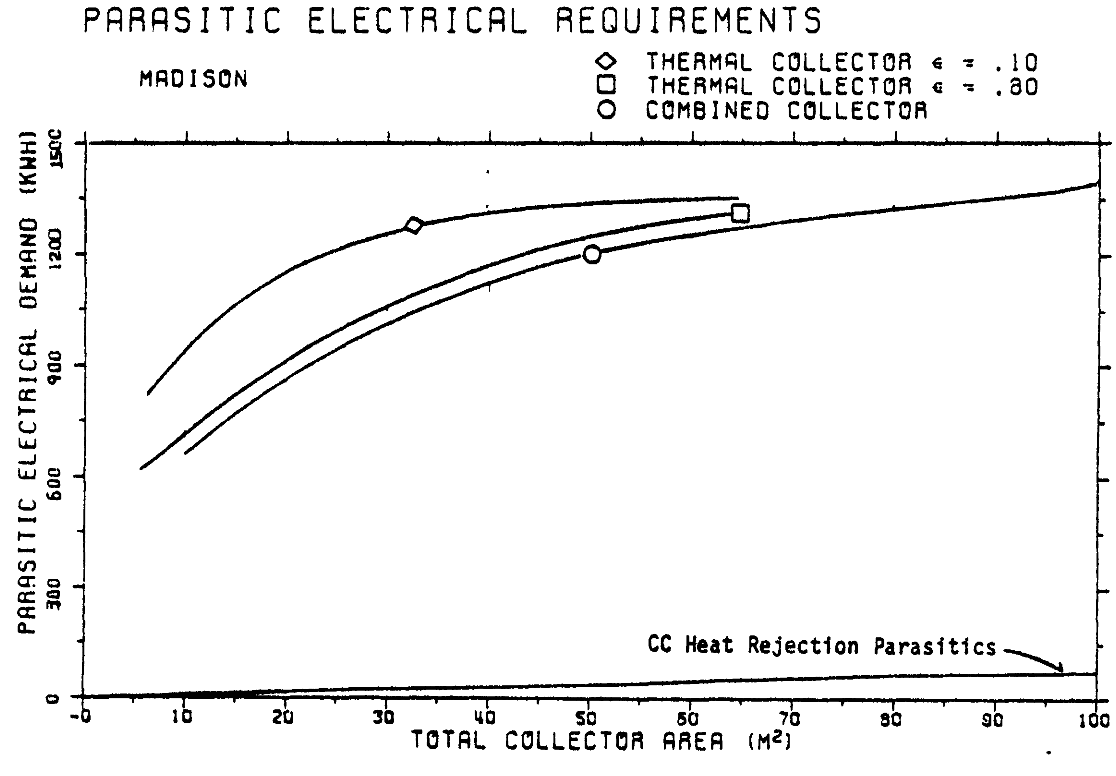


Figure 2-32

ALLOWABLE COMBINED COLLECTOR COST WHEN COMPARING SIDE BY SIDE PV AND T COLLECTORS

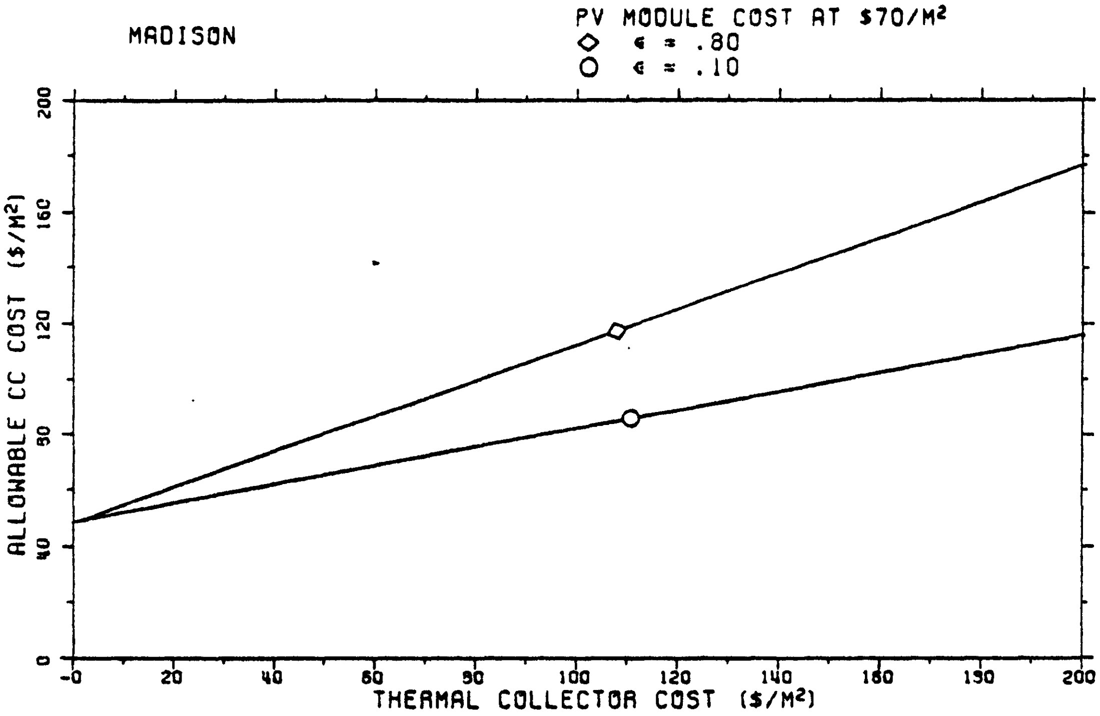


Figure 2-33

INCREMENTAL ALLOWABLE PV COST FOR COMBINED COLLECTOR

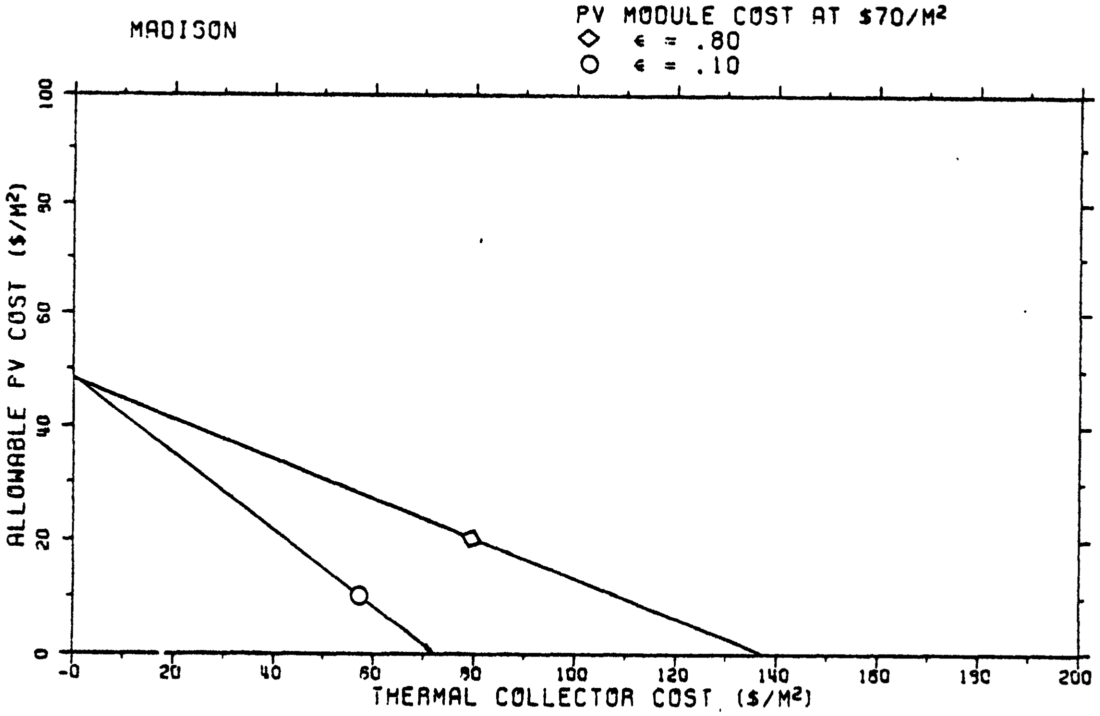


Figure 2-34

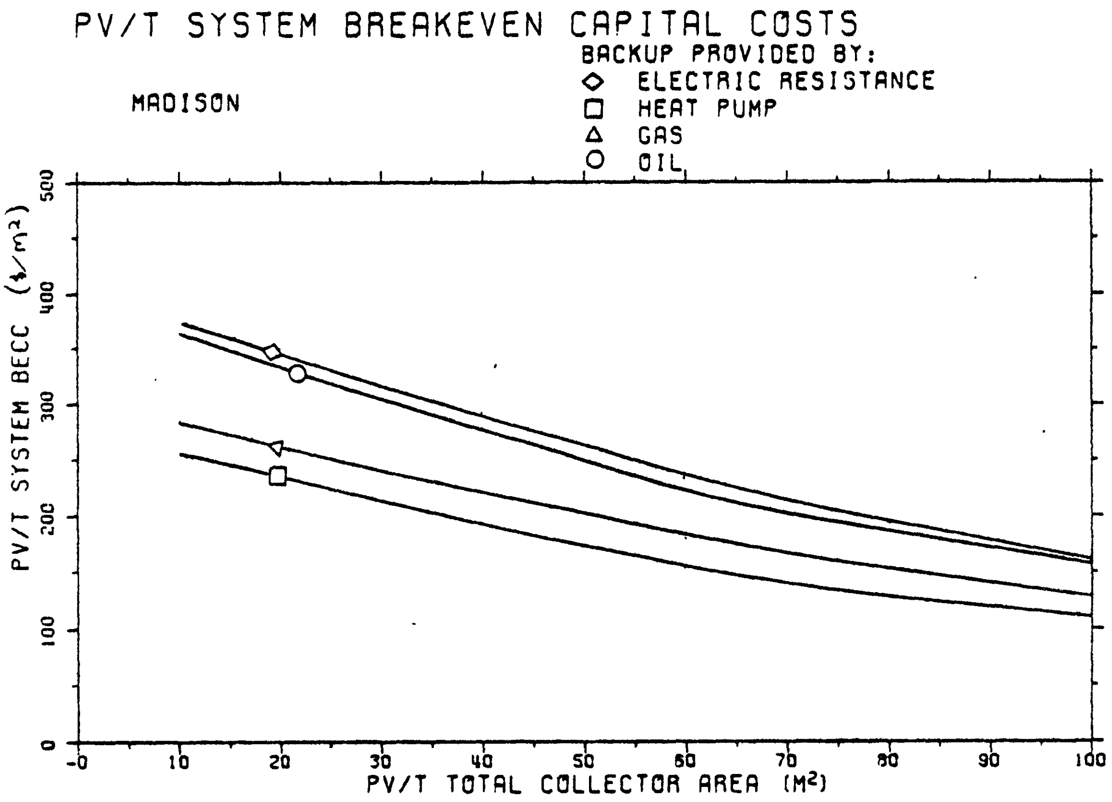


Figure 2-35

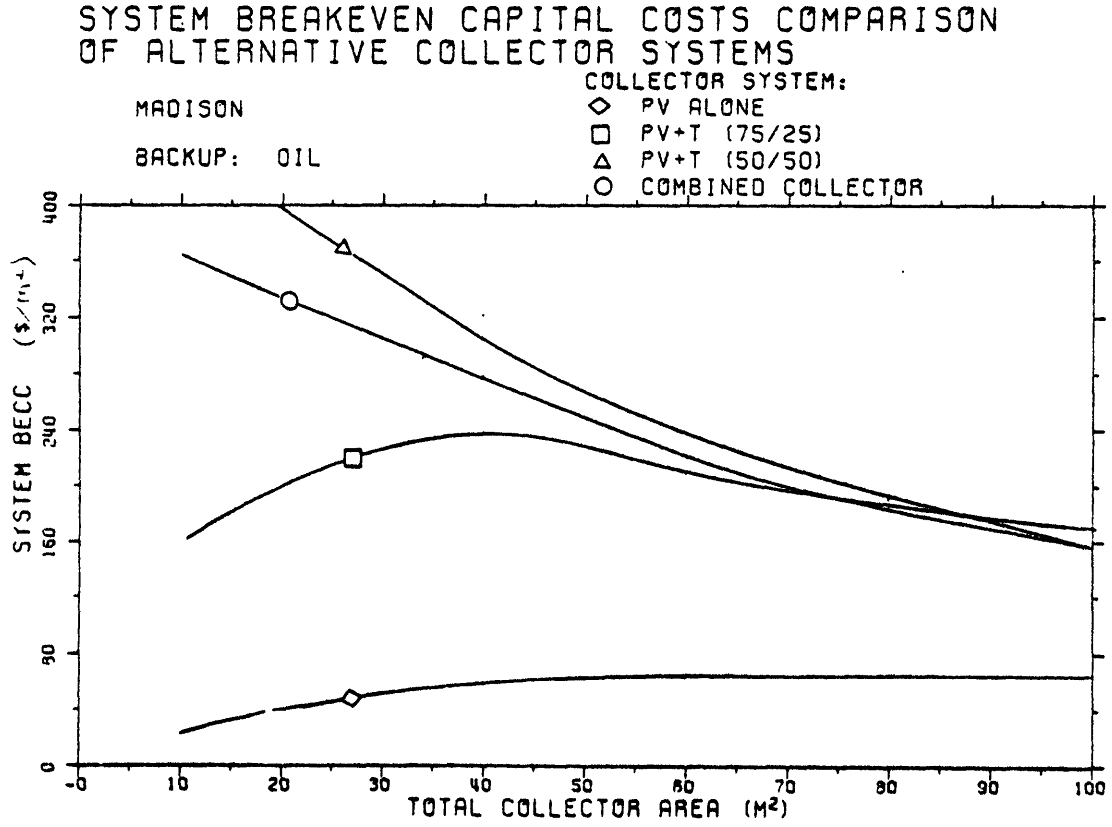


Figure 2-36

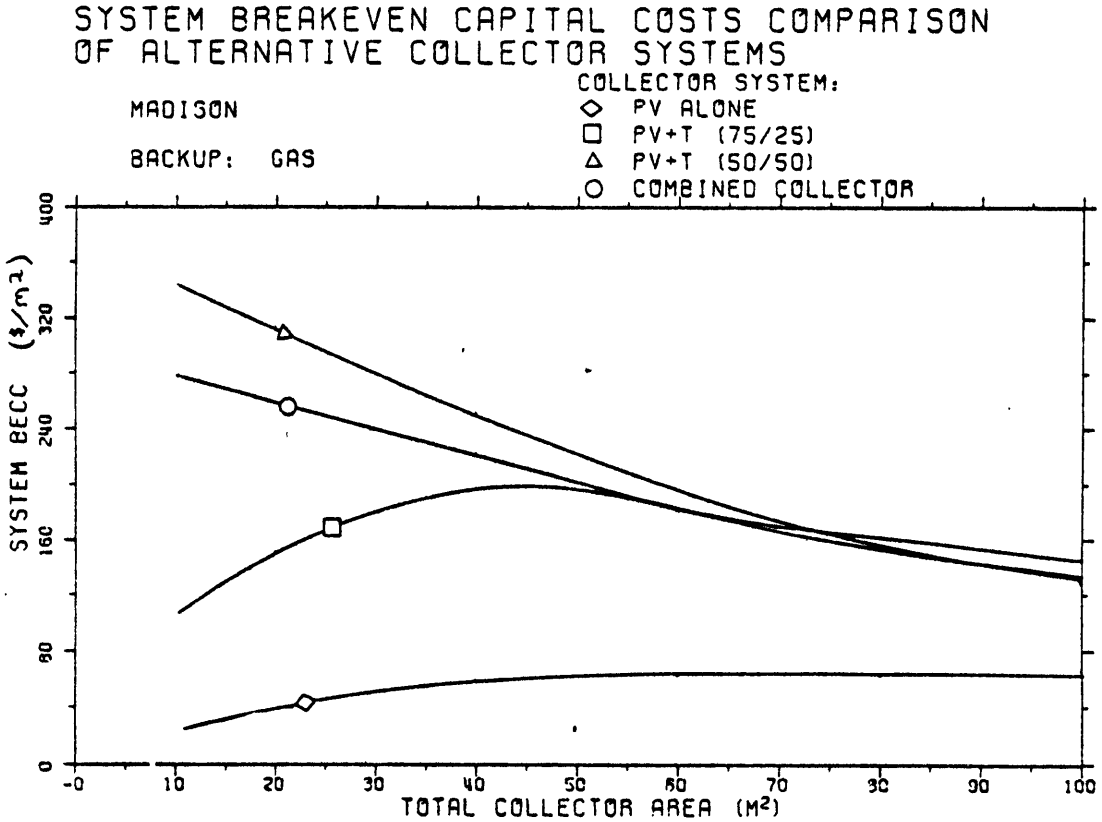


Figure 2-37

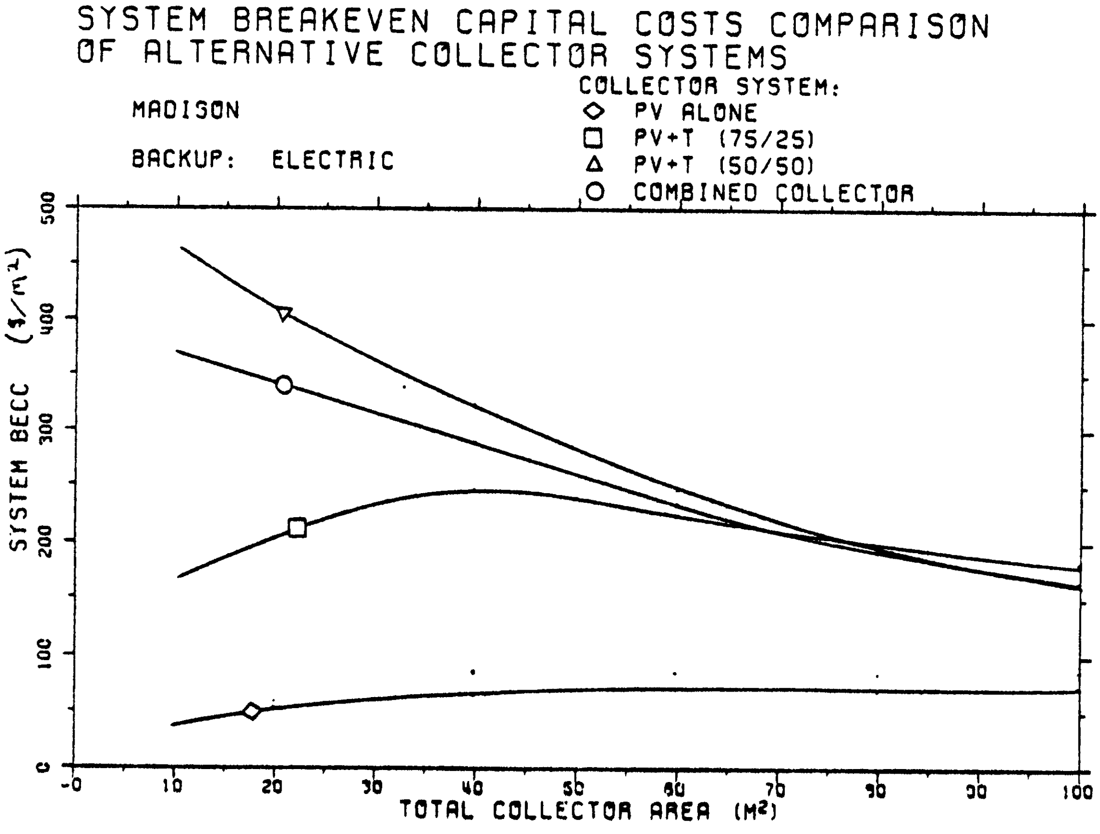
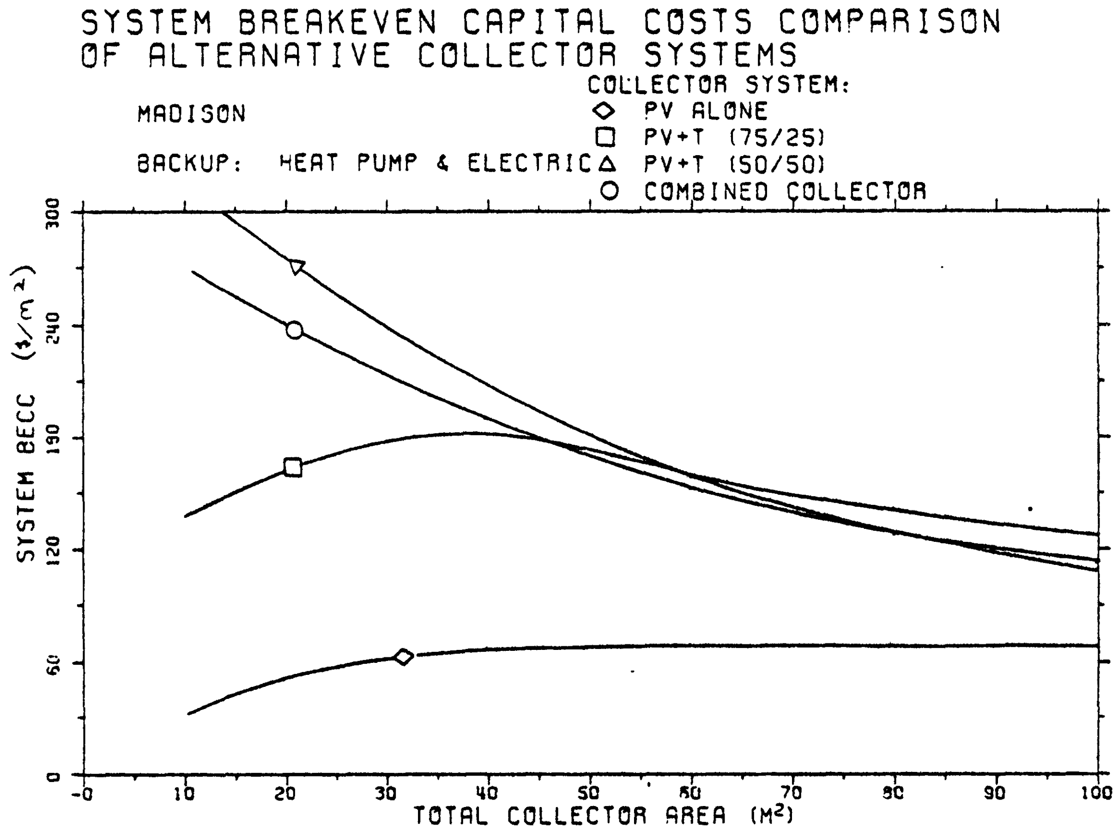
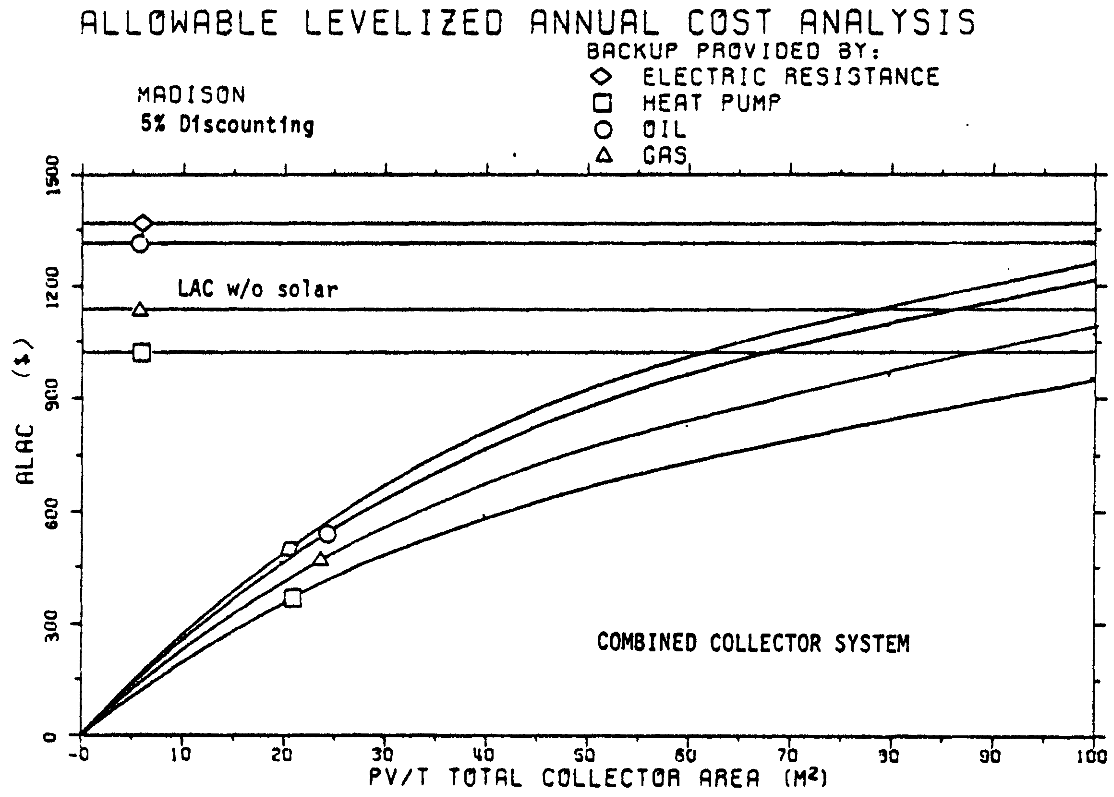


Figure 2-38



SYSTEM BREAKEVEN CAPITAL COSTS COMPARISON OF ALTERNATIVE COLLECTOR SYSTEMS

Figure 2-39



ALLOWABLE LEVELIZED ANNUAL COST ANALYSIS

III.3 Omaha Residence

Figures 2-40 through 2-50 present the same results for the Omaha residence. Again, discussion of these graphs will not be repeated here, but will be dealt with in the conclusions of section V. Again, pay special attention to the vertical axis divisions of Figures 2-46 through 2-49. The Omaha residence thermal loads are summarized as follows:

Space Heating:	33.061 MBtu's
Space Cooling:	10.521 MBtu's
Hot Water Heating:	16.776 MBtu's

Figure 2-40

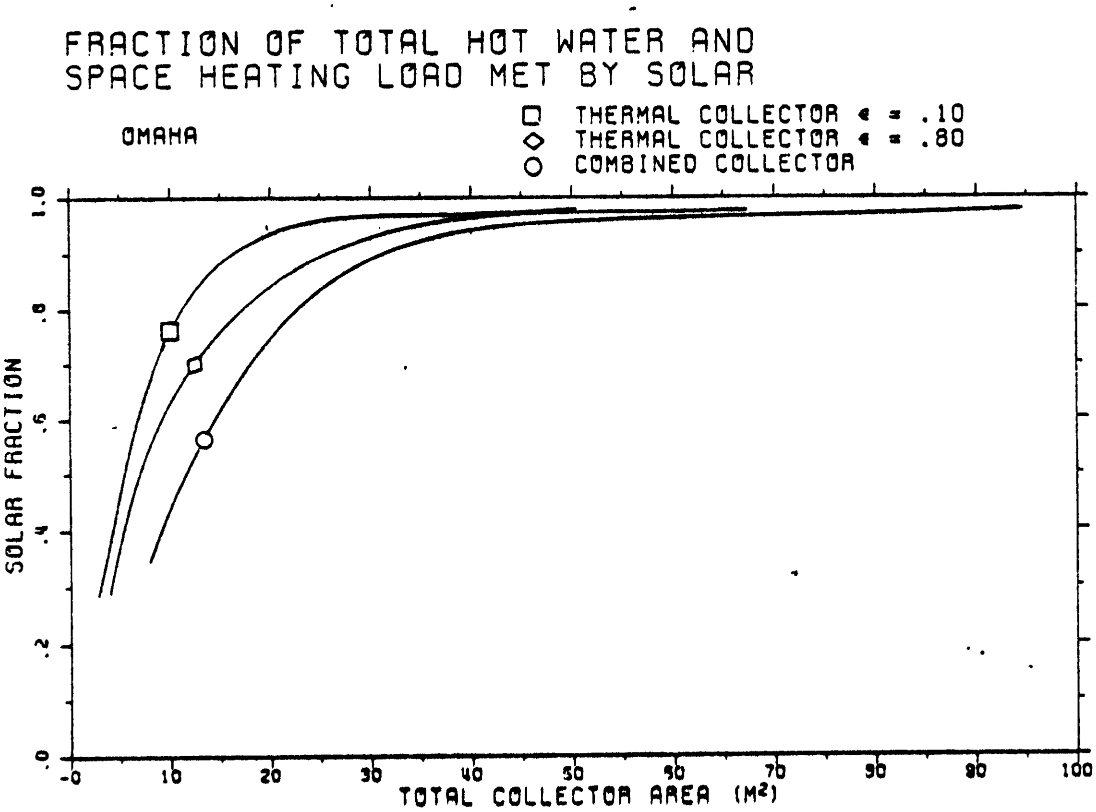


Figure 2-41

TOTAL COLLECTOR SYSTEM ELECTRICAL OUTPUT (ANNUAL)

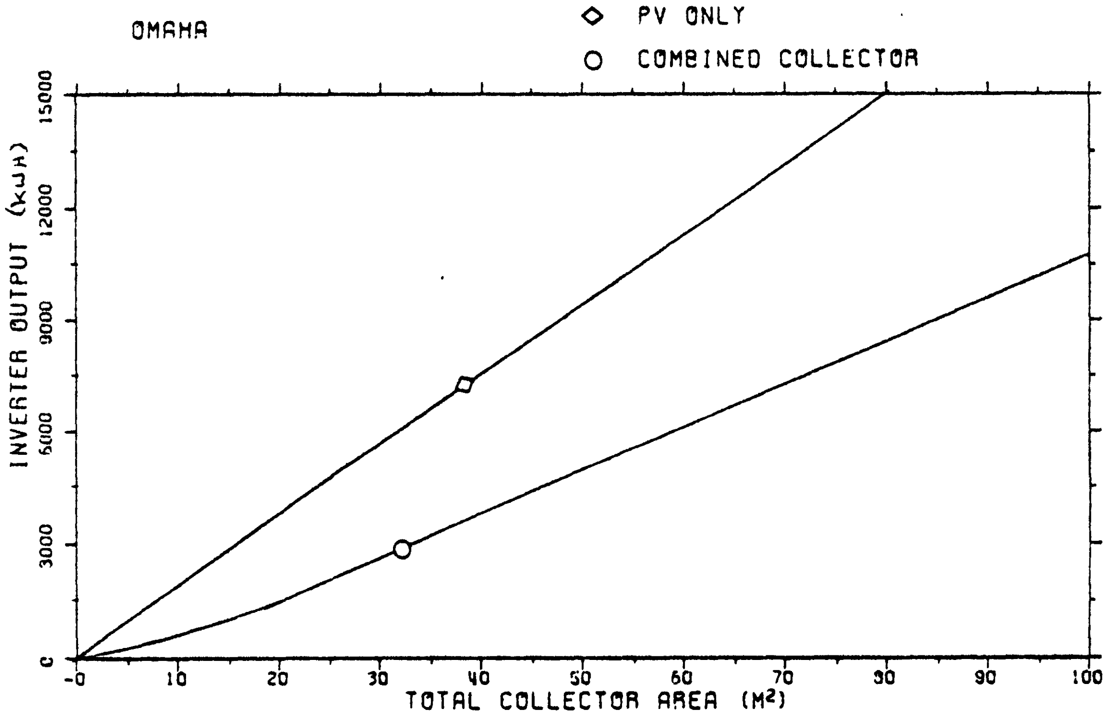


Figure 2-42

PARASITIC ELECTRICAL REQUIREMENTS

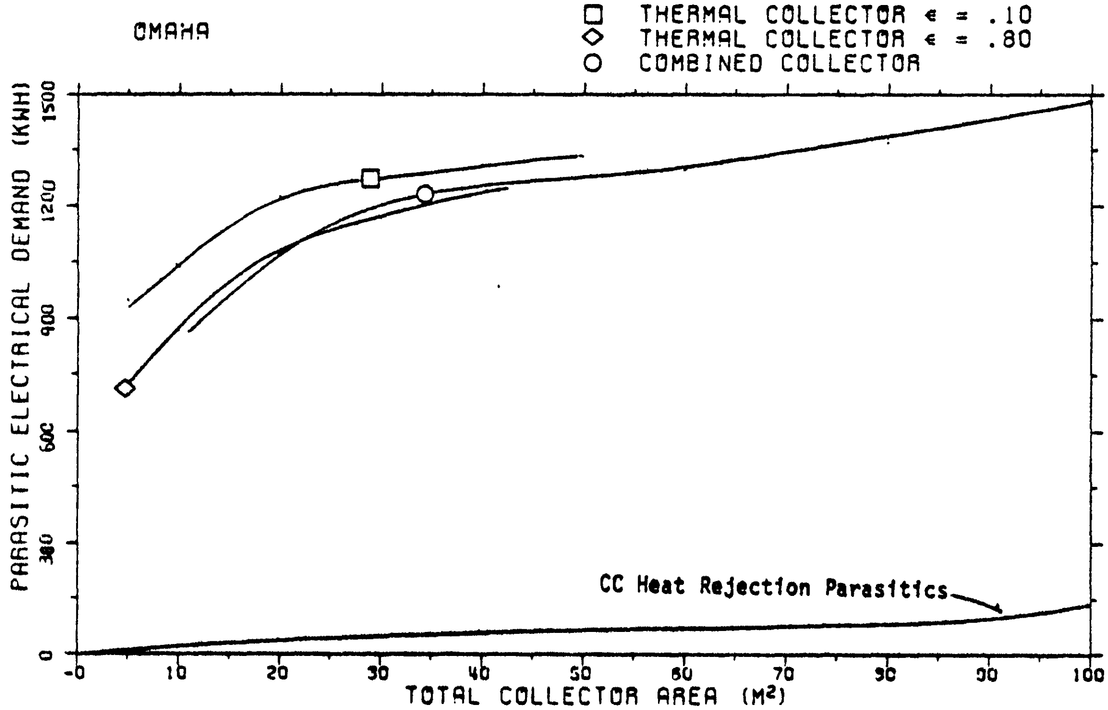


Figure 2-43

ALLOWABLE COMBINED COLLECTOR COST WHEN COMPARING SIDE BY SIDE PV AND T COLLECTORS

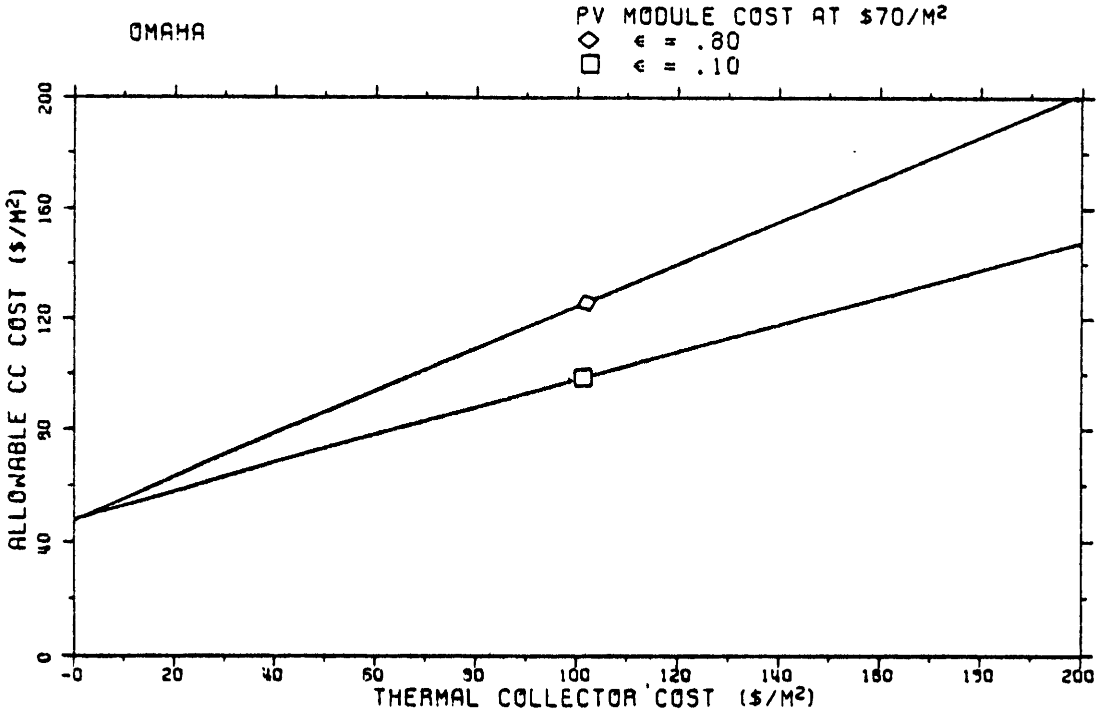


Figure 2-44

INCREMENTAL ALLOWABLE PV COST FOR COMBINED COLLECTOR

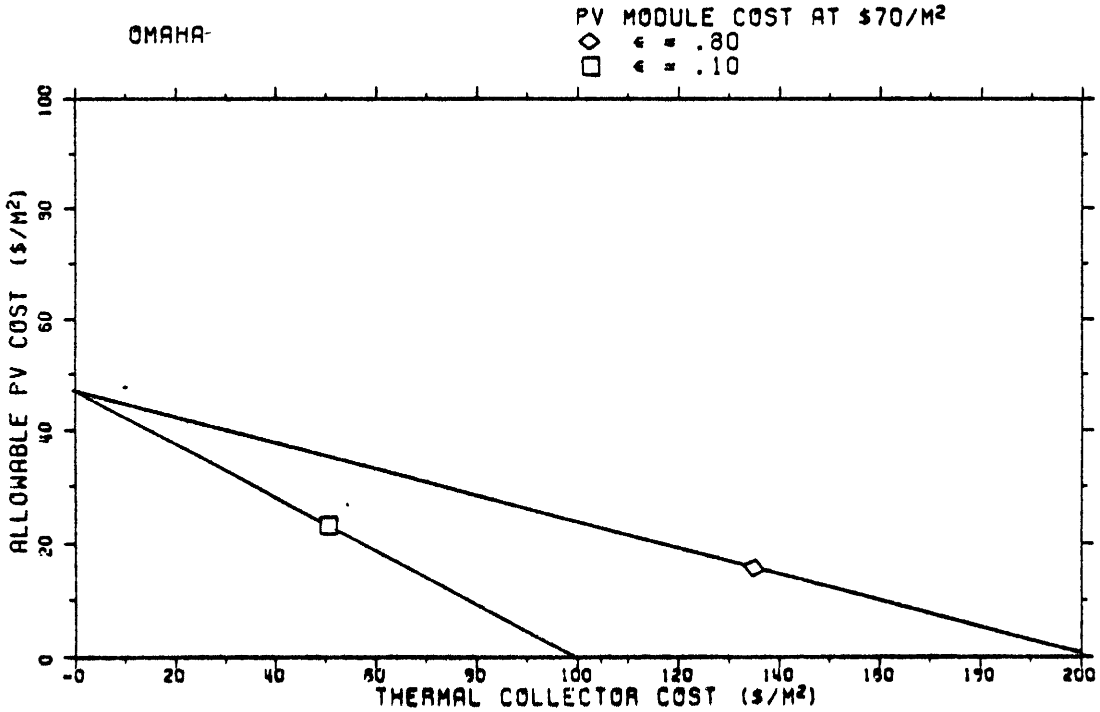
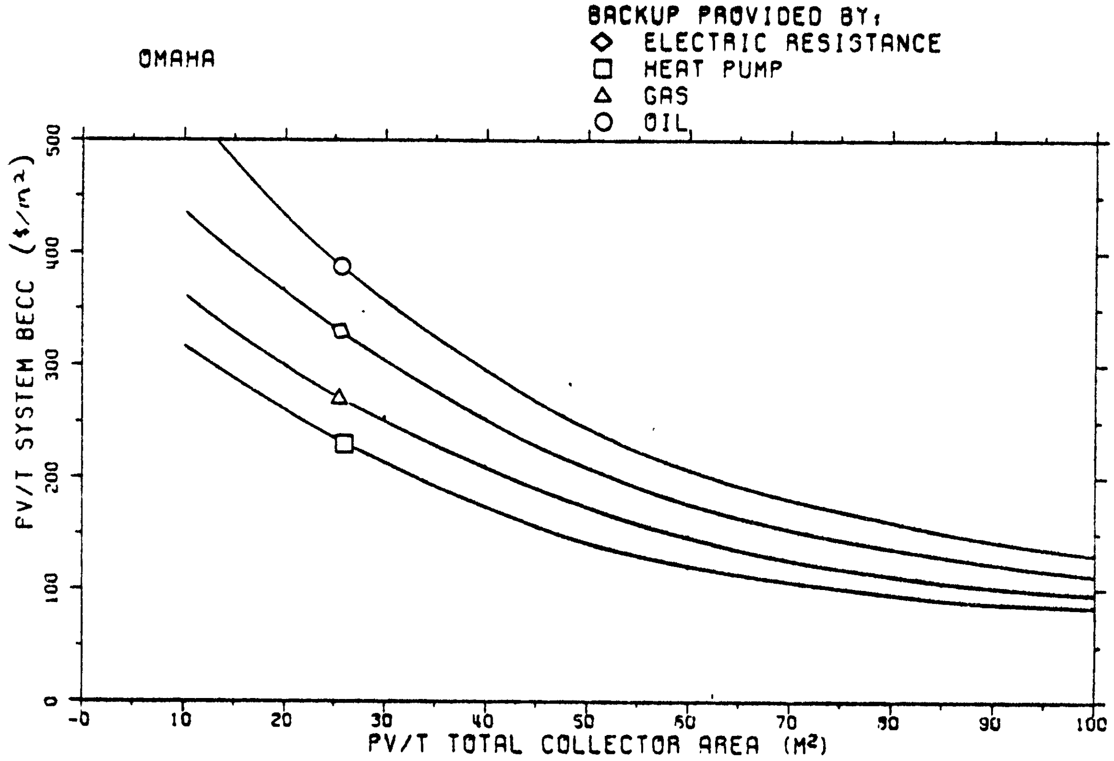
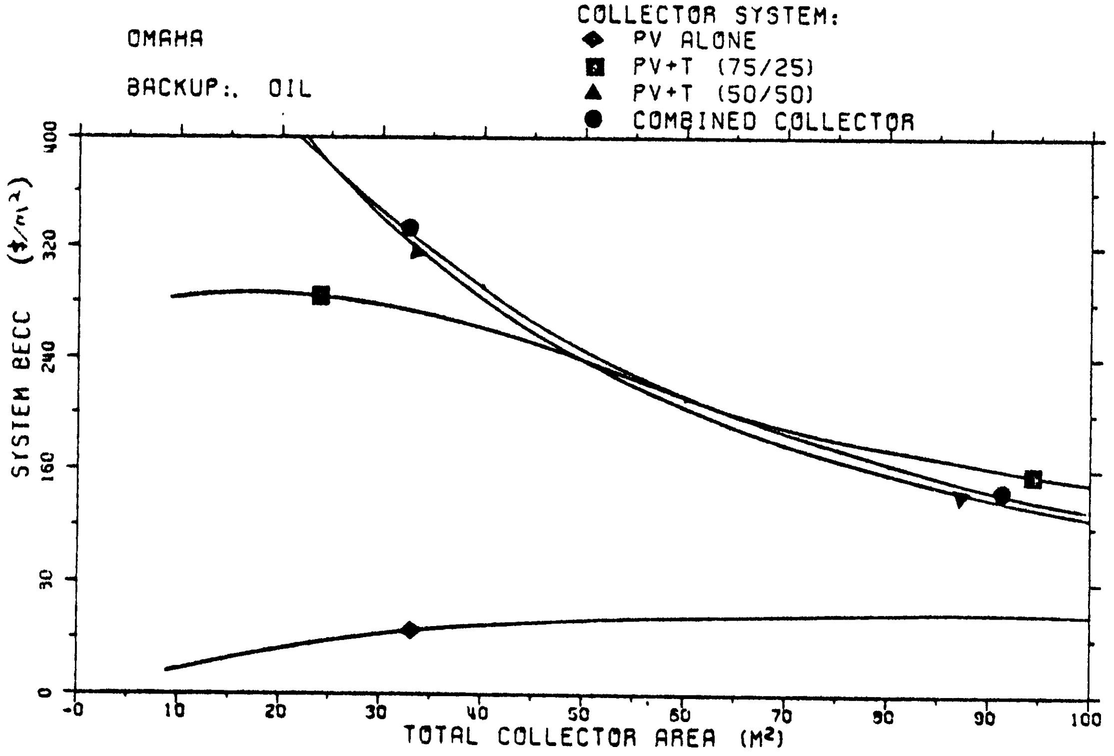


Figure 2-45



PV/T SYSTEM BREAKEVEN CAPITAL COSTS

Figure 2-46



SYSTEM BREAKEVEN CAPITAL COSTS COMPARISON OF ALTERNATIVE COLLECTOR SYSTEMS

Figure 2-47

SYSTEM BREAKEVEN CAPITAL COSTS COMPARISON OF ALTERNATIVE COLLECTOR SYSTEMS

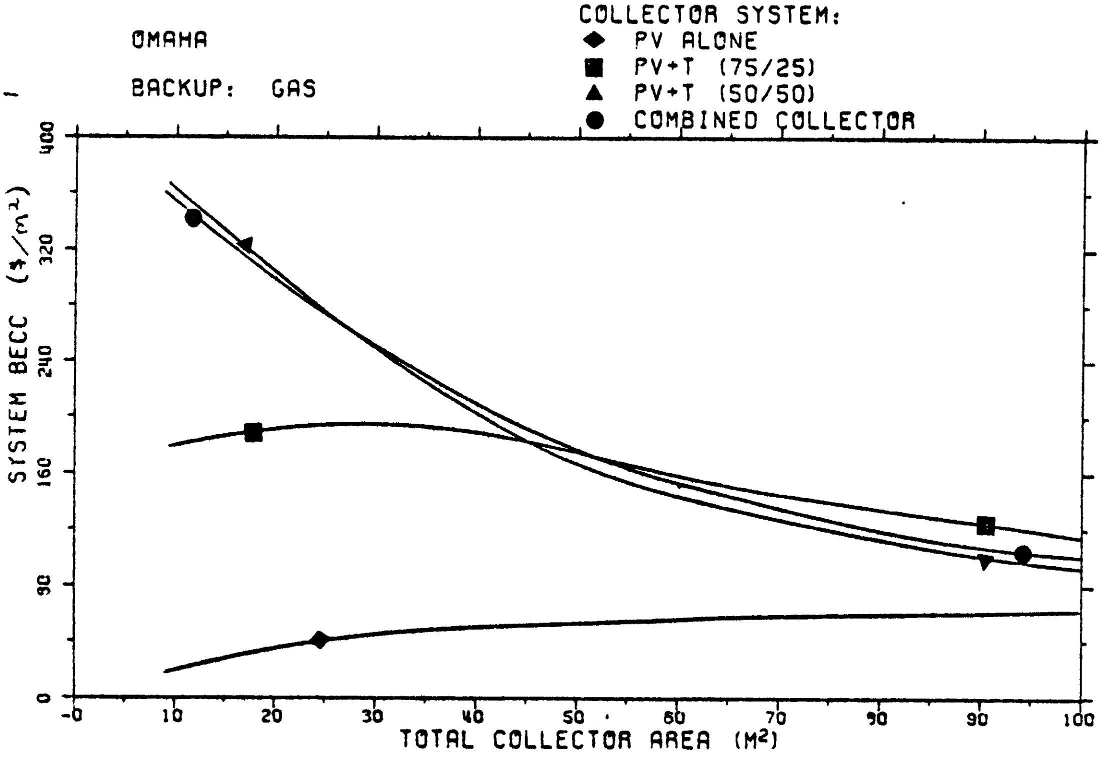


Figure 2-48

SYSTEM BREAKEVEN CAPITAL COSTS COMPARISON OF ALTERNATIVE COLLECTOR SYSTEMS

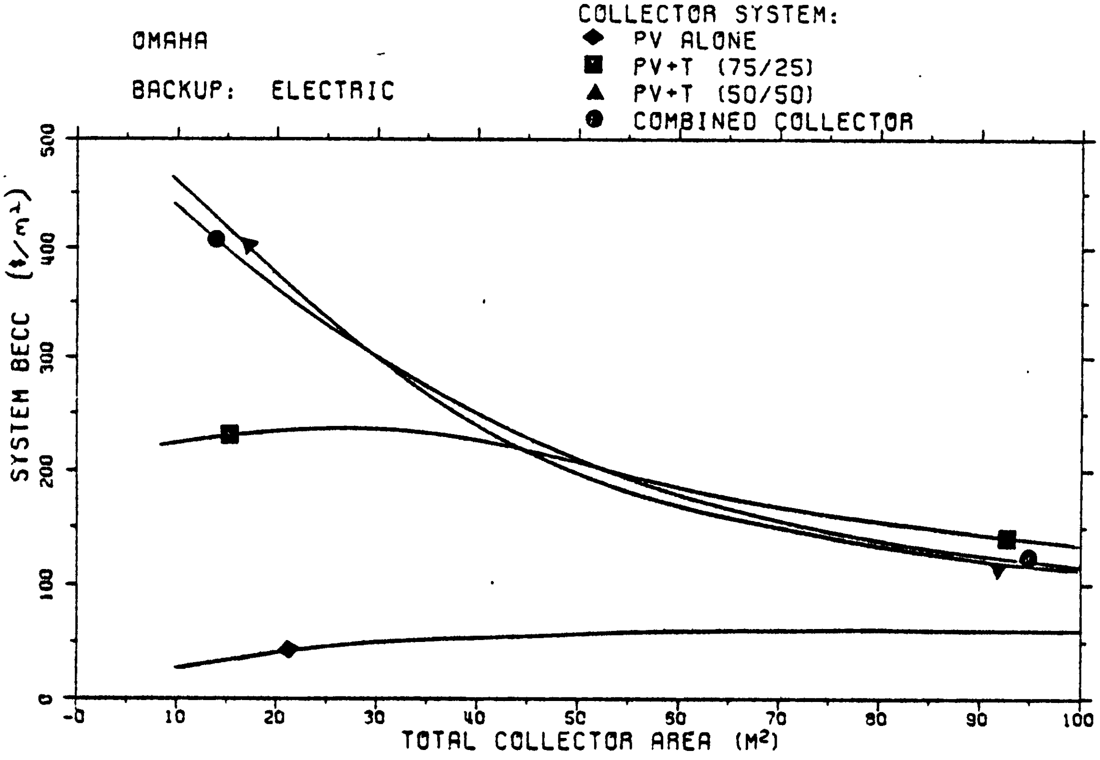


Figure 2-49

SYSTEM BREAKEVEN CAPITAL COSTS COMPARISON OF ALTERNATIVE COLLECTOR SYSTEMS

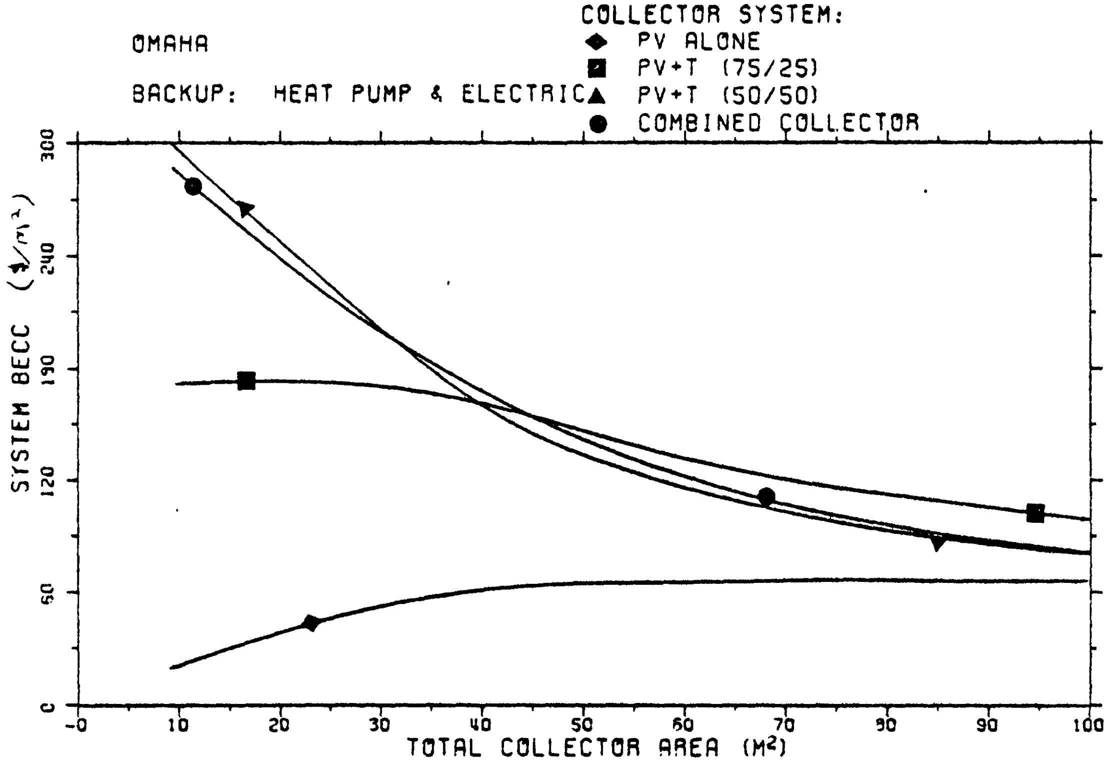
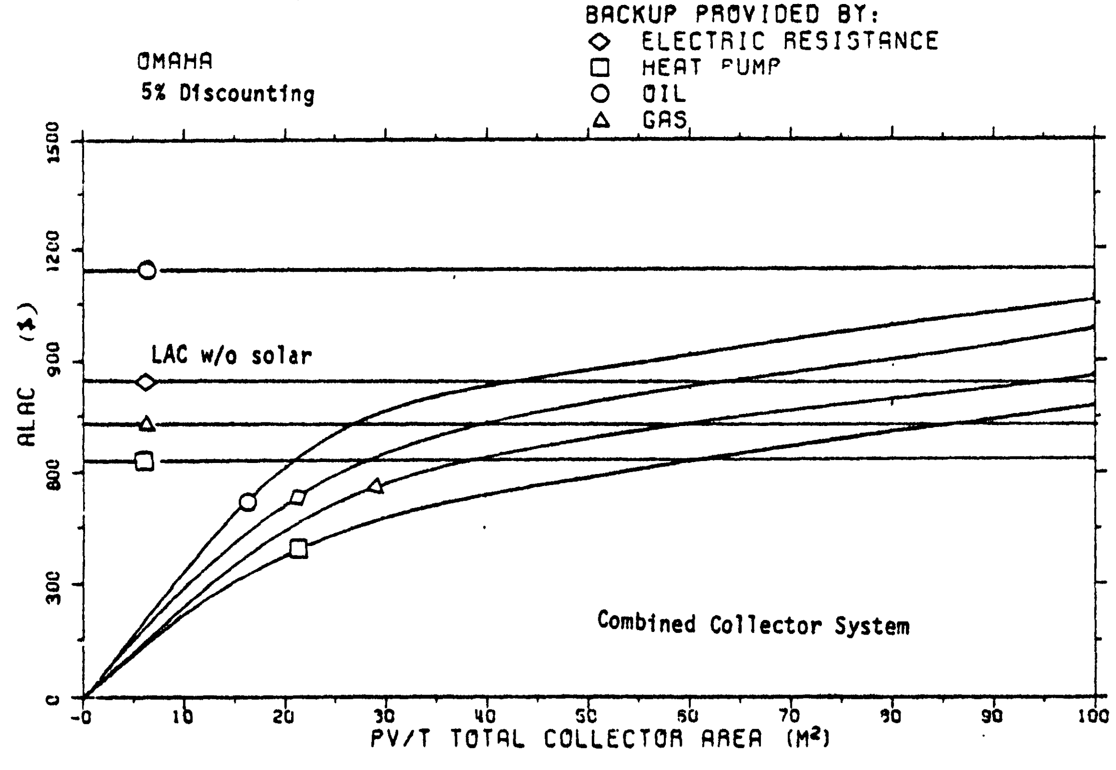


Figure 2-50

ALLOWABLE LEVELIZED ANNUAL COST ANALYSIS



IV. EXTENDED ANALYSIS

In this extended analysis we examine the impact upon combined collector economics of numerous uncertain parameters. Although we perform this study by modeling a combined collector, the results are readily applicable to an investment in any one of the discussed solar options. This is at least true in terms of the relative impact of changes in specific market and financial parameters.

Unless otherwise stated, the collector system is sized at 40 m^2 and all heating is provided by gas. Space cooling is by an electrical vapor compression appliance.

IV.1 Physical Parameter Sensitivity Studies

Figures 2-51 through 2-56 present the results of this analysis. As expected, cell reference efficiency has a large impact on system worth, as does the thermal storage tank volume. The lower ranges of efficiency used for the heater and boiler units would be typical of current units, and hence of retrofit backup systems for 1986. These lower efficiencies were modeled for the retrofit analysis of section IV.4.

Figure 2-51

SENSITIVITY TO COLLECTOR ELECTRICAL EFFICIENCY

PV/T COLLECTOR SYSTEM
BOSTON
ARRAY SIZE: 40 M²

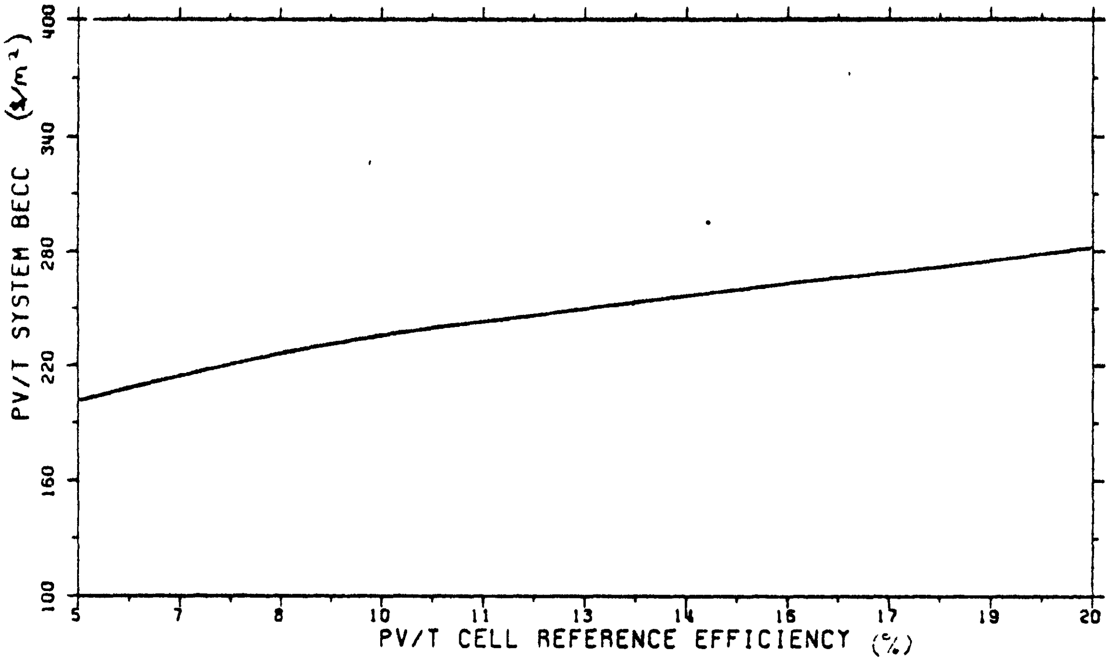


Figure 2-52

SENSITIVITY TO THERMAL STORAGE VOLUME

PV/T COLLECTOR SYSTEM
BOSTON
ARRAY SIZE: 40 M²

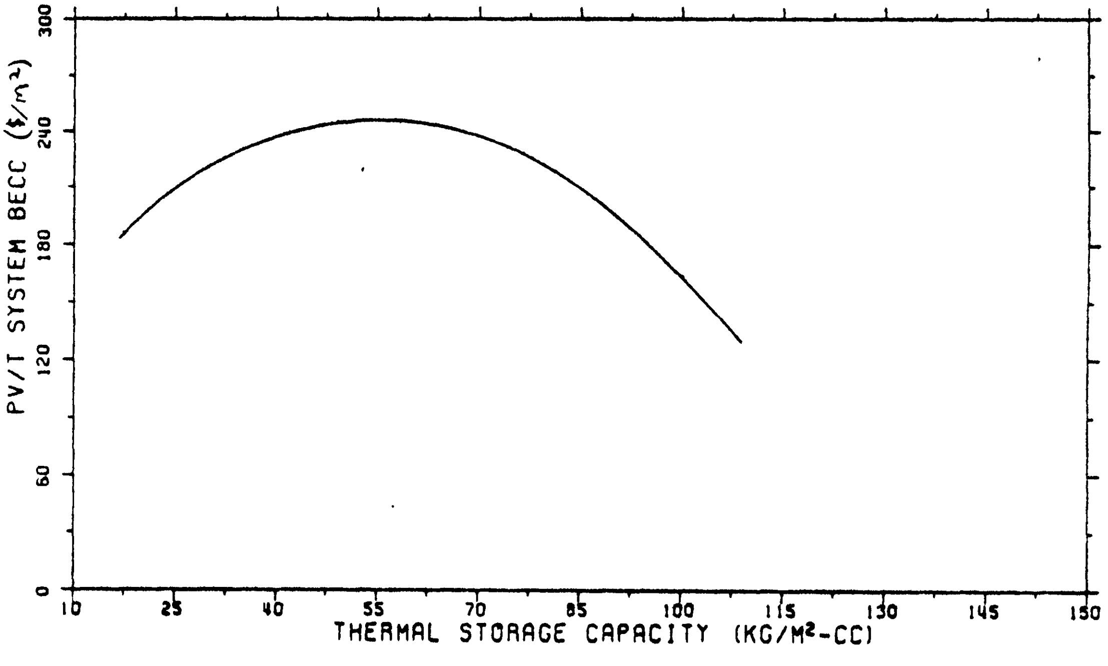


Figure 2-53

SENSITIVITY TO HOT WATER HEATER
AVERAGE FUEL USE EFFICIENCY

PV/T COLLECTOR SYSTEM
BOSTON GAS SYSTEM
ARRAY SIZE: 40 M²

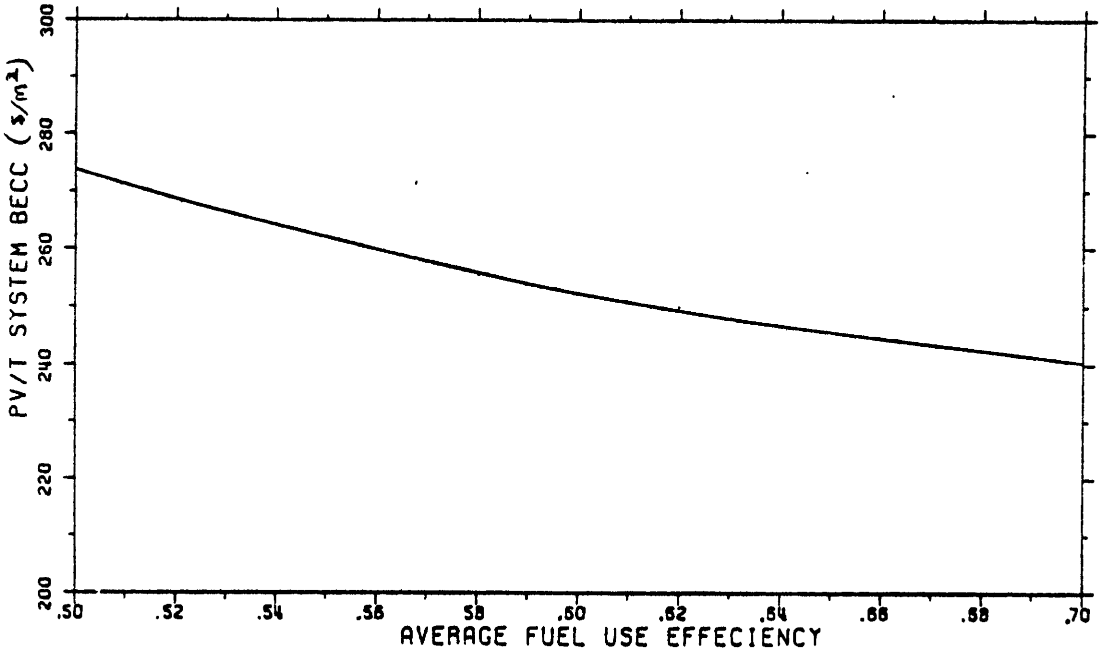


Figure 2-54

SENSITIVITY TO HOT WATER HEATER
AVERAGE FUEL USE EFFICIENCY

PV/T COLLECTOR SYSTEM
BOSTON OIL SYSTEM
ARRAY SIZE: 40 M²

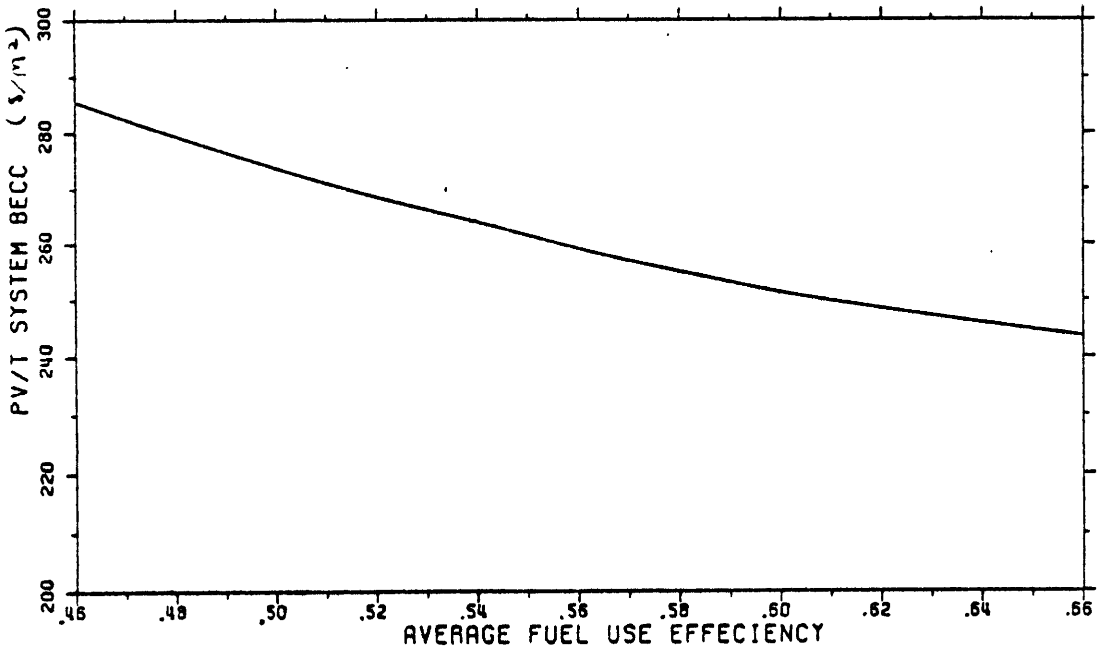


Figure 2-55

SENSITIVITY TO DOMESTIC BOILER
AVERAGE FUEL USE EFFICIENCY

PV/T COLLECTOR SYSTEM
BOSTON GAS SYSTEM
ARRAY SIZE: 40 M^2

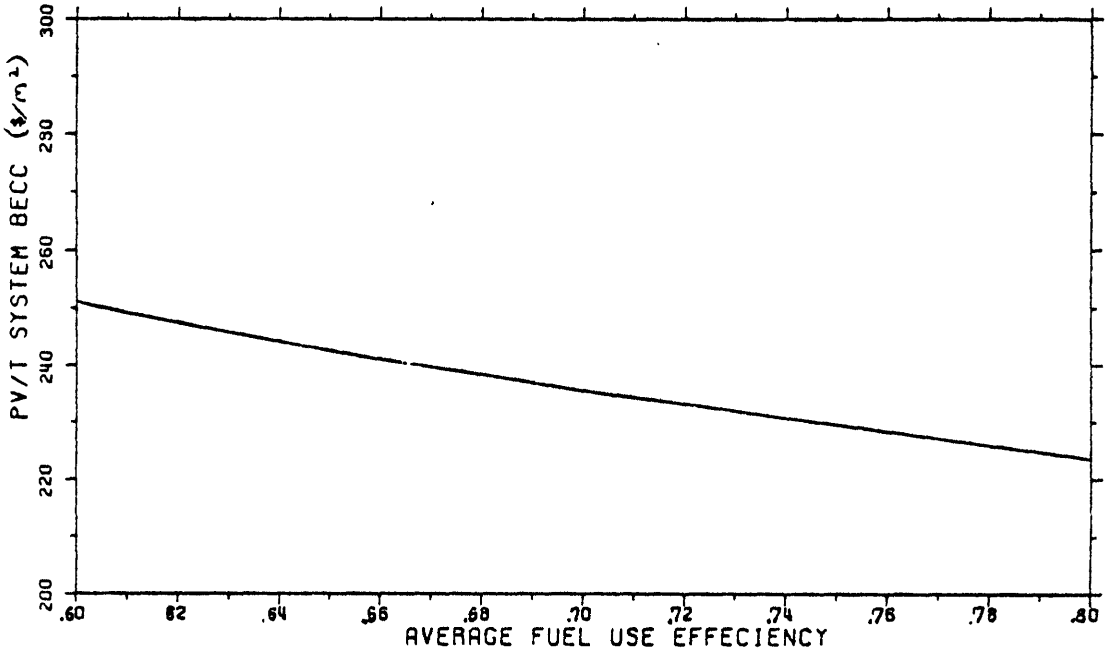
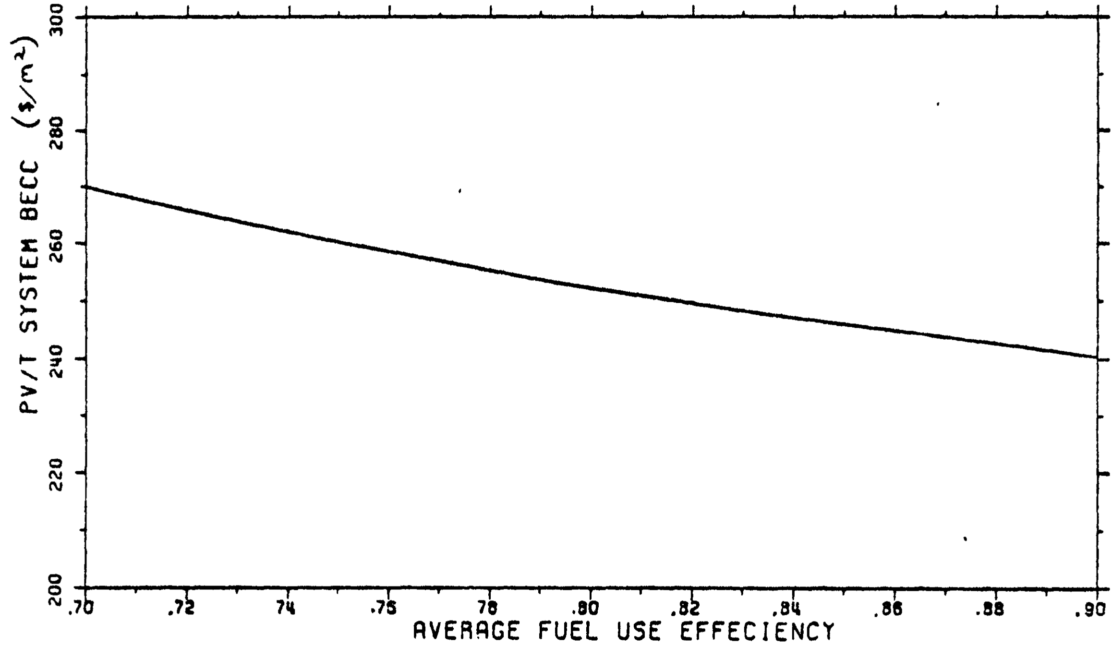


Figure 2-56

SENSITIVITY TO DOMESTIC BOILER
AVERAGE FUEL USE EFFICIENCY

PV/T COLLECTOR SYSTEM
BOSTON OIL SYSTEM
ARRAY SIZE: 40 M^2



IV.2 Market Parameter Sensitivity Studies

The impact upon system worth of changes in specific non-finance-related economic parameters is illustrated in Figures 2-57 through 2-59. The effect of increasing inflation, as shown in Figure 2-58, is to increase system worth. The reason for this is that future (constant dollar) mortgage payments are discounted at a higher (nominal) rate, whereas the effect of inflation upon the benefit stream cancels itself, i.e., nominal discounting of inflating prices. In Figure 2-59, the time of day rates were computed by holding the utility's operating revenues constant, and adjusting both the peak and base period price for electricity. These rates are not the result of any consistent methodology for rate-setting.

Figure 2-57

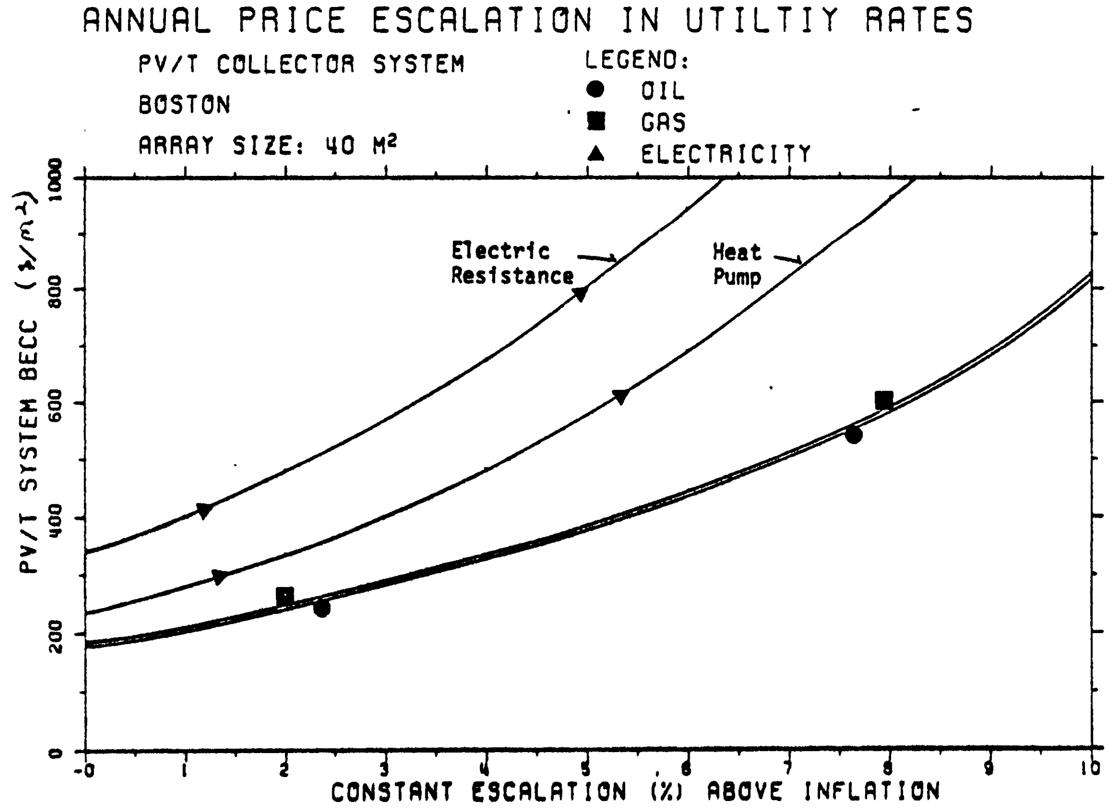


Figure 2-58

SENSITIVITY TO THE RATE OF INFLATION

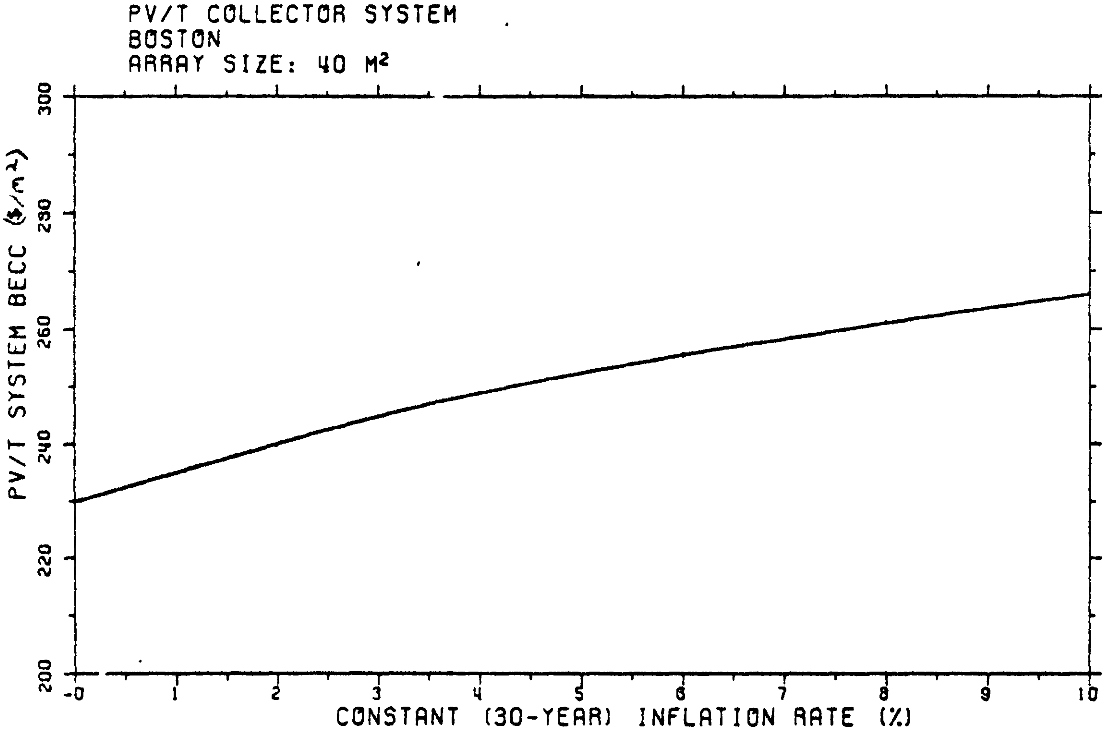
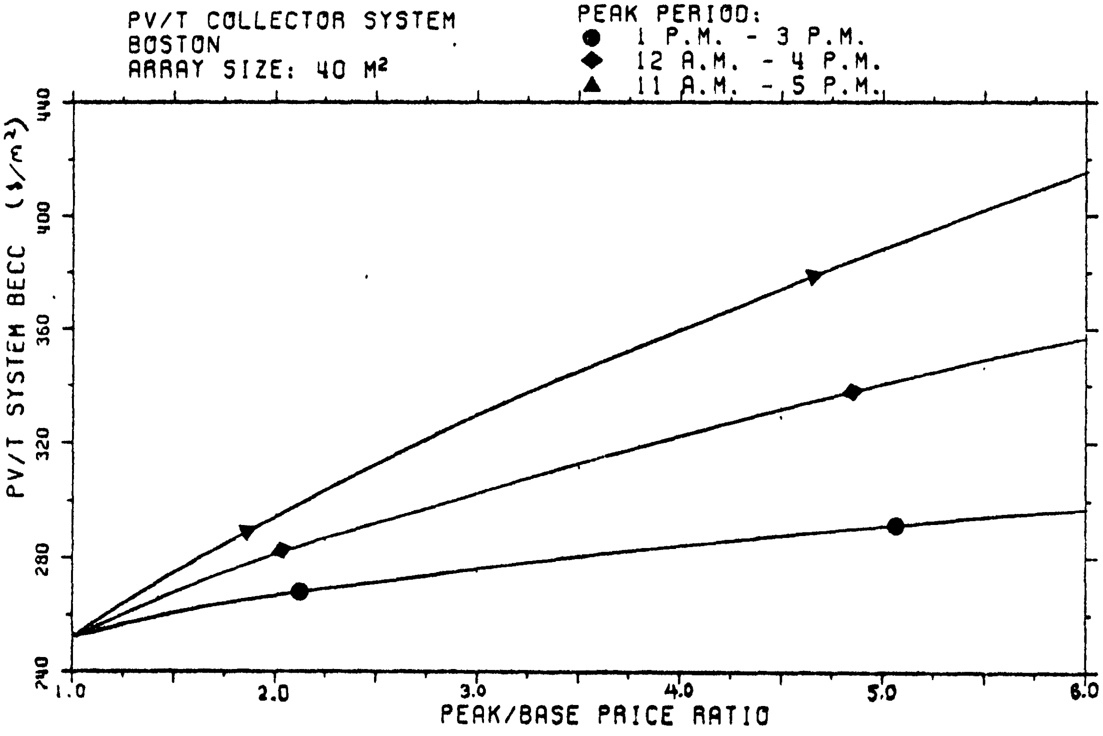


Figure 2-59

SENSITIVITY TO PEAK TO BASE PRICE DIFFERENTIAL IN TIME OF DAY ELECTRIC RATES



IV.3 Finance Parameter Sensitivty Studies

The impact of specific changes in finance parameters is depicted in Figures 2-60 through 2-64. Again, there are no surprises in terms of trends. In Figure 2-60, system worth declines as future benefits are discounted by the homeowner at higher rates. The higher tax brackets offer the investor large claims against mortgage interest charge losses, providing tax liability exists (as assumed in Figure 2-61). In terms of relative impact, the investment tax credit offers the most substantal boost to solar system economics.

Figure 2-60

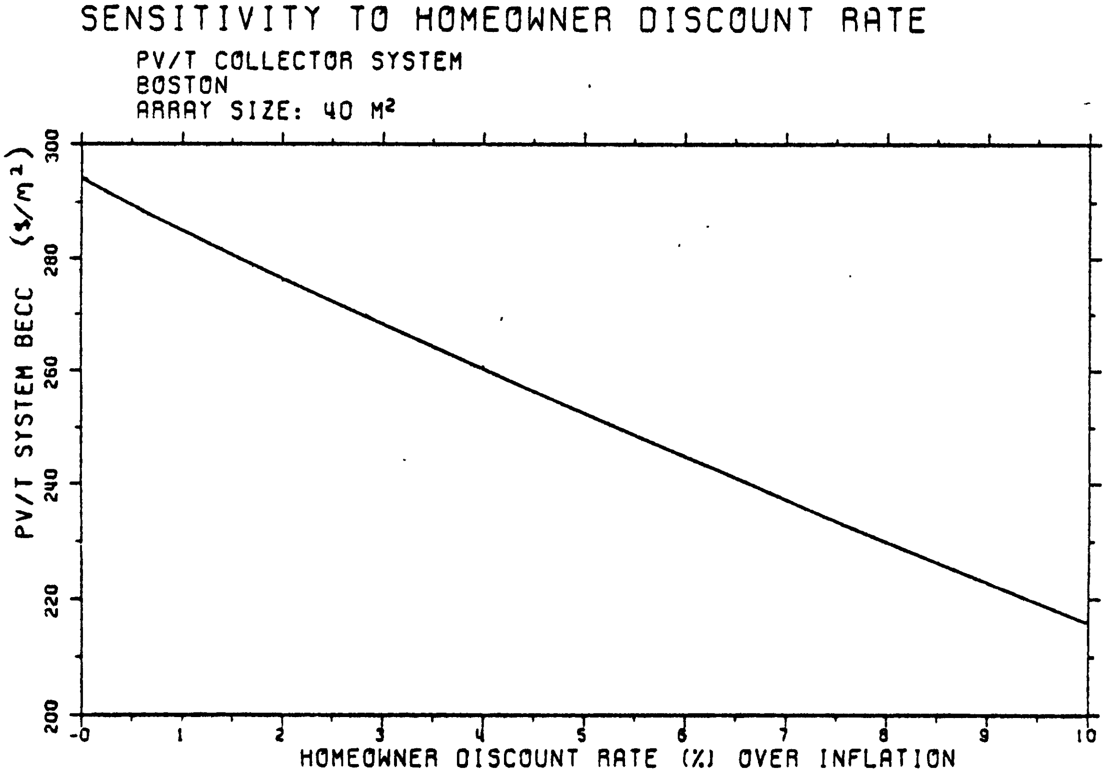


Figure 2-61

SENSITIVITY TO HOMEOWNER MARGINAL TAX BRACKET

PV/T COLLECTOR SYSTEM
BOSTON
ARRAY SIZE: 40 M^2

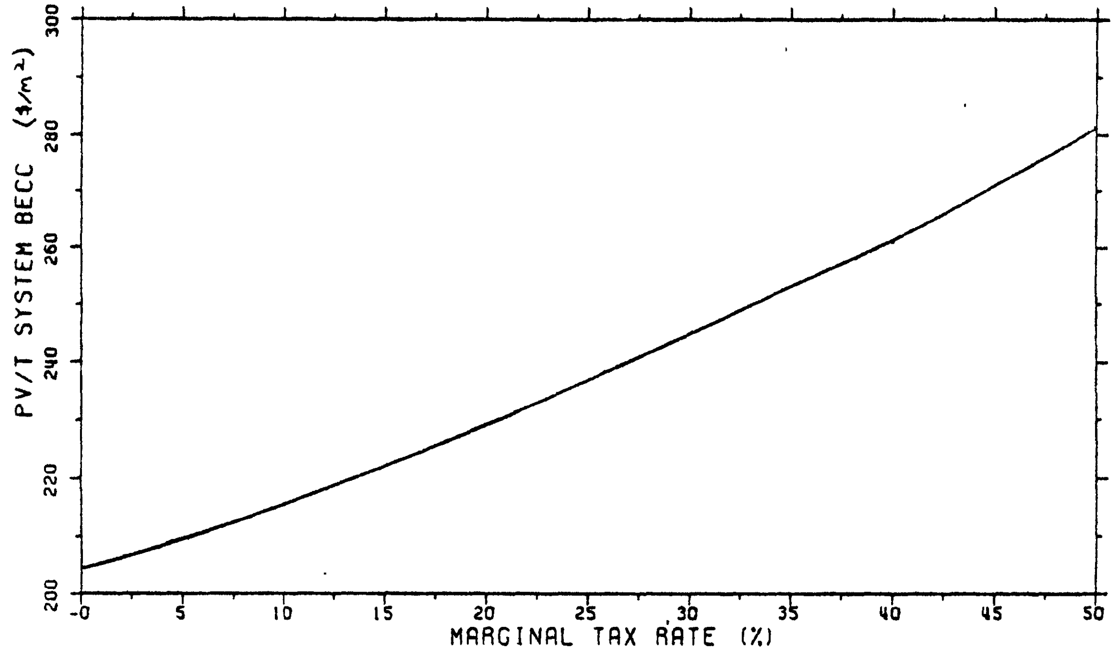


Figure 2-62

SENSITIVITY TO MORTGAGE INTEREST RATE

PV/T COLLECTOR SYSTEM
BOSTON
ARRAY SIZE: 40 M^2

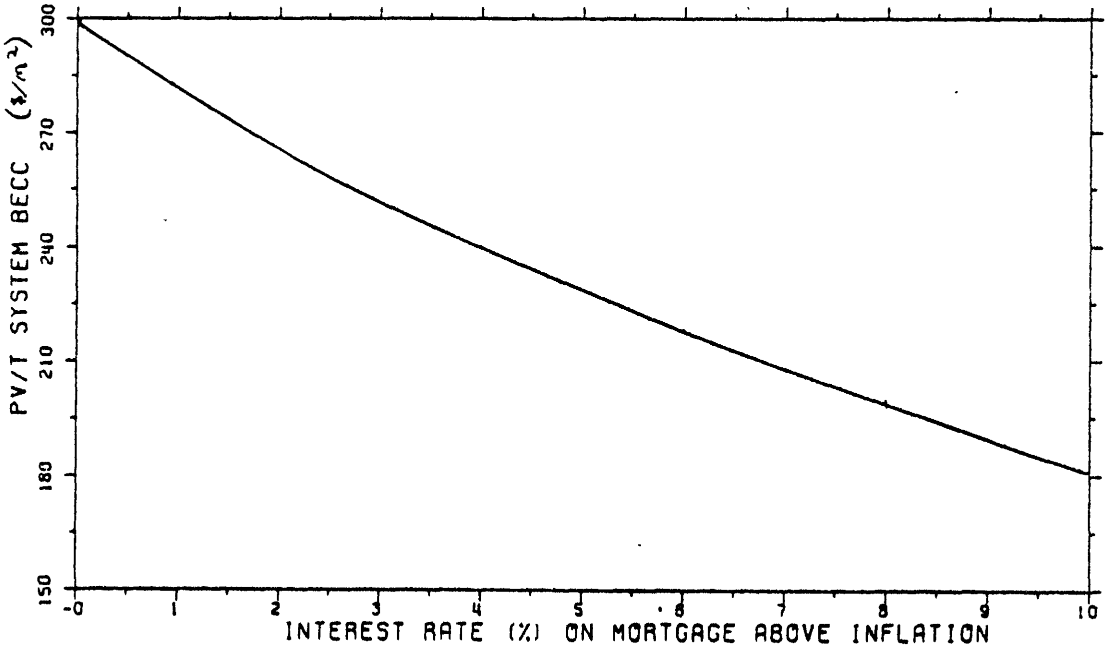


Figure 2-63

SENSITIVITY TO DOWN PAYMENT ON MORTGAGE

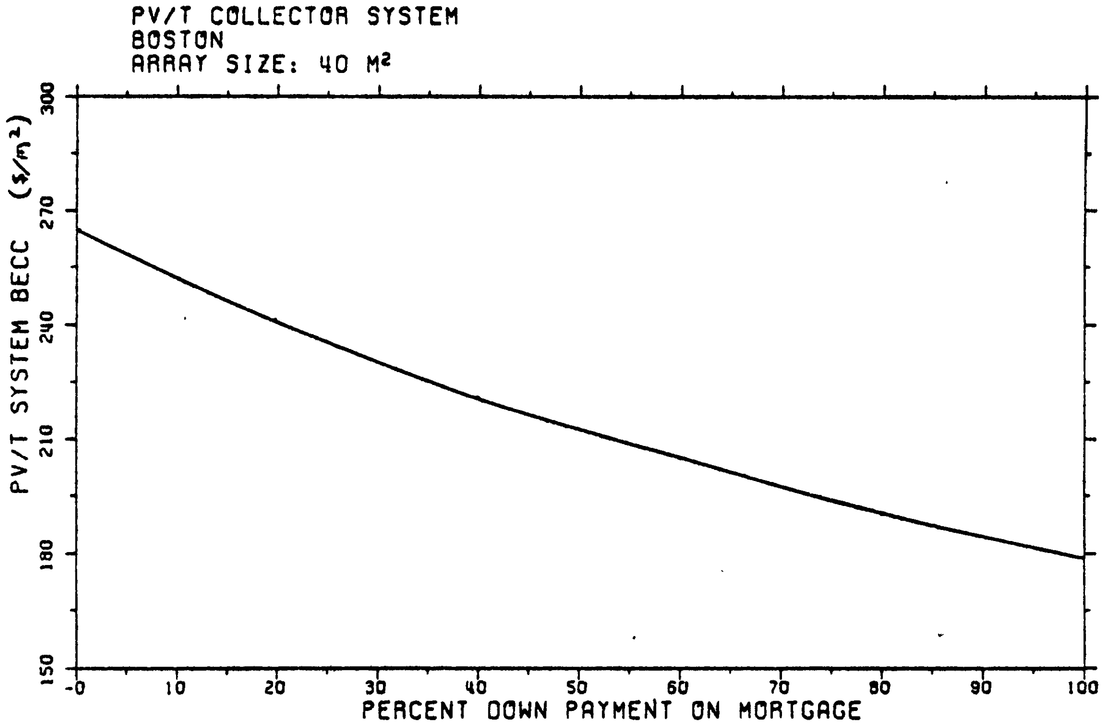
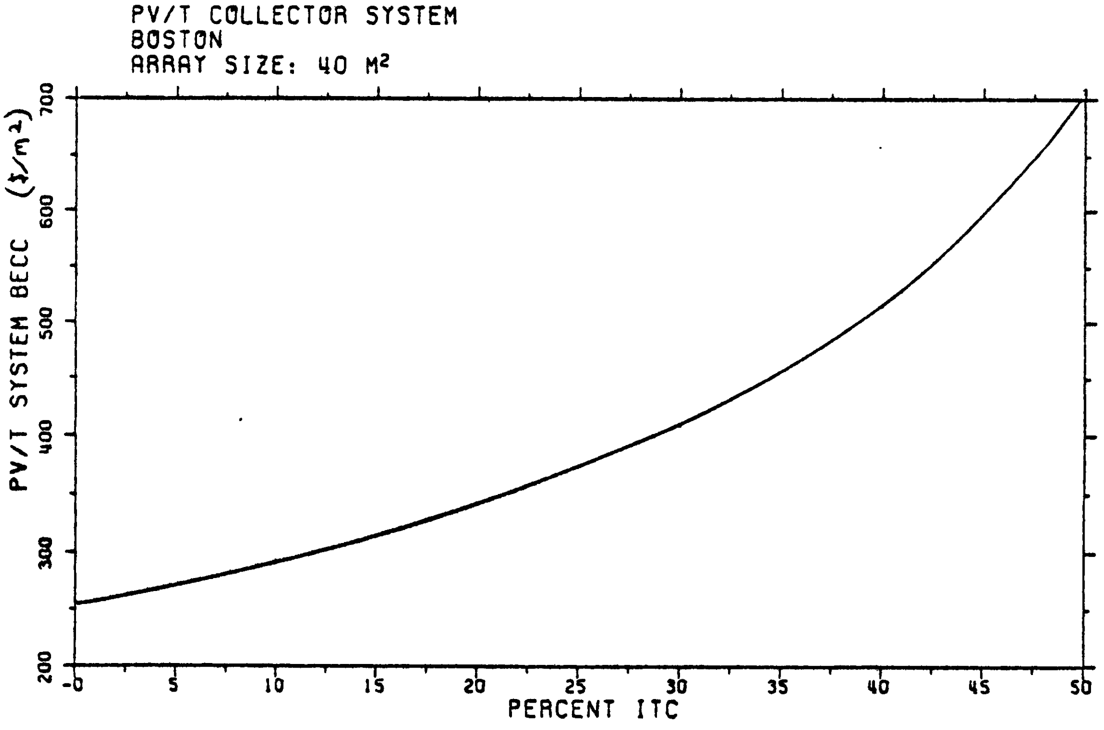


Figure 2-64

SENSITIVITY TO INVESTMENT TAX CREDIT
ASSUMING NO MAXIMUM CREDIT AND
ASSUMING NO LIMIT TO TAX LIABILITY



IV.4 Retrofit Application Analysis

A retrofit application was modeled for a Boston residence by estimating the load characteristics of an older home. Here we increased space heating and space cooling loads by a factor of 1.5 over the base case, and stochastic electrical loads by a factor of 1.2. In addition, we modeled gas and oil boilers and hot water heaters with efficiency ratings characteristic of today's units. The anticipated insurance costs for the residence was also increased, as reported by Cox (7). These changes are summarized as follows:

	Advanced Design (Base Case)	Retrofit
Oil Boiler AFUE	81 percent	70 percent
Gas Boiler AFUE	69 percent	60 percent
Oil Hot Water Heater AFUE	60 percent	45 percent
Gas Hot Water Heater AFUE	60 percent	50 percent
Annual Space Heat Load:	33.285 MBtu	49.904 MBtu
Annual Space Cooling Load:	4.019 MBtu	6.018 MBtu
Annual Insurance Costs:	$60 (NPV)	$80 (NPV)

Both a gas and oil backup system were modeled in this analysis along with a 40 m^2 PV/T collector system. The results are as follows:

	Advanced Design (Base Case)	Retrofit
Hot Water Heating		
Gas Displaced (Annual)	22519 ft^3	27802 ft^3
Gas Used	4992 ft^3	5991 ft^3
Oil Displaced	173 gal.	231 gal.
Oil Used	38 gal.	51 gal.
Space Heating		
Gas Displaced	28332 ft^3	48423 ft^3
Gas Used	19167 ft^3	33489 ft^3
Oil Displaced	185 gal.	319 gal.
Oil Used	125 gal.	220 gal.

Gas Backup	Base Case	Retrofit
Annual Levelized Bill w/o PV/T	$1373	1935
Annual Levelized Bill with PV/T	$ 640	949
Allowable Levelized Annual Cost at 5 percent discounting	$ 732	986
PV/T System Breakeven Capital Cost	\$253.38/m^2	364

Oil Backup	Base Case	Retrofit
Annual Levelized Bill w/o PV/T	$1357	1943
Annual Levelized Bill with PV/T	$ 628	937
Allowable Levelized Annual Cost	$ 728	1005
PV/T System Breakeven Capital Cost	\$251.86/m^2	

Clearly the increased thermal and electrical loads provide substantial improvement in system worth for the retrofitted residence. This is to be expected, since the marginal returns to satisfying increasing portions of a fixed load are certain to decline.

V. CONCLUSIONS

In this analysis we calculated the allowable costs for a PV/T liquid collector system of a specific design. We determined that the system breakeven capital cost for a combined collector is roughly twice that of PV-only in the 40-60 m^2 range, and nearly equal to side-by-side collector systems of both 1:1 and 3:1 PV to thermal area ratios, when the total collector area is greater than 40 m^2. This is true for all three northern locations. Below 40 m^2 total collector area, the system breakeven costs diverge, with side-by-side at 3:1 (PV to T) ratio lowest, side-by side at 1:1 (PV to T) ratio highest, and the combined collector roughly centered between the two. Breakeven capital costs vary only slightly between cities for the combined collector, where at 40 m^2 and for a gas backup system, the BECC is given by \$253/m^2, \$223/m^2, and \$210/m^2 for Boston, Madison, and Omaha, respectively. Breakeven costs decline in order of electric resistance, oil, gas, and heat pump serving as backup units, except in Boston where operating a heat pump is slightly more expensive than burning gas or oil, and the latter two are roughly equivalent in cost in that city (at 1986 expected prices).

In an extended analysis we determined that the following trends had a medium to large favorable impact on system worth:

- increase in average solar cell efficiency
- decrease in the efficiency of conventinal backup energy systems
- utility rate price escalations
- large peak to base time-of-day electricity price differentials with solar-coincident peak periods
- lowering of the homeowner's discount rate
- increasing the homeowner's marginal tax rate
- lowering of the mortgage interest rate
- minimizing the amount of mortgage down payment
- increase in the allowed investment tax credit.

Also in our extended analysis we determined that retrofit applications look appreciably better for solar systems due to 1) higher thermal and electric loads, and 2) less efficient boilers and hot water heaters. These conditions serve to take better advantage of solar availability. This analysis does not compare, however, the investment trade-off between an active solar system and other retrofit options such as conservation.

The results of this analysis paint an unclear picture for the future of this PV/T design. Computation of the allowable combined collector cost using the method described by Hoover (9) suggests an unlikeliness that this combined collector system would ever be competitive with side-by-side systems. Given that the costs for the thermal collector sportion of a combined collector would be roughly that of a stand-alone thermal collector, this method suggests that a manufacturer would be unable to afford the cost of adding photovoltaic cells, given competition with side-by-side systems. Here, combined collectors suffer from inferior operating efficiencies coupled with a mismatch of optimum sizing for the thermal and electrical components. These results are consistent with Hoover's analysis (9) of a southern residence.

These results appear at first glance to contradict the results of the breakeven cost analysis. Here we find for specific ranges of total collector areas that the costs allowed combined collectors exceed those allowed the side-by-side systems modeled. This range centers around 60 m^2 for Boston and 40 m^2 for Omaha. Outside of this range, one or the other side-by-side system shows higher allowable costs, the lower range dominated by higher proportional thermal component and the higher range looking for a lower proportion of thermal. This merely says that the thermal component of a separate PV + T system is optimally sized smaller than the electrical component. It also suggests that given further optimizing of the relative PV to T areas for the separate collector system in all ranges of total collector areas, the allowable costs will always be slightly above those of the combined collector system.

This brings us to a question which must ultimately be answered by those on the supply side. Will the total costs for a combined collector system be lower than those of separate collector systems A review of the previous figures reveals that the allowable cost difference is not significant, on the order of $\$10$-$\$30/m^2$. The costs of installation would likely favor the combined collectors, however roof credits would tend to offset this advantage. The combined collector system consists of all of the components that the separate configuration requires, but in addition must be equipped with a heat rejection unit. It should be noted, however, that the stand-alone PV system modeled in this analysis was a stand-off unit. Experience in the field has shown that overheating is a serious problem for integral mount designs. All costs associated with alleviating this problem must be accounted for on the allowable costs curve. If a stand-off design is used, this eliminates the roof credit. Thus, overheating of integral mount PV may be a point in favor of combined collector systems.

In summary, three means of identifying allowable costs have been demonstrated for a combined PV/T collector system in three northern locations. It is recommended that further funding of research and development of liquid collector PV/T (of design similar to that used in this analysis) proceed on the basis that proposals offer promise of developing systems $\$10$-$\$30$ m^2 less costly than an equivalent area of optimally proportioned separate collector systems.

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